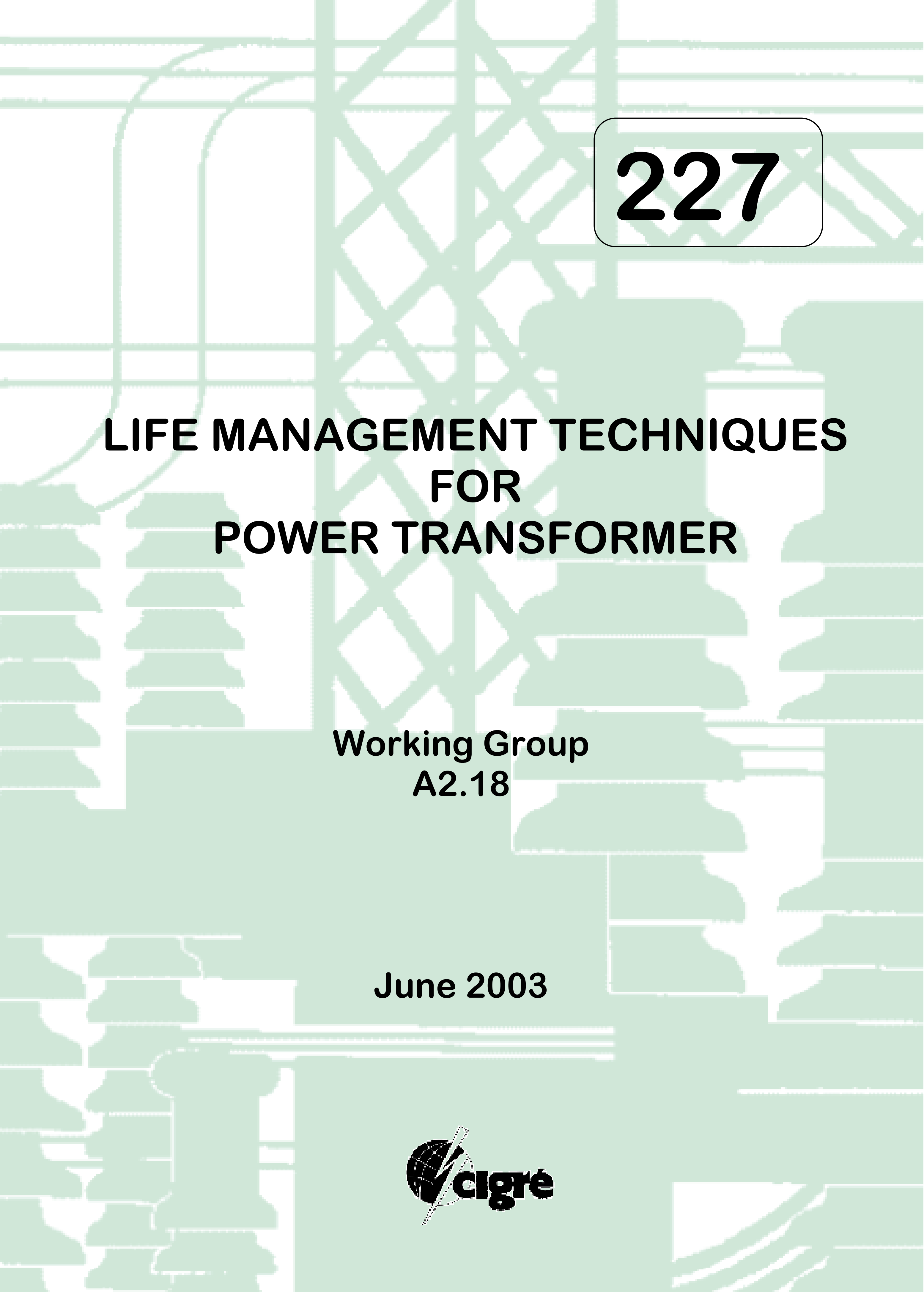

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LIFE MANAGEMENT TECHNIQUES FOR POWER TRANSFORMER

Working Group
A2.18

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cigré

GUIDE

for

Life Management Techniques For Power Transformers

Prepared by

CIGRE WG A2.18

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CIGRE WORKING GROUP A2.18

LIFE MANAGEMENT TECHNIQUES FOR POWER TRANSFORMERS

Chapter 1 Introduction

In recent years, there has been considerable interest in the subject of life management. Foremost among the various reasons stimulating this interest and causing concern among experts and pressures for changes in current practices are:

- Equipment getting older and approaching the end of original design lives
- Fewer people, particularly experts, being available to manage the transformer population
- Pressure to save money by reducing maintenance, and move from time based to condition based action
- Organizational changes, particularly moves to separate utilities into generation, transmission and distribution elements, which focus attention on the need to assess the remaining lives of assets, and the necessity of being accountable to other parties, usually non-experts and often non-technical
- New diagnostic and monitoring techniques and systems becoming available

The fundamental objective of life management can be defined simply as

‘to get the most out of an asset’

by ensuring that actions are carried out to promote the longest possible service life or minimize the life-time operating cost, whichever is the most appropriate. The key planned actions include the areas of: specification, procurement, design review and manufacture, maintenance, condition monitoring and diagnosis, rehabilitation, refurbishment and remedial work, life extension.

To respond to these issues, a new CIGRE Working Group was formed at the end of 1994 under the leadership of Victor SOKOLOV as convener and Jean-Pierre GIBEAULT as secretary with the following terms of reference:

Using the existing body of knowledge and technologies, and looking into the future, develop guidelines with the objective to manage the life of transformers, to reduce failures, and to extend the life of transformers in order to produce a reliable and cost effective supply of electricity.

The work was organized into three task forces:
Task Force 1 - General Knowledge and Theoretical Issues (John LAPWORTH Leader)
Task Force 2 - Diagnostic and Monitoring Techniques (Jack HARLEY Leader)
Task Force 3 - Operations on Transformers (Pieter GOOSEN/Victor SOKOLOV Leaders)

Task Force 4 - Application of Polarisation Techniques (Philippe GUUINIC Leader) was added to provide a review and report on the experience of users of recovery voltage and polarisation current techniques for determining insulation moisture levels. The work was performed within CIGRE WG 15-01-09, and the results have been published in Electra.[1]

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[1] S. Gubanski et al, "Dielectric Response Methods for Diagnostics of Power Transformers," Report CIGRE TF 15-01-09, Electra June 2002.

Chapter 2 Common Goals and Benefits

Where the objective of life management is to minimize costs, then the reduction in direct and indirect operational costs attributable to any planned operations needs to be balanced against the benefits of these operations.

For large capital items such as transformers, the direct capital cost of a replacement is usually by far the largest cost element, and for this reason it is often difficult to justify replacement before end of life failure. However, there are sometimes situations, usually when the indirect outage costs are very high, when a replacement can be justified before an end of life failure if the costs of keeping unreliable equipment in service are sufficiently high.

Clearly then, economic as well as technical and strategic factors determine the effective end of life of equipment. [1, 2] However, it is very difficult to develop universal guidelines because the costs, particularly the indirect costs of unreliability and failures, and also the costs of repair and refurbishment operations vary greatly between utilities.

Similarly, the relative importance of various failure modes can vary greatly depending on local conditions and practices. Many utilities are also nowadays unwilling to discuss failure statistics. Because of the above difficulties, it was considered to be beyond the scope of the present Working Group to provide guidance on the economic and probability aspects of failures, at least initially, and it was decided to concentrate on technical issues.

The objective of the WG was to provide practical tools that can be used by all those charged with managing transformer assets, which can take into account the specific differences arising from local circumstances, practices, and needs. The possible benefits include recommendations on concepts for Life Management of Power Transformers:

- Improvements over traditional time-based maintenance, e.g. Condition based or Reliability Centered Maintenance.
- Maintaining a transformer in service
- Continuity of supply. How to operate a defective unit
- Priority of in-field repair and on-line processing
- Minimizing the remedy actions. Making the most effective remedial actions
- Comprehensive life assessment and/or extension program

A major benefit of the work was to provide formalised and unified descriptions of processes and methodologies, to ensure a complete coverage of all relevant aspects. Thereby, users will be able to satisfy those legitimate demands of interested parties such as consumers, owners (shareholders), regulators, insurers, manufacturers, etc. for responsible action against technical threats, with due regard to non-technical aspects. In this way users should be able to answer important questions such as:

Do I need to do anything?
What should I do?
Why am I doing it?
What are the consequences?

To develop cooperation and communication between parties and to facilitate such communication, a vocabulary (Appendix 1) of commonly used terms was agreed upon and used consistently to avoid confusion and ambiguity.

Chapter 3 General Knowledge and Theoretical Issues

The first task was to improve the knowledge and general theory of degradation processes and end of life failures. An overriding need is to unify and build onto previous work on the subject, most notably by bodies such as IEC, IEEE and CIGRE. The overall goal was to provide a practical Guide to the main types of problems suffered by transformers and means of managing these to optimise asset life and usability.

Transformers are generally very reliable equipment with expected service lives of 40 years or more, so it is difficult for individual engineers to build up sufficient first hand experience of problems and how best to deal with them. In addition, failure processes in transformers are often complex and co-operation between manufacturers, utilities and academics is necessary if these processes are to be understood. For this reason it is important to develop cooperation and communication between parties, so that a central fund of shared knowledge can be built up. In this way the experiences and beliefs of individuals concerning problems, their causes and possible remedial actions, most probably coloured by local practices, can be combined and converted to general knowledge and theory.

3.1 Basic failure concepts

The basic **failure model** proposed for consideration assumes that there are a number of key functions or parameters, such as dielectric and mechanical strength, and that:

> **failure** occurs when the **withstand strength** of the transformer with respect to one of these key properties is exceeded by **operational stresses** (Figure 1).

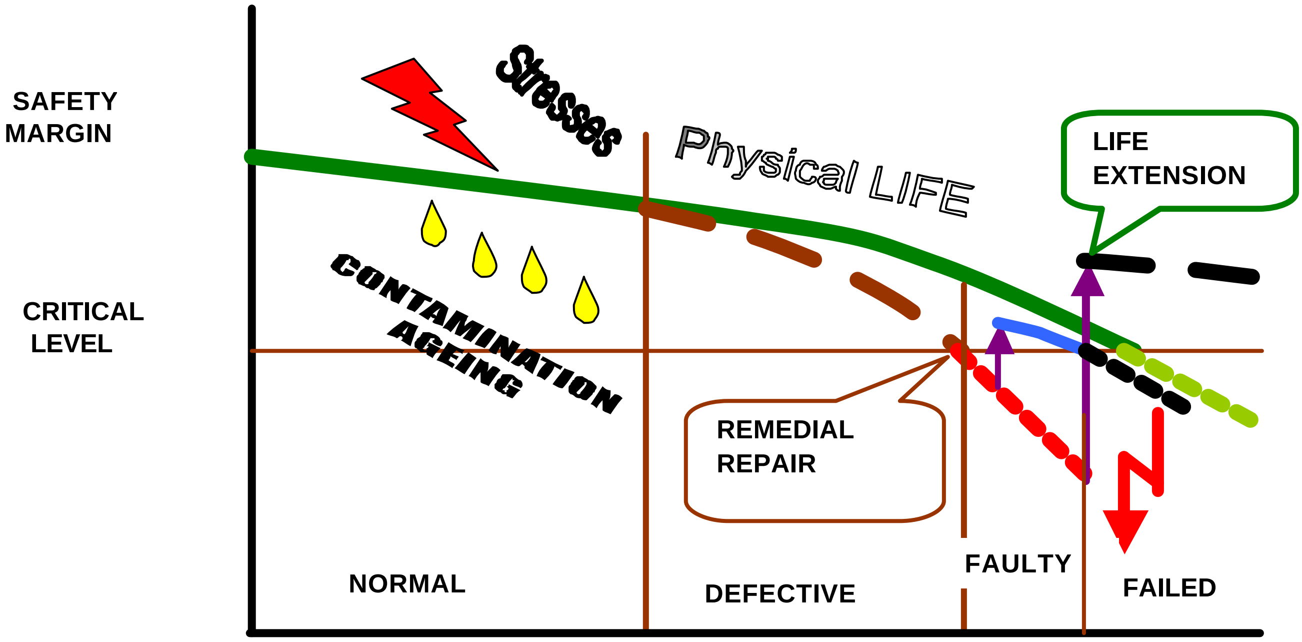


Figure 1 Conditions of a transformer in the course of its life cycle

The **withstand strengths** of a transformer will naturally decrease over its life due to various aging processes (normal aging), but may deteriorate faster than normal under the influence of agents of deterioration (e.g.

moisture) or if some abnormal destructive deterioration process (e.g. tracking) occurs. Theoretically it is possible to distinguish between reversible processes (often referred to as **defects**) and irreversible ones (**faults**), although such a distinction is not always clear-cut. (Refer to 3.2 for additional discussion on these concepts). Ideally, the presence of defects or faults would be detected by monitoring and diagnostic tests.

Operational stresses are usually dominated by intermittent events such as lightning strikes or short circuits. As an example of the changing stresses over the life of a transformer, consider the mechanical stresses imposed on a winding. When the transformer is new, the windings will be well clamped and therefore have a high strength, while the electromagnetic centres of the windings will be aligned to minimise the stresses of electromagnetic forces during short circuits. As the transformer insulation ages, the paper insulation will shrink and may result in a reduction of clamping pressure, thereby reducing mechanical strength. If a short-circuit occurs and the windings move slightly, the electromagnetic centres of the windings may move slightly, which will lead to much higher stresses during subsequent faults. It is probably through such a process of falling strength and increasing stresses that the mechanical condition of a transformer will degrade rapidly over a few short-circuits immediately preceding the final failure.

Because of the random nature of the key operational stresses it is unlikely that it will be possible to predict **when** the final failure will occur. However, if remanent strength and operational stress could be quantified adequately, it would be possible to determine when the circumstances were such that a **failure could occur**, i.e. the onset of increased unreliability. A key task in managing transformer service lives would therefore appear to be the quantitative assessment of the relevant remanent withstand strengths of transformers and operational stresses.

3.2 Condition classification

It is not usually practicable to quantify withstand strengths and operational stresses, so instead a more qualitative assessment of the health of the equipment is carried out, often referred to as its **condition**, and this is used to assess the expected reliability. The following classification in terms of required action is useful:

Table 3-1 Definitions of condition classifications

Condition	Definition
Normal	No obvious problems, No remedial action justified. No evidence of degradation.
Aged? Normal in service?	Acceptable, but does not imply defect-free
Defective	No significant impact on short-term reliability, but asset life may be adversely affected in long term unless remedial action is carried out.
Faulty	Can remain in service, but short-term reliability likely to be reduced. May or may not be possible to improve condition by remedial action.
Failed	Cannot remain in service. Remedial action required before equipment can be returned to service (may not be cost effective, necessitating replacement).

3.3 Recommendations on failure identification

3.3.1 Failure causes

A failure is usually a "tuning fork" of Life Management procedures. Many failures occur due to aging phenomena:

- Shortened life due to accelerated deterioration of components particularly bushings and OLTCs
- Overheating of the HV winding coils due to poor cooling or excessive circulating current
- Change in the condition due to ingress of water, particle contamination, aging of oil, loosening of contacts and clamping forces, vibration, unusual stresses, etc.
- Latent defects of design or defects during manufacture. These may require some other factor such as ageing of insulation or increase in fault level to lead to a failure.

3.3.2 Failure reports

In order to ensure that all relevant information on failures is gathered, a standard failure report form (Appendix 2) has been devised and tested by requesting Working Group members to submit a few examples each of what they consider to be important failures. To date thirteen failure examples covering a wide range of thermal, dielectric and mechanical types have been collected. These are compiled in Appendix 4 and Appendix 6.

In addition to the description of the failure, respondents are requested to identify what deficiency of condition allowed the failure to occur, and whether condition monitoring or diagnostic tests enabled a prior fault to be detected.

3.3.3 Failure code

In order to classify reported failures in a useful way, a failure code is shown as a Catalog of Defects and Faults (Appendix 3). The preferred method was to classify by the location of the failure (where ?) and the nature of the failure (how ?), i.e. thermal/dielectric/mechanical. The cause of the failure (why ?) is recorded as associated information but is not central to the method of classification, since cause is so prone to ambiguity.

Included in the failure report form are suggested categories for location and nature.

3.3.4 Failure guide

The overall goal was to provide the framework for a practical guide to the main types of failure and degradation processes suffered by transformers and means of managing these to optimise asset life and usability. The Guide is the means of drawing together the work of all three Task Forces.

The cornerstone of the Guide is the **Catalogue of Defects and Faults** (Appendix 3) covering the main important problems.

It is envisaged that for each important problem an **Identity Card** (Appendix 5) would be produced to include a complete description in a standardised format of how to manage the problem in question. An **Example** of a filled-in card is in (Appendix 6). In particular, this describes the likely consequences of each particular problem, recommendations on when to act (with suggested Caution and Alarm levels) and recommended remedial action.

An important section of the Guide is advice on how to relate typical symptoms, as indicated by the results of monitoring and diagnostic tests, to the most likely defect diagnoses. Information on this comes from deliberations and analysis of the failure reports. In order to achieve continual improvement, it is important that any difficulties encountered in dealing with a particular problem due to deficiencies in current knowledge or techniques are highlighted in the Guide to identify where further work is required.

3.4 Insulation deterioration: Theoretical issues

3.4.1 Aging factors

Water, oxygen, oil aging products (acids particularly) and particles of different origin are agents of degradation, that can shorten transformer life significantly under impact of thermal, electric, electromagnetic and electrodynamics stresses.

Processes of insulation deterioration involve slow diffusion of water, gases, and aging products and therefore affect basically only a part of the insulation structure, the so-called thin structure (paper insulation of turn and coils, pressboard sheets, etc.) that comprises typically 40-60 % of the total mass. The heated mass of conductor insulation that is subjected to accelerated deterioration comprises typically 2-10 % of the total mass of transformer insulation.

In fact, the fluid is an integral part of the transformer and plays a dynamic role in the condition of the entire system. All impurities in the oil (water, gases, and aging products) are the property of the entire dielectric system. Aggressive decay products being adsorbed by insulation can destroy the cellulose and also affect the properties of new oil after refilling. Reconditioning of oil is a critical step of life extension.

3.4.2 Water contamination

There are three sources of excessive water in transformer insulation: Residual moisture in the "thick structural" components not removed during the factory dry out, ingress from the atmosphere, and aging (decomposition) of cellulose and oil.

A transformer moisture model for a sealed transformer suggested by the WG A2.18 [3] is shown in Figure 2. The main source of water contamination is atmospheric moisture, and the main mechanism of water penetration is viscous flow of wet air or free water through poor sealing under action of a pressure gradient. A large amount of rainwater can be sucked into a transformer in a very short time (several hours), when there is a rapid drop of pressure (after a rapid drop of temperature that can be induced by rain) combined with insufficient sealing.

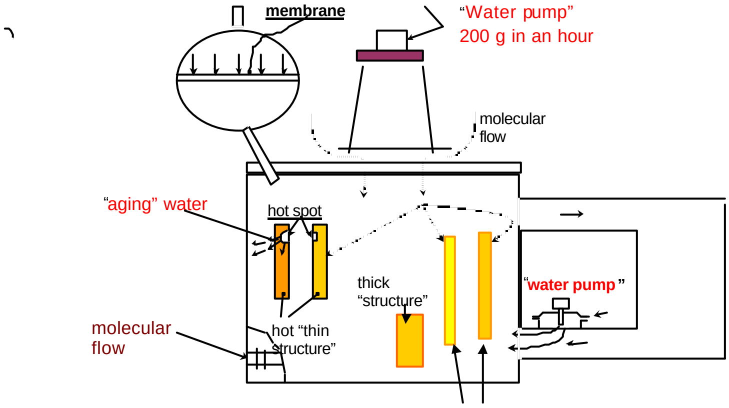


Figure 2 Moisture model

Moistening of insulation during exposure to atmospheric air is another significant factor.

Aging can produce a substantial amount of water only if insulation is subjected to elevated temperature and destructed significantly. In this case water is removed basically from the vicinity of the hot spots in the winding.

Distribution of moisture in the course of transformer life is non-uniform. Most of the water is stored in the thin structure operating at oil bulk temperature (20-30 % of the total mass of transformer insulation).

Parameters of moisture equilibrium depend on the structure of cellulose (they are different for Kraft-paper and for pressboard), temperature, presence of gases, water-in-oil and solubility.

Water content in turn insulation is substantially lower than in pressboard barriers due to higher temperature. However, the influence of temperature results in a non-uniform distribution of water in the layers (elevated concentration in outer layers). Solid insulation is a water accumulator and the main source of oil contamination in an operating transformer.

Oil is a water-transferring medium. Water is present in oil in soluble form that can be revealed by the Karl Fisher titration. As oils become very oxidized with increasing amounts of polar aging byproducts, their water solubility characteristics also increases. At elevated temperatures some amount of hydrated water may transfer into dissolved water.

Bonded water can not be revealed by conventional method as Karl Fisher titration is not valid for aged oils, where active contaminants are accumulated capable of forming hydrates with bonded water.

3.4.3 Particle contamination

The origins of particles are manifold. Cellulose fibres, iron, aluminum, copper and other particles resulting from the manufacturing processes, are naturally present in the transformer oil.

Aging during utilization at normal and overload temperatures slowly forms sludge particles. Localized overheating over 500 °C could be a symptom of forming carbon. The carbon particles produced in the OLTC diverter may migrate by leakage, accidents or human error into the bulk oil compartment to contaminate the active part.

A typical source of metallic particles is wear of bearings of the pumps.

Particle contamination is a major factor of degradation of dielectric strength of transformer insulation and, accordingly, elimination of particles is the most important objective of oil processing.

The most dangerous particles are conductive mode particles (metals, carbon, wet fibers). CIGRE Working Group WG 12.17 Particles in Oil [4] has collected and evaluated a significant number of HV transformer failures being attributed to particles. Particle identification and counting were found to be necessary procedures of condition monitoring. Typical contamination levels, including possible dangerous levels, have been advised.

3.4.4 Paper aging decomposition

Figure 3 shows the Model of Aging of oil-paper transformer insulation for water, particles and oil aging products. The dielectric safety margin of both major and minor insulation contaminated with water is determined by the dielectric withstand strength of the oil.

The presence of bubbles may cause critical partial discharge (PD) to occur even at rated voltage. Bubble evolution is a problem of a "hot transformer". This involves not only high temperature and elevated water content, but also presence of air and decreasing interfacial tension of the oil due to its aging.

The sudden ingress of free water may cause failure of the transformer immediately. The presence of free water in the oil is basically a problem of water coming out of solution because of very cold oil or in the extreme case, a "frozen" transformer. In spite of the fact that oil density is specified to be less than the density of ice, forced or even convective oil flow can be strong enough to move the ice into a critical zone.

The presence of conductive particles can reduce dielectric strength of oil by several times. A dangerous effect of dissolved water is a sharp reduction of dielectric strength of oil with increased relative saturation due to increasing conductivity of particles or emulsion formation in the vicinity of surface-active substances. Dissolved water is basically a problem of a "cold" transformer.

Water accelerates decomposition due to aging and depolymerization of the cellulose. The decomposition is proportional to the water content. This process becomes much more dangerous in the presence of acids. Thus, the condition monitoring of a transformer contaminated with water shall consider also contamination of the oil with particles and aging products.

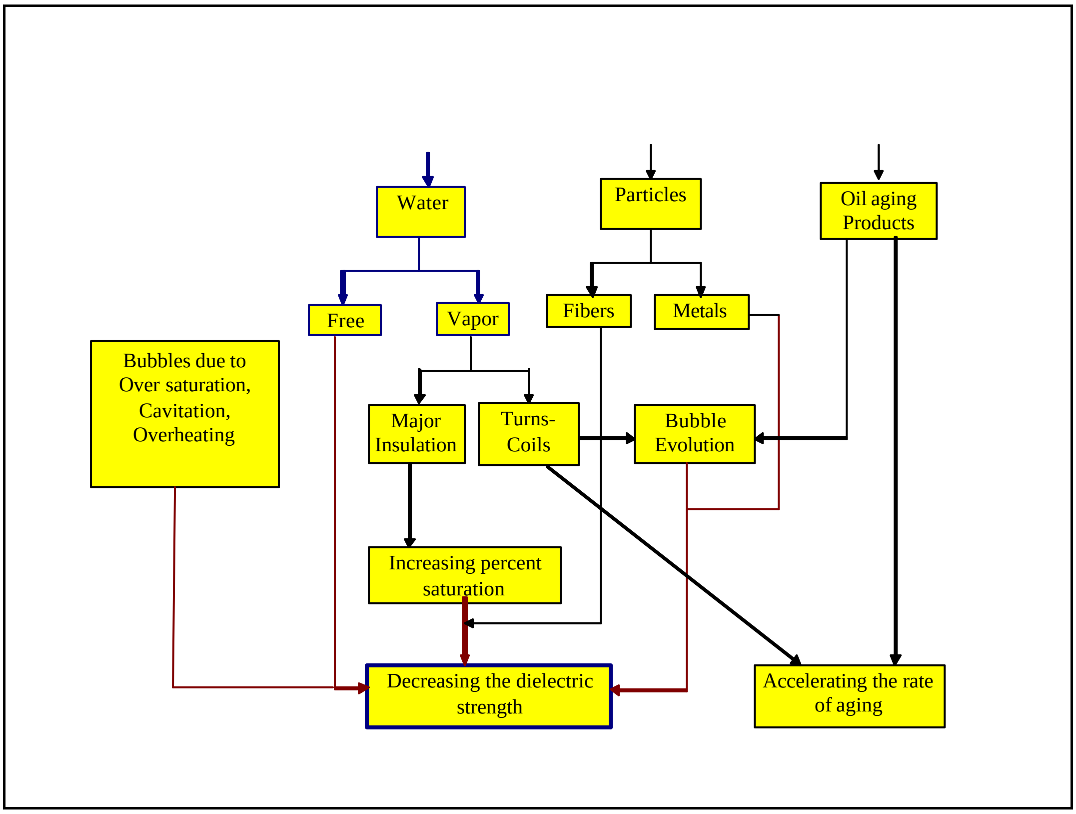


Figure 3 Aging model

3.4.5 Summary: Dangerous effect of degradation factors

A Model "Dangerous effect of degradation factors" suggested by the WG A2.18 is shown in Figure 4.

Temperature, water and oxygen are the main agents of cellulose degradation as well as oxidation of the oil. Insulation decomposition is a chemical phenomenon. The three mechanisms of degradation, hydrolysis, pyrolysis and oxidation, act simultaneously. Hydrolysis is the decomposition of a chemical compound by reaction with water. Pyrolysis is the decomposition or transformation of a compound caused by heat. And oxidation is the combination of a substance with oxygen.

The energy of activation of pyrolysis is 1.4-2.0 times as great as the energy of activation of hydrolysis, so that hydrolysis is a dominant mechanism at least at temperatures up to 110-120 °C. The presence of water is the most important factor in aging of cellulose. The process of hydrolytic decomposition needs an acid catalyst that contains a hydrogen atom to trigger the process. It is sometimes assumed that the main source of acids is oxidation of the oil. Estimation of loss of life could be made if temperature, time, water content and acids are taken into account. Correspondingly, removing of oxygen, water and oil aging products could be the most efficient procedures in order to extend insulation life.

The levoglucosanes are the source of furans.

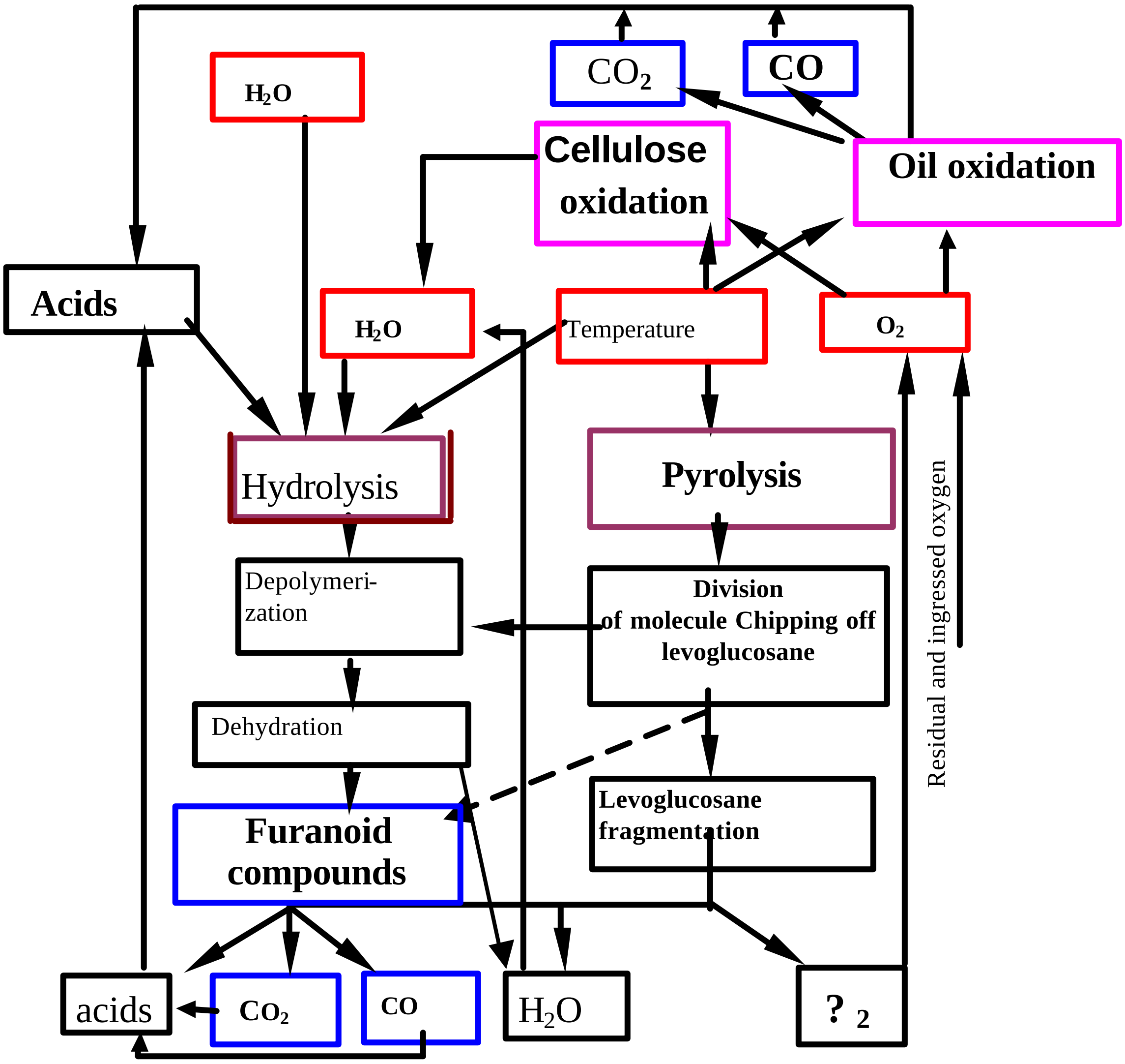
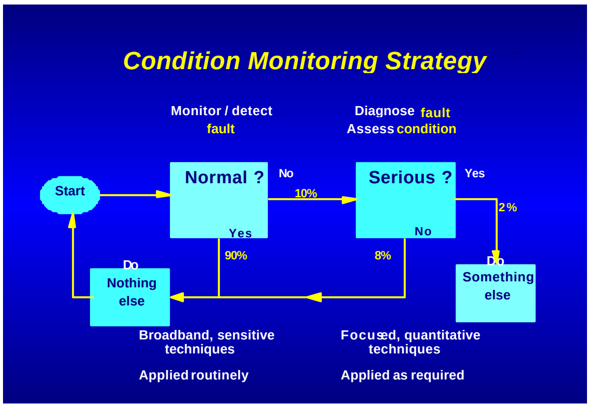


Figure 4 Dangerous effects of degradation factors

Chapter 4 Methodologies

4.1 Condition-based methodology

Although the ideal is to base the assessment of the **condition** of a transformer on the relevant withstand strengths or spare margins, in practise this is not an option at the moment because the necessary tools are not available. Nevertheless, there is a pressing need for some interim methodology to enable important decisions on life management to be made by utilities. Therefore, to enable efforts to be concentrated where they are most needed and will bring the best benefit, and to provide a framework against which a consistent approach can be applied over a population of equipment, a pragmatic two stage condition based methodology has been proposed (Figure 5).



Condition Monitoring Strategy

Monitor / detect fault

Diagnose fault
Assess condition

Start

Normal ?

No
10%

Serious ?

Yes
2%

Yes
90%

No
8%

Do Nothing else

Do Something else

Broadband, sensitive techniques
Applied routinely

Focused, quantitative techniques
Applied as required

Figure 5 Two stage condition-based methodology

In reality many utilities already apply just such an approach. The objective here is to formalise this process.

Life management of transformers naturally follows the same process for the resolution of problems as for the management of human health, with the progression

Symptoms ? Diagnosis ? Cure

once a problem is suspected. The difference is that a human being is usually able to recognise when he or she is ill and a doctor should be consulted, but for the management of transformer health it is necessary to employ some form of **monitoring** to provide an indication of when to initiate the above process.

In this first step, which may be described as **monitoring** or **detection**, the fundamental question to be answered, expressed in its simplest terms is :

Is it **NORMAL**? i.e. **is there a FAULT** ?

The main purpose of this first stage is to filter out those items of equipment that are operating normally so that precious resources are only applied where they are needed. The techniques applied to answer this question must be applied regularly to all items of equipment, and need to be cheap (and therefore ideally on-line) and yet sensitive and broadband so that any potential problem can be detected (but not necessarily diagnosed) at an early stage. The two main alternative techniques commonly used for such routine monitoring are DGA and power factor/tan delta testing.

The second stage process, which may be described as diagnosis or **condition assessment**, would normally only be carried out on those few transformers (probably less than 10 %) which could not definitely be classified as normal. (Transformers categorized as Defective, Faulty or Failed in 3.1.) To these transformers more precious human resources and expensive tests would be applied in order to answer the question:

Is it **SERIOUS** ? i.e**. is it FIT FOR SERVICE ?, what is its RELIABILITY ?, etc**.

Tests would be applied as required to address this question, and can be more expensive and off-line, but need to be focused on individual attributes in an attempt to arrive at an unambiguous diagnosis. The objective of this step is to identify the problem from the symptoms. Recommendations are provided on which tests should be used to identify particular problems. Examples of transformer tests that might be used include magnetising currents, winding resistance, FRA, partial discharge (PD) and polarisation spectrum (recovery voltage) measurements. Any results from the first stage monitoring would also be taken into account in the condition assessment. An important aspect of this second stage process is that it should be as objective and consistently applied as possible. Ideally, a **scoring system** would be used to quantify and combine the results of the various condition assessment tests.

Having identified the problem, then the relevant identify card in the Guide will provide information on the **prognosis**, i.e. what are the likely consequences if no action is taken, and suggestions for remedial action, to allow a decision to be taken on what is to be done.

4.2 Functional-based methodology

4.2.1 Concepts of functional-based methodology

- A transformer is considered to consist not of just some typical components but of a number of functional subsystems, which include relevant components.
- A framework of the monitoring and diagnostic system is the transformer failure model. It defines the possible defects and "sensitive points" in the particular type of the equipment on the basis of the design review and in-field histories. A failure model identifies the goal of the condition monitoring (what to look for?)
- The condition-based methodology is considered as a test-questionnaire in terms to detect a possible defective condition of the certain functional subsystem, which may lead to malfunction. For instance: is there excessive water or particle contamination? (dielectric), abnormal heating? (load transfer), winding distortion? (mechanical defect), etc.
- The test program is focused on a detection of possible defects utilizing a group of methods, which characterize the particular defect. At least two procedures are necessary to quantify the defect, as well as to ascertain its presence. The correlation between relevant methods is to be considered.
- Multi-step diagnostic procedures are typically advised: Indication - Detection (In-Service or On-Line procedures) - Confirmation (Complementary tests) - Prediction (Functional-mode tests) - Verification (Internal inspection).

4.2.2 Key properties of functional serviceability of a transformer

Functional serviceability of a transformer may be determined by its four key properties:

- Electromagnetic ability and integrity- an ability to transfer electromagnetic energy at specified conditions, including permissible over excitation and overloading, without general overheating, excessive losses, appearance of localized hot-spots, gassing, excessive vibration and sound.
- Integrity of current carrying circuit.
- Dielectric withstand strength under the influence of the specified operational stresses, considering a permissible level of deterioration.

- Mechanical withstand strength under the effect of specified through-fault currents.

A failure occurs when the withstand strength of the transformer with respect to one of its key properties is exceeded by operating stresses. Sometimes the transformer can keep serviceability being in a faulty condition (overheating, gassing) but it will fail immediately if a short-circuit or open-circuit happens. The withstand strength of a transformer decreases naturally over its life.

4.2.3 Typical functional subsystems of a transformer

- Electromagnetic circuit
- Current carrying circuit
- Dielectric system
- Mechanical structure
- Cooling system
- Bushings
- OLTC
- Oil preservation and expansion system
- Protection and Monitoring

4.2.4 Functional failure model

A transformer functional failure model has to answer the questions:

- What defects and faults can be expected in particular transformer components related to the particular functional subsystem?
- What is the possible path of defect evolution into the malfunction, and then failure?

Table 4-1 shows Functional Failure Model of Power Transformer Core and Coil Assembly. The functional failure model for OLTCs and bushings are shown in Tables 6-3, 6-4, 6-5 and 6-6.

Some defects can be associated with poor design, for instance, local overheating of the turns/core components/tank due to high stray flux and deficiency of winding mechanical margin. A design review should be considered the first critical step in diagnostic procedures. Another cause of defects can be attributed to errors caused during the manufacturing process.

It is recommended that relevant monitoring systems be designed to separately look at Defects and Fault and Failure-mode.

Table 4-1 Functional failure model of power transformer core and coil assembly

SYSTEM, COMPONENTS	DEFECT (Reversible)	FAULT AND FAILURE-MODE (Not reversible)
Dielectric Major insulation Minor insulation Leads insulation Electrostatic shields	? Excessive water ? Oil contamination ? Surface contamination ? Abnormal aged oil ? Abnormal cellulose aging ? PD of low energy ? Loose connections causing sparking	? Destructive PD ? Localized tracking ? Creeping discharge ? Excessive aging/ overheated cellulose **Flashover**
Electromagnetic circuit Core Windings Structure insulation Clamping structure Magnetic shields Grounding circuit	? Loosening core clamping ? Overheating due to high stray flux ? Short-circuit (open-circuit) in grounding circuit ? Abnormal circulating current ? Floating potential ? Aging lamination	? Excessive vibration & sound ? General overheating ? Localized hot spot ? Sparking/discharges ? One or more turns are short-circuited completely ? Strands within the same turn are short-circuited **Gassing**
Mechanical Windings Clamping Leads support	? Loosening clamping	? Leads support failure ? Winding distortion - radial - axial - twisting **Failure of insulation**
Current carrying circuit Leads Winding conductors	? Poor joint ? Poor contacts ? Contact deterioration	? Localized hot spot **Open-circuit** **Short-circuit**

4.2.5 Mechanisms of typical failures

Dielectric System. It is possible to define two critical stages of dielectric withstand strength degradation:

- Defective condition: reduction of the initial withstand strength under the impact of the degradation agents. It results in appearance of usually nondestructive partial discharges (PD) at operating voltage and reduction in impulse withstand strength.
- Faulty condition: appearance of destructive PD, progressing surface discharges, and creeping discharge occurrence.

The typical failure scenario for an initially defect-free insulation is as follows:
Contamination with occurrence of moderate PD⇒*Occurrence of destructive PD*⇒ *Gas generation*⇒*Progressing PD, accompanied with gas generation*⇒ *tracking/treeing, accompanied with gassing and changing dielectric characteristics, critical pre-failure PD* ⇒*Breakdown.*

Electromagnetic circuit. Experience has shown that defective/faulty conditions typically are attributed to the following abnormal states:

- General overheating, namely, abnormal rise of the oil temperature due to cooling deficiency, poor distribution of oil flow, core overheating
- Local core overheating associated with the main magnetic flux
- Local core overheating associated with stray flux

Faults caused by the closed loops between adjacent members linked by the main flux are the most dangerous. Shorted winding strands (turn-to-turn or layer-to-layer short circuit) cause transformer malfunction immediately. Closed loops in the core (insulated bolts, pressing bolts, pressing metal rings) cause typically an intensive gas generation, activating the Buchholz relay and also may be attributed to failed condition.

Faults associated with stray flux (including short circuit between winding parallels) allow continuing transformer operation on the condition of load limitation. Three typical failure mechanisms may be advised:

- Local overheating due to excessive eddy current losses resulting in generation of gas, carbon and other degradation products, and in insulation deterioration
- Close loops between adjacent members linked by stray flux, if accompanied with poor contacts, result in overheating, sparking and arcing, and in insulation deterioration
- Sparking due to a floating potential (e.g. ungrounded magnetic shields)

Mechanical withstand strength. The following typical scenarios of a transformer failure have been experienced:

- Loose clamping- Distortion of winding geometry ⇒PD appearance ⇒Creeping discharge progressing ⇒Breakdown.
- Distortion of winding geometry + Switching surge ⇒Flashover between coils (sometimes with restoring withstand strength)⇒Gas evolution

Current carrying circuit. The following typical scenario of an equipment failure may be suggested:

- Fixed connection**:** Local heating in places of poor joints, increasing contact resistance, oil overheating, pyrolytic carbon growth, gas generation, coking, impairment of heat exchange, melting the copper, or breakdown of oil due to severe contamination.
- Movable (LTC) connection: formation of film coating reducing the contact surface, increasing the contact resistance and temperature. A progressive rise of contact resistance results in the progressive rise of temperature, gas generation, irreversible degradation of the contacts, coking, open-circuit or short-circuit occurrences.

4.3 Condition assessment methodologies

The experts discussed the topic of condition assessment of transformers in several contexts. One was in ways of fault identification at the site:

- Definition of characteristics of defective condition
- Finger-printing
- Trend Analysis

Another was to do finger-printing during factory tests.

A third view of condition assessment was to evaluate or rank the remaining life of a transformer or a group of transformers. The former is generally done if the transformer is to be moved or if past a certain age, say 25 years. The latter may be part of an asset replacement or refurbishment strategy. It was noted during discussions that the exact remaining life depends on many factors and that it is better to use the concepts of suitability and serviceability for the specific application. This encompasses factors such as design, operational history including short circuits and loading, present status and priorities in the network and future expected stresses.

A number of condition assessment methods can be confirmed or automated with the use of electronic performance support systems such as statistics-based systems, expert systems and algorithms.

4.3.1 Quantification of defective condition

This approach presents definition of characteristics of defective condition based on the process of physical development of possible defect. Correspondingly the image of the defect can be advised, as well as some limited data (yellow and red) that anticipate failed condition.

4.3.2 Fingerprinting

For most diagnostic tests it is desirable to have reference results against which the results of subsequent tests can be assessed. Preferably, these reference results would be for a fault-free, as-new condition. Ideally, the results of a diagnostic test are solely related to the characteristics and condition of the transformer itself, and independent of the measurement system. If this is the case, the reference results should be valid for all transformers of the same design, and such results are often referred to as '**fingerprint**' results.

This is not always the case, and in some cases reference results for the transformer in question have to be obtained, in which case the results are referred to instead as **base line** or **benchmark** results.

4.3.3 Trend analysis

For many diagnostic tests, the way in which measured results change with time can provide valuable additional information. Some techniques rely very heavily on trend analysis, whereas others can provide a diagnosis from the results of only one measurement.

It should always be borne in mind that the occurrence of a rising trend, particularly when the rate of change is increasing, is probably a definite indication of a serious problem or at least something to be investigated further. However, the absence of a rising trend does not necessarily provide a reliable indication of a good condition. The equipment may be suffering from a dormant incipient fault that could be triggered by an abnormal system event.

Trend analysis also suffers the same limitations as other techniques for interpreting the results of diagnostic measurements, e.g.

- It is not always possible to distinguish 'faulty' indications from 'unusual' results
- It is very difficult to decide when a fault is serious enough to justify radical action

4.3.4 Statistical analysis

The use of statistical techniques can help in understanding variability and also facilitate better use of available data to assist in decision-making considering unusual quantities of tested parameters. Test quantities are considered to be acceptable if they are below the level that field experience shows no detectable or possible incipient fault and that are over passed by only an arbitrarily low percentage of higher test data, for example 5 or 10 %, or several standard deviations from the mean. The latter measure depends on the robustness of the data.

Maintaining the databases can help to calculate the probability of failure in service for a given type of equipment. Statistical analysis is especially helpful to evaluate concentration values of DGA, vibro-acoustic test data, temperature distribution, etc.

4.3.5 Electronic performance support systems

Electronic Performance Support Systems (EPSS) are computer systems that provide quick assistance and information. Using measurements mostly from on-line sensors, a number of condition assessment methods can be automated using EPSS. In some systems "what if" scenarios can be created and trial operations run off-line. Commercially available EPSS follow.

- Trending systems analyzing the change of measured or processed data over time are the most widely used EPSS technique and can be applied to many operating parameters. Some examples are
  - Slow data such as gas readings every few minutes or hours
  - Fast data such as the OLTC motor load vs. milliseconds during operation of the mechanism
  - Raw data such as temperature at given time intervals
  - Processed data such as the difference in temperature between the OLTC and the main transformer tank calculated periodically and added over some time period to form an "index" number

- Models can be broadly interpreted as algorithms, look-up tables or neural networks. The latter modeling technique consists of a set of elements that start out connected in a random pattern and, based on operational feedback, are molded into the pattern required to generate the required results. Some examples of processing that can be done with models:
  - Rogers, Dornenburg and IEEE cause of gassing models allow automated analysis of many transformer problems.
  - Static electrification models can alert the operating parameters that signal potential damage from static discharges.
  - Moisture models use the relative saturation of water-in-oil and operating temperature to define unsafe operating and start-up conditions.
  - Thermal load models calculate transformer oil and winding temperatures, thermal ratings, insulation loss-of-life, and the likelihood of gas bubble formation for power transformers operated at load levels near or above nameplate rating. Loads and air temperatures can be provided by on-line sensors.
  - Comparison algorithms estimate the similarity of data between operating units that are expected to behave the same within a substation or between substations. This is a tool for detecting change in one piece of equipment by using another or multiple others as a standard of normalcy.

- Expert systems are artificial intelligence (meaning that it exhibits human intelligence and behavior) applications that use raw and/or processed data in combination with a knowledge base of human expertise for problem solving.
  - An example is the analysis of hydrogen in the oil of a transformer using the output of a gas sensor and transformer operating temperatures. To account for the hydrogen that escapes out of the oil before it is detected by the sensor, the sensor output is corrected to calculate the total hydrogen concentration in the transformer. After correction, the trending analysis is performed over several previous periods of time. Each period is a sliding time window. Analysis takes into account the type of the oil preservation system and conclusions of the off-line Dissolved Gas Analysis.
  - The use of fuzzy logic is being investigated for solving problems with data that come from an imperfect environment of highly variable, volatile or unpredictable conditions. It "smoothes the edges"

so to speak, circumventing abrupt changes in operation that could result from relying on traditional either-or and all-or-nothing logic.

- Statistical analysis is another method to make inferences and predictions in uncertain situations. This is used in two ways:
    - Measurements taken from a small group, the sample, are used to infer the behavior of a larger group, the population. Probability theory is used to determine how well the sample represents the population.

    - The standard deviation, which indicates how closely the data are clustered about the mean, can be used to infer whether the condition of equipment is changing from past characteristics. Sliding time windows are used in on-line systems to compare the deviation of a new data point with the mean of past data.

Many of the above systems can be used to signal alerts / alarms either at the data collection point or at a central processing computer. In these systems, on-line limits of acceptable operation can be set on threshold values, rates of change, differences of parameters and deviation from mean values as appropriate.

Definitions for EPSS, expert system, artificial intelligence, neural network and fuzzy logic are adapted from the Computer Desktop Encyclopedia © 2001.

Chapter 5 Diagnostic and Monitoring Techniques

5.1 Experiences with evaluation of condition of transformers using traditional test techniques (results of questionnaire)

To determine the most effective methods for detecting transformer faults, the extensive experience of CIGRE members and particularly the transformer experts was utilized. A questionnaire was developed and sent to Working Group members. The results (Appendix 7) were processed and supplemented with comments received during meetings and from circulation of working documents in order to:

- Define a transformer in terms of its components,
- Define the functions that a transformer is required to perform,
- Develop a comprehensive list of defects and faults (Appendix 3) that can impair any of the functions,
- Develop the relationship for each defect and fault with the component and function that they affect, and
- Make an evaluation of the effectiveness and the interpretation and sensitivity of the various tests and groups of tests that are being used to detect the defects and faults for each component.

Defects and faults that have tests with low effectiveness, or if no test exists, were also identified. A separate discussion of continuous monitoring techniques is included.

Transformer experts on the Working Group utilized their experience and knowledge to evaluate the tests and groups of tests now being used to monitor transformer operation and to analyze and diagnose transformer problems or failures.

The concept of "groups of tests" (Appendix 8) has been introduced to avoid premature or erroneous judgment from single level or single procedure analysis. After an initial indication of a problem, further testing is generally done to better assess the situation and to define the type and seriousness of defects and faults.

The evaluation of a test or group of tests is stated as being of a varying degree of interpretation/sensitivity as defined in Table 5-1. These evaluations are based on opinions expressed by respondents of the original questionnaire and by the experts during subsequent discussions and revisions of this document.

Table 5-1 Interpretation/sensitivity of tests or groups of tests

Evaluation	Interpretation/sensitivity
1	Good identification
2	Fair identification
3	Good detection and rough identification
4	Fair detection
5	Rough detection
6	Supporting indication (needs other tests in order to begin a diagnosis)

NOTE: Identification indicates that the source or location of a defect or fault has been determined by the test. Detection only indicates that a defect or fault exists.

5.2 Influence of transformer design features on the effectiveness of diagnostic test procedures

Experience has shown that the scope of tests and their interpretation depend on two design features:

- Sensitive points of components and their expected failure modes.
- Variability of the design (diagnostic accessibility)

Following are some typical design features that should be taken into account when conducting a diagnostic test program:

- The presence of an internally grounded electrostatic shield between the windings reduces the sensitivity of measurements of the dielectric characteristics of solid insulation.
- The presence of a waterproof dielectric (e.g. synthetic resin bonded paper (srbp) or cast resin cylinder) in the oil barrier space prevents the estimation of water content in pressboard barriers through measurement of dielectric characteristics.
- The presence of a dielectric material with inherent elevated dielectric losses in the winding support insulation (neutral coils) and tapping lead cleat bars masks the change in the condition of the main insulation.
- Internal connection of tertiary windings and neutral ends of star windings prevents the evaluation of the condition of inter-phase insulation and comparison between phases.
- The presence of resistors in the circuit of the core causes distortion of dielectric characteristics (increasing power factor/tan delta of LV-core; HV-core; and decreasing power factor/tan delta of HV-LV).
- The presence of poor insulation in the bushing tap insulation or internally grounding the last electrode (potential tap design) prevents evaluation of the oil condition and the core surface condition with the bushing through measurement of C_2 dielectric characteristics.
- Grounding the magnetic core through direct contact, e.g. frames (core clamps) with the tank particularly and internal grounding the core generally, make difficult the identification and location of thermal faults caused by circulation currents.
- The presence of a capacitor or non-linear resistor installed on a regulating winding to control the distribution of surge voltages.
- The sensitivity of detection of hoop buckling by leakage reactance or capacitive measurements reduces with increasing voltage rating of the transformer (increasing inter-winding gap).

Controllability of design considerations needs to be addressed in specifications for new transformers and for modification of transformers during a life extension program.

It should be remembered that there are other factors than design that impact on the effectiveness of diagnostic tests, e.g. condition of the oil especially for some ratios of amount of solid to liquid in insulating space.

5.3 Factory and/or commissioning tests (fingerprinting)

These tests are not to be considered acceptance tests. Such fingerprint tests are used to improve diagnostics and will have an important impact in case of investigations for malfunctioning and/or maintenance.

There are a number of well proven procedures which may or should be applied in generally testing as a base for later trend-analysis.

Various practices include for example:

• For magnetic circuit defects:

- Measurement of no load losses/phase and no load current at LV (110/320/380 V)
- Measuring vibro-acoustic spectra at rated voltage

- Measuring the hydrogen gas generation during over excitation (12 h) tests by means of an on-line monitor or by oil sampling before and after the test by DGA
- Core and core clamping resistance

- **For dielectric failure recognition in windings/main insulation, bushings and OLTCs**
  - Measuring the hydrogen gas generation during dielectric testing (before and after by oil sampling and DGA)
  - Dielectric response measurement (PDC - Polarisation Depolarisation Current Measurements, FDS – Frequency Dependent Spectroscopy). Both methods lead to reliable results provided that oil conductivity, material constants and geometry are considered. The RVM (Return Voltage Measurement) in its present form can only be used for trend indication.
  - Power factor/tan delta + capacitance measurements at ambient temp. (20 - 30 °C) between windings with 5 - 10 kV.
  - FRA / Transfer function analysis
  - During PD test, measure pulse repetition rate and PD power in addition to the maximum pulse magnitude
  - Vibration tests under rated voltage + rated current
  - DGA detection of sparking faults due to loose electrostatic shields including bushing corona shields
  - Magnetising current measurements/phase

- **For general aging of oil and cellulose**
  - DGA by sampling before and after dielectric and thermal testing
  - Oil-moisture determination from oil sampling and moisture on-line monitors
  - Dew point measurements before shipment and before commissioning on site
  - Dielectric response measurements under due consideration of geometry, material constants and oil conductivities, e.g. PDC measurements
  - FURAN derivate (2FAL)-Analysis from oil sampling and DP-determination from in-tank-samples. Both methods should be used in addition to PDC/FDS results to correlate ageing, DP degradation, time (age) and moisture.
  - Power factor/tan delta measurements for moisture assessment at ambient and elevated temperature (65° C)

- **For mechanical failures recognition**
  - Leakage impedance/phase with low voltage (110/320/380 V) on different OLTC taps
  - FRA and transfer function analysis.

From the multitude of procedures it is obvious that for condition assessment it always takes several approaches. Therefore fingerprinting and checking by off-line and on-line methods is highly recommended.

5.4 On-line continuous monitoring techniques

A number of utilities are now using on-line monitoring devices to respond to the increasing emphasis on reducing unplanned outages and equipment failures, improving power quality, and deferring capital and maintenance expenditures.

Some users are planning to install these systems for the life of the transformer; others intend to use them for a limited period on suspect transformers.

As a result of recent field experiences, different types of on-line monitoring devices, which show promise in terms of effectiveness, are now available. The list is not a complete one. The designation "Product" means that it is commercially available from at least one manufacturer.

1) Hot spot monitoring both by direct and indirect (thermal model) application	1) Product
2) Dissolved gas-analysis (DGA) with hydrogen only, composite gases or up to eight separate failure gas components	2) Product
3) Partial discharge monitoring, including for static electrification	3) Acoustic - product Electric - product Acoustic w/ RF-field test.
4) Bushing on-line power factor/tan delta and capacitance measurement	4) Product
5) Cooling system: optimization and components	5) Product
6) Moisture in oil	6) Product
7) Clamping force	7) Field test
8) OLTC motor current characteristics to detect motor and linkage defects, relative temperature, control relay timing, through neutral operation, tap position monitoring	8) Product
9) OLTCs acoustic emission or vibration monitoring during tap changing.	9) Field test
10) OLTCs motor drive torque control.	10) Product

5.5 Limitations in existing diagnostic techniques

The list of items with problems of detection and problems of identification is restated below.

Problems of Detection:

- Winding, coil and turns insulation: Water contamination; contamination with oil aging products; overheating of a small amount of cellulose; condition of the conductor insulation, especially in the hot spot area. For instance by measuring dielectric characteristics due to comparatively high capacitance of turn insulation we can assess only the condition of major insulation. The condition of the minor insulation remains undetectable
- Winding, mechanical: twisting of winding; non-uniform loosening the pressure forces
- Major insulation: local contamination of barriers; traces of creeping discharges
- Core: localised hot spot with low rate of gas generation

Problems of Identification:

- Localised water contamination
- Localisation of winding overheating
- Localisation of hot spot or discharges in magnetic circuit
- Axial mode distortion of regulating winding (small number of turns)
- Contamination of bushing internal porcelain

Chapter 6 Condition Assessment Recommendations

6.1 Critical degradation of dielectric system

6.1.1 Defective and faulty conditions

Two critical stages of dielectric withstand strength degradation should be considered:

- **Defective condition**: possible critical reduction of the initial safety margin under the impact of contamination.
- **Faulty condition**: appearance of destructive PD, progressing surface discharges, and creeping discharge occurrence.

6.1.2 Characteristics of defective condition

Two levels of defective conditions could be suggested: 1) Possible reduction of dielectric margin by 10 % or more; 2) Possible occurrence of critical PD at the rated voltage. These two conditions are subcategories of the Defective condition that was described in 3.1. Characteristics of both conditions are summarized in the following table

Table 6-1 Characteristics of defective condition

Caution levels	Alarm levels
Possible reduction of dielectric margin by 10 % or more	Possible occurrence of critical PD at the rated voltage
An increase of the relative saturation over 20 % at operating temperature in presence of particles (water content in fibres >2.5 %). [5, 6, 7, 8, 9]	An increase of the relative saturation over 40-50 % at operating temperature at presence of particles (water content in fibres 6-7 %) [5, 6, 10, 8, 9]
	Presence of free water in oil
Water in major insulation that can result in evolution water in oil at high temperature and increase of the relative saturation of oil over 40 % at minimum operative temperature Water content in barriers 1.5-2 % should be considered [10, 11]	Water in major insulation that can result in evolution water in oil at high temperature and increase of the relative saturation of oil over 40-50 % at normal operative temperature Water content in barriers 3-4 % should be considered [9, 10]
Particles contamination (Classes by NAS 1638) 7-9 [4] Possible coke generation at a place of localized oil heating above 500 °C Relative number of particles in the range of 5-150 microns per 10 ml of oil >1000 [7]	Particles contamination (Classes by NAS 1638): 10-12 [4] The presence of visible and conducting (metals, carbon) particles Relative number of particles in the range of 3-150 microns per 10 ml of oil >5000 [12]
Possible bubbles evolution at a place of localized oil heating above 800 °C (presence of C_2H_2)	Water in winding conductor insulation that may result in bubble evolution during overloading. Water content of 1-1.5-2 % in insulation and gas saturation should be considered [10, 13, 14] Large (3-5 mm in diameter) air/gas bubbles in oil [15]
Oil aging level that results in deposit of sludge across the pressboard under effect of electrical field [5, 6]	Oil aging level that results in occurrence of sludge that can reduce dielectric strength of oil

Caution levels	**Alarm levels**
PD occurrence: First warning signal q > 500-1000 pC. Signal of defective condition q>1000-2500 pC [9, 15]	PD occurrence: First fault signal q >>2500 pC. Critical condition q >>100,000-1000,000 pC [9, 15, 16, 17, 18]

Note: Fault gas generation and relevant DGA data can also characterize occurrence of PD that conforms to defective and critical insulation condition as described in Clause 6.2.

6.1.3 Condition assessment

The program may be presented as quantification of degradation factors that reduce the dielectric margin of operating conditions (water, particles, bubbles, oil degradation by-products)

1. What is the level of contamination with water and particles? Shall we expect a substantial reduction in the dielectric margin at operating temperatures?

Test procedures: (On-Line, In-service):

- Measurement of oil relative saturation;
- WHRT (Water Heat Run Test), considering change of water content and breakdown voltage with temperature;
- Conventional water in oil test;
- Particles in oil counting and qualification; metals in oil
- DGA in oil –in order to assess a possible source of oil overheating and relevant contamination and insulation degradation
- Oil aging degree
- PD parameters-apparent charge magnitude, pulse repetition rate, discharge power, PD signature.

2. What is the level of water content in solid insulation? Shall we expect bubble evolution at overloading?

Test procedures:

On-Line:

- WHRT
- Interpretation through oil relative saturation values;

Off-Line:

- Estimation of water content using temperature response of power factor/tan delta and insulation resistance
- Estimation of water content using polarization spectrum /dielectric frequency response tests;
- Oil interfacial tension test

3. Shall we expect a substantial insulation surface contamination?

Test procedures:

On-line:

- PD measurement;
- Particles counting and qualification
- Oil aging by-products

Off-line

- Temperature response of power factor/tan delta
- Particles identification, and oil tests
- Dielectric frequency response tests

6.2 Aging of winding conductor insulation (insulation life assessment)

6.2.1 Defective and faulty conditions

Defective /faulty conditions typically are attributed to the following abnormal states:

- Abnormal heating of cellulose due to cooling deficiency, over-insulating, overloading
- Abnormal (accelerated) rate of aging of insulation

Critical thermal degradation of the insulation at the location of the hottest spot in the winding could be introduced as the following:

In terms of mechanical degradation:

- Reducing the tensile strength –The end of life is considered as retention of 50-60 % of the initial tensile strength [19, 20, 21]
- Extension to break
- Burst ; Tear strength
- Double –fold strength

In terms of cellulose structure degradation:

- Degree of polymerization DP- (average length of the cellulose molecule). The end of life is typically considered the DP of 200-150. Some experts considers that a more reasonable end of life from a short circuit standpoint is when the paper has reached 50 % of its life (DP is in the order of 450)[11]
- Measurement of the cellulose molecular weight (by gel permeation chromatography [22])

In terms of evolution of decomposition by-products:

- Furans
- CO, CO_2
- Water

In terms of dielectric deterioration of conductor's insulation under effect of oil/paper aging by-products:

- Increasing power factor/tan delta of conductor's insulation [22, 23]
- Change of polarization spectrum [22]. Reduction of the turn-to-turn breakdown voltage (below 60 % of initial value) under effect of oil aging by-product [6, 23]
- Hot spot temperature, time, oxygen concentration, moisture content in conductor insulation, presence of significant amount of aggressive oil aging products (acid, non-acid polar), which substantially accelerate the process of cellulose degradation, should be considered to assess the insulation life.

6.2.2 Characteristics of defective/faulty conditions:

Several characteristics are to be determined to predict thermal degradation of cellulose:

- Temperature of the hottest coils (turns) of the windings
- Furanic compounds that derive only from cellulose;
  - 2-furfuraldehyde or 2-furfural (FAL)
  - furfuryl alcohol or furfural (FOL)
  - 5-hydromethyl-2-furfural (HMF)
  - 2- acetyl furan (AF)
  - 5-methyl-2-furfural
  - Ratio FAL/HML [24]

Normal deterioration of paper is characterized by the rate of furans evolution as 50-90 ppb per year [25]. Large amount of furans can be generated when temperature is above 120-130 °C [26].

Several methods of interpretation of normal and abnormal rate of deterioration and DP values through furans and particularly 2-furfural concentration [20, 27, 109] have been suggested.

- Generation of CO and CO_2, considering concentration of gases, amount (ml or l), rate of generation and ratio CO_2/CO
- Polymerization Degree DP
- Symptoms of excessive oil aging (acids, soaps, non-acid polar sludge)

The following table shows some warning quantities of diagnostic characteristics:

Table 6-2 Warning quantities of paper degradation

Characteristics	Caution levels	Alarm levels
CO	> 540-900 ppm [IEC] > 350 ppm [IEEE] > 300 [19] > 15 litres [28] 351-570 [EPRI, modest concern]	>1400 [IEEE] >1400 [EPRI, imminent risk]
CO_2	>5100-13000 ppm[IEC] >2500 ppm [IEEE] 2400-4000 [EPRI, modest concern]	> 10000 [IEEE] >10000 [EPRI, imminent risk]
$CO+CO_2$	10000 ??m [CIGRE WG15.01} 0.2 ml/g hot spot mass [19]	> 2 ml/g for hot spot mass [19]
CO_2/CO	< 3 [30]	
Furfural	> 1.5 ppm [19] Rate of generation: Log $Y_f = 11.76 - 6723/T$ [29] *T: absolute temperature of paper insulation*	> 15 ppm [19]
Furans (total) [27, 109] (Likely for thermally upgraded paper)	100 ppb-First signal; tests after a year *250 ppb-Expected DP <400; test after 6 Months*	*100 ppb - Expected DP 330-230;Risk of Failure; Test* of oil monthly. Consider oil reclaiming *2500 ppb: Expected DP< 217; Consider replacement*
DP	< 400 [IEC]	< 200 [IEEE] < 450 [19]

6.2.3 Condition assessment

6.2.3.1 Design review

- Preservation system
- Type of paper (thermally upgraded)
- Rise of temperature of oil and winding
- Type of cooling
- Amount of oil
- Amount of total insulation material and particularly of "thin" insulation

6.2.3.2 Operation conditions (history)

- Age
- Average load ratio and relevant oil/winding temperature

- Maximum load ratio and relevant oil/winding temperature
- Overloading events

6.2.3.3 Transformer condition

- Estimation of water content in paper
- Oxygen content in oil
- CO and CO_2 concentration and total amount (ml)
- Measurement of furanic compounds
- Oil aging condition (especially acids. esters, interfacial tension, non-acid polar, potential sludge)
- Measurement of degree of polymerization

6.2.3.4 Loss of life assessment

- Estimation of the hot spot temperature
- Diagnostic of abnormal condition (paper overheating)
- Estimation of loss of life using indirect methods
- Estimation of loss of life using tests of the samples of paper

6.3 Typical OLTC defects

6.3.1 Failure model

Table 6-3 Typical defects or faults and failure modes for OLTC dielectric mode failures of diverter switch

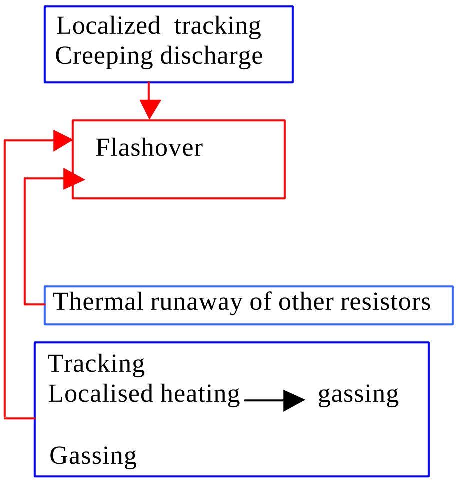
SYSTEM COMPONENTS	DEFECT or FAULT	FAILURE MODE
DIVERTER SWITCH **Dielectric** Solid insulation: - between taps, - to ground, - between phases - barrier board & bushings Liquid insulation : - Across contacts	• Excessive water • Oil contamination (combined with carbon) • foreign matter/objects	 Localized tracking Creeping discharge Flashover Thermal runaway of other resistors Tracking Localised heating → gassing Gassing
Resistor	• Resistor short circuited	
Reactor	• Discharges • Overheating • Incorrect connection • Core fault	

Table 6-4 Typical defects or faults and failure modes for OLTC electrical and mechanical mode failures of diverter switch

SYSTEM, COMPONENTS	DEFECT or FAULT	FAILURE MODE
Electrical Resistor	Open circuit Overheated	Extra wear Gassing Possible flashover
Contacts: Arcing contacts Main contacts	• Worn • Misalignment • Poor contact pressure • overheated	High carbon build-up Thermal runaway Arcing Gassing
Leads Joints & connections	• poor joints(loose connections, poorly crimped etc) • damaged conductor • broken strands	Overheating Gassing
Mechanical Operating springs & etc Operating rods and shafts Operating mechanism	• Slowed operation of switch • Broken drive shaft • Incorrect timing between selector & diverter switch	Incorrect operation of switch Incomplete operation of the Switch. No operation of switch. Flashover

Table 6-5 Typical defects or faults and failure modes for selector switch and drive motor of OLTC

SYSTEM, COMPONENTS	DEFECT or FAULT	FAILURE MODE
SELECTOR SWITCH **Dielectric** Solid insulation: - between taps, - to ground, - between phases - barrier board & bushings Liquid insulation : - Across contacts Adjacent studs in combined selector diverter tapchanger	• Excessive water • Oil contamination • Surface contamination • PD of low energy • Abnormally aged oil	Destructive PD Localized tracking Creeping discharge Excessively aged/ overheated Cellulose Flashover
Electrical Connections Contacts - Selector contacts - Change-over switch/course fine Through bushings	• Poor connections • Misaligned contacts • Silver coating disturbed/worn • Poor contact pressure	Overheating → gassing Sparking/ arcing Overheating Carbon build up between contacts
Mechanical Drive shaft Selector contacts	• Damaged or broken • Incorrect alignment with diverter switch operation • Travel beyond the end stop	Out of synch operation of selector & diverter switches arcing
DRIVE MECHANISM Drive shaft Mechanical end stops Motor and gear drive Control equipment Auxillary switches	• incorrect timing • operation beyond end stop • broken gears • missaligned coupling • worn,damaged, broken auxilliary switches.	Incorrect operation of the selector switch in relation to diverter Tap changer jammed on a tap-will not operate

6.3.2 Failure scenario

The following typical scenario of an equipment failure may be suggested:

Formation of film coating that reduces the contact surface and increases the contact resistance and its temperature. Rise in contact temperature results in a progressive rise of contact resistance and corresponding progressive rise of temperature, erosion of the contacts, coking, and gas generation [31, 32, 33]. Failure process typically results in open-circuit or breakdown between phases due to severe oil contamination. Film coating causes increasing the breakdown voltage between the contacts making contact resistance sensible to the current value. Oil temperature, contact design and material, oil quality, affect the process of contact degradation. Failure occurrence depends on current value and frequency of LTC operation.

6.3.3 Characteristics of defective/faulty conditions

The following diagnostic characteristics may be suggested:

- Rise in contact resistance. A defective condition could be characterized by increasing the initial contact resistance three times [33]. Taking into account that the initial value of contact resistance is 150-200 μOhm per coupling, the test procedure has to consider detecting change in resistance by 600-1000 μOhm. Therefore, the conventional winding resistance measurement can indicate the abnormality only if winding resistance is 0.1 Ohm or less. The faulty condition (erosion of the surface) is expected when the contact resistance is increased 5-10 as large.
- Change in contact resistance with current due to rise of breakdown voltage of the coating film. Dependency of the contact resistance on applied current may serve as a symptom of defective condition [34]. For example [33], in a process of deterioration breakdown voltage of film coating may change from 0.2-0.6 V (normal condition) up to 1-4 V (defective condition).
- Response of the current in the winding to transient [34]. Contact deterioration is suggested to identify by change of the time constant of the applied current response.
- Rise in the contact temperature. Rise in oil temperature in the vicinity of contact –over 100-105 °C could be identified as defective condition [33]
- Rise of the oil temperature in the OLTC compartment.

The method of the OLTC condition assessment based on rise of the oil temperature in the OLTC compartment compared to the main tank has been effectively approved by practical experience [35]. Possible rise of contact resistance can be estimated using rise of the oil temperature, considering the total cooling surface of the OLTC compartment, the normal rise of oil temperature above ambient one and the current magnitude. However, the method can detect only severe contact deterioration. Presuming cooling surface of 3 m^2, and normal rise of the oil temperature 10 °C, one can show that increasing the temperature by 5 °C may be caused by the dissipation of additional power $\leq$ 200 W. Correspondingly, it is possible to detect the increase in contact resistance by about 1200 μOhm at the current of 400 A or about 2000 μOhm at the current of 300 A.

Fault gases generation: The traditional DGA is effective when the contact temperature exceeds 400-500 °C due to a low rate of gas generation at temperatures below the boiling point. A rate of gas generation at 400-500 °C is about 0.01-0.1 ml/cm^2 h [36] and due to small heating surface (a few cm^2) the rate of gas generation could be only a few ppm a month. Marked gassing could be a symptom of severe contact deterioration.

6.3.4 Condition assessment

6.3.4.1 Design Review

- Type designation, presence of reversor, rated current
- Location, mounting
- Type of contact, material (e.g. Copper-copper, Copper–brass, silver coating); contact treatment (e.g.. polishing, grinding)
- Rise of contact temperature above oil, contact resistance, compression pressure
- Type of oil

6.3.4.2 Operation conditions (history)

- Current value
- Oil temperature
- Frequency of taps changing
- Short-circuit events
- Operating time in unmoved tap position

6.3.4.3 Condition assessment

On-line

- Estimation of possible life-span of the contacts based on design review and operation condition data
- Temperature in the OLTC compartment
- DGA
- Oil tests: metals (copper, aging products, sulfur)

Off-Line

- Contact resistance test (winding resistance, considering relative contribution of OLTC contacts)
- Change in contact resistance with current
- Response of the current in the winding to transient

After draining the oil

- Visual inspection
- Compression pressure
- Contact resistance

6.4 Typical faults in electromagnetic circuit

6.4.1 Defective and faulty conditions

Defective /faulty conditions are typically attributed to the following abnormal states:

- General overheating, namely, abnormal rise of the oil temperature due to cooling deficiency, poor distribution of oil flow, core overheating
- Local core overheating associated with the main magnetic flux
- Local overheating associated with stray flux
- Winding insulation failure

6.4.1.1 Faults associated with the main flux

Windings: insulation failure creates a circuit coupled with the main flux. The resulting circulating current creates a load component in the measured exciting current and loss. Typical failure mode is turn-to-turn winding failure: a) one or more turns are short-circuited completely; b) two or more parallel strands of different turns are short-circuited.

Core: Closed loops in the core (insulated bolts, pressing bolts, pressing metal rings). These faults may result in localized overheating or (and) sparking and arcing between adjacent members that create a loop. Faults associated with the main flux are the most dangerous and may be attributed to failed condition.. Shorted winding strands (turn-to-turn or layer-to-layer short circuit) cause transformer malfunction immediately. Faults in the core cause intensive gas generation, often activating the Buchholz relay.

6.4.1.2 Faults associated with a stray (leakage) flux

Windings: insulation failure creates a circuit coupled with the leakage flux. The resulting circulating current contributes a load component to the measured leakage loss. Typical failure mode: strands within the same tum are short-circuited.

Core, frames, tank and other members linked by stray flux:
Three failure mechanisms may be advised:

- Local overheating due to excessive eddy current losses resulting in generation of gas, carbon and other degradation products, and in insulation deterioration
- Close loops between adjacent members linked by stray flux, if accompanied with poor contacts, result in overheating, sparking and arcing, and in insulation deterioration

- Sparking due to a floating potential (e.g. ungrounded magnetic shields)
- Unintentional or accidental closed loops around magnetic shunts.

Faults associated with a stray flux allow continuing transformer operation on certain conditions, e.g. load limitation.

6.4.2 Characteristics of the defective condition

Faults of the windings and in the core can be detected and identified by means of measurements of relevant parameters of transformer equivalent circuit (Figure 6) [37].

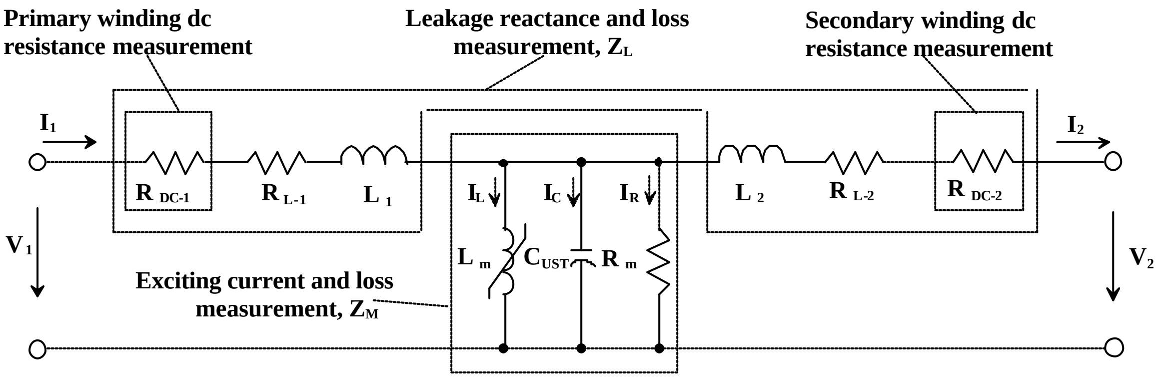


Figure 6 Parameters of transformer equivalent circuit and associated off-line diagnostic measurements

6.4.2.1 *Windings/core failure*

Effective diagnostic characteristics of "Turn-to-turn winding failure" and "Closed loop in the core" are exciting current $\mathbf{I_1}$ and loss in $\mathbf{R_m}$ (core losses). "Shorted strands within the same turn" can be detected by measurement of leakage loss: $\mathbf{[P - I^2(R_{DC-1} + R_{DC-2})]}$ (Figure 6)

6.4.2.2 *General transformer overheating*

Temperature distribution measurements (Thermo-scanning) considering:

- Possible abnormal rise of top oil temperature due to poor oil circulation (low location of outlet pipe)
- Possible abnormal rise of oil above ambient compared to load
- Reduction of coolers capacity due to contamination (decreasing the difference between inlet-outlet temperature)
- Impairment of oil-flow rate

6.4.2.3 *Local overheating and discharges associated with the main magnetic flux*

- Fault gas generation [38, 39, 40]
- Appearance of other by-products associated with high temperature (carbon, metals, furans, if adjacent insulation involved) [39]
- PD activity, acoustic location [38, 40]
- PD activity electric location [41]
- Accelerated deterioration of oil under effect of localized oil overheating [42]
- Increase of no-load losses and magnetizing current if the problem is associated with the main magnetic flux [38]
- Increase of load losses if the problem is associated with the stray flux [38]

6.4.2.4 *Loosening of the core clamping*

- Change in vibro-acoustic spectrum affected by the residual clamping force in the core [43]

6.4.3 Condition assessment

For the "electromagnetic circuit," condition assessment may be reduced to the following questions:

- What is the general thermal health of the transformer? Procedures: temperature in relation to load, thermo-vision.
- Is there any external overheating ? Procedures: thermo-scanning, on maximum load.
- Are there symptoms of internal overheating, sparking, and arcing ? Procedures: DGA; advanced DGA including C3-C5 hydrocarbons.
- Does the gassing associate with the main flux, or with stray flux, or with more dangerous problems that involve contacts (joints) overheating? Procedures: contact resistance test, measurement of no-load and on-load current and losses.
- Are there signs of other abnormalities: unusual noise, change in vibro-acoustic spectrum vibration? Procedures: vibro-acoustic monitoring.
- Does localized overheating of oil produce dangerous by-products (carbon, metallic particles) ?

6.5 Mechanical withstand strength and winding buckling

6.5.1 Defective and faulty conditions

- Loosening the winding clamping
- Distortion of winding geometry (radial buckling, axial, twisting). Most mechanical-mode failures have occurred due to the radial buckling of the inner winding. Experience shows that a transformer with the partially deformed windings can remain in service for a long time; however, the reliability of such a unit is reduced [44].
- Failure progressing typically results in insulation breakdown

6.5.2 Characteristics of defective/faulty conditions

A variety of techniques are being used to detect winding deformation in transformers [55]:

- winding capacitance
- leakage reactance (LR)/leakage impedance
- low voltage impulses (LVI)
- frequency response analysis (FRA) using the impulse method or the swept frequency method
- frequency response of leakage impedance
- frequency response of stray losses.

6.5.3 Condition assessment:

- What is the mechanical safety margin of the windings? Procedure: design review
- What can be learned from transformer history (fault current events with current magnitudes above 70 % of rated short circuit current). How could the winding suffer ?
- What is the leakage reactance and transfer function response to movement of the winding in question? Procedures: calculations, the diagnostic matrix determination.
- How to find the problem ? Procedures: leakage reactance, FRA and winding capacitance measurements

6.6 Typical defects in HV oil-impregnated paper bushings

6.6.1 Failure Model

The Failure Model of oil-impregnated paper condenser type bushings as a collection of typical defects in functionally essential bushings parts and possible developing the faults into probable failure-mode is presented in Table 6-6. The most typical cases involve local faults in the condenser core and problems associated with aging the oil and bottom porcelain staining.

Table 6-6 Failure model for oil-impregnated paper condenser type bushings

COMPONENT	DEFECT or FAULT		FAILURE MODE
CONDENSER CORE		LOCAL NATURE	
	Primary	Residual Moisture Poor Impregnation Wrinkles in Paper Delaminated Paper Overstressing Short-circuit layer	Ionization Gassing Thermal Run Away
	Aging	Ingress of Moisture Ingress of Air Graphite Ink Migration Dielectric Overheating X-wax Deposit	Puncture Explosion
		BULK NATURE	
		Aging of Oil-Paper Body Thermal Unstable Oil Gas Unstable Oil Oversaturation	Flashover Explosions
CORE SURFACE		Contamination	PD Surface Discharge Gassing
OIL		Moisture Contamination Aging	
INTERNAL PORCELAIN SURFACE		Deposited Impurities Conductive staining	PD
TAPS		Ungroundings Shorted Electrodes	PD
CONDUCTOR		OVERHEATING • Top contact • Foot contact • Draw rod Circulating Current in the Head	Overheating Gassing Sparking
EXTERNAL PORCELAIN		Cracks Contamination Surface Discharge	Flashover

6.6.2 Local defects in a bushing core

Irrespective of origin of defects/faults, which are shown in Table 6-6, two types of physical developing faults can be expected:

- Electric-destructive ionization in the place of overstressing
- Thermal-dielectric overheating

In any case, a defective area with excessive conductance is appearing between two or more core layers.

Defects can be characterized with two parameters:

- Dissipation factor of defective area tan δ_d
- Relative portion of defective section

Further process of developing defect can be introduced as increasing conductivity and tan δ_d and then burning paper through and occurrence of short-circuit between two of several layers.

Correspondingly, change in dielectric parameters of defective area causes dielectric response of condenser core and change in partial conductance measured between the central tube and potential (or test) tap.

The image of local defect can be determined with the following characteristics:

- Change in dissipation factor C_1 of the core tan δ_1 (Off-line and On-Line tests [45 47])
- Change in measured dielectric losses C_1 of the core, P_{w1}
- Change in the core capacitance C_1 due to short-circuit between layers and to some extent due to some increasing permittivity of defected area
- Change in the leakage current I_0 at the bushing mainly due to change in capacitance C_1 [46, 47]
- Change in imbalance current which introduces preliminary balanced geometrical sum of three phase bushings system due to increasing tan δ_1 and further increasing C_1
- PD activity
- Faulty gas generation
- Appearance of furanic compounds

As follows from analysis [46], more sensitive parameters at early stage of defect developing are:

- Imbalance current and (or) modulus of relative change of the bushing leakage current [47, 48].
- Relative change in losses.
- Change in tan δ_1.

At the stage of developed fault, the more sensitive parameters are:

- Imbalance current or modulus of relative change of the leakage current.
- Relative change in leakage current.
- Relative change in capacitance C_1
- PD activity
- Faulty gas generation

6.6.3 Critical aging of the oil, formation of semi-conductive residue on the inner surface of the lower porcelain

The failure process associated with aging of the oil and formation of semi-conductive residue may be introduced as the following [46, 47, 48, 49]:

6.6.3.1 Aging of the oil:

- Appearance colloids containing atomic metals (copper, aluminum, zinc, etc.)
- Deposits of conductive sediment on the porcelain; discoloration of the porcelain - from light yellow to dark brown color.

6.6.3.2 Reducing the dielectric strength of the oil:

- Change in the distribution of the voltage along the porcelain;
- Appearance of combustible dissolved gasses, what is typical for PD in oil
- Traces of discharges like trees across the porcelain surface, sometimes with glaze damage.
- Flash over across the porcelain

6.6.3.3 Condition assessment

At the first stage of fault developing: deteriorated oil, porcelain contaminated with semi- conductive sediment:

- Test tap design: Increase of insulation space between grounded layer of the core and grounded sleeve - tan δ C_2 with temperature (due to increase of dissipation factor of the oil [46, 47]
- Reducing tan δ C_1 of the core with temperature (due to conductive staining of the porcelain [50]
- Change in imbalance current [47, 51]
- Increase of dissipation factor and conductivity of the oil [49]
- Appearance of colloid (change in optical characteristics [52, 53])

At the second stage: appearance of discharges across the porcelain:

- Appearance of combustible gasses being typical for PD or surface discharge in oil
- Reducing tan δ C_1 down to negative value [46, 47]
- Increasing imbalance current [47]

6.7 Critical wearing out of cooling system components

The cooling system performs two basic functions:

1.Oil circulation:
Proper convective oil circulation (ON)
Pumping forced oil flow (OFAF, ODAF, OFWF, ODWF)

2.Heat Exchange (Loss dissipation)
Possible defective conditions:

- Loss of oil forced flow
- Oil flow blockage
- Pump deficiency (opposite direction of rotation, bearing wear)
- Pump motor failure
- Improper oil flow rate
- Fan deficiency/failure
- Coolers/ pipe contamination
- Air flow blockage due to contamination

Diagnostic Characteristics

- Forced oil flow rate/pressure
- Pump vibration
- Pump motor current
- Metal-in oil analysis [54]
- Difference in inlet –outlet cooler temperature
- Temperature distribution across the transformer tank, oil pipes
- Temperature distribution across the cooler
- Radiator air flow rate /direction
- Fan motor current
- Bearing monitoring system indicates wear

Chapter 7 Operations On Transformers

7.1 General considerations

The focus of condition monitoring and assessment techniques is to identify defects at the earliest stage before significant damage is done. Early discovery and remedy of defects avoids expensive consequences. However, the earlier that defects are identified, the smaller and more difficult they are to pinpoint in the volume of a transformer. Identification of the presence of a defect and tracking its development is one aspect, but pin-pointing the location for interpreting the risks, is yet another. Knowledge of location allows evaluating the applicability, economics and risk of repair options.

Other key factors are the estimated rate of development and the extent of the damage. A slowly developing defect may be managed with a strategy of inhibiting or modifying stresses, whereas a continuously developing and rapidly escalating defect requires urgent action. The general dilemma is that condition monitoring can never be completely non-intrusive and risk of human error increases when intermittent measurements are done.

It is important to note that a transformer consists of more than just core, windings, insulation, tank and oil. All accessories and parts required to operate the transformer form part of the transformer and each component has its own failure modes, for which methods have been devised for identification, pin-pointing and rectification.

The purpose of this report is to identify and catalogue the methods in use or that are being developed; their parameters, physical underlay, applicability, cost effectiveness, efficiency and success rates. This information should then allow users to identify the most efficient methods for rectifying their particular transformer problems. In this process, any gaps in the repair method "arsenal" should be identified; inefficient methods should be "unmasked" and finally, direction should be given to future developments.

Environment-sensitive issues such as dielectric fluid recovery devices and compliance with the regulations relating to PCBs must also be considered. An example of PCB regulations for France is cited in reference [56].

7.2 Catalogue of operations

Information is being collected on the various methods that have been used to treat transformers and reactors after a problem has been diagnosed. In particular, information is sought to quantify the effort required to do the work in relation to the cost of the unit under treatment, and the impact on the unit in terms of improvement, together with any possible life extension or consumption, or possible risks. The efficiency of each method is to be addressed, as is the impact on the environment (waste products generated). The diagnostic and test methods used to verify the condition of the transformer after operations are carried out are also of interest.

It is important to note that impairment of the insulation condition of a transformer begins at the time of transformer shipping. Shipping without oil results in de-impregnation of insulation and saturation with gas (nitrogen) and in some moisture ingress as well. Large amounts of rainwater can be sucked into a transformer in a very short time (several hours), when there is a rapid drop of pressure (after a rapid drop of temperature that can be induced by rain) combined with insufficient sealing. This phenomenon is especially of concern when transformers are stored partly filled with oil without their conservator preservation system. Direct exposure of the insulation to air cannot be avoided during installation procedures and special preservation measures should be used to mitigate adsorption of moisture and to protect insulation from rain, dust and other contaminants.

The catalogue of relevant operations during transformer installation is introduced in Appendix 9. [57, 58, 59, 60, 61, 62, 63]

Appendix 10 advises catalogue of typical operations on in-service transformer. Scenario of their implementation depends on the condition of the equipment and objective of processing.

7.3 Insulation rehabilitation: The goal and typical program

A transformer insulation rehabilitation program aims to restore or rectify the dielectric safety margin, slow down the rate of further deterioration, or recover the condition of insulation components. The following objectives of dielectric system processing should be considered:

1. Reconditioning the naturally deteriorated transformers, namely:
    - Aged oil
    - Contamination of cellulose insulation with oil aging products
    - Saturation with air
    - Moisture contamination
    - Particles contamination

2. Reconditioning or rectifying the transformer being in a defective condition, namely:
    - Having a source of gas generation (e.g., localized overheating)
    - Having source of particle generation, e.g. carbon, metal or fibers
    - Having severe moisture contamination of solid insulation
    - Having severe insulation contamination with sludge or other aggressive oil aging products

3. Rehabilitation of the dielectric system as a part of a life extension program, which should be focused specifically on restoration of the safety margin and reduction of the rate of further deterioration. The typical program of insulation rehabilitation includes:
    - Degassing and dehydration of oil
    - Filtering (removing particles)
    - Drying out of solid insulation[2]
    - Oil reclaiming – removing of aging products.
    - Insulation regeneration / Desludging
    - Degassing and re-impregnation of the insulation

It is always important to distinguish between a natural deterioration (under impact of temperature, oxygen, mechanical friction, ingress of air and moisture through the breathing system provided by design) and abnormal deterioration when a defect is involved. In the latter case identification of the defect and its correction (or advice to correct) is important.

The following typical cases would happen:

- Elevated water in oil associated with ingress of free water through insufficient sealing (e.g. draw lead bushings). Tightness test by means of pressurizing the transformer could be a good tool to assess and eliminate the problem.
- Excessive aging of oil (particularly in a sealed transformer) can be associated with local or general overheating. A DGA test may recognize the problem.
- Presence of metal particles and carbon is typically caused by wear of the pumps or localized overheating. DGA, vibration and acoustic tests may help to recognize the problem.
- Assumption of high water content in solid insulation may be confirmed or rejected by means of a Water Heat Run Test. This method is a very useful in-service tool to recognize condition of equipment and to select the proper processing method.

7.4 Life extension: Concepts and a typical program

Life extension is a subject that merges the major operations on a transformer to remedy its particular problems and restore the condition [64, 65, 66, 67, 68, 69, 70]. The economic motivation of a life extension program is based on technical premises:

- Most of the problems with aged transformers are of a reversible mode and can be corrected on site.
- Old transformer designs may be improved using modern knowledge.

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[2] Insulation dry-out may adversely affect the winding clamping pressure. Refer to Clause 7.7.5.

- It is feasible to restore the safety margin of the dielectric system, if the insulation gaps are unchanged, by means of drying, cleaning and regeneration of the oil - paper structure to meet requirements for new transformers. Some modification of the insulation can be performed as well, e.g., updating the exterior bushing insulation against the tank.

It is possible to reduce the rate of further insulation deterioration by:

- Evacuation of water and aging products
- Maintaining a low oxygen content by means of modification of the preservation system (installation of membrane-type oil protection)
- Reducing the temperature by modifying the cooling system
- Introduce a modern monitoring system in order to prevent catastrophic failure and to reduce maintenance cost.
- Reduce the level of operational stresses (through fault, current, over voltage).
- Provide better protection against external stresses, e.g. ZnO overvoltage limiter or an inductor limiting short-circuit current in the transformer neutral can be installed outside the transformer.
- Provide post-refurbishment service of a transformer with reliable technical guarantees if the equipment has no major faults, e.g. distorted winding, localized overheating of winding's coils, critical overheating or aging core laminations, critical insulation, decomposition, etc.

The following should support the life extension program:

- Design review with estimation of electrical and mechanical stresses and temperature distribution, assessment of the relevant safety margin, pinpointing the "weak-points" in the design.
- Analysis of operational history and unusual events.
- Comprehensive program of life assessment, considering "weak points" in the design and condition of the transformer in a course of service.
- Comprehensive program of insulation rehabilitation and refurbishment of a transformer considering strategic, technical and economic aspects, including correction of revealed and potential faults (known from experience with sister transformers), restoration of mechanical state of the core and coil, especially the winding clamping, recondition or replacement of the bushings and OLTC; regasketing/ elimination of leaks, etc.
- Comprehensive tests and quality assurance program.

7.5 Oil degassing and dehydration

7.5.1 Volume of gas and vapor to be removed

Oil is degassed in order to remove the air $\mathbf{V_{air}}$ (Nitrogen, Oxygen and Carbon Dioxide), some amount of gases generated during transformer service $\mathbf{V_{DGA}}$ and water vapor **Vw.**

$$V_{total} = V_{air} + V_w + V_{DGA}$$

The volume of dissolved fault gases $\mathbf{V_{DGA}}$ is typically minor and, as a first approximation, only the air and water vapor can be considered. The correlation between water content by volume and water content by weight is given by :

$$V_{oil} = 0.1244 \bullet ? \bullet \frac{T}{273} \bullet W_{oil}$$

Where:
V_{oil} = water content by volume in oil (%)
r = specific gravity (g/ cm^3)
W_{oil} = water content by weight in oil (ppm)
T = absolute oil temperature (K)

Assuming a specific gravity of 0.9 g/cm^3, we can see that water concentration by weight for W_{oil} = 10 ppm is equivalent to a water concentration by volume at 60 °C of approximately 1.36 %.

7.5.2 Degassing and dehydration through vacuum-degassing machine

Parameters of the process (oil flow rate, residual pressure and temperature) shall be coordinated with the characteristics of the vacuum pump (displacement) to remove the amount of air and vapor available.

The displacement of vacuum pump S shall be large enough to remove the sum of the gas-vapor mixture (V_{air}+V_{oil}) during a designated time period and may be estimated according Appendix 11

Oil outside the transformer contains typically 9-11 % of air and 3-5 % of water vapor. Assuming the oil flow rate of the degassing machine is 5 m^3 per hour, residual pressure 1 mm Hg, oil temperature 60 ºC and 15 % of total gas/vapor mixture to be removed (10 % of air and 5 % of water) per single pass, one may show that the displacement of the vacuum pump shall be:

$$S = \frac{760}{1} \bullet \frac{333}{273} \bullet 5 \bullet 0.15 = 700 \text{ m}^3/\text{h}$$

One gram of water at residual pressure of 1 mm Hg takes approximately 1 m^3 of volume (respectively 2 m^3 at 0.5 mm Hg). If the vacuum pump is used to process the oil and to evacuate at the same time some moisture out of the transformer, for instance 30 g/h or 30.0 m^3 of vapor under pressure of 0.5 mmHg, its displacement shall be more than 760 m^3/h. However, in order to process the oil and evacuate at the same time moisture 30 g/h under pressure of 0.1 mmHg the displacement of the vacuum pump shall be more than 1000 m^3/h. Parameters of the process shall be monitored in such a way to remove the desirable amount of "water-gas" mixture in one pass.

Factual (effective) displacement of the vacuum pump can be smaller than the rated one due to effect of vacuum hose conductivity (Appendix 13). A long length of hose or a small diameter of hose is a typical cause of reduction of the vacuum pump displacement and effectiveness of processing.

7.5.3 Optimization of degassing /dehydration process

Residual concentration of a gas or vapor after processing may be expressed as the following:

$$\frac{A_f}{A_{in}} = U + \frac{A_{ul}}{A_{in}}(1-U) \text{ or}$$

$$U = \frac{A_f - A_{ul}}{A_{in} - A_{ul}} = \frac{A_f}{A_{in} \bullet (1+m)}$$

Where:
A_f = final concentration
A_{in} = initial concentration
A_{ul} = ultimate concentration
m = residual amount of gas after treatment, e.g. 5 %
U =coefficient of treatment effectiveness

Treatment process conforms to inequality:
$0 \geq U \leq 1$
if U=1, Af = A_{in} (no treatment);
if U = 0, Af = A_{ul} (ideal treatment).

The ultimate concentration A_{ul} depends on residual pressure p and solubility of gas in oil.

$$A_{ul} = \frac{p \cdot K_0}{P_0}$$

Where
p = residual pressure
K_0 = Ostwald coefficient for gas
P_0=ambient pressure

For instance, the ultimate concentration of air assuming the Ostwald coefficient for air is 11%, ambient pressure 760 mm Hg, and treatment pressure 133 Pa or 1mmHg is equal to:

$$A_{ul} = \frac{p \cdot 11\%}{760} = \frac{1 \cdot 11\%}{760} \cong 0.014\% .$$

Accordingly, under treatment pressure 650 Pa or 5 mmHg the ultimate concentration of air would be 0.07%

The actual process of degassing is diffusion of gas from oil, and the function U may be approximated with an exponential function. After a limited time of vacuum treatment, some quantity of gas remains to be extracted. In order to obtain the desired final concentration value, the treatment pressure should be less than that which corresponds to ultimate equilibrium concentration. The minimum treatment pressure may be estimated on the condition of reaching the given final gas content per single pass:

$$p \cong \frac{P_0}{K_0} \cdot \frac{A_f \cdot m}{1 + m}$$

For example, assuming that treatment process is an ideal one, the final gas concentration of 0.1 % would be reached under treatment pressure.

$$p = \frac{760}{11} \cdot 0.1 = 6.9 mmHg$$

However due to limited time of vacuum treatment some amount of residual gas (above equilibrium value) would still remain in the oil. Assuming relative amount of residual gas m = 0.05 only 0.32% of final gas concentration would be reached under pressure 6.9 mm Hg. In order to reach the final gas content 0.1%, the value of residual pressure in the degassing chamber should be :

$$p \approx \frac{760}{11} \cdot \frac{0.1 \cdot 0.05}{1 + 0.05} \cong 0.33 \text{ mm Hg}$$

Treatment of oil on the same condition but under residual pressure 1 mm Hg can reach final air concentration 0.3%.

The degassing process may be optimized using the most effective stage of degassing process. One can define two degassing stages [73, 74] in a vacuum degassing plant [71]:

- Intensive extraction of dissolved air and water from the oil under vacuum, inevitably causing foaming which provides intensive diffusive emission of gas and vapor out of the oil. This is the most effective stage of degassing. It does not require high vacuum and high temperature.
- Relatively slow gas diffusion out of the flowing layer while oil is flowing down from spray nozzles or spraying to produce the mist. This process needs comparatively high temperature and vacuum.

However, it is important to not allow the foam to get out of the vacuum chamber. The typical volume of oil foam is 6 to 8 times as large as the volume of the oil itself and the time constant of foam sedimentation is about 30 to 60 seconds [74].

To meet the above requirements the flow rate of the oil would be equal to 1/8 the volume of the vacuum chamber. Therefore, if the volume of the vacuum chamber is 1m^3, the flow rate must be less then 1/8 m^3 per hour. However, the foaming tendency of different oils is rather different. Some general guidelines have been suggested by Griffin [73], which recommends not using oil having a foaming tendency more than 150 ml.

7.5.4 Methods of oil degassing and dehydration

7.5.4.1 Dehydration by means of circulation through paper filter (Blotter paper, cartridge type filter)

This plays a small role in moisture removal. Passing dry oil through wet blotter paper would have a negative effect by increasing the moisture content in oil [72]. Wet paper filters may be also a source of small particles generation [63].

7.5.4.2 Dehydration by means of circulation through micro fiberglass filter

This technology has greatly enhanced the filtration efficiency. This type of filter cannot be a particle generator. However, super-absorbent media remove free and emulsified water, and only partly dissolved water considering various temperatures. Super–absorbent media in a filter that has not reached its water holding capacity will not release free water, but can increase to some extent dissolved water content in oil, just like cellulose, when the oil is dryer than the media [72].

7.5.4.3 Dehydration by means of circulation through molecular sieves

This technique allows reaching a very low level of oil humidity per single pass [75]. For instance 200 kg of NaX may effectively dry oil holding up to 40 kg of water. The holding capacity of molecular sieve decreases with temperature from 18 - 20 % at 20 °C to 3 – 4 % at 100 °C, but still allows using the media as an effective adsorbent [76]. Typical flow rate during percolation of oil through the adsorbent is up to 3 m^3 per hour.

Disadvantages of the technology are the necessity to regenerate the molecular sieve with evacuation of oil and mechanical weakness and crumbling of the granules after a certain number of regeneration cycles.

Sorption capacity [76] of molecular sieves Na X is given in the Table 7-1.

Table 7-1 Sorption capacity of molecular sieves, g/100g

Vapor Pressure, Pa	**Temperature C**				
	0	**25**	**50**	**100**	**150**
0.013	**2.0**	**1.6**	**0.4**	**0**	**0**
0.13	**4.8**	**3.2**	**2.0**	**1.0**	**0.4**
1.33	**14**	**6.0**	**3.8**	**3.0**	**2.2**
13.3	**18**	**15**	**8.0**	**3.6**	**3.2**
133	**18**	**18**	**16**	**6.0**	**3.6**

7.5.4.4 Degassing and dehydration by means of a vacuum degassing machine

This is the most widespread technique. Modern devices allow reaching a low gas and water content per single pass, and can be used for treating the oil and vacuum treatment of the transformer insulation simultaneously. However, the process requires heat and a high vacuum, and therefore sometimes looks comparatively costly.

7.5.4.5 Degassing and dehydration taking advantage of foam effect

This technology incorporates a special device (ultrasonic nozzles) to enhance the foam build up and adopts foam to accelerate diffusion of vapor and gases.

Some processing data that could be reached per single pass [74] are shown in the Table 7-2.

Table 7-2 Oil degassing and dehydration from the foam per single pass

Flow rate m^3/h	Temp - erature °C	Residual pressure kPa	Height of foam mm	Total gas %		Water content g/to	
				Initial	Final	Initial	Final
5.6-6.0	25-29	1.1-1.33	190-270	8.7-9.7	0.27-0.3	18-26	6.7-7.8

Typically two stages of treatment are used to reach a very low moisture and oxygen content:

1) Foaming-evacuation of gases and vapor up to a certain level
2) Saturation of the oil with dry nitrogen to build up foam and then repetition of the degassing cycle. This technology does not need a high vacuum and is effective at low temperature.

The effect of foaming is strongly influenced by the type of oil being used.

7.5.4.6 Drying and selective degassing of the oil by means of bubbling (blow through) dried nitrogen (by Dr. Schogl)

This is the most efficient technology of oil dehydration outside a transformer [77] and allows drying the oil during tens of minutes. Gas (nitrogen) blowing through the oil forms a thin layer on the oil surface that contacts with atmospheric air. The partial pressure of other gases except nitrogen is equal to zero. Thus vapor and other gases are desorbing out. Figure 7 shows an example of evacuation of water and oxygen out of oil during one hour at ambient temperature. By means of passing nitrogen through oil under pressure of 5 mmHg. Oxygen content is shown in %, water content in ppm.

It should be noted that this is a promising technology, but is not in common use. There may be applications and situations where it is not effective.

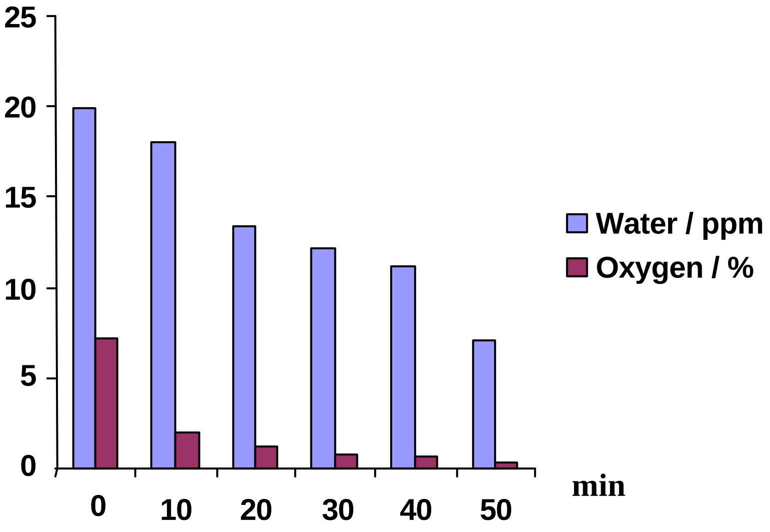

Figure 7 Drying and evacuation of oxygen out of oil

7.6 Oil/insulation cleaning

7.6.1 Typical origins of contamination

The origins of particles are manifold. Cellulose fibers, iron, aluminum, copper and other particles resulting from manufacturing processes are naturally present in the transformer's oil. Aging of the oil during utilization at normal and overload temperatures slowly forms sludge particles. Localized overheating over 500°C is a symptom of forming carbon. The carbon particles produced in the OLTC diverter may migrate by leakage, accidents or human error into the bulk oil compartment to contaminate the active part. A typical source of metallic particles is the wear of bearings of the pumps.

Particle contamination is the main factor of degradation of dielectric strength of transformer insulation and, accordingly, elimination of particles is the most important objective of oil processing. The most dangerous particles are conductive mode particles (metals, carbon, wet fibers, etc.)

The contaminants and oil cleanliness requirements vary depending on where in the apparatus the oil came from (main tank, class of voltage, OLTC). Proper filter selection for the job should not be overlooked. Very efficient particle-removing filters may have little or no capacity to remove moisture from oil. Combination filters, which contain both water removing and micro glass media, often have reduced capacity for one contaminant or another.

7.6.2 Filtering parameters of process

7.6.2.1 Nominal micron ratings

The micron rating does not characterize a filter in a unique manner. [72 78, 79] Nominal filter ratings are based on gravimetric tests and applying efficiency, based on weight, which takes no regard of particle size. What one manufacturer calls a half-micron filter can be designated as a five-micron filter by another manufacturer.

7.6.2.2 Beta ratio ratings

The Beta Ratio is a more precise definition of filter efficiency. Beta Ratio is determined in a multi pass test loop that allows the filter several opportunities to trap particles of various sizes. The Beta Ratio formula denotes both particle size and efficiency. $Beta_6$ = 75 means the following: the number 6 relates to the particle size; the number 75 relates to efficiency: 75 = 98.7 % efficient; 100 = 99 %; 500 = 99.5 %; 1000 = 99.9 %. For example: a filter rated as $Beta_3$ = 500 would mean that the filter was 99.5 % efficient at removing 3 micron sized particles during the multi pass test.

7.6.2.3 Resistance of the filter

The resistance of an unused filter may be expressed according the equation in Appendix 12.

The pump flow rate shall match the particular filter cartridge (filter resistance). Typically the filtration process proceeds with a constant pump flow rate. Therefore an increase in the pressure may be a characteristic of increasing resistance of residue and accordingly, the filter capacity.

7.6.3 Common filtration problems

There are some technical problems with oil purification, which have to be considered [63, 78]:

- Filter cartridge selection for oil processing is critical to achieving good results
- Filtering of small particles, especially carbon, could be a subject of particular concern. Particle counting and microscopic analysis before and after filtration would support the selection of a proper cartridge.
- Removing small light particles (e.g. clay crumb) can also be a problem because they are floating in the oil following convective flow. This is really a disadvantage in comparison with purification of the oil by draining it out of the transformer tank.
- The filter (particularly paper) can be a source of particle generation itself. The useful life of the filter shall be considered, particularly for on-line applications.
- The possibility of gas bubbles coming out of the oil at low pressure points in the system shall be particularly considered. Restrictions in the suction line, using a long length of hose or a small diameter of hose are common reasons for this.
- Filter systems should be checked for proper flow direction through the filter housing and cartridge. Proper matching of the filter with the pump flow rate is also critical to good filtration. Over-flowing a filter will reduce its efficiency and capacity.

7.7 Insulation drying out

7.7.1 Typical conditions of transformers to be subjected to drying out

Accumulation of water on the bottom of the tank. Localized concentration of free water. Solid insulation is comparatively dry. Typical case: free water penetration through poor sealing.

Concentration of water in the vicinity of the surface (predominantly in thin structure). Typical case: exposing insulation to atmospheric air during installation or repair.

Concentration of water in thin structure basically in the pressboard barriers contacting the bulk of oil. Water content in wet zones up to 3 - 4 %. Typical case: transformer operating with free-breathing preservation system for a long period. This would not apply to a transformer with a properly maintained sealed conservator oil preservation system.

Significant moistening of insulation structure. Water content in thin structure up to 6 – 8 %, in thick structure – up to 3 – 4 %. Typical case: a failed transformer being exposed to outdoor air for a very long period (year).

7.7.2 Drying out: Theoretical issues

7.7.2.1 Kinetics of drying

The kinetics of drying is a change of water content and temperature with time to achieve equilibrium condition.

Three stages of drying should be considered [80]:

1) Heating
2) Drying with a constant moisture extraction rate (surface vaporization); process at steady temperature
3) Drying with steadily reducing rate (diffusion)

Three moisture-moving forces may be identified:

1) Moisture gradient (isothermal diffusion)
2) Temperature gradient (thermo-diffusion)
3) Pressure difference (convection diffusion, viscous movement of moisture in macro capillaries)

Moisture and temperature gradients can be directed in a one-way – drying acceleration; and contrarily – process retardation.

7.7.2.2 Drying stage at steady temperature

This stage may be characterized by the following [80, 81, 82]:

1) Diffusion is more intensive than vaporization
2) Drying is vaporization from wet surface at hydrostatic temperature
3) Dry out process may be expressed by equation:

$$\frac{dc}{dt} = a \bullet \left(P_0 - P\right)$$

Where :
dc/dt = change of moisture concentration with time, kg/hour
c = moisture quantity, kg
a = evaporative mass transfer coefficient, kg/m^2•hours•mmHg
P = vapor pressure of drying medium
P_S = saturated vapor pressure, mm Hg, that may be estimated for given temperature by means of the following approximation:

$$P_S \cong P_0 \cdot e^{14 - \frac{5200}{T}}$$

Where:
P_0 = ambient pressure, typically 760 mmHg
T = absolute temperature of paper insulation

Evaporation process requires considerable energy. For example: Evaporation of 20 kg of water requires approximately 12.5 kWH of energy.

7.7.2.3 Drying equation

The diffusion stage of dry-out may be expressed according Lampe [81] see Appendix 14.

The moisture diffusivity for oil-impregnated cellulose may be estimated using Howe's approximation [83] :

$$D = 10.64 \bullet 10^{-12} \bullet P_s \bullet e^{0.52C} \ (m^2/h)$$

Where:
c = moisture content, %

and

$$P_s = 760 \bullet e^{14 - \frac{5200}{T}} \ \text{mm Hg [81]}$$

7.7.2.4 Estimating the drying parameters

The following parameters should be estimated to determine a proper drying technology [81, 84]:

1) The minimum equilibrium water content
2) Drying temperature
3) Residual pressure
4) Estimated drying time

The minimum equilibrium water content may be estimated as the following:

$$W_e = \frac{W_f - K \bullet W_i}{(1 - K)}$$

Where :

K = remnant of water after drying;
W_f, W_i = final and initial water content, %.

For example, assuming $W_i = 3$ %, $W_f = 0.5$ %, and K = 0.1 (10 % of remnant water), we have $W_e \cong 0.225$ % .

Insulation drying temperature should high enough to achieve final dryness, and on the other hand it should be low enough to prevent an essential loss of life of cellulose. The value of residual pressure should be determined considering water equilibrium in the "cellulose – vacuum" system to achieve the necessary level of remnant moisture. For example to achieve finally water content of 0. 5% assuming 10 % of remnant water. At 80 °C, $W_e = 0.22$ % can be achieved in a pressboard under pressure P < 1 mm Hg.

The total drying time can be estimated using parameters of diffusive period of process. A time for drying the thickest pressboard can be taken as a time of whole process on given conditions:

If $\frac{D \cdot t}{d^2} > 0.05$, tentatively (with underestimation) the time of drying out may be estimated using equation [81]

$$t \cong \frac{d^2}{D \bullet p^2} \bullet \ln K \bullet \frac{p^2}{8} \bullet (-1)$$

Where
D = diffusivity, m^2/s
t = time, s
d = insulation thickness, m

Assuming d = 5 cm, $W_0 = 6$ %, $W_f = 0.5$ %, $W_e = 0.2$ %

$$D = 1\ \text{cm}^2 / \text{d}$$

$$K = \frac{0.5 - 0.2}{6.0 - 0.2} = 0.05$$

Estimated drying time is more than 7 days

7.7.2.5 Criteria for completion of drying

Agreement with equilibrium parameters:

- Temperature of the thickest wet insulation component
- Residual pressure
- Rate of moisture removed under equilibrium condition.
- Rise of pressure after the insulation exposure to equilibrium condition.
- Water content in insulation model (pressboard patterns).
- Agreement with equilibrium of participant media:
- Oil – water content (relative saturation)
- Air – water vapor pressure (dew point)
- Agreement with drying time.

Indirect criteria: dielectric characteristics, dissipation factor, DC resistance, polarization index corresponding to final water content.

7.7.3 Transformer heating methods

The typical methods of heating a transformer to provide drying out are summarized in Table 7-3 [6, 57, 58, 62, 63, 85]. It is important to highlight some problems that may accompany transformer heating:

- Dissipation of heat outside the transformer tank. Effective thermal insulation of the tank is required to minimize heat dissipation outside the transformer. Effectiveness of the warming may be checked by means of measurement of surface temperature. Uniformity of temperature distribution is critical to avoid localized moisture condensation during heating.
- Leveling oil temperature within the tank while circulating hot oil. The heat time constant of oil (τ_0) is dependent on the mass of oil (m) and rate of oil circulation q and may expressed as $t_0 = \frac{m}{4 \bullet q}$. Therefore to achieve uniform heating of 60 m^3 of oil, the flow rate of oil circulation should be 45 - 60 m^3 per hour.
- Uniform distribution of the oil spraying should be considered to provide uniform heating of the insulation during the hot oil spray process.
- Possible localized oil overheating in the heater and gas generation should be considered during the hot oil-circulating process. DGA analysis could support the quality of the heating system.
- The risk of overheating the winding insulation during winding resistance heating by means of circulation of current shall be considered particularly. Namely, the possible difference between the hot spot and average winding temperature and error in temperature measurement should be taken into account. The level of the oil above the top of the winding is a critical factor.

Table 7-3 Methods of transformer heating

Heat Agent	Method/Application
Hot Air ® Core and coil assembly	1.Continuous circulation of hot air as the main part of drying. The temperature of the inlet air should be about 100 °C .The tank should be blanketed in order to reduce to a minimum the amount of heating required. The volume of air required to obtain an optimum heating (and minimum drying time) should be more than 10 m^3 per minute per m^2 of the area of the tank base. ***Special precautions shall be taken to prevent fire and forming of an explosive mixture of oil vapors and air.*** This method is advised for medium size transformers. 2.Circulation of hot dry air as a stage of combined hot air / vacuum drying process.
Hot Oil ® Core and coil assembly	1.Continuous circulation of hot oil as the main part of drying. or as a stage of combined process. The oil is circulated from the bottom of the tank through a heat exchanger, to an output temperature of 60 – 90 °C, returning to the top of the tank. Blanketing of the outside of the tank to reduce heat dissipation is required. Oil overheating in the heater and possible gas generation should be considered. 2. Hot oil bath – heating the bottom part of the core and coil assembly in order to provide the internal inspection of a transformer, especially in wintertime.
Hot oil spray ® Core and coil assembly	Hot-spray technology as the main part of drying or regeneration of insulation • Continuous spraying under vacuum • Cycle-mode spraying under low vacuum to provide convective heat exchange ***Oil overheating in the heater and possible gas generation should be considered***.
Winding Internal Losses ® Conductor ® Oil ® Core and coil assembly	Winding resistance heating by means of circulation of direct or rectified current. Typically, series connected HV windings used. **Maximum temperature of winding of 95 °C**. Proper oil level above the top of the windings shall be considered
	Short-circuited windings: the method requires a source of power to heat the transformer by circulating current through the winding. The value of current (not more then rated) and maximum **Temperature of winding of 95 °C shall be considered.**
	Low-frequency heating (LFH) technique: a controlled three-phase current from a solid-state low-frequency power convector is injected into the transformer primary, with its secondary short-circuited.

7.7.4 Methods of drying out

7.7.4.1 Circulation of hot dry oil

Dry oil is circulated through the tank and moisture extracted from the oil is absorbed in a vacuum degasifier. Oil temperature 85 – 100 °C, and oil flow rates about 70 m^3/h are recommended. The method can be efficient in case of fairly low moisture contamination. [57, 59, 62, 86, 87, 88]

7.7.4.2 Vacuum treatment only ("cold trap" technique)

To achieve surface moisture content e.g. 0.5 % residual pressure should be 0.05 mm Hg at 30 °C or less. The cold trap is used to reduce the amount of water reaching the vacuum pump, to improve the operation of vacuum pump and to measure rate of water removed. This technology is efficient at removing "surface moisture" after a prolong exposure of the insulation to air.

7.7.4.3 Heat /vacuum Cycles

This technology incorporates the following procedures:

- Heating core and coil with hot oil circulation or with DC current, or combined up to 80 – 90 °C steady temperature
- Draining the oil
- Vacuum treatment 1 – 5 mm Hg
- Cycle repetition (if necessary)

7.7.4.4 Hot oil spray

This technology incorporates the following procedures:

- Bring oil level to the bottom part of the core
- Oil spraying at flow rate up to 30 – 50 m^3/h and temperature up to 90 – 120 °C under vacuum of 5 – 10 mmHg
- Increase vacuum level to 1 mmHg or less after spray is stopped to ensure final dry out
- Atomizing nozzles for the oil spray are recommended

7.7.4.5 Combined oil-spray / hot air / vacuum / oil circulation / cycles process

Process procedures:

Pre-starting procedures:
Draining the oil
Vacuum pre-dry the tank, core and coil
Bring oil level to the bottom part of the core with dry, clean, stable, well-soluble oil

Heating process:
Oil-spray through spreading pipes installed above the windings at flow rate up to 50 – 60 m^3/h, t = 90 – 95 °C under vacuum 150 – 200 mm Hg. Periodically circulate dry air through the tank to maintain the surface temperature.

Drying process:
Cycle vacuum treatment 0.5 – 1.0 mmHg with circulation of technological oil through the oil heater / filter followed with a cycle of oil spraying at low vacuum to maintain average drying temperature 80 – 85 °C.

7.7.4.6 Combined LFH (Low Frequency Heating) and oil circulation/vacuum drying technology

Process procedures [87]:
A controlled three-phase current from a solid-state low-frequency power convector is injected into the transformer primary, with its secondary short-circuited.
The winding is heated by applying the LFH-Technology and parallel heating of the active parts through hot-oil-circulation via the oil treatment plant.

Drain the oil:
Increase the winding temperature to 110-120 °C; dry the winding and barrier insulation under vacuum with simultaneous LFH-heating of the windings.

Fill with processed oil:
During the process the following parameters are to be monitored:

- LV-current
- Average temperature of high and low voltage windings
- Heating capacity
- Maximum voltage
- Duration of the process phases
- Vacuum
- Specific water extraction rate
- Insulation temperature

7.7.5 Effect of drying out on compression forces of the winding

The moisture in the transformer insulation system has an important impact on the clamping pressure. A tight clamping of the winding coils is a key parameter for safe operation in case of short-circuits. [57, 59, 62, 86, 87, 88]

The nature of the cellulose fibres used in the transformer insulation changes the dimensions of the insulating parts with the temperature and the moisture content. The drying and stabilisation process, as well as the clamping fixture will influence the final behaviour during the operation.

In service, the moisture content will increase due to moisture ingress, aging of cellulose. An increase of 3 % moisture can double the clamping pressure when initial pressure is in the range of 2.5 N/mm^2 based on a test performed on stacked pressboard spacer samples [89]. Similar measurements on real coils are difficult to find in the literature. The effect of drying on real new coil during drying and stabilisation process has been published [90]. A reduction of 10 % in the coil length has been measured under a constant pressure after drying.

An increase of the clamping pressure due to moisture increase will generate a compacting of the insulation parts if the coil is held at constant clamping distance. Unfortunately, this process is only partly reversible; hence the insulation remains physically compressed to some extent. As a consequence, a later loss of clamping pressure is to be expected when these insulating parts are submitted to additional drying process. Therefore, the drying of moist solid transformer insulation can be critical if the coil is losing too much clamping force.

7.8 Insulation regeneration

7.8.1 Typical condition of transformers to be subjected to regeneration (desludging)

Aged oil –degree at which sludge evolution may be expected. [91]

Substantial amount of acids and non-acid polar compounds
- Discoloration of the pressboard/paper
- Localized deposit of sludge on insulation zones under excessive dielectric stress (typically invisible without dismantling)
- Symptoms of substantial increasing of surface conductivity

7.8.2 How to remove oil-aging products out of insulation

Removing oil-aging products out of the oil itself and out of insulation is a critical means to extend a transformer's life [91]. Sludge is the most dangerous enemy of dielectric components:

As an impurity - reduces oil dielectric withstand strength (like particles)
As a semi-conductive sediment – reduces impulse withstand strength of insulation
As an extreme sour-effective killer of **new oil and cellulose insulation**. Sludge acidity may be 30 to 300 mg KOH /g
The aggressiveness of the sludge can be more critical than its quantity

There is an old empirical rule: a substance is dissolved in a similar solvent. Transformer oil can dissolve oil-aging products to some extent. The solubility of oxidation and decay products of different oils can be quite different. The solvent action of oil depends on its aromatic content -the more, the better; and its molecular weight (viscosity) – the less, the better. Some detergents (regenerative oil) can effectively remove aging products.

There have been several techniques of removing oil-aging products out of insulation:
1) Use special regenerative oil:
Utilization of special regenerative oil instead of transformer oil for some time (months, year). ***A detergent is transformer oil with some cleaning agent.*** Flush-out insulation for a certain time to remove aging products.

2) Improve the detergency of operating oil:
By means of some special cleaning additives
By means of establishment of special condition, namely
a) Maintaining a low concentration of oil decay by reclaiming
b) Maintaining a high temperature of oil to improve its solubility

7.8.3 Methods of transformer desludging

References: [6, 64, 65, 68, 91, 92, 93, 94, 95]

7.8.3.1 Regenerative oil technology

Temporary operation with regenerative oil:
Refill the transformer with regenerative oil
Flush very contaminated core and coils before refilling
Operation for 10 to 20 months under special control
Refill with stable transformer oil

7.8.3.2 Desludging as a part of rehabilitation process

Use a regenerative oil as a technological oil during "oil-spray – vacuum cyclic" process, 85 – 90 °C
Cycle of heating sometimes means a cycle of desludging
Monitor for oil aging products during the process
Correct the desludging and washing process depending on insulation contamination

Recondition the regenerative oil during the high vacuum drying process (if necessary)

7.8.3.3 Circulating through Fullers Earth

Desludge by means of desorption of aging products into oil being freshly regenerated through adsorbed percolation columns. Desludging takes place at a higher temperature than oil regeneration. Two critical desludging criteria should be considered:

The temperature of the oil circulating through the transformer should be over its aniline point in order to dissolve the sludge. Oil supplied into transformer during circulation should be freshly regenerated to be able to dissolve and absorb the sludge

7.9 On-Line processing

7.9.1 General considerations

In recent years there has been considerable interest in the subject of on-line processing of power transformers, particularly in reclamation of oil, drying out and regeneration of insulation. Discussions at international conferences have shown an obvious tendency towards implementation of on-line procedures on transformers up to 500 kV (see references). Plain economic benefit encourages fast developing processing techniques. In addition to traditional processing equipment, some special processing systems have appeared: [65, 66, 78, 96, 97, 98]

Some processing methods have had a positive experience for 25-40 years. For instance, the permanent regeneration system (cartridges filled with silica-gel) has been specified for all transformers above 2.5 MVA. There have been also positive experiences with permanent filter system, degassing system and with on-line drying out of some transformers using molecular sieve. However, there are several factors that make some technical and safety concerns hindering wide implementation of on-line procedures:

- Risk of failure due to possible introduction into the tank of air, bubbles, particles or other impurities; loss of oil level; occurrence of static electrification
- Risk of failure while processing an "unhealthy" transformer
- Very long time (in some cases) of treatment (very costly process); e.g. drying out may last several months and, accordingly, cause a high cost of processing.

One should consider that practically all impurities are distributed in certain proportions between oil and solid insulation. Significant amounts of gases and oil aging products are concentrated in cellulose.

Oil is a water-transferring medium. Water is present in the oil in soluble form and also in "hydrate" form, being absorbed by polar aging products (aromatics) and particles. However, using the Karl Fisher method, we measure only the dissolved water, not bounded water. Thus we typically underestimate the water content, particularly in aged oil.

Sometimes just thoroughly filtering the oil may reduce the water content. The dielectric safety margin of both major and minor insulation of a transformer contaminated with water is determined by the dielectric strength of the oil. The dangerous effect of soluble water is a sharp reduction of dielectric strength of oil with increasing saturation percent due to the increasing conductivity of particles. The fewer the particles, the weaker is the effect of water on the dielectric strength of the oil. Effective processing shall incorporate drying and filtering procedures simultaneously. In order to come from the worst to the better from the point of view of improvement of the dielectric safety margin, the following ranking should be advised:

- Do not allow bubbles
- Remove free water
- Remove particles, particularly large and conductive ones
- Remove dissolved water
- Remove oil aging products

Water in the turn insulation accelerates aging decomposition. Depolymerization of cellulose is proportional to the water content. This process becomes much more dangerous in the presence of acids. Elimination of aging products being adsorbed with insulation may significantly reduce the dangerous effect of water, namely, the temperature level of bubble evolution. Thus a treatment program shall consider as a rule a simultaneous complex of procedures: drying, filtering and extraction of aging products.

7.9.2 Treatment methods on an energized transformer

The following procedures have been experienced and may be performed on an energized transformer [99]:

- Drying of oil
- Oil degassing
- Oil reclamation
- Oil filtering
- Purification of insulation through filtering of oil
- Drying of insulation through drying of oil
- Regeneration (desludging) of insulation using oil as a solvent
- PCB elimination

One can distinguish passive and active methods of treatment:

1) Active methods incorporate pumping the oil through the filter, vacuum-degassing machine, Fuller's earth towers, etc. This approach allows monitoring and accelerating the process, but has some disadvantages (adjustment, maintenance, operator's service, loss of power).
2) Passive methods typically incorporate a system of some cartridges filled with sorbent that are connected to the tank or to the coolers. The passive process is much more economical and lasts longer.

The effectiveness of the methods depends on the physical effect chosen for processing. Methods based on diffusion processes: reclamation, vacuum degassing-diffusion through oil film, drying out of cellulose, etc. are more effective at high temperature; methods based on adsorption processes: drying oil through adsorption (e.g., paper) filter, restoration of color, etc. are more effective at low temperature.

7.9.3 Drying and degassing oil *(see also section 7.5)*

The effectiveness of both on-line and off-line procedures is practically equal. An important advantage of on-line processing is the possibility of using internal losses of the transformer. Thus this process may be more economical then off-line treatment when the oil needs to be heated.

In case of treating the oil by means of a vacuum-degassing machine, the parameters of the process shall be monitored to remove the desirable amount of "water-gas" mixture in one pass.

In case of using a treatment device in order to remove moisture only, it is important to establish parameters of the process to get the desirable water content in one pass. The application of molecular sieve is more appropriate. Drying and degassing of oil does not require very high temperature and vacuum. Average oil temperature 40 – 50°C and vacuum 1 - 0.5 mm Hg are sufficient to reach adequate dryness.

7.9.4 Drying out of insulation through drying the oil

This process needs higher temperature than drying only the oil. To get low moisture content, one must maintain a very low relative saturation of oil. The water content in oil is directly proportional to the relative water concentration (relative saturation) up to the saturated level. It is very important to consider solubility characteristics of the oil. Water saturation level W_S of an oil versus the absolute temperature T may be expressed by the following approximation.

$$W_S = W_0 \cdot e^{(-B/T)}$$

W_0 and B are constants, which are typically different for different oils, mainly due to the difference in aromatic content. Some information about water solubility parameters of different oils is shown in Table 7-4:

Table 7-4 Water solubility of oils

Oil samples	C_A, (%)	W_0	B	Water saturation level (ppm)		
				20 °C	40 °C	70 °C
1	5	$16.97 \cdot 10^6$	3777	42.8	97.5	279
2	8	$23.08 \cdot 10^6$	3841	46.8	108	316
3	16	$22.76 \cdot 10^6$	3783	56.2	128.3	369.2
4	21	$13.16 \cdot 10^6$	3538	75	162	436
5	Silicon-oil	$1.9525 \cdot 10^6$	2733	174	314.7	675.4

To get water content in cellulose about 2 %, relative saturation of the oil shall be less than φ < 8 %. Assuming maintaining water content of oil within the transformer 15 ppm, e.g. for oil # 2 we may estimate the starting temperature of drying process:

$$T = \frac{(-B)}{\ln\left(\frac{W_{oil}}{j \cdot W_o}\right)} = \frac{(-3841)}{\ln\left(\frac{15}{0.08 \cdot 23.08 \cdot 10^6}\right)} = 328\text{K}\left(\approx 55^\circ \text{C}\right)$$

One can show that to get moisture content in cellulose of 1 % the drying temperature shall be over 70 °C and process shall allow maintaining water content in oil less than 10 ppm.

Experience has shown that drying out of insulation highly contaminated with water by means of circulating oil through a dehydrator requires high temperature and a rather long time (months) and is less effective and efficient than methods of drying out the transformer free of oil. On the other hand, on-line procedures are definitely more efficient then off-line because of the possibility of utilizing the internal losses of the transformer as the source of heating. Some transformers rated 69 – 115 kV may have a relatively small amount of water adsorbing insulation. Drying out this equipment incorporates mostly drying out of oil, insulation surfaces and elimination of free water. On-line processing may be very efficient when using "passive methods." Two cartridges filled with molecular sieve of 200 kg may extract during several months about 40 kg of water, which effectively dries a transformer rated 200-300 MVA.

7.9.5 Oil filtering (see also 7.6)

Particle contamination is usually the main factor of degradation of dielectric strength of transformer insulation and, accordingly, elimination of particles is the most important objectives of oil processing. A special CIGRE working group "Particles in Oil" (WG 12.17) has found that a lot of failures of HV transformers have been associated with particle contamination. Traditional dielectric breakdown tests are not sufficient to identify the problem and a particle counting method has been advised as a monitoring tool. The denomination of typical contamination levels including possible dangerous level has been advised by WG 12.17, using classification of NAC standard, as the following :

4-6	- Normal: contamination level typical for transformers in service
7-9	- High: possible transformer malfunction
10-12	- Very high: the condition strongly indicates transformer malfunction

The high level means the presence of 32000-64000 particles of 5 µm and above and 8000 particles of µm in 100 ml of oil. It is apparent that improvement of transformer condition in-service is mandatory and that the on-line filtering process is particularly desirable. Both off-line and on-line procedures are practically equal; however, the latter does not need additional heating to reduce the viscosity of the oil.

7.9.6 Oil reclaiming

Similar to drying of oil, this is a widespread process and can be performed for both off-line and on-line applications. On-line procedures are more efficient because of the possibility of using internal losses of a transformer to heat the oil. One must consider some disadvantages of the methods:

A large amount of waste
Loss of oil during reclamation, which is more sensitive in the case of an energized unit
Limited amount of oil processed with one charge
Risk of introducing clay crumbs into the tank (more critical for energized unit)

Passive mode methods with installation of some cartridges filled with adsorbents can sometimes be much more efficient and safe. Experience has shown a very good efficiency of the so-called reclaiming without waste using Fuller's earth reactivation technology.

7.9.7 Estimation of the processing time while reconditioning by means of circulating oil in a transformer

The process of reconditioning a transformer by means of circulating the oil through processing equipment is of exponential mode and, irrespective of the type of purification, may be expressed by the equation:

$$\frac{n(t)}{n_o} = e^{(-x \cdot t/t)}$$

Where

n_o = initial concentration of contaminants (particles, water, gas, acids, etc.)
n(t) = desirable final or current concentration
x = coefficient of purification effectiveness, $0 < x < 1$ - ratio between input and output concentration or rate of removed contaminant per one pass
t = time of processing
t = time constant - with t = V/Q
V = oil volume in the transformer
Q = rate of flow

Three parameters shall be considered:

Ratio of final and initial concentration of contaminants
Ratio of flow rate and total volume of oil in the transformer
Ratio of inlet and outlet concentration of contaminant per one pass of treatment into the processing machine

The most important parameter, which determines effectiveness of the process, is relative rate of contaminant removed per one pass, namely:

- Ratio of input and output water,
- Ratio of particles,
- Ratio of oil aging characteristics (neutralization number, interfacial tension, power factor/tan delta, resistivity)

For example, if the system reduces the water content from the input 50 ppm to output 10 ppm per one pass with flow rate 2 m^3 per hour, the time to reduce water to 10 ppm in the transformer of 20 m^3 will take 20 hours. That is equal to processing two volumes of oil in the transformer. If processing equipment removes only 50 % of input contaminant per one pass, the time will be 32 hours. Another important parameter to be monitored is the ratio of flow rate and the volume of oil to be treated. Both of the above mentioned parameters are variable, which is why it is very important to properly arrange on-line monitoring of processing characteristics. The following approach is recommended to optimize the process:

Check the initial condition (concentration contaminants to be removed)
Define the desirable final condition
Define the optimal parameters of processing: flow rate, temperature, and vacuum, which give the maximal rate of removing contaminant
Estimate the time of process
Evaluate the possible life of adsorbents and filter elements to be replaced during the total time of processing
Arrange monitoring of above mentioned basic parameters of processing and auxiliary parameters (temperature, flow rate, vacuum)

7.9.8 Safety issues

The main disadvantage of on-line processing is a risk of failure due to unintentional impairment of the transformer condition.

Recommendations for some safety measures:

- Minimize the risk of reducing the dielectric withstand strength due to possible introduction into the tank of foreign impurities
- The system shall not incorporate a vacuum process while the transformer is on-line.
- Do not allow air to permeate into the tank
- Thoroughly remove air from lines
- Use a bypass system to allow for closed loop tests and adjustment of the machine before actual operation
- Do not allow oil to splash
- Do not allow foam ingress into the tank
- Reduce flow rate to let foam settle
- Do not process oil with excessive foaming tendency. Consider the presence of silicon
- Do not allow particle ingress into the tank
- Consider reliable filtration
- Consider static electrification (particularly important for transformers 160kV and above)
- Do not allow turbulence of oil

Minimize the risk of losing oil during processing.
Consider minimal volume of oil in the transformer, taking into account possible loss of oil during reclamation (replacement of waste clay).
Watch oil level; consider the oil level gauge.
Consider in some case arrangement of a metal standpipe to minimize the loss of oil.
Consider automatic shut down controls.

<u>Minimize the risk of failure during processing of a defective transformer</u>
In general, any defective transformer can be processed without de-energizing if adequate measures to prevent impairment of its condition are taken. However, lack of the necessary diagnostic characteristics often precludes the determination of the real technical condition of the unit.

Two options could be recommended:

- Process only definitely non-defective transformers which meets e.g. IEEE Guide.
- Assess the condition of the transformer prior to processing.

<u>Consider possibility of overheating the transformer during the process</u>
Processes that need high temperature (drying out, insulation regeneration) may affect the thermal behavior of the transformer. Possible loss of paper life should be considered.

Appendix 1 Vocabulary

The meanings of some commonly used terms need to be agreed and used consistently to avoid confusion and ambiguity.

In particular, the terms *failure*, *fault* and *defect* are the three commonest terms used when discussing plant problems, and there is more variation in the usage of these terms than most others. It is argued here that all three terms are required to completely define the various possible situations, and since they describe different attributes there can be considerable overlap in applicability.

The following recommended usage for some commonly used terms and some suggestions for new terms are proposed, and should be read in conjunction with the proposed failure model.

The definitions of terms contained in this document are not intended to embrace all meanings of the terms, but are applicable to the subject treated in this guide. The definitions proposed here are not necessarily consistent with those provided in other guides or standards, e.g. IEC 60050, ANSI/IEEE C57.117-1986, etc.

Failure

The IEC 60050 definition of failure is:

- ***The termination of the ability of an item to perform a required function.***

Notes on this definition state:

1- After failure the item has a fault.

2- "Failure" is an event, as distinguished from "fault," which is a state.

For the present purposes, this definition appears acceptable as far as it goes and the distinction made in Note 2 between event and state is very important, but the implied definition of fault is not consistent with the usage suggested here (see later). The following alternative definition is suggested:

- ***Any situation which requires the equipment to be removed from service for investigation, remedial work or replacement.***

Notes:

1- After a failure the equipment can be described as being in a failed condition.

2- "Failure" is an event, as distinguished from "failed condition," which is a state.

As previously, this proposed definition of *failure* concentrates on the operational consequences of a problem, as required by its priority role in the discussion of reliability, rather than the state of the equipment which caused it.

This definition clearly covers a wide range of problems. In common usage the term *failure* usually implies a major problem, often requiring the replacement of the equipment. However, there is no intention here of restricting the definition to major failures. The common usage of the simple term *failure* can still be retained for major failures, provided the context is clear.

In order to distinguish between major and minor failures in terms on their effect on reliability the following definitions of failure types based on those in C57.117-1986 may be used:

Failure with forced outage

- ***Failure of an equipment that requires its immediate removal from the system. This is accomplished either automatically by the operation of protection equipment or as soon as switching operations can be performed.***

Failure with scheduled/deferred outage

- ***Failure for which the removal of the equipment from service can be deferred to some more convenient occasion, but still requires a change to planned outage programme.***

Major and minor failures can also be differentiated in terms of the degree of remedial work required, either by describing the condition of the equipment, which may be described as being *normal*, *defective* or *faulty*, or by the use of the terms *restore* or *continue failure* (see later). Minor faults which do not require significant remedial work are often referred to by some other term, e.g. *trouble*. The problem with such a terminology arises when intermediate examples have to be classified.

Fault

The IEC 60050 definition is:

- ***The state of an item characterised by inability to perform a required function, excluding the inability during preventive maintenance or other planned actions, or due to lack of external resources.***

This definition does not seem particularly useful in the context of life management and the proposed failure model since it ties the term too closely to failure. An alternative definition is proposed:

- ***Any deterioration beyond normal wear or aging.***

Notes:

1- A fault results in some non-reversible deterioration.

2- A fault is expected to have some impact on the short term reliability of the equipment.

For example, a localised hotspot resulting in excessive local insulation aging would be considered a fault, but aged insulation resulting from service loading would not. Any discharge activity inside the transformer would also be considered a fault. A fault would normally only become apparent once it had developed to the point that it caused some abnormal change in measured parameters e.g. increases in dissolved gases. A fault therefore corresponds to a real problem with a transformer which is expected to have a significant impact on life expectancy. Therefore, the existence of a fault is expected to increase the probability of a failure, while a major failure is normally expected to occur as the result of the development of a fault. However, according to the definitions proposed here, a fault can also occur without a failure and vice versa, contrary to the IEC definition of fault.

Defect

- ***Any non-conformance to normal condition requiring some investigative or remedial action.***

Notes:

1- If there is sufficient uncertainty about whether the condition of the equipment is normal, it should be classified as defective.

Note that there is no IEC 60050 definition for this term. The IEEE C57.117-1986 definition of ***'Imperfection or partial lack of performance that can be corrected without taking the transformer out of service'*** is a sub-set of the above and is equivalent here to *defect* without *failure*.

The above definition is very wide, covering anything from a very minor problem with no significant impact on the life expectancy of the equipment, e.g. a broken sight glass on a conservator, to a major problem, e.g. through-fault failure. The main use of the term *defect* is related to maintenance reporting, but may be extended to cover any problem requiring rectification, e.g. excess moisture.

In an attempt to illustrate the differences between the proposed definitions of *failure*, *fault* and *defect* the following examples are provided:

(i) An incident in which a Buchholz oil surge was caused by all oil pumps starting simultaneously would be classified as a *defect* but not a *fault*, and would also be counted a *failure* if it caused the transformer to trip during normal service.

(ii) If a confirmed unusual DGA result was obtained for a transformer, then this would be classified as a *defect* since it warrants further investigation. If the DGA result was subsequently determined to be caused by some abnormal deterioration within the transformer, rather than simply a response to unusual conditions, then the *defect* would also be a *fault*. If the transformer had to be removed from service to investigate the DGA result, then this would be classified also as a *failure*.

Reliability

- ***The probability that the equipment will remain in service without a failure occurring.***

Note: Reliability considerations apply throughout the total life of a transformer

End of life

- ***The point at which a transformer should no longer remain in service because of an actual or potential failure of function which is uneconomic to repair or because it is no longer sufficiently reliable.***

Notes:

1- A transformer could have reached an end of life state without having failed and without its true condition having become apparent.
2- In general, factors which determine the end of life of a transformer can be categorised under three headings: strategic, economic, and technical. End of life may be dictated by any one factor or by any combination [2].

By definition, 'end of life' always implies an actual or potential failure, but a failure only means 'end of life' in certain circumstances. For instance, if a transformer had to be removed from service simply because its rating is no longer adequate for the loadings arising at the site, this would have to be described as a failure but the transformer would not be described as having reached its end of life.

Restore Failure

- ***A major end of life failure which requires the transformer to be removed from service for repairs or replacement. Where repairs are required, these involve major remedial work, usually requiring the***

transformer to be removed from its plinth and returned to the factory. The chief characteristic of a restore failure is that its repair would result in the transformer being returned to a substantially 'as new' state.

(For example, a three phase rewind would be considered a restore failure, while a single phase rewind of a three phase transformer would not. End of life failures of components are not in themselves considered restore failures. Therefore, a bushing failure which resulted in the loss of the transformer would be considered a restore failure, otherwise it would be considered a continue failure (see below). Note that a restore failure as defined here would often be described in common usage as simply a 'failure', but not all 'failures' would be classified restore failures as defined here.)

Continue Failure

- ***A failure which requires the transformer to be removed from service for repairs which can usually be carried out on site, and do not involve restoring the transformer to a substantially 'as new' condition.***

(A tap-changer or bushing fault, or any other component fault, which did not cause damage to the windings would be considered a continue failure.)

Failure mode

- ***A description of a failure which illustrates what actually happened when the failure occurred.***

Failure mechanism

- ***A description of the physical processes leading up to a failure.***

Failure cause

- ***The circumstances during design, manufacture or application that led to the failure.***

Contributing cause

- ***A factor which by itself would not have resulted in a failure, but which had some influence on the progression to failure.***

Condition

- ***An expression of the state of health of an equipment which takes into account its aged state as well as any inherent faults.***

Notes:

1- Normally used in the context of the perceived condition as determined from the results of measurements, which may not be a complete and accurate representation of the actual condition.

2- The condition of an equipment is normally taken as indicative of its expected reliability.

Condition monitoring

- ***Any repetitive observations or measurements related to the perceived condition of the equipment for the purpose of detecting the onset of and monitoring the development of faults.***

Notes:

1- These measurements would preferably, but not necessarily be made *on-line*, i.e. with the transformer in service.

Continuous monitoring

- ***On-line monitoring carried out as frequently as possible, i.e. as soon as one cycle of measurements is complete the next is started, or triggered by some event.***

Notes:

1- The cycle period would normally allow several measurement cycles per day.

2- It is usual for continuous monitoring to be a fully automated process involving the repetitive reading of attached sensors and to include some alarm function to warn when a measured value is outside a pre-set limit.

Condition assessment

- ***A comprehensive assessment of the condition of an equipment taking into account all relevant information, e.g., design information, service history, operational problems, results of condition monitoring and other chemical and electrical tests.***

The assessment may require an outage for *off-line* tests.

Diagnostic test

- ***A test carried out for the purpose of investigating a fault or failure, e.g. to determine the nature and location of the fault, with a view to assessing its likely cause, the likelihood of it developing further, the likely consequences for the expected reliability of the transformer and the prospects of making effective repairs.***

Indication (of a fault)

- ***Indirect evidence for the existence of a fault.***

Through fault

- ***An abnormal system event outside the equipment which causes high fault currents to flow through the transformer.***

Notes:

1- This is a commonly used term describing an event affecting, not the state of, equipment. The meaning of *fault* here does not follow the definition given above.

Appendix 2 Failure report form

1. Equipment description

1.1 Type of equipment:

Transformer / Shunt reactor / Series reactor / Phase shifting transformer or quadrature booster

1.2 Application (for transformers):

Generator step-up / Other power station / Transmission / Synchronous compensation / Distribution / Other (please specify)

1.3 Highest voltage for equipment:

1 < 100 kV 2 100 - 299 kV 3 300 - 419 kV 4 > 420 kV

1.4 MVA

1 < 60 MVA 2 60 - 149 MVA 3 150 - 400 MVA 4 > 400 MVA

1.5 Year of manufacture

19??

1.6 Core type

1 Core form 2 Shell form

1.7 Number phases in tank

1 Three phase 2 Single phase

1.8 Tap-changer

1 Combined selector and diverter switches in main tank oil
2 Combined selector and diverter switches in separate compartment from main tank
3 Selector switches in main tank oil with separate compartment for diverter switch
4 Separate compartments for both selector and diverter switches
5 Off circuit
6 None

1.9 Cooling system

1 ONAN 2 ONAF 3 OFAF 4 OFWF

O = Oil; N = Natural convection; A = Air; F = Forced circulation

1.10 Oil conservation system

1 Free breathing via silica gel breather
2 Free breathing via another device (e.g. Drycol)
3 Sealed from atmosphere by elastic seal
4 Sealed from atmosphere by nitrogen blanket
5 Other (to be specified)

1.11 Over voltage protection

1 Spark gaps
2 Surge arresters
3 Both
4 None

1.12 Neutral earthing

1 Insulated from earth
2 Indirectly earthed (via resistor or inductor)
3 Directly earthed

2. Operational history

2.0 Service age to failure

1 < 3 years   2 3 - 10 years   3 10 - 25 years   4 25 - 40 years
5 > 40 years

2.1 Typical loading

1 < 0.5 pu   2 0.5 - 0.8 pu   3 > 0.8 pu   4 Variable
5 Not known

2.2 Loading immediately prior to failure

1 < 0.5 pu   2 0.5 - 0.8 pu   3 > 0.8 pu   4 Variable
5 Not known

2.3 Maintenance history

Please specify

2.4 Unusual events prior to failure

Please specify

2.5 Condition monitoring and assessment

Test	Monitoring before failure	Diagnosis after failure
1 Dissolved Gas Analysis (DGA)		
2 Furfuraldehyde Analysis (FFA)		
3 Moisture in oil		
4 Other oil tests (please specify)		
5 Power factor/tan delta		
6 Leakage reactance/impedance		
7 Magnetising currents		
8 Turns ratio		
9 Winding resistances		
10 Insulation resistances		
11 Frequency Response Analysis (FRA)		
12 Moisture level in paper insulation (e.g. water heat run, RVM - please specify)		
13 Discharge detection and location		

Identify which tests have been used on the equipment in question, whether these indicated a problem prior to the failure, and their usefulness in diagnosing the problem. Please supply test results from before and after failure, together with equivalent data from similar ‘normal’ units if possible.

3. Description of failure

3.1 Special failure type

a Streaming electrification
b Through fault
c Switching resonance
d Geomagnetically induced
e Over-fluxing

Indicate if failure was one of the above special types.

3.2 Indication of failure

How did the failure become apparent? (Protection/Alarm/Trip/Monitor indications).

3.3 Investigation of failure

What investigation was carried out? (Diagnostic testing/Inspection/Strip-down).

3.4 Location of failure

What parts of the equipment were found to be involved in the failure?

				Tick
Winding	Function	HV / Series		
		LV / Common		
		Tapping		
		Tertiary/Stabilising		
	Winding position	Inner		
		Middle		
		Outer		
	Physical location within winding	Axial	Top	
			Middle	
			Bottom	
		Radial	Inner	
			Middle	
			Outer	
		Part	Disc	
			Layer	
			Other	
	Electric location	Line end		
		Middle		
		Neutral end		

Location of failure (cont.)

Insulation	Major	Phase-to-phase		
		Winding-to-winding		
		Winding-to-ground		
	Minor	Turn-to-turn		
		Disc-to-disc		
		Layer-to-layer		
		Across taps		
		Lead		
		Core-to-ground		
	Material	Wrapping		
		Cylinder		
		Spacers		
		Sticks		
		Liquid		
		Gas		
Winding impulse stress control		Line end		
		Neutral end		
Inter-winding shield		Shield		
		Ground connection		
Winding connections		Between windings		
		Tap leads		
		To bushings		

Location of failure (cont.)

Magnetic circuit	Location	Limb	Outer	
			Centre	
		Yoke	Top	
			Bottom	
	Material	Lamination		
		Interlaminar insulation		
		Cooling spacers		
	Associated parts	Core ground		
		Winding Flux Diverters		
		Tank shields		
Mechanical structure	Clamping	Coil		
		Core		
	Coil blocking			
	Lead support			
Tank				
Bushing	Porcelain			
	Core			
	Helmet			
	Draw lead			
Tap-changer	Selector			
	Diverter			
	Drive motor and couplings			
	Control system			

Notes:
i. Indicate location of faulty items by entering symbols in the above table.
ii. If there are two equivalent descriptions which are relevant, e.g.
Physical location - Middle
Electrical location - Line end
then both should be identified with the same symbol.

iii. Identify all affected items using different symbols.

3.5 Nature of failure

Indicate the manner in which the final failure occurred.

Dielectric	Partial discharge		
	Tracking		
	Flashover		
Electrical	Open circuit		
	Short circuit		
	Poor joint		
	Poor contact		
	Ground deterioration		
	Floating potential		
Thermal	General overheating		
	Localised hotspot		
Physical chemistry	Contamination	Moisture	
		Particles	
		Gas	
	Corrosion		
Mechanical	Bending		
	Breaking		
	Displacement		
	Loosening		
	Vibration		

3.6 Causes of failure

Inherent deficiency	Inadequate specification		
	Inadequate design		
Inherited deficiency	Inherent material defect		
	Improper factory assembly		
	Improper site assembly		
	Improper maintenance		
	Improper repair		
	Improper adjustment		
Improper application			
System event	Overload		
	Load removal		
	Over-voltage		
	Resonance		
	Short circuit		
External event	Vandalism		
	Impact of external object		
Environmental	Lightning		
	High ambient		
	Low ambient		
	Rain		
	Water ingress		
	Wind		
	Seismic		
	Geomagnetic		
Abnormal deterioration			

Indicate the three most important contributory causes (enter 1, 2 and 3).

3.7 Initiation of failure

What caused the failure to occur when it did ?

3.8 Aging aspects

In what respects did ‘aging’ or ‘wear-out’ contribute to the failure ?

3.9 Pre-existing fault

What indications were there of any pre-existing faults prior to the failure ?

3.10 Initiation of pre-existing fault

What initiated the pre-existing fault ?

3.11 Other relevant information

Please give any other information considered to be relevant to the failure.

Appendix 3 Catalog of defects and faults

Failure Code*	Description
CB1	Bushing, aged insulation
CB2	Bushing, contamination, internal surface
CB3	Bushing, contamination, external surface
CB4	Bushing, contamination, moisture ingress
CB5	Bushing, aging of oil
CO1	Oil, oxidation and aging products
CO2	Oil, moisture ingress
CO3	Oil, abnormal oxygen / nitrogen content (depends on breathing system)
CO4	Oil, particle contamination
CO5	Oil, gases
CS1	Selector, tap-changer, contact deterioration
CD1	Diverter, tap-changer, contact deterioration
CT1	Tank and accessories, leaks
CT2	Tank and accessories, corrosion external and internal
CW1	Major insulation, contamination by sludge
CW2	Winding and major insulation, excessive moisture
CW3	Winding and major insulation, surface contamination
CW4	Winding, aged insulation
CW5	Winding, oil particles contamination
DB1	Bushing, dielectric problem, e.g. tracking
DW1	Winding, partial discharge
DW2	Major insulation, creeping discharge / tracking along surface of insulation
DW3	Winding and leads, inter-phase or inter-winding partial discharge
DW4	Winding and leads, phase to earth partial discharge
DW5	Winding and leads, streaming electrification
DW6	Winding, inter-turn problem
DW7	Winding, inter-strand insulation problem
DW8	Winding, system overvoltage, lightning
MB1	Bushing, connections problem
MC1	Core, open circuit in grounding leads/shield
MD1	Diverter, tap-changer, mechanical problem, e.g. shaft, cam gear, relay, bearing
MS1	Selector, tap-changer, mechanical problem, e.g. shaft, cam gear, relay, bearing
MT1	Tank, arcing and sparking of shield
MW1	Winding, loose clamping
MW2	Winding, axial movement, i.e. telescoping
MW3	Winding, radial movement
MW4	Winding, spiral movement
MW5	Winding and leads, mechanical disruption of end support /end insulation structure
MW6	Winding, vibration
TB1	Bushing core overheating / thermal runaway due to excessive dielectric losses
TC1	Core, frame to earth circulating currents
TC2	Core, heating and circulating currents within core
TS1	Selector, tap changer, pyrolytic carbon growth
TT1	Tank, stray leakage flux heating of components (includes over-fluxing and GIC)
TW1	Winding, general overheating / cooler problem
TW2	Winding and leads, overheating/ cooling arrangement problem
TW3	Winding, localized hotspot
TW4	Winding, overheated joint

*See next page for "Legend for Code"

Legend for Code

First letter - nature of the defect or fault, transformer function affected	Second letter - location
T- Thermal D- Dielectric M- Mechanical C- Contamination or aging	B- bushing C- core D- diverter, on-load tap changer O- oil S- selector, tap changer (on-load or off-load) T- tank and accessories W- winding, major insulation and leads

Appendix 4 Summary of failure reports

Application	Voltage, MVA Ranges and Cooling	OLTC	Indication of Failure	Failure Cause	Failure Location and Failure Code	Condition Monitoring, Assessment and Post-Failure Tests
Transmission	100-299kV, 60-149MVA, 3*f*, ONAF, 1972	Yes	Protection operation	Incorrect switching operation, aged insulation	Line end of the common winding, CW4	DGA, FFA, moisture in oil, turns ratio, winding resistance, insulation resistance
Generator Step-Up	100-299kV, 150-400MVA, 3*f*, OFWF, 1964	Yes	Buchholtz alarm	Vibration, loose windings, localised hotspots	Bottom of low voltage winding, MW6 &TW3	DGA, moisture in oil. leakage reactance, turns ratio, winding resistance, insulation resistance
Transmission	100-299Kv, <60MVA, 3*f*, ONAN, 1990	Yes	Protection operation	Contamination, no oil filter for OLTC	Between phases of the OLTC, CO4	DGA, FFA, moisture in oil, power factor/tan delta, leakage reactance, turns ratio, insulation resistance, moisture in paper
Generator Step-Up	300-419kV, >400MVA, 3*f*, OFWF, 1970	Yes	Protection operation	No apparent reason	Outside of high voltage winding at top, DW6	DGA, FFA, moisture in oil, particles
Generator Step-Up	300-419kV, >400MVA, 3*f*, OFWF, 1972	Yes	Protection operation	Localised hotspot, inadequate design of 22kV winding	High voltage to low voltage windings to earth, TW1	DGA, moisture in oil
Transmission	300-419kV, 150-400MVA, 3*f*, OFAF, 1966	No	Buchholtz alarm	Inadequate connection	Bushing lead to winding conductor connection, TW4	DGA, bushing power factor/tan delta
Transmission	100-299kV, 60-149MVA, 1*f*, ONAF, 1969	Yes	Buchholtz alarm	High resistance in change-over selector	Change-over selector, TS1	DGA, turns ratio, winding resistance
Transmission	100-299kV, 150-400MVA, 3*f*, OFAF, 1984	Yes	Buchholtz trip	Localised hotspot, inadequate design/assembly	Potential rings of low voltage winding, TW3	DGA, moisture in oil, power factor/tan delta, leakage reactance, magnetising current, turns ratio, winding resistance, insulation resistance
Generator Step-Up	100-299kV, 150-400MVA, 3*f*, OFWF, 1969	No	Buchholtz trip	Inadequate short circuit strength	Low voltage winding, MW5	DGA, moisture in oil, power factor/tan delta, leakage reactance, magnetising current, turns ratio, winding resistance, insulation resistance
Auxiliary Power	100-299kV, <60MVA, 3*f*, ODAF, 1982	No	Buchholtz alarm	Material defect (interlaminar insulation)	Core, TC2	DGA, FFA, moisture in oil, infrared, power factor/tan delta, leakage reactance, magnetising current, turns ratio, insulation resistance, partial discharge
Generator Step-Up	100-299kV, 150-400MVA, 3*f*, ONAF, 1971	Yes	Protection operation	Inadequate short circuit strength	High voltage winding, MW3	DGA, moisture in oil, turns ratio, winding resistance, magnetising current
Transmission	300-419kV, >400MVA, 3*f*, OFAF, 1974	Yes	Protection operation	Lightning and subsequent through-fault	Tertiary winding, DW8	DGA, Hydran, moisture in oil, power factor/tan delta, magnetising current, turns ratio, winding resistance, insulation resistance, FRA

Appendix 5 Failure guide identity card

1 Problem title
(As per the Catalogue of Defects and Faults)

2 Category
(As per the Failure Report Form)

3 Description of consequences of problem
(What are the consequences of continued development of the problem. Will a failure occur ? What happens ?)

4 Key phrases

5 Usual indications of failure
(How does the failure ‘announce’ itself ?)

6 Circumstances of failure
(What causes the failure to occur when it does ? - the TRIGGER)

7 Conditions for failure
(What allows the failure to occur - What is the deficiency of condition ?)

8 Deterioration process
(How does the deficiency of condition arise ?)

9 Initiating and intermediate defects
(What defects/faults preceded final failure and what caused them ?)

10 Aging processes and agents of deterioration
(What aging processes are involved and contribute to the development of the defective condition ?)

11 Timescales
(What are the expected timescales from initiation to the development of a critical condition ?)

12 Detection of defective condition
(How might defective condition be detected, diagnosed and distinguished from normal condition ? What are the recommended condition assessment tests and key measurement parameters/indicators ?)

13 Recommended Caution and Alarm levels
What level indicates with a reasonable degree of confidence that the defective condition exists (**Caution** level) and what level indicates that an imminent failure or serious deterioration can be expected (**Alarm** level) ? Refer to Tables 6-1 and 6-2)

14 Prevention and mitigation of defective condition
(What actions, design changes or operational restrictions short of operations on the transformer would prevent this defective condition arising in the first place or might slow down or even stop the deterioration process ?)

15 Remedial work
(Once the defective condition is recognised, what operations on the transformer or modifications to the design can be carried out to slow down, stop or even reverse the deterioration process ?)

16 Special considerations
(For which design types, operating conditions, etc. is this defect/fault/failure particularly important ?)

17 Particular problems
(What practical difficulties, lack of knowledge or deficiency of techniques currently hinder the successful management of this problem ?)

18 References
(Include references to well documented examples of the problem concerned, recommended test techniques and remedial work)

Appendix 6 Example of failure guide identity card

1 Problem title
(As per the Catalogue of Defects and Faults)
MW1 Winding, loose clamping

2 Category
(As per the Failure Report Form)
Mechanical/loosening

3 Description of consequences of problem
(What are the consequences of continued development of the problem. Will a failure occur ? What happens?)
Electrical failure of the winding(s) during a bus fault

4 Key phrases
Loose windings Clamping support structure Turn to turn fault Section to section fault

5 Usual indications of failure
(How does the failure ‘announce’ itself ?)
Operation of the differential protection and sudden pressure relay

6 Circumstances of failure
(What causes the failure to occur when it does ? - the TRIGGER)
An external bus fault

7 Conditions for failure
(What allows the failure to occur - What is the deficiency of condition ?)
Loose windings and coil clamping structure due to past repeated faults and shrinking or permanent deformation of the radial spacers and end clamping.

8 Deterioration process
(How does the deficiency of condition arise ?)
Frequent faults Inadequate clamping of the windings. Improper material selection.

9 Initiating and intermediate defects
(What defects/faults preceded final failure and what caused them ?)
Loosening of the windings and/or mechanical winding damage.

10 Aging processes and agents of deterioration
(What aging processes are involved and contribute to the development of the defective condition ?)
Winding shrinkage and permanent deformation of the coil end insulation and support structure.

11 Timescales
(What are the expected timescales from initiation to the development of a critical condition ?)
Depends on the frequency and magnitude of the bus faults: estimate is 15 to 20 years.

12 Detection of defective condition
(How might defective condition be detected, diagnosed and distinguished from normal condition ? What are the recommended condition assessment tests and key measurement parameters/indicators ?)
FRA techniques and vibration analysis.

13 Recommended Caution and Alarm levels
(What level indicates with a reasonable degree of confidence that the defective condition exists (**Caution** level) and what level indicates that an imminent failure or serious deterioration can be expected (**Alarm** level) ? Refer to Tables 6-1 and 6-2)
Not established.

14 Prevention and mitigation of defective condition
(What actions, design changes or operational restrictions short of operations on the transformer would prevent this defective condition arising in the first place or might slow down or even stop the deterioration process ?)
Use of higher density insulation and higher clamping pressures during manufacture. Use of spring dashpot assemblies on the coil clamping structure.

15 Remedial work
(Once the defective condition is recognised, what operations on the transformer or modifications to the design can be carried out to slow down, stop or even reverse the deterioration process ?)
Periodic reclamping and repacking of the windings to restore clamping pressure.

16 Special considerations
(For which design types, operating conditions, etc. is this defect/fault/failure particularly important ?)
All older transformers are suspect, especially units that have been exposed to a significant number of faults, even low level faults.

17 Particular problems
(What practical difficulties, lack of knowledge or deficiency of techniques currently hinder the successful management of this problem ?)
Time and resources to check all of the older transformers using FRA and vibration techniques.

18 References
(Include references to well documented examples of the problem concerned, recommended test techniques and remedial work)

Appendix 7 Results of questionnaire

Component	Condition	Agent of Degradation	Highly Effective Tests (Number of responses, if more than one, shown in parenthesis)
Winding	Dielectric Strength	Water	Moisture in oil (9) Power factor/tan delta (4) Insulation resistance (3) Moisture level in paper (2)
		Oil contamination	Power factor/tan delta (6) DGA (4) Moisture in oil (4) Breakdown voltage (3) No answer (6)
		Surface contamination	Insulation resistance (3) Power factor/tan delta (2) No answer (12)
		Shorted turns	Turns ratio (8) Magnetizing current (7) Winding resistance (5) DGA (3)
	Mechanical strength	Radial distortion Axial distortion Twisting	Leakage reactance (6) FRA (2)
	Aging	High losses Bad cooling Bad joints	DGA (10) FFA (5) Moisture in oil (2)
	Defective electrical circuit-shorted turns	Mechanical damage of wire insulation	Turns ratio (5) Magnetizing current (3) DGA (2) Winding resistance (2)
Main insulation	Dielectric strength	Switching surge or transient overvoltage	DGA (2) Power factor/tan delta (2) Insulation resistance (2) Partial discharge (2) No answer (11)
		Water	Moisture in oil (4) Power factor/tan delta (2) Partial discharge (2) No answer (6)
		Oil contamination	Power factor/tan delta (4) Moisture in oil (3) DGA (2) Insulation resistance (2) No answer (9)
		Contamination of surface	Power factor/tan delta (2) Insulation resistance (2) No answer (14)
		Air/gas content	DGA (6) No answer (10)

Component	**Condition**	**Agent of Degradation**	**Highly Effective Tests (Number of responses, if more than one, shown in parenthesis)**
Oil	Dielectric strength	Water	Moisture in oil (11) DGA (3) Power factor/tan delta (2) Insulation resistance (2)
		Particles	Particle count (4) Breakdown voltage (3) No answer (8)
		Aging products	Neutralization value (2)
		Sludge	No answer (9)
		Gases	DGA (15) Continuous monitor (2) No answer (5)
Leads	Dielectric strength	Switching surge or transient overvoltage	Insulation resistance (3) DGA (2) No answer (18)
	Aging	High losses Bad cooling Bad joints	DGA (2) No answer (15)
	Connections	Joint defect	Winding resistance (6) DGA (5) No answer (5)
	Mechanical	Break of clamping support, etc.	Visual (2) No answer (14)
Core	Overheating	Circulating current, head grounding, etc.	DGA (15) Magnetizing current (6) Insulation resistance (4) FFA (3) Power factor/tan delta (2) Dissolved metals by Atomic Absorption Spectroscopy or ICP analysis
	Sparking	Open-circuit in grounding leads	DGA (11) Insulation resistance (3)
On-load tap changer	Dielectric strength	Switching surge or transient overvoltage	Insulation resistance (2) No answer (16)
	Overheated connection (contacts)	Contact continuity, defects, pressure, alignment	DGA (5) Winding resistance (5) Turns ratio (3)
	Mechanical wear-out	Controls, motors, mechanisms	Inspection (4) No answer (9)
		Bad joints	Winding resistance (4) DGA (2) Turns ratio (2) No answer (15)
	Gases and/or carbon migrating to the main tank	Seal or barrier broken	DGA See IEC 60599
Bushing	Dielectric strength	Local defect in core Core surface contamination (internal)	Power factor/tan delta (8) DGA (4) Insulation resistance (2) No answer (6)

Component	Condition	Agent of Degradation	Highly Effective Tests (Number of responses, if more than one, shown in parenthesis)
		Water Porcelain contamination Oil contamination	Power factor/tan delta (4) DGA (4) No answer (8)
	Current integrity	Bad contact	Infrared (5) DGA (3) Winding resistance (2) No answer (12)
Tank and associated devices	Conservation system		Visual (7) No answer (12)
	Inert air system		Visual (4) No answer (20)
	Gauges		Visual (11) No answer (9)
	Fault pressure relay		Functional test (11) No answer (11)
	Cooling system Heat exchanger Fans Pumps		Visual (8) No answer (11)
	Monitoring system		Operational test (4) No answer (20)

Appendix 8 Recommendations and evaluations of tests and groups of tests for defects and faults

LEGEND FOR CODE

SENSITIVITY OF TESTS

First Letter – Nature of the defect or fault, function affected	Second letter – component
T – Thermal D – Dielectric M – Mechanical C – Contamination or aging	B – Bushing C – Core D – Diverter, tap changer O – Oil S – Selector, tap changer (on-load and off-load) T – Tank and accessories W- Winding, major insulation and leads

LEGEND FOR INTERPRETATION

1	Good identification
2	Fair identification
3	Good detection and rough identification
4	Fair detection
5	Rough detection
6	Complementary test

NOTE: The following table is sorted first by Defect/Fault Code and then by Component Code. Using Microsoft Word, it could also be sorted first by Component and then by Defect. To do this, place the cursor inside the table, select Table/Sort, and then specify "Sort by" Component and "Then by" Defect.

Defect/ Fault Code	Component Code	Description	INDIVIDUAL TESTS (Recommended test or group of tests noted by asterisks)	INTERPRETATION/ SENSITIVITY OF INDIVIDUAL TESTS	METHODOLOGY AND LIMITATIONS	Ref.
C	B	1-Aged insulation	Power factor/tan delta* (1) (IEC 137) DGA* (2) (IEC 567) Partial discharge	5 6 4	Power factor/tan delta part of routine test program. DGA only performed if not a risk in sampling and re-sealing the bushing. Sampling restrictions due to limited oil volume. Compare results of power factor/tan delta tests between different phases and with commissioning tests.	

Defect/ Fault Code	Component Code	Description	INDIVIDUAL TESTS (Recommended test or group of tests noted by asterisks)	INTERPRETATION/ SENSITIVITY OF INDIVIDUAL TESTS	METHODOLOGY AND LIMITATIONS	Ref.
C	B	2-Internal surface	Insulation resistance (1) Power factor/tan delta* (2) (IEC 137) DGA * (3) (IEC 567)	2 5 5	Power factor/tan delta and IR would be normal test supported by DGA where considered appropriate. Sampling restrictions due to limited oil volume. Compare results of power factor/tan delta tests between different phases and with commissioning tests.	
C	B	3-External surface	Power factor/tan delta* (IEC 137) Visual Insulation resistance	6 3 4	Routine test. Compare results of power factor/tan delta tests between different phases and with commissioning tests. Limitation: Separation of bushing from transformer	
C	B	4-Moisture ingress	Power factor/tan delta* (1) (IEC 137) DGA (water content) (2) (IEC 567) Water heat run (3) Power factor/tan delta C_1 (at higher temperature) Power factor/tan deltaC_1 and C_2 tests vs. temperature*	1 2 2 5	Further test would be performed after high Power factor/tan delta reading or suspected moisture entry (e.g., cracked gauge glass). Compare results of power factor/tan delta tests between different phases and with commissioning tests.	[100]
C	B	5-Aging of oil	Power factor/tan delta C_2 vs. temperature* Oil tests* DGA	5 1 6	Reliable only if C_2 is the capacitance between the last capacitive layer and the flange.	[100]
C	D	1-Deterioration, wear	DGA Winding resistance Turns ratio Visual (internal, after de-energized) Oscillographic method [101]	4 4 6 2 1	Limitation: Less suitable for detecting wear of contacts	

Defect/ Fault Code	Component Code	Description	INDIVIDUAL TESTS (Recommended test or group of tests noted by asterisks)	INTERPRETATION/ SENSITIVITY OF INDIVIDUAL TESTS	METHODOLOGY AND LIMITATIONS	Ref.
C	O	1-Oxidation and aging products	DGA (1) Resistivity (2) IFT Neutralization number Polar compounds IEC-296 IEC-422 Power factor/tan delta	3 1 1 1		
C	O	2-Moisture ingress	Moisture in oil* DGA Power factor/tan delta	1 5	Temperature of oil should be measured in order to determine % saturation.	
C	O	3-Abnormal oxygen/nitrogen content (depends on breathing system)	DGA*	1		
C	O	4-Particle contamination	Particle count* Breakdown voltage Electric or acoustic PD Pump bearing monitor*	2 3 3 6	If transformer has oil pumps, particle count should be made after they have been turned on.	[100]
C	O	5-Gases	DGA Continuous monitor*	1 1		
C	S	1-Deterioration, wear	DGA Winding resistance Turns ratio Oscillographic method [101]	4 3 6 1	Limitation: Less suitable for detecting wear of contacts. Some experience that 100 amps measuring current is needed for satisfactory result	
C	T	1-Leaks	Visual DGA Neutralization number Dissolved metals	2 4	DGA will detect presence of oxygen and nitrogen.	

Defect/ Fault Code	Component Code	Description	INDIVIDUAL TESTS (Recommended test or group of tests noted by asterisks)	INTERPRETATION/ SENSITIVITY OF INDIVIDUAL TESTS	METHODOLOGY AND LIMITATIONS	Ref.
C	T	2-Corrosion	Visual	3		
C	W	1-Contamination by sludge	IFT Acid Neutralization number Oxidation stability Sludge precipitation Power factor/tan delta FFA	6 2 2 5 6		
C	W	2-Excessive moisture	Moisture in oil Power factor/tan delta Water heat run* Moisture level in paper* Estimate through Power factor/tan delta vs t ^{o}C* RVM	3 2 4 6 5 3	Moisture in oil should measure dissolved and bounded water. Water heat run test in Case 1 of reference #100 was for 54 hours with oil temperature of 65^{o} C. Power factor/tan delta and RVM spectrum can be influenced by ion conductivity of oil.	[100] [102]
C	W	3-Surface contamination	Estimate through power factor/tan delta vs t^{o}C* Electric or acoustic PD Insulation resistance Power factor/tan delta	5 1 1 1		[100]
C	W	4-Aged insulation	DGA* FFA* Moisture in oil DP*	2 5 1 4	For DGA, CO and CO_2 are the key gases. Furan analysis will validate if CO is from paper. DP requires internal access-paper samples limited to accessible parts of winding.	[100]

Defect/ Fault Code	Component Code	Description	INDIVIDUAL TESTS (Recommended test or group of tests noted by asterisks)	INTERPRETATION/ SENSITIVITY OF INDIVIDUAL TESTS	METHODOLOGY AND LIMITATIONS	Ref.
C	W	5-Oil particle contamination	Breakdown voltage Particle count Estimate through power factor/tan delta vs t^{o}C Electric or acoustic PD Dissolved metals	2 4 5 1		[100]
D	B	1-Tracking	Power factor/tan delta* DGA* Insulation resistance Change in power factor/tan delta, losses, and C_1* Change in power factor/tan delta, leakage current and sum current* Partial discharge	5 3 1 3 6 3		[100]
D	W	1-Partial discharge	DGA* (1) Electric or acoustic PD* (2)	2 2		
D	W	2-Creeping discharge/tracking along surface	DGA* (1) Electric or acoustic PD* (2)	4 4	For ON cooling, oil samples from different locations may assist in locating the fault.	
D	W	3-Partial discharge (inter-phase or inter-winding)	DGA* (1) Electric or acoustic PD* (2)	4 4	For ON cooling, oil samples from different locations may assist in locating the fault.	
D	W	4-Partial discharge (phase to earth)	DGA* (1) Electric or acoustic PD* (2)	4 4	For ON cooling, oil samples from different locations may assist in locating the fault.	
D	W	5-Streaming electrificaion	DGA* Electric or acoustic PD*	4 4		

Defect/ Fault Code	Component Code	Description	INDIVIDUAL TESTS (Recommended test or group of tests noted by asterisks)	INTERPRETATION/ SENSITIVITY OF INDIVIDUAL TESTS	METHODOLOGY AND LIMITATIONS	Ref.
D	W	6-Inter-turn problem	Turns ratio* Magnetizing current* Winding resistance DGA Electric or acoustic PD* FRA	2 1 3 4 4 1	Transformer usually tripped from protection for this type of fault	
D	W	7-Inter-strand insulation problem	DGA* (1) Electric or acoustic PD* (2) DC resistance* (3)	5 6 3	DGA may not always detect cellulose involvement, fault will only be evident when on load. Acoustic transducers may be able to detect gas bubbles and help in locating the fault area.	[102] [103] [104]
M	B	1-Connections problem internal	Infrared* DGA Winding resistance	6 1 4	Infrared if external, DGA if internal	
M	C	1-Open circuit in grounding lead/shields	DGA Insulation resistance* Partial discharge	4 1 6		[108]
M	D	1-Mechanical problem	Visual On-line monitor: motor amps at 2 kHz, relay timing*	3 6		
M	S	1-Mechanical problems	Visual On-line monitor: motor amps at 2 kHz, relay timing*	3 6		
M	T	1-Arcing and sparking of shield	DGA* Acoustic PD	4	Occurrence of through-faults may cause damage to shielding.	[100] [105]
M	W	1-Loose clamping	Leakage reactance* Capacitance change Vibration FRA	5 1 2 4	Single phase reactance measurement recommended.	[100]

Defect/ Fault Code	Component Code	Description	INDIVIDUAL TESTS (Recommended test or group of tests noted by asterisks)	INTERPRETATION/ SENSITIVITY OF INDIVIDUAL TESTS	METHODOLOGY AND LIMITATIONS	Ref.
M	W	2-Axial movement, i.e., telescoping	Leakage reactance* FRA/Transfer function analysis*	5 4	Single phase reactance measurement recommended.	[102]
M	W	3-Radial movement	Leakage reactance* FRA/Transfer function analysis*	5 4	Single phase reactance measurement recommended.	
M	W	4-Spiral movement	Leakage reactance* FRA/Transfer function analysis*	5 4	Single phase reactance measurement recommended.	
M	W	5-Mechanical disruption of end support/end insulation structure	Visual	1		
M	W	6-Vibration	DGA* Sound level measurement FRA	4 4 6		[102]
T	B	1-Core overheating, thermal runaway due to excessive dielectric losses	Power factor/tan delta* DGA power factor/tan delta C_1 vs temperature* power factor/tan delta C_1 reduction at 10kV power factor/tan delta C_1 imbalance current Infrared	4 3 4 3 4 3	Key gases for DGA are CO and CO_2	[100]
T	C	1-Frame to earth circulating currents	DGA* Magnetizing current Insulation resistance* FFA Power factor/tan delta	5 2 5 1 6		[106]
T	C	2-Circulating currents within core	DGA* Loss measurement	4 6		[106]

Defect/ Fault Code	Component Code	Description	INDIVIDUAL TESTS (Recommended test or group of tests noted by asterisks)	INTERPRETATION/ SENSITIVITY OF INDIVIDUAL TESTS	METHODOLOGY AND LIMITATIONS	Ref.
T	S	1-Pyrolytic carbon growth (bad contact, coking)	DGA* DC resistance (transient)* Electric or acoustic PD On-line temperature differential*	4 5 3 3		
T	T	1-Stray leakage flux, heating of components, including windings and leads (includes overfluxing and GIC)	DGA* Infrared scan of tank	4 5	Excluding GIC case, monitoring gas levels at different loads will assist in identifying the problem.	
T	W	1-General overheating, cooler problem, blocked, fouled heat exchanger, pumps & fans not operating	DGA*(combustible gases and CO_2) DGA (consumption of oxygen) Visual* Measure oil temperature	4 1 1	Monitor temperature vs load for cooling conditions.	[100]
T	W	2-Overheating, cooling arrangement problem	DGA* 2-furfural*	3 3	Combustible gas generation increases with load. Operation at no load can also provide information.	[107]
T	W	3-Localized hot spot	DGA* DC (transient) resistance*	4 5	To aid in locating a localized hotspot, it may be necessary to review the transformer design (estimated winding and lead temperatures).	[100]
T	W	4-Overheated joint	DGA* DC resistance* Electric or acoustic PD*	3 3 6	Generally, gas level increases with load.	

(1), (2), etc., indicates order of test

Appendix 9 Catalogue of operations during a large transformer Installation

Operations	Procedures
Transformer Receiving and Storage	Inspection on Carrier
	Pressure /leakage test
	Shipping gas /fluids test
	Internal Inspection (optional)
	Handling
	Preliminary oil filling/maintaining positive pressure of nitrogen
Preservation of insulation integrity during erection	Evacuation of the shipping gas
	Heating
	Dry air technique
Assembly	Preparation of components
	Installation of Current Transformers, Bushings, Heat Exchange System, Conservator, Accessories
	Final Internal Inspection
Vacuum treatment and oil filling	Pressure and vacuum leakage tests
	Pressurizing with dry gas to assess humidity level
	Determination of Insulation Moisture Content
	Vacuum Treatment
	Oil Filling
	Impregnation; residual air evacuation/dissolving
	Oil Recirculation Settling
Oil processing outside the transformer	Drying
	Degassing
	Filtering
Insulation dry out	Vacuum Drying/Cold Trap technique
	Heat-Vacuum technique
	Hot Oil Technique

Appendix 10 Treatment of in-service transformer: catalogue of operations

State while processing	Procedures	Particular operation
Oil/ insulation reconditioning of complete transformer	Degassing circulation through degassing machine	Circulation through degassing machine
	Cleaning:	Fibers
		Carbon
		Clay
		Metal particle
		Electrical filter
	Drying out	Circulation through filter,
		Circulation through degassing machine
		Circulation through molecular sieves
	Reclaiming	Fullers Earth treatment (Passive/convective process Fullers Earth treatment (Force circulation)
	Regeneration / de-sludging	Regenerative oil
		Fullers Earth treatment
	PCB removal	
	Chemical additives:	Inhibitors
		Passivators
		Benzotriazole
		Reduce Gassing tendency
		Pour point depressor
	Oil Refilling/changing	Aged oil evacuation
		Desludging
		Re-Impregnation
Treating of oil outside transformer	Drying	Optimum technology
	Particle Cleaning	Filter selection considering size and nature of particles
	Degassing	Optimum Technology
	Reclaiming	Percolation Technology
		Contact technology
		Clay selection
	PCB removal	

Treatment of the Transformer Insulation after draining the oil	Vacuum treatment	
	Drying	Optimum technology
	Cleaning	Flashing
		spraying
	Regeneration	Regenerative oil technology (refilling) Regenerative oil technology" (oil-spraying)
Working inside transformer (internal works)	Preservation procedures (cleanliness; keeping dry; safety(oxygen deficit); condensation; dust	Heating
		Dry air (considering proper oxygen level)
		Covering
	Internal Inspection Main tank	Grounding system
		Contacts
		Insulation gaps
		Lead/connections
		Tap Changer connections
		General condition of insulation
		Shields Condition
		Signs of overheating
		Mechanical damage
		Paint inspection
		Sampling of paper
	Reclamping/ Reblocking/ Pressing	Winding clamping compression
		Deformation of pressing rings
		Difference in windings height
	Inspection of gaskets condition/Regasketing	Relative residual deformation
		Signs of overheating
On-load tap changer	Diverter switch	Cleaning/replacement oil
		Drying out
		Removing aging products
		Contact replacement/adjusting
		Tightness (leaks to transformer)
	Selector/Reverser	Inspection (especially contacts) Pressing Cleaning
	Motor Driver	Inspection
Bushings	On the transformer	General inspection
		Sampling of oil
		Topping up oil
	Outside transformer	Regasketing
		Leaks Repair
		Replacing oil
		Processing

External works (non invasive)	Coolers/Radiators	Cleaning external (air or water side)
		Oil leak repairs
	Pumps	Bearing inspection /replacement
	Fans	Bearing inspection /replacement
	Painting	
	Repairing oil leaks	
	Valves/Pressure relief Inspection	
Replacement of components and Accessories	Bushings	Adaptability with transformer
	LTC and LTC parts	Adaptability with transformer
	Coolers	
	Pumps	
	Air Sealing system (Bags/Membrane)	Conservator modification
	Valves	

Appendix 11 Removal of gas-vapor mixture during designated time period

The displacement of vacuum pump S shall be large enough to remove the sum of the gas-vapor mixture ($V_{air}+V_{oil}$) during a designated time period and may be estimated by the following:

$$S = \frac{P_0}{p} \bullet D \bullet \frac{T}{273} \bullet (V_{air} + 0{,}112 \bullet W_{oil})$$

Where:

S = displacement of vacuum pump (m^3/h)
D = degassing rate (m^3/h)
P_o = ambient air pressure (mmHg)
P = residual air pressure (mmHg)
T = absolute oil temperature (K)
V_{air} = air content by volume in oil (%)
W_{oil}= water content by weight in oil (ppm or g/to)

Appendix 12 Resistance of an unused filter

The resistance of an unused filter may be expressed with the equation :

$$R_f = \frac{?p}{\mu \bullet W}$$

Where W is velocity of filtration :

$$W = \frac{dV}{Sdt} = \frac{?p}{\mu \bullet (R_r + R_f\ )}$$

Where:

V = volume of the infiltrate (m^3)

t = time of filtering (s)

S = surface (m^2)

? p = the difference in pressure

$\frac{dV}{dt}$ = volume rate of filtering

µ = viscosity (N.sec/$m^{2)}$

R_r = resistance of the residue

R_f = resistance of the filter obstacle

Appendix 13 Vacuum system selection

Mass of a gas air exhausting by a vacuum pump at a constant temperature is determined with value of pV (a product of gas pressure and volume).

Rate of a gas flow or vacuum pump efficiency is expressed as the following:

$$Q = p \cdot S$$

Where S is vacuum pump displacement (pumping speed), m^3/h, m^3/s and p is pressure

$$Q = U \cdot (p_1 - p_2)$$

Where U is vacuum conductivity(transmissivity) of the suction hose, m3/s.

Vacuum pump parameters:

Rated displacement of the vacuum pump S_R can be reduced to effective displacement S_{ef} (pumping speed of an object, e.g. transformer tank) due to drop of pressure in the vacuum hose in accordance with the basic equation of vacuum technique:

$$\frac{1}{S_{ef}} = \frac{1}{S_R} + \frac{1}{U}$$

To provide stable operation of a vacuum pump, U shall be more than S_R. Effective displacement may be also expressed in terms of pressure values:

$$S_{ef} = S_R \cdot (1 - \frac{p_{\lim}}{p}) \qquad (2)$$

Where $p_{\lim}$ is a limiting pressure

Vacuum pump blank-off pressure shall be at least 0.05mm Hg (7Pa)

Hose selection parameters:

Conductivity of a long hose may be determined from equation:

$$U = \frac{pd^4}{128 \cdot h \cdot l} \cdot \frac{(p_1 + p_2)}{2}, \text{ m3/s}$$

Where ? is gas/air viscosity and d and l are the diameter and length of a hose and

$\frac{p_1 + p_2}{2} = p_{av}$ is average pressure which may be taken as half-sum of treatment pressure.

e.g. for if treatment pressure is 133Pa, average pressure would be 66.5 Pa on condition of exhaustion of air at 20^0C assuming $h = 1.82 \cdot 10^{-5} N/m^2 \cdot s$

$$U \cong \frac{p \cdot d^4 \cdot p_{av}}{128 \cdot 1.82 \cdot 10^{-5} \cdot l} \cong 1350 \cdot \frac{d^4}{l} \cdot p_{av}, m^3/s$$

,

In order to provide a stable operation of vacuum pump vacuum conductivity should be more than rated displacement of the vacuum pump:

$U > S_R$

The latter inequality may be used to determine a minimum diameter of the suction hose.

$$d^4 > \frac{S_R \cdot l}{1350 \cdot p_{av}}$$

For example assuming S_R =200 m^3/h or 0.0556 m^3/s, length of the hose l =10 m, and treatment pressure 133 Pa the diameter of the hose shall be more than 50 mm.

Estimation of the time of air exhausting:

$$p = P_0 \cdot e^{-({S_{ef}}/{V}) \cdot t} + p_{\lim}$$

Where:
V = transformer tank volume;
V/S_{ef} = time constant of exhausting

$$t \cong \frac{\ln({p}/{P_0})}{(-{S_{ef}}/{V})}$$

Assuming P_0=760 mm Hg, p=1 mm Hg, S_{ef}=180 m^3/h, V=60 m^3, we have

$$t \cong \frac{\ln(1/760)}{(-180/60)} \cong 2.2h$$

Appendix 14 Drying equation

According to Lampe [B129], the diffusion stage of dry-out may be expressed:

$$\frac{W_f - W_e}{W_0 - W_e} = K = F_{(Z)} = \frac{8}{p^2} \cdot \sum_{n=0}^{\infty -} \frac{1}{(2n+1)^2} \cdot e^{-(2n+1)^2 \cdot p^2 \cdot Z}$$

(1)

Where :

K = relative (remnant) water content after dry out;
W_0, W_f, W_e = initial, final and equilibrium water content

$$Z = \frac{D_{(W,T)} \cdot t}{d^2}$$

Where:
Z = a non-dimensional parameter
D = water transfer coefficient (diffusivity), dependent on:

- Presence of oil
- Drying temperature
- Vacuum
- Insulation density
- Direction of diffusion

t = time (s)
d = insulation thickness

Equation (1) may be simplified if $Z > 0.05$

In this case

$$K \cong \frac{8}{p^2} \cdot e^{-\frac{p^2 \cdot Dt}{d^2}}$$

The drying time may be roughly estimated as:

$$t \cong \frac{\ln(\frac{Kp^2}{8})}{p^2} \cdot \frac{d^2}{D}$$

Assuming remnant water content K=0.1

$$t \cong \frac{\ln(\frac{Kp^2}{8}) \cdot (-1)}{p^2} \cdot \frac{d^2}{D}$$

Appendix 15 Defects and faults detectable by dissolved gas analysis

Appendix 15 is a contribution to this document by WG 15 TF 11 which was convened by Michel Duval. The following tables are similar to Tables 4-1, 6-5 and 6-6 with the addition of a fourth column that indicates how dissolved gas analysis (DGA) may be used to detect various types of faults. See the table on the following page for the precise definitions of faults detectable by DGA.

Table A15-1 System or component defects or faults detectable by DGA

SYSTEM, COMPONENTS	**DEFECT (Reversible)**	**FAULT AND FAILURE-MODE (Not reversible)**	**FAULTS DETECTABLE BY DGA (Examples)**
Dielectric Major insulation Minor insulation Leads insulation Electrostatic shields	? Excessive water ? Oil contamination ? Surface contamination ? Abnormal aged oil ? Abnormal cellulose aging ? PD of low energy ? Loose connections causing sparking		Discharges (D1) Discharges (D1) Discharges (D1, D2) Thermal fault (T1, T2) Discharges (D1)
Electromagnetic circuit Core Windings Structure insulation Clamping structure Magnetic shields Grounding circuit	? Loosening core clamping ? Overheating due to high stray flux ? Short-circuit (open-circuit) in grounding circuit ? Abnormal circulating current ? Floating potential ? Aging lamination	? Excessive vibration and sound General overheating ? Localized hot spot ? Sparking/discharge ? One or more turns are short-circuited completely ? Strands within the same turn are short-circuited **Gassing**	Thermal fault (T1) Thermal fault (T2, T3) Discharges (D1) Discharges (D2)
Mechanical Windings Clamping Leads support	? Loosening clamping	? Leads support failure ? Winding distortion - radial - axial - twisting **Failure of insulation**	Discharges (D1, D2)
Current carrying circuit Leads Winding conductors	? Poor joint ? Poor contacts ? Contact deterioration	? Localized hot spot **Open-circuit** **Short-circuit**	Thermal fault (T2, T3) Discharges (D1, D2)

Table A15-2 Faults detectable by DGA: Definitions

PD	Partial discharges
D1	Discharges of low energy
D2	Discharges of high energy
T1	Thermal faults T < 300 °C
T2	Thermal faults 300 °C < T < 700 °C
T3	Thermal faults T > 700 °C

Table A15-3 Typical defects or faults for selector switch and drive motor of OLTC detectable by DGA

SYSTEM, COMPONENTS	DEFECT or FAULT	FAILURE MODE	FAULTS DETECTABLE BY DGA (Examples)
SELECTOR SWITCH **Dielectric** Solid insulation: - between taps, - to ground, - between phases - barrier board & - bushings Liquid insulation : - Across contacts Adjacent studs in combined selector diverter tapchanger	• Excessive water • Oil contamination • Surface contamination • PD of low energy • Abnormally aged oil	Destructive PD Localized tracking Creeping discharge Excessively aged/ overheated cellulose **Flashover**	Discharges (D1) Discharges (D1) Discharges (D1, D2) Thermal fault (T1, T2) Discharges (D1)
Electrical Connections Contacts - Selector contacts - Change-over switch/ - course fine Through bushings	• Poor connections • Missaligned contacts • Silver coating disturbed/worn • Poor contact pressure	Overheating? gassing Sparking/ arcing Overheating Carbon build up between contacts	Thermal fault (T1) Discharges (D1) Thermal fault (T1) Thermal fault (T2, T3)
Mechanical Drive shaft Selector contacts	• Damaged or broken • Incorrect alignment with diverter switch operation • Travel beyond the end stop	Out of synch operation of selector & diverter switches arcing	Discharges (D1, D2)
DRIVE MECHANISM Drive shaft Mechanical end stops Motor and gear drive Control equipment Auxillary switches	• incorrect timing • operation beyond end stop • broken gears • missaligned coupling • worn,damaged or broken auxillary switches.	Incorrect operation of the selector switch in relation to diverter Tap changer jammed on a tap—will not operate	

Table A15-4 Typical defects or faults for bushings detectable by DGA

COMPONENT	DEFECT or FAULT	FAILURE MODE	FAULTS DETECTABLE BY DGA (Examples)
CONDENSER CORE	LOCAL NATURE Residual Moisture Poor Impregnation Wrinkles in Paper Delaminated Paper	Ionization Gassing Thermal run away	Partial discharges (PD) Thermal fault (T2, T3)
	Over-stressing Short-circuit layer		Discharges (D1, D2)
	Ingress of Moisture Ingress of Air Graphite Ink Migration Dielectric Overheating X-wax Deposit	Puncture Explosion	Discharges (D1) Thermal fault (T2, T3) Discharges (D2) Partial discharges (PD)
	BULK NATURE Aging of Oil-Paper Body Thermal Unstable Oil Gas Unstable Oil Over-saturation	Flashover Explosions	Discharges (D1) Discharges (D2)
CORE SURFACE	Contamination	PD	Discharges (D1)
OIL	Moisture Contamination Aging	Surface Discharge Gassing	Discharges (D1)
INTERNAL PORCELAIN SURFACE	Deposited Impurities Conductive Staining		
TAPS	Ungroundings Shorted Electrodes	PD	Discharges (D1)
CONDUCTOR	OVERHEATING • Top contact • Foot contact • Draw rod Circulating current in the head	Overheating Gassing Sparking	Thermal fault (T1, T2) Discharges (D1) Thermal fault (T2,T3)
EXTERNAL PORCELAIN	Cracks Contamination Surface Discharge	Flashover	Discharges (D1)

Appendix 16 References

(Note: Certain entries are annotated which are shown in italics.)

1. Petersson, L., "Estimation of the Remaining Life of Power Transformers and Their Insulation," Electra No.133, Dec.1990, pp. 65-71.

2. Breen, G. "Essential Requirements to maintain Transformers in Service," CIGRE 1992, Report 12-103.

Any decision on rehabilitation, refurbishment, repair or replacement must be made with reference to the age of the transformer and the complete service records.

3. CIGRE Report of WG 12.18, "Moisture equilibrium and moisture migration within transformer insulation systems," (to be published as CIGRE brochure in 2003).

Upper Estimate of the Rate of Water Contamination

Conditions	***Rate of Water Contamination***
Direct exposure of oil-impregnated insulation to air: *a) RH* = 75%, 20 °C* *b) RH*= 40%, 20 °C*	*Sorption of water in pressboard with surface of 1000* m^2 *up to 0.5 mm depth:* *13,500 g in 16 hours* *8,100 g in 16 hours*
Water vapor molecular flow** • *Via capillaries in seals (pores in gaskets)* • *Via loose gaskets*	 *Less then 1 – 5 g per year* *Less then 30 – 40 g per year*
Viscous flow of air *Shipping condition: core and coil covered with oil* • *Adequate sealing* • *Insufficient sealing*	 *600 g per year* *15 g in a day*
Operation with open-breathing conservator	*6,000 g per year*
Insufficient sealing with rain water present	*200 g in an hour as free (liquid) water*

**RH = relative humidity*

***Water vapor molecular flow would apply to a transformer with a properly maintained sealed conservator oil preservation system*

4. "Effect of Particles on Transformer Dielectric Strength," Working Group 12.17, CIGRE, Ref. 157, 2000.

5. Beletsky, et al, "Short-Term Dielectric Strength of HV Power Transformer Insulation," Electrichestvo, 1978, No. 9. (in Russian).

6. Sokolov, V., "Experience with the Refurbishment and Life Extension of Large Power Transformers," Proceedings of the Sixty – First Annual International Conference of Doble Clients, 1994, Sec. 6-4.

The 50 Hz one-minute breakdown stress of new and wet (2.5 %) and aged and wet insulation is 10-12 % less than new and dry (0.5 %).

Increasing the concentration of particles from 50 cm^{-3} *up to 160* cm^{-3} *leads to a further decrease of breakdown stress by 29 %.*

Lightning Impulse Test (1.2/50 ③s standard waveshape)

No effect of moistening and aging was revealed in these tests. Only contamination of models with soot particles (160 cm^{-3}*) had an affect, which was to decrease the breakdown strength by 12 %.*

Switching Surge Test (250/2000 ③s standard waveshape)

In this test, we see the effect of aging. Standard deviation of switching surge breakdown stress increased significantly after aging. The minimum breakdown voltage at switching surges may decrease approximately by 15 % after aging. Increasing the concentration of particles from 50 cm^{-3} *up to 160* cm^{-3} *may decrease switching surge breakdown voltage additionally by 10 %.*

7. Sokolov, V., "Effective Criteria of Oil Condition in Large Power Transformers, Diagnostic and Maintenance Techniques," Proceedings of CIGRE Symposium "Diagnostic and Maintenance Techniques," Berlin, Germany, 19-21 April 1993, pp. 35-36.

Contamination of oil with wet cellulose fibres (7 %) can reduce dielectric strength practically to the same degree as contamination with metal particles of equal concentration. Moistening of fibre particles up to 7 % may occur at a relative saturation of oil above 50 %.

8. Griffin, P.J., "Water in Transformers – so What," National Grid Conference on Condition Monitoring in High Voltage Substations, Dorking, UK, May 1995.

W, ppm wt/wt	*Dielectric breakdown by D-1816, U, kV*	*% saturation*	*Decrease of dielectric breakdown in %, U%*
10	*36*	*17*	*100*
20	*32*	*33*	*89*
26	*28*	*43*	*78*
30	*24*	*50*	*67*
36	*20*	*60*	*56*
40	*16*	*66*	*44*
44	*14*	*73*	*39*
50	*12*	*83*	*33*
52	*12*	*83*	*33*

9. Kalentyev, Y., "Investigation of Short –Term and HV Power Long-Term Behavior of Oil-Barrier Insulation of transformers in Real Operation Conditions," Dissertation, Sankt-Peterburg, Russia, 1985.

Effect of wet fibres
N=2400, particles in 10 ml; Size 500-1500 mkm
$E_{bd} = E_{bd0} - k_w W_f$
k_w*=0.38, kV/mm%*
wf= moisture content in particles, %
E_{bd-} *= breakdown field intensity, kV/mm*
$E_{bd0\,=}$ *breakdown field intensity kV/mm for dry fibres W<0.5 %, kV/mm = 6.4kV/mm*
Increasing moisture content up to 2.5 % results in reduction of E_{bd} *by >10 %*
$E_{bd} = E_{bd0} - k_w W_f = 6.4 - 0.38 \bullet 2.5 = 5.45$ *kV/mm (15% reduction)*
Critical condition $W_f = 6$ *%*
Increase in the moisture content in the paper up to 3-4 % and relevant increase in the concentration of moisture in oil, which causes reduction of PD inception voltage by 20 % and occurrence of PD with the level up to 2000-4000 pC,

10. Sokolov, V. and Vanin, B., "Experience with In-Field Assessment of Water Contamination of Large Power Transformers," Proceedings of the EPRI Substation Equipment Diagnostic Conference VII, New Orleans, LA, February 20-24, 1999.
Four classes of transformer condition from a moisture content point of view:
CLASS I: "good" – dry transformer, water content in the insulation is 0.5 to 1.0 % or less on average. There is little change in water content of the oil with temperature (it remains typically below 15 ppm). The relative saturation of the oil is typically about 5 % or less at a constant operating temperature of 60 – 70 °C. With increasing operating temperature of a transformer, initially the relative saturation of water in oil decreases exponentially.
CLASS II: "fair" – under normal operating conditions the relative saturation of water in oil remains below 50 % even at the lowest operating temperatures. The characteristics of this condition are maximum water contents in the solid insulation of 1 to 1.5 %. There is a slight (typically less than two times the initial value) rise of water

content in the oil after increasing and maintaining the temperature test. The relative saturation of water in oil is expected to be about 5 % at 60-70 °C, but less than 8 %.
CLASS III: "probably wet" – under normal operating conditions the relative saturation of water in oil may exceed 50 % at the lowest operating temperatures.
CLASS IV: "wet" – under normal operating conditions an emulsion of water in oil can form as the relative saturation exceeds 100 %.

11. Moore, H.M., "Factors Affecting the Health and Life of Transformers," Proceedings of TechCon 2000, Mesa, Arizona, February 2-3, 2000.
The dielectric strength of oil is a function of water and particle content that exist in oil. The dielectric strength of oil is a function of percent saturation.
1500-2000 particles in 10ml are acceptable. Suggested limits: 3000 ppm of oxygen and 1 % of water.
More reasonable end of life from short circuit standpoint is when the paper has reached 50 % of its life (DP is in the order of 450).

12. Cameron, R.F., Traub, T. P. and Ward, B.H., "Update on EPRI Transformer Expert System (XVISOR)," Proceedings of the EPRI Substation Equipment Diagnostic Conference VII, New Orleans, LA, February 20-24, 1999.

Limits EPRI	*100 % good*	*100 % bad*
Insulation power factor/tan delta	*≤ 0.4 %*	*≥ 0.9 %*
Oxygen content		*≥ 2000 ppm*
Core insulation resistance, M?	*≥ 1000*	*≤ 100*
Oil acidity,mg KOH/g	*≤ 0.1*	*≥ 0.18*
Oil power factor/tan delta, %, 25C	*≤ 0.2*	*≥ 0.5*
Oil dielectric strength, kV	*≥ 35*	*≤ 26*
Oil interfacial tension, dynes/cm	*≥ 38*	*≤ 24*
Metallic particles in oil > 3 microns and < 150 /10 ml	*≤ 1500*	*≥ 4000*

13. Oommen, T.V., Petrie, E.M. and Lindgren, S.R., "Bubble Generation in Transformer Windings under Overload Conditions," Proceedings of the Sixty-Second Annual International Conference of Doble Clients, 1995, Sec. 8-5.

14. Oommen, T.V., "Bubble Evolution from Transformer Overload," IEEE Insulation Life Subcommittee, Niagara Falls, Canada, October 17, 2000.
At 2 % water content, the bubble evolution temperature is 140-150 °C.

15. Harrold, R. T., "The Influence of Partial Discharges and Related Phenomena on the Operation of Oil Insulation Systems at Very High Electrical Stresses," IEEE Transactions on Electrical Insulation, Vol. EI-11, 1976, No. 1.
Poor impregnation caused discharges of about 1,000-2,000 pC. Large (3-5 mm in diameter) air/gas bubbles in oil resulted in discharges ranging in magnitude from 1,000 to 10,000 pC

16. Sokolov, V. et al, "On-site PD Measurements on Power transformers," Proceedings of the Sixty-Seventh Annual International Conference of Doble Clients, 2000, Sec. 8-10.

Mechanism of PD action and classification of PD for defect-free and defective insulation:

Defect free	*10-50 pC*
Normal deterioration	*<500 pC*
Questionable	500-1000 pC
Defective condition	*1000-2500 pC*
Faulty (Irreversible)	*>2500 pC*
Critical	*>100,000-1,000,000 pC*

17. Yakov, S., et al, "Corona in Power Transformers," CIGRE 1968, Report 12-06.
In general, PD level over 2500 pC (in paper) and over 10,000 pC (in oil) may be considered as a destructive ionization in a long-term action.

18. Marutchenko, P. and Morozova, T., "Voltage versus Time Characteristics of Surface Discharge in Transformer Oil under Long –Time Voltage Action," Elektrotechnika, 1978, No. 4, pp. 25-28 (in Russian).

19. Okubo, H. et al, "Electrical Insulation Diagnostic Method and Maintenance Criteria for Oil-Immersed Power Transformers," Proceedings of the 13th International Conference on Diagnostic Liquids (ICDL 99), Nara, Japan, July 20-25, 1999.

Aging criteria

Characteristics	*Warning*	*Trouble*
$CO_2 + CO$	*0.2 ml/g*	*2 ml/g*
Furfural	*1.5 ppm*	*15 ppm*

20. Goto, K. et al, "Measurement of winding temperature of Power Transformers and Diagnosis of Aging Deterioration by Detection of CO and CO_2," CIGRE 1990, Report 12-102.
Amount of the CO_2*+CO (In the range of temperature 140-180° C) is 1 to 4 mg/g of paper for 60 % retention of tensile strength.*

	CO_2+CO *From both paper* *And pressboard*	CO_2+CO *From paper* *Ml/g*	*Life time,ml/g h*
Normal	*<0.048*	*0.53*	$<2.0\ 10^{-6}$
Caution	*0.048-0.4*	*0.53-2.1*	$2.0\text{-}8.010^{-6}$
Abnormal	*>0.41*	*>2,1*	$> 8.0\ 10^{-6}$

Calculation formulas:

CO_2 *and CO:* $\log Y_1 = 11.16 - 5865/T$

Y_1*: generation rate of* CO_2 *and CO*

T: absolute temperature of insulation paper

Furfural: $\log Y_f = 11.76 - 6723/T$

Y_f*: generation rate of furfural*

T: absolute temperature of insulation paper

21. IEEE Standard C57.91-1995, IEEE Guide for Loading Mineral-Oil Immersed Transformers.

Life (per unit) at 110° C= $9.80 \bullet 10^{-18} \bullet e^{\left[\frac{15000}{q_H + 273}\right]}$

Life until reduction of DP to 200

Where $?_H$ *= hot spot temperature*

Criterion	*Normal Life at 110º C*	
	Hours	*Years*
Retention of 50 % of initial tensile strength	*65000*	*7.42*
Retention of 25 % of initial tensile strength	*135000*	*15.41*
Retention of DP= 200	*150000*	*17.12*
Life tests on distribution transformers	*180000*	*20.55*

22. Saha, T. K. and Darveniza, M., "The Application of Interfacial Polarization Spectra for Assessing Insulation Condition in Power Transformers," Proceedings of the CIGRE SC12 Transformers International Colloquium, Sydney, Australia, 5-10 October 1997.

23. "Determination of Life-Limiting Factors Based On Investigation of Functional Life-Models Turn-to-Turn Insulation," Report of the Transformer Research Institute (Zaporozhye).
An investigation has been performed at the Transformer Research Institute (Zaporozhye) as an original continuation of work that had been done by McNutt and Kaufmann. The goal was to clarify the combined effects of thermal aging and short-circuit stresses on the short-term electrical strength of turn-to-turn insulation.

A set of models of the simplest coil-type continuous winding with non-upgraded paper insulation was placed in oil in hermetically sealed tanks and was aged at hot-spot temperatures of 160°C, 140°C, and 125°C. Periodically the models were subjected to short-circuit stresses (15 MPa) and 50 Hz, one minute, ac voltage test. End of Life was determined as that point when turn-to-turn breakdown voltage had been reduced below 60 % of initial data. Insulation paper tested at 125°C endured over 1200 days. Oil was not changed during the tests though it became very aged. The coils were covered with sludge in all these test models.

These tests showed that the most probable Life-Limiting Factor of aged turn insulation is deterioration of short-term dielectric strength due to the effects of temperature and oil aging products.

Life until reduction of dielectric strength by 40 %

$$\log\tau = -7.94 + \frac{4934}{T}.$$

Where T = absolute temperature of paper insulation

24. Carballeira, M., "HPLC contributions to transformer survey during service or heat run test." Current problems in insulating systems including assessment of aging and degradation, Joint Colloquium CIGRE SC-12 and SC 15, Rio de Janeiro, October 1989.

Ratio $R=\frac{Furanal}{5-hydroxymethil-2\,furanal}$ *suggested as additional criteria of paper decomposition with temperature*

25. Tutorial on Electrical-Grade Insulating Papers in Power Transformers, Doble Planning Conference, October 1993.

26. Linhjell, D., Hansen, W. and Lundgaard, L., "Aging of Oil-impregnated Paper for Electric Power Use – A Multiparameter Experiment," NORD-IS 2001, Stockholm.

27. Sans, J. R., Bilgin, K. M., and Kelly, J. J. “Large Scale Survey of Furanic Compounds in Operating Transformers and Implications for Estimating Service Life”, Conference Record of the 1998 IEEE International Symposium on Electrical Insulation, Washington, D. C., June 7-10, 1998, pp. 543-53.
Suggested furan concentration limits:
<=100 ppb- First signal; expected DP 1200 to 444, retest in one year

101 to 250ppb- Expected DP 443 to 333, re test in 6 months
251 to 1000ppb- Expected DP 332 to 237, retest in 3 months
1001 to 2500 ppb-expected DP236 to 217, lower equipment reliability, retest in 1 month
>2500ppb-expected DP <217, consider rewind or replacement.

28. Current problems in insulating systems including assessment of aging and degradation, Joint Colloquium CIGRE SC-12 and SC 15, Rio de Janeiro, October 1989.
FURNAS pays special attention to transformers with amount of CO over 15 litres.

29. Hitachi Ltd., Japan "Diagnosis of Aging Deterioration of Power Transformers," Discussion contribution, CIGRE Session 2000, SC 15.
Data for the relationship between mean degree of polymerization and CO_2 *and CO generation and furfural were submitted by the utilities and transformer manufacturers as the answer to a questionnaire. The data were analyzed to develop the formulas for calculating the relationship between the temperature of insulation paper and the generation of* CO_2 *and CO and furfural.*

$$CO_2 \text{ and } CO: \log Y_1 = 11.16 - 5865/T$$

Y_1: *generation rate of* CO_2 *and CO*
T: absolute temperature of insulation paper

$$\text{Furfural: } \log Y_f = 11.76 - 6723/T$$

Y_f: *generation rate of furfural*
T: absolute temperature of insulation paper

30. IEC 60599, "Mineral Oil-impregnated Equipment in Service- Interpretation of Dissolved and Free Gases Analysis."

31. Lemelson, K., "Beitrag zur Kleurung des Verhaltens geschlossener Starkstromkontatstellen unter Isolierroel im Dauerbetrieb," T.H. Braunschweig, Dissertation, 1973.

32. Onori, T., "Relation between Contact Resistance and Its Temperature," Electric Engineering, Japan, 1967, No. 6, pp. 110-117.

33. Dmitrenko, A.I., "Loadability of Closed Contacts of LTC for Power Transformers," Thesis, Zaporozhye, 1982.

34. Kramer, A. et al, "Monitoring Methods for On-Load Tap-Changers- An Overview and Future Perspectives," CIGRE 1996, Report 12-108.

35. Savio, L., "Con Edison Experience with LTC Monitoring," Proceedings of the EPRI Substation Equipment Diagnostic Conference VII, New Orleans, LA, February 20-24, 1999.

36. Tsukioka, H. et al, "Behavior of Gases Generated from Decomposition of Insulating Oils Under Effect of Localized Heating," Denki Gakkai Rombunsi 1978, vol. 98-A, No. 7, 381-388.

37. Lachman, M. F., "Application of Equivalent-Circuit Parameters to Off-Line Diagnostics of Power Transformers (A Review)," Proceedings of the Sixty-Sixth Annual International Conference of Doble Clients, 1999, Sec. 8-10.

38. Austin, P. L., "Use of DGA and Acoustic Devices to Detect and Locate Faults in a 588 MVA Generator Step-up Transformer," Proceedings of the Fifty - Ninth Annual International Conference of Doble Clients, 1992, Sec. 6-18.
A loose top yoke clamping screw and also a loose winding clamping screw were detected and located using acoustic discharge detection and location equipment. Loosening of the corona shield on top of an oil to oil bushing caused a sparking discharge which produced acetylene in oil and this was also detected and located with the acoustic discharge equipment. Overheating of the winding jacking screws (those in highest leakage field were coated with carbon) was initially detected by DGA. The paper insulated top exit lead of the LV windings became overheated because of reduced oil flow caused by a dislocated oil pipe. This fault was detected by Buchholz relay and load limit determined by DGA until it could be repaired.

39. Crofts, D., Hughes, B. and Moore, H. M., "Generator Step-up Transformer Problems at Texas Utilities Comanche Peak Nuclear Plant - Identification and Resolution," Proceedings of the Sixty – Second Annual International Conference of Doble Clients, 1995, Sec. 8-7c.

40. Berent, D., "Acoustic Monitoring and Gas-in-Oil Analysis for Transformers," Proceedings of the Sixty - Second Annual International Conference of Doble Clients," 1995, Sec. 8-3.

41. Sokolov, V. et al, "On-Site Partial Discharge Measurement on Power Transformers," Proceedings of the Sixty-Seventh Annual International Conference of Doble Clients, 2000, Sec. 8-10.

42. Grestad, P., "Life Management of Transformers: Case Story," Proceedings of the CIGRE SC12 Transformers International Colloquium, Sydney, Australia, 5-10 October 1997.
Failure due to bad cooling of HV coils

43. Golubev, A. et al, "On-line Vibro-acoustic Alternative to the Frequency Response Analysis and On-line PD Measurements on Large Power Transformers," Proceedings of TechCon 1999, New Orleans, LA, 1999.

44. Sokolov, V. and Vanin, B., "Experience with Detection and Identification of Winding Buckling in Power Transformers," Proceedings of the Sixty-Eighth Annual International Conference of Doble Clients, 2001, Sec. 8-3.

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48. Kassikhin, S. D., Lizunov, S.D., Lipstein, R.A., Lokhanin, T.K., and Morozova, T.I., "Service Experience and Reasons of Bushing Failures of EHV Transformers and Shunt Reactors," CIGRE 1996, Report 12-105.

49. Evseev, Y. A., Kassikhin, S.D., Kulikov, I.P., and Savina, E.I., "Some Considerations About Failures of HV Hermetic-sealed, Oil-impregnated Bushings," (published in Russian), Electrical Stations No. 1, Moscow, 1989, pp. 67-72.

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52. Sabau, J. and Stokhuyzen, R., "Aging and Gassing of Mineral Insulating Oils," Proceedings of TechCon 2000, Mesa, Arizona, February 2-3, 2000.

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55. Fyvie, J., Lindroth, A., Spoorenberg, K. and Lapworth, J., "The Short-Circuit Performance of Power Transformers," Working Group 12.19 Task Force 4: Diagnostic and Monitoring, "Winding Movement Detection Techniques," CIGRE 2002, Ref. 209.

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57. Johnson, D.C., "Field Installation and Maintenance of Oil-Immersed Transformers," Special Publication of IEEE Power Engineering Society No. 13, Application of Distribution and Power Transformers, New York, 1976, pp. 66-77.

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59. "Power Transformers Shipping, Receiving, Installation and Commissioning," Guide of Canadian Association Engineering and Operating Divisions, Electrical Apparatus Section.

60. IEEE Guide for Installation of Oil-Immersed Transformers (10 MVA and Larger, 69-287 kV Rating).

61. IEEE Guide for Installation of Oil-Immersed Transformers 345 kV and Above.

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65. Pahlavanpour, B. et al, "Extension of Life Span of Power Transformers by On-site Improvement of Insulating Oil," Proceedings of the CIGRE SC12 Transformers International Colloquium, Sydney, Australia, 5-10 October 1997.

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100 ppb total furans - estimated DP 700
250 ppb total furans - estimated DP 563
500 ppb total furans - estimated DP 460
1000 ppb total furans - estimated DP 356
1500 ppb total furans - estimated DP 295

2000 ppb total furans - estimated DP 253
2500 ppb total furans - estimated DP 219
2800 ppb total furans - estimated DP 202
Estimated DPs are rough guides and apply only to 65 °C rise transformers

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(Note: Certain entries in this Bibliography are annotated. Such entries are shown in italics.)

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Life Evaluation Reasons:
Reliability consideration for aged transformers
Planning of replacement or refurbishment
Life extension
Up rating power capability
Improved maintenance
Better asset utilization
Basic Groups of methods:
Statistical Assessment- is not specific to individual units and does not take into consideration design differences and operational history
Influential factor methods- is used to compare the risks associated with failure or loss of life for a group of transformers. Each unit is evaluated and assigned a relative score for each of the factors (electrical, thermal, DGA).
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Examples are shown of life assessment on an analysis of generator transformers from TVA nuclear power station.
PF for transformers and bushing since 1975 until 1979 one bushing shows PF higher than 1 %.
CO/CO_2 since 1990 till 1998 (one was removed due to a hot spot CT in the transformer)
Combustible gas-in –oil
Ranking of 27 units considering: maintenance; short circuit; thermal; core megger; PF; C_2H_2; CH_4; CO; H_2; time in service
Estimation of remaining life using modern method and ANSI standard C57.91-1995, table 21 upon criteria 50% retained tensile strength of insulation- 4 of units were suggested as having loss of life over 60-70 %.
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Average load ratio
Actual years in service
Progressed years which are in service
Cooling
Test data of factory:
Rated oil temperature rise
Rated winding temperature rise
Amount of oil
Amount of total insulation material and that of pressboard

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Moisture criteria:

Insulation condition	*IEEE Std 62 -1995*		*ZTZ-Servce suggestions*	
	Wp	*j %*	*Wp*	*j %*
Dry (at commissioning)	*0.5-1.0 %*	*< 5 %*	*0. 5%*	*<3-5 %??? t>60^{0}C*
Normal in operation	*<2 %*		*<2 %*	*< 8 % ??? t>60 ^{0}C*
Wet	*2-4 %*	*6-20 %*	*> 2-3 %*	*>40 % ??? t<20^{0}C*
Extremely wet	*>4,5 %*	*>30 %*	*>4 %*	*>40 % ??? t>20 ^{0}C*

Particle contamination:

	IEEE,3-150 m m	*CIGRE,>5 m*
Particle count / 10 ml *3-150 m m/10 ml*	*<1500 –normal* *1500-5000 marginal* *>5000 contaminated.*	*3200-6400.* *6400-13000* *13000-25000*

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1. *Recovery Voltage Measurement (RVM)*
2. *Dielectric Spectroscopy in Time Domain (PDC)*
3. *Dielectric Frequency Domain Spectroscopy (FDS)*

These methods reflect the same fundamental polarisation and conduction phenomena . However, the measurements confirm the influence of oil gaps, oil condition, especially the oil conductivity, material properties and geometry. This must be taken into account when moisture contents in the solid insulation are derived from all 3 methods. The practical consequences are:

1. *FDS and PDC methods are sincerely considering these dependencies on:*
   - oil condition, oil conductivity
   - insulation geometry
   - material properties

and derive from the whole response curve and by mathematical modelling very good relative moisture results, which can be verified by alternative methods.

2. *The RVM method is not considering these parameters so far with the old interpretation (simple relationship of dominant time constant and maximum of polarisation spectrum)*

Therefore the moisture content evaluation is not correct

3. *Before operational decisions concerning life management of power transformers can be made further validation of the dielectric response technique is required.*
   An example is given in paper 12-101 (CIGRE 2002).

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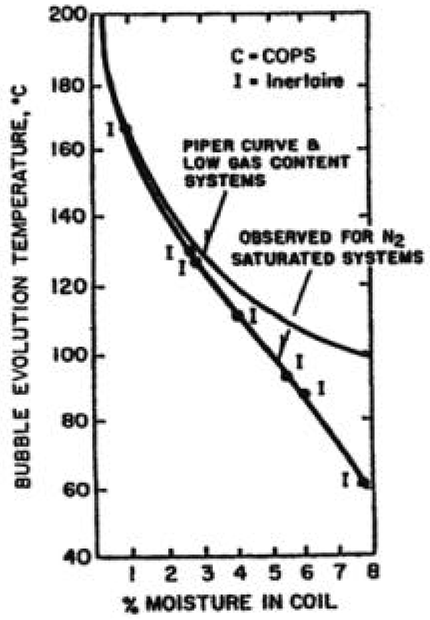

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High CO and CO_2 accompanied by H_2 without the presence of hydrocarbons such as CH_4, C2H6, and C_2H_4 are indicators of deterioration of paper caused by high oxygen and water content in the system

	CO_2	*CO*
Condition 1 Normal	*0-2,500*	*0-350*
Condition 2 Modest Concern	*2,400-4,000*	*351-570*
Condition 3 Major Concern	*4,001-10,000*	*571-1,400*
Condition 4 Imminent Risk	*>10,000*	*>1,400*

Voltage	*Maximum water content in the paper*
230kV	*1 %*
115 up to 230 kV	*1,5 %*
Less than 115 kV	*2,0*

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DP = f (CO_2+CO) and DP = f(furfural content ml/g) in a graphic form,
DP warning level: 450 to 850, and trouble level: 250 to 450,
Accordingly:

	Warning level	*Trouble level*
CO_2+CO	*0.2 ml/g*	*2.0 ml/g*
Furfural level	*0.0015 mg/g*	*0.015 mg/g*

Formula that gives an approach of DP vs. time (t) dependence:

$$DP(t) = (1 - 0.014 \times t) \times DP(0)$$

Where DP(0) = initial DP value

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