INTERNATIONAL STANDARD

ISO 18095

First edition
2018-02

Condition monitoring and diagnostics of power transformers

Surveillance et diagnostic de l'état des transformateurs de puissance

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Reference number
ISO 18095:2018(E)

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Published in Switzerland

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Foreword

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The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

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For an explanation on the voluntary nature of standards, the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the World Trade Organization (WTO) principles in the Technical Barriers to Trade (TBT) see the following URL: www.iso.org/iso/foreword.html.

This document was prepared by Technical Committee ISO/TC 108, *Mechanical vibration shock and condition monitoring*, Subcommittee SC 5, *Condition monitoring and diagnostics of machine systems*.

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Introduction

This document provides guidance for condition monitoring and diagnostics of power transformers using parameters (such as oil condition, oil contamination, dielectric condition, temperature, power, voltage and current) typically associated with performance, condition and quality criteria. The evaluation of the power transformer function and condition may be based on performance, condition or output quality.

This document is aimed at asset managers, equipment specifiers, owners, operators and reliability and maintenance engineers. It provides a selection process "road map". The parameters and techniques are directed towards best-practice condition-based maintenance, detecting fault conditions, directing maintenance decisions and estimating asset health.

It is principally aimed at people who are not transformer experts, but who have a small number of transformers; for example, supplying power into a manufacturing site where many other items of equipment depend on the power continuing to be supplied by the transformers. The upper limit for the size of such transformers is probably around 50 MVA. While the same principles will also apply to owners and operators of large numbers of transformers such as utilities, which can exceed 50 MVA, it is expected that they will already have their own internal company guidelines and procedures for monitoring their transformers and so are not the primary target of this document.

This document follows on from ISO 17359, which outlines the general process of implementing a condition-based maintenance programme.

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Condition monitoring and diagnostics of power transformers

1 Scope

This document gives guidelines for the monitoring techniques to be considered when setting up a condition monitoring programme for power transformers and includes references to associated standards required in this process. It is intended to help in the implementation of a coherent condition monitoring and condition-based maintenance programme, such as described following ISO 17359.

This document is applicable to single-phase alternating current power transformers of ≥ 1 kVA and three phase alternating current power transformers of ≥ 5 kVA.

2 Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 13372, *Condition monitoring and diagnostics of machines — Vocabulary*

IEC 60050, *International Electrotechnical Vocabulary*

3 Terms and definitions

For the purposes of this document, the terms and definitions given in ISO 13372, IEC 60050 and the following apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

— ISO Online browsing platform: available at https://www.iso.org/obp

— IEC Electropedia: available at http://www.electropedia.org/

3.1
magnetostriction
property of ferromagnetic materials that causes them to change their shape or dimensions during the process of magnetization

4 Abbreviated terms

For the purposes of this document, the following abbreviated terms apply.

C1	main capacitance of transformer bushings, measured from central current carrying conductor to C1 measurement electrode embedded in the bushing
DGA	dissolved gas analysis
DFR	dielectric frequency response
DETC	de-energized tap-changer

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FFT	Fast Fourier Transform: analysis that converts a time-domain signal into a frequency spectrum
FRA	frequency response analysis
IEEE	Institute of Electrical and Electronics Engineers
KOH	potassium hydroxide, used in titration technique for assessing acidity of oil
LV	low voltage NOTE In this document, referring to the lower voltage side of the transformer as distinct from the higher voltage side, rather than to any specific voltage level.
OLTC	on-load tap-changer
OIP	oil impregnated paper, a type of construction for bushings (see also RBP, RIP and RIS)
PD	partial discharge
PDC	polarization and de-polarization current
PF	power factor
RBP	resin bonded paper
RIP	resin impregnated paper
RIS	resin impregnated synthetics
RVM	recovery voltage method
tan-delta	tangent dissipation angle

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5 Approach to selecting appropriate condition monitoring techniques

5.1 Implementing condition monitoring of transformers

The general process of implementing a condition-based maintenance programme is described in ISO 17359. This document provides more detailed examples and guidance on a range of techniques specifically applicable to the condition monitoring of transformers.

5.2 Components, failure modes and detection techniques

The main objective of condition monitoring is to know about the condition of equipment, to be forewarned of possible failures, and to be able to carry out appropriate maintenance tasks at the appropriate time, i.e. condition-based maintenance. Maintenance tasks are carried out to avoid or rectify failures, so the key to condition-based maintenance is to have an understanding of the failure modes that can affect the equipment, and the techniques that can be used to detect the early stages of those failure modes (potential failure) before functional failure. Specific failure modes affect specific components of the equipment, and certain detection techniques are more applicable to particular failure modes on particular components. Selecting the most appropriate condition monitoring regime therefore involves understanding the most applicable techniques to the particular components and failure modes involved. This can be represented in a three dimensional matrix, as shown in Figure 1 where the blue boxes indicate the area of applicability of particular techniques.

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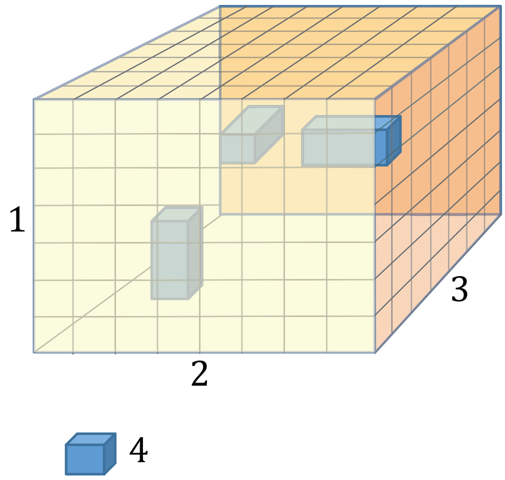

Key

1 failure modes
2 transformer components
3 detection techniques
4 applicable zone

Figure 1 — Matrix of applicable CM techniques vs. components and failure modes

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Clauses 6 to 10 explain the different types of transformers in common use, the components involved in those transformers types, the failure modes associated with those components, and the detection techniques for detecting those failure modes.

6 Power transformer types

6.1 Oil-filled transformers

The majority of larger transformers are filled with oil or a similar dielectric fluid for cooling and insulating purposes. These can often be described in a number of ways depending on their size and application. Some typical examples are as follows.

— Main output transformer (MOT) or generator step up transformer (GSU): connects a power generation station to the transmission system, typically in a size range of 100 MVA to 1 000 MVA.

— Transmission transformers: typically 30 MVA to 400 MVA.

— Distribution transformers: typically 2,5 MVA to 70 MVA.

— Pole mounted transformers: typically 10 kVA to 3 MVA.

— Factory or site feed-in transformers: typically 1 MVA to 50 MVA.

A diagram of a typical oil filled transformer is shown in Figure 2, indicating the components involved that are subsequently referred to in 7.1 and Table 2.

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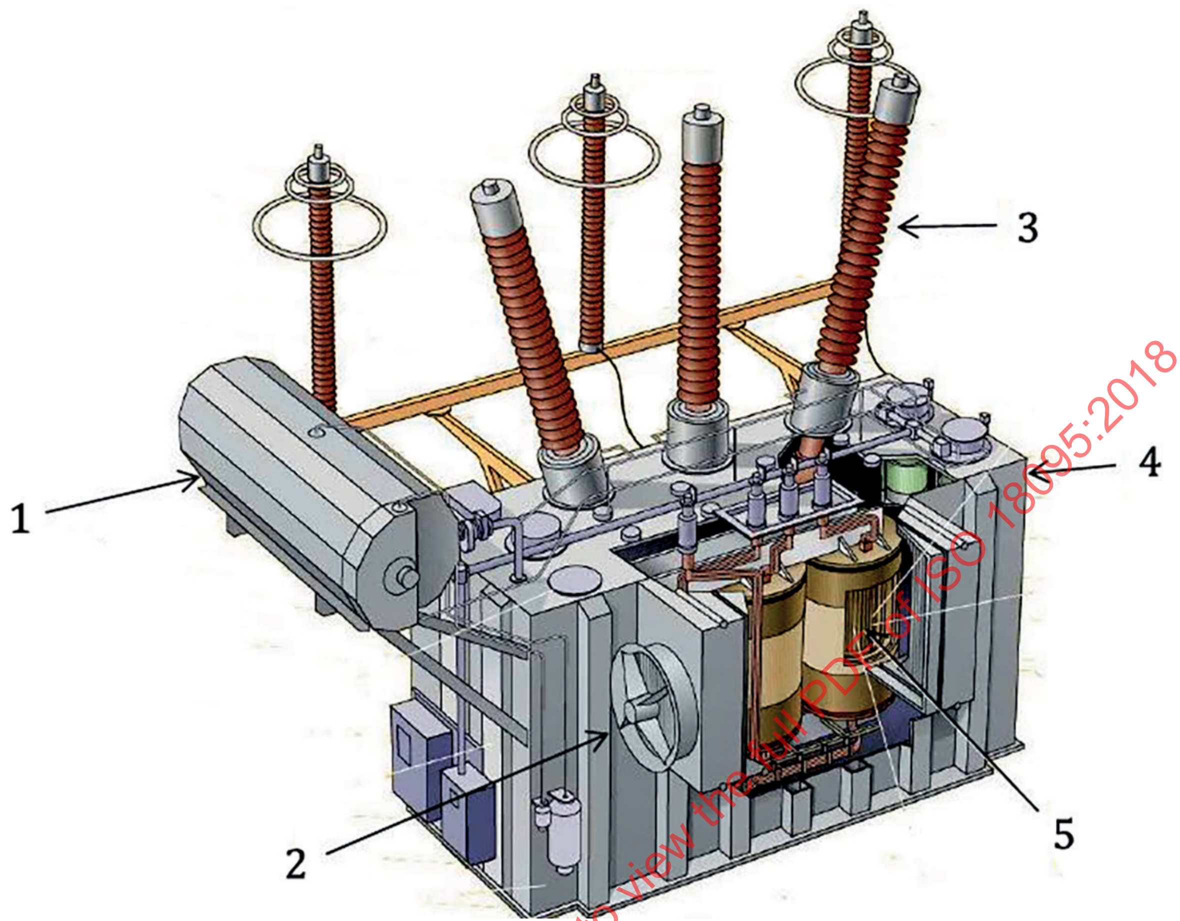

Key

1 oil conservator
2 radiator and fan
3 bushings
4 tank
5 windings and core

Figure 2 — Oil filled transformer with key components identified

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6.2 Dry-type transformers

Dry-type transformers are used where the avoidance of fire risk and environmental contamination are important. Since they contain no dielectric fluids like oil, their contribution with calorific energy to the source of a fire is very limited. Dry-type transformers are self-extinguishing. They can be used in protected environments where a leakage of oil or other fluids must be avoided.

Typical applications of dry-type transformer are industries (oil and gas, metals and mining, etc.), buildings (hospitals, airports, stadiums, large tower blocks, etc.), on- and off-shore applications (wind turbines, ships, platforms, etc.) and many more.

Currently dry-type transformers are available up to 63 MVA and voltage ratings up to 72,5 kV. They can also be installed with non-liquid insulated on-load tap-changers.

The dielectric insulation is generally provided by a solid insulation or a mixture of a solid insulation and air. The coils are either impregnated with a varnish or resin encapsulated. This sort of construction

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gives rise to a different set of failure modes compared to oil-filled transformers, since clearly there is no paper insulation or oil to degrade. A typical example is given in Figure 3.

Oil-filled transformers have more components than the dry-type transformer, as is shown in Table 1. This has implications for the failure modes possible and therefore for the maintenance requirements and appropriate condition monitoring techniques.

Dry type transformers can also be equipped with on-load tap changers. Figure 4 shows an example. It is rated at 25 MVA and 69 kV.

NOTE Photo courtesy of ABB Inc.

Figure 3 — Example of dry type transformer

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NOTE Photo courtesy of ABB Inc.

Figure 4 — Example of dry-type transformer 69 kV 25 MVA with OLTC device

6.3 Gas-insulated transformers (GITs)

For applications where low flammability is paramount, designs have been developed in which the transformer is insulated and cooled with SF6 gas. This provides an alternative to dry-type construction where it is critical to eliminate the risk of fire and avoid the possible contamination of the environment by oil spillage.

High-voltage SF6 transformers are available at ratings up to 300 MVA at 275 kV and prototype designs have been tested at up to 500 kV. Gas-filled transformers and reactors are more expensive than oil-filled units but the costs may be justified to eliminate a risk of fire, particularly at a site where the cost of land is high and where the overall “footprint” of the unit can be reduced by the elimination of fire-fighting equipment.

7 Power transformer failure mode analysis

7.1 Components

Condition monitoring is directed at detecting incipient failures sufficiently early that appropriate interventions can be made to rectify the problem before complete failure occurs, i.e. to be able to adopt condition-based maintenance. Since failures are associated with particular components within the transformer, the description of the failure modes and detection techniques in this document is structured around the components. The components of different types of transformers are shown in Table 1.

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Table 1 — Components of main types of transformer

	Components												
	Windings	Core	Internal connections	Bushings	Insulation	Tank/case	Conservator	Cooling system				Tap-changer	
								Oil	Pump	Radiator	Fans	On-load	De-energized
Oil filled transformers	✓	✓	✓	✓	✓	✓	(✓)	✓	(✓)	(✓)	(✓)	(✓)	(✓)
Dry type transformers	✓	✓	✓	✓	✓	(✓)	–	–	–	(✓)	(✓)	(✓)	(✓)
Gas insulated transformers	✓	✓	✓	✓	✓	✓	(✓)	–	(✓)	(✓)	(✓)	–	(✓)

Key

✓ Always present

(✓) Could be present

– Not normally present

7.2 Categories of failure mode

7.2.1 General

Failure modes in power transformers are typically grouped into the following four categories:

a) dielectric;

b) thermal;

c) mechanical;

d) external.

7.2.2 Dielectric failures

Degradation of insulation between conductors and grounded parts, such as core iron, core frames, and other structural metal parts inside a transformer can lead to increased losses, excessive heating, and for oil-filled transformers, the generation of gases in the oil. As insulation degrades, its ability to withstand voltage stresses decreases, and the transformer's ability to withstand voltage surges can be dramatically reduced. As degradation becomes more severe, the insulation can eventually fail under normal operating conditions, leading to complete catastrophic failure of the transformer.

7.2.3 Thermal

Radiators, coolers, fans, pumps, heat exchangers, oil/water coolers and their associated control equipment all have to be in proper working condition to keep the transformer temperature within acceptable levels. Excessive heating can lead to increased levels of insulation degradation and uneven thermal expansion. High oil temperatures can also create dielectric problems, especially in wet (oil filled) transformers, and can cause oil expansion problems. Many faults (including connection faults, bushing faults, winding faults etc.) can also generate localized heating, leading to problems even when the overall temperature of the transformer is within normal limits.

7.2.4 Mechanical

The primary mechanical concern is the transformer's ability to withstand through-faults, the large currents caused by short circuits external to the transformer. The most common factors affecting the structural integrity of the core/coil assembly are tightness of the core clamping structure and insulation degradation. Loose coils will more likely get damaged by the forces generated by high fault currents. The cellulose that forms the main component of the paper-based insulation in most oil-filled

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transformers can become weak and brittle as it degrades, lessening its ability to withstand short circuit forces. Other mechanical factors can include such problems as excessive noise and vibration.

7.2.5 External

Degradation of the tank or case, control cabinet components, wiring, insulators, gaskets, valves, monitors, gauges, etc. can result in oil leaks, external flashovers, and improper functioning of control, monitoring, and protection equipment.

7.3 Failure modes

Failure modes and how they relate to each of the components are shown in Table 2.

A strong relationship of a failure mode to a particular component is shown with a solid circle, •, whereas a possible but less likely relationship is shown with a hollow circle, ○. Note that the cause and effect in these relationships can in some cases be that a problem in the component results in the failure mode indicated, whereas in other cases, the failure mode occurring can then have an impact on the component shown.

Information on failure mode and symptoms analysis (FMSA) can be found in Annex C.

Table 2 — Typical failure modes of key components

		Components													
	Failure modes/ failures detected	External e.g. load	Win dings	Core	Connections (internal)	Bush-ings	Insula tion	Cooling system				Case/ tank	Cons erva tor	Tap-changer	
								Oil	Pump	Radia-tor	Fans			On-load	De-ener-gized
Dielectric faults	Insulation deteriora-tion	•	•	○	•	•	•	•						•	•
	Moisture ingress content		•	•		•	•	•				•	○	•	•
	Tap-changer condition/ problem							•						•	•
	Oil quality deteriora-tion		•	•			•	•	•				○	•	•
	Arcing/ electrical discharge	•	•	•	•	•	•	•				•		•	•
	Connection/ bushing problem		•		•	•		○				○			
Thermal faults	Overheat-ing/ auxiliary cooling system problem	•	•	•			•	•	•	•	•				
	Low oil level		•	•		•	•	•	•			○	•	•	•
	Oil circulation system problem		○	○			○	•	•	•	•	○	○	•	

Key

• Likely relationship

○ Less likely relationship

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Table 2 *(continued)*

		Components													
	Failure modes/ failures detected	External e.g. load	Win dings	Core	Connections (internal)	Bush-ings	Insula tion	Cooling system				Case/ tank	Cons erva tor	Tap-changer	
								Oil	Pump	Radia-tor	Fans			On-load	De-ener-gized
Mechani-cal faults	Winding distortion	•	•	•			•					○		•	•
	Winding looseness		•	•	•		•								
	Core looseness			•			•								
	Oil leak		○			•	•	•	•			•	○	•	•
	External damage/ disturbance	•		○	•	•	○		○	•	•	•	○	•	•
External faults	e.g. Animals		○			○				○	○	○			
	Through fault, e.g. lightning strike or short circuit	•	•	•	•	•	•	○	○		○	○		○	○
	Supply faults, e.g. excessive harmonics and over fluxing	•	•	•	•	•	•	○	○		○			○	○

Key
- • Likely relationship
- ○ Less likely relationship

7.4 Influences on rate of failure mode progression

7.4.1 General

A variety of factors influence the rate of failure mode progression in power transformers, including:

a) loading;

b) environment;

c) design;

d) maintenance;

e) protection.

7.4.2 Loading

The magnitude and characteristics of the electrical load placed on a transformer are some of the most important factors affecting a power transformer's usable life. System disturbances such as voltage surges, through faults, etc. can have a cumulative effect on the transformer. Undetected damage from such events can also lead to accelerated degradation in localized areas, leading to a failure.

7.4.3 Environment

Environmental conditions surrounding a transformer can affect the rate of a transformer's degradation. Some of the normal environmental conditions which have such an effect are ambient temperature

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and altitude. Factors such as wind, sunlight and rain can affect operating temperature as well. Other environmental factors that can affect the life of the transformer include aggressive or corrosive atmospheres, mechanical vibration, etc.

7.4.4 Design

Differing design approaches or construction techniques often have inherent strengths and weaknesses making them more or less prone to a particular problem. When a transformer is subjected to a set of circumstances which aggravate such a problem, its condition can degrade more rapidly than expected.

7.4.5 Maintenance

There are many aspects of maintenance which greatly influence the condition and service life of a transformer. One aspect of particularly high importance for oil-filled transformers is the quality of the insulating liquid. The presence of moisture and other contaminants in the oil can accelerate degradation of cellulose insulation within the transformer, especially at high operating temperatures.

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7.4.6 Protection

Transformers are often fitted with protection devices that locally monitor the condition of one or more parameters. Examples of such devices are as follows:

a) gas actuated relay device (e.g. Buchholz);

b) oil temperature high alarm;

c) winding temperature alarm;

d) oil level alarm;

e) cooler supply failure alarm;

f) tap-changer supply failure alarm;

g) on-load tap-changer oil flow relay;

h) breather failure alarm.

For example, a Buchholz relay detects and responds to over-pressure conditions in oil-filled power transformers.

8 Range of techniques

A range of techniques is available to measure and monitor the condition of power transformers. Each technique can detect a particular range of problems as shown in Table 3.

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Table 3 — Examples of power transformer faults matched to measurement parameters and techniques

Equipment type: Power transformer		Symptom or parameter change or detection technique																
		Amps/ volts/ load (9.1)	Visual (9.2)	Oil con- dition (9.3)	Tempera- ture (9.4)	Partial dis charge (9.5)	DGA (9.6)	Noise (9.7)	Ultra- sound (9.8)	Vibra- tion (9.9)	PF/ Tan δ (9.10)	Resist- ance (9.11)	DFR/ PDC/ RVM (9.12)	FRA (9.13)	Excita- tion current (9.14)	Leak reac- tance. flux (9.15)	Bushing capaci- tance (9.16)	Other – e.g. novel tech- niques
	Can be done with trans- former energized?	✓	✓	✓	✓	✓	✓	✓	✓	✓							✓	(✓)
Examples of faults - Dielectric	Insulation deterioration	•		•	•	•	•		○		•	•	•	•	•			
	Moisture ingress/content			•			•				•	•	•					
	On-load tap-changer con- dition/fault	•		•	•	○	•	○	•	○		•		•	•			
	De-energized tap-changer condition/fault	•		•	•	○	•	○	•	○		•		•	•			
	Oil quality deterioration			•			•				•		•					
	Arcing/electrical discharge		•	•		•	•	•	•		•							
	Connection/bushing faults				•	•	○	○	•		•	•					•	
Thermal	Overheating/auxiliary cooling system fault		○	•	•		•		○									•[a]
	Low oil level		•	○	○		○	○	○									
	Oil circulation system problem		•	○	•		○											
Mechanical faults	Winding distortion								○				•	•		•		•
	Winding looseness							•	•	•								•
	Core looseness							•	•	•								○
	Oil leak		•															
	External damage/ disturbance		•															
External faults	Through fault e.g. lightning strike										•			•				
	Supply faults, e.g. excessive harmonics and over fluxing	○																

[a] Overheating can also be because of blocked cooling pipework or similar. This is a mechanical issue that can be detected by feeling individual radiators: if one is cold while the others are hot a problem is indicated.

• Indicates symptom could occur or parameter could change if fault occurs.

○ Indicates less common symptom.

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9 Overview of techniques for condition monitoring power transformers

9.1 Mains current/voltage/load

9.1.1 Fault mechanism

All transformers are designed for a particular load: a particular voltage and a particular current. IEC 60076 provides a standard for how transformers are to be specified, including the definition of power rating, the reference temperature for losses, temperature rises, and some dielectric testing. This design specification could also have taken into account particular conditions for the transformer in question, such as the temperature of the surrounding environment, any particular features of the environment such as aggressive or corrosive conditions, restricted access to fresh air, and assumptions about working in parallel with other adjacent transformers.

The specification is likely to have included elements such as the overall power, cooling rate, and single phase load; the voltages in and out, and the position the tap-changer is expected to be in for a particular voltage; the capability to handle overloads, over-voltages and over- or under-frequency.

If the transformer is operated outside the design parameters, it is likely to deteriorate much more rapidly. Examples are as follows.

a) Drastic over-voltage from (repeated) transients could cause distortion or loosening of the core, or exceed the dielectric strength (breakdown voltage) of the insulation and create rapid damage or make it more susceptible to early failure.

b) Mild over-voltage or over-current is likely to lead to higher temperatures, which will have a direct impact on the life of the insulation.

9.1.2 Technique

Routine logging of the voltages and currents on both sides of the transformer gives an indication of the overall load the transformer is working under, and an easy comparison with design ratings will indicate if there is any overloading. Changes and trends in these records can indicate that something has changed either inside or outside the transformer, and prompt further checks to establish the cause. These data might already be captured in operational SCADA systems or in data historian systems, allowing for easy graphical review. Some protection systems and online monitoring systems can also provide this data easily.

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9.1.3 Faults detected/components covered

Changes in voltage and current could indicate either changes in the downstream demand on the transformer, or could indicate some problem with voltage regulation mechanisms. Significant changes in the relationship between input and output currents and voltages could be an indication of internal damage to the windings or core or to the tap-changer mechanism.

9.2 Visual

9.2.1 Fault mechanism

External corrosion is the key long-term failure mode that can be detected by visual checks. Damage to the paintwork of the tank and components such as radiators can lead to corrosion into the metal that can eventually lead to perforation and hence loss of oil, which if significant would lead to lowering of the oil level, reduction of cooling system effectiveness, and hot spots at the top of the transformer and possible insulation degradation leading to a flashover. Oil leaks can also occur from joints and penetrations into the tank for pipework, bushings, etc., and these can be identified visually. Visual checks should also look for external damage from physical impacts, or general contamination of components with dirt, debris, etc., that could reduce effective creepage and clearance resistance or block radiator cooling surface

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or fan air flow. Visual checks should also cover external safety guards and enclosures, to ensure the integrity of measures to keep people away from hazardous areas.

9.2.2 Technique

Conventional visual checks, backed up by the other human senses of hearing and smell, can be adequate to spot developing corrosion problems, or oil leaks. These simple visual checks should be carried out routinely on their own. Visual checks should also be carried out in combination with other specific checks such as infrared camera checks, ultrasound tests or ultraviolet tests, which are likely to be performed less frequently than the visual checks on their own.

9.2.3 Faults detected/components covered

A typical checklist for visual checks should include looking for:

a) paint condition/external corrosion;

b) oil leaks from anywhere, e.g. pipework connections, radiators, bushings;

c) external damage from physical impacts;

d) general contamination of components with dirt, debris, etc.;

e) signs of tracking on bushings;

f) external safety guards and enclosures;

g) condition of cooling system;

h) foundations;

i) control and supervision equipment;

j) oil level;

k) condition of the air dryer;

l) number of switchings of the OLTC.

9.3 Oil condition

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9.3.1 Fault mechanism

In this clause and in 9.6, the term “oil” is used to describe the fluid within the transformer, which is most commonly mineral oil, but could also be silicone oil, synthetic ester or natural ester.

Over time, contamination can build up in the oil, principally sludge from the decomposition of the paper insulation, and acidic elements resulting from the breakdown of the cellulose of the paper and from breakdown of the oil itself. Moisture is also a key contaminant of transformer oil, getting into the oil via atmospheric contamination (high humidity air entering the tank as it breathes) or via leakage from bushing connections or other joints in the tank. Moisture in the oil is then preferentially transferred to the paper of the insulation, leading to degradation of the paper (see Annex A for a longer description of the behaviour of cellulosic insulation and the effects of moisture, temperature, acidity, sulfur compounds, etc.).

The oil is also directly affected by internal arcs and sparks and partial discharges that lead to local overheating and a reduction in the dielectric strength of the oil. These phenomena also lead to the generation of gases that become dissolved in the oil; an assessment of the condition of the transformer from an analysis of these gases is covered in 9.6.

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Deterioration in the quality of the oil can thus be both an indication and a cause of problems inside the transformer, principally from hot spots (sludge impairing the flow of oil within the windings) and accelerated deterioration of the paper insulation. Sulfur compounds in the oil can attack and corrode the copper windings directly, which in turn can result in copper sulfide depositing on the paper, making the paper conductive and obstructing heat flow from the paper, leading to hot spots and short circuits.

There is a standard recommended set of oil analysis tests that may be carried out on transformer oil, as defined in IEC 60422, and laboratories frequently offer a standard suite of tests as a package. IEC 60422 recommends the tests to be performed, the frequency, and the acceptable limits for the test results. The tests cover dielectric strength, water content, particle content, acidity, colour, interfacial tension, corrosive sulfur and polychlorinated biphenyls (PCB) levels as shown in Table 4 below.

Table 4 — Tests for in-service mineral insulating oils from IEC 60422

Property	Group[a]	Subclause	Method
Colour and appearance	1	5.2	ISO 2049
Breakdown voltage	1	5.3	IEC 60156
Water content	1	5.4	IEC 60814
Acidity (neutralization value)	1	5.5	IEC 62021-1 or IEC 62021-2
Dielectric dissipation factor (DDF) and resistivity	1	5.6	IEC 60247
Inhibitor content[b]	1	5.7.3	IEC 60666
Sediment sludge	2	5.8	IEC 60422:2013, Annex C
Interfacial tension (IFT)[c]	2	5.9	ASTM D971 EN 14210
Particles (counting and sizing)[c]	2	5.10	IEC 60970
Oxidation stability[c]	3	5.7	IEC 61125
Flash point[d]	3	5.11	ISO 2719
Compatibility[d]	3	5.12	IEC 61125
Pour point[d]	3	5.13	ISO 3016
Density[d]	3	5.14	ISO 3675
Viscosity[d]	3	5.15	ISO 3104
Polychlorinated biphenyls (PCBs)	3	5.16	IEC 61619
Corrosive sulfur[c]	3	5.17	IEC 62535 ASTM D1275, Method B DIN 51353
Dibenzyl disulfide (DBDS) content	3	5.18	IEC 62697-1
Passivator content[b]	3	5.19	IEC 60666:2010, Annex B

[a] Group 1 are routine tests, Group 2 are complementary tests, Group 3 are special investigative tests.

[b] Restricted to inhibited and or passivated oils.

[c] Only needed under special circumstances, see applicable subclause.

[d] Not essential, but can be used to establish type identification.

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Tests are grouped into three types, the first being routine tests that should always be carried out, the second being tests depending on the oil quality and age in service, and a third being special tests

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according to need. IEC 60422 also sets out the frequency of testing recommended, which ranges from 1 to 2 years for the highest voltage transformers (400 kV+), down to 2 to 6 years for lower ratings of transformers below 72,5 kV. The details of the method for carrying out each test are covered by other standards listed in the Bibliography.

A more general description of the use of oil analysis for condition monitoring can be found in ISO 14830.

Transformer oil can be recovered by pumping the oil through external treatment equipment to remove moisture, dissolved gases, particulates (cellulosic fibres), corrosive sulfur and acids. This treatment process can typically take several days. Moisture, dissolved gases and particulates can be removed via filtration, absorbent media and vacuum treatment; corrosive sulfur and acids can be removed by a Fullers Earth treatment.

9.3.2 Technique

Assessment of the oil is carried out by taking a sample of the oil and sending it off to a specialist laboratory for testing and analysis. These specialist laboratories can be expected to provide a full report covering all the relevant test parameters. The report should categorize the oil under each parameter as either good, fair or poor, and advise on the action to be taken accordingly. The techniques for testing are described in a variety of standards which are shown in Table 4 and listed in the Bibliography.

These tests are designed to detect some contaminants at very low levels, and it is therefore very important that the oil sample is taken very carefully, to avoid introducing contaminants during the sampling process itself, e.g. from dirt on the outside of the sampling point, or from dirt or moisture inside the sample vessel. Training of staff in appropriate sampling techniques should be considered. Standard procedures for such sampling can be found in IEC 60475:2011, *Method of sampling insulating liquids*. It may be appropriate to contract an external organization to perform the entire process, including collection of the sample, management of the tests, and analysis and interpretation of the results.

9.3.3 Faults detected/components covered

Tests on the oil can indicate problems on many of the components with which the oil is in contact, including those shown below.

NOTE Where values are quoted from IEC 60422, they assume the values are for “category C” assets, i.e. power transformers operating from medium to low voltage, with a maximum system voltage of 72,5 kV.

a) Reduced **dielectric strength** (breakdown voltage) of the oil is an indication of other problems such as water content, particle content, oxidation of the oil, acidity, which each indicate a number of potential problems inside the transformer.

   The values given in IEC 60422 for the interpretation of dielectric strength test results are:

   — >40 kV = good;

   — 30 kV to 40 kV = fair;

   — <30 kV = poor.

b) High **moisture content** can be an indication of tank integrity problems (non-watertight joints somewhere) or breather system function (silica gel system saturated or not functioning correctly) or it can be caused by breakdown products from oil and insulation (water can be a product of decomposition). The presence of moisture in the oil indicates high moisture content in the paper insulation, which in turn will lead to more rapid deterioration of the paper. Moisture in the oil also directly reduces the dielectric strength of the oil, making the transformer more vulnerable to electrical problems, and increases the dielectric losses which in turn create more heat which in turn contributes to faster deterioration of many components of the system. As a general rule, doubling the moisture content in the oil halves the life of the insulation in the transformer.

   The values given in IEC 60422 for water content in oil are:

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— <30 mg/kg = good;

— 30 mg/kg to 40 mg/kg = fair;

— >40 mg/kg = poor.

c) High **particle content** (associated with sludge inside the transformer) is an indication of deterioration of the paper insulation, which in turn can be caused by a range of factors including moisture in the oil, particularly when combined with hot spots or arcing/sparking/partial discharge. High particle content can also be caused by internal corrosion of the tank or other components, which also indicates the presence of moisture.

The values of particle content corresponding to good, fair and poor oil quality are given in IEC 60422:2013, Annex B.

d) **Acidity** in the oil is caused by breakdown of the paper insulation, particularly in the presence of moisture, which is exacerbated by higher temperatures, particularly local hot spots, and, by breakdown and oxidation of the oil associated with arcing/sparking/partial discharge, so the presence of acidity is an indication of problems in these areas. The presence of acidity in turn causes more rapid deterioration of the paper insulation and can result in corrosion of metallic components in the transformer. A by-product of oxidation of the oil is the creation of sludge which can obstruct the flow of oil, leading to impaired local cooling and in turn leading to more rapid deterioration of the insulation.

The values given in IEC 60422 for acidity, measured in mg_{KOH}/g_{oil} required to neutralize the sample are:

— <0,15 = good

— 0,15 to 0,30 = fair

— >0,30 = poor

e) **Colour and appearance** of the oil is an indication of oxidation and the presence of other contaminants, so the faults detected and components covered are described under those specific sections.

The values given in ISO 60422 for colour and appearance are:

— clear and without visible contamination = good;

— dark and/or turbid = bad.

f) **Interfacial tension** is a particular technique for assessing the presence of polar contaminants in the oil, which can be an indication of ageing of the oil. It is a general measure of contamination level, including moisture, so the faults detected and components covered are as described in b) and d) for high moisture content and acidity, respectively. In general, the results of an interfacial tension test will be closely correlated with the results of the acidity test.

g) **Corrosive sulfur:** certain oils under specific temperature conditions can deposit copper sulfate on the copper and conductor insulation, reducing the dielectric strength of the insulation and ultimately leading to breakdown. The oil can be tested for its tendency to deposit copper sulfide. Potentially corrosive oils can be passivated to prevent the deposits from occurring.

h) **PCB levels** are not an indication of faults in the system, rather they are an indication of contamination of the transformer with old oil that contained PCBs. PCBs are harmful to health and are an environmental pollutant, and are removed by specialists. Such specialists can replace the PCB contaminated oil with new oil and reduce the PCB to acceptable levels (<50 mg/kg).

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9.4 Temperature including thermography

9.4.1 Fault mechanism

High temperature in a transformer leads to more rapid ageing of the components, principally the cellulosic insulation components (paper and press board) and to more rapid ageing and oxidation of the oil. A widely recognized guideline is that a 10 °C increase in temperature above the design value halves the life of the insulation, so maintaining a low temperature is very important. Higher temperatures also speed up the process of corrosion. Hot spots inside a transformer can lead to breakdown of the insulation and the oil, resulting in the generation of gases. Poor internal connections, resulting in areas of higher resistance, lead to significant localized heating. In the extreme, local corona discharge/partial discharge/tracking and arcing are the cause of intense local hot spots.

The overall temperature of the transformer will be affected by the heat input (largely the load) and the heat output (cooling system effectiveness). Overall cooling levels are affected by the ambient temperature, airflow over the cooling surfaces, and oil flow rate. Local cooling inside the transformer is affected by oil flow patterns within the transformer, which can be disrupted over time by the build-up of sludge, or by distortion of internal components.

9.4.2 Technique

Overall temperature may already be measured by a fixed temperature sensor in the oil, which may be used to control fans or pumps for the cooling system, and may also be connected to a high temperature alarm.

On some transformers, local temperature may already be detected by fixed sensors. Some transformers may be supplied from new with a number of internal temperature sensors, located at points that aim to detect localized hot spots, which can be used to adjust load or cooling to keep within safe temperature limits. Some transformers already include the use of fibre optic temperature sensors, mounted in locations intended to pick up the hottest spot. Newer techniques use optic fibres that can sense temperature along the entire length of the fibre optic sensor. Such temperature sensors can only be installed in the windings when the transformer is manufactured or repaired and the optimum location of the sensor is difficult to predict. Because the temperature sensors are inserted into the insulation structure which will see service under high voltage conditions, special precautions should be applied in order to preserve the electrical and mechanical strength of the insulation system.

In the absence of sophisticated built-in temperature sensors, infrared thermal cameras can provide a very useful means of assessing the surface apparent temperature, with the advantage that they can readily identify relative hot spots on the transformer, and can help identify problems with the cooling system. They cannot generally identify local hot spots deep within the transformer, inside the windings.

Details of condition monitoring using thermographic techniques can be found in ISO 18434-1.

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9.4.3 Faults detected/components covered

Transformer components most affected by elevated temperature are the insulation; both the oil and the paper deteriorate at higher temperatures. Extreme high temperatures can result in thermal stresses and distortions of the windings and the core, which can in turn put additional stresses on other components and the paper insulation. High temperature readings can be caused either by high electrical loads, or by some form of fault in the cooling mechanism.

9.5 Partial discharge (PD)

9.5.1 Fault mechanism

A transformer is subject to electrical and thermal stresses. These two stresses can break down the insulating materials. An early indication of insulation breakdown is partial discharge. The term partial discharge (PD) can be used to describe both the underlying phenomenon and the technique for

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detecting it. Detecting PDs in a transformer is important as the presence of PD can result in progressive deterioration of the insulation to the point of destruction.

The phenomenon of PD is the localized dielectric breakdown of a small portion of a solid or fluid electrical insulation system under high voltage stress, which does not bridge the space between two conductors. While a corona discharge is usually revealed by a relatively steady glow or brush discharge in air, PDs within solid insulation system are not visible.

PD can occur in a gaseous, liquid or solid insulating medium. It often starts within gas voids, such as voids in solid epoxy insulation or bubbles in transformer oil. Protracted PD can erode solid insulation and eventually lead to breakdown of insulation.

9.5.2 Techniques

9.5.2.1 General

PD pulses generate electromagnetic waves, acoustic waves, local heating and chemical reactions at their point of origin. Established methods for detecting PD activity and defect location are typically based on one or more of the following techniques.

a) **Ultrasonic/acoustic techniques** detect sound waves emitted by the PD activity. This is a test that can, and indeed can only, be done while the transformer is in normal operation, so is a useful online technique (this technique is also described in 9.8).

b) **Electromagnetic field/radio frequency interference (RFI) detection** picks up radio waves generated by the PD activity. This is also an online technique, and is described in more detail in 9.5.2.3.

c) **PD sensing via ultra-high frequency method (UHF)** uses sensors that penetrate the tank wall via valves and access plates. These sensors can pick up the effects of ultra-high frequencies of PD from a wide area within the transformer. Additional sensors may help further segregate the PD source.

d) **Electrical measurements using directly connected sensors** can measure PD directly, and can be both online or offline techniques.

e) **DGA** detection is also useful to detect that PD activity has been occurring, but does not detect it directly in the same way as the three other techniques. DGA is covered in 9.6.

9.5.2.2 Ultrasonic/acoustic techniques

Problems such as arcing, destructive corona or tracking (sometimes referred to as “baby arcing”) as well as PDs and mechanical looseness all produce detectable ultrasound that warns of impending failure. Detecting these emissions is relatively easy with ultrasound. The acoustic difference among these potentially destructive events is the sound pattern. Arcing produces erratic bursts, with sudden starts and stops of energy, while corona is a steady “buzzing” sound. Destructive corona has a build-up and drop-off of energy resulting in a buzzing sound accompanied by subtle popping noises. If the subject equipment is at a distance while scanning for these emissions, a parabolic reflector can be used to focus the sound into the collector. This also allows for directional identification of the source.

PD which occurs inside electrical components such as in transformers and insulated bus bars is another problem that can be detected with ultrasound. This is heard as a combination of buzzing and popping noises. A contact probe is normally employed for PD detection which can place some restrictions on the ability to use this as an online test.

Details of condition monitoring using ultrasound can also be found in ISO 29821-1.

9.5.2.3 Electromagnetic field/radio frequency interference (RFI) techniques/UHF techniques

The high frequency pulses of current that are associated with PD result in the radiation of electromagnetic waves across a wide range of frequencies, including the ranges from 50 kHz to 1 MHz

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(RFI) and from 300 MHz to 3 000 MHz (UHF), and these will interfere with other radio transmissions in these frequencies. These are the sort of noise and interference that will be familiar to people watching TV or listening to the radio when there is a source of sparks in the vicinity. This radio wave transmission can be used as a detection technique. A device that senses radio waves in this frequency range detects them, and displays the output as the strength of signal at each frequency as a spectrum plot. Changes in the level of output against time, or against a known good transformer of similar design indicate the presence of PD. Because the signal drops off quite strongly with distance from the source, readings taken from different locations around the transformer can identify the approximate location of the fault. A typical monitoring regime might involve taking regular tests from 6 to 12 specified points around the periphery of the transformer, allowing identification of the location with the strongest signal, or the greatest change over time. The shape of the spectrum can also give useful information; for example, the development of a peak or hump around a particular frequency can sometimes give an indication of the likely source of the problem. Time series plots can also be produced, which can show correlations with other factors such as overall load on the transformer, or temperature. Different faults can show up as different patterns.

In addition to detecting UHF signals external to the transformer, specially designed UHF sensors (antenna or plate) can be put into the tank wall (either via a valve or other specially designed place) and can be used for continuous or periodic PD monitoring of signals within the transformer itself.

9.5.2.4 Electrical measurements using directly connected sensors

Partial discharge testing using directly coupled detectors is a standard procedure for factory acceptance tests (FAT) of transformers according to IEC 60270 or IEC 60076-3. Some appropriate form of couplers is required, which may be capacitive or may be Rogowski coils. Partial discharge shows up as very short-lived blips of current, corresponding to the transfer of charge across the discontinuity in the insulation. The number of such events and the amount of charge flowing in each event is an indicator of the severity of the problem, and their location on the applied voltage waveform can indicate the nature of the problem. Testing can be online if sensors are permanently connected, or offline, in which case a high voltage is applied to the transformer by the testing device.

This type of test is covered by IEC 60270.

9.5.3 Faults detected/components covered

The use of these techniques can identify insulation breakdown in gaseous, liquid or solid insulating mediums. The technique is also particularly applicable to resin-filled transformers where it detects small voids in the insulation, which can, over time, gradually deteriorate and lead to actual failure of the insulation. Partial discharge readings can give a very early warning of the early onset of this sort of problem, although the directly connected sensor method does not detect the later stages of actual measurable short circuit current flow.

9.6 Dissolved gas analysis (DGA)

9.6.1 Fault mechanism

An oil-filled power transformer is subject to electrical and thermal stresses. These two stresses can break down the insulating materials leading to the release of gaseous decomposition products. Distinct patterns of gases are generated by specific types of faults, owing to the different intensities of energy dissipated by the particular fault type, which in turn leads to different temperatures at which the dielectric is decomposing.

9.6.2 Technique

DGA is used to detect specific dissolved gas concentrations in samples of insulation oil from oil-filled transformers. Factors such as the rate of generation of gas, the overall level or concentration of gas, the type of gas and the relative concentrations of the different gases can be used to assess the presence of faults within the transformer.

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Dissolved gas generation rate can be monitored online. Frequently the level of hydrogen is detected by automated online equipment. Off-line sampling methods are normally used to carry out laboratory analysis of dissolved gases. This can give more detailed information. Some of the more sophisticated online monitoring systems can also analyse the concentration of a number of different gases, typically up to eight gases. There are several reliable methods of online measurement for these gases, and a number of the standards describing these methods are shown in the Bibliography. The principal standard defining DGA tests and the interpretation of the results is IEC 60599.

These standards cover 13 specific gases, which are: carbon dioxide (CO_2), acetylene (C_2H_2), ethylene (C_2H_4), ethane (C_2H_6), hydrogen (H_2), oxygen (O_2), nitrogen (N_2), methane (CH_4), carbon monoxide (CO), methyl acetylene [C_3H_4 (Y)], propadiene (C_3H_4), propylene (C_3H_6) and propane (C_3H_8).

Because the different gases tend to be produced at different temperatures, the presence of specific gases, and the ratio between them, can be an indication of the underlying fault that has caused them. Interpretation of these gas ratios is given by IEC 60599.

Different gases are produced at different rates at different temperatures of fault; so, for example, hydrogen is generated by hot spots with temperatures from 150 °C upwards in ever increasing quantities right through to full arcing at temperatures of 800 °C and above; methane is generated by hot spots with temperatures of 150 °C and above, but the rate tails off above 300 °C. Acetylene in contrast is only generated by temperatures above 500 °C and particularly above 700 °C, and so is a key indicator of arcing inside the transformer.

IEC 60599 uses these phenomena to classify the type of faults in two categories each with three levels:

a) discharge faults: PD, low energy discharge or high energy discharge;

b) thermal faults: <300 °C, 300 °C to 700 °C and >700 °C.

Annex A contains an outline description of the methods of interpreting the different gases present covered by IEC 60599, including the Duval triangle method, which plots the levels of three gases, methane, ethylene and acetylene, to identify the likely cause.

9.6.3 Faults detected/components covered

Faults detected include overheating (hot spots), arcing and corona discharge.

Components affected include oil, insulation of main windings, conductors, etc.

9.7 Noise

9.7.1 Fault mechanism

The alternating electric and magnetic fields in a transformer create physical forces on the conductors and the core, tending to make them vibrate at twice the mains frequency. In addition, magnetostriction means that the core will physically be changing in shape slightly as it is magnetized and demagnetised on each cycle. This vibration can be heard as the characteristic "mains hum".

In a well-constructed transformer, the components should all be tightly secured in place with little opportunity for movement, but if there is any looseness, it can allow the components to move more, and hence vibrate more, leading to a louder audible noise. If components are able to rattle against one another, the noise will be very significantly greater.

Because the driving force for the vibration is the magnetic fields of the primary and secondary coils and the core interacting with one another, the force and hence the noise can be expected to increase with higher currents, i.e. higher loads on the transformer. In the early stages of a developing looseness problem it is possible that the noise level could only be noticeably louder under conditions of high load.

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9.7.2 Technique

Subjective assessments of noise can be made routinely by anyone in the area of the plant, and a routine walk-around patrol should be encouraged to listen out for noise. However, a problem that develops only gradually can be difficult to pick up with the human ear, so numerical measurements with a sound level meter are useful. When taking such measurements, the load on the transformer at the time of the measurement should be noted, to avoid false interpretations of noise increase that are purely due to a higher load condition.

In some situations, e.g. where there are local environmental limitations on the noise level, a formalized noise measurement approach can be required. Methods for carrying out such noise tests in a standard manner are described in IEC 60076-10.

9.7.3 Faults detected/components covered

Looseness in any of the internal or external components of the transformer.

9.8 Ultrasound

9.8.1 Fault mechanism

A transformer is subject to electrical, mechanical and thermal stresses. These produce detectable ultrasound and can serve as an early warning for impending failure.

Problems such as arcing, destructive corona or tracking (sometimes referred to as “baby arcing”) as well as PDs and mechanical looseness all produce detectable ultrasound that warns of impending failure. Detecting these emissions is relatively easy with ultrasound. The acoustic difference among these potentially destructive events is the sound pattern. Arcing produces erratic bursts, with sudden starts and stops of energy, while corona is a steady “buzzing” sound. Destructive corona has a build-up and drop-off of energy resulting in a buzzing sound accompanied by subtle popping noises. If the subject equipment is at a distance while scanning for these emissions, use a parabolic reflector such as the UE UWC (ultrasonic wave form concentrator) or the UE LRM (long range module). These accessories more than double the detection distance of the standard scanning modules.

PD that occurs inside electrical components such as in transformers and insulated bus bars is another problem that can be detected with ultrasound. Partial discharge can be quite destructive. It is effected by and causes deterioration of insulation. This is heard as a combination of buzzing and popping noises. The contact probe is employed for PD detection.

9.8.2 Technique

Ultrasound is a passive technique that processes the acoustic anomalies that are produced by the electrical, mechanical and thermal stresses. Ultrasonic amplitude and ultrasound pattern changes are used to classify the severity of degradation. Signals are detected by either contact sensors or airborne sensors. The raw ultrasound signals created by the phenomena within the transformer in some cases correspond directly with the fault condition, in other cases the ultrasound signals are modulated by lower frequency phenomena. By examination of the frequencies present in the signal, the likely cause of the problem can be identified.

Details of condition monitoring using ultrasound can also be found in ISO 29821-1.

9.8.3 Faults detected/components covered

Ultrasound can detect and localize PD associated with internal faults in a transformer. It can also detect corona, tracking and arcing associated with faults on external components. It can also detect issues associated with tap-changer condition and loose winding/loose lamination faults. On large oil filled transformers, auxiliary cooling components such as faulty fan motor bearings and cavitation in oil recirculating pumps can be detected.

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9.9 Vibration

9.9.1 Fault mechanism

The alternating magnetic field inside a transformer creates electromagnetic forces in the windings, between the windings, and between the windings and the core; in addition, magnetisation of the iron core of the transformer causes changes in the dimensions of the iron, through the phenomenon of magnetostriction. All of these lead to physical stresses within the transformer at frequencies related to the supply frequency, typically at twice the applied supply frequency since the forces are generated on both the positive and negative halves of the electric cycle. These stresses lead to actual movement of the components of the transformer, the scale of which will depend on the stiffness and “tightness” of the structure. Any loss of tightness or stiffness tends to result in greater movement, and this movement can be detected by vibration monitoring. These same phenomena also generate noise, which can also be used to detect developing problems.

9.9.2 Technique

Vibration sensors, typically piezo-electric accelerometers, are mounted in appropriate locations on the transformer. Different locations are better suited to particular faults. Typically the sensors need to be installed during the construction of the transformer in order to give the most effective measurements, as mounting on the outside of the tank tends not to give sufficiently specific identification of the location of the problem. Laser Doppler vibrometers have also been used experimentally to give a direct, non-contact measurement of winding vibration.

9.9.3 Faults detected/components covered

High vibration can indicate looseness of the windings, core structure, or other internal components particularly if they come into contact with the casing. Vibration measurement can also be used to detect problems in on-load tap-changers.

Vibration signal analysis is being pursued as a likely means of achieving a dependable transformer winding mechanical integrity diagnostic tool. The vibration sensors are magnetically mounted piezo-electric accelerometers attached to the sides and top of the transformer tanks. The signals are optically isolated for transmission to a data recorder. The occurrence of winding looseness has been investigated. A similar approach has been also applied as a method for diagnostics of on-load-tap-changers. Vibration measurement and analysis could, however, prove to be complicated due to the various sources which cause vibration of a transformer (e.g. primary excitation, leakage flux, mechanical interaction, and on/off load switching) and the various locations where vibration signals can be taken.

9.10 Power factor/tan-delta and capacitance

9.10.1 Fault mechanism

As a transformer ages, the dielectric loss in the insulation increases. The increased loss could be due to either

a) contamination: moisture ingress, carbon, foreign materials, or

b) degradation: overheating and corona activity.

In the case of contamination, a transformer’s tank can be compromised, allowing moisture or other foreign materials to enter the transformer. Carbon can become present in both the fluid and the winding insulation due to faults that create high temperatures, such as high resistance connections. With time the main winding insulation can degrade and continue to create more carbon and possibly generate corona activity within the tank as bulk ionization occurs.

All of these related problems cause an increase in dielectric loss and an associated increase in power factor.

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Another risk during the lifetime of a transformer is that the main windings can experience gross mechanical deformation such as hoop buckling for a number of reasons. It this occurs, it will lead to changes in the bulk capacitance of the transformer, which can be detected by changes in capacitance.

9.10.2 Technique

PF/tan-delta and capacitance tests are performed on transformers offline but some insulation systems such as bushing C1, can be measured online. Most common equipment measures PF/tan-delta and capacitances of a connected insulation configuration at the same time and expresses both values.

For offline tests, the test is performed by injecting a high voltage, typically 10 kV, to the insulation system and measuring the real resistive current and the quadrature capacitive current. The PF/tan-delta test results are then calculated and compared to historical, population or accepted insulation-type limits. Results can also be trended over time for analysis.

Test techniques allow for the use of different circuits that are designed to isolate insulation systems whenever possible, thus not lumping together multiple insulation systems as this will dilute the result. The two test circuits used are the ungrounded specimen test and grounded specimen test. When using these two test circuits, auxiliary leads can be used to pull more insulation systems into the test or guard them out.

Key to obtaining good PF/tan-delta test results are ensuring the apparatus under test is well grounded and that the test circuit being used has a good ground connection to the same circuit. Ensuring the exterior accessible components are clean and dry can also improve test results and prevent false positive test results.

The terms PF (power factor) and tan-delta are often used more or less interchangeably. Strictly speaking, they describe two slightly different values, in that PF is the cosine of the angle between the real loss current and the total charging current, whereas tan-delta is the tangent of the dissipation angle called delta, which is the angle between the quadrature charging current of the test specimen and the total charging current (see Figure 5). For values of PF or tan-delta of less than 10 %, the difference between the two calculations is very small so in practice the distinction between the two terms is not important. This is particularly so since only a very poorly performing insulation system would have a tan-delta or a PF approaching 10 %. Most real world results are well below 1 % and do not require any conversion, so the terms may be used interchangeably.

The capacitance value is sensitive to changes in the winding geometry which normally should not vary during the lifetime of the transformer. However, the value is also affected by changes in temperature, oil and paper quality. These changes should normally be small, so the values measured should not vary by more than the variations and uncertainties of the measurement equipment. The results can be compared to previous results such as the readings taken during final acceptance test, site acceptance test or other previous diagnostic measurements.

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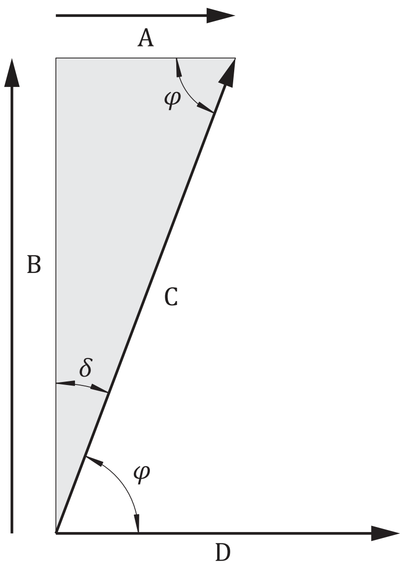

Key

δ delta

φ phi

A resistive, loss current — in phase with applied voltage

B capacitive current — in quadrature to applied voltage

C total charging current — at angle φ to applied voltage

D applied voltage

NOTE

1 Power factor = Cos (φ)
= resistive current/total charging current
= A/C

2 Dissipation factor = Tan (δ)
= resistive current/capacitive current
= A/B

3 For angles of δ < 10°, B and C are very similar in size, therefore Tan (δ) is approximately equal to Cos (φ), i.e. Power factor and Dissipation factor will be very similar in number. Within 1,6 % at 10°, within 0,4 % at 5°, and within 0,06 % at the 2° typical limit of most real-world values.

Figure 5 — Explanation of differences between PF and tan-delta

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9.10.3 Faults detected/components covered

Power factor can detect a wide variety of faults including mechanical, thermal, contamination and degradation defects. The most common problem detected is high moisture content. The moisture content in a transformer increases its real (watts) insulation losses leading to an increased power factor. Over time, this increased power factor insulation operates at a higher temperature which can lead to further degradation and damage to surrounding insulation and ultimately a fault. It is very important to maintain a relatively low power factor over the course of a transformer's life due to the accelerated ageing effects of a high power factor.

Changes of the capacitance value normally indicate a change of the geometry of the windings being measured. Changes in the measured capacitance value can also be caused by changes in the oil or paper quality, but these factors are much more clearly seen by changes in the PF/tan-delta value.

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9.11 Resistance

9.11.1 Fault mechanism

The series resistance across a winding phase can be compromised by a number of factors during the life of a transformer, including faults introduced during manufacture, faults that gradually develop over time, and damage as a result of transport, installation, commissioning and operation of a transformer. The series circuit between terminals of a transformer winding can include the winding, bushing, draw leads and tap winding leads. Any loss of integrity of contact can be detected by measuring the inline resistance. This method can be used to detect winding short-circuits.

If moisture enters a transformer or there is a short circuit between the winding and the ground, the insulation will have become effectively compromised. In the case of moisture, if the moisture ingress is extreme it is possible that the DC insulation resistance of the main winding would decline. If a fault occurs and the winding insulation shorts to ground the DC resistance will drop to or near zero. Moisture in the insulation will give a low DC insulation resistance.

9.11.2 Technique

Winding resistance is measured while the transformer is offline and the terminals are isolated. Note that there are two distinct DC resistance tests performed on transformers.

a) Winding resistance test (WRT). Winding resistance tests are performed by commercially available WRT test sets that measure the series resistance of conductors, connectors and contacts. This type of test is looking for very low resistance as this indicates good contact and connector mating. It is also possible to compare the three phase winding resistances to analyse the results. Ensure that the WRT test set used has adequate current to excite and achieve a steady-state value. If original test results are available, these can be compared with the values measured on site to establish whether the values have changed.

b) Insulation resistance. The DC insulation resistance test measures the DC insulation resistance from main windings to ground and in-between main windings. A low value could indicate a problem and that a fault is detected. Note that the DC insulation resistance has low sensitivity on transformer windings and degradation would have to be very advanced to be diagnostically significant.

9.11.3 Faults detected/components covered

Winding resistance can detect loose connections in leads and tap-changers, degraded tap-changer contacts, winding de-stranding and broken strands or short-circuits within windings. These failure modes include: high fault currents, poor contact tightness between winding elements and loosening due to vibrations in lead connections.

Looseness, degraded on-load tap-changer (OLTC) contacts, poor lead contact and conductor de-stranding faults can be detected by the DC winding resistance test.

Extreme moisture ingress, manufacturing defects, and LV winding to core faults can be detected by the DC insulation resistance tests.

9.12 Dielectric frequency response (DFR), polarization/depolarisation current (PDC), recovery voltage method (RVM)

9.12.1 Fault mechanism

DFR, PDC and RVM are three related techniques which have a common goal of detecting moisture within a transformer's windings. Moisture (together with oxygen and high temperature) is the leading cause of transformer insulation ageing, and subsequent dielectric failure. Moisture affects the properties of the paper, and these techniques seek to detect these changes in properties by detecting the resulting

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changes in the electrical behaviour of the transformer. All three techniques are offline tests, and require a highly trained individual and controlled conditions to use effectively.

9.12.2 Technique

DFR, PDC and RVM are variations on the dielectric frequency response analysis (FRA) technique (see 9.13). Each of the techniques relies on observing the change in injected voltage or current signal over time and/or frequency. The response of the injected signals will vary over time and/or frequency depending on several variables, or parameters, such as moisture. The three test methods are designed to estimate moisture within transformer insulation. These methods also require that the transformer being measured is an oil-paper system, so they are inappropriate for dry-type transformers. These methods also require a trained tester who understands how to perform and evaluate the test results, the analysis of which is outside the scope of this discussion. A brief description of the three methods follows.

a) **DFR**: The DFR test is performed offline by sweeping a low voltage waveform across a large frequency range starting close to DC and ending at 1 kHz. The power factor and capacitance is measured and then plotted, and the resulting curve is then compared to mathematical and library models to estimate the level of moisture within the transformer winding. A number of assumptions need to be made to properly estimate moisture, including transformer volume and the ratio of solid insulation to oil.

b) **PDC**: The PDC test is performed by injecting a polarizing DC current (P) then a depolarizing DC current (D) at 100 V into the transformer winding. The test is repeated multiple times to obtain an average result and minimize test inconsistencies. The test is typically performed 5 to 10 times. The currents for both directions (polarizing and depolarising) are then plotted and checked for consistency. Finally, the results are reviewed by a trained PDC analyst.

c) **RVM:** The RVM is an offline test performed by conducting a series of charge and discharge cycles across a transformer winding and then measuring the voltage which is 'recovered' at the terminals, generated by the test specimen itself. The voltage is plotted versus time during both the charge and discharge cycle. The test is often conducted several times to average out test inconsistencies and can take up to 10 000 s to complete. By analysing the recovered voltage curve the moisture can then be estimated.

9.12.3 Faults detected

DFR/PDC/RVM are all designed to estimate or ascertain the level of moisture within a transformer's cellulosic insulation. Elevated levels of moisture within windings can lead to accelerated ageing and reduced dielectric strength. These conditions compromise the insulation and increase the possibility of a fault. These tests are not applicable to dry-type or gas-filled transformers.

9.13 Frequency response analysis (FRA)

9.13.1 Fault mechanism

The FRA test is a very sensitive test that can detect a number of variable changes within a transformer including mechanical, contact and grounding changes. The primary purpose is to detect mechanical movement of the main windings within a transformer. Mechanical movement within a transformer leads to geometric changes to the winding and the relative position of the winding to neighbouring windings, the core, tank and support members. As a result the characteristic frequency response of the individual winding will change, causing a change to the shape of the FRA measurement curve. The frequency response measured during this test is very sensitive to changes in geometry within the transformer. A transformer can be thought to be a complex ladder of resistance, inductive and capacitive elements all relating to the geometric position of the winding and the various components that surround and support the winding. A fault that leads to alteration of this impedance ladder will cause an associated change to the FRA curve.

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9.13.2 Technique

The FRA test technique measures the transfer function of individual windings when the transformer is out-of-service and disconnected. The unique characteristics of the transformer that can be represented as a network of resistances, inductances and capacitances are assessed by taking measurements between selected terminals and then recorded in the form of a transfer function curve. The FRA test is performed by one of two methods.

a) Sweep frequency method: This method sweeps a low voltage waveform through a range of frequencies and measures the voltage input and output and then calculates the frequency response.

   It is important to ensure that the core is de-magnetised before commencing the sweep FRA test as remnant flux in the core can affect the measurements. This test should not be carried out immediately after DC resistance tests, as they can magnetise the core.

b) Impulse method: This method injects a medium- to high-voltage pulse into the winding and then measures the output. An FFT is then conducted to transform the time-based signal to the frequency domain and the frequency response is then calculated.

   FRA tests are performed offline on transformer windings using various test sequences.

9.13.3 Faults detected

FRA tests are capable of finding and localizing physical deformations within the transformer that can occur and are caused by

a) significant over-current (such as arising from a short circuit),

b) through fault,

c) shipping damage,

d) loose grounds,

e) loose connections, or

f) tap winding contact degradation or damage.

The defects created by these causes can include hoop buckling/radial winding deformation, telescoping/axial winding elongation, core defect, core delamination, bulk winding movement, shorted turn, contact defects, open circuited turn, loose winding, and floating shield.

By measuring the transfer function of the transformer, deformations of the windings can sometimes be detected, provided that a reference fingerprint of the unit is available. Deformation or changes in geometrical distances of the windings leads to changes in internal capacitances, and thereby a change in the transfer function of the transformer. In practice, an impulse is injected on one side, and the Fourier spectrum is measured of both the impulse and of the response on the other side. The transfer function is calculated by dividing the two spectra. If the reference fingerprint is not available, comparison between the phases or to a similar transformer can highlight a problem.

As an alternative to the formerly used time domain testing (low voltage impulse method), the FRA is one of the more frequently used techniques for diagnosing deformations of the transformer's windings. However, this technique presents as major disadvantages the need to take the transformer out of service and it involves great uncertainties due to the fact that the result is affected by a large number of factors.

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9.14 Ten (10) kV single-phase excitation current

9.14.1 Fault mechanism

The single-phase excitation current is sensitive to inter-winding insulation damage as well as abnormal tap change currents. Insulation degradation and contamination can lead to breakdown of the inter-winding insulation. In addition, circulating current between turns or through poor core/yoke grounding can also lead to abnormally high excitation current results.

In the case of damaged on-load tap-changers, the excitation current results can be altered as the online tap-changer could fail to move or be altered by poor contact.

9.14.2 Technique

Excitation current is normally measured by using commercially available test instruments that are also used for PF/tan-delta testing. The excitation current test is performed offline by injecting a 10 kV test voltage (or as high as possible without exceeding rated voltage and current) and measuring the total current and loss on the highest rated voltage windings. All other windings are open circuited during the test.

NOTE It is also possible to use 400 V for testing purposes.

The technique can also be used at different de-energized tap change and on-load tap-changer positions to ascertain the condition of the tap-changers. Typically DETCs are not moved during test, but the entire range of OLTC positions are tested. The measurement is then analysed by comparing the value measured between windings as well as comparing the pattern generated through the different OLTC positions. This measurement relies on the fact that during every tap-change operation of the OLTC a circulating current flows, and the test can pick up the changes in frequency response associated with this current.

9.14.3 Faults detected/components covered

The single-phase excitation-current test can be used to detect undesirable conditions in single-phase or three-phase transformers. Normally the test results are analysed by comparing currents between all three phases in a given transformer and between the similar single-phase units. Certain problems, however, can be detected on the basis of current change when the measurements are performed on different load tap-changer positions.

Accordingly, understanding how the load tap-changer affects the current magnitude of individual phases is essential for developing proper analysis. Moreover, this method also requires the transformer to be disconnected.

Analysis of the excitation current magnitude is especially sensitive to the condition of inter-winding insulation in both the main and tap windings and can detect turn to turn short circuits as well as partial (or degraded) turn to turn insulation. Analysis of the excitation current pattern is effective at finding damaged or mis-operating tap-changers as well as magnetized cores.

9.15 Leakage reactance flux

9.15.1 Fault mechanism

In an ideal world, all of the flux in a transformer will flow inside the core and within the windings. In the real world, not quite all of the flux passes through the core, but some “leaks” out, passing through the dielectric, in the gaps between the core and the windings. Physical distortion of the transformer main winding will alter the relative geometries of the main windings relative to each other and to the core. Leakage flux within a transformer travels through the gaps between the core steel and windings. The permeability of fluids such as transformer mineral oils, ester oils and air is much smaller than that of the core so the leakage flux through these alternate gaps is much smaller than the flux through the core. However, this means that the leakage flux is very sensitive to changes in geometry, so measuring

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the level of leakage flux, and particularly detecting changes in the level of leakage flux, is a sensitive way of detecting distortion of the transformer components. The physical distortion changes the physical cross-sectional areas of the gaps, thus altering the amount of leakage flux travelling through these gaps. When measured, the leakage flux will change as the winding and/or core is physically distorted.

9.15.2 Technique

Leakage reactance is closely associated with the short circuit impedance test and comparison is possible between the two tests though leakage reactance is considered a field test for condition assessment. Leakage reactance is measured when the transformer is out of service and disconnected. There are two types of leakage reactance tests:

a) per-phase leakage reactance;

b) three-phase equivalent leakage reactance.

Leakage reactance is performed commonly using commercially available test instruments that can inject current into a primary winding and measuring the resulting reactance (X). The three-phase leakage reactance test is analysed by comparing the three phase equivalent leakage reactances to one another. The per-phase leakage reactance test is analysed by comparing to an initial benchmark.

9.15.3 Faults detected/components covered

During an over-current fault or transportation, a transformer can experience large mechanical forces on the main windings. These forces can lead to mechanical distortion of the main windings. The result is a distortion of the windings geometries. These distortions can lead to several problems including migrated or increased hotspot temperatures, degraded or damaged winding insulation, or increased vibration and noise. A transformer with bent winding might not survive the fault and could be more likely to fail in subsequent normal service.

This is a traditional method for detecting changes in the winding geometry. The winding mechanical displacement results mainly in modifications of the leakage flux radial component. By using search coils, conveniently installed in the transformer, it is possible to measure such modifications. However, some of the problems previously mentioned regarding temperature sensors installation will apply here.

9.16 Bushing capacitance measurement

9.16.1 Fault mechanism

This method detects progressive deterioration of the insulation properties of bushings leading, ultimately, to failure of the bushings altogether, resulting in a catastrophic short to earth.

9.16.2 Technique

According to an Electric Power Research Institute (EPRI) study on accelerated transformer ageing, relative power factor (tan-delta) tests provided the earliest indication of incipient faults that could lead to failure. Bushing condition may be assessed by measuring the capacitance and power factor of the bushing. This can be done either offline using portable equipment, or online if permanent sensor equipment is installed.

Off-line testing can only be performed effectively in dry conditions, on a day with moderate temperature and low humidity, and, of course, can only be done with the transformer taken out of service. Off-line testing under such static conditions is not likely to detect all incipient faults that can be evident under operational conditions. In addition, several factors can influence offline measurement, including voltage fluctuations, contamination on the bushings, moisture ingress, oil level, damaged porcelain, ambient humidity and temperature.

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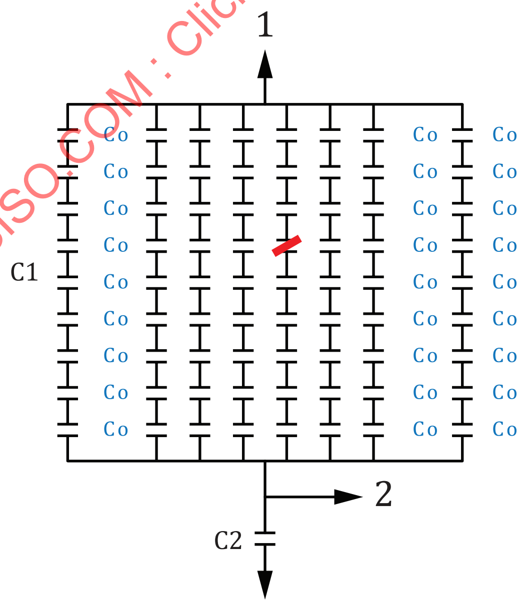
Online monitoring of bushings can be carried out continuously, following the recommendations of IEEE C57.19.00-2004. Online monitoring requires the installation of capacitive sensors in the bushing taps, as shown in the example in Figure 6.

Figure 6 — Capacitive sensor mounted in bushing tap

A bushing can be represented by several small capacitance values in series and in parallel, as shown in Figure 7. Measurements are taken from a sensor installed in each bushing tap (as shown in Figure 6). As a bushing fault starts to develop, some of these very small capacitors become resistive. The leakage current from deep inside the bushing is miniscule when measured to ground. However, if a capacitive voltage divider is used in a measuring circuit it can sense and measure the voltage drop due to these resistive components.

From this online measurement, both bushing power factor and dissipation factor (tan-delta) can be calculated and measurements stored in an appropriate instrument database that can be accessed by LAN system for remote monitoring. It is important that these measuring systems are designed to eliminate any noise that can affect readings taken.



Key

1 high voltage, in kV

2 bushing tap

Figure 7 — Equivalent circuit model of bushing

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Trending of these power factor and tan-delta values can provide an early indication of bushing degradation. If a significant upward trend develops, this is an indication of bushing degradation. As mentioned, offline power factor measurement is usually performed on a moderate day with low humidity. However, in service the bushing operates under varying environmental and loading conditions. These conditions have an impact on the power factor readings and should be measured and recorded by the monitoring instrument at the same time as power and dissipation factor measurements are taken. If this is done, changes in measured values could be found to relate to variations in operating and ambient conditions rather than further bushing degradation. Online monitoring systems provide the most accurate and the earliest indication of bushing condition and insulation integrity because they operate continuously and acquire data under all weather and environmental conditions. Online power factor values can also be used to verify offline test data.

9.16.3 Faults detected/components covered

Bushing PF and tan-delta measurement can detect deterioration in the insulation properties of the bushing and help avoid catastrophic failure of the bushing that can lead to destruction of the transformer.

Ageing of the bushing can be monitored with the help of periodic measurement of PF/tan-delta of the bushing (mainly C1, see Clause 4).

This value is normally measured during measurement of bushing capacitance. The principle is the same as described in 9.10 for winding configurations. The expected dissipation factor depends on the type of the bushing (RIP and OIP should be below 0,7 %, RBP below 1,5 % for new, not aged bushings). Continuously recorded dissipation factors can help to identify increase (therefore aging) over time.

9.17 Novel techniques

9.17.1 Winding clamping force estimation (WCE) method

9.17.1.1 Fault mechanism

The windings of power transformers experience significant mechanical forces caused by the interaction between the current in the windings and the resulting magnetic field induced in the core. These mechanical forces in the coils are contained by the winding clamping system. Over time, a combination of the aging of components and the effect of normal vibrations created during operation can result in the clamping forces decreasing.

High current events, such as an external short circuit, can lead to the creation of very high mechanical forces which must be contained by the clamping system. If the clamping force is inadequate, for example if it has been weakened by aging effects, the winding will be deformed. This can lead to further damage such as internal short circuits.

9.17.1.2 Technique

This is still a novel technique that is not yet widely adopted but has been subject of a number of patents over the years, and is currently being developed and explored by some transformer manufacturers. To assess the condition of the clamping system a technique can be used where a mechanical impulse is applied to the tank of the transformer. The vibrations from this impulse will propagate through the tank and excite the windings, which will start to vibrate with their own mechanical characteristic frequency which depends, among other things, on the mass of winding but also on the remaining clamping force.

Due to the remaining magnetism of the core in the winding a voltage will be induced which will contain the same frequencies as the mechanical vibration of the winding. If the voltage is recorded in the time domain it can be converted into frequency domain. The maxima in the frequency domain then represent the characteristic mechanical frequencies. Evaluation can be done by comparing the achieved frequencies with previous measurements, results recorded at other phases of the same unit, results recorded at other but similar units or expected behaviour.

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9.17.1.3 Faults detected/components covered

Using this method it is possible to assess the condition of the winding clamping to avoid the risk of a serious deformation or damage at the winding in case of an external short circuit event.

9.17.2 Online model-based voltage and current waveform analysis

9.17.2.1 Fault mechanism

As faults develop in a transformer, the relationship between the input and output waveforms of voltage and current are subtly changed, owing to factors such as movement of the windings, changes in insulation characteristics, permittivity, etc. This can be seen as a change in the transfer function between input and output sides of the transformer.

9.17.2.2 Technique

This is still a novel technique that is not yet widely adopted but is the subject of current patent applications. Measurements of the voltage and current waveform on both the input and output side of the transformer are taken, using online metering devices (usually existing current and voltage transformers that are already in place for operational monitoring purposes). The transfer functions between these inputs and outputs are then obtained by mathematical modelling techniques of system identification. Outputs are obtained in two formats: the parameter values of the transfer functions themselves; and the value of the residual components between the outputs from the model and the measured values. These residual components correspond to the nonlinear elements of system behaviour, which typically indicate faults such as loose windings.

Faults are indicated both by changes in the transfer function parameters, and by the absolute values of the residual components. By analysis of the frequencies of these components, using Fourier analysis, it is possible to identify the likely elements causing the problem.

9.17.2.3 Faults detected/components covered

Changes in characteristic behaviour of the transformer, which can include changes in resistance of the windings, changes in capacitance between input and output windings, changes in permittivity of the system, changes in shape, and looseness of windings.

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10 Establishing the programme

10.1 Selection of techniques — Individually and in combination

The earlier sections of this document have described the methods that can be used for monitoring the condition of power transformers, with the objective of adopting a condition-based maintenance regime. In order to turn this list of techniques into a viable condition monitoring programme, it is necessary to select the techniques that will be adopted, and the frequency at which they will be applied.

Techniques should be selected that will give sufficient indication of condition to address the principal failure modes of concern to the major components in the transformer in question, using Tables 1, 2 and 3. It is not anticipated that every condition monitoring programme on every transformer will involve every one of the techniques described in Table 3. Rather, a combination of techniques should be selected that cover the main areas of concern affecting the relevant components. The decisions should take into account the criticality of the equipment, following the guidelines set out in ISO 17359.

Online testing techniques have the advantage of not requiring an outage in order to take the measurement, so are likely to be the first choice where they are applicable. Offline techniques should then be chosen to fill in the picture more completely where required.

The conclusions for each transformer should then be captured and recorded as the basis for planning and controlling the condition monitoring work. A suggested format for this is given in Annex B.

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10.2 Selection of frequency of each monitoring technique

The general objective of condition monitoring is to avoid unexpected breakdowns, and to be able to carry out maintenance work in a planned manner. This requires that monitoring is carried out sufficiently frequently that faults can be reliably detected with sufficient warning time to organize maintenance work before failure occurs. The point at which deterioration can first be detected reliably is generally referred to as the point of potential failure, P, and the point at which functional failure occurs is generally referred to as point F. The time between these two points is the P-F interval. For reliable condition monitoring programmes, the interval between successive measurements should be no longer than half the P-F interval, and to cope with noisy signals, a shorter frequency than this is preferred, e.g. three to five tests during the P-F interval. So to set the required frequency of monitoring tests, it is necessary to have an idea of the likely P-F interval for the failure mode in question. Transformers are generally long-lived items, with in-service lives of often more than 40 years, and relatively slow deterioration rates, so the required testing frequency is normally measured in months, rather than days.

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Annex A
(informative)

Factors influencing the life of paper-based insulation and the role of transformer oil analysis/dissolved gas analysis

A.1 Paper insulation

In the most common construction of oil-filled transformers, the windings, generally made of copper strips or bars, are insulated by being wrapped in special paper called kraft paper, which is strong, and has a very high proportion of cellulose in its composition. Kraft board, which is made from similar material to the paper, is used as an insulating material to create blocks to keep the coils apart from one another, and to create parts of the supporting structure for the coils. The entire assembly is then immersed in oil which can circulate around the coils to provide cooling. The oil is also an insulating material.

When new, the paper has a high mechanical strength and a high dielectric strength, i.e. it can withstand a high voltage before breaking down. However, over time, the paper degrades, losing both mechanical strength and dielectric strength. Mechanical strength is important to the insulation as the electro-mechanical forces on the windings try to flex the conductors and vibrate them relative to one another. The paper needs to be strong to avoid tearing or wearing away in these situations. Dielectric strength is important to avoid it breaking down and becoming a conductor instead of an insulator. As the paper deteriorates, both these areas, mechanical and dielectric strength, get weaker. In the extreme, if the paper becomes too weak, it eventually starts to fall apart, and it fails to provide the necessary insulation, so that short circuits can occur inside the transformer.

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A.2 Paper chemistry and physical deterioration

The chemical structure of cellulose is a polysaccharide, i.e. it is a long chain molecule made up of individual units that are chemically sugars, glucose molecules, joined end to end. When new, kraft paper has a typical molecular chain length of around 1 200 saccharide units, and has a high tensile strength. As the cellulose deteriorates, the polymer chains break, and the average length of the cellulose molecules reduces, and with it the mechanical strength, until the point where, with a degree of polymerisation (DP) of around 150, i.e. 150 saccharide units in the chain, it has very little tensile strength at all.

The relationship between the tensile strength of paper and the DP is nonlinear, with the strength falling off more rapidly as the DP decreases. Once the DP is below around 400, the loss of tensile strength is very rapid. A DP of 250 is often used as an indicator that the transformer has very little service life left, and the coils need to be replaced entirely.

The rate of deterioration is dependent on a number of factors, and is exacerbated particularly by elevated temperatures and the presence of water. The breakdown process of the paper and oil is a self-catalysing reaction, accelerated by the water and carboxylic acids that are generated by the reaction itself, so the rate of deterioration will accelerate if not detected early on and steps taken to correct the situation.

A.3 Breakdown products

The chemical processes of this gradual deterioration lead to the generation of a number of different breakdown products. Electrical discharge in oil leads to a variety of gases including carbon dioxide (CO_2), acetylene (C_2H_2), ethylene (C_2H_4), ethane (C_2H_6), hydrogen (H_2), oxygen (O_2),

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nitrogen (N_2), methane (CH_4), carbon monoxide (CO), methyl acetylene [C_3H_4 (Y)], propadiene (C_3H_4), propylene (C_3H_6) and propane (C_3H_8).

The fact that gases are generated when there is a fault inside the transformer is the phenomenon that led to the development and adoption of the gas-actuated relay devices of the type commonly known as Buchholz relays. (Buchholz is actually a specific manufacturer's name, although it tends to be used to refer to gas-actuated relay devices in the same way that vacuum cleaners are often referred to as Hoovers.) These have mechanisms for detecting both a slow but continued generation of gas, and for detecting a high rate of gas, with the ability to trip the transformer. Nowadays, much more subtle and sophisticated devices can be used to analyse the specific composition of the gases being evolved, and to identify the likely nature of the underlying cause (see A.5).

Breakdown of the paper in the presence of water is via a process of hydrolysis of the cellulose, which results in acid breakdown products. Subsequent oxidation of the breakdown products leads to glucose and pentose and then to furfural (2-FAL) – $C_5H_4O_2$ (also known as 2-furaldehyde or furan 2 carboxaldehyde). The level of furfural can be used as a guide to the condition of the paper.

The presence of acid breakdown products in the oil is therefore a recommended monitoring measure. The standard technique, as described in IEC 62021 (all parts), is the use of a titration technique, measuring the amount of potassium hydroxide required to neutralize a standard sample of oil.

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A.4 The role of water

Water gets into transformers either from initial assembly, particularly if the tank has been leak-tested using water, or from atmospheric moisture, or from ingress through leaky joints on the top of the tank such as bushings. Initially, the water mixes with the oil. Water is not highly soluble in oil, but even in low concentrations it reduces the dielectric strength of the oil, which can make electrical discharges inside the transformer more likely. These will lead to local hot spots and will cause the oil and paper to break down.

The water migrates preferentially from the oil into the paper, where it leads to deterioration of the paper. Water weakens the mechanical strength of the paper, can reduce the dielectric strength, and encourages chemical decomposition of the paper.

It is generally easier to measure the water content of the oil than to directly measure the water content of the paper. A higher level of water in the oil generally indicates a higher level of water in the paper, although the two are not directly related in a simple 1:1 relationship. The water level in the paper can be calculated from the water content of the oil only under very stable conditions and other assumptions (see IEC 60422).

Because the water preferentially migrates from the oil to the paper, measuring the concentration of water in the oil can give an underestimate of the quantity of water in the transformer. This can be important when carrying out remedial action to remove water from the transformer, in that the time taken, and the quantity of water removed, can be more than a simple calculation based on the water level in the oil would suggest.

So water adversely affects the behaviour and condition of both the paper and the water, as well as potentially being a trigger for corrosion. Analysing the concentration of water in the oil is therefore an important monitoring measure, and the standard technique, as described in IEC 60814, is a Karl Fisher titration technique which measures the electrical charge required to complete the titration. It can give results correct to within 1 % of the true water concentration.

A.5 Gas evolution and fault diagnosis

Different gases are produced at different rates at different temperatures of fault; so for example, hydrogen is generated by hot spots with temperatures from 150 °C upwards in ever increasing quantities right through to full arcing at temperatures of 800 °C and above; methane is generated by hot spots with temperatures of 150 °C and above, but the rate tails off above 300 °C. Acetylene, in contrast, is only generated by temperatures above 500 °C and particularly above 700 °C, and so is a key indicator of arcing inside the transformer. This does not necessarily indicate a fault, particularly if

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