REVIEW ON AN ANALYSIS OF CONDITION MONITORING METHODS AND DIAGNOSTIC PROCEDURES FOR ESTIMATING THE RESIDUAL LIFE OF POWER TRANSFORMERS

Vijay B. Desle[1], Dr. Dattesh Y. Joshi[2]

[1] Assistant Professor, Department of Electrical Engineering, Krishna School of Emerging Technology & Applied Research, Drs. Kiran & Pallavi Patel Global University, Vadodara – India

[2] Associate Professor, Head of Electrical Engineering Department & Director of Krishna School of Diploma Studies, Drs. Kiran & Pallavi Patel Global University, Vadodara - India

Abstract: Electrical networks' essential power transformers are costly to replace and challenging to improve in a functioning network. Numerous utilities keep an eye on the state of a power transformer's parts and use the data they gather to reduce outages and increase service life. Power transformers' core, windings, bushings, and tap changers are currently subjected to routine and diagnostic tests for condition monitoring, assessing ageing, and identifying problems. Methods for correlating the results of many routine and diagnostic tests have been developed in order to properly estimate the amount of life left and the likelihood of failure. This document discusses well-known tests, including dissolved gas analysis, oil characteristic tests, dielectric response, frequency response analysis, partial discharge, infrared thermograph test, turns ratio, power factor, transformer contact resistance, and insulation resistance measurements. It also takes into account commonly employed techniques for calculating lifetime probabilities, calculating health indices, and failure rates. The experts also emphasize the benefits and drawbacks of the techniques that are currently in use. This study compares a variety of strategies from academic and professional sources in a coherent framework.

Keywords: *Power transformers, Health index, Condition monitoring, Asset management, Diagnostic tests, Residual life.*

Introduction

Power transformers are typically the most expensive component in electric power systems, accounting for over 60% of high-voltage substation expenditure [2]. Utilities are compelled to appropriately evaluate the health of transformer assets due to the substantial investment and increasing demand for power. Transformers frequently encounter electrical, thermal, chemical, and environmental challenges when they are in operation. Transformer oil gradually produces a variety of catalytic aging by-products, including moisture, acids, and gases, as a result of these strains, defects, and chemical reactions. The aging products gradually weaken the insulation's mechanical and dielectric properties. Transformers are therefore more likely to fail as they get closer to the end of their service life. Furthermore, frequent overloading and short circuit events on old transformers can cause unanticipated early failures that harm customer relations by cutting off the power. Transformer failure can also result in expensive repairs and large revenue losses since it can harm the environment by leaking oil and endanger utility personnel by igniting fires and exploding.

This paper highlights the limits of individual methods and discusses established routine and diagnostic procedures for lifespan estimation and condition monitoring. After a predetermined amount of time, routine tests are carried out to evaluate the general state and verify the functionality of transformers. Diagnostic testing might be required if regular tests reveal any performance degradation. Furthermore, certain diagnostic tests are always carried out to verify the integrity of a transformer following any failure, commissioning, and transportation. Most utilities utilize the information from these tests to create health indices that show the state of operation and provide an estimate of remaining lifetime. To assist in developing a maintenance plan, this paper will be helpful to newly appointed maintenance engineers who will be handling the management of electrical power assets. On the other hand, a catastrophic fault could occur during the intervals between scheduled maintenance examinations. Utilities are encouraged by this restriction to switch from scheduled to condition-based maintenance [3,4]. When a transformer is subjected to condition-based monitoring, its test schedule is determined by taking into account the most up-to-date information available regarding its condition, which is derived from test outcomes. This suggests that a transformer deemed to be in bad condition is checked more frequently than it would be during planned maintenance. By better evaluating insulation, condition-based monitoring can help prevent unanticipated failures and save downtime and money that would otherwise be spent on planned repair. While online monitoring has become established for critical assets, condition-based monitoring does not imply online monitoring, which uses remote sensing to monitor the transformer in real time. The structure of this document is as follows: Standard diagnostic and statistical failure rate have been covered in Sect. 2. A brief summary of various routine and diagnostic testing is given in Section 3. The methods for calculating remaining service life have been covered in Sect. 4. The paper is concluded in Section 5.

2. Statistics on transformer failure

According to industry standards, the average expected working life of a power transformer is about 40 years [2]. After this time, it is widely accepted that the probability of catastrophic failure is very high. Different condition monitoring and diagnostic techniques are currently in use to improve the service quality and reduce the operating cost of an aged transformer. The age profile of power transformers of a leading utility company in Australia is shown in Fig. 1. Power transformer insulation deteriorates with increasing service time, increasing the probability of failure and decreasing the residual life.

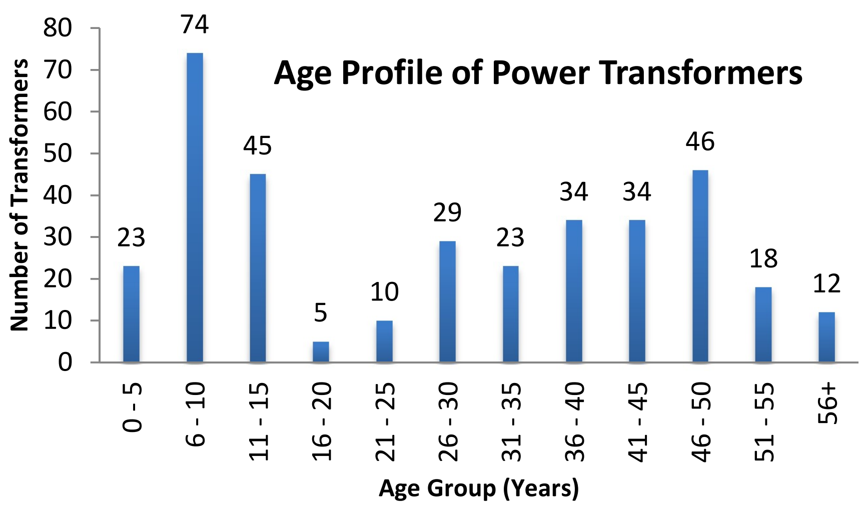

Figure 1- Age profile of power transformers

Based on the age profile, 110 out of 360 transformers have already exceeded their typical service life, and that number is expected to rise to 167 in the upcoming ten years. Accordingly, 31% of these transformers have already outlived the operator's projected lifespan based on the period of their service, and 16% more will fail in the next ten years. However, transformers that have outlived their estimated lifespan are functioning well and the rate of failure is lower than what the utilities had anticipated. Continuous condition monitoring is particularly important in order to prevent unexpected failures of these transformers in the near future and instead increase time-based maintenance.

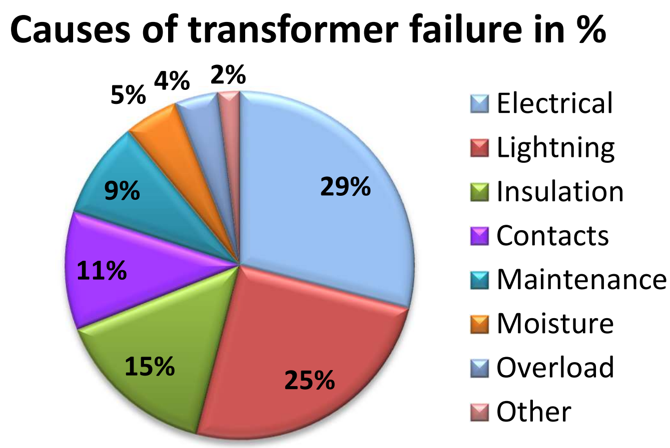

Figure 2 - Causes of Power transformer failure

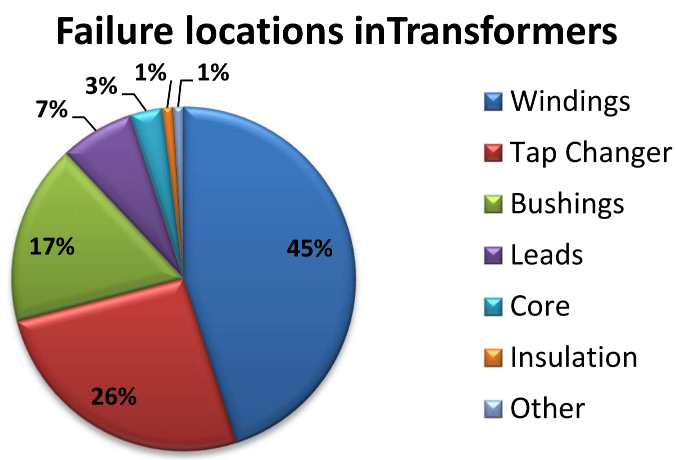

Figure 3 – Failure locations in Transformers

A variety of internal and external factors, including mechanical, thermal, and electrical ones, can impact the life expectancy and failure rate of transformers. Transformer failure is eventually caused by electrical stresses such as repeated overloading, lightning impulses, and switching surges that gradually weaken the insulation's dielectric strength. Operating temperature is raised by partial discharge (PD), increased contact resistance, and cooling system issues; mechanical deformation can result from transportation and short-circuit current. When moisture and contamination are added to mechanical flaws and thermal stresses, insulation ages more quickly and electrical failure occurs sooner. Fig. 2 [5] provides statistics regarding the most common causes of transformer failure. Bushings, tap changers, and other accessories also have a big impact on transformer failure, even if the main tank accessories are the main cause of failure.

Fig. 3 shows the statistics of the typical failure location based on a survey on 364 failures (>100 kV) that was recently carried out by CIGRE work group WGA2.37 [6]. Furthermore, their research on Europe reveals that 30% of transformer failures and 80% of bushing failures happen in the 12- to 20-year-old age range. This figure makes it clear that a transformer's integrity depends on a number of different parameters. Prioritizing the diagnostic tests according to each component's level of impact on transformer health is also crucial. Fig. 4 provides taxonomy of key diagnostic techniques for transformer condition assessment.

3. Power Transformer Condition monitoring and diagnostic tests

In electrical engineering, condition monitoring of transformers refers to the procedure of gathering and analyzing data regarding different transformer parameters in order to assess the quality of the transformers and forecast when they would fail. Utilities always anticipate operating power transformers continuously for the duration of their service lives with the least amount of incidental maintenance following installation and commissioning. Utilities typically perform a range of routine and diagnostic tests to evaluate the insulation state and mechanical integrity of each transformer in an effort to minimize unplanned outages and operational costs. The following sections have provided a quick overview of common and advanced routine and diagnostic testing.

3.1 DGA (Dissolved Gas Analysis)

A well-recognized and commonly used technique for power transformer status monitoring is dissolved gas analysis (DGA). Without stopping the service, it can locate defects such partial discharge, arcing, low-energy sparking, overheating, and hot spot detection early on [7]. Analyzing the combustible and noncombustible gases dissolved in transformer oil is a step in this process. Transformers frequently experience thermal, electrical, mechanical, and chemical flaws and stresses throughout their working lives, which result in a variety of fragments, aging, and polar oxidative products.

The molecular characteristics of oil-paper insulation are altered over time by a variety of chemical processes brought on by the interaction of fragments or aging products [8].
The reaction rate is also accelerated by the moisture and oxygen created by the oil-paper insulation, as well as by thermal dynamics. Transformer oil eventually produces and dissolves a variety of gases, including hydrogen (H_2), oxygen (O_2), nitrogen (N_2), carbon dioxide (CO_2), carbon monoxide (CO), methane (CH_4), ethylene (C_2H_4), ethane (C_2H_6), acetylene (C_2H_2), propane (C_3H_8), and propylene (C_3H_6). Many DGA methods, including Key Gas, Roger's Ratios, Duval Triangle, Doernenburg, IEC ratio, and single gas ratio, are currently in use to evaluate the state of oil and paper insulation and find problems indirectly from the gases [7]. DGA can identify 70% of common power transformer defects, according to CIGRE [9]. Operators are assisted in continuously monitoring the production and trends of gases produced by working transformers by an integrated gas monitoring system.

Comparing results from various techniques on the same sample, however, can result in contradictions, and it is unclear how to give one result priority over another. By cross-checking the errors, an integrated gas monitoring system and additional testing could help get over this restriction. While DGA can identify and categorize errors, it is typically unable to pinpoint the exact position of the fault. Operators must therefore add to the findings using additional diagnosing techniques. Here is a summary of the different DGA techniques.

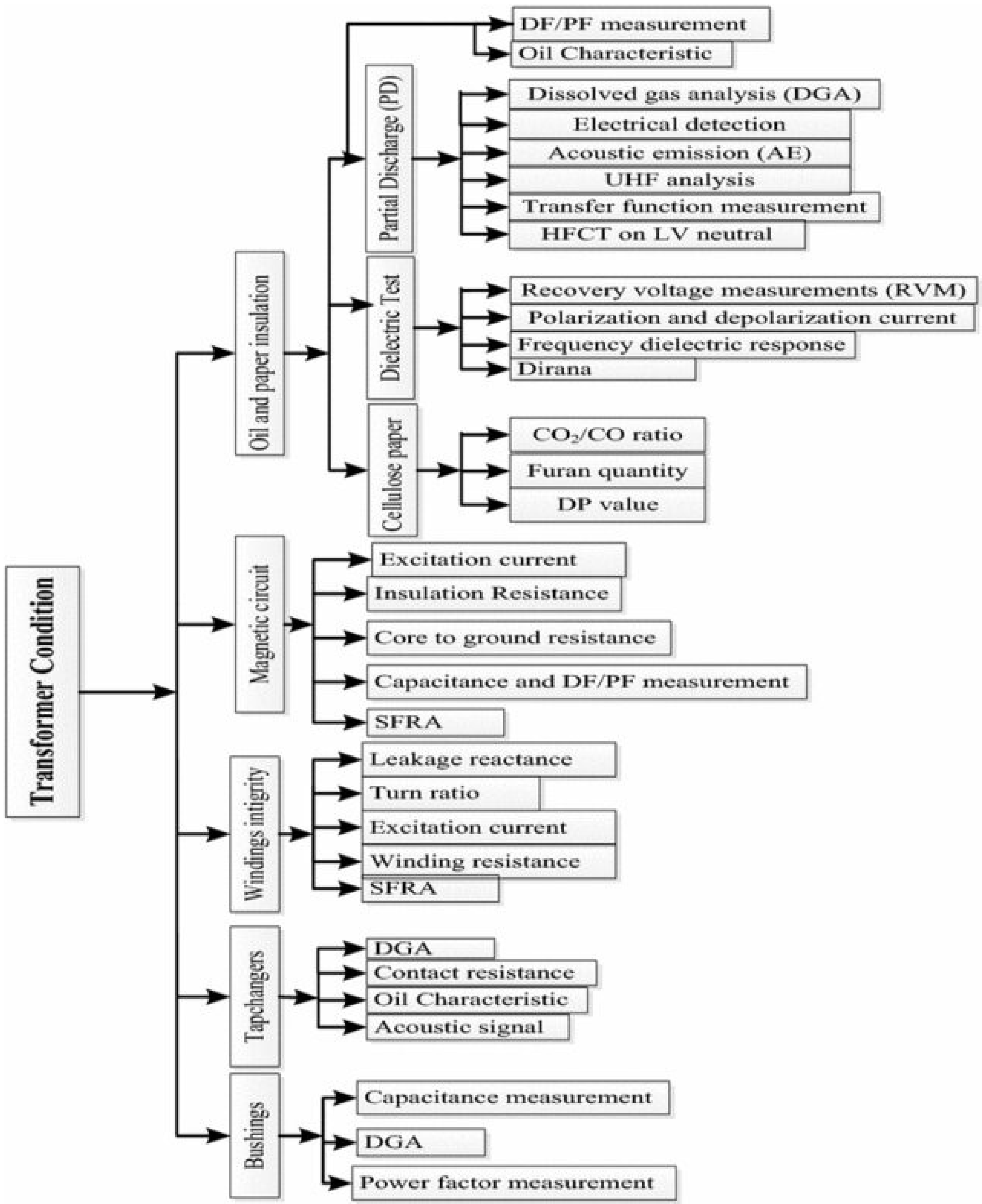

Figure 4 - Condition monitoring and diagnostic techniques [1]

3.1.1 Key gas analysis (KGA) method

The proportion of combustible gases is used by the Key Gas Method to diagnose defects. It offers a number of "templates" connected to common failure scenarios. Transformer oil overheating is indicated, for example, by 63% of ethylene and small amounts of ethane (19%)

and methane (16%) [10]. The cellulose is overheated if carbon monoxide makes up the majority of the gas (92%). Partial discharge is indicated by high hydrogen (85%) with a little amount of methane (13%) while arcing in oil is indicated by high hydrogen (60%) with a small amount of acetylene (30%). In real life, it is nearly hard to get precisely the right amounts of gases to fill these templates. Although the percentages are frequently lower, experience allows one to recognize trends and take action before a crucial point is reached. Therefore, the expertise and correlation abilities of the investigator have a major impact on the accuracy of KGA.

3.1.2 Roger's Ratios method

The Roger's Ratios technique (RRM) classifies and locates transformer faults using ratios of gas concentration. This approach makes use of the C_2H_2/C_2H_4, CH_4/H_2, and C_2H_4/C_2H_6 ratios. Table 1 displays the various electrical and thermal fault classifications, per RRM. There are situations where the estimated ratios do not fit into any of the Table 1 classes. Furthermore, over time, transformers typically produce gasses faultlessly. Consequently, one of the main drawbacks of the Roger's Ratios approach is the possibility of misclassification.

Table 1 Roger's ratios [10]

Case	$R_1 = CH_4/H_2$	$R_2 = C_2H_2/C_2H_4$	$R_5 = C_2H_4/C_2H_6$	Suggested Fault Diagnosis
0	> 0.1 to < 1.0	< 0.1	< 0.1	Unit normal
1	< 0.1	< 0.1	< 0.1	Low-energy density arcing—PD
2	0.1 – 1.0	0.1 – 3.0	> 3.0	Arcing-high-energy discharge
3	> 0.1 to < 1.0	< 0.1	1.0 to 3.0	Low temperature thermal
4	> 1.0	< 0.1	1.0 to 3.0	Thermal <700º C
5	> 1.0	< 0.1	> 3.0	Thermal >700º C

3.1.3 Gas patterns method

Methane (CH_4) and ethylene (C_2H_4) are the main gases that are utilized to identify bad conductor connections in accordance with the gas patterns approach [11]. The series resistance may rise as a result of the conductors' weakened contact over time as a result of the transformer's vibration. Consequently, the current flow causes the contacts to overheat, producing hot metal gases like (C_2H_4) and (CH_4). Furthermore, a transformer naturally contains a tiny amount of catalytic metals, such as dibenzyl disulphide (DBDS), iron, copper, zinc, and aluminum [11]. Dibenzyl disulphide (DBDS) typically has a concentration in transformer oil of 40–65 mg/kg.
As the temperature rises, the concentration of DBS falls. Copper sulphide is created when the sulfur in DBS reacts with copper at high temperatures [11]. The concentration of copper sulfide and DBS can be used to evaluate the quality of transformer internal connections because this reaction is entirely temperature dependent.

3.1.4 Doernenburg method

Doernenburg is a four gas ratio technique that can identify faults and PD activity in a transformer. It is based on five distinct critical gases (H_2, CH_4, C_2H_2, C_2H_4, and C_2H_6). This method has a high accuracy, but only if a sizable quantity of essential gases is generated. Table 2 displays the summary of the link between the four gas ratios and faults.

Table 2 Gas ratios for Doernenburg method [12]

Ratio 1 CH_4/H_2	**Ratio 2** C_2H_2/C_2H_4	**Ratio 3** C_2H_2/CH_4	**Ratio 4** C_2H_6/C_2H_5	**Suggested Fault Diagnosis**
0.1–1.1	0.75–1.0	0.3–1.0	0.2–0.4	Thermal decomposition
0.01–0.1	Not significant	0.1–0.3	0.2–0.4	Corona (low intensity PD)
0.01–0.1	0.75–1.0	0.1–0.03	0.2–0.4	Arcing (high intensity PD)

3.1.5 Duval Triangle Method

The three axes of the Duval Triangle Method (DTM), a coordinated graphical technique, represent the percentages of CH_4, C_2H_4, or C_2H_2 from 0% to 100% [1]. It is commonly utilized by utilities because of its precision and capacity to identify a huge number of issues.

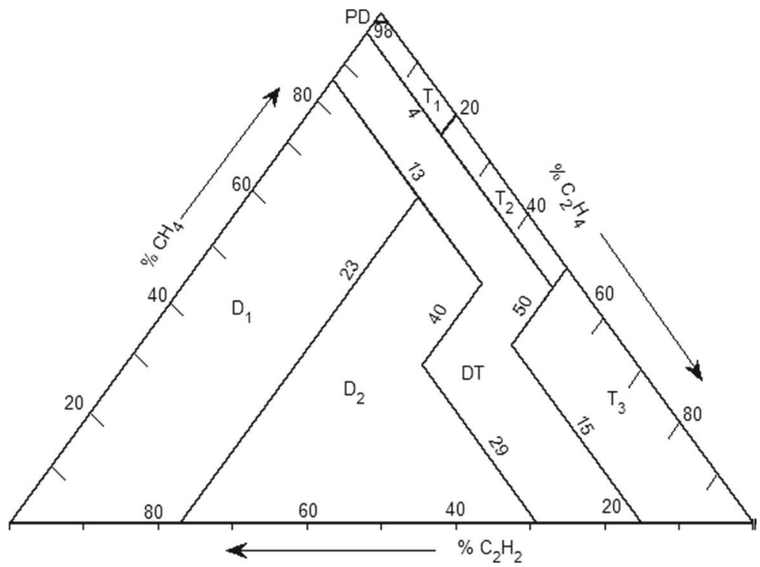

Figure 5 Duval Triangle [14]

The entire triangular area in DTM has been split into seven fault regions, which are designated as follows: PD, D1, D2, and DT, as shown in figure 5. D1 and D2 indicate partial discharge, low-energy and high-energy discharges, respectively, T1 and T2 indicate thermal faults below 300^0C, 300–700C, and 700 ◦C, and DT indicates a combination of thermal and electrical faults. Near the borders between adjacent sections, there is a possibility of misdiagnosis even though this method always provides a diagnostic [14].

The PD and thermal fault cannot be precisely detected using the traditional Duval Triangle. Duval created Triangles 4 and 5 for transformers filled with mineral oil in order to get around the restriction. The gases H2, CH4, and C2H6 present the axes in Triangle 4. Triangles 4 must be utilized for additional explanation if the fault classification using the traditional triangular technique is a PD or a thermal fault (T1, T2) [15]. Gas concentrations of CH4, C2H4, and C2H6 are used in Triangle 5; these concentrations are created especially for high-temperature faults (T2, T3). Triangle 5 should only be utilized if Triangle 1 determined that the fault was T2 or T3 in order to obtain more information about the thermal faults. For electrical faults D1 or D2, none of the Triangles 4 or 5 should be utilized. In actuality, Triangles 4 and 5 occasionally generate classifications that are in conflict with one another. Additionally, there is an unclassified area in every triangle. As a result, the expert's experience, which is bolstered by additional ratio techniques, determines the accuracy of fault classification. Furthermore, it cannot pinpoint the location of a fault or quantify the discharge, particularly for small discharges like the pico-coulombs (pC) range; it can only anticipate the amount of discharge from changes in gases. Over the past ten years, researchers have analyzed DGA data using a variety of artificial intelligence (AI) techniques, including fuzzy logic, support vector machines (SVM), and artificial neural networks (ANN), to track performance, identify faults, detect insulation degradation, and determine the health index of transformers [16–20]. The DGA data sets may now be analyzed in multi-dimensional spaces to extract the gas pattern for defect identification and classification thanks to AI techniques. Additionally, AI can reduce decision-making mistake by integrating various components and handling the nonlinearity of gas production, which is typical in field measurements.

3.2 Oil quality test

Testing the quality of insulating oil is a popular technique for evaluating the state of transformers that are still in use. Transformer oil condition monitoring has proven to be quite successful since the oil condition directly affects the transformer's performance and service life. The properties and state of the oil change over the service term as a result of oxidation, chemical reactions, and varying stressors (chemical, thermal, and electrical). Numerous physical, chemical, and electrical tests, including dielectric breakdown voltage (DBV), power factor, interfacial tension (IFT), acidity, viscosity, color, and flash point, are carried out in order to measure these changes and determine their severity. DBV evaluates oil's ability to sustain electrical stress without failing [21]. The oil's dielectric losses are measured using the power factor or dissipation factor test [22]. The test can determine the level of impurities in the insulating oil because it is highly sensitive to soluble polar pollutants and aging products. Different kinds of acids are created in transformer oil during operation as a result of oxidation products and air pollution [23].

The acids break down various aspects of the oil, as do oxidation products, moisture, and solid impurities. As a result, the acidity test is crucial for determining the state of oil. IFT calculates the force of attraction between water and oil molecules, which can be used to determine how much moisture is present in oil [5]. The soluble polar impurities and degradation products that impact the insulating oil's electrical and physical characteristics can be estimated with the aid of the IFT value. New transformer insulating oil typically exhibits high IFT values between 40 and 50 mN/m, but an oil sample with IFT <25 mN/m denotes a serious situation [24]. A comprehensive guide to IFT measuring may be found in [25]. One element that significantly affects heat transfer in transformers is the viscosity of the oil. The viscosity of pure oil reduces as the temperature rises. As a result, the insulation loses strength. To regulate the viscosity of insulating oil, which may be determined by applying a COMPASS force field, several nano-particle kinds, including SiO2, Al2O3, and ZnO, can be added [26]. Furthermore, impurities in service-aged oil are found using tests including color and flash point [27]. To determine each transformer's status and plan maintenance (reclamation or replacement) to prevent expensive shutdown and early failure, several outcomes are connected. Table 3 displays the insulating oil classification provided by IEEE C57.106-2006, which is based on transformer rated voltage and variable test conditions.

Table 3 Classification based on oil test parameters

	$U \leq 69$ kV	69 kV < U < 230kV	230kV ≤ U	Classification
Dielectric strength (kV/mm)	≥ 45 35 – 45 30 – 35 ≤ 30	≥ 52 47–52 35–47 ≤30	≥60 50–60 40–50 ≤40	Good Fair Poor Very poor
Interfacial tension (dyne/cm)	≥ 25 20 – 25 15 – 20 ≤ 15	≥30 23–30 18–23 ≤ 18	≥60 50–60 40–50 ≤ 40	Good Fair Poor Very poor
Neutralization number (acidity)	≤ 0.05 0.05 – 0.1 0.1 – 0.2 ≥ 0.2	≤ 0.04 0.04 – 0.1 0.1 – 0.15 ≥ 0.15	≤ 0.03 0.03 – 0.07 0.07 – 0.1 ≥ 0.10	Good Fair Poor Very poor
Water content (ppm)	≤ 30 30 – 35 35 – 40 ≥ 40	≤ 20 20 – 25 25 – 30 ≥ 30	≤ 15 15 – 20 20 – 25 ≥ 25	Good Fair Poor Very poor
Dissipation factor at 50 Hz (25 ºC)		≤ 0.1 0.1 – 0.5 0.5 – 1.0 ≥ 1.0		Good Fair Poor Very poor

3.3 Infrared thermograph test

Transformers' external surface temperature can be seen using infrared thermography, a rapid and non-destructive imaging technique, without affecting the transformers' ability to function [28]. Transformers typically operate at temperatures between 65 and 100 ºC [29]. Numerous factors, such as short-circuit current, excessive winding resistance, poor contact in the cable/clump joint, oil leaks, and malfunctioning cooling systems, can cause a transformer's operating temperature to increase. The pace at which insulation ages rises with rising temperatures. At 6 – 8 K (Kelvin), the insulation's aging rate doubles from the reference value, rapidly reducing its remaining working life [5]. A severe condition that cuts the design life in half is a temperature increase of 8 to 10 ºC from the nominal value [5]. A transformer will fail right away if the temperature rises by 75 ºC above its typical level, claims [30]. The elevated temperature can be a sign of a cooling system issue or a core, winding, bushing, or joint issue. Infrared thermography transforms the targeted surface's infrared radiation into color-coded pattern images in order to detect flaws. The test is able to visualize the temperature differential at joints and surfaces and localize the hot sport. A DGA on the same transformer or comparison with historical records can be used to confirm the test result. As a result, this technique can be utilized in conjunction with DGA as an initial fault detector. Nevertheless, a transformer tank's internal temperature cannot be detected by a thermograph [31]. Table 4 provides a summary of the infrared thermography-based heating severity classification.

Table 4 Heating severity classification [31]

Increased temperature °C	Classification
0 – 9	Attention
10 – 20	Intermediate
21 – 49	Serious
> 50	Critical

3.4 Excitation current test

Short-circuited turns, ground faults, core de-laminations, core lamination shorts, shoddy electrical connections, and load tap changer (LTC) issues are all detected by this test. This test is carried out by energizing the high-voltage (HV) side while maintaining the LV neutral grounded and all other terminals floating since the magnetizing current magnitude in the HV winding is lower. If there is a ground fault, a significant amount of current will flow into the HV side with low excitation voltage because of the grounded neutral. The single phase voltage and magnetizing current magnitudes, along with their phase angle, are measured during this test [32]. To find flaws, the measured value is compared to previous tests or other stages. A deviation of more than 5% between phases for an excitation current rated at 50 mA indicates short-circuited turns, ground faults, core de-laminations, core lamination shorts, poor electrical connection, and LTC issues, while a divergence of more than 10% indicates an internal fault [5]. This test must be performed prior to any direct current test since the residual magnetism affects the test outcome.

3.5 Power factor/dielectric dissipation factor test

Transformer windings, bushings, and oil tanks can all have their insulation quality examined using the dielectric dissipation factor (tan δ) test. A leakage current with reactive (capacitive) and resistive components begins to flow when an alternating voltage is placed across the insulator. While the capacitive current depends on frequency, the resistive component's amplitude is influenced by moisture, aging, and conductive impurities in the oil. The dissipation factor is the ratio of capacitive to resistive current. The overall leakage current and the capacitive current are nearly similar at low frequencies. This test is therefore also known as the power factor test. Depending on the transformer's rating, the value of tan δ for new oil at 90 °C could range from 0.010 to 0.015, per IS-1866.The following formula can be used to construct a mathematical relationship between power factor and tan δ [33].

$$\cos\theta = \frac{\tan\delta}{\sqrt{1+(\tan\delta)^2}} \qquad Or \qquad \tan\delta = \frac{\cos\theta}{\sqrt{1+(\cos\theta)^2}} \qquad (1)$$

The dielectric losses of insulation, including bushings, are measured in Watts using contemporary testing instruments such as the DobleM4100. An insulation problem is indicated by a value greater than 0.5% tan δ deviation, and an impending failure is highly likely if the value is greater than 2% [4]. On the other hand, PD may also be indicated by a larger tan δ value.

3.6 Polarization index measurement

Depending on the insulation classes (A, B, or C) and winding components, one popular technique for evaluating the dryness and cleanliness of windings solid insulation is the polarization index (PI) measurement [34]. After applying the test voltage to evaluate the insulation state, API measurement calculates the ratio of 10-min resistance to 1-min resistance [35]. Insulation resistance (IR) measurement is significantly impacted by winding temperature. However, since PI is based on the ratio of two resistances, winding temperature has a negligible effect during the 10-minute test. The PI value steadily drops as insulation becomes more wet and contaminated. [34] states that insulation with a PI between 1.5 and 2 is considered dry, insulation with a PI between 1 and 1.5 is considered dirty or damp, and insulation with a PI less than 1 indicates extreme humidity and pollution. Additionally, cleaning the insulation is advised if the PI value drops by 25% quickly from a prior test [34]. Despite being a very rapid and easy testing approach, it is unable to identify insulation degradation brought on by aging and stress over time.

3.7 Capacitance measurement

Capacitance measurement is used to identify gross winding movement and evaluate bushing condition. Electrically, a transformer's bushings are comparable to several series capacitors. The capacitance between the bushing conductor and the dielectric dissipation factor (DDF) tap is often referred to as C1, and the capacitance between DDF and ground is commonly referred to as C2. Bushings often last for thirty years. Any issues with the bushing, such as moisture intrusion or resin-bonded paper cracking, would raise the capacitance value and shorten its service life. As a result, bushing condition can be determined by measuring capacitance. According to [5], moisture intrusion accounts for roughly 90% of bushing failures. Capacitance between windings and between individual windings and the main tank can also be measured using this technique. The mechanical deformation of the windings and core can be detected by any variation in the capacitance value. A more sensitive method, like transfer function measurement and SFRA, may be employed in addition to capacitance testing because this test is less sensitive and only detects the gross deformation of windings.

3.8 Transfer function measurement

One of the recognized techniques for predicting the amount of moisture in solid insulation [36] and identifying mechanical issues such as winding displacement and deformation brought on by short-circuit current, switching impulse, and transportation [37–39] is the measurement of the transfer function (TF). The ratio of an input terminal's current to its voltage, or the ratio of output to input voltage on the same phase, is used to calculate the transfer function, a frequency-dependent quantity. A known voltage is typically provided to the HV terminals during TF measurement, and the resulting input current is measured from the same side as the voltage on the matching LV winding. A thorough test protocol for measuring TF can be found in [37]. The traditional leakage reactance measurement is unable to detect winding axial and radial buckling, while the TF measurement is sensitive enough to do so. Additionally, TF measurement has both online and offline modes and can describe problems without opening the unit [38, 39].

3.9 Tap changer condition

Despite changes in the load, a transformer's load tap changer (LTC) controls the voltage. A tap changer's insulation is made of a variety of materials, including oil, fiber glass, cardboard, and imitation resin. A tap changer failure could cause adjacent transformers to fail catastrophically. According to the authors of [5] and [2], respectively, tap changer malfunction accounts for 30 and 40% of transformer failures; the exact percentage may vary based on the manufacturer, kind of tap changer, frequency of operation, and maintenance. In contrast to the main tank, a certain quantity of flammable gas generated by LTC operation is normal in the tap changers. The breathing system determines how gasses are trapped. While gas rapidly vents from a free breathing system, the majority of gases can be trapped in a sealed LTC [40]. However, it is challenging to evaluate the state of LTC directly from DGA due to the lack of guidelines and the inadequate adoption of standards [2]. In order to evaluate the state of the tap changer and its insulation, a number of tests are conducted, including DGA, oil quality, contact resistances, and acoustic signals. At the same time, the number of operations, temperature, and motor current are tracked.

3.10 Cellulose paper insulation tests

About 90% cellulose, 6-7 % hemicelluloses, and 3-5 % lignin with lengthy chains of glucose rings make up the solid insulation (paper) found in transformers [33]. This paper aims to hold the windings in place while also offering mechanical support and insulation against stresses caused by inrush and short circuit current. The quantity and length of glucose rings in the paper affect its tensile strength and dielectric characteristics [4]. Age, stress, and loading patterns cause the paper's electrical and mechanical qualities to deteriorate with time, producing a variety of chemical compounds and byproducts such as water, acid, and gases (CO and CO_2). These byproducts are employed in a number of diagnostic methods to evaluate the state of paper insulation, including furan analysis, degree of polymerization (DP), and CO_2/CO ratio. A review of all three approaches is provided below.

3.10.1 Ratio of CO_2 and CO

The CO_2/CO ratio can be used to evaluate the state of paper insulation. Different proportions of flammable gases, including CO_2 and CO, are always created in the transformer and dissolved in the oil during the service period, usually without any faults. Paper can produce carbon oxide gases (CO_2 and CO) as a result of cellulose overheating, poor connections, and issues with the transformer cooling system. However, these gasses can also be produced by oil degradation because of various flaws [5]. Insulation exposed to the air may break down immediately if the CO_2/CO ratio is greater than 10, whereas cellulose degrades more quickly if the CO_2/CO ratio is less than 5. The identification of gas sources is essential for appropriate maintenance. The sources cannot be identified using the CO_2/CO ratio approach. One of the main drawbacks of the CO_2/CO ratio approach is the possibility of an incorrect diagnosis. Other tests, such furan analysis and the DP, are advised in addition to analysis of other important gases in order to get over this restriction.

3.10.2 Furan analysis

Furan analysis is a post-diagnostic, integral, non-periodic method that may evaluate the state of the cellulose paper inside transformers without causing service interruptions. The following kinds of furanoid compounds, which are partially soluble in oil, are produced when the glucose rings of cellulose degrade due to age, loading patterns, and chemical reactions: 2-furfural (2-FAL), 5-hydroxy methyl-2-furfural (5-HMF), 5-methyl-2-furfural (5-MEF), 2-furfurol (2-FOL), and 2-acetylfuran (2-ACF) [33]. A partition between the solid insulating inter phase and the oil is created by the generated furanoid chemicals [41].

Temperature affects the rate of furanoid compound synthesis, as do catalytic ageing byproducts including moisture, acids, oxygen, and CO that are created by a variety of defects and accelerate the rate at which paper degrades [5]. These furanoid chemicals breakdown in the insulating oil and cause color changes over time. If there are other catalytic ageing by-products present and the oil color changes significantly, furan analysis is advised [31]. As furan increases, cellulose paper gradually loses its mechanical strength. This can be measured using gas chromatography (GC), mass chromatography (MC), or high-performance liquid chromatography (HPLC) on an oil sample that has been collected in accordance with IEC method 61198 or American Society for Testing and Material (ASTM D5837) [42,43].

A thorough HPLC method for measuring furan can be found in [44]. Additionally, transformers' remaining lifespan can be estimated using the measured furan. The transformer's electrical integrity is at risk if the paper's strength is diminished to the point where it can no longer support the windings mechanically. Compared to other furanoid chemicals, furan is relatively stable and extremely sensitive to the aging of paper. Furan is primarily analyzed by academics since it steadily rises with paper aging. This method's primary drawback is its inability to precisely determine the state of solid insulation before a transformer's insulating oil is changed or recovered. Table 5 displays the furan-based thresholds for analyzing the aging of paper insulation.

Table 5 Displays the furan-based thresholds for analyzing the aging of paper insulation.

Furaldehyde (ppm)	Service life (years)
0 – 0.1	< 20
0.1 – 0.25	20 – 40
0.25 – 0.5	40 – 60
0.5 – 1.0	> 60
> 1.0	-

3.10.3 Degree of polymerization

Another reliable technique for evaluating the condition of paper insulation is the degree of polymerization (DP). The complex carbon, hydrogen, and oxygen substance known as transformer paper ($C_5H_{10}O_5$) is made up of glucose monomer molecules joined in a unique way to generate cellulose. The glucose rings weaken and begin to shatter as the insulation ages. In DP, the integrity of the paper insulation is estimated by measuring the length of the rings of glucose molecules [45]. Paper samples are taken from various locations around the windings, including the hot spot area, which is often found in the center of the windings, in order to quantify DP. It is not feasible to take paper samples from a live, free-breathing transformer, and doing so could damage the transformer or result in its total failure [46]. Paper samples are thus taken from the de-energized transformer and subjected to molecular weight estimate techniques such as gel permeation chromatography (GPC) or viscometry. By averaging the length of cellulose chains according to their viscosity, the viscometry method calculates the DP value [47, 48]. Variations in ambient temperature and the oxidative degradation of the samples affect this method's accuracy [49, 50]. Ali demonstrated in [51] that whereas viscometry can only roughly determine the length of a cellulose chain, GPC has a higher potential than viscometry to provide more comprehensive and actionable information regarding cellulose aging. By measuring the shift in the cellulose paper's molecular weight distribution, a DP value is determined in GPC. GPC can identify a slight cellulose degradation through the chromatogram because it is highly sensitive to molecular weight [50]. A comprehensive sample and testing procedure for GPC can be found in [50]. The reason furan analysis is more popular than DP is because it involves intrusive sampling. The furan test can readily determine furan from an in-service transformer's oil sample. As furan breaks apart glucose rings into smaller pieces, the DP value falls as furan increases. Cellulose paper thus loses its tensile strength and insulating properties. The health of paper/solid insulation can be estimated by correlating the DP value with the furan level. Table 6 displays the association between DP and furan to estimate insulation condition. Despite being nondestructive and quite simple, the determination of DP from the furan is limited in practice by oil contamination and uneven paper aging [47].

Table 6 Correlation of 2-FAL and DP value with insulation health [31]

2-FAL (ppm)	DP value	Significance
0 – 0.1	700 – 1200	Healthy insulation
0.1 – 1.0	450 – 700	Moderate deterioration
1 – 10	250 – 450	Extensive deterioration
> 10	< 60	End-of-life criteria

3.11 Dielectric response analysis

A popular technique for determining the amount of moisture in transformer oil-paper insulation is dielectric response analysis (DRA). Both cellulose paper and oil are used as insulation in power transformers. Chemical reactions inside a transformer create moisture, which is then absorbed by the oil and solid insulation (up to 99%). The organic acids, gasses, humidity, ambient temperature, and oxygen content all affect how quickly moisture is produced. There is always a complicated dynamic moisture migration between paper and oil insulation, and temperature affects how quickly it happens. When the temperature rises, moisture from the solid insulation enters the oil and then returns to the insulation when the temperature falls. The conventional Karl Fischer Titration (KFT) or Piper-Fessler isothermal model can be used to directly assess the moisture content of solid insulation [52,53]. The moisture content of solid insulation can also be indirectly estimated from the oil moisture content using an equilibrium chart [52]. For KFT, gathering paper samples from various locations is largely impractical and inappropriate for on-site testing. Additionally, inadequate and improper placement of moisture sensors in the transformer tank affects the accuracy of the Piper–Fessler method [53]. Furthermore, temperature influences make it difficult to reach the moisture equilibrium between oil and paper, which might result in a large measurement error [54].

In order to get around the aforementioned restrictions, several indirect, sensitive, and non-destructive techniques have gained a lot of attention in the past ten years. These techniques include recovery voltage measurement, polarization and depolarization current analysis, and frequency dielectric response. These techniques precisely measure the moisture content and its effect on the dielectric response in order to evaluate the aging of the insulation [3,29]. Below is a summary of various dielectric response analysis methods along with their drawbacks.

3.11.1 Recovery voltage measurement

A time domain dielectric response method called recovery voltage measurement (RVM) is used to measure the amount of moisture in transformer insulation. As insulation ages, the amount of moisture it contains progressively rises. One of the most important determining elements for measuring insulation breakdown is the amount of moisture present. As a result, determining the moisture content of the paper and oil insulation is essential for assessing the insulation's condition. RVM assesses the true condition and ageing trend using the polarization spectrum of the insulation recovery voltages [3,55]. The circuit design in Figure 6 can be used to illustrate the RVM approach.

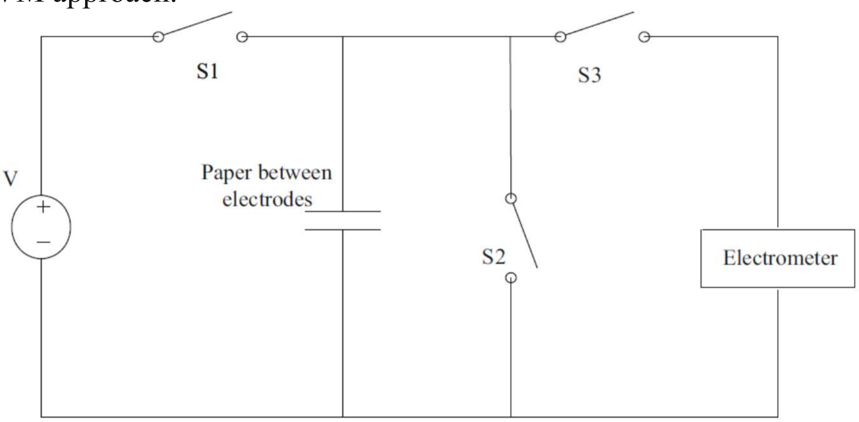

Figure 6 Circuit diagram for RVM [56]

The test involves closing switch S1 for a duration T_c to apply a DC voltage V by a standard recovery voltage meter across the dielectric, and then closing switch S2 (after opening switch S1) to discharge the capacitor through a short circuit for a duration T_d. The geometric capacitance (C_0) loses all of its charge after discharge in each cycle, but certain charges are limited in the dielectric insulation, and the quantity of these charges depends on the quality of the insulation. By keeping the charging and discharging time ratio (T_c/T_d) = 2, the measurement cycle is repeated and increased from a fraction of a second to thousands of seconds. A portion of the bounded charge will be transferred to the geometric capacitance when the circuit is open following each cycle of charging and discharging. Eventually, a voltage known as the recovery voltage (RV) is created. A programmed electrometer with very high input impedance records the RV values as a function of time Tc, and the RV spectra are obtained by plotting the values. The important characteristics of the polarization spectra are the voltage peak magnitude and the associated time constant. As the amount of moisture in the oil-paper insulation increases, the central time constant value falls, reflecting the insulation's moisture content [2]. The insulation's time constant is negatively correlated with age and moisture content, as per [57]. They also showed that the maximum return voltage falls as the moisture content rises and that the time constant is inversely proportional to the temperature. At some point, the measured time constant and the RVM peak can be used to estimate the moisture content and ageing trend. The authors of [58] claim that the RVM disregards the impact of insulation geometry and the distinct conductivity of paper and oil insulation. This results in inaccurate RVM spectra. Separating the effects of paper and oil from RVM spectra is challenging, according to [59]. Nevertheless, the limitation can be overcome and the accuracy increased with the development of advanced software and appropriate modeling tools for dielectric phenomena that can incorporate the various contributing parameters, such as the conductivity and permittivity of paper and oil insulation.

3.11.2 Polarization and depolarization current analysis

One of the newest and non-destructive methods for determining the moisture content and oil conductivity of transformer insulations, both homogeneous and composite, is the polarization and depolarization current (PDC) testing. The PDC approach became quite popular and is now frequently used as a supplement to other procedures because of its ease of use and ability to evaluate HV insulation. Additionally, PDC is able to measure the moisture and evaluate how it affects the aging of the paper and oil insulation [60]. In PDC measurement, a DC voltage U0 is supplied across the oil-paper insulation for a duration (e.g., 10,000 s) in order to measure the polarization current and evaluate the condition of transformer insulation (oil-paper). A large magnitude current with varying time constants that correlate to the conductivity and insulating materials begins to flow as soon as the voltage is introduced. The magnitude progressively diminishes over time. The conductivity and polarization process of each particular insulating material affect the charging current's time constant [59].
The equation of the polarization current can be expressed as

$$i_p(t) = C_0 U_0 \left[\frac{\sigma}{\epsilon_0} + f\,(t)\right] \tag{2}$$

Where, σ, ϵ_0, C_0 and $f\,(t)$ represent, respectively, the composite conductivity, vacuum permittivity, geometric capacitance and dielectric response function of the oil–paper insulation. The influence of the conductivity on the polarization current could be investigated by simulating Eq. (2) using different values of oil and paper conductivity.
The geometric capacitance C_0 between oil–paper insulation can be calculated using the following equation

$$C_0 = \frac{C_m}{\epsilon_r} \tag{3}$$

Where, C_m represents capacitance between transformer and ground, and ϵ_r is the effective relative permittivity of heterogeneous oil–paper insulation.
A short circuit is now used in place of the voltage source to measure the depolarization current. As a result, a depolarization current in the opposite direction will begin to flow without the insulating conductivity's contribution [59]. The following formula can be used to express the depolarization current.

$$i_d(t) = C_0 U_0 [f(t) - f(t + t_c)] \tag{4}$$

Where, t_c is the duration of the applied voltage.
By charging the insulation with a step voltage or by monitoring the depolarization current after swapping out the step voltage for a short circuit, one can experimentally determine the dielectric response function $f(t)$.
The dielectric responses function for the polarization current $f(t + t_c) \cong 0$ if the time $t + t_c$ is very long. Consequently, Eq. (4) can be rearranged as follows

$$f(t) \approx \frac{-i_d(t)}{C_0 U_0} \tag{5}$$

Rearranging Equations (2) and (4) yields the average conductivity of a composite insulator if the polarization and depolarization currents are known.

$$\sigma \approx \frac{\epsilon_0}{C_0 U_0}\left[i_p(t) - i_d(t)\right] \tag{6}$$

The ratio of average conductivity at various voltages, or the nonlinearity factor, can also be used to compute the combined conductivity [61]. The PDC curve in Figure.7 can be used to evaluate the conductivity, aging, and moisture content of insulation, as per [62]. This curve shows that, during the time range t < 100 s, the conductivity has the greatest impact on the PDC value. As the conductivity rises, so does the current. After 100 seconds, the oil's characteristics, aging, and geometry become noticeable, and after 1000 seconds, the moisture content variation becomes obvious. According to the authors of [63], the difference between the polarization and depolarization current (conduction current) is constant and time independent if the intrinsic non-linearity of a homogeneous insulator is disregarded. Furthermore, according to reference [59], long-term current is mostly impacted by the state of solid insulation, while initial conduction is highly sensitive to the oil condition.

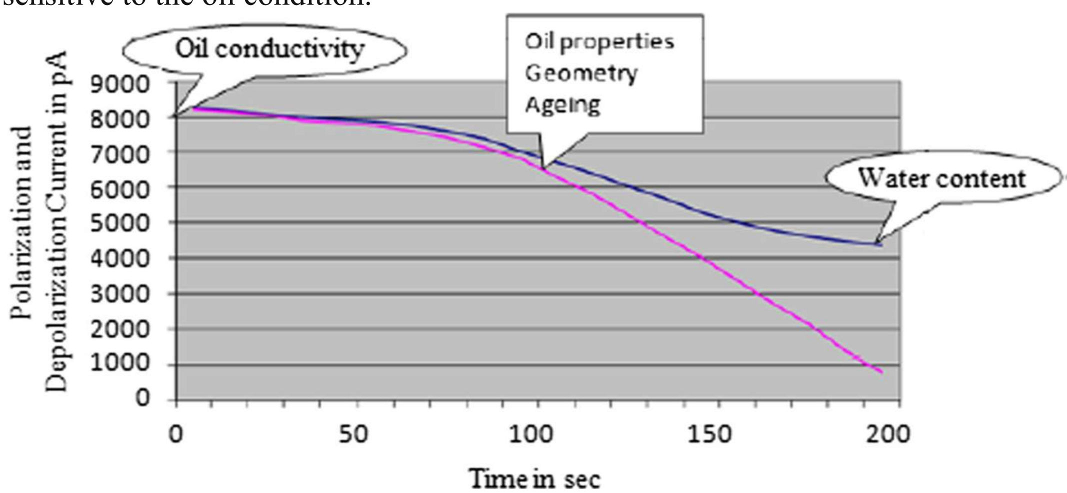

Figure.7 Oil conductivity, oil properties, geometry, ageing and water content influence on the PDC-curves [62]

The genuine combined conductivity of the transformer's oil-paper insulation is reflected in the time-dependent difference in composite insulation, which is impacted by the independent circumstances of the two types of insulation [64]. PDC testing can therefore be used to precisely evaluate the state of oil-paper insulation. Conversely, the PDC's accuracy depends on having a thorough understanding of the composition and design of the oil-paper insulation, and the measurement procedure takes a long time. In actuality, one of the main drawbacks of this approach is the difficulty in obtaining precise design and insulation composition data. A modeling procedure to partially get around the restriction has been explored in [59].

3.11.3 Frequency dielectric response

A commonly used method for determining the moisture content and aging status of power transformer oil-paper insulation is frequency dielectric response (FDS) [65]. Compared to the RVM and PDC approaches, FDR has drawn greater attention because it is highly resistant to external frequency (noise) and can provide detailed analysis [66]. Composite oil-paper insulation's dielectric response is evaluated in FDR at frequencies ranging from 100 μHz to 1 kHz [65]. Depending on how much moisture is present in the insulation, the range may change. However, the maximum frequency of FDR is limited to 1 kHz because to the strong resonance effect and poor dielectric response. Temperature, insulation geometry, and moisture intrusion are the primary factors that affect insulation aging. The link between the dielectric response spectrum and temperature, moisture content, and insulation geometry can be used to assess the quantity of moisture and ageing state. The dielectric response, which is employed to measure the moisture content and ageing condition, makes it difficult to distinguish the effects of moisture, aging, and geometric influence [67]. Based on the dependent variables, a thorough procedure to get around these restrictions is provided in [66]. [66] states that the relative permittivity (ϵ_r) and dissipation factor (tan δ) of oil-paper insulation rise in proportion to the moisture in the frequency range of 10^{-3}–10^{2} Hz. However, only between 10^{-3}–10^{-1} Hz are ϵ_r and tan δ susceptible to aging. Therefore, it is possible to distinguish and measure the impact of moisture and aging on the insulation using the frequency range 10^{-3}–10^{2}. The dielectric response of a press board sample, however, can be utilized to detect the moisture concentration (1, 2, and 3%), according to a recent study of the same name in [65]. It was discovered that as frequency increases, the dielectric response's slope diminishes. All of the sample slopes align and flatten out above 100 Hz. In the end, the state of transformer paper insulation can be evaluated using the slope of the dielectric response below 100 Hz. Fig. 8 illustrates a typical oil-paper insulation's dielectric response, per [68].

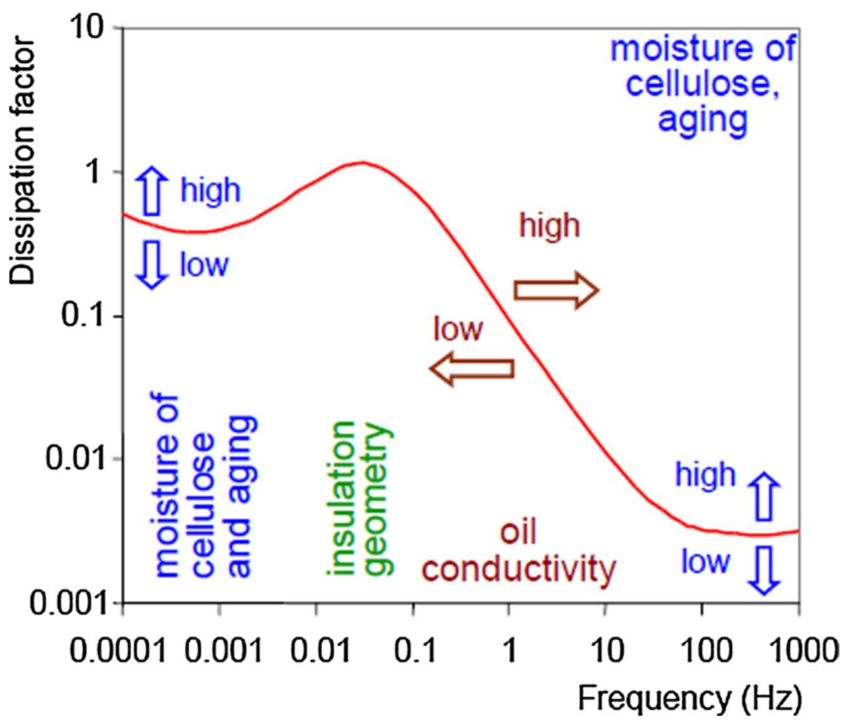

Figure. 8 Dielectric response of oil–paper insulation [68]

3.11.4 Time–frequency domain dielectric response

The most recent method, time-frequency domain dielectric response, combines the benefits of PDC and FDS to evaluate the insulation quality of transformers [69]. The PDC approach is quicker at low frequencies and depicts the deterioration of paper and oil insulation. The FDS approach can evaluate the ageing of paper and oil insulation and is quicker than the PDC at high frequencies. The benefits of both FDS and PDC have been integrated in this approach to provide a more rapid, clever, and potent evaluation technique. The dielectric response may be measured over a larger frequency range (0.05 mHz to 5 kHz) thanks to the integrated technology. To precisely evaluate the condition of the paper/pressboard and oil insulation, the measured reaction could be compared with factory test results or historical measurements.

3.12 Partial discharge analysis

A dielectric discharge in a portion of an electrical insulation system that is subjected to a high electrical field intensity is known as a partial discharge (PD). PD occurrences are frequently thought regarded as an early sign of a full insulation failure. As a result, PD measurement has been used for a long time to monitor the state of power transformers and to prevent unforeseen problems. When the electric field stress in transformers surpasses the insulation's breakdown strength, PD can occur in cellulose paper, oil, or the oil-paper insulation interface. Any flaw, like gas bubbles, tiny floating metal particles in oil, or cavities and spaces in solid insulation, can disrupt the uniformity of electrical stress throughout the insulation and start PD, which can result in a flashover. Furthermore, insulating materials gradually lose their dielectric strength as a result of ongoing thermal, electrical, and dielectric stress, which has a direct impact on the likelihood of Parkinson's disease. [70,71] state that when the temperature rises, the PD's inception voltage falls. The size of the gas bubbles in the oil has a substantial impact on the PD magnitude and repetition rate [72]. As overall harmonic distortion rises, surface discharges on transformer insulation rise and the inception voltage falls [73]. After PD begins, it spreads throughout the insulation until it breaks down completely. As a result, PD detection, quantification, and localization during operation are critical [74]. A variety of phenomena, including ozone generation, the release of nitrous oxide gases, acoustic emission in audible and ultrasonic ranges, and electromagnetic emission (in the form of radio waves, light, and heat) may be seen during Parkinson's disease [75]. It is possible to identify and pinpoint the PD phenomenon by employing a variety of testing methods, including electrical, chemical, acoustic, and optical. Below is a brief overview of various PD assessment techniques.

3.12.1 Chemical detection

By monitoring the chemical shift in the composition of insulating materials, this is one of the most straightforward techniques for chemically detecting Parkinson's disease. Its foundation is the gathering and analysis of oil and gas samples that are discharged from PD operations. There are now two chemical methods for measuring PD, including DGA and HPLC. The DGA test measures the concentration of important gases in transformer oil by sampling it. The Duval Triangle Method is then used to analyze the detected gases in order to identify PD. The reading, gas level, and identified faults are not calibrated and properly associated, despite the fact that this procedure may be monitored online [76]. By analyzing chemically stable byproducts like glucose during insulation breakdown, the HPLC technique calculates the PD. This approach is not appropriate for real-time PD monitoring due to the time-consuming nature of the sample collection and analysis process. Furthermore, the measurement error is increased by the inadequate criteria for determining the severity of Parkinson's disease based on glucose measurements. Moreover, neither HPLC nor DGA can identify the cause of PD.

3.12.2 Electrical detection

The detection of high-frequency electrical pulses generated from a void as a result of a strong electric stress across it is the foundation of this technique. There are two ways to take the test: online and offline. When using offline mode, the detecting impedance that must link across the test object is coupled in series with a coupling capacitor of known value. The circuit is powered by a high voltage AC source once the wiring is finished. For an improved signal-to-noise ratio, the detecting impedance can alternatively be linked in series with the test item (see Fig. 9). In order to protect the measuring instrument from any harm caused by the breakdown insulation of test objects, the impedance is frequently connected in series with a capacitor, even if doing so increases sensitivity. Additionally, in order to connect a detector in series with the test object, it must be detached from ground. With regard to power transformers, this is an uncommon practice. In the online mode, the bushing's inner grading foil layer serves as a capacitor, and an inductor is grounded via the outer layer, provided that the bushing tab is grounded. Fig. 9 displays the circuit diagram for common PD measurement techniques.

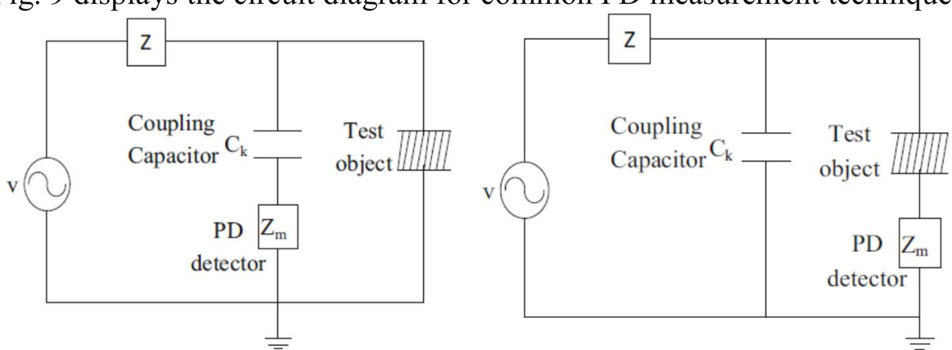

Figure 9 Measurement of apparent PD by connecting detector at different position

When PD is present, the void acts as a capacitor, causing the voltage across it to rise steadily until it breaks. The voltage across the capacitor will consequently drop to zero when the capacitor is discharged. As long as the AC source is connected, the charging and discharging operation will continue. The charging and discharging repetition rate is more than 1 MHz, per [77]. The coupling capacitor, which is transformed into a voltage signal via the detecting impedance, will mostly compensate for the discharged energy. The converted signal can provide important details concerning PD, such as the shape, intensity, relative phase location, and degree of insulation degradation, when compared to the AC cycle. When compared to other methods, this approach can yield the most accurate results, despite being time-consuming, very susceptible to noise, and unable to locate PD sources [78,79].

3.12.3 Acoustic detection

In order to identify and pinpoint the location of PD, the acoustic emission method (AE) examines the amplitude, attenuation, or phase delay of acoustic signals generated from PD. The AE is a technique based on the PD phenomenon that detects PD by sensing acoustic waves in a frequency range up to 350 kHz [78,80]. An audible or non-audible AE signal is produced during PD when materials adjacent to the place of origin experience mechanical stress.

Numerous sensors, including piezoelectric transducers, microphones, accelerometers, sound resistance sensors, and fiber optic acoustic sensors, are frequently employed to detect the signal [81]. The sensors are placed in various locations on a transformer tank's exterior wall. To identify the cause of PD and gauge the extent of an insulation problem, the relative travel times of the signal to several sensors are triangulated [78]. Despite the fact that AE signals are disrupted by a transformer's low frequency mechanical vibration, it exhibits greater tolerance to electromagnetic interference than electrical detection. This method is perfect for online PD detection because of its unique feature and excellent signal-to-noise ratio (SNR) [81]. Conversely, this method's primary limitations are thought to be its measuring complexity, significant data processing, and limited sensitivity to the damping of the oil, core, conductors, and main tank [80].

3.12.4 Ultrahigh-frequency detection

For power transformers, ultrahigh-frequency (UHF) detection is a standard and ongoing PD monitoring technique. In order to identify and pinpoint PD, this technique detects electrical resonance in the frequency range of 100 MHz to 2 GHz [82]. The shielding effect of the tank helps to reduce any outside noise because the sensor is mounted inside the transformer [83]. Additionally, the high sensitivity for an on-site measurement and the low signal attenuation in oil insulation have led to a rise in the adoption of this technique for transformer testing. A number of sensors with high sensitivity broad band antennas are mounted inside the transformer tank to measure PD. Before starting the test, a calibration method is used to determine the sensors' precise phase and amplitude relationship and gauge their sensitivity. The sensors are positioned so that at least three sensors working in parallel can pick up signals from pertinent areas of a transformer, such as the tap changer or windings. To link the sensor to the control module, high-frequency wires with known attenuation and phase shift must be utilized. Lastly, a PD event may be identified and its source pinpointed by employing proven triangulation techniques and the measured amplitude and travel duration of the signals [84]. [82] provides a thorough calibration and sensitivity assessment process.

3.12.5 Optical detection

One of the newest approaches for locating and detecting transformer PD is optical detection. In addition to electromagnetic emission, different ionization, excitation, and recombination processes during PD always produce light spectra in the ultraviolet, visible, and infrared ranges. An optical sensor may identify and localize Parkinson's disease (PD) by measuring the energy level of discharge, which is conveyed by the emitted spectrum [85]. The surrounding insulating substance affects the energy's amplitude. The PD-induced optical spectrum in oil begins at about 400 nm and can reach into the infrared spectrum [85].
The type of insulation and the surrounding medium can affect the wavelength. For PD detection, a sensor that can display the appropriate optical spectrum is therefore essential. A single or multimode fiber optic sensor is submerged in the oil tank for transformers. [86] states that Fig. 10 depicts the optical detecting equipment setup.

A He–Ne laser, photo-transistor, amplifier, oscilloscope, and multimode sensor make up the setup shown in the diagram for PD detection. A coherent power of 10 mW is produced by operating a He–Ne laser in continuous wave mode [86]. An HV source across the electrodes is used to replicate the PD source. The sensor directs the signals to the photo-transistor, the receiver, after gathering them from the source. The photo-transistor's output automatically adjusts to variations in light intensity. An oscilloscope displays the incoming signal to anticipate Parkinson's disease (PD) following the required conversion (optical to electrical) and amplification. To find the PD source, more computerized software analysis is needed. The technique is totally immune to electromagnetic interference because it solely receives optical signals. Furthermore, the approach is most widely used in the high-voltage industry because to its high sensitivity and wide-bandwidth measurement capacity [83]. A thorough process and examination of this approach can be found in [85, 86].

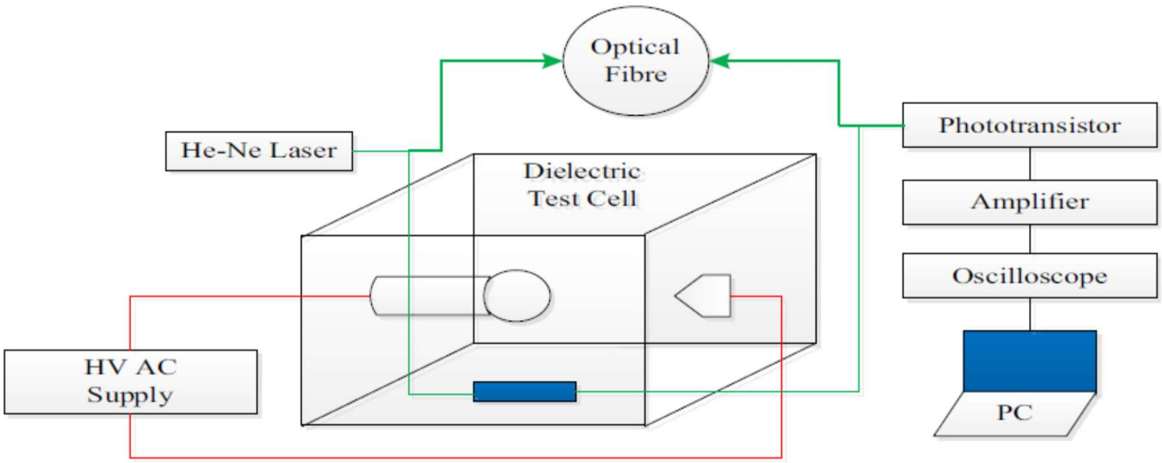

Figure. 10 Schematic diagram for optical PD detection [86]

3.12.6 High-frequency current transformer installation

Online PD in a power transformer can be detected using an inductive coupling sensor, such as a high-frequency current transformer (HFCT) [87]. The cable shield next to the bushing is connected directly to the main ground in the HFCT approach, creating an externally accessible loop (PD loop) on the LV side. The loop wire is securely clipped with an HFCT to monitor PD. A high-frequency electromagnetic pulse will be produced by active PD and transmitted through the ground conductor. Because of induction, the HFCT will detect this radiation. Despite enabling online PD monitoring, this approach has a relatively low signal magnitude, is less sensitive, and is susceptible to noise. Therefore, before using tools like oscilloscopes, PD detectors, or pulse counters to analyze the data, an amplifier needs to be fitted [87,88].

3.12.7 Transfer function measurement

The high-frequency transfer function (TF) of a transformer winding can be utilized to assess and pinpoint the source of PD that starts inside the windings [80,89,90]. It is possible to separate each transformer winding into multiple winding portions. The transfer function of all windings can be computed if the transfer function of each winding's constituent sections is known [91]. Both the bushing and the neutral terminals will receive a signal that is altered throughout its propagation if PD is started at an unknown allocation along the transformer winding. The distance between the origin and the detection impedance is one of several variables that affect the distortion rate. Both narrow band and broad band methods can be used to measure the distorted PD signal [80]. The offline narrow band approach can measure the phase shift with the power frequency, the repetition rate, the energy of individual pulses, and the apparent charge, even though it is unable to localize PD [80]. IEC 60270 states that a frequency range of 9 to 30 kHz is appropriate for this technique. The wide band method detects Parkinson's disease using the same technique as the narrow band method. By examining its shape, it may also pinpoint the location of the PD signal. According to [92], this technique works best with a bandwidth of roughly 10 MHz. This approach makes use of the idea of a transfer function to localize PD. As a result, the PD signal will be attenuated more than noise [91].

Table 7 Comparison of different PD measurement techniques

Method	Advantage	Disadvantage
Electrical	High sensitivity	Difficult to apply on-site measurement
	High measurement precision	High measurement precision Influenced by electromagnetic interference
	Good in laboratory environment	Unsuitable for long-term monitoring
	Calibration of the apparent charge	
UHF	Better sensitivity then AE [84]	No direct correlation with conventional measurement following the IEC60270
	Higher immunity against noise	Sensitivity need to check for individual transformer due to identical internal impedance
	Lower signal attenuation	Insufficient scope to install sensors in old transformer
Chemical	Good in laboratory environment	High uncertainty due to unknown relationship between glucose and severity
	High sensitivity	
AE	Good in real-time monitoring	Low sensitivity
	Noise immunity	Influenced by external noise
	Detect the position of PD	
Optical	Immune to electromagnetic interference	No significant disadvantage
	Visualization of PD is possible	
	High sensitivity	
	High-frequency response	
	Easy portability	
HFCT	Capable to do real-time monitoring	Cannot detect source even the nearby phase
	Easy to install	Influenced by external interference
TF	Good in laboratory environment	On-site test, vulnerable to background noise
	Capable to detect and locate PD	

Furthermore, the noise signal's computed transfer function and the transformer's transfer function will match. In a lab setting, noise can be isolated using this method. The spurious sinusoidal and pulse-shaped noise during on-site measurement can be suppressed using optical transducers, digital filters, amplifiers, windowing (software), and the common mode rejection technique [91]. The uncertainty of the sectional transfer function of the windings determines how accurate this method is. Only a quarter of the entire winding length can be used to pinpoint the origin of PD in older transformers, where the transfer function is determined by step response. This method's error is only a few percent if the sectional transfer function of the windings is known [91]. Table 7 provides a summary of the various PD assessment techniques that are currently available.

3.13 Leakage reactance or short-circuit impedance measurement

Over the years, short-circuit impedance (SCI), a frequency-dependent metric, has been employed to identify transformer core displacement and winding deformation. One of the primary signs of core and winding mechanical deformation is thought to be short-circuit current. Any modification to a transformer's mechanical geometry would alter its SCI. The voltage regulation is directly affected by a high SCI value because of the large voltage drop across it. Conversely, low values signify short-circuit current. Winding deformation and core displacement are shown by a variation of ±3% [93]. Transformers with a capacity greater than 100 MVA, however, shouldn't be more than ±1% of their name plate value [94].

According to Ampere's force law, if two conductors carry current in the same direction, an attractive force will be seen between them, and vice versa. This formula summarizes that the forces between HV and LV windings are repulsive, but the forces from one HV (or LV) winding loop to the next will be attractive. In order to try to rupture the winding conductors, the axial flux generated by short-circuit currents eventually produces tensional force on the outer windings and compressive force on the inner windings [95,96]. Either the 3-phase equivalent test or the per-phase test procedures can be used to measure the SCI. An input voltage must be applied successively in HV windings while maintaining the appropriate LV winding shorted in order to measure SCI. The SCI measuring setup is displayed in Fig. 11a, b.

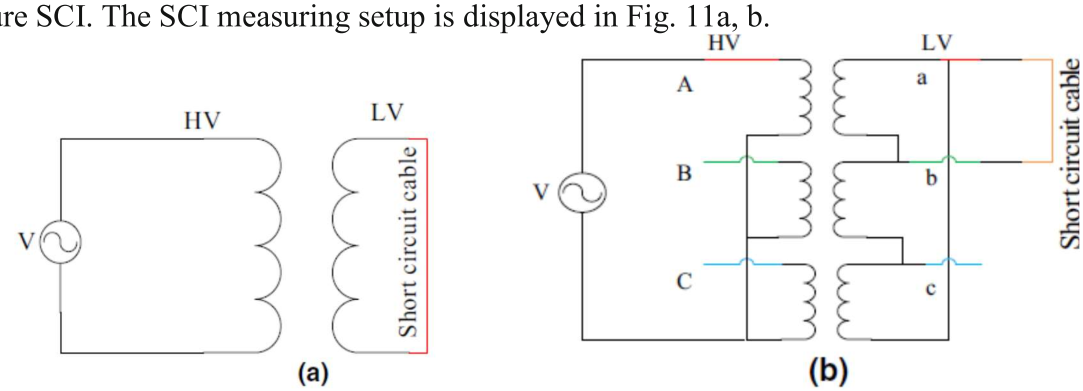

Fig. 11 Circuit connection of SCI for single phase (a) and three-phase (b) measurement

The shorting cable should be as short as possible and have a cross-sectional area that is at least 30% larger than the winding conductors in order to carry a high current [97]. The 3-phase equivalent test makes it possible to evaluate a transformer's mechanical integrity by comparing the results between phases and with the nameplate value. This outcome might serve as a fingerprint for upcoming examinations. As a follow-up exam, a per-phase test may be conducted. This approach has several drawbacks [97], including

1. Because the test only uses one frequency (50 or 60 Hz), it does not offer comprehensive information on the state of the windings.
2. Because considerable distortion is necessary to produce a discrepancy, it is less sensitive.
3. It is unable to identify axial deformation, such as conductor tilting or bending.

3.14 Turns ratio test

One way to find open or short circuits between turns of the same winding is to utilize a transformer's turn ratio test (TTR). Open turns, short circuits, or insulation failure are indicated by a variation of greater than 0.5% [5]. The ratio must be checked at every tap point in the TTR test. Evidence of a divergence in gross winding resistance can be obtained from the TTR. Starting the test at a low voltage (100 V) and comparing the outcome to the nameplate value is advised. It is safe to raise the voltage to the rated voltage if no appreciable variation is discovered. This method aids in preventing unintended insulation degradation.

3.15 Winding resistance test

To find weak connections, broken stands, or inadequate contacts in LTC, a winding resistance test can be utilized. To confirm the LTC contact resistances, the resistance needs to be measured at each tap. The outcome might be compared to historical data, nameplate information, or data from different periods. The test data needs to be translated to the factory test reference temperature in order to compare with nameplate values. If DGA shows the production of hot metal gases such acetylene (C2H2), ethane (C2H6), and methane (CH4), this test could be utilized in addition to DGA and TTR [5]. A manual internal inspection could be planned based on the variance %.

3.16 Core-to-ground resistance test

To avoid circulating currents and detect numerous grounds, the core of the majority of contemporary transformers is purposefully attached to a single ground point via a tiny bushing. The grounding system may come loose or sustain damage while being transported. Deliberate core grounding can be identified and the integrity of deliberate ground points verified using the core-to-ground resistance test. When the test detects hot metal gases, it can be utilized in addition to DGA. The purposeful ground cable is left open while the insulation resistance between the core and tank is measured in order to check multiple grounds. As shown in Table 8, the measured resistance can be used to identify and categorize the severity of several reasons.

Table 8 Insulation condition based on core-to-ground resistance [5]

Resistance value (MΩ)	Condition
Resistance >1000	New transformer
Resistance >100	Aged insulation
Resistance 10–100	Degraded insulation
Resistance <10	Destructive circulating current

3.17 Sweep frequency response analysis

A nondestructive, highly precise, economical, and sensitive technique for identifying mechanical deformation and displacement of a transformer core and windings is the sweep frequency response analysis (SFRA) [97]. Because of its high sensitivity in identifying a transformer's mechanical faults, SFRA is becoming more and more significant with time. Without opening the main tank, it can identify defects like loose contact at the HV and LV winding terminals, winding tank grounding, and axial or radial winding deformation [97,98]. Generally speaking, the primary causes of core and winding deformation in transformers are thought to be short-circuit current, negligent driving, natural disasters like earthquakes, and flammable gas bursts within the transformer [97]. Each transformer has an own fingerprint known as frequency response, which varies when a mechanical flaw appears.

Mechanical deformation alters a transformer's frequency-dependent impedance, which results in a changed frequency response [99]. To guarantee the windings and core integrity of transformers, FRA is advised following commissioning, short-circuit occurrences, or transportation. Either the transfer function or the impedance can be measured using SFRA in a two-winding, three-phase transformer. It is possible to determine impedance from transferred measurements and transfer function from non-transferred measurements [98]. Short-circuited winding turns can be identified using the observed transfer function [100]. Fig. 12 and 13 display the circuit schematics for a transferred measurement and a non-transferred measurement. In a transferred measurement, the neutral terminals remain grounded and the other untested terminals are either floating or shorted to the main tank via a 1 k resistance. An input voltage Vin is injected at each HV terminal, and the output voltage Vout is measured from the appropriate LV winding [98,101]. Only frequencies below 8 kHz are suitable for this measurement [102]. It is affected by inter-winding capacitance at higher frequencies. The impact of coupling capacitance between HV and LV windings is thus highlighted by this test [98]. Non-tested HV terminals and LV terminals are left open or shorted out while the input voltage is measured from the HV windings and the output voltage is measured from the corresponding neutral terminal of the same winding for the non-transferred measurement. It is advised to add some resistance (1 k~) with both non-excited and excited terminals in order to prevent damping oscillation and lessen the effect of stray capacitance [98,101]. Analyzing the results to confirm the mechanical integrity is a crucial step after performing SFRA and documenting the reaction. The highest limit of the frequency range for SFRA that is helpful for fault detection must be known in order to analyze the data. The highest reproducible range is at least 1 MHz, per [98].

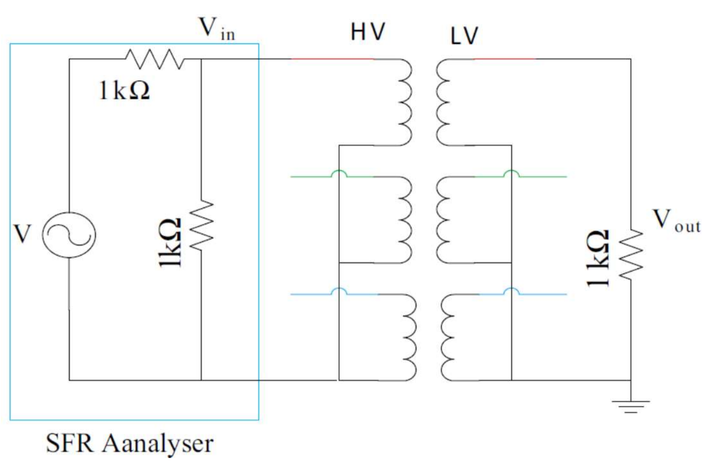

Fig. 12 Transferred measurement

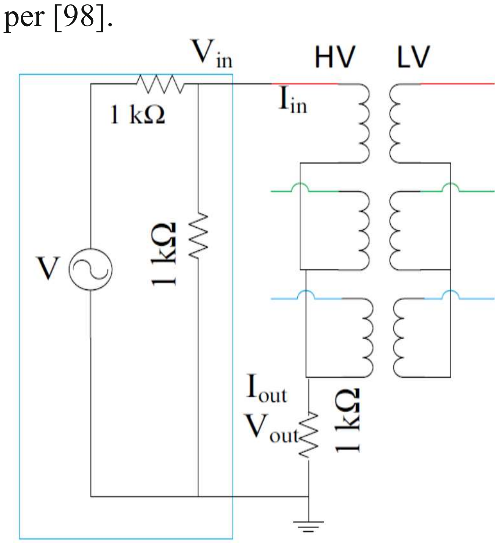

Fig. 13 Non-transferred measurement

The distributed capacitance tended to function as a shunt capacitor with winding inductance at higher frequencies (beyond 1.5 MHz), when winding lead effects are noticeable and resonance recurrence is less noticeable [101]. It is well acknowledged that the medium frequency range (100–600 kHz) is controlled by winding structure, the high frequency range (600 kHz–1 MHz) can detect issues in connection leads, and the low frequency range (1–100 kHz) is helpful for identifying core deformation [97]. [103] states that Fig. 14 displays the frequency response across several spectrum segments. For the detection of minor flaws such as conductor bulging, tiny displacement, and inter-turn fault, the frequency range can be extended up to 2MHz [104]. Low-voltage or high-voltage windings' respective impedance values can be used to identify faults near either high-voltage or low-voltage terminals, leaving the opposing side open-circuited [104]. Although SFRA can detect vast ranges of mechanical distortion sensitively, the interpretation and analyzing of data are not easy. As there is no standard technique, it is still relying on experts' judgment, visual inspection, statistical indices like standard deviation, correlation coefficient and relative factor, and comparison with previous data. Data can be analyzed by comparing several phases of the same transformer or twin/symmetrical transformers if previous data is unavailable. Any inherent constructional asymmetries must be taken into account when comparing data between stages.

4 Calculation of residual life of power transformer

In addition to condition monitoring, utilities are paying more attention to transformer lifetime estimation for technical and financial reasons. They can create a forecasting system for future investment and establish a refurbishment strategy with the aid of the expected lifespan. The remaining service life of a transformer is determined using a variety of methods over the course of ten years, including the computation of the health index, the evaluation of the chance of failure, statistical depreciation analysis, and the association between the insulating life and operating temperature and DP. The following is a summary of a review of various lifetime estimating techniques.

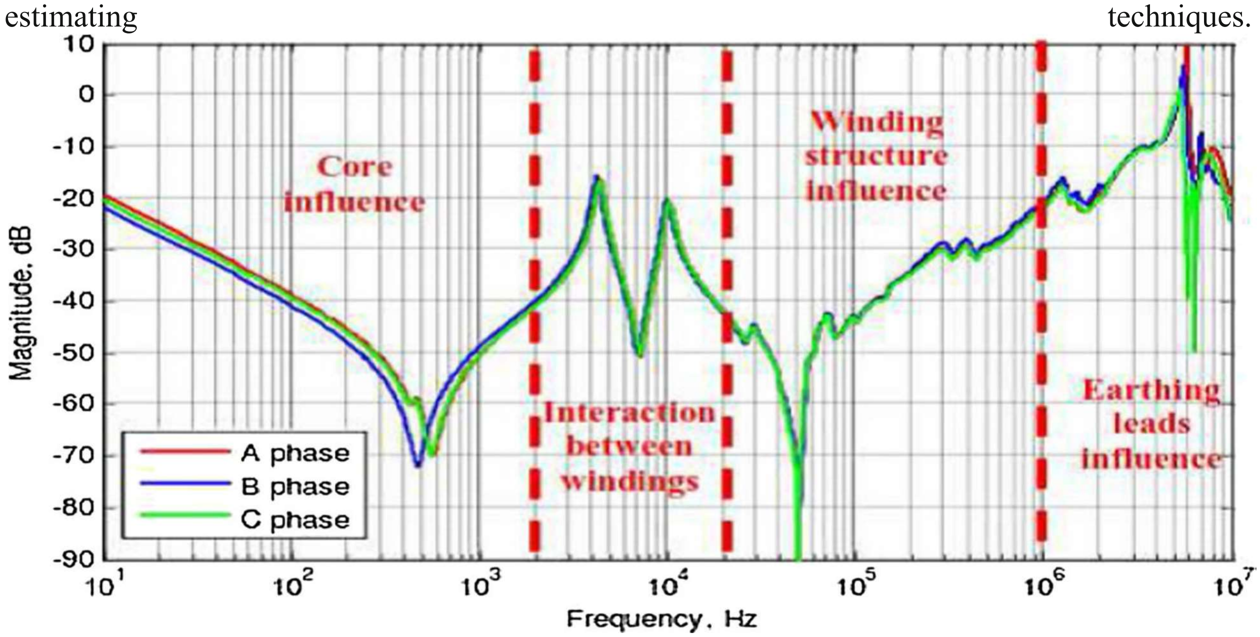

Fig. 14 Transformer sweep frequency response [103]

4.1 Concentration of furan and DP value measurement

By evaluating the deterioration of the cellulosic paper insulation, the DP value calculation and the furan concentration measurement are two additional techniques used to determine a transformer's residual life. Unaged paper should typically have a DP value between 1000 and 1200 [109,110], while paper with a DP value between 200 and 300 is deemed to be nearing the end of its useful life [111]. Temperature, water content, and oxygen all have an impact on a transformer paper's DP value, which gradually drops as a result of chemical reactions. As a result, it can offer important details regarding the mechanical strength and degree of cellulose degradation. The following equation [111] can be used to relate the DP value to temperature in terms of a time-dependent reaction rate (k) in accordance with the Arrhenius relation.

$$DP\ (t) = \frac{DP\ (t_0)}{1 + DP\ (t_0) * \int_{t_0}^{t} k(t)dt} \tag{7}$$

where $k = A\ *\ e^{\frac{-E_a}{RT}}$, A is a constant that depends on the water content, oxygen or acidity, E_a is the minimum activation energy in J/mol, required to start the chemical reaction, T is the temperature (in degrees Kelvin) and $R = 8.314\ mol^{-1}K^{-1}$ is the ideal gas constant. The DP value after any ageing period t_n can also be calculated by the following Emsley's equation [112].

$$DP_n = \frac{1}{A\ *\ e^{\frac{-E_a}{RT}}\ *\ t_n + \frac{1}{DP_{n-1}}} \tag{8}$$

where the value of A is dependent on both the water content and the dissolved oxygen gas but not on the temperature [112,113]. Finally, the loss of life after any time period t_n can be calculated by dividing the ageing during the time interval by the expected life at a particular temperature [112]. Consequently, the life lost at a particular time interval can be expressed as follows

$$LL_n = \frac{t_n}{\frac{\frac{1}{200} - \frac{1}{1000}}{A}\ *\ e^{\frac{-E_a}{RT}}} \tag{9}$$

The Percentage of residual life

$$\%RL = \left(1 - \sum_{n=1}^{N} LL_n\right) * 100 \tag{10}$$

Where, N is the total number of time interval, and $\%RL$ for a new transformer has been considered 100 %.

The furan concentration is frequently used to determine a transformer's remaining residual life because direct testing of the DP value for a live transformer is crucial and necessitates disconnecting the transformer from the live network [42]. Furan (2-FAL) is liberated from the materials that are created when cellulose breaks down and continues to have an inverse relationship with DP. In order to minimize the difficulty of direct DP measurement, many correlation approaches have been devised to associate the furan concentration with DP. The following equation has been used in [114] to connect the furan concentration with the value of DP.

$$DP = \frac{\log(2FAL) -\ 1.51}{-0.0035} \tag{11}$$

where the concentration of furan (2FAL) is used in mg/l.

Additionally, [115] provides an overview of various correlation techniques between DP and furan. The residual life of a transformer is finally determined using the computed DP value, which is dependent on furan concentration. The advantage of this approach is that the DP value may be confirmed from the measured value of furan, and the error can be decreased by updating the measured quality parameters.

4.2 Hot spot temperature calculation

A transformer's insulating life is directly impacted by its hot spot temperature (HST). The increase in HST accelerates the pace at which insulation ages. Temperature is the main factor lowering transformer service life, according to industry loading guides (IEE, IEC, CIGRE, and ANSI). Transformer oil-paper insulation has a nominal HST of 110 ˚C, while it may be acceptable as high as 140 ˚C [31, 49]. The HST is raised and transformer life is decreased by the effects of ambient temperature, winding defects, malfunctioning cooling systems, excessive loading, and undesired harmonics (non-sinusoidal load). As a result, the relationship between HST and insulation aging rate can be used to determine a transformer's remaining service life.
The equation of HST in ˚C can be written as follows, per [105]

$$\theta_{HS} = \theta_A + \delta\theta_{TO} + \delta\theta_H \tag{12}$$

where θ_{HS} is the hot spot temperature, θ_A is the ambient temperature, $\delta\theta_{TO}$ is the top oil temperature raise, and $\delta\theta_H$ is the winding HST raise over top oil temperature. The value of $\delta\theta_{TO}$ is directly influenced by the transformer's load. According to [106], the impact of load variation on $\delta\theta_{TO}$ can be expressed by the following equation

$$\delta\theta_{TO} = (\delta\theta_{TO.U} - \delta\theta_{TO.i})\left(1 - e^{\frac{-t}{\tau_{TO}}}\right) + \delta\theta_{TO.i} \tag{13}$$

where $\delta\theta_{TO.U}$ is the top oil temperature gradient at ultimate state, $\delta\theta_{TO.i}$ is the initial top oil temperature gradient, t is the duration of loading (in hours) and τ_{TO} is the oil time constant (in hours). However, the operational load and its duration also have an impact on winding HST. The following equation [106] can be used to represent a relationship between winding HST and loading time for different loads.

$$\delta\theta_H = (\delta\theta_{H.U} - \delta\theta_{H.i})\left(1 - e^{\frac{-t}{\tau_W}}\right) \tag{14}$$

where $\delta\theta_{H.U}$ is the hot spot temperature gradient at ultimate steady state, $\delta\theta_{H.i}$ is the initial temperature gradient, t is the loading duration in hour and τ_W is the winding time constant (in hours). If the θ_{HS} is known, the Arrhenius Dakin formula can be used to calculate the life consumption. According to the formula

$$Per\ unit\ life\ consumption = Ae^{\left(\frac{B}{273+\theta_{HS}}\right)} \tag{15}$$

where A and B are the constants. The value of A and B represents the characteristics of insulation. The typical value of A and B is 9.8×10^{-18} and 15000, respectively, [105]. The ratio of per unit life at design temperature *(*110 ˚C*)* relative to the per unit life at any other operating temperature *(*θ_{HS}*)* is known as the ageing acceleration factor. According to [107], the ageing acceleration factor can be expressed by the following equation

$$F_{AA} = e^{\left(\frac{15000}{383} - \frac{15000}{\theta_{HS}+273}\right)} \quad (16)$$

According to [108], the loss of unit life and its percentage in a given period of time for a transformer can be approximated as:

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AAn}\delta t_n}{\sum_{n=1}^{N} \delta t_n} \quad (17)$$

where F_{EQA} is the equivalent ageing factor, F_{AAn} is the ageing acceleration factor during the time interval δt_n and N is the total number of time intervals.

$$\%Loss\ of\ life = \frac{F_{EQA} * t * 100}{Insulation\ design\ life} \quad (18)$$

An annual estimate of the cycle ambient temperature and load has been taken into consideration in order to simplify this computation process. As a result, the hourly basis annual temperature and load curve makes it simple to determine the unit life of a transformer. However, a more advanced modeling technique that can more precisely account for additional aging parameters as well as the environmental impact of ambient temperature and HST is required to increase the dependability of a transformer's predicted residual life.

4.3 Probability of failure calculation

After a certain amount of insulation and performance deterioration, a transformer failed. By describing the degradation as a function of time, the likelihood of failure may be computed. The following differential equation, per [116], can be used to define the transformer deterioration model

$$\frac{d\chi}{dt} = -A_F R_0 \chi^k \quad (19)$$

where A_F is an ageing factor, k is a shape parameter, R_0 is a constant and χ is a performance parameter representing the ratio of initial and later performance. The evaluation and observation of specific properties can be used to compute the aging factor. The following formula has been used to estimate how temperature affects the deterioration of paper insulation since it speeds up the insulation's aging process.

$$A_F = \delta^{\frac{1}{T_0}[\theta-25]} \quad (20)$$

where θ and T_0 are the temperature in Celsius and Kelvin, respectively, and δ is the model coefficient. Suppose, a transformer fails at time t, for a degradation level χ_f the probability of failure for the transformer can be expressed as follows [116]

$$P(\chi) = 1 - exp\left[-\left(\frac{\chi}{\chi_f}\right)^{\eta}\right] \quad (21)$$

where $P(\chi)$ is the probability of failure, χ is the initial degradation, χ_f is degradation after time t and η is the shape parameter. Lastly, a transformer's remaining service life can be estimated using the computed likelihood of failure (99%). According to [1], the following equation can be used to express a transformer's remaining service life in terms of failure probability

$$\tau_R = \frac{\tau_{P(\chi)} - \tau_e}{A_F} \qquad (22)$$

Where τ_R is the remaining life, $\tau_{P(\chi)}$ is the age at which probability of failure is in the range 80 – 99% and τ_e is the effective age. It is advised to compute the remaining life using a failure probability that is a little sooner (80%) than the 99% in order to obtain a safety margin for preventing failure. The strategy and maintenance procedures of a specific utility determine this margin. The cost of replacing a defective transformer and the effects of an outage must also be taken into account. The amount of insulating strength left and the active stress at any given moment determine the likelihood of a transformer failing. Insulation's mechanical and dielectric qualities deteriorate with time, increasing the likelihood of failure. Transformer failure probability follows the traditional bathtub curve, which shows a high initial failure rate that significantly decreases and flattens after a few years of faultless operation before beginning to rise rapidly once more as the transformer ages [31].

4.4 Health index calculation

One of the trustworthy techniques for estimating a transformer's lifespan is the percentage health index (HI) computation. Numerous routine and diagnostic tests are merged in HI calculation to specifically evaluate a transformer's overall status. HI computations often use the following equation [2]

$$(\%)HI = 60\% * \frac{\sum_{i=1}^{n-3} C_i DI_i}{\sum_{i=1}^{n-3} C\ D_{i\,max} *\ C_i} + 40\% * \frac{\sum_{i=n-2}^{n} C_i DI_i}{\sum_{i=n-2}^{n} C\ D_{i\,max} *\ C_i} \qquad (23)$$

Here DI_i are the index scores; C_i are the weight factors of each individual test; n is the number of tests (weight criteria) for a transformer and its LTC, respectively. Based on a survey by the CIGRE group, the formula assigns 40% of the overall weight to the LTC and the rest 60% models the reasons behind direct transformer failure. Depending on the utilities' failure rate, this could change [117]. A description of this approach can be found in [2]. This linear approach's decreased sensitivity to the individual test is one of its disadvantages.

Table 9 Health index and remaining lifetime [2]

Health index	Description	Approximate expected lifetime
85 – 100	Minor deterioration of a limited number of components	More than 15 years
70 – 85	Significant deterioration of some components	More than 10 years
50 – 70	Widespread significant deterioration	Up to 10 years
30 – 50	Widespread serious deterioration	Less than 3 years
0 – 30	Extensive serious deterioration	At end-of-life

For example, the total HI score won't vary much if a bushing is in extremely bad condition, which could cause transformers to fail catastrophically. The test results can be multiplied to get around the restriction, making the overall HI score extremely low if one test result is really subpar. Table 9 shows the correlation between the estimated anticipated lifetime and the computed HI.

5 Conclusion

Transformers are unique among industrial plants in that many of its operational parts are hidden beneath an oil bath, making direct visual inspection impossible. This has made it necessary to develop a wide range of creative methods that assess a transformer's operational state using a variety of indirect metrics. In order to determine the factors that have the greatest impact on transformer performance and service life, this study examined a broad variety of recognized diagnostic tests. Testing techniques have been arranged according to their sensitivity and detection capability against defects and insulation degradation in order to increase measurement accuracy and identify fault kinds. Table 10 provides a summary of routine and diagnostic testing based on fault detection capability. As mentioned earlier, DGA alone can identify 70% of common errors; however, other tests are required to determine whether mechanical faults have occurred.

Table 10 Comparison between online, routine and diagnostic tests for fault detection

Name of the tests	Online monitoring	Routine test	Diagnostic test	Type of faults detection		
				Electrical	Mechanical	Thermal
DGA	Y	Y	Y	Y		Y
Oil testing		Y	Y	Y		
Furan analysis			Y	Y		
DP measurement			Y	Y		
SFRA		Y	Y		Y	
Power factor measurement	Y	Y	Y	Y	Y	
Leakage reactance			Y		Y	
Insulation resistance		Y		Y		
PD measurement	Y		Y	Y		Y
Turns ratio measurement		Y				Y
Dielectric response analysis			Y			Y
Winding resistance		Y				Y
Core-to-ground resistance			Y			Y
Excitation current			Y			Y

The majority of power transformers are run by utility companies, who regularly check their assets online and do less frequent offline maintenance. Very few power transformers are privately held. Targeting a small pool of resources to maximize the value of their assets while lowering the chance of unanticipated and disastrous failures is the problem these businesses face. It is anticipated that methods for condition monitoring and lifetime estimation will aid in the correlation of several tests to determine the true degree of insulation and performance deterioration. Relevant industry standards and survey data, including those from CIGRE, IEEE, and IEC, have been applied to specific techniques for comprehending and interpreting test findings in order to increase dependability. The maintenance engineers will be able to analyze test results and recommend crucial transformer characteristics that require monitoring with the aid of these analytical and diagnostic techniques. By using accurate prediction, these methods can assist utilities in averting unplanned breakdowns and give asset managers a rationale for replacing outdated, faulty transformers. An overview of current tests and power transformer condition monitoring methods is given in this article. In order to better understand the features of the many tests and to develop better techniques for combining test data to monitor the condition of this costly and essential equipment, there is a lot of ongoing research being done in this field. It appears likely that the significance of these strategies will only grow as the installed base of assets ages.

References

1. Islam, M. M., Lee, G., & Hettiwatte, S. N. (2017). *A review of condition monitoring techniques and diagnostic tests for lifetime estimation of power transformers. Electrical Engineering, 100(2), 581–605.* doi:10.1007/s00202-017-0532-4.
2. Jahromi A et al (2009) An approach to power transformer asset management using health index. IEEE Electr Insul Mag 2(25):20–34.
3. Saha TK, Purkait P (2004) Investigation of an expert system for the condition assessment of transformer insulation based on dielectric response measurements. IEEE Trans Power Deliv 19(3):1127–1134.
4. Gockenbach E, Borsi H (2008) Condition monitoring and diagnosis of power transformers. In: International conference on condition monitoring and diagnosis, 2008. CMD 2008. IEEE
5. Zhang X, Gockenbach E (2008) Asset-management of transformers based on condition monitoring and standard diagnosis [feature article]. IEEE Electr Insul Mag 24(4):26–40
6. Florian PredlMR(2015) Case studies on tap changer diagonostics using dynamic winding resistance measurement. Omicron Seminar, Perth, WA
7. 7.Ashkezari AD et al (2011) Evaluating the accuracy of different DGA techniques for improving the transformer oil quality interpretation. In: Universities power engineering conference (AUPEC) 2011 21st Australasian
8. Arakelian V (2002) Effective diagnostics for oil-filled equipment. IEEE Electr Insul Mag 6(18): 26–38.
9. Guidelines for life management techniques for power transformers, CIGRE. Technical Brochure 227 (2003)
10. IEEE guide for the interpretation of gases generated in oil immersed transformers. IEEE Std C57.104 (2008)
11. Tenbohlen S, Figel F (2000) On-line condition monitoring of power transformers. In: Power engineering society winter meeting, 2000. IEEE
12. IEEE guide for the interpretation of gases generated in oilimmersed transformer. IEEE Std C57.104 (1991)
13. IEC International Standard forMineral oil-impregnated electrical equipment in service guide to the interpretation of dissolved and free gas analysis. International Electrotechnical Commission, IEC60599:2.1 (2007)
14. Hettiwatte SN, Fonseka HA (2012) Analysis and interpretation of dissolved gases in transformer oil: a case study. In: 2012 International conference on condition monitoring and diagnosis (CMD)
15. Islam MM, Lee G, Hettiwatte SN (2016) A nearest neighbor clustering approach for incipient fault diagnosis of power transformers. Electr Eng. doi:10.1007/s00202-016-0481-3
16. Abu-Elanien AEB, Salama MMA, Ibrahim M (2011) Determination of transformer health condition using artificial neural networks. In: 2011 International symposium on innovations in intelligent systems and applications (INISTA)

17. Pal M, Foody GM (2010) Feature selection for classification of hyperspectral data by SVM. IEEE Trans Geosci Remote Sens 48(5):2297–2307
18. Abu-Elanien AEB, Salama MMA, IbrahimM(2012) Calculation of a health index for oil immersed transformers rated under 69 kV using fuzzy logic. IEEE Trans Power Deliv 27(4):2029–2036
19. Bakar NA, Abu-Siada A (2016) Fuzzy logic approach for transformer remnant life prediction and asset management decision. IEEE Trans Dielectr Electr Insul 23(5):3199–3208
20. Islam MM, Lee G, Hettiwatte SN (2016) Incipient fault diagnosis in power transformers by clustering and adapted KNN. In: 2016 Australasian Universities power engineering conference (AUPEC)
21. IEC, Measurement of relative permittivity, dielectric dissipation factor and d.c. resistivity of insulating liquids, IEC 60247 Ed. 2.0 (2004)
22. Ashkezari AD et al (2013) Application of fuzzy support vector machine for determining the health index of the insulation system of in-service power transformers. IEEE Trans Dielectr Electr Insul 20(3):965–973
23. IEC, Insulating liquids—Determination of acidity—Part 1: automatic potentiometric titration, IEC 62021-1 (2003)
24. Rouse TO (1998) Mineral insulating oil in transformers. IEEE Electr Insul Mag 14(3):6–16
25. Baka NA et al (2015) A new technique to measure interfacial tension of transformer oil usingUV-Vis spectroscopy. IEEE Trans Dielectr Electr Insul 22(2):1275–1282
26. Li Y et al (2016) Molecular dynamics simulation of temperature impact on the viscosity of transformer oil-based nanofluids. In: 2016 International conference on condition monitoring and diagnosis (CMD)
27. IEEE guide for the reclamation of insulating oil and criteria for its use, IEEE Std. 637 (2007)
28. Utami N et al (2009) Evaluation condition of transformer based on infrared thermography results. In: IEEE 9th international conference on the properties and applications of dielectric materials, 2009. ICPADM 2009. IEEE
29. Saha T, Purkait P (2008) Understanding the impacts of moisture and thermal ageing on transformer's insulation by dielectric response and molecular weight measurements. IEEE Trans Dielectr Electr Insul 15(2):568–582
30. IEEE guide for loading mineral–oil-immersed transformers, IEEE Std. C57.91 (2002)
31. Wang M, Vandermaar A, Srivastava KD (2002) Review of condition assessment of power transformers in service. IEEE Electr Insul Mag 18(6):12–25
32. IEEE standard test code for liquid-immersed distribution, power, and regulating transformers, IEEE Std. C57.12.90 (2006)
33. Malik H, Azeem A, Jarial R (2012) Application research based on modern-technology for transformer health index estimation. In: 2012 9th International multi-conference on systems, signals and devices (SSD). IEEE
34. Torkaman H, Karimi F (2015) Measurement variations of insulation resistance/polarization index during utilizing time in HV electrical machines—a survey. Measurement 59:21–29
35. Xiao L et al (2013) Influence of aging degree on polarization and depolarization currents of oil-paper insulation. In: 2013 Annual report conference on electrical insulation and dielectric phenomena.
36. Baral A, Chakravorti S (2014) Prediction of moisture present in cellulosic part of power transformer insulation using transfer function of modified debye model. IEEE Trans Dielectr Electr Insul 21(3):1368–1375
37. Florkowski M, Furgal J (2003) Detection of transformer winding deformations based on the transfer function—measurements and simulations. Meas Sci Technol 14(11):1986
38. Leibfried T, Feser K (1999) Monitoring of power transformers using the transfer function method. IEEE Trans Power Deliv 14(4):1333–1341

39. Bigdeli M, Vakilian M, Rahimpour E (2011) A new method for detection and evaluation of winding mechanical faults in transformer through transfer function measurements. Adv Electr Comput Eng 11(2):23–30
40. Jakob F et al (2003) Use of gas concentration ratios to interpret LTC and OCB dissolved gas data. In: Electrical insulation conference and electrical manufacturing and coil winding technology conference, 2003. Proceedings. IEEE
41. Sans JR, Bilgin KM,Kelly JJ (1998) Large-scale survey of furanic compounds in operating transformers and implications for estimating service life. In: Conference record of the 1998 IEEE international symposium on electrical insulation, 1998
42. Stebbins RD, Myers DS, ShkolnikAB (2003) Furanic compounds in dielectric liquid samples: review and update of diagnostic interpretation and estimation of insulation ageing. In: Proceedings of the 7th international conference on properties and applications of dielectric materials, 2003
43. Dervos CT et al (2006) Dielectric spectroscopy and gas chromatography methods applied on high-voltage transformer oils. IEEE Trans Dielectr Electr Insul 13(3):586–592
44. Poniran Z,Malek ZA (2007) Life assessment of power transformers via paper ageing analysis. In: 2007 International conference on power engineering, energy and electrical drives
45. McDermid W, Grant D (2008) Use of furan-in-oil analysis to determine the condition of oil filled power transformers. In: 2008 International conference on condition monitoring and diagnosis.
46. Norazhar AB,Abu-Siada A, Islam SA(2013) Reviewon chemical diagnosis techniques for transformer paper insulation degradation. In: Power engineering conference (AUPEC), 2013 Australasian Universities.
47. Baird PJ et al (2006) Non-destructive measurement of the degradation of transformer insulating paper. IEEE Trans Dielectr Electr Insul 13(2):309–318
48. Das N, Abu-Siada A, Islam S (2013) Impact of conducting materials on furan-spectral correlation of transformer oil. In: 2013 Australasian Universities power engineering conference (AUPEC).
49. Abu-ElanienAE, SalamaM(2010) Assetmanagement techniques for transformers. Electr Power Syst Res 80(4):456–464.
50. Saha TK (2003) Review of modern diagnostic techniques for assessing insulation condition in aged transformers. IEEE Trans Dielectr Electr Insul 10(5):903–917.
51. Ali M et al (1996) Measuring and understanding the ageing of kraft insulating paper in power transformers. IEEE Electr Insul Mag 12(3):28–34
52. Yi C et al (2015) Understanding moisture dynamics and its effect on the dielectric response of transformer insulation. IEEE Trans Power Deliv 30(5):2195–2204
53. Martin D, Perkasa C, Lelekakis N (2013) Measuring paper water content of transformers: a new approach using cellulose isotherms in nonequilibrium conditions. IEEE Trans Power Deliv 28(3):1433–1439
54. Ekanayake C et al (2006) Frequency response of oil impregnated pressboard and paper samples for estimating moisture in transformer insulation. IEEE Trans Power Deliv 21(3):1309 1317
55. Talib MA et al (2003) Diagnosis of transformer insulation condition using recovery voltage measurements. In: Power engineering conference, 2003. PECon 2003. IEEE
56. Bitam-Megherbi F, Mekious M, Megherbi M (2013) A recovery voltage as non-destructive tool for moisture appreciation of oil impregnated pressboard: an approach for power transformers testing. Int J Electr Eng Inform 5(4):422–432
57. Bognar A et al (1990) Diagnostic tests of high voltage oil-paper insulating systems (in particular transformer insulation) using DC dielectrometrics. Proc CIGRE 90:33-08
58. Gubanski SM, Boss P, Csépes G, Houhanessian VD (2003) Dielectric response methods for diagnostics of power transformers.IEEE Electr Insul Mag 19(3):12–18
59. Saha TK, Purkait P (2004) Investigation of polarization and depolarization current measurements for the assessment of oil-paper insulation of aged transformers. IEEE Trans Dielectr Electr Insul 11(1):144–154

60. Gafvert U et al (2000) Dielectric spectroscopy in time and frequency domain applied to diagnostics of power transformers. In: Proceedings of the 6th international conference on properties and applications of dielectric materials, 2000
61. Jamail NAM, Piah MAM, Muhamad NA (2011) Comparative study on conductivity using polarization and depolarization current (PDC) test for HV insulation. In: 2011 International conference on electrical engineering and informatics (ICEEI)
62. Silva HAP, Bassi W, Diogo ACT (2004) Noninvasive ageing assessment by means of polarization and depolarization currents analysis and its correlation with moisture content for power transformer life management. In: Transmission and distribution conference and exposition: Latin America, 2004 IEEE/PES
63. Yao ZT, Saha TK (2002) Analysis and modeling of dielectric responses of power transformer insulation. In: Power engineering society summer meeting, 2002 IEEE. IEEE
64. Jonscher AK (1999) Dielectric relaxation in solids. J Phys D Appl Phys 32(14):R57
65. Jaya M, LeibfriedT,KochM(2010) Informationwithin the dielectric response of power transformers forwide frequency ranges. In: Conference record of the 2010 IEEE international symposium on electrical insulation (ISEI). IEEE
66. Liao R et al (2015) Extraction of frequency domain dielectric characteristic parameter of oil paper insulation for transformer condition assessment. Electr Power Compon Syst 43(5):578-587
67. Koch M, Prevost T (2012) Analysis of dielectric response measurements for condition assessment of oil-paper transformer insulation. IEEE Trans Dielectr Electr Insul 19(6):1908-1915.
68. Santos E, Elms M, Jabiri Z (2013) End management of power transformers–operational perspective," unpublished, presented at the Omicron Seminar, Perth, Australia
69. Liu J et al (2015) Condition evaluation for aging state of transformer oil-paper insulation based on time-frequency domain dielectric characteristics. Electr Power Compon Syst 43(7):759– 769
70. Hui W, Chengrong L, Huimin H (2010) Influence of temperature to developing processes of surface discharges in oil-paper insulation. In: Conference record of the 2010 IEEE international symposium on electrical insulation (ISEI)
71. Wang H et al (2009) Experimental study on the evolution of surface discharge for oil-paper insulation in transformers. In: IEEE conference on electrical insulation and dielectric phenomena, 2009. CEIDP '09
72. Chen X, Cavallini A, Montanari GC (2008) Improving high voltage transformer reliability through recognition of pd in paper/oil systems. In: International conference on high voltage engineering and application, 2008. ICHVE 2008
73. Sarathi R et al (2014) Influence of harmonic AC voltage on surface discharge formation in transformer insulation. IEEE Trans Dielectr Electr Insul 21(5):2383–2393
74. Pinpart T, Judd MD (2009) Experimental comparison of UHF sensor types for PD location applications. In: 2009 IEEE electrical insulation conference.
75. Tenbohlen S et al (2008) Partial discharge measurement in the ultra high frequency (UHF) range. IEEE Trans Dielectr Electr Insul 15(6):1544–1552
76. Yaacob MM, Alsaedi MA, Rashed JR, Dakhil AM, Atyah SF (2014) Review on partial discharge detection techniques related to high voltage power equipment using different sensors. Photonic Sens 4(4):325–337
77. Boggs S (1990) Partial discharge: overviewand signal generation. IEEE Electr Insul Mag 6(4):33–39
78. Janus P (2012) Acoustic emission properties of partial discharges in the time-domain and their applications. School of Electrical Engineering, Kungliga Tekniska Hogskolan, Stockholm
79. Howells E, Norton E (1978) Detection of partial discharges in transformers using acoustic emission techniques. IEEE Trans Power Appar Syst PAS–97(5):1538–1549
80. Akbari A et al (2002) Transfer function-based partial discharge localization in power transformers: a feasibility study. IEEE Electr Insul Mag 18(5):22–32

81. Niasar MG (2012) Partial discharge signatures of defects in insulation systems consisting of oil and oil-impregnated paper. Royal Institute of Technology (KTH), Stockholm, pp 33–35
82. Gautschi D,TW,BuchsG(2012) Ultra high frequency (UHF) partial discharge detection for power transformers: sensitivity check on 800 MVA power transformers and first field experience Cigre paper
83. Yaacob MM, Alsaedi MA, Rashed JR (2014) Review on partial discharge detection techniques related to high voltage power equipment using different sensors. Springer 4(4):325–337
84. Markalous SM, Tenbohlen S, Feser K (2008) Detection and location of partial discharges in power transformers using acoustic and electromagnetic signals. IEEE Trans Dielectr Electr Insul 15(6):1576–1583.
85. Schwarz R, Muhr M, Pack S (2005) Partial discharge detection in oil with optical methods. In: IEEE International conference on dielectric liquids, 2005. ICDL 2005
86. Karmakar S, Roy NK, Kumbhakar P (2009) Monitoring of high voltage power transformer using direct optical partial discharge detection technique. Springer 38(4):207–215
87. Ariastina WG et al (2009) Condition monitoring of power transformer: a field experience. In: IEEE 9th international conference on the properties and applications of dielectric materials, 2009. ICPADM 2009
88. Blackburn, TRet al (1998) On-line partial discharge measurement on instrument transformers. In: Proceedings of 1998 international symposium on electrical insulating materials, 1998
89. Akbari A et al (2001) High frequency transformer model for computation of sectional winding transfer functions used for partial discharge localization. In: Proceedings of the 12th international symposium on high voltage engineering, Bangalore, India
90. Werle P et al (2001) Localisation and evaluation of partial discharges on power transformers using sectional winding transfer functions. In: 12th International symposium on high voltage engineering (ISH), Bangalore, India
91. Gockenbach E, Borsi H (2008) Transfer function as tool for noise suppression and localization of partial discharges in transformers during on-site measurements. In: International conference on condition monitoring and diagnosis, 2008. CMD 2008
92. Tenbohlen S et al (2000) Enhanced diagnosis of power transformers using on-and off-line methods: results, examples and future trends. CIGRE paper: 12-204
93. IEEE guide for diagnostic field testing of electric power apparatus—part 1: oil filled power transformers, regulators, and reactors. IEEE Std 62-1995 (1995), pp 1–64
94. Transformers—part, 5: ability to withstand short circuit. IEC Standard, 2000: 60076-5
95. Jayasinghe JASB et al (2006) Winding movement in power transformers: a comparison of FRA measurement connection methods. IEEE Trans Dielectr Electr Insul 13(6):1342–1349
96. BehjatV, TamjidiV(2015) Leakage inductance behavior of power transformer windings under mechanical faults. In: Proceedings of the international conference on information technology and computer engineering (ITCE), ITCE'15
97. Bagheri M et al (2013) Frequency response analysis and shortcircuit impedance measurement in detection of winding deformation within power transformers. IEEE Electr Insul Mag 29(3):33–40
98. Secue JR, Mombello E (2008) Sweep frequency response analysis (SFRA) for the assessment of winding displacements and deformation in power transformers. Electr Power Syst Res 78(6):1119–1128
99. Patel K et al (2013) Power transformer winding fault analysis using transfer function. In: 2013 Australasian Universities power engineering conference (AUPEC)
100. Rahimpour E et al (2000) Modellierung der Transformatorwicklung zur Berechnung der Ubertragungsfunktion fur die Diagnosevon Transformatoren. Elektrie 54(1–2):18–30
101. Dick EP, Erven CC (1978) Transformer diagnostic testing by frequency response analysis. IEEE Trans Power Appar Syst PAS– 97(6):2144–2153
102. PhamDAKet al (2012) FRA-based transformer parameters at low frequencies. In: ICHVE 2012—2012 international conference on high voltage engineering and application 2012

103. Prevost T (2015) Power transformer insulation diagnostics, Omicron Seminar, Perth, WA
104. Birlasekaran S, Fetherston F (1999) Off/on-line FRA condition monitoring technique for power transformer. IEEE Power Eng Rev 19(8):54–56
105. ANSI/IEEE C57.91, IEEE guide for loading mineral-oilimmersed transformers (1995)
106. John J, Winders J (2002) Allentown. Marcel Dekker Inc, Pennsylvania
107. IEEE guide for loading mineral-oil-immersed transformers, IEEE Std C57.91 (1996)
108. Bai CF, Gao WS, Liu T (2013) Analyzing the impact of ambient temperature indicators on transformer life in different regions of Chinese Mainland. Sci World J 2013:125896
109. Schaut A, Autru S, Eeckhoudt S (2011) Applicability of methanol as newmarker for paper degradation in power transformers. IEEE Trans Dielectr Electr Insul 18(2):533–540
110. Wouters PAAF, Schijndel AV,Wetzer JM (2011) Remaining lifetimemodeling of power transformers: individual assets and fleets. IEEE Electr Insul Mag 27(3):45–51
111. Gorgan B et al (2012) Calculation of the remaining lifetime of power transformers paper insulation. In: 2012 13th International conference on optimization of electrical and electronic equipment (OPTIM).
112. Martin D et al (2015) An updated model to determine the life remaining of transformer insulation. IEEE Trans Power Deliv 30(1): 395–402.
113. Emsley AM (2000) Degradation of cellulosic insulation in power transformers. Part 3: effects of oxygen and water on ageing in oil. IEEE Proc Sci Meas Technol 147(3): 115–119.
114. ME (2015) Life cyclemanagement of power transformers: results and discussion of case studies. IEEE Trans Dielectr Electr Insul 22(4): 2379–2389.
115. Oommen TV, Prevost TA (2006) Cellulose insulation in oil-filled power transformers: part II maintaining insulation integrity and life. IEEE Electr Insul Mag 22(2): 5–14.
116. Gockenbach E et al (2012) Life time prediction of power transformers with condition monitoring. In: 44th International conference on large high voltage electric systems 2012.
117. An international survey of failures in large power transformers in service, CIGRE Working Group 05, Electra, no. 88, 21–48 (1983).