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ORIGINAL PAPER

A review of condition monitoring techniques and diagnostic tests for lifetime estimation of power transformers

Md Mominul Islam[1] · Gareth Lee[1] · Sujeewa Nilendra Hettiwatte[2]

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Abstract Power transformers are a key component of electrical networks, and they are both expensive and difficult to upgrade in a live network. Many utilities monitor the condition of the components that make up a power transformer and use this information to minimize the outage and extend the service life. Routine and diagnostic tests are currently used for condition monitoring and appraising the ageing and defects of the core, windings, bushings and tap changers of power transformers. To accurately assess the remaining life and failure probability, methods have been developed to correlate results from different routine and diagnostic tests. This paper reviews established tests such as 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 considers the methods widely used for health index, lifetime estimation, and probability of failure. The authors also highlight the strengths and limitations of currently available methods. This paper summarizes a wide range of techniques drawn from industry and academic sources and contrasts them in a unified frame work.

✉ Md Mominul Islam
md.islam@murdoch.edu.au

Gareth Lee
Gareth.Lee@murdoch.edu.au

Sujeewa Nilendra Hettiwatte
sujeewa@nsbm.lk

1 School of Engineering and Information Technology, Murdoch University, Murdoch, Australia

2 School of Engineering, National School of Business Management, Colombo, Sri Lanka

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1 Introduction

In electric power systems, power transformers are usually considered the most costly item and comprise about 60% investment of high-voltage substations [1]. The huge investment and growing demand of electricity motivate utilities to accurately assess the condition of transformer assets. During operation, transformers regularly experience electrical, thermal, chemical and environmental stresses. Over time, due to these stresses, faults and chemical reactions, different types of catalytic ageing by-products like moisture, acids and gases are produced in transformer oil. The ageing products gradually reduce the dielectric and mechanical strength of insulation. Consequently, as transformers approach the end of their service life, their probability of failure increases. Additionally, regular overloading and short-circuit incidents on aged transformers may lead to unexpected premature failures, resulting in damage to customer relationships due to interruption of power supply. Moreover, failure of transformers can damage the environment through oil leakages and could be dangerous to utility personal by creating fire and explosions, resulting in costly repairs and significant revenue losses.

This paper reviews established routine and diagnostic tests for condition monitoring and lifetime estimation and underlines the limitations of individual methods. Routine tests are periodically conducted after a certain interval to assess the overall condition and check the performance of transformers. If any degraded performance is detected in routine tests, diagnostic tests may need to be performed. Moreover, after any fault, commissioning and transportation, some diagnostic tests are always performed to check the integrity of a transformer. The measurements produced by these tests are used by most utilities to produce health indices that indicate the operating condition and estimate the remaining lifetime. This paper would be useful for new maintenance engineers taking responsibility for managing electrical power assets to help them set up a strategy for maintenance.

However, in scheduled maintenance, a fault can develop in the time between inspections and can be catastrophic. This limitation promotes utilities to move away from scheduled to condition-based maintenance [2,3]. Condition-based monitoring means that the schedule for conducting tests reflects the best current knowledge about the condition of a transformer based on the results of previous tests. This implies a transformer that is considered as being in poor condition is monitored more frequently than the scheduled maintenance rate. Condition-based monitoring can help to avoid unexpected failures through improved assessment of insulation and can save both down time and money wasted by scheduled maintenance. Condition-based monitoring does not imply online monitoring, where remote sensing is used to monitor the transformer in real time, but online monitoring has become established for important assets. This paper has been organized as follows: In Sect. 2, statistical failure rate and standard diagnosis have been discussed. Section 3 provides a short review of different routine and diagnostic tests. In Sect. 4, remaining service life calculation methods have been discussed. Section 5 concludes the paper.

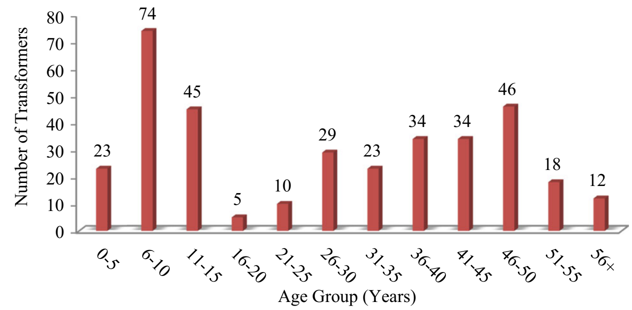

Fig. 1 Power transformers age profile

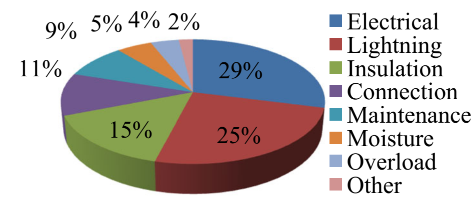

Fig. 2 Causes of failure [4]

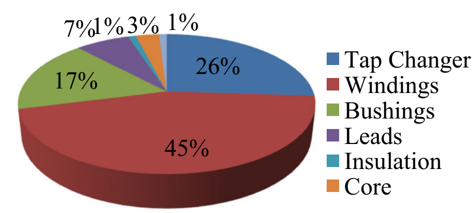

Fig. 3 Failure locations of transformers [5]

2 Transformer failure statistics

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

According to the age profile, a large population of transformers (110) out of 360 has already crossed the average service life and increasing to 167 within the next decade. So, around 31% of these transformers based on their service length have already exceeded the operator's expected lifetime and an additional 16% will lapse within a decade. Nevertheless, the rate of failure among transformers beyond their projected lifetime is less than expected by the utilities and they are performing well. In order to avoid unpredicted failures of these transformers in the near future, instead increasing time-based maintenance, continuous condition monitoring is highly desirable.

Transformer failure rate and life expectancy are affected by a range of external and internal mechanisms such as electrical, thermal and mechanical causes. Electrical stresses like switching surges, lightning impulses or frequent over loading gradually reduce the dielectric strength of insulation that ultimately leads to transformer failure. The increased contact resistance, partial discharge (PD) and problems with the cooling system increase operating temperature, while mechanical deformation can arise from short-circuit current and transportation. Thermal stresses and mechanical defects, when combined with moisture and contamination, will increase the ageing rate of insulation and hasten the electrical failure. Statistics about the common causes of transformer failure are shown in Fig. 2 [4].

Although the main tank accessories are the primary contributors to transformers failure, there is also a significant contribution from bushings, tap changers, and other accessories. According to a recent survey conducted by CIGRE work group WGA2.37 on 364 failures (>100 kV) [5], the statistics of typical failure location has been illustrated in Fig. 3. Additionally, their study on Europe shows that 80%

of bushing failure occurs in mid-service age (12–20 years) and initiate 30% of transformer failures. Given this statistic, it is apparent that the integrity of a transformer is dependent on multiple factors. It is also essential to prioritize the diagnostic tests based on the degree of influence each component has on transformer health. A taxonomy of important diagnostic methods for condition assessment of transformers is provided by Fig. 4.

3 Condition monitoring and diagnostic tests

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

3.1 Dissolved gas analysis

Dissolved gas analysis (DGA) is a widely accepted and established method for condition monitoring of power transformers. It can identify faults such as arcing, partial discharge, low-energy sparking, overheating, and detect hot spots at an early stage without interrupting the service [6]. This approach is accompanied by analysing combustible and non-combustible gases dissolved in transformer oil. During their working life, transformers regularly have to face faults and stresses (thermal, electrical, chemical, and mechanical) that produce various fragments, ageing and polar oxidative products. Over time, due to interaction between fragments or interaction among ageing products, various chemical reactions start that change the molecular properties of oil–paper insulation [7]. Additionally, the catalytic behaviour of oxygen and moisture produced in oil–paper insulation along with thermal dynamic increases the reaction rate. Eventually, different type of gases such as 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) are produced and dissolved in transformer oil. To assess the condition of oil and paper insulation and detect faults indirectly from the gases, a number of DGA methods like Key Gas, Roger's Ratios, Duval Triangle, Doernenburg, IEC ratio and single gas ratio are currently in use [6]. According to [8], 70% of power transformer common faults can be detected by DGA. An integrated gas monitoring system is helping operators to continuously monitor the trends and production of gases produced by operating transformers. However, comparison of results from different methods on the same sample may lead to contradiction and there is no clear way to prioritize one result over another. An integrated gas monitoring system along with supplemental tests might help to overcome this limitation by cross-checking the faults. Although DGA can detect and classify faults, in most cases, it cannot identify the fault location. Consequently, operators need to supplement the results with other diagnosis methods. A review of the various DGA methods follows.

3.1.1 Key gas analysis (KGA) method

The Key gas method diagnoses faults based on the proportion of combustible gases. It provides a series of "templates" associated with standard fault conditions. For instance, 63% of ethylene with some ethane (19%) and methane (16%) indicates that transformer oil is overheated [9]. If the majority of gas is carbon monoxide (92%), then it indicates that the cellulose is overheating. A high percentage of hydrogen (85%) with some proportion of methane (13%) indicates partial discharge, while a high percentage of hydrogen (60%) with some percentage of acetylene (30%) indicates arcing in oil. In practice, it is almost impossible to obtain exact proportions of gases that perfectly match these templates. Often the percentages are lower, but experience can see a trend and intervene early before a critical stage is reached. As a result, the accuracy of KGA is highly dependent on the investigator's experience and correlation skills.

3.1.2 Roger's Ratios method

Roger's Ratios method (RRM) uses the ratios of gas concentration to identify and classify faults in a transformer. The ratios of C_2H_2/C_2H_4, CH_4/H_2 and C_2H_4/C_2H_6 are used in this method. According to RRM, the classification of different electrical and thermal faults is shown in Table 1. In some cases, the calculated ratios may not fall any of the classes shown in Table 1. Additionally, over time, gases are normally produced in transformer without any fault. Consequently, the chance of misclassification is a major limitation of the Roger's Ratios method.

3.1.3 Gas patterns method

According to the gas patterns method, ethylene (C_2H_4) and methane (CH_4) are the key gases that are used to detect poor connection between conductors [10]. Over time, due to vibration of the transformer, the contact between conductors may become weaken and increase the series resistance. As a result, with the flow of current, the contacts get over heat and the hot metal gases such as (C_2H_4) and (CH_4) are pro-

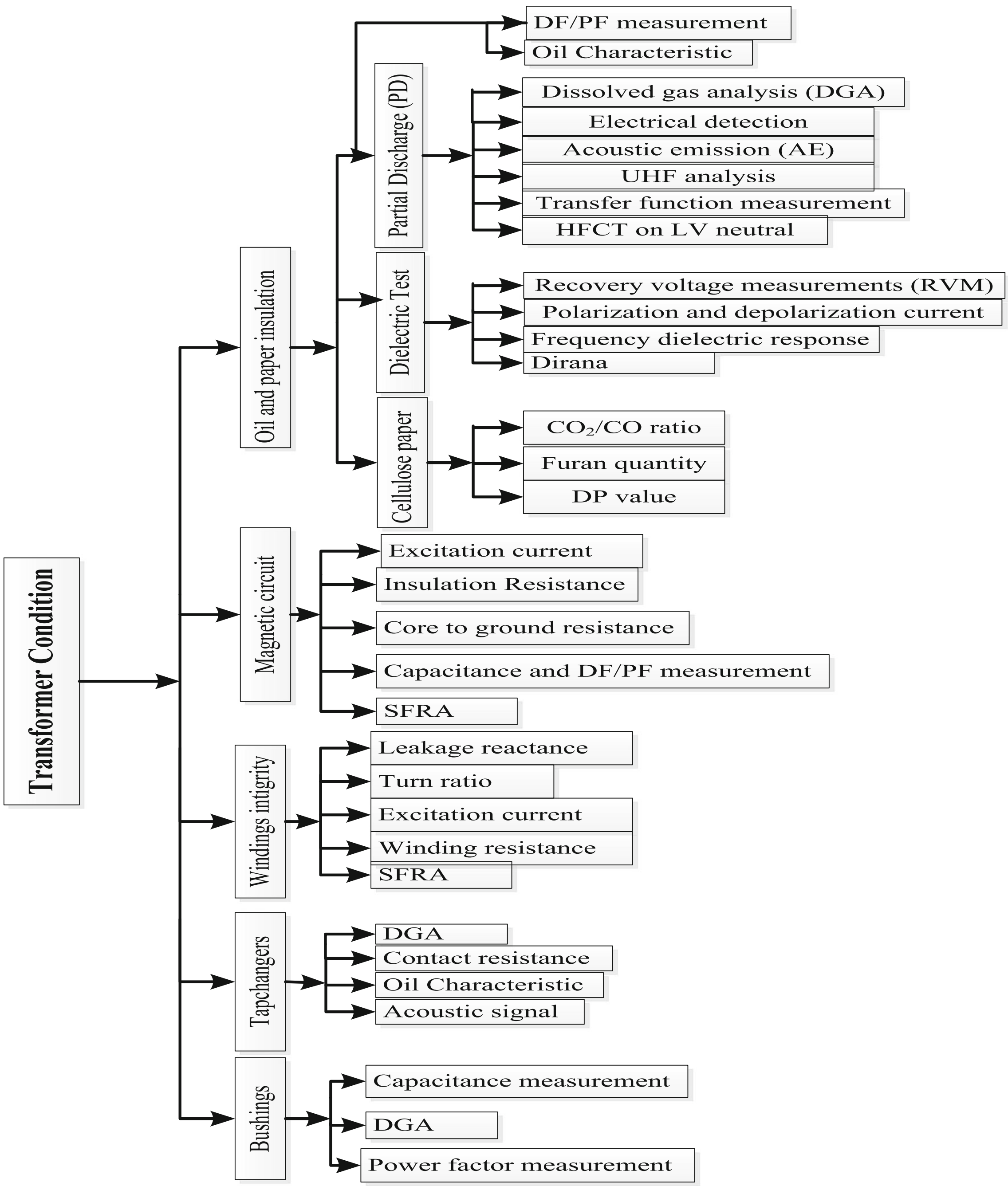

Fig. 4 Condition monitoring and diagnostic techniques

Table 1 Roger's ratios [9]

Case	$R2 = C_2H_2/C_2H_4$	$R1 = CH_4/H_2$	$R5 = C_2H_4/C_2H_6$	Suggested fault diagnosis
0	<0.1	>0.1 to <1.0	<1.0	Unit normal
1	<0.1	<0.1	<1.0	Low-energy density arcing—PD
2	0.1–3.0	0.1–1.0	>3.0	Arcing-high-energy discharge
3	<0.1	>0.1 to <1.0	1.0 to 3.0	Low temperature thermal
4	<0.1	>1.0	1.0 to 3.0	Thermal <700 °C
5	<0.1	>1.0	>3.0	Thermal >700 °C

Table 2 Gas ratios for Doernenburg method [11]

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_2	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)

duced. Additionally, a small proportion of catalytic metals for instance iron, copper, zinc, aluminium and dibenzyldisulphide (DBS) are inherently present in a transformer [10]. The normal proportion of dibenzyldisulphide (DBS) in transformer oil is between 40 and 65 mg/kg. The concentration of DBS decreases with an increase of temperature. At high temperature, the sulphur of DBS starts reacting with copper and produces copper sulphide [10]. As this reaction is completely temperature dependent, the concentration of copper sulphide and DBS can be used to assess the quality of internal contacts of transformers.

3.1.4 Doernenburg method

Doernenburg is a four gas ratios method based on five individual key gases (H_2, CH_4, C_2H_2, C_2H_4 and C_2H_6) that can detect faults and PD activity in a transformer. The accuracy of this method is high, but only if significant amount of key gases is produced. The correlation summary between faults and four gas ratios is shown in Table 2.

3.1.5 Duval Triangle Method

The Duval Triangle Method (DTM) is a three axis coordinated graphical method, where the axes represent CH_4, C_2H_4 or C_2H_2 percentages from 0 to 100% [12]. Due to its accuracy and capability of detecting large number of faults, it is widely used by the utilities. In DTM, the entire triangular area has been subdivided into 7 fault regions labelled PD, D1, D2, T1, T2, T3 and DT, as shown in Fig. 5 [13]. The PD region indicates partial discharge, D1 indicates discharges of low energy, D2 indicates discharges of high energy, T1 indicates thermal faults of less than 300 °C, T2 indicates thermal faults between 300 and 700 °C, T3 indicates thermal faults greater than 700 °C, and DT indicates a mixture of thermal and electrical faults. Although this method always gives a diagnosis, there is a chance of misclassification close to the boundaries between adjacent sections [14]. The classical Duval Triangle cannot accurately detect the PD and thermal fault. In order to overcome the limitation, Duval introduced Triangle 4 and 5 for mineral oil filled transformers. In Triangle 4, axes are presented by H_2, CH_4 and C_2H_6 gases. If the fault classification is a thermal fault (T1, T2) or a PD by the classical triangular method, then Triangles 4 must be used for further clarifica-

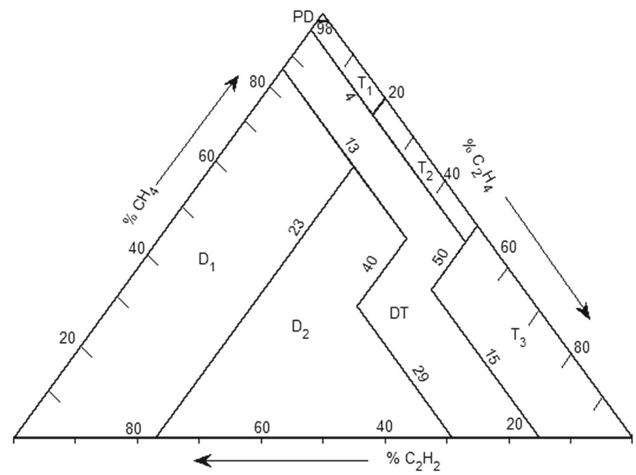

Fig. 5 Duval Triangle [14]

tion [15]. Triangle 5 uses gas concentrations of CH4, C_2H_4 and C_2H_6, respectively, that are formed specifically for faults of high temperature (T2, T3). In order to get more information about the thermal faults, Triangle 5 should be used only if Triangle 1 identified the fault as T2 or T3. None of the Triangles 4 and 5 should be used for electrical fault D1 or D2. In practice, there are cases where contradictory classifications are produced by Triangles 4 and 5. Moreover, all triangles have an unclassified region. Consequently, the accuracy of fault classification is dependent on the expert's experience supported by other ratio methods. Furthermore, it can only predict the amount of discharge from the changes of gases, not quantify the discharge, especially for small discharges like pico-coulombs (pC) range, nor can it locate the origin of a fault.

Over the last decade, a several artificial intelligence (AI) methods such as artificial neural networks (ANN), support vector machines (SVM) and fuzzy logic have been used by the researchers to analyse the DGA data to detect insulation degradation, identify faults, track performance and calculate health index of transformers [16–20]. The AI approaches have made it possible to analyse the DGA data sets into the multidimensional spaces to extract the pattern of the gases for faults detection and classification. Moreover, AI can integrate multiple factors and can deal with the nonlinearity of gases production which is common in field measurements to reduce the error in decision making.

Table 3 Classification based on oil test parameters

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

3.2 Oil quality test

Insulating oil quality testing is a common method for assessing the condition of in-service transformers. As the oil condition has a direct influence on the transformer's performance and the service life, condition monitoring of transformer oil has proven very effective. Over the service period, due to the oxidation, chemical reactions and variable stresses (thermal, electrical and chemical stresses), oil characteristics and condition change. To quantify these changes and diagnose the severity, a number of physical, chemical and electrical tests like dielectric breakdown voltage (DBV), power factor, interfacial tension (IFT), acidity, viscosity, colour and flash point are performed. DBV measures the strength of oil to withstand electrical stress without failure [21]. The power factor or dissipation factor test is used to measure the dielectric losses in the oil [22]. As the test is very sensitive to ageing products and soluble polar contaminants, it can assess the concentration of contaminants in the insulating oil. During service time, different types of acids are produced in the transformer oil resulting from atmospheric contamination and oxidation products [23]. The acids, along with oxidation products, moisture and solid contaminants degrade different properties of the oil. Consequently, the acidity test plays an important role to assess the condition of oil. IFT measures the attraction force between oil and water molecules that can be used to assess the amount of moisture in oil [4]. The value of IFT can help to estimate the soluble polar contaminants and products of degradation that affect the physical and electrical properties of the insulating oil. Usually, new insulating oil in transformers shows high levels of IFT in the range of 40–50 mN/m, while an oil sample with IFT <25 mN/m indicates a critical condition [24]. A detailed procedure for IFT measurement is available in [25]. Viscosity of oil is a factor that plays an important role in heat transfer in transformers. With the increase in temperature, viscosity of pure oil decreases. Therefore, the strength of the insulation decreases. Different types of nanoparticles such as SiO_2, Al_2O_3 and ZnO can be added to insulating oil to control its viscosity, which can be measured by applying a COMPASS force field [26]. Additionally, tests such as colour and flash point are used to detect contaminants in service-aged oil [27]. Multiple results are correlated to assess the condition of each transformer and schedule its maintenance (reclamation or replacement) to avoid costly shutdown and premature failure. IEEE C57.106-2006 presents a classification of insulating oil based on variable test parameters and transformer rated voltage that has been shown in Table 3.

Table 4 Heating severity classification [31]

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

3.3 Infrared thermograph test

Infrared thermography is a non-destructive and quick imaging process that can visualize the external surface temperature of transformers without interrupting their operation [28]. The normal operating temperature of transformers lies between 65 and 100 °C [29]. The operating temperature of a transformer can rise based on variable reasons like short-circuit current, high winding resistance, poor contact in cable/clump joint, oil leaks and faulty cooling system. With the increase in temperature, the ageing rate of insulation increases. The ageing rate of insulation becomes double at 6–8 K (Kelvin) from the reference value and reduces the residual working life quickly [4]. A temperature rise of 8 to 10 °C from nominal value is considered as a critical condition and reduces the design life by half [4]. According to [30], a transformer will fail immediately with an increase in 75 °C from normal temperature. The increased temperature could be an indication of problematic cooling system, or a problem in core, winding, bushing and joints. To identify faults, infrared thermography converts the infrared radiation from targeted surface into colour-coded pattern images. The test can localize the hot sport and visualize the temperature gradient at joints and surfaces. The test result can be verified by comparing with historical record or conducting a DGA on the same transformer. Consequently, this method can be used as an initial fault detector and supplement of DGA. However, thermograph cannot detect the internal temperature of a transformer tank [31]. A classification of heating severity based on infrared thermography has been summarized in Table 4.

3.4 Excitation current test

This test is used to detect short-circuited turns, ground faults, core de-laminations, core lamination shorts, poor electrical connections and load tap changer (LTC) problems. Since the magnitude of magnetizing current in high-voltage (HV) winding is less, this test is performed by exciting the HV side, keeping the LV neutral grounded and all other terminals floating. Due to the grounded neutral, if there is any ground fault, a huge amount of current will flow into the HV side with low excitation voltage. During this test, the magnitude of single phase voltage and magnetizing current including their phase angle is measured [32]. The measured value is compared with historical test or other phases to detect faults. For 50 mA rated excitation current, a difference of >5% between phases is an indication of short-circuited turns, ground faults, core de-laminations, core lamination shorts, poor electrical connection and LTC problems, whereas >10% deviation is an indication of internal fault [4]. As the test result is influenced by the residual magnetism, this test must be conducted before any direct current test.

3.5 Power factor/dielectric dissipation factor test

The dielectric dissipation factor (tan δ) test may be used to check the insulation integrity in windings, bushings and oil tank of transformers. When an alternating voltage is applied across the insulation, a leakage current having reactive (capacitive) and resistive components starts to flow. The magnitude of the resistive component is dependent on the moisture, ageing and conductive contaminants in the oil, while the capacitive current is dependent on the frequency. The ratio of resistive and capacitive current is known as the dissipation factor. At low frequencies, the magnitude of capacitive current is almost equal to the total leakage current. Consequently, another name of this test is the power factor test. According to IS-1866, at 90 °C, the value of tan δ for fresh oil could vary from 0.010 to 0.015 depending on the transformer's rating. A mathematical correlation between power factor and tan δ can be established using the following equation [33].

$$\cos\theta = \frac{\tan\ \delta}{\sqrt{1+(\tan\ \delta)^2}} \text{ or } t\mathrm{an}\,\delta = \frac{\cos\theta}{\sqrt{1-(\cos\theta)^2}} \quad (1)$$

Modern testing tools, like Doble M4100, measure the dielectric losses of insulation (including bushing) in Watts. A value of more than 0.5% tan δ deviation indicates problematic insulation, while >2% means the high chance of imminent failure [4]. However, a higher value of tan δ could also be an indication of potential PD.

3.6 Polarization index measurement

The polarization index (PI) measurement is one of the common methods to assess the dryness and cleanness of windings solid insulation that depends on the insulation classes (A, B or C) and winding components [34]. A PI measurement determines the ratio of 10-min resistance to 1-min resistance after applying the test voltage to assess the insulation condition [35]. The winding temperature has a strong influence on the measurement of insulation resistance (IR). However, PI is determined by the ratio of two resistances, so the impact of winding temperature during the 10-min test is almost insignificant. With the increase in moisture and impurity in insulation, the PI value gradually decreases. According to [34], insulation having PI in the range 1.5–2 indicates dry insulation, the range 1–1.5 indicates dirty/wet insulation and <1 indicates severe pollution and humidity. Moreover, if the PI value rapidly decreases 25% from a previous measurement, it is advisable to clean the insulation [34]. Although it is a comparatively quick and convenient testing method, it cannot detect the degradation of insulation due to the ageing and stresses over time.

3.7 Capacitance measurement

The capacitance measurement is used to assess the condition of bushings and detect the gross winding movement. The bushings of a transformer are electrically equivalent to a number of series capacitors. If a bushing has a dielectric dissipation factor (DDF) tap, the capacitance between the bushing conductor and DDF tap is commonly known as C_1 and the capacitance between DDF and ground is known as C_2. The average lifetime of bushing is about 30 years. Any problems in bushing like cracking of its resin-bonded paper or moisture ingress would increase the value of capacitance and reduce its service life. Consequently, the measured capacitance can diagnose the condition of bushings. In [4], it has been stated that about 90% of bushing failure is due to moisture ingress. The test can also be used to measure capacitance between windings and between individual windings and the main tank. Any deviation of the capacitance value can be used to detect the mechanical deformation of windings and core. As this test is less sensitive and only detects gross deformation of windings, a more sensitive approach such as transfer function measurement and SFRA may be used as a supplement to the capacitance testing.

3.8 Transfer function measurement

Transfer function (TF) measurement is one of the acknowledged methods that can predict moisture content in solid insulation [36] and detect mechanical faults like winding deformation and displacement due to the short-circuit current, switching impulse and transportation [37–39]. The transfer function is a frequency-dependent parameter that is measured from the ratio of current and voltage of an input terminal, or from the ratio of output and input voltage on the same phase. During TF measurement, a known voltage is generally applied to the HV terminals and the resulting input current is measured from the same side while voltage is measured on the corresponding LV winding. A detailed test procedure for TF measurement is available in [37]. The TF measurement is sensitive enough to detect both axial and the radial buckling of windings, which cannot be detected by the conventional leakage reactance measurement. Moreover, TF measurement can specify faults without opening the unit and both online and offline modes are available [38,39].

3.9 Tap changer condition

The load tap changer (LTC) of a transformer is used to regulate the voltage despite variations in the load. A range of insulating materials like oil, fibreglass, cardboard and proxy resin are used in a tap changer as its insulation. Failure to a tap changer can result into a catastrophic failure of nearby transformers. The authors of [4] and [1], respectively, state that 30 and 40% of transformer failure results from the tap changer malfunction and this could varies depending on the tap changer types, manufacturer, operation and maintenance frequency. Unlike in the main tank, a certain amount of combustible gas in the tap changers is considered normal, which is produced from the operation of LTC. The trapping of gases is depending on the breathing system. A sealed LTC can trap most of the gases while gas is rapidly vents from a free breathing system [40]. However, insufficient adoption of standards and the lack of guidelines make it hard to assess the condition of LTC directly from DGA [1]. Consequently, a series of tests such as DGA, oil quality, contact resistances and acoustic signal are performed; at the same time, the number of operations, temperature and motor current is monitored to assess the condition of tap changer and its insulation.

3.10 Cellulose paper insulation tests

The solid insulation (paper) within transformers is composed of about 90% cellulose, 6–7% of hemicelluloses and 3–4% of lignin that have long chains of glucose rings [33]. The purpose of this paper is both to provide insulation and mechanical support against forces that arise from short-circuit and inrush current, and holding the windings in position. The dielectric properties and tensile strength of the paper are dependent on the number and length of glucose rings [3]. Over time, due to the ageing, stresses and loading pattern, the electrical and mechanical properties of the paper degrade and a number of chemical compound and by-products like water, acid and gases (CO and CO_2) are produced. These by-products are used in several diagnostic techniques like furan analysis and the degree of polymerization (DP) and CO_2/CO ratio for assessing the condition of paper insulation. All three methods have been reviewed below.

3.10.1 Ratio of CO_2 and CO

The ratio of CO_2/CO can help to assess the condition of paper insulation. Generally, without any fault occurring, during the service time, including CO_2 and CO different proportion of combustible gases are always produced in transformer and dissolved in the oil. The carbon oxide gases (CO_2 and CO) can be produced from the paper due to cellulose overheating, bad connection and problematic cooling system of transformers. However, oil decomposition can also produce these gases due to different faults [4]. A $CO_2/CO > 10$ could mean atmospheric exposure of insulation and instant breakdown, while a CO_2 to CO ratio less than 5 indicates faster degradation of cellulose. For proper maintenance, the identification of gas sources is important. The CO_2/CO ratio method cannot distinguish the sources. Consequently, there is a chance of wrong diagnosis providing a major limitation of CO_2/CO ratio method. In order to overcome this limitation, additional tests such as furan analysis and the DP are recommended along with analysis of other key gases.

3.10.2 Furan analysis

Furan analysis is an integral, non-periodic and post-diagnostic technique that can assess the condition of cellulose paper inside transformers without interrupting the service. Due to the ageing, loading pattern and chemical reaction, the glucose rings of cellulose may break down and the following types of furanoid compounds, namely, 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) are produced which are partially soluble in oil [33]. The produced furanoid compounds develop a partition between the oil and the solid insulation interphase [41]. The production rate of furanoid compounds is influenced by the temperature, catalytic ageing by-products such as moisture, acids, oxygen and CO, that are produced by various faults and increase the degradation rate of paper [4]. Over time, these furanoid compounds dissolve in the insulating oil and changes its colour. It is recommended to perform furan analysis, if the colour of oil changes remarkably and other catalytic ageing by-products are present [31]. Cellulose paper gradually loses its mechanical strength with the increase in furan which can be measured by the gas chromatography (GC), mass chromatography (MC) or high-performance liquid chromatography (HPLC) on collected oil sample following the American Society for Testing and Material (ASTM D5837) or IEC method 61198 [42,43]. A detailed method of HPLC for furan measurement is available in [44]. Moreover, the quantified furan can be used to estimate the remaining lifetime of transformers. If the strength of paper is reduced to such an extent that it cannot ensure the mechanical support to windings, the electrical integrity of transformer becomes threaten. The furan is very sensitive to the ageing of paper and comparatively stable than other furanoid compounds. As furan increases consistently with paper ageing, researchers mostly analyse it. The main limitation of this method is that if the insulating oil of a transformer is replaced or reclaimed, it cannot accurately assess the condition of solid insulation prior to the change. The thresholds for analysing ageing of paper insulation based on furan are shown in Table 5.

Table 5 Age profile of cellulose paper based on furan [1]

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

The degree of polymerization (DP) is another dependable method for assessing the health of paper insulation. The paper of transformers is a complex compound of carbon, hydrogen and oxygen ($C_5H_{10}O_5$) where glucose monomer molecules are linked in a special way to form cellulose. As the insulation ages, the glucose rings become fragile and start to break. In DP, the length of glucose molecules rings is measured as a way of estimating the integrity of the paper insulation [45]. To measure DP, paper samples are collected from multiple positions around the windings including the hot spot area, which is generally located at the centre of windings. The collection of paper samples from a live and free-breath transformer is impractical and could be destructive or may cause complete failure of a transformer [46]. Consequently, paper samples are collected from the de-energized transformer and analysed by molecular weight estimation methods like viscometry or gel permeation chromatography (GPC). In the viscometry method, the DP value is measured by averaging the length of cellulose chains based on their viscosity [47,48]. The accuracy of this method is influenced by the oxidative degradation of the samples and variation in ambient temperature [49,50]. In [51], Ali has shown that viscometry can only approximate the length of a cellulose chain, but GPC has greater potential than viscometry method to give more useful and detailed information about cellulose ageing. In GPC, a DP value is calculated by measuring the change in molecular weight distribution of the cellulose paper. As GPC is very sensitive to molecular weight, it can detect a small degradation of cellulose through the chromatogram [50]. A detail sampling and testing process for GPC is available in [50]. Due to the intrusive sampling process, furan analysis is more widely used than DP. The furan test can easily make estimates of furan from oil sampling of an in-service transformer. As furan splits glucose rings into small segments, with the increase in furan, the DP value decreases. Consequently, cellulose paper loses its insulation quality and tensile strength. The value of DP and the level of furan can be correlated to estimate the health

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	<250	End-of-life criteria

of paper/solid insulation. A correlation between DP and furan to estimate insulation state is shown in Table 6.

Although the measurement of DP from the furan is non-destructive and relatively straightforward, the contamination of the oil and non-uniform ageing of the paper constrain the method in practice [47].

3.11 Dielectric response analysis

Dielectric response analysis (DRA) is a widely adopted method for evaluating the moisture content in the oil–paper insulation of transformers. In power transformers, both the oil and cellulose paper provide the insulation. Moisture occurs inside a transformer is produced from chemical reactions and is absorbed in the solid insulation (up to 99%) and oil. The production rate of moisture is influenced by the organic acids, gases, humidity, ambient temperature and oxygen content. A complex dynamic migration of moisture between oil and paper insulation always continues, and the rate is influenced by the temperature. At high temperature, moisture from the solid insulation moves in to the oil but returns to the insulation with a decrease in temperature. The amount of moisture in solid insulation can be measured directly by the traditional Karl Fischer Titration (KFT) or Piper–Fessler isothermal model [52,53]. The oil moisture content with the help of an equilibrium chart can also indirectly estimate the moisture in solid insulation [52]. The collection of paper samples from different places for KFT is mostly impractical and unsuitable for on-site testing. Additionally, the accuracy of the Piper–Fessler method is affected by the insufficient and incorrect positioning of moisture sensors in the transformer tank [53]. Moreover, the influence of temperature also makes it hard to achieve the equilibrium state of moisture between oil and paper, which can lead to a significant error in the measurement accuracy [54]. Consequently, over the last decade, to overcome the above limitations, different indirect, sensitive and non-destructive methods like recovery voltage measurement, polarization and depolarization current analysis and frequency dielectric response have gained significant attention for accurately measuring the moisture content and its impact on the dielectric response to assess the insulation ageing [2,29]. A review on different dielectric responses analysis techniques with their limitations has been provided below.

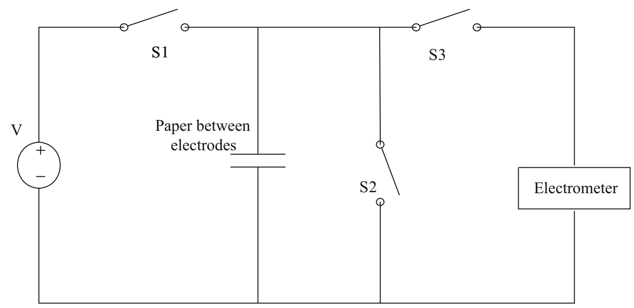

Fig. 6 Circuit diagram for RVM [56]

3.11.1 Recovery voltage measurement

Recovery voltage measurement (RVM) is a time domain dielectric response technique that is used to detect the moisture level in the insulation of transformers. The quantity of moisture in insulation gradually increases over time due to the ageing. The level of moisture is one of the key decisive factors used to measure insulation breakdown. Consequently, the individual knowledge of moisture level in the oil and paper insulation is crucial for evaluating the insulation health. RVM uses the polarization spectrum of the insulation recovery voltages for evaluating the actual state and ageing trend [2,55]. The RVM method can be represented by the circuit diagram shown in Fig. 6.

To perform the test, a DC voltage V by a standard recovery voltage meter is applied across the dielectric by closing the switch S_1 for a period of time T_c and then the capacitor is discharged through a short circuit for a period of time T_d by closing the switch S_2 (having previously opened the switch S_1). After discharge in each cycle, the geometric capacitance (C_0) loses its full charge but some charges are bounded in the dielectric insulation whose amount is dependent on the insulation quality. The entire cycle of the measurement is repeated and increased from a fraction of second to the thousands of second by maintaining the charging and discharging time ratio $(T_c/T_d) = 2$. After charging and discharging on each cycle, when the circuit is open, a part of the bounded charge will be transferred to the geometric capacitance. Eventually, a voltage is developed which is known as a recovery voltage (RV). The values of RV are recorded by a programmable electrometer having very high input impedance, as a function of time T_c and plotted to get the RV spectra. The peak magnitude of the voltage and the corresponding time constant are the significant features of the polarization spectra. The value of central time constant decreases with the increase in moisture in the oil–paper insulation and reflects the moisture content in the insulation [2]. According to [57], time constant of the insulation is inversely proportional to the moisture content and ageing. They also presented that the time constant is also inversely related to the temperature and the maximum return voltage decreases with the increase in moisture. Eventually, the moisture content and ageing trend can be estimated from the measured time constant and the RVM peak. However, the authors of [58] state that the influence of insulation geometry and separate conductivity of oil and paper insulation is ignored in the RVM. Consequently, the RVM spectra are not accurate. According to [59], it is hard to separate the impact of oil and paper from RVM spectra. However, the introduction of sophisticated software and proper modelling tools for dielectric phenomena which can combine the individual influencing factors like permittivity and conductivity of oil and paper insulation can overcome the limitation and improve the accuracy.

3.11.2 Polarization and depolarization current analysis

The polarization and depolarization current (PDC) measurement is one of the latest and non-destructive technologies used to measure the oil conductivity and moisture content of homogenous and composite insulations of transformers. Due to the simplicity and capability to assess HV insulation, PDC technique gained immense popularity and is widely used as a supplement of other techniques. Moreover, PDC can quantify the moisture and appraise its impact on the ageing of the oil and paper insulation [60]. For assessing the state of transformer insulation (oil–paper), in PDC measurement, a DC voltage U_0 is applied across the oil–paper insulation for a period of time (e.g. 10,000 s) to measure the polarization current. As soon as the voltage is applied, a high magnitude current with different time constants corresponding to the insulating materials and conductivity starts to flow. Over time, the magnitude gradually reduces. The time constant of the charging current is dependent on the conductivity and polarization process of the individual insulating material [59]. The equation of the polarization current can be expressed as

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

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.

Now, for measuring the depolarization current, the voltage source is replaced by a short circuit. Consequently, an opposite directional depolarization current will start to flow without the contribution of insulation conductivity [59]. The depolarization current can be expressed by the following equation.

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

where t_c is the duration of the applied voltage.

The dielectric response function $f(t)$ can be measured experimentally by charging the insulation through a step voltage or measuring the depolarization current after replacing the step voltage with a short circuit. If the time $t + t_c$ is significantly long, the dielectric responses function for the polarization current $f(t + t_c) \cong 0$. Consequently, Eq. (4) can be rearranged as follows

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

If the polarization and depolarization current of a composite insulation is known, the average conductivity of the combine insulation can be found by rearranging Eqs. (2) and (4)

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

The combined conductivity can also be calculated from the nonlinearity factor, which is the ratio of average conductivity at different voltages [61]. According to [62], conductivity, ageing and moisture content of insulation can be estimated from the PDC curve shown in Fig. 7.

As can be seen from this curve, the PDC value is mainly influenced by the conductivity in a time range $t < 100$ s. The current increases in proportion to the conductivity. The oil property, ageing and geometry are apparent after 100 s and the variation of moisture content is visible after 1000 s.

In [63], the authors state that if the inherent nonlinearity of a homogeneous insulation is neglected, the difference between polarization and depolarization current (conduction current) is constant and time independent. Moreover, reference [59] states that the initial conduction is very sensitive to the oil condition, whereas long-term current is mostly influenced by the condition of solid insulation. In the case of composite insulation, the difference is time dependent and is influenced by the separate conditions of oil and paper insulation, thus reflecting the true combined conductivity of the transformer's oil–paper insulation [64]. Thus, PDC testing can be used to accurately assess the condition of oil–paper insulation. On the contrary, the accuracy of the PDC

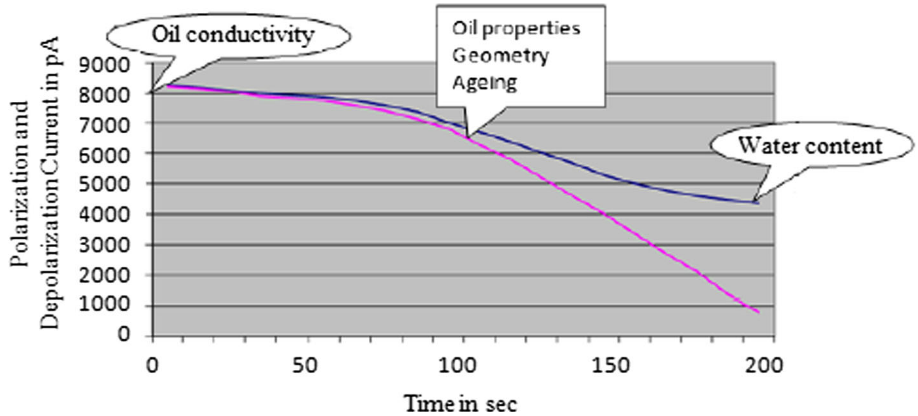

Fig. 7 Oil conductivity, oil properties, geometry, ageing and water content influence on the PDC-curves [62]

is dependent on the precise knowledge about the design and the composition of the oil–paper insulation and the measurement process is very time consuming. In practice, the exact design and insulation composition information are not easily available which is considered a major limitation of this method. In [59], a modelling process has been discussed to partially overcome the limitation.

3.11.3 Frequency dielectric response

Frequency dielectric response (FDS) is a widely accepted technique to diagnose the ageing state and moisture content in the oil–paper insulation of power transformers [65]. As FDR is very reluctant to external frequency (noise) and capable of giving detail analysis, it has received more attention than the RVM and PDC methods [66]. In FDR, the dielectric response of composite oil–paper insulation is measured at frequencies between 100 μHz and 1 kHz [65]. The range can vary depending on the moisture quantity in the insulation. However, the prominent resonance effect and impure dielectric response restrict the maximum frequency of FDR to 1 kHz. The ageing of insulation is mainly influenced by ingress of moisture, insulation geometry and temperature. The amount of moisture and ageing state can be estimated from the correlation of temperature, moisture and insulation geometry with dielectric response spectrum. However, it is hard to separate the impact of moisture, ageing and geometric impact from the dielectric response that is used to quantify the moisture content and ageing state [67]. A detailed process to overcome these limitations based on the dependent variables is presented in [66]. According to [66], in the frequency range of $10^{-3}-10^{2}$ Hz, the relative permittivity (ϵ_r) and dissipation factor (tan δ) of oil–paper insulation increases in proportion to the moisture. However, ϵ_r and tan δ are only sensitive to the ageing between $10^{-3}-10^{-1}$ Hz. Consequently, the frequency range $10^{-3}-10^{2}$ can be used to discriminate and quantify the effect of moisture and ageing on the insulation. However, a recent similar study in [65] states that the

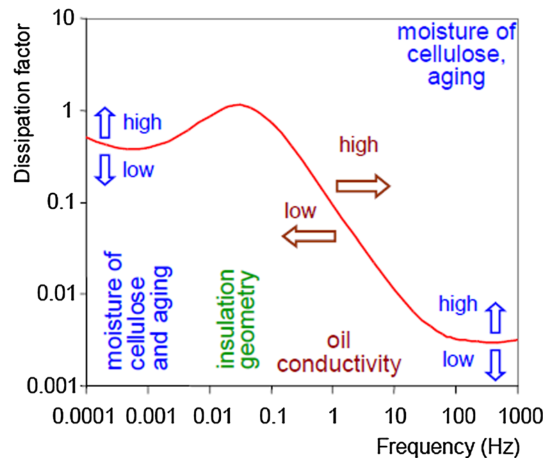

Fig. 8 Dielectric response of oil–paper insulation [68]

dielectric response of some pressboard sample may be used to determine moisture concentration (1, 2 and 3%). It was found that the slope of the dielectric response decreases with an increase in frequency. Above 100 Hz, all the sample slopes coincide and become flat. Eventually, the slope of the dielectric response below 100 Hz can be used to assess the condition of transformer paper insulation. According to [68], a typical dielectric response of oil–paper insulation is shown in Fig. 8.

3.11.4 Time–frequency domain dielectric response

Time–frequency domain dielectric response is the latest technology where the advantages of PDC and FDS have been combined to assess the condition of transformers insulation [69]. At low frequency, the PDC method is faster and represents the ageing of oil and paper insulation. At high frequency, the FDS method is faster than the PDC and can also assess the oil and paper insulation ageing. In this method, the advantages of both FDS and PDC have been combined to develop a faster, intelligent and powerful assessing method. The combined technology makes it possible to measure the dielectric response over a wider range of frequency (0.05

mHz to 5 kHz). The measured response could be compared with factory test data or historical measurement to accurately assess the state of oil and paper/pressboard insulation.

3.12 Partial discharge analysis

Partial discharge (PD) is a dielectric discharge in a partial area of electrical insulation system experiencing high electrical field intensity. In many cases, PD phenomena are considered as a preliminary stage of a complete breakdown of the insulation. Consequently, for monitoring the condition of power transformers and to avoid unexpected hazards, PD measurement is used over a long period of time. In transformers, PD can happen in cellulose paper, oil or in the interface of oil–paper insulation when the electric field stress exceeds the breakdown strength of insulation. Any defect such as cavities and voids in solid insulation, gas bubbles or small floating metal particles in oil can damage the uniformity of electrical stress across the insulation and may initiate PD that can lead to a flashover. Additionally, over time insulating material lose its dielectric strength due to continuous electrical, thermal and dielectric stress that directly influences the possibility of PD. According to [70,71], the inception voltage of PD decreases with an increase in temperature. The PD magnitude and repetition rate increase significantly with the size of gas bubbles in the oil [72]. The surface discharges on transformer insulation increase and the inception voltage also decreases with an increase in total harmonic distortion [73]. Once PD starts, it propagates throughout the insulation until complete breakdown occurs. Consequently, it is very important to detect, quantify and localize PD during operation [74]. During PD, a range of phenomena like electromagnetic emission (in the form of radio wave, light and heat), acoustic emission (in audible and ultrasonic ranges), ozone formation and the release of nitrous oxide gases may be observed [75]. By using different types of measurement techniques such as electrical, chemical, acoustic or optical, the PD phenomena can be detected and localized. A short review on different PD assessment methods has been included below.

3.12.1 Chemical detection

This is one of the simplest methods that can detect PD chemically by observing the chemical change in the composition of insulating materials. It is based on the collection and measurements of gas and oil samples released from PD activity. To measure PD, two chemical techniques such as DGA and HPLC are currently available. In the DGA test, oil from a transformer is sampled to measure the level of key gases in it .The measured gases are finally analysed by the Duval Triangle Method to detect PD. Although online monitoring of this method is available, the reading, level of gases and classified faults are not calibrated and scientifically correlated [76]. The HPLC method measures the PD by evaluating chemically stable by-products such as glucose during insulation breakdown. As the sample collection and analysis process is time consuming, this method is not suitable for real-time monitoring of PD. Moreover, the insufficient standard for assessing the severity of PD from glucose measurement increases the measurement uncertainty. Furthermore, both DGA and HPLC are unable to locate the origin of PD.

3.12.2 Electrical detection

This method is based on the detection of high-frequency electrical pulses produced from a void due to a strong electric stress across it. The test can be performed in either online or offline mode. In the case of offline mode, a known value of a coupling capacitor is connected in series with the detection impedance that need to connect across the test object. After completing wiring, the circuit is energized from a high-voltage AC source. The detection impedance can also be connected in series with test object (see Fig. 9) for a better signal-to-noise ratio. Although, connecting the impedance in series with test object gives more sensitivity, it is commonly used in series with a capacitor to save the measuring device from potential damage due to the breakdown insulation of test objects. Moreover, the test object needs to be disconnected from ground to allow a detector to be connected in series with it. This is an unusual practice for power transformers. For the online mode, the inner grading foil layer of the bushing is used as a capacitor and an inductor is connected to the ground through the outer layer subject to the bushing tab being grounded. The circuit diagram of typical PD measurement methods is shown in Fig. 9.

If PD is present, the void behaves like a capacitor and the voltage across it will continue to increase until breakdown happen. Consequently, the capacitor will be discharged and the voltage across it returns to zero. The charging and discharging process will continue throughout the cycle as long as the AC supply is connected. According to [77], the repetition rate of charging and discharging is over 1 MHz. The discharged energy will mostly be compensated by the coupling capacitor which is converted to a voltage signal through the detection impedance. Comparing with the AC cycle, the converted signal can give valuable information about PD like pulse shape, intensity, relative phase location, severity of insulation damage. Although this method is very sensitive to noise, time consuming and cannot localize PD sources, it can provide the most accurate result compared with other methods [78,79].

3.12.3 Acoustic detection

The acoustic emission method (AE) measures the amplitude, attenuation or phase delay of acoustic signals that are pro-

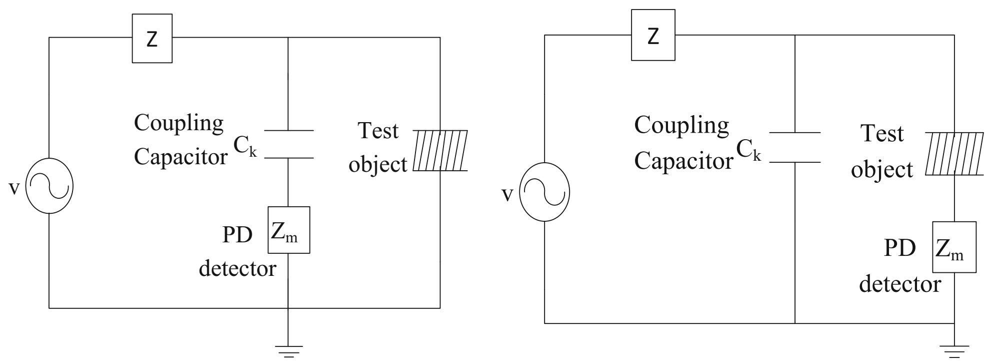

Fig. 9 Measurement of apparent PD by connecting detector at different position

duced from PD, to detect and locate the position of PD. The AE is a PD phenomenon-based method that senses acoustic waves in a frequency spectrum up to 350 kHz to detect PD [78,80]. During PD, mechanical stress of materials next to the point of origin causes an audible or non-audible AE signal to be produced. In order to detect the signal, a number of different sensors like piezoelectric transducers, microphones, accelerometers, sound resistance sensors and fibre optic acoustic sensors are commonly used [81]. The sensors are mounted on the outside wall of a transformer tank at multiple positions. The relative travel times that the signal reaches multiple sensors are triangulated to detect the source of PD and assess the severity of insulation defect [78]. Although AE signals are interfered with by the low-frequency mechanical vibration of a transformer, compared to electrical detection, it shows strong immunity against electromagnetic interference. Due to this special characteristic and high signal-to-noise ratio (SNR), this is an ideal method for online PD detection [81]. On the contrary, measurement complexity, extensive data processing and low sensitivity to the damping of oil, core, conductors and main tank are considered the main limitation of this method [80].

3.12.4 Ultrahigh-frequency detection

The ultrahigh-frequency (UHF) detection is a routine and continuous PD monitoring procedure for power transformers. This method measures the electrical resonance in the frequency range between 100 MHz and 2 GHz to detect and locate PD [82]. As the sensor is installed inside the transformer, the shielding effect of the tank helps to suppress any external noise [83]. Moreover, the low signal attenuation in oil insulation and the high sensitivity for an on-site measurement have increased the use of this method to test transformers. To measure PD, several sensors equipped with high sensitivity wideband antennas are installed inside the transformer tank. A calibration technique is applied before commencing the test to measure the sensitivity of the sensors and understand their exact phase and amplitude relationship. The position of the sensors is chosen in such a way that at least three sensors in parallel can detect signal from relevant parts of a transformer like the windings or tap changer. High-frequency cables with known attenuation and phase shift must be used for connecting the sensor to the control module. Finally, using the measured amplitude and travel time of the signals and applying established triangulation methods, a PD phenomenon may be detected and its source localized [84]. A detailed calibration and sensitivity checking procedure are available in [82].

3.12.5 Optical detection

Optical detection is one of the latest technologies used to detect and locate PD of transformers. During PD, beside electromagnetic emission, light spectra such as ultraviolet, visible and infrared always radiate from the various ionization, excitation and recombination process. The radiated spectra transport information about the energy level of discharge that can be measured by an optical sensor to detect and locate PD [85]. The amplitude of the energy depends on the surrounding insulating material. The optical spectrum in oil due to PD starts at approximately 400 nm and can extend into the infrared region [85]. The wavelength can vary depending on the insulation type and surrounding medium. Consequently, a sensor that can show the correct optical spectrum is crucial for PD detection. For transformers, a single or multimode fibre optic sensor is immersed in the oil tank. According to [86], the equipment set-up for optical detection is shown in Fig. 10.

In the diagram, the set-up consists of a He–Ne laser, phototransistor, amplifier, oscilloscope and multimode sensor to detect PD. He–Ne laser is operated in continuous wave mode to emit coherent power of 10 mW [86]. The PD source is simulated by using a HV source across the electrodes. The sensor collects the signals from the origin and guides it to the receiver (phototransistor). Output of the phototransistor automatically changes with the change of light intensity. After necessary conversion (optical to electrical) and amplification,

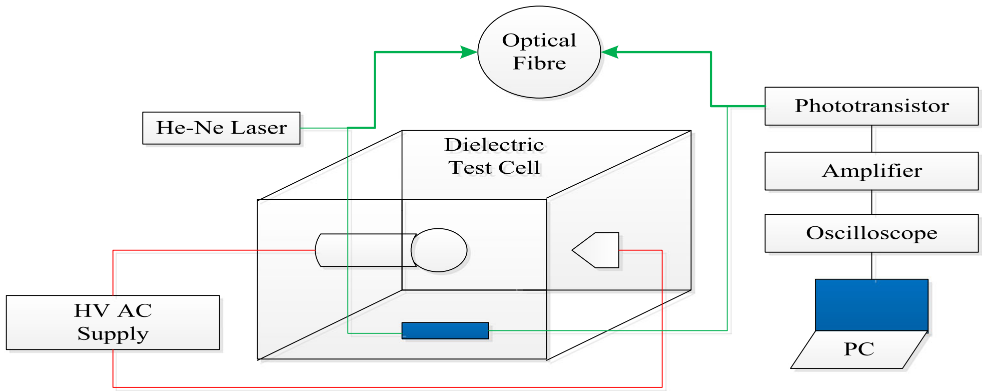

Fig. 10 Schematic diagram for optical PD detection [86]

the received signal is displayed by an oscilloscope to predict PD. Further analysis is required in computerized software to locate the PD source. As the method only receives optical signals, it is completely free from electromagnetic interference. Moreover, the high sensitivity and measurement capability in a wide bandwidth have made the method most popular in the high-voltage industry [83]. A detail procedure and analysis of this method are available in [85,86].

3.12.6 High-frequency current transformer installation

An inductive coupling sensor such as a high-frequency current transformer (HFCT) can be used to detect online PD in a power transformer [87]. In the HFCT method, an externally accessible loop (PD loop) is made on the LV side by connecting the cable shield next to the bushing, directly to the main ground. In order to monitor PD, a HFCT is permanently clipped around the loop cable. If active PD is present, it will generate a high-frequency electromagnetic pulse that will transmit through the earth conductor. The HFCT will pick up this radiation due to induction. Although this method allows online PD monitoring, it is less sensitive, susceptive to noise and the magnitude of the detected signal is very low. Consequently, for analysing the data, an amplifier must be installed before analysing devices such as oscilloscope, PD detectors or pulse counters [87,88].

3.12.7 Transfer function measurement

A transformer winding's high-frequency transfer function (TF) can be used to evaluate and localize the origin of PD that initiates within the windings [80,89,90]. Each transformer windings may be divided into numerous winding sections. If the transfer function of individual sections of each winding is known, the transfer function of all windings can be calculated [91]. If PD is initiated at unknown allocation along the transformer winding, a signal will travel to both the bushing and neutral terminals and will be distorted as it propagates. The distortion rate depends on multiple factors including the distance from origin to the detection impedance. The distorted PD signal can be measured either using narrow band or wide band techniques [80]. Although the offline narrow band method cannot localize PD, it can quantify the apparent charge and measure the repetition rate, individual pulse energy and phase shift with the power frequency [80]. In accordance with IEC 60270, a frequency range of 9 to 30 kHz is suitable for this method. The wide band method uses the same technique as narrow band to detect PD. In addition, it can localize the PD signal by analysing the shape of it. In accordance with [92], about 10 MHz bandwidth is optimal for this method. In order to localize PD, this method uses the concept of a transfer function. Following the known sectional transformer function of a winding, it calculates the shape of a PD signal at multiple points within the windings from both bushing and neutral terminal. The point at which the calculated signals are comparable with the practical observations pinpoints the origin of PD [91]. On factory test, the accuracy of this method is satisfactory where background noise is controlled by some external means. During on-site test, background noise and the transformers own noise, which is similar in nature to PD, directly affect the sensitivity and accuracy of this method [80]. The noise from multiple sources has to travel through the complete winding, but the PD signal will travel through only some sections of the winding. Consequently, noise will face more attenuation than the PD signal [91]. Additionally, the calculated transfer function of the noise signal will be the same as the transformer's transfer function. This principle can be used to isolate noise in a laboratory environment. During on-site measurement, optical transducers, digital filters, amplifiers, windowing (software) and common mode rejection technique can be used to suppress the spurious sinusoidal and pulse-shaped noise [91]. The accuracy of this method is dependent on the uncertainty of the windings' sectional transfer function. For old transformers, where transfer function is measured from step response, it can only localize the origin of PD within a quarter of the complete winding length. If the sectional transfer function of windings is known, the error of this method is only few percent [91]. A comparison of different available PD measurement methods have been summarized in Table 7.

3.13 Leakage reactance or short-circuit impedance measurement

Short-circuit impedance (SCI) is a frequency-dependent parameter that has been used over many years to detect winding deformation and core displacement of a transformer. Short-circuit current is considered one of the main symptoms of mechanical deformation of core and windings. Any change in mechanical geometry of a transformer would change its SCI. A high value of SCI has a direct impact on the voltage regulation due to the significant amount of voltage drop across it. On the contrary, low values indicate short-circuit current. A deviation of $\pm 3\%$ is an indication of winding deformation and core displacement [93]. However, transformers over 100 MVA should not exceed $\pm 1\%$ from their nameplate value [94]. Ampere's force law states that an attractive force will be observed between conductors if they carry current in same direction and vice versa. According to this formula, it can be summarized that the forces from one HV (or LV) winding loops to the next will be attractive but the force between HV and LV windings is repulsive. Eventually, the axial flux produced from short-circuit currents create compressive force on inner windings but tensional force on outer windings that try to rupture the winding conductors [95,96]. The SCI can be measured either using 3-phase equivalent test or per-phase test methods. In order to measure SCI, an input voltage must be applied in HV windings one after another keeping the corresponding LV winding shorted. The measurement set-up for SCI has been shown in Fig. 11a, b.

To reduce the resistance of the shorting cable, it should be minimal in length and the cross-sectional area must be more than 30% greater than the winding conductors to handle a large amount of current [97]. The 3-phase equivalent test allows comparing the result with nameplate value and between phases to assess the mechanical integrity of a transformer. This result could be used as a finger print for future tests. Per-phase test can be performed as a follow-up test. This method has a number of limitations [97] such as

1. It does not provide detailed information of windings state due to single frequency (50 or 60 Hz) test.
2. It is less sensitive as significant deformation is required to cause a discrepancy.
3. It cannot detect axial deformation like tilting or bending of conductors.

3.14 Turns ratio test

The turn ratio test of a transformer (TTR) is used to detect open or short circuits between turns of the same winding. A deviation of more than 0.5% is an indication of insulation failure, short circuit or open turns [4]. In the TTR test, the ratio needs to check at all taps position. The TTR can provide evidence of gross winding resistance deviation. It is recommended to start the test at low voltage (100 V) and verify the result against the nameplate value. If no significant deviation is found, then it is safe to increase the voltage up to the rated voltage. This approach helps to avoid unwanted insulation breakdown.

3.15 Winding resistance test

Winding resistance test can be used to detect loose connection, broken stands or poor contacts in LTC. The resistance must be measured at all taps to verify the LTC contact resistances. The result can be analysed in comparison with nameplate information, historical data or between phases. When comparing with nameplate values, the test data must be converted to the reference temperature used during the factory test. This test could be used as a supplement of DGA and TTR, if DGA indicates generation of hot metal gases such as methane (CH_4), ethane (C_2H_6) and acetylene (C_2H_2) [4]. Depending on the percentage of deviation, a manual internal inspection may be organized.

3.16 Core-to-ground resistance test

In most modern transformers, the core is intentionally connected to a single ground point through a small bushing, preventing circulating currents and detecting multiple grounds. During transportation, the grounding system could become loose or damaged. The core-to-ground resistance test is used to detect unintentional core grounding and check the integrity of intentional ground points. The test can be used as a supplement of DGA when it indicates hot metal gases. For checking multiple grounds, the insulation resistance between the core and tank is measured, while the intentional ground cable is kept open. The measured resistance may be used to detect and classify the severity of multiple grounds as indicated in Table 8.

3.17 Sweep frequency response analysis

The sweep frequency response analysis (SFRA) is a non-destructive, highly accurate, cost-effective and sensitive method that is used to detect mechanical deformation and displacement of a transformer core and windings [97]. Over time, the importance of SFRA is increasing due to its high sensitivity for detecting mechanical failures of a transformer.

Table 7 Comparison of different PD measurement techniques

Method	Advantage	Disadvantage
Electrical	High sensitivity	Difficult to apply on-site measurement
	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	

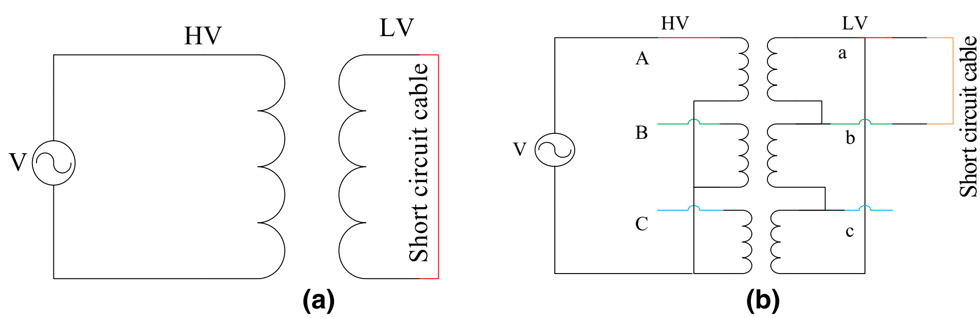

Fig. 11 Circuit connection of SCI for single phase (**a**) and three-phase (**b**) measurement

Table 8 Insulation condition based on core-to-ground resistance [4]

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

It can detects faults such as winding deformation (axial or radial), winding tank grounding and loose contact at HV and LV winding terminals without opening the main tank [97,98]. Generally, short-circuit current, careless transportation, natural disasters like earthquakes and combustible gas explosions inside a transformer are considered the main reasons for core and windings deformation [97]. Frequency response is a unique fingerprint of each transformer that changes with the onset of a mechanical defect. The impedance of a transformer, which is a frequency-dependent parameter, changes with mechanical deformation, leading to modified frequency response [99]. After commissioning, short-circuit incidents or transportation, it is recommended to perform FRA to ensure the windings and core integrity of transformers. In a two-winding three-phase transformer, SFRA measurement

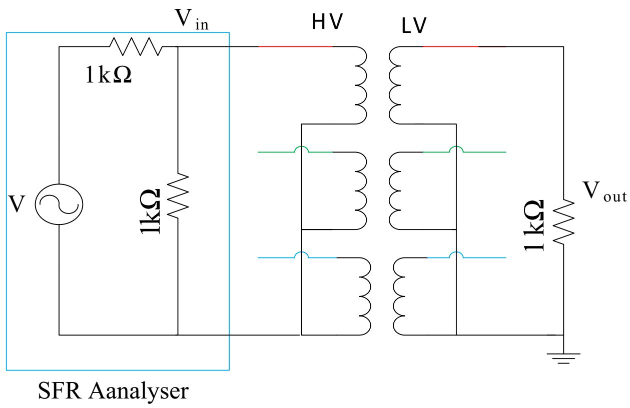

Fig. 12 Transferred measurement

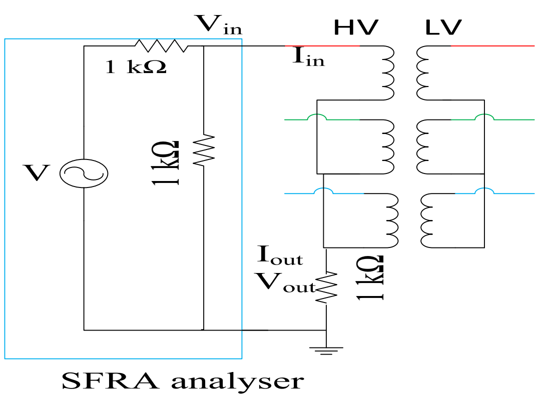

Fig. 13 Non-transferred measurement

can be performed for either transfer function or impedance measurement. Transfer function can be measured from non-transferred measurement, and impedance can be measured from transferred measurement [98]. The measured transfer function can be used to detect short-circuited turns of the windings [100]. The circuit diagrams of a transferred measurement and non-transferred measurement are shown in Figs. 12 and 13.

In transferred measurement, an input voltage V_{in} is injected at each HV terminal and the output voltage V_{out} is measured from the corresponding LV winding, keeping the neutral terminals grounded and the other non-tested terminals floating or shorted to the main tank through 1 kΩ resistance [98,101]. This measurement is acceptable only at frequencies lower than 8 kHz [102]. At higher frequency, it is influenced by inter-winding capacitance. Consequently, this test highlights the influence of coupling capacitance between HV and LV windings [98]. For the non-transferred measurement, input voltage is measured from HV windings and output voltage is measured from the respective neutral terminal of the same winding, keeping non-tested HV terminals open and LV terminals open or short circuited. In order to avoid the damping oscillation and reduce the impact of stray capacitance, it is recommended to add some resistance (1 kΩ) with both non-excited and excited terminals [98,101]. After conducting SFRA and recording the response, the next important task is to analyse the result to verify the mechanical integrity. To analyse the data, it is important to know the upper limit of the frequency range for SFRA that is useful for fault detection. According to [98], the maximum reproducible range is at least 1 MHz. At higher frequencies (over 1.5 MHz), the distributed capacitance tended to work as a shunt capacitor with winding inductance, winding lead effects is apparent and recurrence of resonance is less pronounced [101]. It is commonly accepted that the low-frequency range (1–100 kHz) is useful for detecting core deformation, the medium frequency range (100–600 kHz) is dominated by winding structure and the high-frequency range (600 kHz–1 MHz) can identify problems in connection leads [97]. According to [103], the frequency response in different sections of the spectrum is shown in Fig. 14. The frequency range can be extend up to 2 MHz for detecting minor faults like conductor bulging, small displacement and inter-turn fault [104]. Faults close to either high-voltage terminal or low-voltage terminal can be detected using the impedance value of low-voltage or high-voltage windings, respectively, setting the opposite side open-circuited [104]. Although SFRA can detect wide ranges of mechanical distortion sensitively, the interpretation and analysation of data are not easy. As there is no standard procedure, it is still dependent on experts' judgement, visual inspection, statistical indices like standard deviation, correlation coefficient and relative factor, and comparison with historical data. If historical data are not available, data can be analysed by comparing between different phases of the same transformer or twin/symmetrical transformers. For comparing data between phases, the nominal difference must be allowed for due to any inherent constructional asymmetries.

4 Calculation of residual life

Due to economic and technical reasons, beside condition monitoring, the lifetime estimation of transformers has gained more attention from utilities. The estimated lifetime can help them to set up a strategy for refurbishment and develop a forecasting system for future investment. Over the decade, different techniques like health index calculation, probability of failure estimation, statistical depreciation analysis, correlation of operating temperature and DP with insulation life are used to calculate the remaining service life of transformer. A review of different lifetime estimation methods can be summarized as follows.

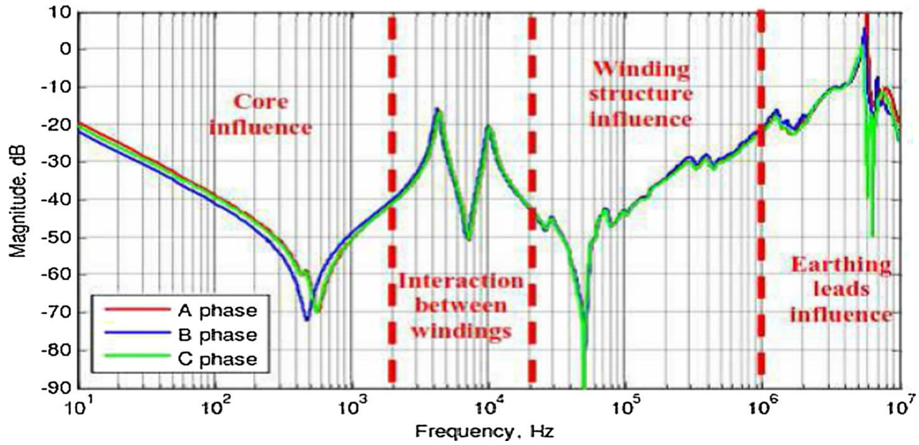

Fig. 14 Transformer sweep frequency response [103]

4.1 Hot spot temperature calculation

The hot spot temperature (HST) of a transformer has a direct impact on its insulation life. The ageing rate of insulation is accelerated with the increase in HST. According to industry loading guides (IEE, IEC, CIGRE and ANSI), temperature is the principle factor for reducing the service life of transformers. The nominal HST of a transformer oil–paper insulation is considered as 110 °C and could be acceptable up to 140 °C [31,49]. The effect of ambient temperature, windings faults, faulty cooling systems, over loading and unwanted harmonics (non-sinusoidal load) increases the HST and reduces the life of transformers. Consequently, the remaining service life of a transformer can be calculated from the correlation of HST and ageing rate of insulation. According to [105], the equation of HST in °C can be expressed as follows

$$\theta_{\mathrm{HS}} = \theta_A + \delta\theta_{\mathrm{TO}} + \delta\theta_H \tag{7}$$

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

$$\delta\theta_{\mathrm{TO}} = (\delta\theta_{\mathrm{TO}.U} - \delta\theta_{\mathrm{TO}.i})\left(1 - \mathrm{e}^{-t/\tau_{\mathrm{TO}}}\right) + \delta\theta_{\mathrm{TO}.i} \tag{8}$$

where $\delta\theta_{\mathrm{TO}.U}$ is the top oil temperature gradient at ultimate state, $\delta\theta_{\mathrm{TO}.i}$ 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, winding HST is also influenced both by the operating load and its duration. A correlation between winding HST and loading time for various loads can be modelled by the following equation [106].

$$\delta\theta_H = (\delta\theta_{H.U} - \delta\theta_{H.i})\left(1 - \mathrm{e}^{-t/\tau_W}\right) \tag{9}$$

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

$$\text{Per unit life consumption} = A\mathrm{e}^{\left(\frac{B}{273+\theta_{\mathrm{HS}}}\right)} \tag{10}$$

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

$$F_{AA} = e^{\left(\frac{15000}{383} - \frac{15000}{\theta_{\mathrm{HS}}+273}\right)} \tag{11}$$

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

$$F_{\mathrm{EQA}} = \frac{\sum_{n=1}^{N} F_{AAn}\delta t_n}{\sum_{n=1}^{N} \delta t_n} \tag{12}$$

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.

$$\%\ \text{Loss of life} = \frac{F_{\mathrm{EQA}} * t * 100}{\text{Insulation design life}} \tag{13}$$

In order to avoid the complexity of this calculation process, annual estimation of cyclic ambient temperature and load has been considered. Consequently, a transformer's unit life can easily be estimated from the hourly basis annual temperature and load curve. However, to improve the reliability of a transformer's estimated residual life, a more sophisticated modelling approach is necessary that can incorporate other ageing factors along with the environmental effect of ambient temperature and HST more accurately.

4.2 Concentration of furan and DP value measurement

The DP value calculation and the furan concentration measurement are another method that is using to calculate the residual life of a transformer by assessing the degradation of the cellulosic paper insulation. Generally, for unaged paper, the value of DP is expected to be 1000–1200 [109,110], whereas paper having a DP value of 200–300 is considered to have reached its end of life [111]. Over time, due to chemical reactions, the DP value of a transformer paper decreases due to the influence of temperature, water content and oxygen. Consequently, it can provide valuable information about the mechanical strength and the degradation state of cellulose. According to the Arrhenius relation, the DP value can be linked with temperature in terms of a time-dependent reaction rate (k) by using the following equation [111]

$$\mathrm{DP}\,(t) = \frac{\mathrm{DP}\,(t_0)}{1 + \mathrm{DP}\,(t_0) * \int_{t_0}^{t} k\,(t)\,\mathrm{d}t} \tag{14}$$

where $k = A * \mathrm{e}^{-E_\mathrm{a}/RT}$, 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 $R = 8.314\,\mathrm{mol}^{-1}\,\mathrm{K}^{-1}$ 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].

$$\mathrm{DP}_n = \frac{1}{A * \mathrm{e}^{-E_\mathrm{a}/RT} * t_n + \frac{1}{\mathrm{DP}_{n-1}}} \tag{15}$$

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

$$\mathrm{LL}_n = \frac{t_n}{\frac{\frac{1}{200} - \frac{1}{1000}}{A} * \mathrm{e}^{E_\mathrm{a}/RT}} \tag{16}$$

The percentage of residual life

$$\%\mathrm{RL} = \left(1 - \sum_{n=1}^{N} \mathrm{LL}_n\right) * 100 \tag{17}$$

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

As direct testing of DP value for a live transformer is critical and requires that the transformer be disconnected from the live network [42], the furan concentration is widely used to estimate the remaining residual life of a transformer. The furan (2-FAL) is released from the degradation of materials produced by the breakdown of cellulose and maintains an inverse relationship with DP. Consequently, different correlation techniques have been developed to relate the furan concentration with DP to avoid the complexity of direct DP measurement. In [114], the value of DP has been correlated with the furan concentration using the following equation.

$$\mathrm{DP} = \frac{\log\,(2FAL) - 1.51}{-0.0035} \tag{18}$$

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

A summary of different correlation methods between DP and furan is also available in [115]. The calculated DP value, based on furan concentration, is ultimately used to calculate the residual life of a transformer. The benefit of this method is that the error can be reduced by updating the measured quality parameters and DP value can be verified from the measured value of furan.

4.3 Probability of failure calculation

Failure of a transformer occurred after certain level of insulation and performance degradation. The probability of failure can be calculated by characterizing the degradation as a function of time. According to [116], the degradation model of transformers can be expressed by the following differential equation

$$\frac{\mathrm{d}\chi}{\mathrm{d}t} = -A_\mathrm{F} R_0 \chi^k \tag{19}$$

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 ageing factor can be calculated from the assessment and observation of selected properties. As temperature increases the ageing rate of insulation, the effect of temperature on paper insulation degradation has been approximated by the following equation.

$$A_\mathrm{F} = \delta^{\frac{1}{T_0}[\theta - 25]} \tag{20}$$

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]

Table 9 Health index and remaining lifetime [1]

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

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	X	X	X	X		X
Oil testing		X	X	X		X
Furan analysis			X	X		X
DP measurement			X	X		
SFRA		X	X		X	
Power factor measurement	X	X	X	X	X	
Leakage reactance			X		X	
Insulation resistance		X		X		
PD measurement	X		X	X		X
Turns ratio measurement		X				X
Dielectric response analysis			X			X
Winding resistance		X				X
Core-to-ground resistance			X			X
Excitation current			X			X

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

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. Finally, the calculated probability of failure (99%) can be used to estimate the remaining service life of a transformer. According to [1], the remaining service life of a transformer in terms of probability of failure can be expressed by the following equation

$$\tau_R = \frac{\tau_{P(\chi)\approx 80-99\%} - \tau_e}{A_\mathrm{F}} \tag{22}$$

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. To get a safety margin for avoiding failure, it is recommended to calculate the remaining life based on slightly earlier failure probability (80%) than the 99%. This margin is dependent on a particular utility's strategy and maintenance practice. Additionally, the financial risk of replacing a faulty transformer and the consequences of an outage need to be considered. The probability of a transformer's failure at any time is dependent on the remaining insulation strength and active stress on that particular time. Over time, insulation loses its mechanical and dielectric strength and the probability of failure increases. The failure probability of transformers follows the typical bathtub curve, where the initial failure rate is high but greatly reduces and flattens after few years of faultless operation until it starts to steadily climb again as the transformer starts to age [31].

4.4 Health index calculation

The percentage health index (HI) calculation is one of the reliable methods for lifetime estimation of a transformer. In HI calculation, a large number of routine and diagnostic tests are combined for explicitly assessing the overall condition of a transformer. The following equation is typical of HI calculations [1]

$$\begin{aligned}(\%)\mathrm{HI} = 60\% * \frac{\sum_{i=1}^{n-3} C_i \mathrm{DI}_i}{\sum_{i=1}^{n-3} CD_{i\,\max} * C_i} \\ + 40\% * \frac{\sum_{i=n-2}^{n} C_i \mathrm{DI}_i}{\sum_{i=n-2}^{n} CD_{i\,\max} * C_i}.\end{aligned} \tag{23}$$

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. The formula allocates 40% of the total weight to the LTC, and remaining 60% models the causes of direct transformer failure, based on a survey conducted by the CIGRE group. This could vary depending on the failure statistic of utilities [117]. A detail of this method is available in [1]. One of the drawbacks of this linear approach is that it is less sensitive to the individual test. For instance, if the condition of a bushing is very poor which could potentially lead transformers into a catastrophic failure, the overall HI score will not be changed significantly. To overcome the limitation, the test results can be combined in a multiplicative way so that if one test result is very poor, the overall HI score will be very low. The calculated HI can be correlated with approximate expected lifetime as follows in Table 9.

5 Conclusions

Transformers are unusual among industrial plant, since many of their operating components are not amenable to direct visual inspection as they are obscured within a bath of oil. This has necessitated a wealth of ingenious techniques that judge a transformer's operating condition from a diverse set of indirect measurements. This paper has investigated a wide range of established diagnostic tests to identify the most influential parameters on transformer performance and service life. To improve the measurement accuracy and detect fault types, testing methods have been organized following their sensitivity and detection capability against faults and insulation degradation. Based on the fault detection capability, routine and diagnostic tests have been summarized in Table 10. As previously stated, 70% of common faults can be diagnosed by DGA alone, but additional tests are needed to indicate when mechanical faults have occurred.

Few power transformers are privately owned, and most are operated by utility companies that subject their assets to regular online monitoring and less frequent offline maintenance. The issue these companies face is targeting a limited pool of resources to get the greatest benefit to their assets while simultaneously minimizing the risk of unexpected and catastrophic failures. It is expected that condition monitoring and lifetime estimation approaches will help to correlate various tests to measure the actual level of insulation and performance degradation. For improving reliability, relevant industrial standards and survey results, such as CIGRE, IEEE and IEC, have been used on selected methods for understanding and interpreting the test results. These analytical and diagnostic techniques will help the maintenance engineers to interpret the test results and suggest the important parameters of transformers that need to be monitored. These techniques also help utilities to prevent unexpected failures and provide justification to asset manager for replacing unreliable aged transformers through proper prediction. This review provides a snap shot of current tests and power transformer condition monitoring techniques. This is an area where there is significant ongoing research to better understand the characteristics of the various tests and to devise better methods for combining test results to monitor the condition of these expensive and critical devices. As the installed base of assets age, it seems likely that the importance of these techniques will only continue to increase.

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