

445

Guide for Transformer Maintenance

**Working Group
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Chapter 1 Introduction

1.1 Guide for Transformer Maintenance

Maintenance, availability and reliability are closely related and the transformer user has to specify a level of maintenance that will ensure an acceptable level of transformer reliability in the particular context. This guide has been prepared to help transformer users to define and apply best practice for transformer maintenance. Although the document was prepared with specific consideration of liquid immersed transformers rated 69 kV and above and larger than 25 MVA, its principles may be applied to a wider range of transformers. Subjects including best practice, checking and testing in order to evaluate transformer condition, time intervals for the various actions, advanced maintenance activities, and human and material aspects of transformer maintenance are covered.

This guide is not intended in any way to set the level of maintenance that a user must perform on a transformer in order to maintain a manufacturer's warranty. The required maintenance should be set out clearly in the documentation supplied with the transformer.

1.2 Transformer Operation and Maintenance Cycle

A transformer is usually a robust apparatus with very good reliability requiring relatively low maintenance. During the life of a transformer, the user has to establish a maintenance strategy that will ensure the appropriate level of reliability and an optimized operational life.

The operational life of a transformer begins with commissioning after it is installed in a substation. Once in operation, a maintenance strategy starts to be applied. An optimized maintenance strategy will provide the required availability and reliability of the transformer over its lifetime at minimum cost. It is the goal of good maintenance to detect any abnormalities before they cause unnecessary damage.

Once an abnormality is detected, then some or all of the available diagnostic techniques set out in this brochure can be applied to evaluate the severity of the problem, localize it, and determine if the transformer can return to service with or without a restriction on operation. If necessary the appropriate corrective action can then be performed, or depending on the transformer condition, it may be appropriate to invoke a more intensive intervention on the transformer. Ultimately, it may be decided that it is time to refurbish or repair the transformer or even to replace it, depending on the results of an evaluation that will include consideration of the safety (both to utility staff and the general public), the potential environmental consequences and the system reliability aspects of continued operation.

Figure 1 represents the Transformer Operation and Maintenance Cycle, from the time of commissioning to end of life.

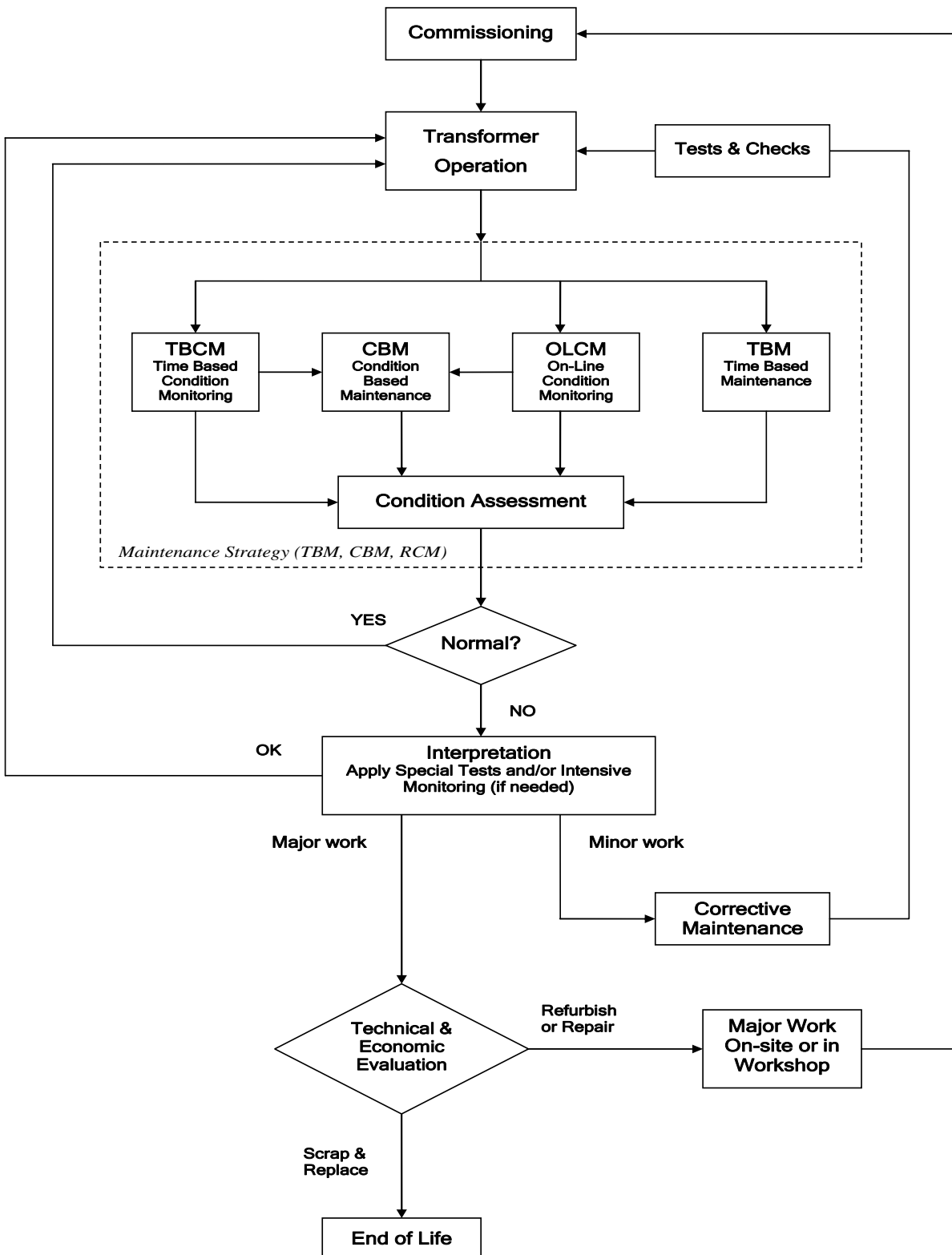


Figure 1: Transformer Operation and Maintenance Cycle

The different terms used in the Transformer Operation and Maintenance Cycle are described below.

Commissioning

When a new or repaired transformer is put into service, baseline measurements and tests are made so that the results are available for use as a reference if a problem is suspected in the future. The proper operation of the transformer and all its components are verified.

Transformer Operation

The transformer is connected to the electrical system and a fixed or variable load is applied. The transformer is exposed to the various system and service stresses such as ambient temperature variations, load variations, frequency and voltage deviations, lightning impulses, switching over-voltages, short-circuit.

Time Based Maintenance (TBM)

This maintenance is carried out at predetermined intervals to reduce the likelihood of an item of equipment failing in service. It includes maintenance actions to improve the condition (oil change, lubrication, preventive replacement of parts). The term "systematic preventive maintenance" is also used. A TBM action is given a fixed time interval and the action is carried out irrespective of condition, i.e. the planner defines what should be done and how often it is done. This method can offer a high degree of risk coverage if the original equipment manufacturer's (OEM) recommendations for maintenance (which are traditionally based on regular intervals) are followed. TBM is often considered as the easiest but not the most cost effective way of maintaining assets. It has the significant advantage of being easily planned and this is particularly important for maintenance that requires an outage.

Time Based Condition Monitoring (TBCM)

These are actions to evaluate the condition of the equipment (for example visual checks, measurement and tests) carried out at regular and pre-planned intervals. These are most often carried out in conjunction with maintenance particularly for tasks that require an outage. The results of TBCM are often used to decide on the extent of maintenance required at the time or in the future. But the information gained is limited to 'snap-shots' at a particular time.

Condition Based Maintenance (CBM)

This maintenance is carried out depending on equipment condition to reduce the likelihood of an item of equipment failing in service. The term "conditional preventive maintenance" is also used. CBM is based on assessing the actual physical condition of the asset and takes into account its usage, occurrence of events, possible wear of moving or current switching parts, and the performance of similar equipment. In order to use this maintenance philosophy it is necessary to assess the asset condition by methods such as TBCM, OLCM and continuous on-line monitoring. CBM applies in cases where technical condition can be measured and assessed against criteria for invoking action. Incorporating CBM in a maintenance strategy seeks to reduce costs by performing maintenance only when a change in equipment condition warrants taking action. CBM however requires a more complicated planning process. CBM is often used within a time-based outage plan to defer maintenance to the next available outage.

On-line Condition Monitoring (OLCM)

This is a technique, method or measurement that is, or can be, performed or made with the transformer in operation that provides information about the condition of the transformer. This might include oil sampling for dissolved gas analysis using a laboratory, performing infra-red thermal scanning, or making simple observations such as oil levels in condenser bushings and conservators.

Continuous On-line Monitoring

This is a refinement of the OLCM technique, where a measurement or measurements are continuously tracked or supervised, normally by means of an Intelligent Electronic Device (IED). This device will immediately communicate, either by means of an alarm or message, any significant deterioration in condition to alert staff to take appropriate action. To be effective, the Continuous On-Line Monitor should announce the change of transformer condition in advance of failure. Continuous On-line Monitoring can form the basis for Condition Based Maintenance and can effectively reduce the risk of unexpected catastrophic failure.

Maintenance Strategy

The Maintenance Strategy is the combination of the different maintenance philosophies used to achieve the required system reliability. The strategy may include different maintenance philosophies for different components of the transformer. For example, tap changers and bushings. TBM is usually considered to be an elementary strategy, whereas CBM is usually more cost effective than TBM. A combination of TBM, TBCM, CBM and OLCM is often used to maintain large complex

assets such as power transformers. Time based inspections or checks are used for overall condition assessment (for example oil leaks) or the usual diagnostic measurements (for example DGA), while CBM methods are used for wearing parts (for example OLTC diverter contacts). Results of CBM provide knowledge of the average or actual asset condition and this may be used to influence future TBM intervals.

Reliability Centred Maintenance (RCM)

Reliability Centred Maintenance is an optimised strategy that takes into account not only the operation time and/or the technical condition of an asset, but also its position in the network, its operational importance, any potential safety or environmental risk arising from its failure and any likely consequence of its potential outage. In order to apply this maintenance strategy, each transformer has its safety, environmental and operational criticality factors assessed and combined and the asset can then be assigned a value (criticality index) indicating the required reliability. This index is used to influence the future maintenance tasks, their intervals (which may also be condition based) and their priority ranking within a limited resource environment. This leads to assets in risky or important positions being maintained in a different (more intensive) manner to assets in a position where reliability can be allowed to be lower. In practice, the criticality index is usually combined with a health index to prioritise maintenance activity. RCM may be applied to components either together or in isolation.

Condition Assessment

This is the process by which the condition of a transformer is assessed taking into account all the aspects that could affect future performance. The inputs to this process will be the test and measurement results, observations, operating history, knowledge of the failure mechanisms and processes, previous experience with similar or comparable equipment and any other relevant knowledge and information. The normal output can range from a simple normal or abnormal assessment to a sophisticated 'asset health index' which is a ranking or scoring system on a single or multiple scale to allow decisions on future maintenance or replacement prioritized over a fleet of units.

Interpretation – Special Tests and/or Intensive Monitoring

When a transformer problem is suspected or indicated (for example by routine condition monitoring), all the available information is collected and then evaluated to decide the correct course of action. To facilitate this, a wide range of special off-line diagnostic tests are available and may be used to evaluate the conditions of different parts of the transformer (for example the core, windings, bushings, OLTC and accessories). In some cases, the application of intensive monitoring, for example continuous on-line monitoring, may be required in order to gather additional data or to operate the transformer safely. The purpose of these tests is to evaluate whether the transformer could be put back into service with or without corrective actions. Continuous on-line monitoring is often useful to gain a deeper understanding of the fault condition and its dependencies on operating conditions such as load, tap-position and temperature.

Corrective Maintenance - Minor Work

Corrective Maintenance is an operation carried out to restore any part of the transformer which has failed or degraded to the point where it needs corrective action to avoid loss of performance or a major failure. The need for Corrective Maintenance follows the identification of an abnormal condition and excludes routine maintenance (TBM, CBM). Examples might include oil processing, cooling fan replacement, leak repairs.

Major Work

Major Work ranges from replacement or refurbishment of major components such as bushings, tap changers or the complete cooling system to the return of the transformer to works for replacement of the windings. Any work that involves the removal of oil from the transformer may be considered to be major.

Technical and Economic Evaluation

The cycle of transformer operation and routine and corrective maintenance is not perpetual. When a transformer suffers severe damage or when the transformer reliability is no longer satisfactory, a technical and economic evaluation has to be made to decide the best option between scrap and replace, repair or refurbish and if the work is to be done on-site or in a workshop. When evaluating the best option considerations such as outage time, spare availability, outage cost, transport and general equipment condition will be taken into account.

End of Life

The service life of a transformer should end when its condition is such that it cannot be kept in service, nor be put back into service, primarily because a technical and economic evaluation determines that its return to a serviceable condition is not economical.

1.3 Standards and CIGRE References

The following table describes some CIGRE references and standards applicable to transformer maintenance:

Designation	Title	Description
CIGRE #170 2000	Static Electrification in Power Transformers	Static Electrification characteristics of the material used in and adjacent to the flow path, mitigation methods, tests, recommended limits.
CIGRE #227 2003 (WG A2.18)	Life Management Techniques for Power Transformers	Failure identification (causes, reports), Methodologies for life management (condition-based, functional-based), Diagnostic and Monitoring Techniques, Condition Assessment recommendations, Operation on Transformers (process)
CIGRE #248 2004 (WG A2.20)	Economics of Transformer	Risk Management, Specification and Purchase, Operation and Maintenance, Repair versus Replacement decision process
CIGRE #296 2006 (JTFD1.01/A2.11)	Recent developments in DGA interpretation	Gas level in service, stray gassing oils, gas formation
CIGRE #298 2006 (WG A2.23)	Transformer Lifetime Data Management	Transformer data in the power industry enterprise; data categories, amount, quality, dynamic, lifetime data management
CIGRE #323 2007 (D1.01.10)	Ageing of Cellulose in Mineral Oil Insulated Transformers	Material, ageing process, factors of influence, degradation products, diagnostic and life management
CIGRE #342 2008 (WG A2.26)	Mechanical conditioning assessment of transformer windings	Frequency Response Analysis features and advantages, practices; guide of interpretation
CIGRE #343 2008 (WG A2.27)	Recommendations for condition monitoring and condition facilities for transformers	Review of sensors, data and recommendations for condition monitoring; Summary of recommended condition monitoring and test facilities
CIGRE #349 2008 (WG A2.30)	Moisture Equilibrium and Moisture Migration within Transformer Insulation Systems	Understanding of the mitigation of moisture during overloading, drying process and on-site repair
CIGRE #378 2009 (WG A2.32)	Copper Sulphide in Transformer Insulation	Description of the phenomena of copper sulphide in transformers, diagnostic and mitigation techniques.
CIGRE #409 2010 (D1.01.15)	Report on Gas Monitor for Oil-filled Electrical Equipment	Description of gas monitors for transformers, principles of operation, application and evaluation
CIGRE #413 2010 (TF D1.01.12)	Insulating Oil Regeneration and Dehalogenation	Description of transformer insulating material, oil contamination and degradation, oil reclamation and dehalogenation, health and safety aspects.
CIGRE #414 2010 (D1.01.14)	Dielectric Response Diagnostic for Transformer Windings	Influence of different types of solid insulation and ageing products on the dielectric response with case examples
CIGRE TF D1-01-15	DGA in LTCs	Under development

1.3 Standards and CIGRE References (continued)

Designation	Title	Description
IEC60422-2005	Mineral insulating oil in electrical equipment – Supervision and maintenance guide	Oil test description and their significance, Oil test intervals, Test results criteria (new and in-service), Test results analysis, Recommended actions, Oil treatment
IEC60599 – 1999 am1-2007	Mineral oil-impregnated electrical equipment in service – Guide to the interpretation of dissolved and free gases analysis	Mechanism of gas formation, Type of faults, Interpretation, Typical values
IEEE Std C57.93-2007	IEEE Guide for Installation of Liquid-Immersed Power Transformers	Transformer Commissioning, Transformer maintenance tasks and tests, Tasks and test intervals
IEEE Std C57.104-2008	IEEE Guide for the Interpretation of Gasses Generated in Oil-Immersed Transformers (ANSI)	General decomposition theory of oil, Type of faults, Guidelines for gas and gas generation rate (normal, caution and warning values), Interpretation
IEEE Std C57.106-2006	IEEE Guide for Acceptance and Maintenance of Insulating Oil in Equipment	Oil test description and significance, limit values for new and service aged oil for different voltage classes
IEEE Std C57.140-2006	Guide for the Evaluation and Reconditioning of Liquid Immersed Power Transformer	Extending the useful life of a transformer: Insulating Oil maintenance and diagnostic, oil reclamation, testing, etc.
IEEE Draft Guide PC57.143/Draft 21	Guide for the Application for Monitoring Liquid Immersed Transformers and Components”	Under development
IEEE Std 62-1995 To become Guide PC57 .152/ Draft 2 May 2008	IEEE Guide for Diagnostic Field Testing of Electric Power Apparatus – Part 1: Transformer, Regulators, and Reactors	Diagnostic test chart, tests and test techniques for windings, bushings, insulated fluids, tap changer, core, tank and associated devices, typical results, suggested limits (including oil tests), analysis of test results
IEEE Std C57.637-1995 (R2007)	Guide for the Reclamation of Insulating Oil and Criteria for its use	Reclaiming used mineral insulation oil by chemical and mechanical means, classification of service-aged oil, criteria for reuse, reclaiming and reclamation process

Table 1: Standards and CIGRE References

Chapter 2 Maintenance Strategy

2.1 The Importance of Transformer Maintenance

Transformer Maintenance has a fundamental impact on transformer life and reliability. From the transformer user point of view, an ideal transformer would require minimal maintenance during its lifetime (at least 40 years) together with utmost reliability. Technology improvement has reduced the need for maintenance, but as transformer lifetimes are long, transformer users have to deal with a wide variety of transformer technologies, requiring different levels and scopes of maintenance.

Possible Impacts of on a Transformer by Lack of Maintenance

The following table gives an overview of the possible impacts of a lack of maintenance as a function of transformer age, for a typical transformer:

Life Used	Possible Impacts of Lack of Maintenance
NEW	<ul style="list-style-type: none"> - Baseline data not recorded, commissioning errors missed - Failure to detect early life problems within warranty period
20%	<ul style="list-style-type: none"> - Oil oxidation begins - OLTC contacts wear (medium and heavy loads) - Weathering and UV takes affect - Trends in condition not observed
40%	<ul style="list-style-type: none"> - Corrosion in severe environments - Visible affects of weathering and UV - Transducers go out of calibration - Fan and pump bearing wear - Trends in condition not observed
60%	<ul style="list-style-type: none"> - Gaskets and seals lose resilience, oil leaks manifest - Oil decay products affect paper insulation - Weathered paint, edge and spot corrosion - Miss opportunity to intercept accelerated ageing - Miss benefits of implementing a mid-life intervention
80%	<ul style="list-style-type: none"> - Uncertainty on remnant life - Oxidation and hydrolysis enters accelerated ageing stage - Paper DP drops, sometimes prematurely - OLTC and bushing failure rates increase - Paint system protection fails
100%	<ul style="list-style-type: none"> - Expect sludge if oil has been in poor condition - Exposure causes device malfunctions - Wiring and cable insulation en-brittle - Bad oil leaks need regular topping up - Dielectric withstand diminishes (moisture) - Expensive failure (often bushing or OLTC)

Table 2: Possible Impacts on a Transformer by Lack of Maintenance

It is clear that there are many transformer degradation and failure mechanisms that can either be detected and corrected, or prevented, or slowed by appropriate maintenance. To determine the appropriate level of maintenance, the maintenance tasks and when to perform them, a maintenance strategy is required. This starts with commissioning.

Commissioning and Early Life Maintenance

Good Commissioning is essential, particularly with regard to initial oil quality, full functionality of auxiliaries such as coolers and tap changers, the proper setting of protective devices and cooler controls, the full availability of baseline measurement and test results for future comparison and diagnostics, and the full functioning of communications for alarms indications and monitoring.

In the first five years, maintenance should have no impact on transformer reliability except perhaps for the need for tap changer servicing if the number of operations dictates, however it is essential to make sure the transformer is operating properly, particularly by taking regular dissolved gas analysis (DGA) samples. It is recommended that DGA samples are taken immediately before and after commissioning and then at short (weekly) intervals until confidence in the correct operation of the transformer is gained. Thereafter, the intervals can be gradually extended until the routine intervals are reached.

2.2 Condition Monitoring

Any maintenance strategy, other than the simplest time based strategy, will depend on feedback of the condition of the transformer. To be useful however, a Condition Monitoring task must be technically and economically justifiable.

The technical justification depends on whether a condition can be detected and corrected before a loss of performance occurs.

Figure 2 shows a theoretical condition in terms of degradation as a function of time for a transformer. In this figure, three important points can be observed:

- At point X, the condition is still good but is starting to change
- At point Y, the condition has changed enough to be detectable by a specific diagnostic technique
- At point Z, the condition has deteriorated sufficiently to cause a transformer failure

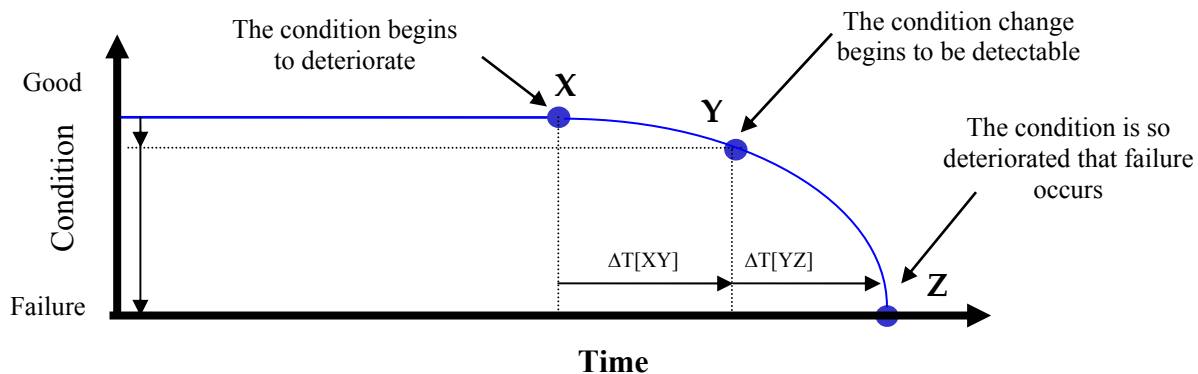


Figure 2: Theoretical Transformer Condition Degradation

To be technically feasible, a Condition Monitoring task should have the ability to;

- detect a given condition change that is relatively small compare to the condition change where the failure occurs,
- have a measurement or inspection interval that is smaller than $\Delta T[XY] + \Delta T[YZ]$ to allow detection before failure occurs,
- have a period of time $\Delta T[YZ]$ that is long enough to be able to take the preventive action (transformer outage).

As a very short time interval between condition measurements may not be practical, a valuable alternative may be to apply continuous on-line monitoring techniques. For very fast deterioration processes, Condition Monitoring with even continuous on-line monitoring may not be adequate to detect the problem in time to take action, in which case reliance has to be placed on protection devices to limit the consequence of the failure. Even for these fast processes, early detection of underlying deterioration will reduce the risk of failure if timely action is then taken. Condition Monitoring based on measurements can only be as good as the integrity of the data.

Of course, in addition to all these technical conditions, a maintenance task or a group of tasks should only be implemented if it is justifiable (for economics or safety). In other words, the cost to apply a task or of a group of tasks has to be less than the total cost of the failure that it is intended to prevent, taking into account the probability that this failure occurs. When a preventive maintenance program is designed, a group of tasks with similar "ideal" intervals will be regrouped for optimization. Moreover, applying a Condition Monitoring program to a large group of identical transformers sometimes identifies a problem in one unit that then allows the timely application of corrective actions to all members of the group.

2.3 Time Based Maintenance and Time Based Condition Monitoring

As indicated previously, these actions include maintenance actions to improve the condition and actions to evaluate condition. These time-based actions, as the name indicates, have the unique feature of being predictable and it is possible to prepare maintenance plans yearly. It is already known that maintenance practices may be significantly different from country to country and even from company to company, for several reasons that will be studied in this section.

2.3.1 Survey on Maintenance Practices

A survey conducted by the WG evaluates Maintenance Practice. Representatives of major transformer owners indicated whether tasks were performed as Time Based Maintenance or Condition Based Maintenance. The survey was divided in two parts, one for the transmission transformers and one for generator step-up (GSU) transformers. 30 respondents completed the survey and the detailed results are in Appendix 1. Survey results show that many transformer users try to apply Condition Based Maintenance rather than Time Based Maintenance.

Among the highlights of the survey results, it is noted that:

- There are significant differences on the task intervals for "visits"
- Oil test task intervals are in general in accordance with IEC 60422
- A majority of respondents use electrical tests on a "Conditional based" criterion only
- For "Accessories verifications", task intervals vary significantly (from 1 to 12 years)
- OLTC task intervals vary between 4 and 12 years
- Bushing maintenance practices vary significantly between utilities

For GSU transformers, it is observed that:

- Visits are made at a significantly shorter interval,
- Periodic sampled DGA are made, for the great majority, at an interval of one year or less
- Continuous DGA monitoring is not applied as often, probably due to the proximity of the maintenance crew
- A minority of the respondents are performing electrical tests periodically

For Transmission transformers, it is observed that:

- The intervals between visits vary greatly between the respondents but in general, are longer intervals than for GSU users
- Continuous DGA monitoring is used more intensively than for GSU users, by about 50% of the respondents and on the more critical units (selected by different criteria)
- Electrical tests are performed by about two third of the respondents

2.3.2 Maintenance Frequency from Survey Interpretation

The survey shows that maintenance practices vary significantly between transformer users. The possible factors that may influence maintenance practices are:

- Transformer characteristics and specifications
- The quality of the components installed on the transformer
- The required duty of the transformer (load, OLTC operation)
- The transformer environment (temperature, humidity)
- Historical transformer failure rate and failure types
- The level of transformer redundancy and the consequences of unavailability
- The failure mode and its effects on substation safety
- Company culture and focus based on maintenance
- The availability and costs of labour
- The degree of implementation of modern technologies
- The presence of a maintenance optimization program

The following table summarizes the typical maintenance practices that were reported in the survey. It remains for each user to determine which level is appropriate depending on the situation. It can also be noted that the maintenance level may be different for each action made on the same transformer population depending on each particular situation. As there are many factors that influence a maintenance policy, the maintenance "intensity" was divided into three different levels as described in the following table:

Action	Task Interval			Remark
	Light	Regular	Intensive	
Visit	6 m	1 m	1 d	In service
Detailed inspection visual	1 y	3 m	2 w	In service
DGA	2 y	1 y	3 m	Task interval may differ with monitoring
Oil tests	6 y	2 y	1 y	
Cooling system cleaning	Conditional	Conditional	Any Interval	Outage may be required
Accessories verification	12 y or Cond.	6-8 y	1-2 y	Outage required
Electrical basic tests	Conditional	Conditional	Any Interval	Outage required
Insulation tests (DF or PF)	Conditional	6-8 y	2-4 y	Outage required
OLTC inspection internal	12 y	6-8 y	4 y	Consider number of operation, technology and manufacturer recommendations

Table 3: Typical Maintenance Intervals

Note: - The survey does not apply to the maintenance practices for industrial transformers;
 - SF6 transformers and their unique requirements for maintenance are described in Appendix 2.

The three levels of maintenance task intervals are described as follow:

Light:

- Transformer equipped with components that are known to be very reliable
- Low load and low number of tap changer operations
- Transformer does not operate in a harsh environment
- Advanced transformer technologies that require less maintenance
- Low consequences in case of unexpected failure

Intensive:

- Components that are known to require frequent attention
- High load, high number of OLTC operations
- Transformer operates in a harsh environment
- Older transformer technologies
- High consequences in case of unexpected failure

Regular: - Any situation that is in between the two previous ones.

2.4 Condition Based Maintenance

Condition Based Maintenance (CBM) relies on identifying a reason or need for a maintenance intervention. In Chapter 1, the maintenance cycle of Figure 1 illustrates that CBM requires knowledge of the transformer condition from regular surveillance, either through performing the routines of time based maintenance or time based condition monitoring, or from on-line condition monitoring. Measured parameters or observed states are assessed against pre-defined criteria (limit values) for acceptable service condition. Maintenance is only performed when a change in equipment condition warrants taking action. This represents an advance in maintenance strategy because it seeks cost effectiveness.

This section describes two examples of Condition Based Maintenance using oil tests and dissolved gas analyses (DGA), where exceeding some limit values leads to identifying causes and taking remedial action.

2.4.1 Example 1: Oil Tests Reveal "Abnormal Values"

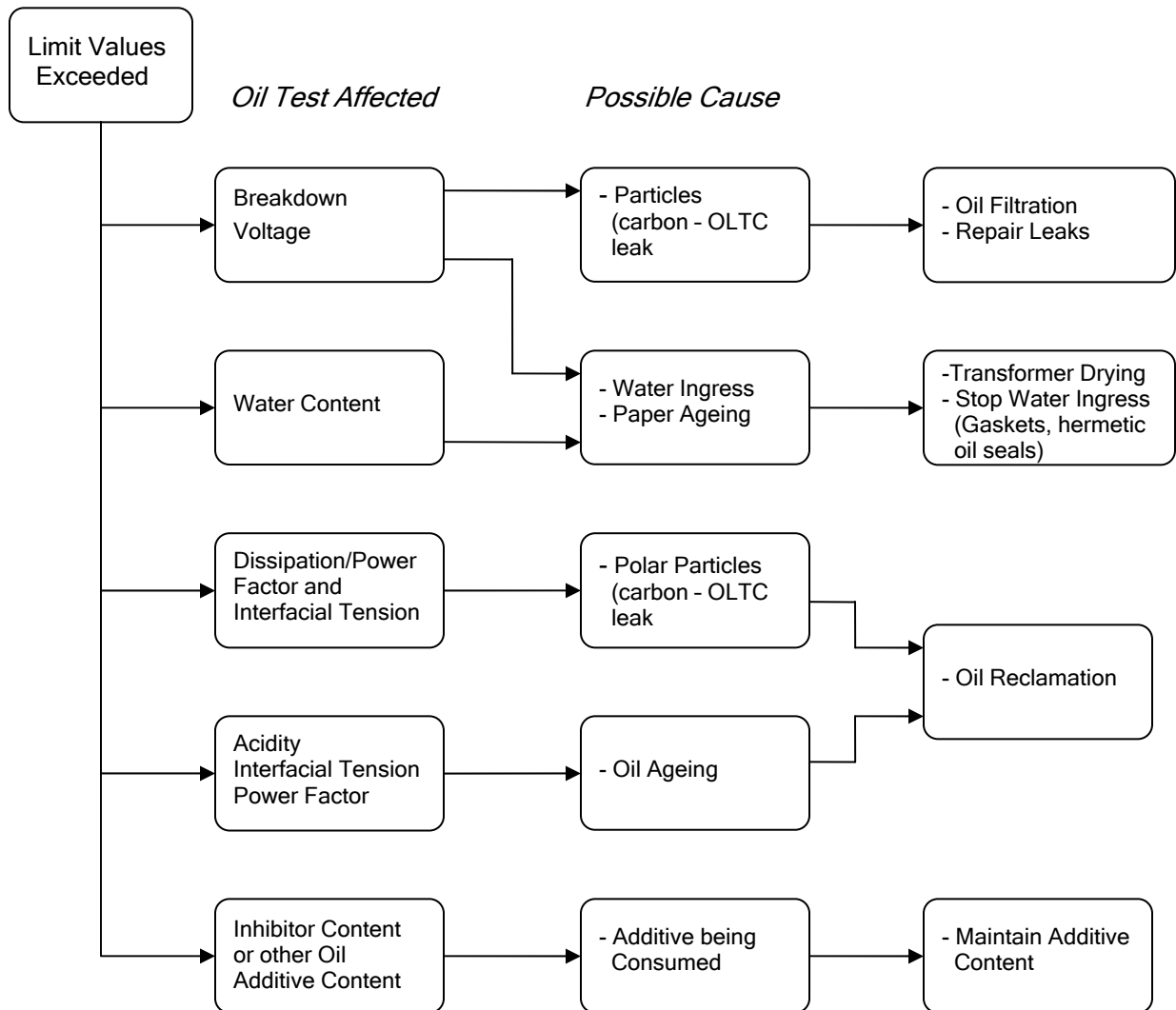


Figure 3: Decision Process in Cases of Oil Tests Returning "Abnormal Values"

To establish the limit values, refer to IEC60422 and IEEE Standard C57.106

2.4.2 Example 2: DGA Reveals "Abnormal Values"

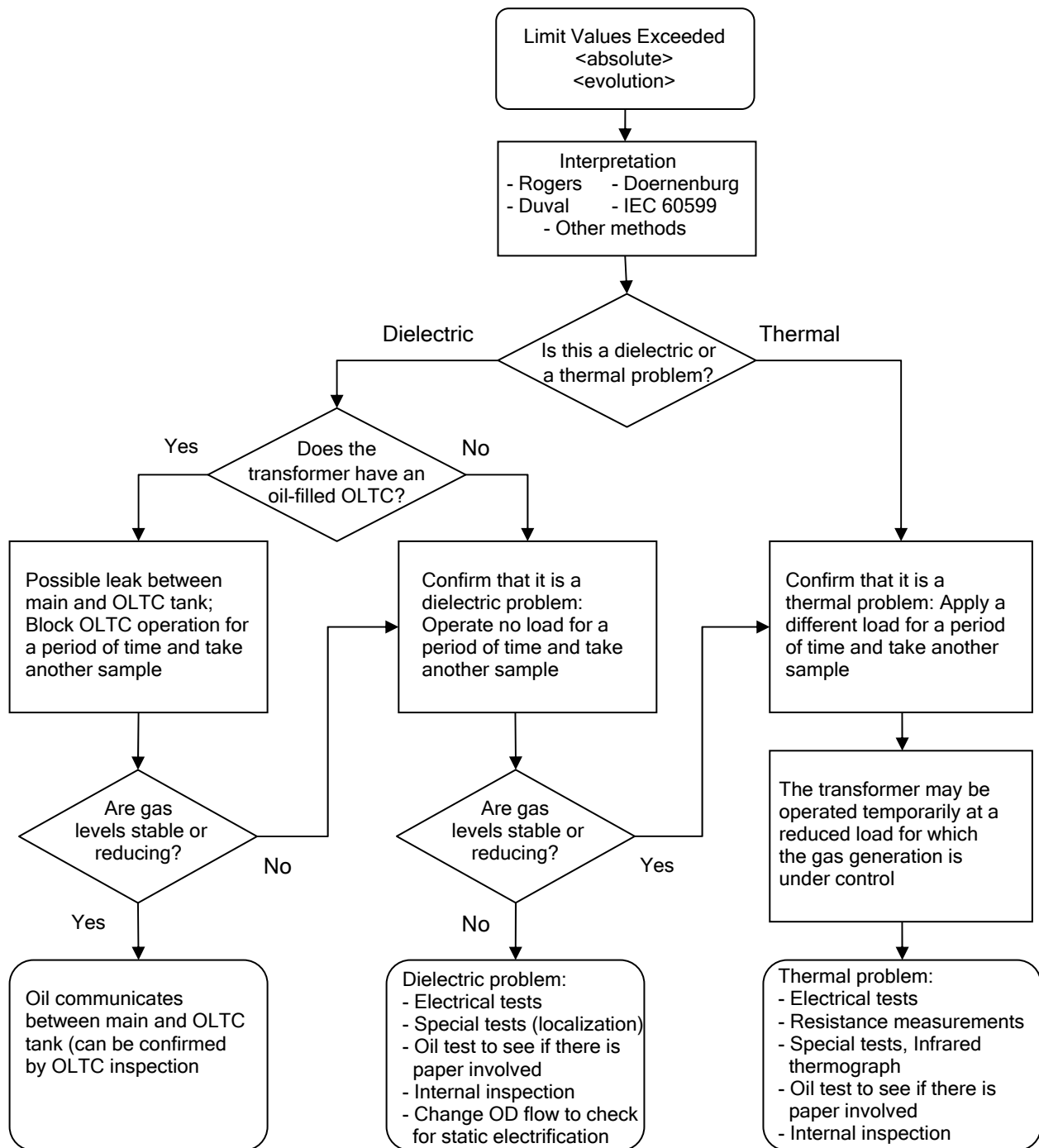


Figure 4: Decision Process in Cases of DGA Returning "Abnormal Values"

To establish the limits values, refer to the following documents:

- [1] IEC60599: "Mineral oil-impregnated electrical equipment in service - Guide to the dissolved and free gases analysis"
- [2] IEEE Std C57.104: "IEEE Guide for the Interpretation of Gasses Generated in Oil-Immersed Transformers"

The transformer manufacturer may also be contacted in order to obtain information about transformer design and possible problems or safety considerations.

2.5 Corrective Maintenance

The following figure describes an example of corrective maintenance that is applied when a transformer has been tripped by its protection.

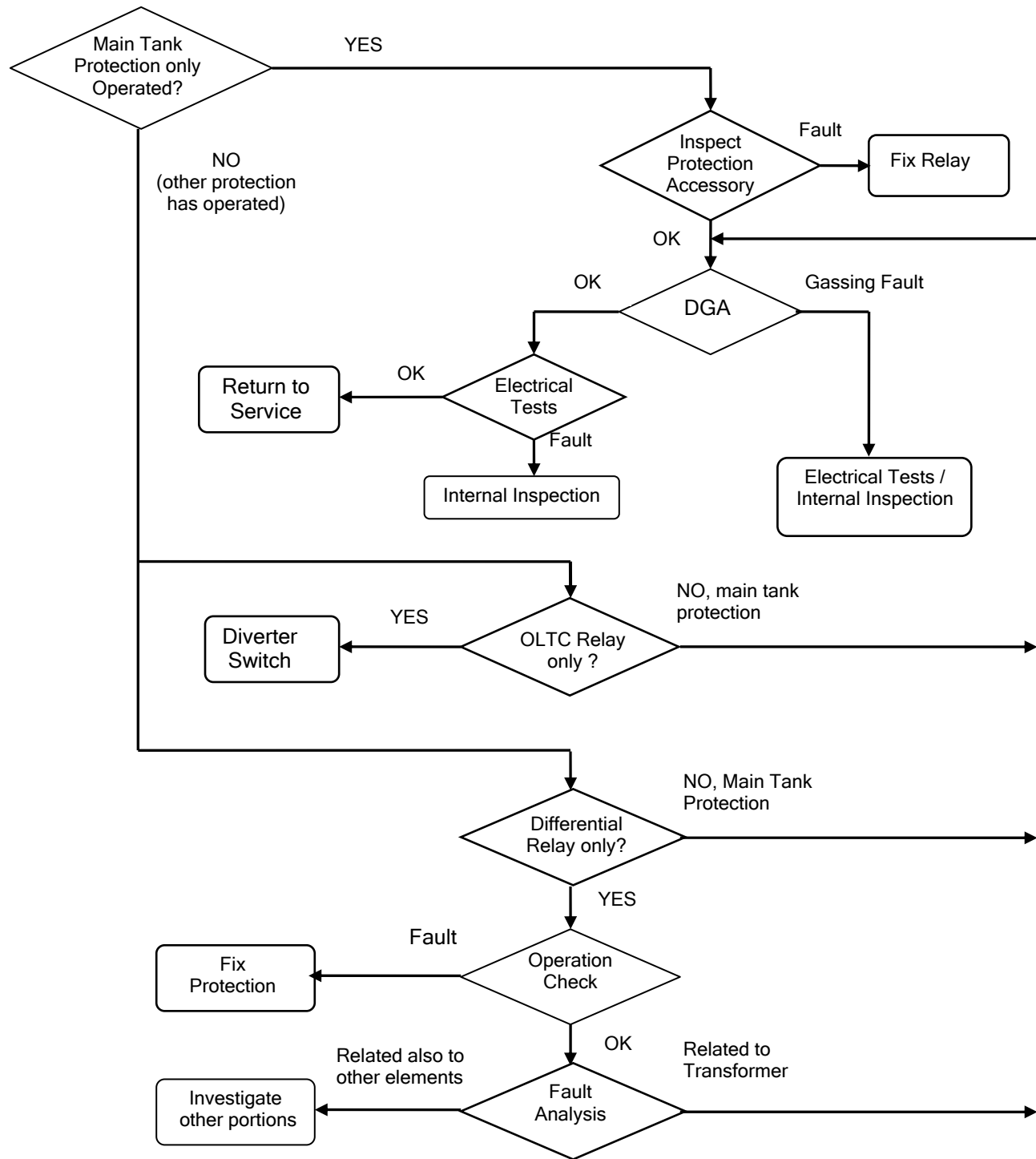


Figure 5: Decision Process after a Transformer Trip

Note: Additional information about what do when a Buchholz relay operates is given in Chapter 5, Section 5.5.6.

2.6 Continuous On-Line Monitoring

2.6.1 Definitions and Justifications

Monitoring can be described as all aspects of performance management concerned with tracking the system activities in order to gather the appropriate data needed for determining performance.

On-Line Monitoring implies aspects where data can be collected while the equipment is electrically energized and in service. Data (or samples such as oil) can be collected and /or measured while the equipment is energized (subject to local safety regulations).

Continuous On-Line Monitoring implies the two previous notions and also the application of intelligent electronic devices (IED). These are devices with a measurement mechanism of some type, together with internal signal and data processing capabilities, that can be described as 'smart sensors' or 'smart systems' providing measurement and control functions, while the subject equipment is energized and in service.

The basic goals of Continuous On-Line Monitoring are:

- To generate early warnings in case of incipient faults, to reduce the risk of unexpected failure
- To follow up the development of the diagnostic values on suspect or faulty units which cannot be taken out of service immediately
- To reduce costs for periodic diagnostic testing and assign workers to other tasks
- To archive measured and computed data in a database for future analyses

If applied adequately, Continuous On-Line Monitoring technology may have the following significant advantages:

- It reduces the condition monitoring task interval nearly to zero (compared with off-line diagnostics)
- It can detect the change of measured parameter(s) shortly after its occurrence
- It can generate an automatic warning if preset limits or trends are exceeded
- In case of unexpected failure, it performs a "black box" function (records the data before and after the failure and thus enhances the available evidence used for failure analysis)

2.6.2 Continuous DGA On-Line Monitoring

As DGA are proven to be a very good indicator for a large proportion of transformer incipient fault and because an early detection of an incipient fault may avoid major failure, Continuous DGA On-Line Monitoring is the most implemented on-line monitoring technology for transformers. Several sensors technologies are available in the market using different detection techniques (fuel cell, chromatography, semiconductor, photo-acoustic spectroscopy, thermal conductivity). Depending of the technology and its implementation, the systems are able to provide:

- A single measurement of one specific gas
- A single measurement of a composition of several gases with specific proportions and sensitivities
- Multiple measurements of different gases

Gas-in-oil monitors often include a built-in moisture sensor to provide data on the moisture content in oil.

2.6.3 Other On-Line Continuous Monitoring Technologies

In addition to the Continuous DGA On-Line Monitoring systems described above, other discrete systems are available and can be combined with DGA monitors. Some of them include:

- Systems supporting mathematical models designed to calculate additional information such as winding hot spot temperatures, rate of ageing of paper insulation, moisture content in paper or barriers, and effectiveness of the cooling systems
- Monitoring of bushings by measuring the leakage current through capacitance tap (where capacitance taps are available)
- OLTC monitoring including mechanical conditions of the drive system, contact wear, temperature differential, dissolved gas analysis, tap position tracking/counting
- Partial discharge using electrical, acoustical, or UHF signals

Literature:

- [1] *Cigré WG A2.27: Technical Brochure 343, "Recommendations for condition monitoring and condition facilities for transformers"*
- [2] *IEEE Draft Guide PC57.143/20, "Guide for the Application for Monitoring Liquid Immersed Transformers and Components"*

Chapter 3 Maintenance Process

The Maintenance Process can be summarized in four stages: Planning, Organization, Execution and Recording with a feedback stage providing for Optimization. These maintenance stages are shown in the following figure:

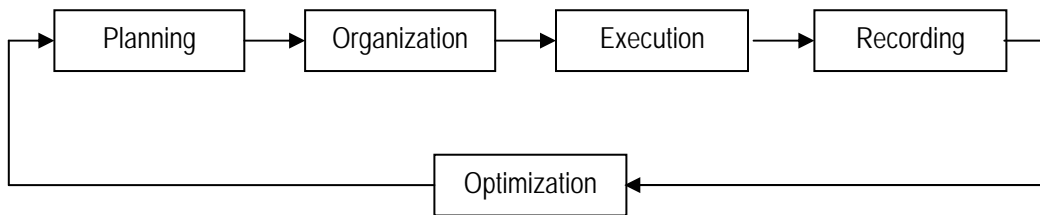


Figure 6: Maintenance Process

Like most processes, maintenance requires the input of data. Making prudent decisions over any activity to be performed on a power transformer, including maintenance, requires the availability of detailed lifetime data about the transformer, its operational and maintenance events, and data collected from performance records over its service history.

Of necessity, transformer life data at each stage of the process must be available, relevant and timely. Furthermore, the data has to be systematically collected, processed and stored for future needs. Ideally, transformer lifetime data management will have a lifetime data strategy and a lifetime data model for the transformer [Ref: *Cigre Technical Brochure 298, "Transformer Lifetime Data Management"*]

When the Maintenance Process is performed on a large transformer population, it becomes impossible to manage the Maintenance Process without the use of a Maintenance Management System (MMS). Also, optimization of the Maintenance Process is facilitated by using the MMS. This is discussed in the stages of the Maintenance Process below.

3.1 Planning

3.1.1 Maintenance Guidelines

A Maintenance Guideline should provide a clear and comprehensive response to three essential questions for each asset: What maintenance has to be done? When does it need doing? How is it done? The answer to the last question is generally available in the manufacturer's manual (refer to Appendix 3 for the suggested content of an operation and maintenance manual), or could be contained in a generic procedure or might even be prescribed as obligations under corporate policy, regulatory rules or law (for example environmental legislation). Maintenance Guidelines can be effectively stored as a 'library' of maintenance tasks in any computerized Maintenance Management System. And like a book, each Maintenance Guideline should be kept in a unified structure and be subject to document management in order to reflect all possible changes occurring in time.

Maintenance Guideline Structure

The structure of a Maintenance Guideline could include:

- General information about the transformer (for example type, power, voltage)
- Types of maintenance work to be done with the relevant criteria to invoke it (for example time interval, event, condition, result of diagnostics) and operational status (for example energized, de-energized, or both de-energized and disconnected)
- Qualification and skills required to perform individual maintenance works
- List of tasks related to individual maintenance works and the associated time required
- Excerpt from, or reference to manufacturer's manual giving detailed information (for example work steps, sequence, tools, material, safety aspects)
- Maintenance report forms
- Source of information for maintenance data collection and reporting – based on standard report forms

3.1.2 Computer-Aided Maintenance Management Systems

There are different Computer-Aided Maintenance Management Systems used worldwide by utilities for planning maintenance, however essentially they all have a similar structure with common key features. They mainly handle the planning of Time Based Maintenance activities (including TBCM) and provide tools to plan conditional and corrective maintenance. These tools do not focus on power transformers specifically, but are also suitable for use on any type of equipment. The key elements of a MMS and their features are listed below.

Equipment Inventory

Equipment Inventory is a fundamental component of the Maintenance Management System. Equipment Inventory should contain all necessary information about the equipment. Every transformer should have its own equipment inventory number that is unique and with all relevant characteristics are attached such as: transformer type (for example auto, GSU), position in the power system (for example plant identity, location), voltage level (for example HV, LV, TV), power for different cooling stages, year of manufacture, OLTC type, and bushing type. The system requires a database with the functionality to browse the network, search for the required equipment, show its characteristics, and selectively retrieve some relevant information or even compile a complete dossier.

Computerized Maintenance Guidelines

Part of the MMS incorporates a register of Maintenance Guidelines with which to manage maintenance activities. These consist essentially of Task Lists, which register all of the tasks to be done within a work package, and a set of criteria defining at what intervals, or under what circumstances, to perform them. To facilitate Maintenance Planning, the Maintenance Guidelines should differentiate between actions that improve condition, and actions that evaluate condition.

Task Lists and Operations

All tasks are stored in a register under codes and may be associated to a large number of different Task Lists. The number of tasks is thus substantially reduced and statistical evaluations are made possible.

Maintenance Plan

Establishing a logical link between a piece of equipment (where), a task list (what) and a strategy (when) is in essence all that the MMS has to do to create a Maintenance Plan for the equipment. It actually defines in detail how a piece of equipment should be maintained by linking the respective Maintenance Guidelines stored as code in the MMS 'library'. Each piece of equipment may have more than one Maintenance Plan. For example, have one plan for condition assessment and another for other maintenance tasks. The Maintenance Plan then governs any maintenance scheduling and future work order generation for that equipment.

Maintenance Schedules

Once a maintenance plan has been set up, a Maintenance Schedule for the related piece of equipment can be developed. Detailed Work Order requests, commonly referred to as 'maintenance calls', may then be generated utilizing the link between Task Lists, strategies and a defined starting point. The first proposal for the Maintenance Schedule is created from the list of 'maintenance calls' and is usually depicted in a time-based Gantt chart. The 'maintenance calls' can then be edited (for example deleted, added, shifted, skipped or inserted) in order to reach a final practicable version in accordance with the usual maintenance constraints of work co-ordination, staff availability, budgetary allowances and operational requirements.

Work Orders

The MMS uses a simple transaction to change the status of a selected 'maintenance call' into a Work Order. The Work Order is then issued and needs to be administered during and after execution of the work. In effect this becomes a "technical order" used principally for following up and evaluating the planned maintenance allocated to the equipment. Alternatively, a package of Work Orders could be grouped to make a "commercial order" and issued to maintenance contractors.

Outage Planning

The creation of a Maintenance Schedule for a power transformer in the MMS does not mean that the scheduled maintenance will actually be performed precisely at the planned time. System operators usually develop and maintain a table of planned outages for key assets that considers asset criticality, system reliability and availability. Outage Planning usually has three horizons; weekly, monthly and yearly. Outage Planning opens a wide range of possibilities for coordination of maintenance activities on assets that have a co-dependent outage. Once the yearly outage schedule has been set up, the planned outage terms may then influence the Maintenance Schedules planned by the MMS.

Maintenance Task Tracking

This element is discussed in detail in Chapter 3, Section 3.4.

Link between Asset Inventory and Maintenance

Figure 7 below illustrates how the MMS creates links between a transformer in the Equipment Inventory and its Maintenance Guidelines and the detailed Task Lists.

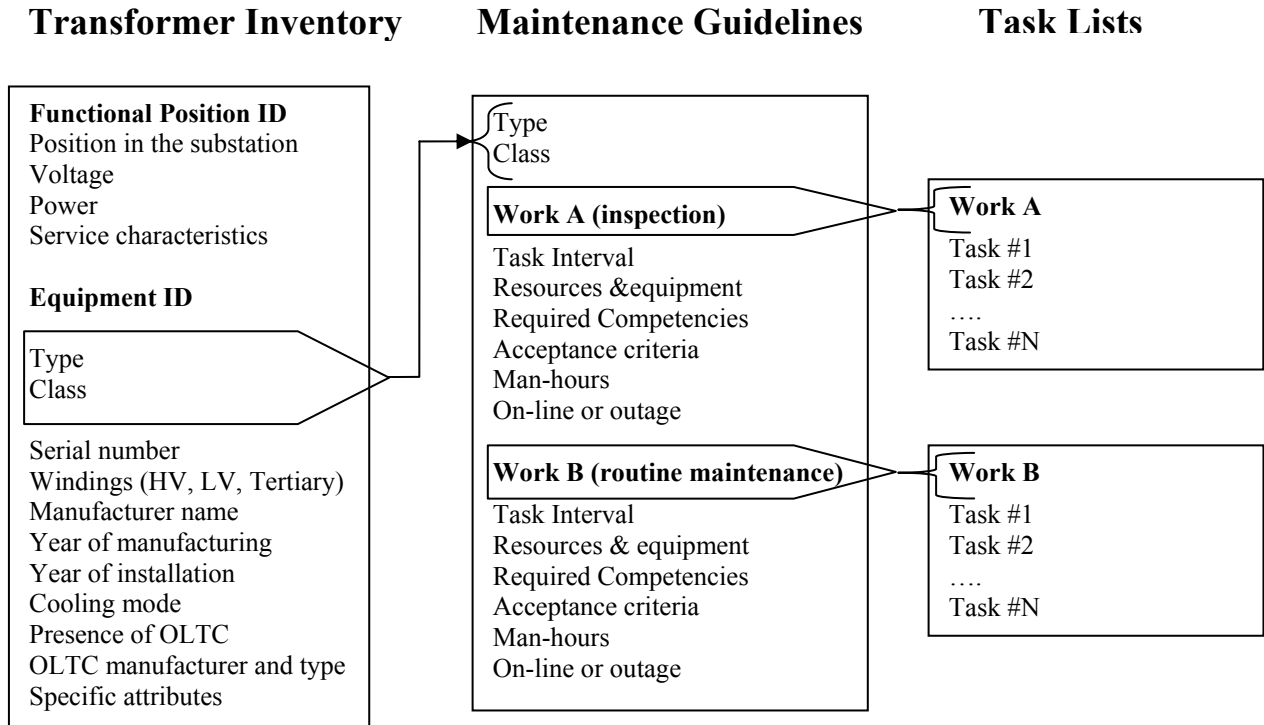


Figure 7: Linking between Transformer Inventory, Maintenance Guidelines and Task Lists

Furthermore, Figure 7 shows diagrammatically how the MMS could be used to select a transformer via its Functional Position ID and its Equipment ID at any point in time to formulate a complete Maintenance Plan by retrieving relevant data from the Maintenance Guidelines and the Task Lists. Accordingly, the Maintenance Plan captures the resources required and a Maintenance Schedule can then be created from the Task Lists.

3.2 Organization

3.2.1 Introduction

At the Planning stage, a list of transformers, their respective maintenance tasks and the required resources, is produced and made available for the Execution stage. At the Organization stage, the maintenance manager will apply maintenance planning in the day-to-day operations including resource management, outage planning and work contracting. The basic task for the maintenance manager is to respond the questions – *Who will do it? When does maintenance start? How long can it take? Will the equipment be switched off for maintenance? What resources (both human and technical) are needed to fulfil all maintenance tasks?* In reality, during the operation of an electrical grid, changes in load, switching and unplanned events are continual. Maintenance managers have to react rapidly to new situations in order to optimize the maintenance work as much as possible. For GSU transformers, transformer outages coincide with the outages of the generating machines. Common practice is to group maintenance work together (for example an overhead line together with the substation bays at each end of the line, or a network transformer together with the switchgear in the same bay).

The way of organizing transformer maintenance is also affected by the type of organization structure that is in place within the utility. Some utilities are very much centralized with a very strong headquarter group and others have decentralized into regions with many decisions made locally. The maintenance standards are usually defined at the headquarter level and the Planning, Scheduling and Execution are under local responsibility. Moreover, depending on remoteness, management philosophy and company history, the technical support may also need to be de-centralized. Another important prerequisite for Maintenance Organization is the availability of competent and effective human resources to perform the maintenance tasks. Maintenance may also be coordinated with other activities such as installation of new equipment through load growth, the redeployment of replaced units, manufacturer recall, and modernization.

3.2.2 Human Resources - Competencies

Performing maintenance tasks has risk, and to mitigate this requires personnel to command certain competencies. Every maintenance task requires a certain measure of competence, skill and experience. Some tasks require authorization (e.g. some diagnostic measurements), further education (chemistry for dielectric tests such as DGA, furan analysis), acquired experience (dismantling or erecting) or operator training on special devices (oil treatment).

Another part of competence is linked with health and labour safety issues, training, capabilities, legal regulations. Some works on electrical equipment can only be carried out by people with current electrical qualifications. Some tasks require special training (working at height, fork lifts, lifting devices).

Special procedures and qualifications are usually required to secure the work zone and the equipment within as being electrically isolated and made safe (disconnecting and grounding) and to provide work permit access to the transformer for work.

Five levels of competency are defined:

- Level 1:* Actions to be taken on certain transformer components and are generally described in the maintenance manual issued by the manufacturer. *Examples: control operations, check of oil levels, exchange of consumable materials*
- Level 2:* Actions performed with basic written procedures and/or supporting equipment or devices. Personnel use simple to use (tools) or to assemble, being part of the transformer or external. Such actions are generally described in the maintenance manual issued by the manufacturer. *Examples: replacement or exchange of accessories, junction parts, and routine checks.*
- Level 3:* Actions performed with complex written procedures or the use of special supporting equipment. Personnel are trained in using complex tools or processes. *Examples: Exchange of an original part or component, complex setting or re-setting*
- Level 4:* Actions requiring personnel trained in special techniques or technologies and utilization of special tools, and/or supporting equipment. *Examples: Modifications and upgrading activities (modernizations), changes in functions, changes in the way of operation and use.*
- Level 5:* Actions needing specialist technical knowledge and with the support of industrial processes, industrial equipment or devices. *Examples: Complete inspections or revisions which require detailed dismantling of the equipment, its reconstruction, and replacement of obsolete or worn parts or components*

The following table describes what level of competence is recommended (for at least one member of the maintenance team) to perform maintenance actions on transformers.

DESCRIPTION OF THE OPERATION	Level	DESCRIPTION OF THE OPERATION	Level	
Switching of off-load tap changer	1	Other maintenance work: - Tank and pipe painting-coating - Oil treatment - Replacement or oil retreatment - Tan delta tests on transformer or bushings - Replacement of HV/LV/N bushings - Replacement of motor-powered fan - Change of circulation pump - Change of oil circulation indicator - Replacement of thermometers - Replacement of relief valve - Replacement of Buchholz relay	2	
Overall inspection: cleanliness, moisture content and oxidation	1		3	
Search for leaks, unusual noises, hot spots	1		4	
Visual check on HV-MV-LV bushings	1		4	
Air dryer check	1		4	
Visual check on electrical auxiliary cabinet	1		3	
Oil level check	1		3	
Check on desiccant breather condition	1		3	
Maintenance of air coolers / water coolers:			3	
- Heat exchanger cleaning	2		3	
- Motor-powered fan	2		3	
Oil analysis:			Expert appraisal upon failure: - Nature and origin of the failure - Operating background analysis - Voltage and current disturbance analysis - Oil analysis: Buchholz gas, DGA, furans, PCB - Electrical measurements: Ratio, Resistance, Impedance, Insulation Tests - Endoscopy - On-site expertise • Result interpretation • Definition of the type of repair (on site, in workshop) and operating processes	4
- Physical-chemical	3			4
- Dissolved gas analysis	3	4		
- Particle count, furan content	3	4		
On-load tap changer:		3		
- Operating and safety checks	2	3		
- Oil analysis	3	3		
- Complete overhaul of OLTC including replacement of parts and oil	4	3		
Check on transformer accessories:		3		
- Oil level indicator	1	5		
- Cooling system functional check	2	4		
- Filter clogging	2			
- Oil circuit check	2			
- Thermostat	2			
- Replace filter off-line for OLTC oil filtering	2			
- Replace filter on-line for OLTC oil filtering	3			
- Buchholz relay	3			
- Protection relays for transformer and OLTC	3			
		On-site repair:		
		- Without untanking	4	
		- With untanking and expert appraisal of active part	5	
		Repair in factory (with untanking):		
		- Disassembly to view the fault and validation of the repair process	5	
		- Expert appraisal (causes and origin of fault)	5	
		- Reassembly and tests	5	

Table 4: Examples of Actions versus Competence Levels

With the broad range of maintenance tasks, and their requisite qualifications and competencies, there needs to be in place a training program to provide, maintain and develop the skill base. For example, some organisations arrange structured training programs based in a classroom. Another method is on-the-job training, where trainees work with experienced personnel.

Reference:

"The Five Levels", Excelec (Gimélec), July 2007.

3.2.3 Local Organization

Efficiency and cost minimization can be very easily compromised unless there is prudent Maintenance Organization. Clearly, the basic maintenance actions of in-service visual inspection and taking oil samples, from a number of transformers in one locality, are best performed concurrently in the one visit. Whereas, if the maintenance consists of intensive work requiring the transformer to be out of service for several days or weeks, then maintenance may be done alternately or intermittently on different transformers in the same substation. The basic problem is usually to negotiate relevant outage times with the dispatch centre. The preparation of long-term outage plans usually alleviates this issue. The outage, during which a transformer can be taken out of service, is usually limited in time. To take advantage of the transformer outage, maintenance may be also applied to neighbouring switchgear that will also be out of service with the transformer. It is generally more practical to allocate maintenance to a group of transformers in different years. Moreover, maintenance

sometimes uncovers unforeseen issues requiring additional investigation, some repairs and an extension of time, and good practice is to allow for this contingency with some ‘float’ time in the allocated outage.

3.3 Execution

3.3.1 Internal and External Resources

Some of transformer maintenance activities (routine works) can be provided by the utility’s own staff, whilst more specialized tasks (OLTC inspections, special diagnostic works) may be assigned to specialist external contractors.

Different levels of outsourcing may be used to execute the maintenance activities. Some utilities use maintenance outsourcing exclusively, whilst others use outsourcing only for very specific and specialized tasks. There are basically two views on outsourcing specialized tasks:

- Only specialized, highly demanding tasks are outsourced to obtain the best results
- Specialized tasks are performed by internal staff to maintain technical knowledge and competencies

Economic aspects also have to be taken in consideration when deciding about the extent of outsourcing. Common tasks may be outsourced only in the case where it would not be efficient to keep their own staff, and is usually less costly than external contractors. Other factors such as remote locations, and the level of specialization needed may influence which resources are used.

3.3.2 Safety When Working on a Transformer

Several safety aspects have to be considered when working on a transformer. The following items are not necessarily exhaustive. The local safety code should always be referred to.

Grounding

Electrostatic and electromagnetic induction is always present in an operating substation. After the transformer has been de-energized, it is good practice to ground all bushings before disconnecting the leads of the transformer and to keep them grounded at all times during the work, in order to avoid electrostatic and electromagnetic induction. The only exception to this would be to allow electrical testing.

Working at Height

For any work performed above ground level on a power transformer, it is necessary to use the safety measures for working at height. Possible measures include:

- Wearing a safety harness and always tethering it to various anchorage points or devices
- Using a fall restraint and/or fall arrest device with the safety harness
- Erecting a safety fence around the tank lid perimeter
- Wearing safety helmets, also by ground workers in case of dropped objects
- Tethering the top of a ladder to the transformer tank
- Erecting scaffolding for all long duration activity
- Using an elevating work platforms for long reach, awkward access or very high bushings

Use of Voltage or Current Sources

Because insulation tests are performed at relatively high voltages, workers should avoid touching all bushings during the application of test voltage, even bushings or wires that are grounded. Moreover, when applying a DC source to a transformer winding, a discharge circuit should be connected before interrupting the current, in order to avoid an over-voltage.

Pressure

Before applying vacuum on a transformer, insure that the tank is designed to withstand a certain level of vacuum. This information is usually available on the nameplate of the transformer or in the OEM manual. If a positive pressure has to be applied (for example to transport the transformer empty of oil), apply appropriate precautions if a manhole has to be opened because light pressure applied to the large area on a manhole cover will create large force. A good procedure would at first only loosen the manhole cover bolts, then break the seal and vent the gas pressure, and then continue to remove the cover.

Auxiliary Circuit

No work should proceed on the control cabinet, until all auxiliary circuits that feed the transformer are switched off. Beware always to check for multiple sources supplying the control cabinet.

Accumulated Mechanical Energy

When working on an OLTC, remove all stored energy in the energy accumulator springs.

Closed Vessel

All work inside a tank should be treated as confined space work with the relevant regulatory controls. The air inside the tank should be continuously monitored to ensure it sustains life and to detect any explosive gases inside the tank. Always have an emergency response plan ready to implement in the event that the occupant becomes trapped or injured.

Tank Gas Filling

When a transformer is filled with any gas other than air (for example nitrogen), it is mandatory to inform all workers and to prevent all tank access. Should the need for subsequent tank access become unavoidable, then this must only occur after the gas has been replaced by air, and must always be treated as confined space access.

Accumulated Gas

When maintenance is performed on an OLTC and the oil compartment has to be opened, a good practice is to appropriately vent the trapped explosive gases. This precaution also applies if the main tank is opened after an internal fault.

Fire Extinguishing System

Perform a risk assessment on the need to deactivate the Fire Extinguishing System.

3.4 Recording

Maintenance Recording has two main aspects;

- the financial aspect, which is dealing mainly with hours spent, travel and material or parts used, and
- the technical aspect, which is dealing with reliability, performance, risk and condition.

The technical aspect of Maintenance Recording has a very important function that allows the maintenance crew to describe in a structured way what maintenance was performed on a transformer and to enter this information into the transformer lifetime data management system. Maintenance data has an important place in the lifetime data of an individual transformer. Maintenance data has to be considered beside the other data that is collected over the life of the transformer such as operational data, environmental data and network events, with events starting from commissioning and recorded up until scrapping of the unit, as represented in Figure 8 below.

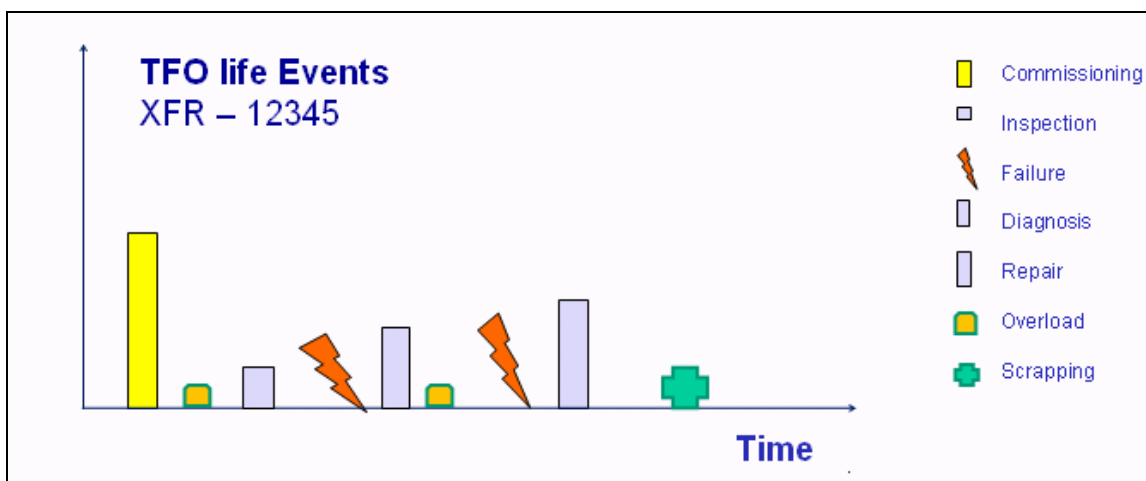


Figure 8: Maintenance Events as Important Life Events

Refer to Appendix 4 for an example of the information structure used for Maintenance Recording.

Simple cases are well described within a system using a paper or computerized form. In more complex cases, especially for repair cases or where a complex diagnostic precedes the repair, the reporting requires more details or additional written reports. The main advantages and goals of Maintenance Recording are making use of best practice and proven methodology in every maintenance reporting case, using a systematic approach and clear wording, and having easy access to the Maintenance Recording data.

Preventive Maintenance Tracking:

Different forms of technical maintenance records are used. The most common way is filling out prepared paper forms by ticking the scheduled maintenance tasks and filling in measured values or other results. These records are often used as attachments in the maintenance hand-over to the maintenance engineer. These reports may be entered into the computerized Maintenance Management System. Output or findings that require corrective actions may be immediately planned and/or ordered by the system. The use of electronic forms in conjunction with mobile devices has been trialled in some areas, and is expected to become common practice in future years.

Corrective Maintenance Tracking:

Performed in addition to preventive maintenance tracking, this function includes the tracking of corrective maintenance in order to show a complete history of what was done on each transformer over its service life. This body of information also allows the facility to optimize future Maintenance plans and accumulate knowledge of the equipment. The data to be collected and stored for technical Corrective Maintenance Tracking should contain the following categories:

- Data for a unique identification of the transformer and its properties and location
- Transformer location details
- Time of maintenance action
- Environmental conditions on site during maintenance action: *Temperature, wind, rain, storm, humidity*
- Components, parts and material used and the parts replaced
- Photographs: *The ‘as found’ and ‘return to service’ condition, providing a reference for future work*
- Tests results taken before a return to service: *Proves serviceability and provides new benchmark test data*
- Problem description: *Failure, symptoms and circumstances*
- Problem cause: *Data on what was causal to the failure or malfunction. In some cases the root-cause may not be obvious, and requires more detailed diagnosis and investigation. The root cause may also not be found*
- Remedy / Action: *A report of the remedial action take*

Recording the Results of Diagnostic Tests and Establishing Trends:

It is very important to record and retain the results of diagnostic tests performed on each transformer over time. Besides the ability to compare measurements, the accumulated data also facilitates establishing trends for any one particular transformer, and furthermore to compare trends within a group of transformers to easily identify those units displaying atypical behaviour.

There are usually several variables that may affect the performance of a diagnostic test. Especially the factors that may affect the repeatability of a diagnostic test need to be fully understood, and their value or status recorded at the time of performing the diagnostic test. Good practice employs a discipline of recording the details of the diagnosis measurement set-up, the test equipment used, the raw test data obtained, as well as the usual derived calculated values, results, or graphs used in a diagnostic test report.

3.5 Optimization

Maintenance Guidelines may change (evolve) depending on level of knowledge, the amount and quality of data available, and the development of diagnostic, monitoring or other condition assessment methods. Systematic and accurate reporting of relevant information from maintenance activities, the lifetime data model and data storage are essential. They provide the available data for decision-making on the immediate maintenance of any particular transformer, as well as the knowledge base for maintenance evaluation. Mid term and long term improvements to the transformer maintenance system can be derived from continuously improving standards, whether they are internal, utility-based or industry wide.

Condition Based Maintenance (CBM) or Reliability Centred Maintenance (RCM) often require different maintenance strategies according to the actual technical condition or system criticality of the transformers to be maintained. This would require individual condition assessment for every unit in the fleet and a ranking system indicating which units deserve special maintenance attention.

Assessing Individual Transformer Condition

There are more factors based on technical condition, which define the likelihood of failure and indicate the need for maintenance:

- Actual (immediate) condition – results of current maintenance (for example electrical measurements, DGA)
- Cumulative wear – number of severe through faults, over-voltages, inrush currents, average load, degree of overloading, ageing of cellulose, OLTC condition – contact wear, quality of oil, corrosive sulphur
- Number and nature of failures – failure modes and history, bath-tub curve failure rates, common mode failures for accessories
- Number of failures related to type (design)
- Age and accumulated service time

Other factors may be followed in order to assess the “net future value” of the transformer:

- Accessibility of repair, availability of spare parts, manufacturer and documentation
- General operational experience related to type (design)

The last two factors often play a key role in making decisions related to disposing of units with high probability of failure or purchasing new units. The “technical” factors multiplied by appropriate weighting coefficients provide the basis for calculating a Health Index which effectively ranks the technical condition of every transformer.

Computer based Maintenance Management Systems may contain lifetime data about the transformers, including life events (forced outages, failures), diagnostic results (findings), and records (findings) of maintenance. As the systems usually allow for export of the data in various formats, this data can be easily used for statistical analyses. This gives the system operator the facility to follow the performance of equipment, to select records according to type, age and design of the transformer. The results of statistical reviews may be used to selectively adjust the maintenance rules and guidelines for an atypical transformer or even a subset of the transformer population.

Time Based Maintenance

A register of all events connected with the particular transformer (minor and major failures, repairs, diagnostic results) may be used to set or adjust maintenance intervals. The number of failures, and the mean time between failures, are two parameters used to optimize the setting of maintenance intervals. In some cases, the recognition of common mode failures (oil leaks) may lead to some maintenance tasks being added, whilst other failure modes force some tasks to be deleted from the task list. Practically all computer-aided Maintenance Management Systems include event registers, which provide all the information necessary for such decision-making. If the registered failures are interpreted in relation with the design and/or make of a transformer, a selective maintenance optimization may be carried out as indicated in the following examples:

- I. *The annual statistical report shows an increased rate of repeated minor failures for transformers type XYZ; as a recommendation based on this fact, an increased frequency of visual inspections was introduced for this type of transformer*
- II. *General preventative Maintenance Guideline requires a yearly inspection of component X for transformers type Y. As this inspection has never revealed any failure or bad condition, the guideline has been modified and the regular inspection was cancelled*
- III. *The transformer monitoring system displayed gassing of the unit; in order to facilitate the follow up of the event, it was decided to apply intensive DGA sampling of oil for a limited period of time (until the decision on corrective action has been made)*

Condition Based Maintenance

The failure rate is not the same for all transformers of the same type. It also depends on the condition of the transformer, on its age, past average load, number of through faults and over-voltages it has seen, results of diagnostic tests (paper insulation, copper sulphide). All these features may be expressed in a form of a Health Index. The Health Index is usually calculated as a combination of previous performance scores (for example ranging 1 to 5) assessed for the particular transformer. Transformers with an unsatisfactory Health Index should be maintained more intensively. The Health Index may be used to rank transformers according to their condition and to optimize their maintenance as indicated in the following example:

- IV. *The operational history says that the transformer XYZ is over 40 years old, has spent 80% of its service time in a heavily loaded area and its diagnostic interpretation reveals a higher than normal degree of paper insulation ageing, (70% loss of life). The maintenance of such transformer should be modified to higher diagnostic intensity and more efficient care. Relocation to area with lower load should be considered.*

Reliability Centred Maintenance

Another point of view influencing maintenance optimization is importance of the transformer in the system and possible consequences arising from its unplanned or forced outage (failure). An important transformer serving many power consumers may require a higher level of maintenance than when a back up unit is available in an emergency. The extent of maintenance to be performed on a transformer is proportional to the level of risk associated with the unit. A quantitative risk score may be calculated by the following equation.

$$\text{Risk} = \text{likelihood of failure} * \text{failure consequence}$$

The likelihood of failure can be represented by the above-mentioned Health Index of the unit (obsolescence, service history, technical condition...). The following example is an example of a transformer with high risk:

- V. *Transformer XYZ is in poor technical condition (health index 15) (higher likelihood of failure) and serves a critical area (severe consequence of failure or unplanned outage). Due to the high risk for this situation, the transformer should be maintained with increased frequency or consider using continuous on-line monitoring.*

For efficient maintenance optimization, it is recommended to take into account all maintenance strategies (TBM, TBCM, CBM, RCM). From the previous example, the maintenance engineer could request more frequent periodic preventive maintenance, carry out intensive testing or implement Continuous On-Line Monitoring to assess the development of the transformer condition and to plan the refurbishment or replacement of the transformer with high priority in order to reduce the risk.

Risk reduction measures should not necessarily only focus on reducing the likelihood of failure. Reducing the failure consequence part of the risk equation could also contribute to mitigating the risk. Measures might include:

- Upgrading transformer protection
- Performing switchgear and surge arrester checks and maintenance
- Emergency load switching and load shedding
- Contingency planning
- Deploying a spare transformer
- Installing fire walls and oil containment (in cases where collateral damage may be an issue)
- Checking condition of fire walls and oil containment (where they already exist)

Chapter 4 Transformer Component Selection and Maintenance

Improvements in technology and product quality mean that the maintenance required on a new transformer can be significantly less than that required on older units. The frequency, extent and safety of required maintenance operations deserve to be important factors in the specification and evaluation for a new transformer. Design for low maintenance, and ideally no invasive maintenance, is very important to utilities with increasing pressure on operational budgets and their due regard to the safety of personnel performing all foreseeable actions on the transformer.

Transformer maintenance effort is strongly related to the nature of its components. This chapter describes the main categories of transformer components and discusses their options, selection, initial costs, maintenance level, maintainability, technical constraints, reliability, potential failure modes, and life expectancy.

4.1 Bushings

4.1.1 Bushing Insulating Core

The core insulation of bushings rated above 36 kV is composed of graded capacitance (a series of concentric layers made of conductive material) that controls the uniform distribution of the electrical field. In order to facilitate the bushing diagnostic, one layer (usually the last or the second last layer) is made accessible externally at an electrode commonly referred to as the capacitance tap. The electrode may also be referred to as the measuring tap, test tap, or power factor tap. This capacitance tap allows measurement of the capacitance and power factor of the bushing itself, despite the fact that the bushing could be connected to a transformer winding that has a ground capacitance significantly higher than the capacitance of the bushing. When the transformer is in service, the tap may be connected to a measuring instrument (voltage measurement, or leakage current measurement) that maintains the tap voltage at close to ground potential. If no instrument is used, the tap must be grounded. The tap may also be used for partial discharge measurements. The integrity of the capacitance tap is dependent on the quality of the tap, the insulation of the tap, the mode of connection to the bushing layer and the type of connection of the tap to the ground. Anything that compromises its integrity could damage the bushing or result in catastrophic bushing failure.

Some old bushings (so called "DIN" bushings up to 123kV) do not have grading layers. Certain older resin bonded paper (RBP) bushings with grading layers do not have a measuring tap. In this case, the outermost layer is connected directly to the flange. Some of these bushings are mounted with an insulating plate between the bushing flange and the transformer tank to make the measurement of capacitance and dissipation/power factor possible. In service, both are connected by a short circuit cable or bar, but for measuring purposes these connections can be removed and the bushing flange is used as measuring electrode.

The core insulation may be made of the following material types:

Oil Impregnated Paper (OIP)

This is the most common type of bushing insulation. The bushing core is made of paper impregnated with insulating oil and has additional free oil between the core and the exterior insulator envelope.

Advantages	Disadvantages
<ul style="list-style-type: none">- Very long history with relatively good performances- Very low partial discharge – can be used at any voltage level- Relatively low cost- Minimal handling and storage requirements- DGA diagnostics are possible	<ul style="list-style-type: none">- Vulnerable to insulating oil leaks and water ingress if the gasket/sealing system is compromised- higher risk of bushing explosion and resultant transformer fire- Positioning angle during transportation, handling and storage

Table 5: Oil Impregnated Paper (OIP) Bushings

Resin Bonded Paper (RBP)

This type of bushing core is made of paper coated with a uniform and thin layer of epoxy resin, with semi-conductive material such as graphite interspersed to form the concentric grading layers. Most manufacturers have discontinued the production of RBP bushings.

Advantages	Disadvantages
<ul style="list-style-type: none">- Non-flammable core- Bushing failure is less likely to release main tank oil- Relatively low costs- No constraints of positioning during transportation, handling and storage	<ul style="list-style-type: none">- Generally higher levels of PD – can be used typically up to 400 kV- Ageing experience varies- Constraints of handling and storage- The core is affected by water ingress if incorrectly stored- Oil end of bushing is susceptible to transport damage

Table 6: Resin Bonded Paper (RBP) Bushings

Resin Impregnated Paper (RIP)

This type of bushing insulation is made of paper impregnated with resin. A resin-impregnated paper bushing can be provided with an insulating envelope. The intervening space can be filled with an insulating liquid or another insulating medium.

Advantages	Disadvantages
<ul style="list-style-type: none">- Non-flammable core- Bushing failure is less likely to release main tank oil- The core is less likely to be affected by water ingress- Very low partial discharge levels – can be used at any voltage level- No constraints on the attitude of the bushing during transportation, handling and storage	<ul style="list-style-type: none">- Relatively higher costs- Constraints on handling and storage- The oil end of the body must be protected from moisture during storage- Oil end of the bushing is susceptible to transport damage

Table 7: Resin Impregnated Paper (RIP) Bushings

Other Bushing Types for Special or Unique Applications

For direct connection to gas insulated switchgear (GIS), gas insulated bushings are used. These bushings use SF₆ gas as the main insulation medium in conjunction with concentric metallic screens to control the electric field. Epoxy bushings are growing in popularity for voltage applications up to 160 kV, where both the core insulation and the external housing are made exclusively of epoxy.

Special bushings are often used for connecting generator bus-bars to the primary windings of GSU transformers. They are usually placed in special junction boxes. They are often very heavily loaded by high generator currents (up to several tens of kA) and relatively low voltages (up to 30kV). Such bushings have to withstand high dynamic forces arising from high short-circuit currents.

Neutral bushings are usually a basic low voltage, stem and porcelain type, as they are invariably connected to graded insulation with no significant voltages expected to appear at the winding neutral under normal conditions.

Medium voltage bushings often terminate the tertiary windings of the transformer. All types of bushings (materials) can be used. Bushings are sometimes installed to make all three windings separately accessible. The final delta connection is then realized outside the tank. In the case of 'idle' delta connection of the tertiary, one corner should be earthed or surge arrestors should be installed.

4.1.2 Exterior Insulator

Porcelain Insulators

Historically, porcelain has been the only material available to provide both the necessary mechanical strength and electrical insulator properties required for the outer shell of a bushing. Advances in material technology have made alternative insulators to porcelain available. Selecting between porcelain bushings and an alternative material to suit a particular application requires comparisons of their advantages and disadvantages.

Advantages	Disadvantages
<ul style="list-style-type: none"> - No ageing - Long history of good reliability 	<ul style="list-style-type: none"> - Could create exploding projectiles if the bushing fails - Relatively fragile in the event of shock or heavy force - Makes the bushing relatively heavy

Table 8: Porcelain Insulators

In cases where the installed bushings are not suited to a heavy pollution situation, corrective measures include applying special grease on the porcelain or regularly washing the porcelain.

Composite Insulators

Composite insulators are made either with an internal tube of glass resin surrounded by a silicone shell, or with epoxy in the case of the full epoxy design. The condenser body would typically be of the RIP design. Any space between the insulator and condenser core may be filled with oil, gel, solid foam or gas.

Advantages	Disadvantages
<ul style="list-style-type: none"> - Relatively lightweight - Lower risk of projectiles in the event of a bushing failure - High seismic withstand capability - Better hydrophobicity in polluted conditions 	<ul style="list-style-type: none"> - Less field experience compare to porcelain - Long term reliability is not known, early examples have suffered from surface deterioration

Table 9: Composite Insulators

4.1.3 Types of Bushing Connections

There are several different styles of internal bushing connections. The style of connection used depends on the rated current of the bushing and the insulating mediums that the bushing is installed into.

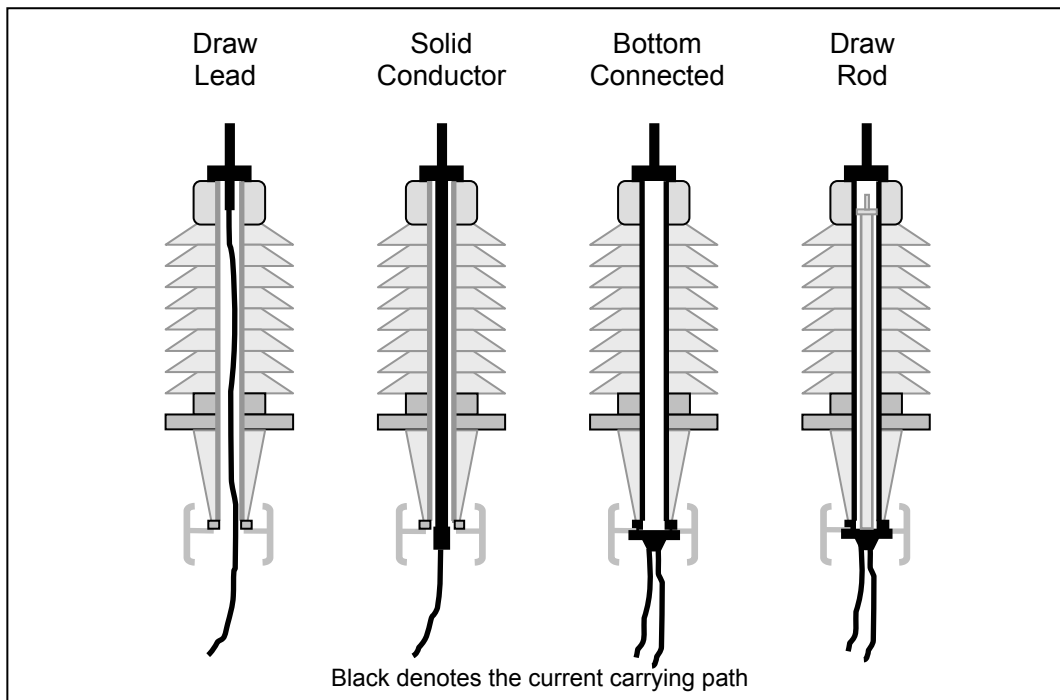


Figure 9: Principal Types of Bushing Connections

Draw Lead

Draw lead bushings are typically used for currents up to 1200 A. A cable connected to the winding of the transformer passes through the hollow central tube of the bushing and is externally connected at the top end of the bushing.

Solid Conductor

Bushings with a solid conductor can be used for currents up to 2000 A. Instead of a continuous cable connecting the transformer winding to the top terminal of the bushing, a cable from the winding is connected to a removable solid conductor inserted into the central tube of the bushing. The removable conductor is connected to the top terminal of the bushing.

Draw Rod

For higher current applications, the central metallic tube within the bushing is used as a conductor. A non-current carrying rod is inserted through the metallic tube in order to apply a specific pressure and allow a good electrical contact between the bushing tube and the terminal inside the transformer.

Bottom Connected

For very high current applications, the bushing must have an integral, heavy section, central conductor that requires making a direct connection at the bottom of the bushing. Accordingly, there must always be in close proximity a tank access cover for making a connection or disconnection to the bushing.

Cable Box

For voltages up to 36 kV, a cable connection can be made directly to the bushing. For these voltages, the cable box may be air insulated, pitch filled, compound filled or oil filled. Irrespective of the insulating medium, any fault in the cable box is likely to cause catastrophic failure. Careful surveillance for moisture ingress, condensation or leakage of the insulating medium is important. Cable boxes also need periodic inspection because mechanical movement or heat expansion on the power cables can transfer substantial forces onto the bushings causing oil leaks or mechanical damage.

For voltages up to 400 kV, an oil filled cable box can be used. The cable box arrangement is well suited to high current bushings or for severe environments. In some cases, the cable box oil is physically separated from the transformer oil to limit moisture migration due to temperature differences between the oil volumes. Periodic verification of sealing tightness and the oil quality is required.

Direct Connection to SF6 Bus Trunking

In gas insulated substations it is possible to connect the transformer directly to the gas insulated bus bar using oil to SF6 bushings. These bushings may be of the oil impregnated paper or more commonly the epoxy resin type.

Advantages	Disadvantages
<ul style="list-style-type: none">- May be cheaper than using an oil to air bushing and an air to SF6 bushing in gas insulated substations- No exposure to pollution resulting in increased reliability	<ul style="list-style-type: none">- Interchangeability of transformers depends on an exact mechanical match of the transformer tank and bushings, so keeping a spare unit may be difficult and more costly- Testing is more difficult because the gas must be removed to gain access to the connections- Special provisions for testing may have to be made such as having an earth switch adjacent to the transformer

Table 10: Direct Connection to SF6 Bus Trunking

4.2 Oil Preservation Systems

Although the primary function of the Oil Preservation System is to accommodate the changes in oil volume due to temperature variations, it also has a major role in preserving the oil quality by preventing contaminants to enter the transformer. Where a transformer may have several oil compartments besides the main tank, for tap changers, cable boxes and auxiliary devices, then each compartment usually requires its own dedicated Oil Preservation System.

There have evolved many different technologies and variants for Oil Preservation Systems, and each has particular maintenance requirements. The most common types are discussed below.

4.2.1 Pressure Regulated Gas Blanket System

Gas blankets are used in some transformers as a method to stop oxygen and moisture from entering the transformer. These systems offer some advantages and disadvantages that the user should be aware of.

Advantages	Disadvantages
<ul style="list-style-type: none"> - Positive nitrogen pressure (along with a good gasket) keeps oxygen and moisture out - Purging of nitrogen during thermal cycles removes moisture and oxygen - Lower values for moisture and oxygen content in the transformer decreases the rate of insulation deterioration 	<ul style="list-style-type: none"> - If the nitrogen bottle is empty, moisture and oxygen may enter the transformer - High levels of nitrogen in the oil could lead to nitrogen bubble entrapment in the insulation or pumps under certain conditions of cool down - Purging of nitrogen will remove other gas from the transformer making dissolved gas analysis of limited value for long term trending, particularly for low solubility gases that are easily released from the oil, such as hydrogen - Higher maintenance resource requirements

Table 11: Pressure Regulated Gas Blanket System

Typically, the main components installed on a transformer with a regulated gas blanket system include the following items: nitrogen cylinder, high and low pressure regulators, high pressure gauge to indicate the pressure in the nitrogen cylinder, sump to collect any moisture or oil condensate, pressure relief device, and high and low pressure alarms.

4.2.2 Conservator Systems

The transformer oil Conservator System typically consists of one or more externally mounted reservoirs (or expansion tanks). They are installed at the height required to provide an oil level in the transformer that is above the cover of the main tank of the transformer, or in many cases, above the highest oil filled bushing boss. Many Conservator Systems generally include a bladder inside the tank that provides an oil-to-air barrier to prevent moisture and dissolved air from entering the transformer oil. The system also has an air equalization line that allows air to enter the bladder when the transformer temperature is decreasing and air to discharge from the bladder when the temperature is increasing. There is also normally a desiccant container in line with this equalization line to dry the incoming air.

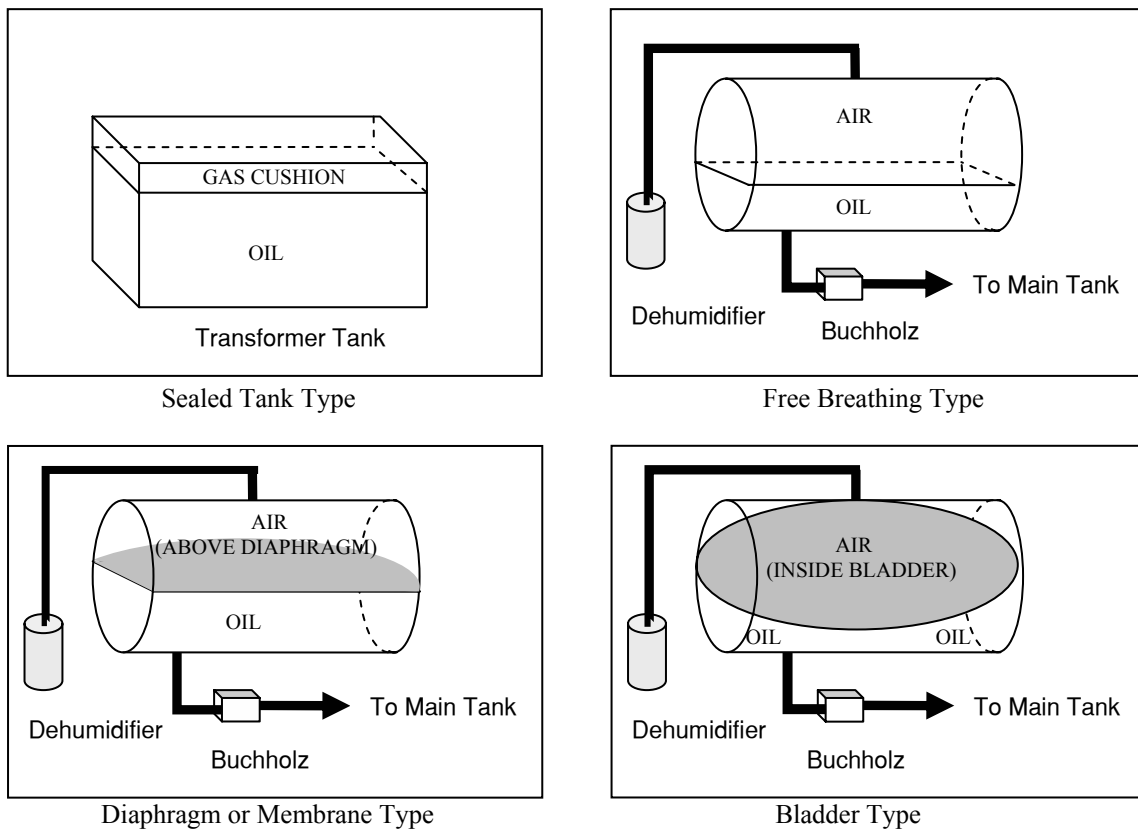


Figure 10: Principal Oil Preservation Systems

Some conservator systems have a separate pressure equalization tank and do not have the internal bladder. These systems do not maintain degassed oil in a transformer, but allow the oil to become saturated with air or nitrogen (depending on whether air or nitrogen is used in the gas space of the system). Conservator systems usually have an oil level gauge attached to the tank with an alarm connection to alert operators when the oil level is either at the minimum, or the maximum, acceptable oil level in the tank. There is also often a Buchholz valve or other non-return valve that shuts off in the event of a main tank rupture. Some of these valves also contain a gas collector that traps gas generated in the main tank and provides an alarm when a certain volume is collected. Transformers with conservator systems may also have gas detector relay systems that are mounted separately on the tank. Generally, the life of a bladder should be considered in the range of 10-20 years.

Note that air injection tests on the Buchholz relay would cause accumulation of air bubbles on the oil side of any bladder, diaphragm or membrane installed within a conservator.

4.2.3 Sealed Tank Transformers

A sealed tank system simply utilizes a transformer's sealed tank to keep the oil isolated from external atmospheric conditions. The use of a sealed tank system requires that the tank be large enough to accommodate the minimum volume of oil required by the transformer when the oil is cold, and the maximum volume of oil generated when the transformer is operated at its maximum load rating under its maximum designed ambient temperature. The tank must therefore be able to accommodate the oil's full volumetric excursions from a de-energized "dead cold" condition to a fully loaded "maximum heat" condition. This type of preservation system is typically used for smaller transformers whose minimum and maximum oil level requirements can be accurately predicted.

Many Sealed Tank Transformers are filled with dry nitrogen and have pressure gauges and fill valves to manually add nitrogen, if the pressure drops. One of the advantages of the sealed tank system is that they are less expensive than the pressure regulated gas-blanketed system. One of the disadvantages is that a leak can allow oxygen and moisture to enter the tank. Some Sealed Tank Transformers can suffer a slight loss of gas pressure at peak loads, which will result in negative pressures (or vacuum) during periods of light loading. Consideration should be given to converting these transformers to a pressure regulated gas-blanketed system.

4.2.4 Free-Breathing Transformers

By far the most common form of oil preservation system is the Free-Breathing Transformer. In order to maintain the dryness of the oil, most Free-Breathing Transformers are fitted with either a desiccant breather, or a refrigerating type breather, so that only dry air is admitted to the conservator. However, some Free-Breathing Transformers do not have any provision to prevent humid air making contact with the oil, and inevitably the moisture content of the oil increases. In such cases, consideration should be given to making some provision that ensures the dryness of the oil. After oil replacement, reconditioning or reprocessing, the preferred modification is to include a bladder in the expansion tank (if so equipped). If the cost of conversion to bladder sealed design is not justified, an alternative improvement would be to vent the expansion tank through a desiccant system. Bladder addition is preferred because its design includes sealing the oil from oxygen entry as well as moisture entry.

4.3 Cooling Systems

Cooling Systems are used to maximize the heat exchange between the hot oil inside the transformer with a fluid at lower temperature, outside the transformer. Depending on transformer specification and design, different types of cooling systems can be used. A detailed description of each type of cooling system can be found in IEC 60076-2.

4.3.1 Radiator

Radiators comprise of cooling elements with large surface areas. They are distributed around the transformer and are positioned at a height that enhances the convectional oil flow driving the heat transfer from the hot transformer oil to the free air at ambient temperature, outside the transformer. Radiators give very little restriction to oil flow and function adequately with a natural convectional circulation of the transformer oil. If necessary, radiators can be fitted with additional components to increase the rate of heat transfer. Instead of free air delivery, cooling fans may be installed to produce forced

air flow that increases the heat loss from the radiator cooling surfaces. Furthermore, oil pumps can also be added to deliver hot oil quickly to the radiators for more efficient heat transfer.

Advantages	Disadvantages
<ul style="list-style-type: none"> - Low maintenance, especially if used without pumps - Low cost - Multi-mode cooling is available to minimize auxiliary power losses for fans and pumps 	<ul style="list-style-type: none"> - Requires a bigger area and as a result may not be appropriate when land is limited - May require periodic cleaning to remove dust from the radiator surface

Table 12: Radiator

4.3.2 Cooler (Finned-Tube Radiators)

In this type of cooling, oil pumps force the oil to circulate across compact finned-tubes that increase the cooling surface areas on both the oil and air sides. Depending on transformer design, different group of coolers may be controlled individually in order to optimize their utilization.

Advantages	Disadvantages
<ul style="list-style-type: none"> - Very compact 	<ul style="list-style-type: none"> - Requires more maintenance or the use of filters because of the susceptibility to blockage by airborne particles, insects and debris - Fine tubing may be more fragile or susceptible to oil leaks or rupture - Some transformer designs may require the coolers to run continuously resulting in accelerated wear - High capital costs - Transformer must be de-rated to low load or even no load capability in case of pump failure

Table 13: Cooler

The cooling efficiency and maintenance effort for power transformers fitted with OFAF cooling may be affected by the direction of the air flow through the cooler. It is intended that external free air is drawn by the cooling fan and blown through the cooler, towards the tank. If the air flow is reversed and is drawn through the cooler and blown outwards, the air entering the cooler will be pre-heated by radiation from the tank walls, elevating the cooler temperature, especially on hot days, causing high operating temperatures for the fan motors. Within months, the elevated temperatures can affect fan motor bearings, increasing their friction resulting in overheated bearings, seized bearings, thermal cut-outs, or even burn out of the electric motor. As a consequence, the cooling capacity of the cooler is reduced when the cooling fan is not available.

4.3.3 Oil-to-Water Heat Exchanger

In this type of cooling, oil pumps force the oil to circulate through oil-water heat exchangers. In order to avoid any possibility of the two liquids mixing in the event of a leak, double tube technology is often used.

Advantages	Disadvantages
<ul style="list-style-type: none"> - Very efficient - Relatively cheap 	<ul style="list-style-type: none"> - Possibility of leakage and possible environmental consequence or transformer failure - If used in hydro-generation plant, the cooling water is not available for generation - cleaning and inspection of water side chambers and pipe work

Table 14: Oil-to-Water Heat Exchanger

4.3.4 Oil Pumps

Depending on the type of cooling, the cooling system may require the use of Oil Pumps. Experience has shown that these components require significant corrective maintenance effort. As a result, special attention must be given in the selection of these components.

These rotating machines may require the usual maintenance regime of checking bearing wear, imbalance problems, testing and checks. After any reconnection of electrical supply, some method must be employed to verify correct pump rotation.

Changes in the supply current as well as oil temperature and viscosity changes may cause tripping of motor protection or spurious on-line monitoring alarms.

4.3.5 Fans

Some cooling systems employ the use of cooling fans. Similarly to the oil pumps, careful consideration must be given when selecting these components due to the significant corrective maintenance that they require.

These rotating machines require the usual maintenance regime of checking bearing wear, imbalance problems, testing and checks. After any reconnection of electrical supply, proper phase rotation will ensure the correct air flow.

4.4 Gaskets

Gasket material must be compatible with the transformer insulating fluids. Incompatibility will result in the failure of the gasket and the development of leaks. Gaskets must be applied properly, and when they deteriorate they must be replaced, in order to ensure the reliability of the insulation system, safety of personnel, and prevent fluid escaping into the environment. Gaskets in good condition will be smooth, firm, and pliable. When selecting gasket material, consideration must be given to the temperature extremes it will be subjected to due to ambient temperatures and load variations. Some gasket materials need their contact surfaces to be lubricated prior to gasket installation. These lubricants must be compatible with the gasket material and with the transformer insulating fluids. The gasket material should be checked for any chemical and thermal degradation. These types of degradation result in softening or hardening of the material and possibly cracking. These defects may be caused by improper storage, material selection or manufacturing. It is good practice to always install new gasket material and to never re-use a previously installed gasket.

Modern tank designs employ welded lids or covers in order to reduce the extent of gasket-sealed openings.

4.4.1 Forms of Gasket

There are three basic forms of gasket.

Extruded toroidal:

- Large selection of different lengths
- Joints to form closed rings need to be made by the vulcanization process by qualified operators

One piece moulded or O-ring type:

- No vulcanization needed
- Limit on overall diameter and length

Flat gaskets:

- Very effective to insure sealing on transformer accessories
- One piece dimensions are limited by the sheet size of the source gasket material
- Large flat gaskets require 'dovetail' or scarf joint techniques to adjoin smaller pieces together

4.4.2 Types of Gasket Material

Gaskets used in a transformer will vary between manufacturers and as the available supply of gasket material and the sealing technology has changed over time.

Flat Gaskets

A blend of CR or NBR elastomer and cork is the traditional flat gasket material and is manufactured in large sheets of various thicknesses. The blend mix, and quality of compositional materials varies. It is recommended that the physical and chemical properties, together with the ability to withstand mechanical stress, be carefully assessed when selecting a suitable grade.

CR: Chloroprene rubber (also known as neoprene) for utilization between -30 °C and +120 °C

NBR: Nitrile rubber (copolymer of polybutadiene and acrylonitrile) for utilization between -30 °C and +120 °C

The following table indicates the properties to evaluate with corresponding recommended performance criteria.

Tensile Strength ASTM F152	1.5 MPa minimum
Recovery ASTM F36 (2.8 N/mm ² load)	75% minimum
Compressibility ASTM F36 (2.8 N/mm ² load)	In the range 20 - 35%
Hardness IRHD Shore A	In the range 65 - 80
% Volume Swell in Transformer Oil	In the range 5 - 15%

Table 15: Properties of Transformer Grade Cork-Elastomer Gasket Material

The gasket should be pliable to handle, yet does not noticeably flow under compression.

O-Rings

Usually formed as an extruded elastomer and subsequently spliced or butt-jointed to form the O-ring seal.

NBR: Nitrile rubber (copolymer of polybutadiene and acrylonitrile) for utilization between -30 °C and +120 °C.

FKM: Fluoroelastomers family (usually called Viton) for utilization between -20 °C and +180 °C

Note:

The temperature range may be enlarged if the gasket is only used for static gaskets.

The gasket material and additives should be fully compatible with transformer oil.

The gasket should not contain oil soluble sulphur compounds.

The selection of seal and gasket materials is a trade off between longevity, temperature, cost, accuracy of jointing faces.

4.4.3 Gasket Installation

Usually, it is recommended to apply the following for gasket compression:

- Limit of 25 to 30 % for flat gaskets
- Limit of 33 % for toroidal gaskets

4.4.4 Gasket Stocks

Stocks of gasket material are often kept by transformer users because gaskets are used in all transformers and they need periodic replacement. Consideration must be given to the duration of time that gasket material is kept in stock because their typical shelf life is only 7 years before their mechanical properties start to deteriorate.

Ideally, in storage, the gaskets should be protected from air and light in an environment where the temperatures are between 5 °C and 30 °C and the humidity between 45 % and 70 %.

4.4.5 Examples of Proper Gasket Mounting

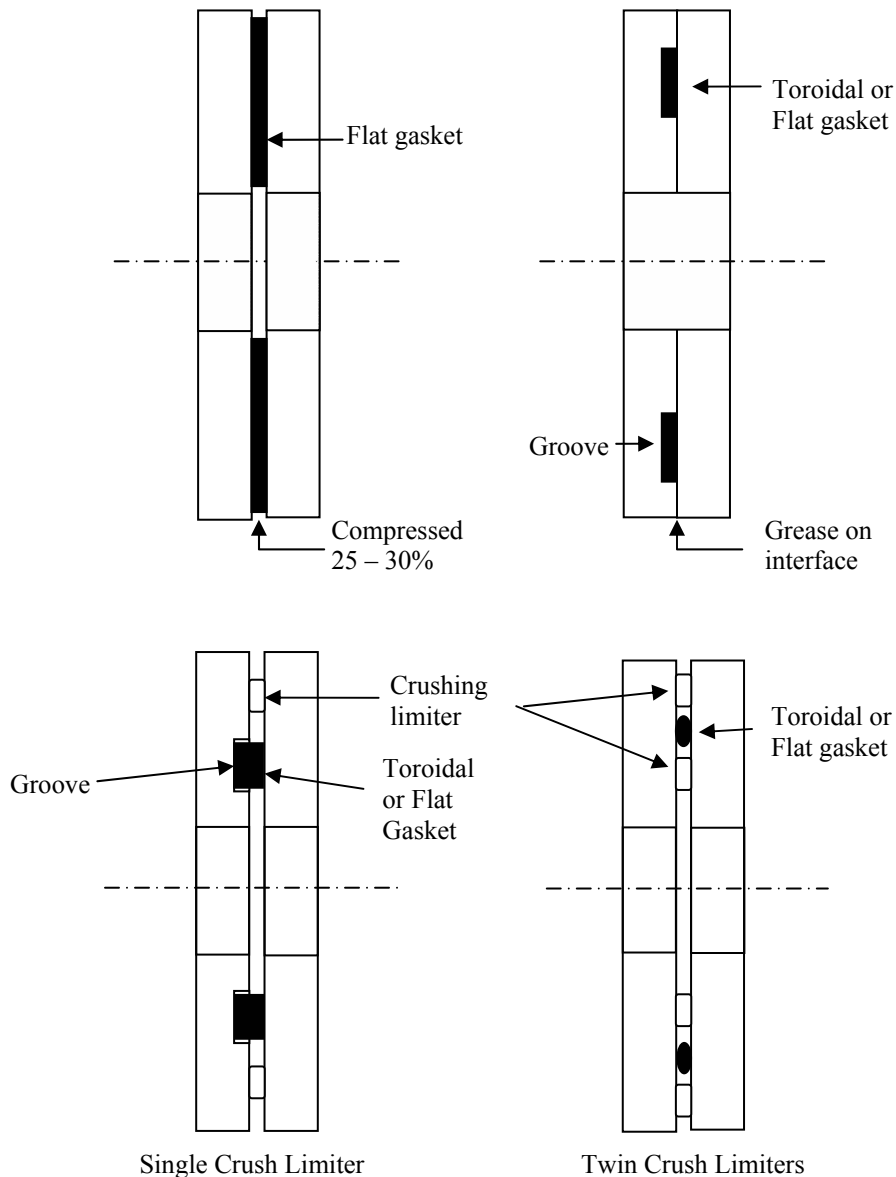


Figure 11: Gasket Mounting Examples

4.5 Gauges, Indicators and Relays

4.5.1 Liquid and Winding Temperature Indicators

Temperature Indicators are fundamentally used to indicate the insulating liquid temperature and the simulated hotspot winding temperature. The Liquid Temperature Indicator (LTI) is also commonly referred to as an Oil Temperature Indicator (OTI) with oil-filled equipment. Transformers fitted with forced air or forced oil cooling systems may also use these indicators to control the cooling system by switching them in or out, in order to optimize energy consumption. Finally, these indicators may also be used to generate alarms at pre-set temperature levels to warn of over-temperatures, or overloads or problems with the cooling system. Some utilities also require these indicators to have a role in transformer protection to automatically trip the transformer upon reaching a pre-set over temperature. However, implementation of the trip function depends on transformer operation philosophy. Many operators prefer to manually control an emergency overload condition (accepting with it comes accelerated ageing and calculated risk) rather than to have an automatic transformer trip aggravate an already difficult situation.

Conventional Mechanical Indicators

Normally used in pairs, one indicator measures the top oil temperature, while the other represents the winding hotspot temperature. These indicators are typically sealed spiral-bourdon-tube dial type, with liquid-filled bulb sensors. The bulbs are normally inside separate thermometer wells that penetrate the tank in the hottest oil near the top of the tank. Each indicator will normally include a “drag” hand (usually red in colour) that indicates the maximum temperature reached since the last time it was reset.

The winding hotspot temperature indicator (WTI) is intended to provide only a simulation of the winding hot spot temperature. This simulation is created by a built-in thermal image device that essentially forces the WTI to indicate a temperature that is equal to top oil plus the hotspot gradient, instead of just the top oil temperature. This indicator reading is often only accurate at maximum nameplate rating load and then only if it is calibrated correctly. It should not be relied upon as being accurate. Winding hot spot indicators are often used for turning on additional cooling fans and pumps.

Advantages	Disadvantages
<ul style="list-style-type: none"> - Simple, well known and common technology 	<ul style="list-style-type: none"> - Not accurate - Requires regular verification and calibration - Measurements are not accessible electronically (if needed) - The winding temperature measurement is only a simulation of the winding hotspot

Table 16: Conventional Mechanical Indicator

Electronic Indicator

This technology, for measuring transformer temperature, uses a single RTD sensor that measures the top oil temperature and a current-transformer that measures the load on the transformer. Rather than using a heater, the indicator uses an algorithm with appropriate formulas, coefficients and exponents particular to the transformer design to calculate the winding temperature. The indicator then activates a series of dry contacts at different preset winding temperatures, to control the different cooling stages.

Advantages	Disadvantages
<ul style="list-style-type: none"> - More accurate measurement - Minimal maintenance - Measurements are accessible electronically - Cooling stages can be interchanged by the controller to minimize the degree of ageing 	<ul style="list-style-type: none"> - The life of an electronic component is usually much less than the life of a transformer - The winding temperature measurement is only a simulation of the winding hotspot

Table 17: Electronic Indicator

Fibre Optic Temperature Probe

Fibre Optic Temperature Probes can be imbedded directly into the winding as the transformer is being manufactured and are much more accurate. These fibres are also connected to an electronic indicator. Fibre Optic Temperature Probes are often used to validate the transformer thermal design during the factory temperature rise and overload tests.

Advantages	Disadvantages
<ul style="list-style-type: none"> - Very accurate measurement if localized on the hottest spot - Measurements are accessible electronically - Cooling stages can be interchanged by a controller to minimize the degree of ageing 	<ul style="list-style-type: none"> - Maintainability is very poor – it is practically impossible to fix a fibre without dismantling the winding - The life of an electronic component is usually much less than the life of a transformer - Fibres may not necessarily be located at the winding’s hottest spot (fibre locations decided during design stage)

Table 18: Fibre Optic Temperature Probe

4.5.2 Oil Level Indicators

All liquid filled transformers, except perhaps smaller units of the hermetically sealed type, will have some kind of fluid (oil) level indicator. Traditionally, this is a gauge or sight glass which makes the liquid level visible. The gauge often has a magnetic coupling between a float inside the transformer and the indicator outside, eliminating the need for a movement

seal and reducing the possibility of leaks. Observing and recording the fluid level is a frequent and necessary site operation if fluid leaks are to be detected and inadvertent operation of the Buchholz relay is to be avoided. To eliminate this operation, the gauge may be fitted with a low fluid level alarm (often with both a low and a very low level contact) and possibly a remote indication option.

Because the fluid level is temperature dependent, then the fluid temperature must be taken into account when deciding whether topping up the oil is necessary. Care is required with sight glasses if they have become dirty, as any residual staining may appear to indicate a fluid level, when in fact the glass is empty. For very large transformers, the gauge or sight glass may be very high up on the conservator and consequently difficult to see from ground level. Either a sufficiently large gauge can be fitted, or a remote indication option can be added to be viewed at ground level. Given the importance of the indication and the requirement to switch out the transformer if a very low fluid level is indicated, consideration should be given to having two level indicators on critical units.

4.5.3 Buchholz Relay

A Buchholz Relay (Buchholz) is commonly fitted between the main tank of the transformer and the conservator. This relay normally has two functions, the first is to collect any gas emanating from the transformer which might indicate a serious fault and produce an alarm when the volume of gas reaches a pre-set volume (usually 100 to 300 ml). The second function is to respond to a rapid movement of fluid from the transformer to the conservator (1-3 m/s) indicating an internal fault and trip the transformer. The internal arrangement of the relay usually means that the trip will operate if the fluid level falls below the level of the Buchholz Relay, providing an important protection against sudden loss of insulating fluid. Buchholz Relays or single contact oil surge relays may also be fitted to other oil containing compartments such as separate tap changer diverter or selector compartments. Piping can also be installed between the Buchholz Relay and a ground level gas receiver. This device facilitates checking the presence of gas in the Buchholz Relay and sampling that gas for diagnosis, should a transformer alarm or trip eventuate.

A long service history with Buchholz Relays fitted with mercury contact switches has shown that they are susceptible to spurious alarms or trips due to vibration and shock. Together with their inherent mercury hazard, these considerations have lead to a steady phasing out of these relay types.

4.5.4 Pressure Relief Device

The Pressure Relief Device (PRD) is designed to relieve internal pressure and protect the transformer tank when the internal pressure exceeds the calibrated limit of the Pressure Relief Device. In older transformers, the PRD takes the form of a tall venting pipe, covered on one end with a membrane, metal foil or thin piece of glass that is designed to rupture when an overpressure occurs, and its height prevents excessive loss of oil. A modern PRD is relatively compact and comprises of a sealing disk under spring pressure that is calibrated to open and vent oil at a defined pressure. These modern devices are designed to re-seal the tank automatically under spring pressure, but will also protrude a manually reset indicating button, thereby verifying that the PRD has operated. The PRD can also be fitted with an alarm contact to alert venting of oil and abnormal pressure rise.

4.5.5 Rapid Pressure Rise Relay

The Rapid Pressure Rise Relay (RPRR) is typically used to trip the transformer off line to protect the transformer from damage caused by an internal fault. This relay is also known as a Fault Gas Relay, Fault Pressure Relay, and Sudden Pressure Relay. The operating characteristics and sensitivity are designed and calibrated so that the device only operates in the event that pressure rise exceeds the threshold expected for through faults or similar phenomenon. There are two basic types of Rapid Pressure Rise Relays, gas space and liquid space. The gas space RPRR is set to respond slightly faster than the liquid space RPRR to compensate for the compressibility of gas versus a non-compressible liquid. There are no general rules as to which type of RPRR functions better under various conditions. A recent trend is to place dual relays on the tank in perpendicular planes with the relay switches wired in series. This arrangement obviates a nuisance trip should one of the relays become more sensitive or experience fault conditions when the other relay does not.

4.5.6 Oil Flow Indicators

Oil Flow Indicators are used on power transformers to indicate that the oil is circulating. These devices can be used to generate alarms in cases of oil pump failure or oil circulation problems through the cooling system.

4.6 Control Cabinet

The transformer Control Cabinet contains all the devices required to control the cooling system and to monitor the transformer. The Control Cabinet comprises:

- Wiring and terminal blocks
- Current transformer terminations, sensors, fuses, contactors and relays
- Filters, anti-condensation heaters, ventilator to maintain the control cabinet in proper condition
- Local status indicators
- Monitoring devices where applicable

Inspection of the Control Cabinet is required periodically. Inspections should include checks on the wiring connections for tightness. Infrared scanning is a useful technique for checking live circuitry. The air filters should be maintained and functional checks performed on the cabinet lighting, anti-condensation heaters, thermostats and ventilators. The Ingress Protection (IP) rating of the Control Cabinet may also be compromised by perished or split door seals, faulty cable glands, or corrosion in the cabinet panels.

Sometimes, a modernization of the Control Cabinet is required before the transformer reaches its end of life.

It is important that power is supplied to the Control Cabinet anti-condensation heaters whilst the transformer is in storage or de-energised for protracted periods.

4.7 Current Transformers

Current Transformers (CT) are primarily used to measure transformer winding currents for metering and protection purposes, with their secondary circuits typically running long distances to a relay room. One commonly fitted CT on any transformer is used for the thermal image device of the winding hotspot temperature indicator. Transformers fitted with multiple CTs usually have a mix of ratios, accuracy classes and rated burdens that vary with their application.

CTs may be installed in power transformers either:

Internally, usually as a toroidal type mounted on a high voltage line lead, fitted either below the mounting flange of a LV or HV bushing, or around a LV bus bar, and generally located just below the transformer cover or within a bushing turret. For CT replacement, it is necessary to drain transformer oil and to remove the bushing or bus bar.

Externally, usually as an encapsulated bar primary type CT, or encapsulated window type CT, and installed on the transformer cover or tank side as the neutral CT. This configuration has the advantage of facilitating CT replacement. However, care is required in their positioning to insure adequate electrical clearances.

CTs do not normally require any maintenance. However replacement may be needed following failure, thermal overheating, or for transformer up rating modifications. Also, the supports for these heavy mass items may slump or fracture in service.

In any case, there are important precautions for maintenance activity associated with these devices:

- The secondary of a CT must never be an open circuit when in a presence of a primary current as it would destroy the CT
- Avoid disturbing the CT secondary wiring circuits during any on-line intervention activity in their vicinity

- Ensure CTs are reconnected with the correct polarity (secondary leads are not swapped or CT toroid is not turned over)
- Extreme care is required to prevent loose termination fasteners being dropping into the main tank or windings when disconnecting the secondary wiring on an internal CT
- Ensure unused CT cores are shorted and earthed prior to returning a transformer to service
- Ensure CT test links are returned to the required service position prior to returning a transformer to service
- Check the status of the CT circuits before conducting transformer tests (open circuit CTs must be shorted and earthed)

4.8 On-Load Tap Changer

4.8.1 Resistor and Reactor Types

On-Load Tap Changers (OLTC) can be divided into two groups according to the type of current limiting impedance used during the transition time of their diverter switch. The first group are the high-speed resistor types. The second group are the relatively slower acting reactor types.

Resistor Type OLTCs are suited to high voltage power transformers but require a high speed mechanism to limit time the resistors are inserted to typically 50 - 150 ms. These spring-operated mechanisms can be sophisticated and require more skills for maintenance. HV applications are more susceptible to dielectric failure. Therefore oil quality is also a maintenance issue for most Resistor Type OLTCs.

Reactor Type OLTCs are limited to lower voltage (less than 138 kV) power transformers but they can sustain higher loads and have no limitation in transition time. The Reactor Type OLTCs all feature the use of a preventive autotransformer that provides the OLTC with twice as many voltage positions when compared to a Resistor Type OLTC that uses the same number of steps in the tapping winding. High load applications make them more susceptible to coking, but most are equipped with slower mechanisms that are easier to maintain. The preventative autotransformer usually brings additional transformer cost, size and, occasionally, testing issues.

4.8.2 Switching Principles

The OLTC may incorporate one or more of the following switch types.

Diverter Switches (also called Transfer Switch) are always used in conjunction with a tap selector that comprises two sets of moving and stationary contacts that alternately carry the load. The operation of the Resistor Type OLTC involves two steps. First, the target tap is preselected with the unloaded moving contact. Then the Diverter Switch transfers the load to the pre-selected tap. This contrasts with the Reactor Type OLTC where the Diverter Switch has to first interrupt the load on one set of moving contacts before that set can be used to pre-select the next tap.

Diverter Switches that are the Resistor Type must have high speed mechanisms (usually spring operated) in order to limit contact wear from arcing and to limit the temperature rise of their transition resistors.

Selector Switches (also called Arcing Tap Switch) effectively carry out the two step operation described above, but with only a single motion. This is achieved with an arrangement of auxiliary moving contacts that can bridge across the two taps for the all important make-before-break transition. Selector Switches that are Resistor Type must also have high speed mechanisms for the same reasons outlined for the Diverter Switches. Selector Switches are usually spring-operated for high-speed action when used on Resistor Type OLTCs, and motor-driven with slow action on Reactor Types. These devices are usually limited to equipment voltages up to 138 kV and having less than 33 tap positions.

Vacuum Switches can use both principles described above, but in most cases through the addition of a number steps in the sequence (by-pass switch).

Table 19 below summarizes the comparative features of these three switching principles from the maintenance point of view.

Principle	Advantages	Disadvantages
Diverter Switch	<ul style="list-style-type: none"> - Maintenance free tap selector - Minimum maintenance outage possible with spare diverter insert 	<ul style="list-style-type: none"> - Maintenance complexity - Oil contamination
Selector Switch	<ul style="list-style-type: none"> - Less components - Low mechanical wear for slow action mechanisms (reactor type) - Easy maintenance (for modern design) 	<ul style="list-style-type: none"> - Oil contamination
Vacuum Switch	<ul style="list-style-type: none"> - Lowest maintenance - No oil contamination 	

Table 19: Comparative Maintenance Features of Different Switching Principles

4.8.3 Types of Connection

Just where the OLTC is positioned in the windings can affect the required maintenance effort. For example in double wound transformers, positioning the OLTC at the neutral end of the HV winding will result in a more compact, and less costly OLTC because a single, three-phase unit is usually sufficient. The associated lower insulation level also allows for longer intervals between maintenance.

In contrast, the OLTC must be fully insulated if it is to be fitted onto delta connected windings, or at the line end of a winding. This can be achieved using a fully insulated selector switch that is rated for the line end insulation level. This will mean that a single, three-phase, diverter switch is no longer suitable, and instead the OLTC must comprise of three, single-phase units. Therefore, maintenance costs are multiplied respectively and the higher insulation level requires more careful maintenance of the oil quality. Alternative connections to reduce the voltage stress on the OLTC are the mid-winding arrangement and connection through a booster transformer.

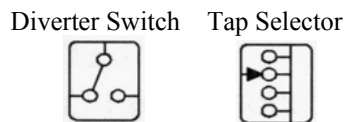
Position of OLTC	Advantages	Disadvantages
Neutral end	<ul style="list-style-type: none"> - Least stringent requirement on oil maintenance - Longest maintenance intervals - Usually only a single, three-phase unit required 	
Line end or in delta connected windings		<ul style="list-style-type: none"> - Higher insulation required - Higher oil quality requirements - Three single-phase units need to be maintained (unless a selector switch can be used)
Mid-winding	<ul style="list-style-type: none"> - Voltage stress lower than line-end connection - Longer maintenance intervals - Less stringent requirement on oil quality 	<ul style="list-style-type: none"> - Three single-phase units need to be maintained
Booster transformer	<ul style="list-style-type: none"> - Voltage stress lower than line-end connection - Longer maintenance intervals - Less stringent requirement on oil quality (for some configurations) 	<ul style="list-style-type: none"> - Additional maintenance may be required for the booster transformer

Table 20: Comparative Maintenance Effort According to the OLTC Position in the Windings

4.8.4 Design

Special provision is made in all transformers fitted with a tap changer, to keep the carbon contaminated oil of the diverter or selector switch from reaching the active parts. Table 21 below illustrates the principal tank designs used to accommodate an OLTC and gives their advantages and disadvantages.

The following symbols are used in Table 21 to indicate the Diverter Switch and the tap selector:



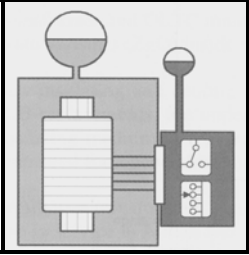
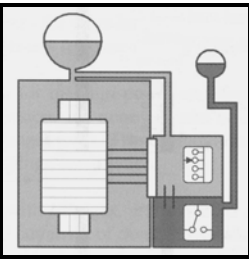
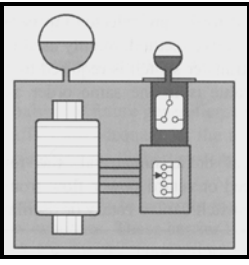
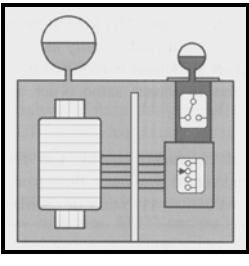
Type Design		Maintenance Issues
<p style="text-align: center;">Compartment</p>		<p>Advantages:</p> <ul style="list-style-type: none"> - OLTC oil expansion reservoir can sometimes be eliminated - Easy access for maintenance
		<p>Disadvantages:</p> <ul style="list-style-type: none"> - Leakage to environment - Tap selector is in carbon-contaminated oil
<p style="text-align: center;">Double Compartment</p>		<p>Advantages:</p> <ul style="list-style-type: none"> - Easy access for maintenance - Less oil handling - Tap selector is in clean oil
		<p>Disadvantages:</p> <ul style="list-style-type: none"> - More leak possibilities to the environment
<p style="text-align: center;">In-Tank</p>		<p>Advantages:</p> <ul style="list-style-type: none"> - Less oil handling - Diverter switch is easily replaced
		<p>Disadvantages:</p> <ul style="list-style-type: none"> - Leakage of contaminated oil to main tank - Need crane to remove diverter switch
<p style="text-align: center;">Weir Type or Separate Chamber with Barrier Board</p>		<p>Advantages:</p> <ul style="list-style-type: none"> - Same as In-Tank - Tap selector can be inspected/repaired without draining all the main tank oil
		<p>Disadvantages:</p> <ul style="list-style-type: none"> - Same as In-Tank - Bigger tank - More complicated design - More components to cause problems

Table 21: Principal Tank Designs to Accommodate an OLTC and Their Maintenance Issues

Source: A. Kramer, "On-Load Tap-Changers for Power Transformers", MR Publication 2000

4.8.5 Motor Drive Mechanism and External Drive Shafts

The Motor Drive Mechanism also requires regular maintenance for proper performance. Although the consequences of the drive failure are usually less critical, insufficient care will eventually lead to unplanned outages or low quality of the supply.

The main components from a maintenance point of view are:

Cubicle - Door seals and anti-condensation heaters need checking for maintenance.

Electric Motor - DC motors require brush maintenance. Three phase motors are preferred because they can be considered maintenance-free.

Braking System - Many tap change control problems are related to poor maintenance of the braking system.

Gearboxes and Shafts – Checking for maintenance of lubrication oil level, corrosion, support mountings, and condition of drive shaft shear points.

Relays, Contactors and Circuitry - Checking required for relay coil failure, sticking or damaged contacts, condensation damage, gear box oil leaks and wiring integrity.

Drive Component	Technology	Maintenance Issues
Relays and contactors		- No specific issue
Motor	DC	- Brush gear maintenance
	3 phase	- Most common - Most reliable
	1 phase	- Maintenance of capacitors
Braking	None	- Not reliable
	Mechanical	- Can slip - Requires maintenance
	3 phases short-circuited	- No maintenance
	DC injection	- Maintenance of capacitors
Gearbox	Grease	- Requires periodic greasing
	Oil	- Gasket maintenance is more critical - Check oil level, top up or oil change
	Sealed	- Recent models can be maintenance free

Table 22: Maintenance Issues Associated with the Drive Components

4.8.6 Typical Intervals - Manufacturer Recommendations

Tap changer manufacturers usually specify time-based maintenance that has to be carried out after either a certain number of tap-change operations, or after an elapsed time, whichever occurs first. Table 23 indicates the typical criteria for each of the OLTC types, and the effect that OLTC position and load may have on these intervals.

OLTC Type	OLTC Position	Load	Inspection Intervals	
			Number of Operations*	Time** (years)
Resistor	Neutral	Low	40k -100k	5 – 7
		High	30k - 60 k	5 – 7
Resistor	Line, Single phase or Delta	Low	30k - 100k	3 – 7
		High	10k - 50k	3 – 7
Reactor	HV winding		50k - 100k	3 – 5
Reactor	LV winding		35k - 60k	3 – 5
Vacuum			150k - 300k	5 years to unlimited

* This criteria is normally established by the estimated life of an arcing contact at full load (about 20%), except for the vacuum switch which is based on the mechanical life of the bellows.

** Basic time criteria is typically established on a typical network application.

Table 23: Typical Recommendations from OLTC Manufacturers for Maintenance Intervals

By assessing the dielectric integrity of the insulating oil for deterioration, contamination and moisture, the time-based overhaul intervals can be considerably extended, and even eliminated in the case of some Vacuum Switch OLTCs.

4.8.7 Duty

The Duty for an OLTC can vary substantially depending on the application as shown by the survey results (updated from Breuer, Stenzel 1982) in the table below:

Power transformer	Transformer data			Number of operations per year		
	Power	Voltage	Current	Min	Mean	Max
	MVA	kV	A			
Generator	100-1300	110-765	100-2000	500	3,000	10,000
HVDC Converter	200-1500	110-765	300-3000	300	5,000	50,000
Network	15-400	60-525	50-1600	2,000	7,000	20,000
Electrolysis	10-300	20-110	50-3000	10,000	30,000	150,000
Chemistry	1.5-80	20-110	50-1000	1,000	20,000	70,000
Arc furnace	2.5-150	20-230	50-1000	20,000	50,000	300,000

Table 24: OLTC Duty

On resistor type OLTCs, the number of operations per hour is limited by the heat dissipation in the oil by the resistors (typically 150 operations per hour).

The expected OLTC Duty (number of operations) and rating (compared to load) should be taken into account to modulate the recommended maintenance schedule accordingly. For example:

- Network transformers operating on low load could easily exceed the prescribed time, but caution must be taken not to exceed the number of operations on some units. High speed Resistor Type OLTCs that operate long term on very light loads may suffer higher contact wear on their transition resistor contacts, solely because the resistance value of the transition resistors were originally selected to match normal 75% or 100% loading on the transformer.
- Arc furnace transformers that operate intensively and steadily may exceed the recommended maximum number of operations, provided that a maintenance record with contact wear is well documented.

However, OLTCs on Generator and HVDC transformers, that are usually fully loaded, should not exceed the recommended intervals.

4.8.8 On-Line Filtering

In oil OLTCs, the implementation of On-Line Filtering provides a direct benefit in allowing the number of operations between maintenance interventions to be increased by between 50% and 200% depending on the current rating. The time criterion might be extended too, depending on the application and the type of OLTC. However, a major limitation on the possibility to increase these intervals will be the mechanical wear on parts, requiring parts replacement after a certain number of operations. Benefits from using On-Line Oil Filtering systems are expected to be most evident for the following applications:

- High current rating OLTCs
- OLTCs fitted at the line end or in delta connected windings
- High annual number of operations (HVDC and furnace transformers)

For application to typical network transformers, the time criterion usually determines the interval between maintenance operations. Moreover, On-Line Oil Filtering is normally not used in neutral connected OLTCs. In subtropical or tropical areas, On-Line Oil Filtering with a dehumidifying filter is very often used to keep the oil in serviceable condition. A derived benefit of On-Line Filtering is a cleaner environment for maintenance work. Ultimately, the decision on whether to use an On-Line Oil Filter would need to weigh all the advantages against the extra maintenance costs (replacing the cartridge) and the initial investment required for the device.

4.8.9 Selector and Pre-Selector Switches

Selector and Pre-Selector Switches may experience coking formation. This will usually occur when the switches are not operated over a long period of time while carrying high currents. Contact surface degradation may start with the

development of an oxidation or contamination film, increasing resistance which in turn creates a hotspot, carbon formation eventually leading to a thermal runaway and coking. Contact friction from regular operation usually provides an adequate surface cleaning. A good practice therefore is to ensure that each switch is operated once a year as a minimum.

Pre-Selector Switches (or Changeover Selectors) are used to increase the total number of tap positions with only the same number of winding taps. The two main types are the Reversing and Coarse-Fine Pre-Selector Switches. The only other specific maintenance issue associated with Pre-Selector Switches is that they will produce minor levels of dissolved gas in the main tank for the in-tank OLTC types, especially if the operating excursions of the tap changer regularly pass through the tap position where the Pre-Selector Switch operates. The gas levels are typically low but may interfere with DGA interpretation.

4.8.10 OLTC Barrier Boards

Barrier Boards are located in the chambers of all Compartment Type OLTCs, primarily to isolate switch oil from the main oil. They may be used in association with certain In-Tank OLTCs where special provision has been made to house the entire OLTC in a separate oil chamber. Because of the large number of tapping winding leads that must pass through these Barrier Boards, the materials used must be mechanically strong enough to support the mass of the leads, and support the through bushing insulators or shaped moulding that insulates the leads and provides phase to phase isolation. Accordingly, all maintenance activity that involves oil handling, oil heating or application of vacuum must always involve very careful checks of the ability of the Barrier Board to withstand differential pressure, together with elevated temperature. This precaution especially applies where oil processing or a dry out is being carried out on either the transformer or the OLTC. Good practice is to ensure that the transformer main tank and the separate OLTC compartments are at equalised pressure during the application of vacuum.

Inspection of the OLTC during maintenance can include the Barrier Board to observe any signs of structural failure, oil leaks, delaminated board, electrical tracking or discharge patterns. Unless it proves to be superficial, any damage to the Barrier Board requires the board to be replaced because of the attendant risk of electrical breakdown. All tapping lead terminals on the through connectors or bushings should be checked for tightness, and localised resistance checks performed, especially when any winding resistance anomalies are detected on certain tap positions.

4.8.11 Tie-In Resistors and Non-Linear Resistors

Some OLTCs are fitted with these devices and awareness of their presence is a consideration for DGA interpretation as a potential source of gassing in oil.

A Tie-In Resistor effectively connects the tapping winding to the main winding during the operation of the Pre-Selector Switch and thereby limits the recovery voltage that would otherwise appear across the contacts of that switch. In order to reduce the resistive losses, some designs have the tie-in resistor normally switched out of service by a potential switch, except when the Pre-Selector Switch is about to operate. Usually no maintenance is required, but a failure of the potential switch or the resistor will cause dissolved gas and may lead to failure of the Pre-Selector Switch.

Non-Linear Resistors, sometimes called ‘Metrosils’ may be fitted between terminals of the tapping winding to limit induced voltages on these terminals under lightning impulse or switching impulse conditions. Although they require no maintenance, they are a potential source of problems.

4.8.12 Cooling System

Some OLTCs are used in applications where a high number of continuous operations are required (e.g. HVDC or arc furnace applications). During periods of continuous operation, the transition resistors in the OLTC oil compartment heat up the surrounding insulating oil. These OLTCs might then be equipped with a Cooling System. A standard On-Line Oil Filter used in combination with a cooling radiator may be used as the Cooling System. The oil flow through the system should be matched to the capacity of the cooling radiator. Periodic maintenance is required according to the manufacturer’s recommendations.

4.9 De-Energized Tap Changer

De-Energized Tap Changers (DETC) are used off-line to modify the ratio of a transformer, usually brought about by a change in system configuration, load or bus voltage setting. There is a substantial incremental cost to incorporate a DETC in a transformer due to the need for a special regulating winding and a drive mechanism. Considering how rarely it is operated, and that the device may affect the reliability of the transformer being susceptible to contact coking, this component should be installed only when there is a real need expected in the future.

If a transformer is equipped with a DETC, then locking hardware should be installed and clear labelling provided to prevent any operation while the transformer is energized. It is usually recommended by the manufacturers that the DETC is operated periodically (during a transformer outage) in order to exercise the mechanism and clean the contact interface. Indeed, experience shows that DETCs that have not been operated for many years may suffer from coking of the load carrying contacts and that an attempt to operate them could damage the mechanism.

4.10 Lightning (Surge) Arresters

Current practice is to equip transformers with Metal Oxide Surge Arresters (MOA), which offer the best lightning and surge protection. These arrestors have series connected zinc oxide varistors with excellent non-linear volt-ampere characteristics, and are also gapless as they do not require the use of spark gaps.

Past practices included the use of arcing horns, comprising of a pair of rods, mounted on the transformer bushings, forming a spark gap in parallel with the bushing, or the use of Silicon Carbide Surge Arrestors that incorporate the use of in-built air gaps. If the transformer installation has these gap-type arresters, improved surge protection can be achieved by replacing the gap-type arrestors with a properly rated MOA Surge Arrester.

4.11 Transformer Active Part

4.11.1 Windings

The transformer windings are a very important part of the transformer. Unlike other components, end-of-life for the winding solid insulation can be considered to correspond to the end-of-life of the transformer. Unless a winding develops a serious problem, signalling that some major maintenance intervention is required, the windings themselves require no maintenance. However, the transformer user must keep in mind that many other repairable and replaceable components have important impacts on the life of solid insulation in the windings.

Winding Arrangement

The windings of a power transformer may be either auto-connected or double wound, and the latter can have a Two-Winding (primary and secondary) or a Three-Winding (primary, secondary and tertiary) arrangement. Each winding is characterized by the following parameters: construction type, number of turns, size and form of wire, wire insulation, cooling ducts, insulating cylinders and insulating barriers. Concentric coils are typically wound over cylinders with spacers attached so as to form a duct between the conductors and the cylinder. The flow of liquid through the windings can be based solely on natural convection, or the flow can be somewhat controlled through the use of strategically placed barriers within the winding.

The winding parameters are chosen in conjunction with the characteristics of the transformer and the need to provide adequate withstand to over-voltages, inherent short-circuit withstand, good heat resistance, acceptable thermal design and optimized load losses. The basic conductor material for power transformer windings is insulated copper or aluminium wire of rectangular shape. While aluminium is lighter and generally less expensive than copper, a larger cross section of aluminium conductor must be used to match the current carrying performance of copper. The winding conductor is usually insulated using electrical grade kraft paper. In core-form transformers, the windings are usually arranged concentrically around the core leg. In shell-form transformers the windings are usually arranged in an interleaved “pancake” arrangement. The choice of the turn section (one or more parallel conductors) depends on the winding’s rated current. The number of winding turns depends on the winding voltage. In core-form power transformers several different types of windings may be used: layer windings, helical windings and disc windings.

Cellulosic Insulating Paper

For correct function, each transformer winding needs to be insulated turn from turn. Several solid insulating materials can be used for this purpose. In power transformers, cellulosic insulating paper, also known as kraft paper, is by far the most widely used material. Sometimes synthetic material based papers or thermally upgraded paper are used to insulate the winding regions where the operating temperature is expected to be high, creating windings with hybrid insulation. Where the entire transformer is specially designed to operate at higher temperatures, the insulation is made exclusively with aramid papers.

An important feature to note is that cellulose is constituted by a large number of the very polar C-O and H-O bonds. These bonds may interact with the other polar compounds dissolved in the oil, mainly water and acidic compounds, thus making cellulose susceptible to such compounds in the process of degradation.

Mechanism of Kraft Paper (Cellulose) Degradation

Cellulose degradation, like oil degradation, is a very complex process that is accelerated by the combined effect of heat, water, acids and oxygen, all of them available to the cellulose in the environment of the transformer. It depends primarily on the following processes.

Hydrolytic Degradation: The effect of water on cellulose oxygen bonds leads to the formation of C5 and C6 sugars. Then, an acid-catalysed dehydration reaction occurs and produces furan products.

Oxidative Degradation: Cellulose is highly susceptible to oxidation. The hydroxyl groups being the weak areas where carbonyl and carboxyl groups are formed and can cause secondary reactions causing chain scissions. Low weight products like CO, CO₂, H₂, and H₂O are usually produced.

Pyrolytic Degradation: In the temperature range above 130-150°C, paper degradation accelerates. At these temperatures, rapid pyrolytic degradation reactions may occur without the presence of water or oxygen. The decomposition products are mostly water and carbon oxides.

In recognising that these degradation processes take place and produce the various decay products, then there are several observables in the transformer oil that could be used as a measure of the level of paper degradation. However, the challenge remains for researchers and maintenance practitioners to make the appropriate quantitative correlations between the levels of paper decay products in the oil and the degree of paper ageing, especially when some of these chemicals are also oil decay products.

Clamping Pressure of the Windings

Another important factor for the windings is the clamping pressure. When the transformer windings are exposed to short-circuit fault current, no matter how robust the winding strength and the core frames may be, if there is inadequate clamping pressure then some freedom for winding displacement may result causing significant increase in the acting forces, some conductor dislocations and scission of paper insulation. Electrical failure would then result.

Early transformer manufacture often utilized press paper (a relatively compressible material) for making the wraps, spacers and collars in the winding ducts and parts of the end insulation. Manufacturers now use pre-compressed transformerboard exclusively for these parts. Together, the inevitable shrinkage of paper, press paper and also transformerboard brought about by the degradation processes, must result in some relaxation of the clamping forces although in widely varying degree. Special attention should be kept on this parameter, especially if a drying process is applied to older transformers.

Transformers of modern manufacture and design should not require verification or modification of the clamping pressure during the life of the transformer. This has been brought about by the substantial use of transformerboard, higher clamping pressure and improved clamping arrangements.

4.11.2 Transformer Oil

Transformer Oil condition has a big impact on the ageing of the transformer oil-paper insulation system and there are several maintenance actions that can be performed on Transformer Oil. Also, because Transformer Oil impregnates the transformer solid insulation, and is purposely circulating for heat transfer, there can be very fast chemical interaction between them.

Transformer Oils, used in oil filled electrical equipment, can be divided into four different groups as described next with their advantages and disadvantages.

Mineral Oil

Advantages	Disadvantages
<ul style="list-style-type: none">- Extensive in-service experience in all type of apparatus, including UHV- Available world wide, however quality will vary (specific additives may improve poor quality oils)- Oil can be treated to remove aging by-products- Low price- Easy to eliminate as waste	<ul style="list-style-type: none">- Low flashpoint temperature- Moderate biodegradability

Table 25: Mineral Oil

Silicone Oil

Advantages	Disadvantages
<ul style="list-style-type: none">- High flashpoint temperature- High thermal performances- Low viscosity suited for cold climate applications	<ul style="list-style-type: none">- Very low biodegradability- Combustion by-products are harmful (opacity and toxicity of fumes)- High price- Not easy to eliminate as waste- Little experience in HV applications- Aged oil can not be treated (only replaced)

Table 26: Silicon Oil

Natural Ester

Advantages	Disadvantages
<ul style="list-style-type: none">- Very good biodegradability- Easy to eliminate as waste- High flashpoint temperature	<ul style="list-style-type: none">- High price- Rapid oxidation (ageing) when exposed to air- No experience in HV applications- Marginal low temperature performance compared to other oils (pour point of -15 °C instead -25 to -45 °C for mineral oil or synthetic ester)- Aged oil can not be treated (only replaced)

Table 27: Natural Ester

Synthetic Ester

Advantages	Disadvantages
<ul style="list-style-type: none">- Good biodegradability- Easy to eliminate as waste- High flashpoint temperature- Good low temperature performance- Good longevity	<ul style="list-style-type: none">- High price- Little experience in HV applications- Aged oil can not be treated (only replaced)

Table 28: Synthetic Ester

Mineral insulating oil, the most common fluid used in transformers, is produced from refining crude oil. Over time, insulating liquids may become contaminated or deteriorated to a stage where they are unsuitable for continued service. Oil contamination is either of a physical or a chemical nature. Physical contamination, such as particles and water can be removed by filtration and dehydration of the oil, whereas chemical contamination cannot be removed by such simple means. Depending on the type of contaminants, different corrective actions are required. If no corrective action is taken then equipment failure may follow.

The options available to the equipment owner are either to change or to reclaim the oil. Although oil reclamation is capable of removing oxidation products and polar compounds from the oil, not all chemical contamination can be removed by this process. Furthermore, not all used, oxidised oils are reclaimable. PCB contamination cannot be removed by oil reclamation and requires the chemical technique of dehalogenation, or in extreme cases oil incineration. It should be noted that neither flushing nor hand cleaning can remove all the sludge that accumulates in the voids of the insulation. Only about 25 % of the surface of the transformer winding can be reached through flushing and cleaning in a workshop. Changing the oil does not remove all the deposited sludge, especially material trapped in the cooling fins, in the solid insulation and in between the windings. This residual sludge will dissolve into the new oil and will trigger the oxidation process immediately.

4.11.3 Transformer Core

The core of a transformer requires no maintenance. For diagnostic purposes, the ground connections of the core laminations and core frames should be brought to an externally accessible point so that an insulation resistance test may be performed without the need to drain oil and enter the transformer tank. Breakdown or shorting out of the core insulation by a foreign object or debris will cause circulating currents to flow, causing gas generation that could mask other developing problems in the transformer or could even develop into more serious core problems. To prevent circulating currents, some transformer manufacturers insert a resistance of 30-50 ohms (50-100 W) into the core ground circuit. The resistor keeps the core tied to ground but limits circulating currents in the event that a problem develops with the core insulation. This solution could also be retro-fitted to other transformers that develop a circulating current problem in their core earthing.

4.11.4 Maintenance Focus on the Active Part

The degradation of cellulosic insulation and oil are complex phenomena triggered by the combined effects of heat, water, acids and oxygen. In order to minimize the ageing of the cellulose, the transformer Maintenance Process takes into account the following items.

Oil Preservation System and Sealing

The oil preservation and sealing system must be maintained and kept in good condition to prevent oil contamination, and thereby reduce ageing of the active part.

Cooling System and Temperature Indicators

Assuming that the ambient temperature and loading conditions are normal, the greatest influence on the oil and winding operating temperatures will be the performance of the transformer's cooling system. If the cooling system does not function as intended, the oil and winding will be exposed to higher than normal temperatures and the ageing process will accelerate. Correct operation and calibration of the temperature indicators are also required since they initiate the operation of the cooling system, alarms and trips.

Insulation Condition

High moisture content in the oil and solid insulation is an important contributor to insulation ageing. Thus, it is important to monitor water content through oil analysis or through an appropriate monitoring system. If the insulation is proven to have high moisture content, appropriate insulation drying should be applied. Assessing the moisture content in the insulation system of the transformer must focus on the amount of water held within its two components - the oil, and the solid insulation. Oil and water do not have an affinity for each other, whereas the cellulose and water do have a strong affinity, so the majority of the moisture inside the tank is held within the solid insulation.

The technical brochure 349, published by Cigre WG A2.30 in 2007, provides an understanding of the complexity of the dynamics of moisture distribution within the insulation system of a transformer. It describes various techniques commonly used to try to determine the amount of moisture contained within the solid insulation system. As with most transformer diagnostics, it is strongly recommended not to rely on one technique but preferably to look for correlations between two or more.

One method, uses an On-Line Monitoring System to gain an understanding of this very dynamic situation by using moisture sensors that measure the relative saturation (% RS) of moisture in the oil, combined with systems that measure and compute temperatures such as top and bottom oil temperature and the winding hot spot temperature (via fibre-optic probes). Taking into account the time constants to achieve moisture equilibrium between the oil and paper interface, the amount of water in paper, relative to the hotspot temperature, can be estimated.

Other contaminants will also accelerate insulation ageing. Critical oil condition parameters should also be measured through oil analysis or through an appropriate monitoring system. Oil acidity, presence of oxygen (depending on the oil preservation system) or low level of oil inhibitor should be monitored. When the condition becomes unsatisfactory, oil treatment (physical and chemical) should be applied. Refer to IEC 60422 for recommended oil condition criteria.

4.12 Sensing and Monitoring Devices

While utilities have accumulated much experience with transformer maintenance, this is not the case with Sensing and Monitoring Devices. Experience with these devices is increasing as the number of installations, the time in operation and improved technologies evolve. On new transformers, the Sensing and Monitoring Devices are predominantly fitted by those utilities that have adopted them as part of their asset strategy. For older transformers, the majority of Sensing and Monitoring Devices have been retrofitted to units that have been identified to have an incipient fault, or alternatively because of their system criticality.

Irrespectively, these devices and associated components should be evaluated by all users in seeking to facilitate the advanced maintenance strategies outlined in this guide. In principle, the real value of the sensing and monitoring devices is in intercepting a failure of the transformer, and its cost effectiveness only comes with the ability to optimize the maintenance costs required to achieve this goal over the life of the transformer. A part of that evaluation should also consider that there are possible maintenance issues for the Sensing and Monitoring Devices that stem from:

- *Operational Time* - Sensing and Monitoring Devices have much shorter operational lifetime than main transformers
- *Electric versus Electronic* - electronic devices need quite different skills and actions than main transformer maintenance
- *Failures Modes* - varied and may include hardware, software and communication aspects that require specific skills, tools and technical support

The typical structure of Sensing and Monitoring Devices contain the sensors and associated electronic parts such as adaptation and processing circuits, a display means and power supply (battery or power source). Additional parts may include cables, connectors, switches or other electrical and electronic devices. Processing and data storage are often required to collect and process the sensor signals. Finally, additional components may be required to insure the functionality of sensing devices such as environmental controls for the cabinet, and calibration or preparatory equipment for the measurement transducers.

Depending on the components used, the two common reasons to invoke maintenance action are:

- *Failure in one of the components of the Sensing and Monitoring Device*: These devices commonly include an in-built self check function which is helpful to detect malfunctions. Besides the devices themselves, some associated systems may also fail such as power supplies and communications.
- *The need to replace obsolete devices*: This may be the case when the sensing and monitoring itself, the communication or control means may become obsolete during the life of the transformer, for example after installing another communication or SCADA system in the substation. Typically, the electronic parts may become obsolete in terms of functions offered, changes in communication technology, or limitation of the interfaces provided to accept modular additions. Such electronic devices used for sensing and monitoring have a life cycle of 15 to 20 years compared to 30 to 40+ years for power transformers.

Although Sensing and Monitoring Devices are often used stand-alone, there is a trend to integrate them into substation networks and with SCADA systems. Communication issues in the substation environment, networking the Sensing and Monitoring Devices, as well as trends for using the Ethernet, switches and routers, escalate the maintenance demands from that of a stand-alone device to the maintenance of an interconnected device in a network.

Also the use of electronic devices for sensing, monitoring and communication raise needs for these devices to be certified for special EMC, temperature or other on site conditions. Maintenance actions should not change the device qualification or capabilities. A special issue for the Sensing and Monitoring Systems are improper functionality and false alarms. Maintenance checks and adequate design of these devices should prevent most malfunctions. The two categories for concern are "alarm without failure" or "failure without proper alarm".

The maintenance required for the Sensing and Monitoring Devices should be systematically specified, in a similar way to that for the main power transformer asset. The maintenance manual for the transformer should also include the maintenance manuals for the Sensing and Monitoring Devices.

Chapter 5 Maintenance Action Catalogue

This chapter gives an overview of the different maintenance actions that may be performed during the life of a transformer. The Maintenance Action Catalogue includes condition assessment actions (for example electrical testing, oil testing and inspections) and maintenance actions to improve condition (for example dry outs and oil treatment).

5.1 Electrical Measurement Methods for On-Site Transformer Diagnosis

5.1.1 Introduction

Transformer life management requires a portfolio of the different kinds of on-site electrical tests to be performed. The principal purposes for performing them include:

- fingerprint measurements of new transformers to characterize the initial status
- routine tests (periodic checks) for observing trends
- monitoring as an early "warning system"
- tests for troubleshooting and fault location

The main targets of on-site tests are:

- control of the aging performance of insulating oil and the solid insulation due to dielectric and thermal aging
- discrimination of failure type as thermal or dielectric
- measurement, localization and assessment of partial discharge activity
- control of mechanical changes due dynamic impacts
- trending of moisture absorption and aging of both the liquid and the solid insulation

The following table give a summary of the typical problems that may be detected with electrical tests and DGA:

		Type of Problem					
		Magnetic Circuit Integrity	Magnetic Circuit Insulation	Winding Geometry	Winding/Bushing/OLTC Continuity	Winding/Bushing Insulation	Winding Turn to Turn Insulation
		Diagnostic Technique					
Basic Electrical	Winding Ratio	•					
	Winding Resistance			•			
	Magnetisation current	•					•
	Capacitance and DF/PF		•		•	•	•
	Leakage Reactance				•		
	Insulation Resistance		•			•	
	Core Ground Test						•
Advanced Electrical	Frequency Response of Stray Losses			•	•		
	Frequency Response Analysis	•			•	•	•
	Polarisation/Depolarisation		•				
	Frequency Domain Spectroscopy		•				
	Recovery Voltage Method		•				
	Electrical Detection of PD	•	•				
	Acoustical Detection of PD	•	•				
	UHF Detection of PD	•	•				
	Dissolved Gas Analysis	•	•	•		•	•

Table 29: Electrical Tests and DGA Diagnostic Matrix

5.1.2 Basic Measurements

Winding Ratio

Detectable failures	Shorted winding sections or turns
Indication	Buchholz relay tripping OLTC repair
Test method	An AC source is connected to each phase of the HV winding with all other windings open circuited. The source voltages across the HV winding and across the LV winding are measured.
Reference	Test report or rating plate, comparison of phases
Interpretation	Measurement should be $\pm 0.5\%$ of the nameplate values
Comments	<ul style="list-style-type: none"> - Some test equipment may allow magnetising current to be measured concurrently - Avoid performing winding resistance tests before the winding ratio measurement is carried out. The residual flux could impact the measurement. - The ratio test is normally performed following internal work on the transformer involving disconnections of any leads, especially the OLTC

Table 30: Winding Ratio

Winding Resistance

Detectable failures	Contact problems on the tap selector, contact problems on the diverter switch, broken conductors, broken parallel strands, shorted winding disks, shorted winding layers, poor bushing connections
Indication	High internal temperatures, normally indicated by the DGA
Test method	A constant current source is used to feed a DC current into the winding. The test current and the voltage across the winding are measured and the resistance value is calculated. The accuracy of the equipment should guarantee that differences of 1% or even lower can be detected. Since the winding resistances are small, the test set should be connected in 4-wire technology. A relatively high no-load voltage enables a quick saturation of the core and a fast reaching of the stationary final value. It is recommended to measure the resistance for all taps of the OLTC. The resistance values should be corrected to 75°C according to IEC 60076 Part 1
Reference	Test report of the manufacturer, fingerprint measurements
Interpretation	The measured winding resistance should not differ more than about 1% compared to the factory test report, if the winding temperature at measurement conditions is corrected to the factory conditions. Difference between phases usually less than 2-3%; Comparison between HV and LV resistance is usually in the order of the square of the winding ratio, when losses are balanced between HV and LV
Comments	In comparison to the LV winding, the resistance of the HV winding is much higher. Therefore identification of contact problems can be less sensitive on the HV side than the LV side. If the LV windings have very low resistance values, in the order of a few mΩ, it can be helpful to use the HV winding of the same limb in serial connection to get faster stabilization of the measurement current. The time needed to get stable readings can be in the order of tens of minutes for very low resistance values

Table 31: Winding Resistance

Magnetising Current

Detectable failures	Core faults (shorted laminations), shorted turns or winding parts
Indication	Buchholz relay tripping or DGA
Test method	An AC source is connected to each phase of the HV winding with all other windings open circuited. The source voltage across the HV winding and the source current are measured. If possible, the phase angle should also be measured
Reference	Comparison of phases, fingerprint measurements
Interpretation	Normally the outer phases have similar values within 5%. The current on the middle phase can be up to 30% lower
Comments	<ul style="list-style-type: none"> - Some test equipment may allow winding ratio to be measured concurrently - Magnetising current at rated voltage is only 0.1 – 0.3 % of rated current. Voltage dependency of magnetising current means comparison testing must use the same test voltage and tap position - Avoid performing winding resistance tests before the magnetising current measurement is carried out. The residual flux could impact the measurement

Table 32: Magnetising Current

Capacitance and Dielectric Dissipation Factor (or Power Factor)

Detectable failures	<ul style="list-style-type: none"> - Capacitance: Winding to winding: change of the geometry between windings due to high currents or mechanical damage - Winding to ground: change of the geometry between winding and ground due to high currents or mechanical damage - Core to ground: change of the core position to the tank due to mechanical damage - Condenser bushings: breakdowns between grading layers - Dielectric Dissipation Factor or Power Factor: Insulation failures, contamination of insulation liquids with particles, acids, water in solid and liquid insulation, partial discharges due to bad contacts on bushing test tap, breakdown in bushing condenser layers 																				
Indication	Moisture, tests on regular bases (e.g. on high voltage bushings)																				
Test method	<p>A sinusoidal HV AC source (preferable with variable frequency) is connected to the test object in parallel to a low loss reference capacitor. The currents through the test object and through the reference capacitor are measured and the time difference between their zero crossings is determined. The loss angle delta can be calculated from this time difference. Normally this test is done at 10 kV for on-site measurements.</p> <p>The following figure shows the equivalent parallel circuit of an insulator (capacitance) with its losses (resistance) and the comparative definitions of Dissipation Factor (DF) and Power Factor (PF), expressed as a ratio of currents in the equivalent circuit components. For historical reasons, European countries mostly use DF, whereas PF is mostly used in North America. For values up to 10%, the typical range for insulating material, DF and PF are numerically equivalent anyway</p> <div style="text-align: center;"> </div> <p>DF : $\tan \delta = \frac{ I_{RP} }{ I_{CP} } = \frac{1}{R_p \cdot \omega \cdot C_p}$</p> <p>PF : $\cos \varphi = \frac{ I_{RP} }{ I_{tot} }$</p> <p>Figure 12: Insulation equivalent circuit and Definitions for DF and PF</p> <p>Terminology: This test method, and its result, may be referred to by many terms such as: loss factor, loss angle, dielectric loss angle (DLA), $\tan \delta$, tangent delta, δ, dielectric dissipation factor (DDF), dissipation factor (DF), power factor (PF), $\cos \varphi$ or $\cos \theta$. The units of measure can also vary : radians, milli-radians (mR), %, ‰ (rarely used) The absence of units usually means the result is the arithmetic value of $\cos \varphi$ or $\tan \delta$</p>																				
Reference	Test report, fingerprint measurements, trend analysis, comparison to identical units Nameplate values for bushings																				
Interpretation	<p>For measurements on windings, values are normally in the order of 0.5%. A measurement higher than 1% is questionable. For bushings, the following values are given in IEC and IEEE standards:</p> <table border="1" data-bbox="548 1528 1312 1793"> <thead> <tr> <th>Typ</th> <th>RIP</th> <th>OIP</th> <th>RBP</th> </tr> </thead> <tbody> <tr> <td>Insulation</td> <td>Resin impregnated paper</td> <td>Oil impregnated paper</td> <td>Resin bonded paper</td> </tr> <tr> <td>DF $\tan \delta$ (RT) (IEC 60137)</td> <td>< 0,7% *</td> <td>< 0,7% *</td> <td>< 1,5% *</td> </tr> <tr> <td>PF $\cos \varphi$ (RT) IEEE C57.19.01</td> <td>< 0,85% *</td> <td>< 0,5% *</td> <td>< 2% *</td> </tr> <tr> <td>Typical new values</td> <td>0.3-0.4% *</td> <td>0.2-0.4% *</td> <td>0.5-0.6% *</td> </tr> </tbody> </table> <p>* at 50/60Hz and 20°C</p>	Typ	RIP	OIP	RBP	Insulation	Resin impregnated paper	Oil impregnated paper	Resin bonded paper	DF $\tan \delta$ (RT) (IEC 60137)	< 0,7% *	< 0,7% *	< 1,5% *	PF $\cos \varphi$ (RT) IEEE C57.19.01	< 0,85% *	< 0,5% *	< 2% *	Typical new values	0.3-0.4% *	0.2-0.4% *	0.5-0.6% *
Typ	RIP	OIP	RBP																		
Insulation	Resin impregnated paper	Oil impregnated paper	Resin bonded paper																		
DF $\tan \delta$ (RT) (IEC 60137)	< 0,7% *	< 0,7% *	< 1,5% *																		
PF $\cos \varphi$ (RT) IEEE C57.19.01	< 0,85% *	< 0,5% *	< 2% *																		
Typical new values	0.3-0.4% *	0.2-0.4% *	0.5-0.6% *																		
Comments	This is the most common technique for assessing the bushing condition (see information below)																				

Table 33: Capacitance and Dielectric Power/Dissipation Factor

Additional Information for Bushing Diagnostics

The most common technique for assessing the condition of a bushing is the dissipation factor (DF) / power factor (PF) and capacitance measurement. Test results are then compared to nameplate values or previous tests. Increases or decreases from reference values are usually an indication of contamination and/or deterioration of the insulation system. Limits for the maximum permissible change tend to be manufacturer and type specific. A doubling of the initial dissipation/power factor value warrants either more frequent monitoring or replacement. A 10 % change in capacitance also warrants replacement. The temperature of the insulation can affect the dissipation/power factor results. Temperature correction factors for OIP and RIP bushings are shown below in Figure 13 [1]. The temperature of the bushing lies between the oil temperature of the transformer and the ambient temperature. The temperature of the oil and the ambient temperature should be recorded in the test report.

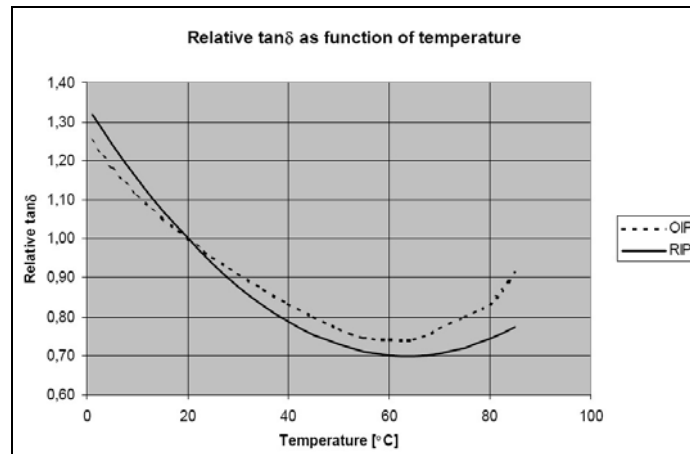


Figure 13: Effect of Temperature on Dissipation/Power Factor (tanδ) Measurement

Leakage currents across the surface of the outer insulator (porcelain or silicone) may also have some influence, particularly if the surface is dirty and wet. In case of unexpectedly high dissipation/power factor values, the bushing should be cleaned before the measurement is repeated. For silicone composite bushings, the cleaning instructions of the manufacturer should be followed, because some cleaning chemicals can damage the silicone. Additionally, a collar which is connected to the guard circuit can be used to suppress the influence of the surface current. With a “hot-collar”, the capacitance and dissipation/power factor of the insulation between the collar and the grounded centre conductor can be measured. This technique can be used to detect local faults in bushings or low oil level in oil filled bushings.

All given reference values are valid for the capacitance “C1”, which lies between the inner conductor and the measuring tap. In oil filled bushings, the dielectric losses of the capacitance “C2”, which lies between the measuring tap and the flange, can give some information about the oil around the active part of the bushing. Care has to be taken that the measuring tap is clean and dry, otherwise this will affect the result. The evaluation is based on a comparison of tests on similar bushings on the transformer. The condition of bushings can also be evaluated using infrared thermography and, in the case of oil filled bushings, by dissolved gas analysis of bushing oil or by monitoring the pressure within the bushing.

The bushings are sealed and leak tested at the time of manufacturing. In order to take an oil sample, the bushing has to be opened and this introduces a risk of improper re-sealing and possible contamination (moisture, dust) after sampling is completed. It is therefore recommended not to sample oil on bushings. However, when a problem is known, for example high dissipation/power factor for the C1 measurement, there might be a need for oil sampling and gas analysis. The interpretation of the analysis is done according to Technical Report IEC 61464. If questions remain, the manufacturer can usually assist with the evaluation. If oil needs to be sampled the following recommendations should be followed:

- Ask the original manufacturer for a sampling procedure
- Sample is preferably taken during dry weather conditions
- If this is not possible, clean the area around the sampling plug, and also protect that area from rain
- The internal pressure of the bushing must not be altered before and after the sampling. This requirement is satisfied if the sample is taken when the mean temperature of the bushing is between 0°C and 30°C
- The time when the bushing is open should be as short as possible
- Immediately replace the removed oil with an equal amount of new, dry, degassed transformer oil
- The gasket should always be replaced when the bushing is re-sealed

Because bushings are hermetically sealed components, measuring the pressure of the oil within the oil filled bushing is a valuable diagnosis tool. The advantage is that it allows monitoring of the on-line condition of the bushing to detect possible oil leakage or overheating. However this requires the bushing to be installed already equipped with a pressure sensor at the foot of the bushing.

Literature: "Bushings diagnostic and conditioning", ABB Brochure 2750 515-142en 2000-08-30

Leakage Reactance (Short Circuit Impedance)

Detectable failures	Deformation of windings
Indication	High through current faults, high inrush currents, Buchholz relay tripping, protective relay tripping
Test method	An AC source (preferable with variable frequency) is connected to each phase of the HV winding with the corresponding LV winding short circuited. The source current and the voltage across the HV winding are measured to determine the leakage impedance. To determine the leakage reactance, the imaginary part of the complex impedance has to be measured. This can be done by using a complex impedance measuring device or a wattmeter to determine the real part of the complex impedance. The reactance can be calculated from these results
Reference	Fingerprint measurements (one phase test), or comparison to identical units
Interpretation	The measured impedance should not differ more than 2% compared to the factory test report. The difference between phases is usually less than 2%. Changes >1% ought to be investigated with other tests such as FRA. Care is required comparing 3 phase and 1 phase test measurements
Comments	The test can be done also from the LV side, but in this case the values have to be corrected using the square of the winding ratio.

Table 34: Leakage Reactance (Short Circuit Impedance)

Insulation Resistance

Detectable failures	Insulation deterioration or failures in the windings or core earthing
Indication	Buchholz relay tripping, DGA
Test method	A high DC voltage (typical values are 1kV up to 5kV) is applied to the winding under test. The insulation between core and tank can also be verified by this measurement. The leakage current is measured and the insulation resistance calculated and indicated by the instrument. As this measurement uses DC voltage, the measurement cannot be compared with AC losses that comprise of polarisation losses and capacitive coupling through the insulation. The temperature can affect the measurement results. The test voltage and temperature must be recorded
Reference	Test report, fingerprint measurements, comparison to identical units
Interpretation	Transformers with rated voltage > 69kV, >1GΩ measured at 20°C Transformers with rated voltage ≤ 69kV, >500MΩ measured at 20°C
Comments	- Another way of applying Insulation Resistance is to measure the Polarization Index (PI) by measuring the current after 1 and 10 minutes of voltage application. The PI was introduced to detect moisture in the winding insulation of rotating machines. For the complex oil-cellulose insulation system of transformers the PI results can be misinterpreted. FDS/PDC measurements are preferred for quantitative assessments of the moisture in the insulation - The measurement of the insulation resistance can influence RVM, PDC and FDS measurements, if they immediately follow the Insulation Resistance test

Table 35: Insulation Resistance

Core Grounding

Detectable failures	Multiple core grounding by core grounding faults
Indication	High internal temperatures, normally indicated by the DGA
Test method	The test can be done only if the core grounding can be disconnected outside the tank to measure the insulation resistance of the core to ground
Reference	Test report of the manufacturer, fingerprint measurements
Interpretation	The insulation resistance of the core to ground is in the order of 10MΩ or higher. Values lower than 100kΩ can indicate core grounding problems. In some cases resistances are used to ground separated core lamination packets. These resistances are normally in the order of several kΩ
Comments	Measurements of the core ground current in service, show that the measured current is in the order of some mA for a well insulated core; if the core has grounding faults, the current is several amps or even higher

Table 36: Core Grounding

5.1.3 Special or Advanced Measurements

Frequency Response Analysis (FRA)

Detectable failures	Shorted turns, core faults, winding deformation, winding displacement, faulty core grounding, faulty screen connections, damage during transportation
Indication	High through fault currents, Buchholz relay warning or tripping, DGA, impact recorder results (transportation)
Test method	<p>Frequency Response Analysis (FRA) is a method to evaluate the mechanical and geometrical integrity of the core and windings within a power transformer by measuring the electrical transfer functions over a wide frequency range. The FRA is a comparative method, that evaluates the transformer condition by comparing the obtained set of FRA results to reference results on the same, or a similar, unit.</p> <p><i>Method 1 - Sweep Frequency Response Analysis SFRA:</i> A sinusoidal AC voltage with variable frequency (several Hz to several MHz) is connected to each phase of the HV and the LV windings with all other windings open circuited. The input voltage (U_{in}) and the output voltage (U_{out}) are measured at different frequencies. For both Method 1 and Method 2, the ratio "20 log (U_{out} / U_{in})" (in dB) is calculated for each frequency and the results are plotted on a trace.</p> <p><i>Method 2 - Impulse Frequency Response Analysis IFRA:</i> An impulse is injected to each phase of the HV and the LV windings with all other windings open circuited. The input and output impulse curves = f(t) of the windings are recorded. The time domain results are transformed into the frequency domain by using FFT algorithms. The input voltage (U_{in}) and the output voltage (U_{out}) are calculated for different frequencies.</p> <p>It is observed that both methods give satisfactory results but Method 2 does not give results in the low frequency range (below 1kHz). Refer also to Technical Brochure 342 (SCA2 WG A2.26).</p>
Reference	<p>Three methods are commonly used to assess the measurements (traces):</p> <ul style="list-style-type: none"> - time-based (current FRA results will be compared to previous results of the same unit) - type-based (FRA of one transformer will be compared to an equivalent type) - phase comparison (FRA results of one phase will be compared to the results of the other phases of the same transformer)
Interpretation	No limits are defined. Comparison with benchmark data will indicate changes.
Comments	<p>For transportation assessment the FRA should be the last test before departure and the first test upon arrival. No winding resistance DC measurement should be made before an FRA measurement is carried out. The residual flux could impact the measurement.</p> <p>Benchmark raw data should be stored to facilitate later comparisons.</p>

Table 37: Frequency Response Analysis (FRA)

Literature:

Cigre Technical Brochure 342, "Mechanical Conditioning Assessment of Transformer Windings"

Polarization Depolarization Current (PDC) Method

Detectable failures	Water content in the solid cellulose insulation of oil-paper insulation, insulation failures, ageing of insulation, contamination of insulation liquids with particles, acids, water in solid and liquid insulation, partial breakdowns of capacitive bushing layers
Indication	High moisture in the oil, general assessment of insulation condition
Test method	<p>The principle of this measurement is to apply a DC voltage across the insulation during a certain time and to measure the polarisation current. Then the insulation is short-circuited a variable time and the current is measured again (depolarisation current). Dielectric diagnostic methods deduce moisture in paper or pressboard from the polarization and depolarization currents measured at time intervals. Experience shows that moisture strongly influences these measurements. The dielectric response of insulation can be recorded in the time domain or the frequency domain. A time domain current measurement records the charging and discharging currents of the insulation. The derived measurement method is called the Polarization Depolarization Current method.</p> <p style="text-align: center;">Figure 14 – Polarisation and Depolarisation Current</p>
Reference	Moisture determination by modelling, comparison to fingerprint measurements
Interpretation	Moisture determination is based on a comparison of the transformer's dielectric response to a modelled dielectric response. An algorithm rearranges the modelled dielectric response and delivers moisture content and oil conductivity. A reliable moisture analysis of onsite measurements is based on an exact data pool for the modelled dielectric response. The data pool includes the measurements on new pressboard at various temperatures, moisture contents and oils used for impregnation. Once water content has been assessed, refer to the limits for dry, moderately wet and extremely wet insulation provided in IEC 60422.
Comments	New procedures consider also the dielectric properties of aged pressboard in order to compensate for the influence of aging.

Table 38: Polarization Depolarization Current (PDC) Method

Literature:

- [1] M. Koch et al. "Improved Moisture Analysis of Power Transformers Using Dielectric Response Methods", MatPost 2007 Lyon
- [2] Cigré Technical Brochure 227, "Life Management Techniques for Power Transformers"
- [3] Cigré Technical Brochure 414 "Dielectric Response Diagnoses for Transformer Windings"
- [4] Cigré Technical Brochure 349 "Moisture Equilibrium and Moisture Migration"

Frequency Domain Spectroscopy (FDS)

Detectable failures	Water content in the solid cellulose insulation of oil-paper insulation, insulation failures, contamination of insulation liquids with particles, acids
Indication	High moisture in the oil, general assessment of insulation condition
Test method	<p>The principle of this measurement is the same as Capacitance and Dissipation/Power Factor described previously but differs by being applied at different frequencies, typically from 0.001 Hz to 1000 Hz as shown in the following traces:</p> <p style="text-align: center;">Figure 15: Frequency Domain Spectroscopy</p>
Reference	Moisture determination by modelling, comparison to fingerprint measurements, limits for dry, moderately wet and extremely wet insulation are given in IEC 60422
Interpretation	Moisture determination is based on a comparison of the transformer's dielectric response to a modelled dielectric response. An algorithm rearranges the modelled dielectric response and delivers moisture content and oil conductivity. A reliable moisture analysis of the onsite measurements is based on matching them with a data pool for the modelled dielectric response. The data pool consists of measurements on new pressboard at various temperatures, moisture contents and oils used for impregnation. New procedures consider also the dielectric properties of aged pressboard as well in order to compensate for the influence of aging. Once water content has been assessed, refer to the limits for dry, moderately wet and extremely wet insulation provided in IEC 60422.
Comments	The combination of time domain polarization current measurements with frequency domain spectroscopy reduces the test duration compared to existing techniques. Essentially, time domain measurements can be accomplished in a short time but are limited to low frequencies (typically below 1 Hz). In contrast, frequency domain measurements are feasible for high frequencies as well but take very long time at low frequencies.

Table 39: Frequency Domain Spectroscopy (FDS)

In its application to high voltage bushings, the measurement of Dissipation/Power Factor at low frequencies (some Hz) enables the detection of moisture with high sensitivity. Figure 16 below demonstrates the typical moisture sensitivity of the Dissipation/Power Factor Measurement on OIP bushings between 20 Hz and 400 Hz.

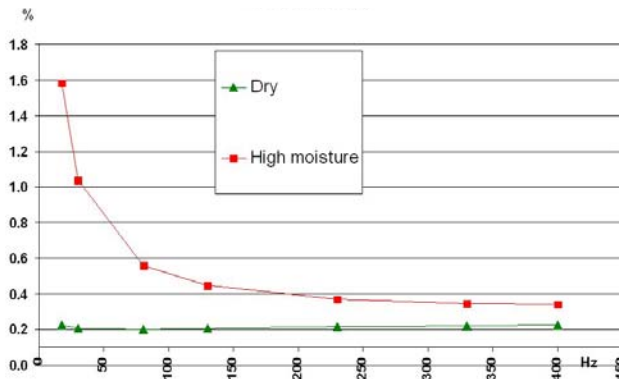


Figure 16: Dissipation/Power Factor Measurement on OIP Bushings at Different Frequencies

As a guide, indicative limits for Dissipation/Power Factor in new and aged bushings at frequencies of 15 Hz, 50/60 Hz and 400 Hz are given in the following table.

Frequency	RIP		OIP		RBP	
	Resin impregnated	Oil impregnated	Resin bonded paper			
	new	aged	new	aged	new	aged
15Hz	<0.6%	<0.7%	<0.5%	<0.7%	<0.7%	<1.5%
50/60Hz	<0.5%	<0.5%	<0.4%	<0.5%	<0.6%	<1%
400Hz	<0.6%	<0.7%	<0.5%	<0.7%	<0.7%	<1.5%
at 20°C						

Table 40: Indicative DF/PF Limit Values for Condenser Bushings
(Source - “New Diagnostic for High Voltage Bushings”)

Literature:

- [1] M. Perkins, G. Frimpong, A. Fazlagic, "Dielectric Frequency Response Measurement as a Tool for Troubleshooting Insulation Power Factor Problems", IEEE ISEI Conference Paper, Boston, MA, April 2002
- [2] M. Koch et al. "Improved Moisture Analysis of Power Transformers Using Dielectric Response Methods", MatPost 2007 Lyon
- [3] Cigré Technical Brochure 227, "Life Management Techniques for Power Transformers"
- [4] Cigré TF D1.1.09: Technical Brochure 245, "Dielectric Response Methods"
- [5] Cigré WG A2.30: Technical Brochure 349, "Moisture Equilibrium and Moisture Migration"

Electrical Method for Partial Discharge (PD) Measurement

Detectable failures	Partial discharges, singular insulation faults
Indication	DGA
Test method	For detection, different types of coupling are used, for example bushing capacitance taps, high frequency current transformers or coupling capacitors. The test method outlined in IEC 60270 is a useful tool, because it is a sensitive method and can be calibrated. Electromagnetic noise external to the transformer can interfere with the measurement. For this reason, the method may be unsuitable for some on-site measurements. However, modern multi-channel PD measuring systems which can record the PD on all channels simultaneously, and new methods such as the Three Phase Amplitude Relation Diagram (3PARAD) or the Three Centre Frequency Relation Diagram (3CFRD), can be used to separate PD sources from each other and from external electromagnetic noise (interference).
Reference	Fingerprint measurements, trend analysis
Interpretation	For PD On-site measurement, limits cannot be defined; This technique can be used with Acoustic PD in order to facilitate PD localization.
Comments	PD measurement is important to detect and locate a weakness in the insulation system. Partial discharge activity typically occurs within insulation voids, on ungrounded metal objects lying in an electric field, or as corona due to the intense electric stress on the insulation surrounding sharp edged/shaped electrodes. In transformers, some PD sources include gas bubbles in the oil, voids in solid insulation material or floating metallic particles. The long term effect of PD is destructive for organic insulation systems, by degrading their insulation qualities. A significant increase of the PD level or the rate of the PD can provide an early indication for evolving defects. The PD pulses generate electromagnetic waves, acoustic signals, chemical reactions, local heating and optical signals. Different techniques can be used to detect these phenomena.

Table 41: Electrical Method for Partial Discharge (PD) Measurement

Literature:

- [1] IEC 60076-3
- [2] IEC 60270
- [3] K. Rethmeier et al. "Experiences in On-site Partial Discharge Measurements and Prospects for PD Monitoring", CMD Beijing 2008

Acoustic Partial Discharge (PD) Measurement

Detectable failures	Partial discharges
Indication	DGA
Test method	<p>The acoustic partial discharge measurement uses the fact that an acoustic signal is emitted by PD activity as a result of pressure fluctuations. Because of the short duration of the PD impulses, the resulting compression waves have frequencies that range up to ultrasonic. The frequency spectrum lies in the range between several Hz and several 100 kHz. In transformers, mechanical waves generated by PD propagate through the oil, hitting the tank walls where Piezoelectric sensors for acoustic signal detection are fixed externally. By using trigonometry techniques, the source of the acoustic emission can be localized, greatly assisting any corrective maintenance.</p> <p>This method has a limited sensitivity to PD faults on the inner windings. It is also very sensitive to noise which is not generated by the internal PD. To improve the sensitivity, this method can be combined with the electrical PD method or with the UHF PD method. The electrical signals can be used to trigger the recording of acoustic signals. By using an averaging algorithm, the influence of the acoustic noise coming from other sources outside the tank can be reduced.</p>
Reference	Fingerprint measurements, trend analysis
Interpretation	For Acoustic PD measurements, there are no limits applicable;

Table 42: Acoustic Partial Discharge (PD) Measurement

Partial Discharge (PD) Measurement using UHF Technology

Detectable failures	Partial discharges, Singular insulation faults
Indication	DGA
Test method	<p>Decoupling of the UHF PD signals from within the tank of a power transformer requires the sensitive UHF sensors to penetrate through the tank wall. Alternatively, a UHF antenna installed inside the tank is used. UHF signals have a much less damping than acoustic signals. Because of the sensitivity differences between UHF and acoustic signals, it can be advantageous to combine the two methods. By averaging the acoustic signals, by triggering them with the high sensitivity to arriving UHF impulses, the influence of acoustic noise can be reduced. The important localization of the PD is achieved by using the acoustic signal travel times. Wave shape and time of flight methods may be used for localisation of PD sources.</p>
Reference	Fingerprint measurements, trend analysis
Interpretation	For UHF PD measurements, there are no limits applicable

Table 43: Partial Discharge (PD) Measurement using UHF Technology

Frequency Response of the Stray Losses (FRSL)

Detectable failures	Local overheating due to excessive eddy current losses linked by the stray flux. Short circuits between parallel strands of Continuously Transposed Conductors (CTC)
Indication	If parallel strands of CTC have short circuits between them, the losses in the stray channel are increased. This results in high internal temperatures, normally indicated by the DGA
Test method	<p>An AC source with variable frequency (typically some Hz up to some hundred Hz) is connected to each phase of the HV winding with the corresponding LV winding short circuited. The source current and the voltage across the HV winding are measured. The stray losses are represented by the AC resistance of the short circuit impedance at higher frequencies. The resistive part of the complex impedance has to be measured. This can be done by using a complex impedance measuring device. Instead of the complex impedance measuring device, a wattmeter can be used to determine the real part of the complex impedance.</p>
Reference	Comparison of the three phases, fingerprint measurements (one phase test)
Interpretation	ΔL : Less than 2.5% between phases ΔR : Less than 15% between phases
Comments	The test can be done also from the LV side. For comparison of the results the values have to be corrected by the square of the winding ratio.

Table 44: Frequency Response of the Stray Losses (FRSL)

Literature:

P Picher, C Rajotte, "Comparison of FRA and FRSL Measurements for the Detection of Transformer Winding Displacement", CIGRE SCA2 Colloquium, June 2003, Merida

Recovery Voltage Method (RVM)

Detectable failures	Trend indication of internal moisture or aging in oil-paper insulation
Indication	High moisture in the oil
Test method	DC voltage measurements are used to record a recovery voltage that develops across composite oil-solid insulation due to the phenomenon of space charge relaxation. Initially, the insulation is charged with a DC voltage over a certain time. Next, a short circuit is applied for a much shorter time (typically half the charging time). The short circuit is then removed and the recovery voltage is measured, with its maximum value used for the assessment. This is one of a series of recovery voltage measurements taken with steadily increasing charging times. The accumulated series of voltage maxima yields a "Polarization Spectrum" used to evaluate the moisture content in cellulose. This derived diagnostic is the Recovery Voltage Method (RVM)
Reference	Fingerprint measurements, trend analysis
Interpretation	The RVM (Return Voltage Measurement) in its present form can only be used for trend indication [1].

Table 45: Recovery Voltage Method (RVM)

Literature:

- [1] M. Koch et al. "Improved Moisture Analysis of Power Transformers Using Dielectric Response Methods", MatPost 2007 Lyon
- [2] Cigré Technical Brochure 227, "Life Management Techniques for Power Transformers"
- [3] Cigré WG A2.30: Technical Brochure 349, "Moisture Equilibrium and Moisture Migration"
- [4] Cigré TF D1.1.09: Technical Brochure 245, "Dielectric Response Methods"

5.2 Dissolved Gas Analysis

Dissolved Gas Analysis (DGA) is a very useful diagnostic tool and is universally applied for condition assessment of power transformers. The gases that are normally measured are Hydrogen (H₂), Methane (CH₄), Ethane (C₂H₆), Ethylene (C₂H₄), Acetylene (C₂H₂), Carbon Monoxide (CO) Carbon Dioxide (CO₂) Oxygen (O₂) and Nitrogen (N₂).

There is no consensus about the absolute maximum levels that are acceptable for each gas. There are some transformers known to have considerably higher gas content than other similar transformers, yet they have been in service for many years without failure.

For this reason, the interpretation of DGA has to consider not only the absolute values for individual gas concentrations, but also their rate of rise over time. Accordingly, algorithms have been developed that:

- Identify levels of significance by calculating how much the gas concentration exceeds the limit value for each gas
- Evaluate the rate of rise by comparing the current value of gas concentration with a previous value
- Assign weightings to each combustible gas according to the activation energy required to produce it (for example hydrogen has the lowest weighting and acetylene the highest)

Furthermore, several tools have been developed for the interpretation of DGA results. The early valuable works of Rogers and Doernenberg uses the ratios of certain gas concentrations to match the DGA gas profile to typical sources of gas generation, as well as the level of energy involved. For example, the ratios help to discern whether the gas profile is the result of:

- Thermal fault of low temperature
- Thermal fault of medium temperature
- Thermal fault of high temperature
- Discharges of low energy
- Discharges of high energy
- Partial discharge

The ratio method is also discussed and utilized in IEC 60599 "Guide to Interpretation of Dissolved and Free Gas Analysis". The work of Duval provides another tool for the interpretation of DGA. Figure 17 below shows the graphical representation of the Duval triangle.

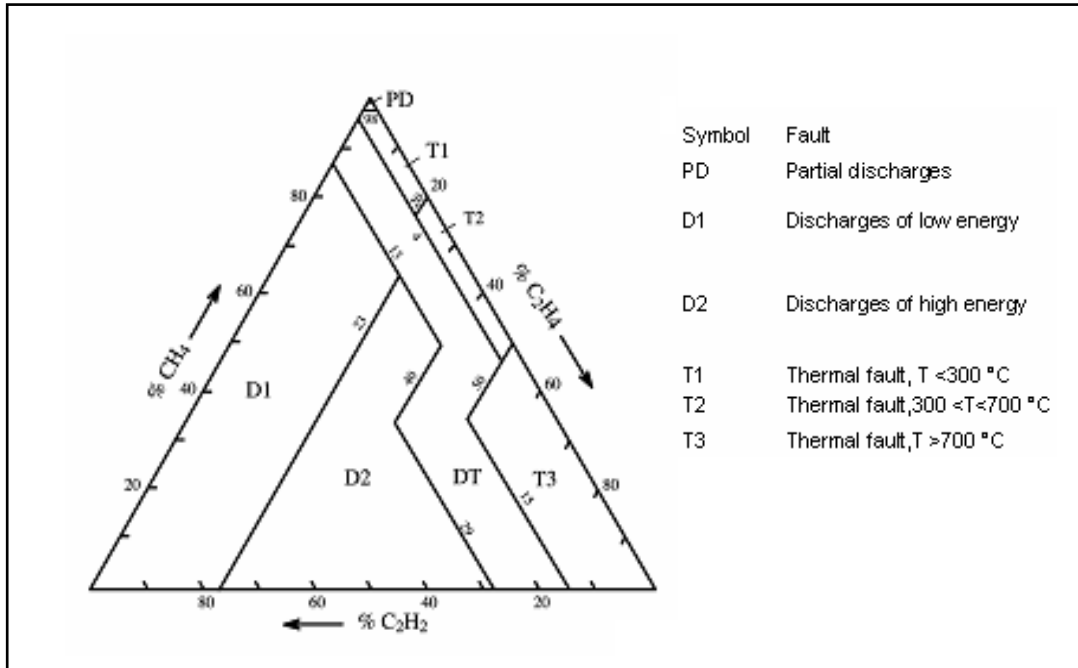


Figure 17: Duval DGA Interpretation

Literature:

[1] IEC 60599

[2] IEEE Std C57.104 - 1991 "Guide for the Interpretation of Gases Generated in Oil Immersed Transformers"

5.3 Oil and Paper Tests

This section is mainly based on the work of TF D1.01.12. Refer to CIGRE Brochure #413 for further information.

5.3.1 Introduction

Requirements of Insulating Oil

Mineral insulating oil has been used as a coolant and insulator in oil-filled electrical equipment since the beginning of the 20th century. The oil is highly refined in order to meet the characteristics and quality requirements outlined in IEC 60296, the international standard for unused mineral insulating oil. The three main functional requirements for insulating oil are:

- Withstand the electric stresses imposed in service. Meeting the specified insulation criteria, requires the oil to have high dielectric strength and low dielectric dissipation/power factor
- Circulate freely at the lowest temperature conditions for the equipment. Meeting the specified heat transfer and cooling criteria, requires the oil to have a sufficiently low viscosity and pour point
- Provide sufficient insulation and cooling thus ensuring that arcing is extinguished. Meeting the arc quenching criteria requires the oil to have a high flash point as well as high dielectric strength and low viscosity

The oil should also have good resistance to oxidation to ensure long service life. Oil in electrical equipment deteriorates in service under the conditions of use. The reliable performance of oil in insulation system depends on the basic character of the oil, which in turn may affect equipment performance. A variety of processes degrade the oil, and some are inter-related. These processes include oxidation; contamination by water, particles or fibres; electrical arcing or discharge; localised overheating and general overheating.

Oil Oxidation

Oxidation of the oil will occur in all equipment where oil is in contact with air. In such equipment, oxidation of the oil will occur gradually and inevitably over many years. Oxidation is accelerated as operating temperatures of the oil increase. Oxidation can also be accelerated by the presence of catalysts such as metals or metallic compounds. The cumulative effects of oxidation on the oil are to darken the oil, produce water and acids, and can culminate in producing sludge. The production of water and acids can lead to corrosion of metal surfaces, particularly above the oil surface and can attack cellulose material, resulting in loss of mechanical strength and possible breakdown.

If the oil reaches an advanced state of oxidation, insoluble products are generated, which result in sludge formation in the oil. The sludge produced is soluble in the oil depending on the type of oil, and once it reaches a saturation point it will precipitate. Generally, sludge is soluble in naphthenic oil and relatively insoluble in paraffinic oil. The sludge deposits tend to grade in thickness due to temperature, and are especially evident in the cooler regions of the tank, core and windings, cooling system and other parts, constricting the oil ducts and reducing cooling efficiency. The overheating of the oil and windings and the oxidation of the oil increase cumulatively, leading to possible breakdown.

A useful characteristic of sludge is that it is soluble in naphthenic oil if the oil temperature in the transformer is elevated to its aniline point (78 °C), the temperature at which the oil acts as a solvent for re-dissolving the deposited sludge. This may be exploited by circulating hot oil in order to re-dissolve sludge into the oil. This step is then followed by an oil reclamation process to remove the sludge by chemical separation as the oil passes through the 'structured clay/fuller earth columns'.

Early warning of the onset of oil oxidation is provided by monitoring of the colour and appearance of the oil, regular testing for acidity levels in the oil, monitoring moisture levels in the oil and visual inspection during maintenance for signs of sludgy deposits on internal surfaces of equipment.

Testing $\tan \delta$ (dissipation factor) and interfacial tension (IFT) of the oil may also help in the early detection of the formation of polar by-products due to oxidation.

Oil Contamination

Insulating oil in electrical equipment is in contact with other materials and therefore, can easily be contaminated. In general, the presence of foreign material in the oil can be regarded as contamination. Some of this contaminant may affect the electrical properties of the oil.

Contamination by moisture can occur from degradation of the oil by oxidation, degradation of cellulose in the equipment and ingress due to breathing of the equipment in service or during maintenance or repair work. Water is soluble in oil within certain temperature and acidity dependent limits. If these limits are exceeded, the oil becomes saturated and free water will appear in the form of cloudiness or visible droplets. Dissolved water may or may not affect the electrical properties of the oil. However, dissolved water in the presence of other contaminants, particularly fibres, can significantly reduce the electrical strength of oil. Free water, further reduces the electrical strength of the oil and indicates excessive moisture content in the oil. For rapid reductions in transformer temperature there is the additional risk of free water forming due to the sudden reduction of water in oil solubility.

In transformers, or other equipment containing paper insulation, the moisture is contained in both the oil and the paper. However, the water content in the paper easily predominates with typically over 99% of the total water content being in the paper. High moisture content of paper is one of the factors which reduces the life of the paper insulation, and hence the life of the equipment. Maintaining low moisture content is therefore important in equipment containing paper insulation such as transformers. Monitoring of moisture content is achieved by routine laboratory analysis for dissolved moisture, and by visual inspection for signs of free moisture.

Contamination by particles or fibres can occur from particulate or fibrous matter taken up by the oil from the components of the equipment itself, from arcing, fault degradation products in the equipment, or ingress during maintenance or repair. Particle or fibre contamination can reduce the electrical strength of the oil, particularly in the presence of moisture. Monitoring is achieved by laboratory testing for electric strength, which reduces with high fibre content, and by visual inspection for particulate contamination. Particle and fibre contamination may also increase the dielectric loss of oil.

Electrical breakdown or arcing in the oil produces gases and arc products such as carbon or metallic particles. The degradation of the oil results in a reduction in electrical strength, accelerated oxidation and higher acidity. This type of degradation is to be expected in tap changer diverter switches. The design of this equipment includes an allowance for the degradation of the oil.

Oil Testing

The tests for in-service oil are divided into three groups:

- Group 1: Minimum tests required to monitor the oil and to ensure that it is suitable for continued service
- Group 2: Additional tests which may be used to obtain further specific information about the quality of the oil and assist in the evaluation of the oil for continued use
- Group 3: Tests used mainly to determine the suitability of the oil for the type of equipment in use and to ensure compliance with environmental and operational considerations

The tests from each group are discussed below. It should be noted if the test results for Group 1 do not exceed recommended action limits, then the tests from Group 2 are usually deferred until the next scheduled oil sampling.

5.3.2 Oil Tests Group 1

Acidity

Oil oxidation forms acidic oxidation products, and these will gradually increase the acidity of the oil. Acids and other oxidation products will, in conjunction with water and solid contaminants, affect the dielectric and other properties of the oil. Acids also have a major impact through causing direct degradation of cellulosic materials and may also be responsible for the corrosion of metal parts in a transformer. The rate of increase of acidity of oil in service is a good indicator of the ageing rate once it has entered into the advanced stage (acidity > 0.1 mg/g). Interfacial tension is a more sensitive indicator of ageing in the early stages. The acidity level is used as a general guide for determining when the oil should be replaced or reclaimed. However, by the stage acidity has reached 0.1 mg/g there has already been a deleterious affect on the DP values of conductor insulation. This is why interfacial tension provides a better early warning. Mineral oil oxidation forms acid which can attack metal, accelerate cellulose deterioration, and form soaps (sludge).

Colour

Colour change can be a direct indication of contamination of the insulating oil. Colour change is normally attributable to oil oxidation. Carbon contamination tends to darken the oil, and can be caused by Diverter Switch oil mixing with the main oil or as a result of sparking or arcing in the main oil.

Water Content

Oil serves as the water-transfer medium within a transformer. The total mass of water is divided between the content in paper and the content in the oil, with the great majority absorbed in the paper. There are two forms of moisture present in insulating oil, free moisture (separated from the oil, emulsified, possibly cloudy) and dissolved moisture (can not be seen and it will not separate, chemically bonded, invisible). Small changes in temperature significantly alter the dissolved water content of the oil, but only slightly change the water content of the paper. Comparisons between transformers, or for trending purposes, will require the analytical result of the water content in oil at a given sampling temperature to be corrected to the equivalent water content at a reference temperature. For practical reasons, the defined temperature is set at 20°C, since below 20°C the rate of diffusion of water is too slow to achieve equilibrium in operational equipment. However, a weakness with this comparative technique is that the temperature corrected water content is based on the characteristics of new oil, and is not strictly valid for aged oil with its high proportion of chemically bonded water in the molecular structure. This is because the analytical result for aged oil also includes the bonded water content, and that content is not necessarily involved in the temperature dependent moisture transfers. Consequently, service-aged mineral oil, which is normally identifiable by its high acidity level, can hold more moisture than new mineral oil.

Nonetheless, to obtain a meaningful result for moisture content, the transformer should be operational and reach equilibrium prior to oil sampling.

Breakdown Voltage

Dry and clean oil exhibits an inherently high breakdown voltage. Free water and solid particles, the latter particularly in combination with high levels of dissolved water, tend to migrate to regions of high electric stress and reduce breakdown voltage dramatically. The measurement of breakdown voltage, therefore, serves primarily to indicate the presence of contaminants such as water or particles. A low value of breakdown voltage can indicate that one or more of these are present. However, a high breakdown voltage does not necessarily indicate the absence of all contaminants. Methods for measurement of breakdown voltage are covered by IEC60156, ASTM D877, D1816.

Dissipation/Power Factor and Resistivity

These parameters are very sensitive to the presence of soluble polar contaminants, ageing products or colloids in the oil. The Dissipation/Power Factor indicates the dielectric loss of the oil. Changes in the levels of the contaminants can be monitored by measurement of these parameters even when contamination is so slight as to be near the limit of chemical detection. High Dissipation/Power Factor results can indicate contamination from oxidation by-products, water or conducting particles. Acceptable limits for these parameters depend largely upon the type of equipment. However, high values of Dissipation/Power Factor, or low values of Resistivity, may deleteriously affect the Dissipation/Power Factor and/or the Insulation Resistance of the electrical equipment. There is generally a relationship between Dissipation/Power Factor and Resistivity, with resistivity decreasing as Dissipation/Power Factor increases. It is normally not necessary to conduct both tests on the same oil and generally Dissipation/Power Factor is found to be the more common test. However, experience with oil reclamation has shown that Resistivity is the slowest and last parameter to be restored to an acceptable level compared with IFT, Acidity and Dissipation/Power Factor.

Resistivity and Dissipation/Power Factor are temperature dependent. Useful additional information can be obtained by measuring Resistivity or Dissipation/Power Factor at both ambient temperature and a higher temperature such as 90°C.

Interfacial Tension

The Interfacial Tension (IFT) between oil and water provides a means of detecting soluble polar contaminants and products of oil degradation. This characteristic changes fairly rapidly during the initial stages of ageing but levels off when deterioration is still moderate. This phenomenon makes IFT the preferred ageing indicator for its early trending. In contrast, acidity changes slowly during the initial stages of ageing, but changes quickly in the terminal stages. In recognizing this differential sensitivity to oil degradation, the "Oxidation Index" (interfacial tension divided by acidity) provides a more useful index because its value varies more proportionately with the oil degradation.

Some care is still needed with interpretation though. A rapid decrease of IFT may also be an indication of compatibility problems between the oil and some transformer materials (varnishes, gaskets), or of an accidental contamination when filling with oil. This possibility may be cross-checked by testing other parameters of the oil, particularly the electrical ones.

For overloaded transformers, the deterioration of materials is rapid and IFT is a tool for detection of deterioration. IFT of an oil is affected by presence of polar, soluble contaminants like dissolved moisture and oil deterioration by-products.

5.3.3 Oil Tests Group 2

Oxidation Stability

The ability of mineral oil to retard oxidation when subjected to thermal stress, whilst in the presence of oxygen and a copper catalyst, is called Oxidation Stability. Measuring it gives general information about the life expectancy of the oil under conditions that are representative for oils in service in electrical equipment. The property is defined as resistance to the formation of acidic compounds, sludge and compounds, influencing the Dissipation/Power Factor (DF or PF) under given conditions. The property depends mainly on the refining process and how it is applied to a given feedstock. Refined mineral oils contain, to a varying degree, natural compounds acting as oxidation inhibitors (also known as natural inhibitors). Oils containing only natural inhibitors are designated as uninhibited oils.

Synthetic oxidation inhibitors can be added to enhance the oxidation stability. In transformer oils, mainly phenolic inhibitors are used. The commonly used compounds are 2,6-di-tert-butyl-paracresol (DBPC) and 2,6-di-tert-butyl-phenol (DBP). The effectiveness of the inhibitor will vary with the chemical composition of the base oil. Inhibited oils have an oxidation trend that contrasts greatly with uninhibited oils. At the beginning of service life, the synthetic inhibitor is consumed with little formation of oxidation products. This is referred to as the induction period. After the inhibitor is consumed, the oxidation rate is determined mainly by the base oil oxidation stability.

Because both the ageing process and the oil reclamation process itself can lower the inhibitor content, it is advisable that monitoring of the inhibitor content should always follow oil reclamation. The recommended way to monitor the inhibitor consumption is to measure the inhibitor concentration according to IEC 60666.

Sediment and Sludge

Sediment is the insoluble material present in the oil. Sediment includes:

- Insoluble oxidation or degradation products of solid or liquid insulating materials
- Solid particles released into the oil by the transformer, such as carbon, metal and metallic oxides
- Fibres, and other foreign matter, of diverse origins

Sludge is the polymerised end-product formed by the degradation of solid and liquid insulating material. Sludge is soluble in oil up to a certain limit, depending on the oil solubility characteristics and temperature. At levels above this, sludge is precipitated, adding to the sediment. The presence of sediment or sludge may change the electrical properties of the oil, and the build up of their deposits may hinder heat transfer, thus exacerbating thermal degradation of insulating materials.

The propensity for oil to form Sediment and Sludge should be measured, according to Method C described in IEC 61125, before submitting the oil sample to the oxidation process.

Particle Count

The presence of particles in the insulating oil may have a number of possible sources. The transformer may contain particles from manufacture and the oil may contain particles from storage and handling if not properly filtered. Wear, and the ageing of oil and solid materials, may produce particles throughout the service life of the transformer. Localised overheating of over 500°C may form carbon particles. The carbon particles produced in the on-load tap changer diverter switch may migrate by leaking into the main oil compartment and contaminate the transformer. A common source of metallic particles is wearing of the oil pump bearings.

The effect of suspended particles on the dielectric strength of insulating oil depends on the nature of the particles (for example metals, fibres and sludge) and on their water content. It is very important to follow correct oil sampling procedures as the oil samples may be contaminated during oil sampling from the equipment.

Flash Point

Lowering of the Flash Point temperature of the oil may be due to the oil breaking down in electrical discharges or prolonged exposure to very high temperature. The lowering of the Flash Point temperature results from producing sufficient quantities of low molecular weight hydrocarbons during the breakdown of the oil.

Pour Point

Pour Point is a measure of the ability of the oil to flow at low temperature. There is no evidence to suggest that this property is affected by normal oil deterioration. Changes in Pour Point can normally be interpreted as the result of topping-up with a different type of oil.

Density

Density may be useful for oil type identification. In cold climates, the density of oil may be important in determining its suitability for use. For example, ice crystals formed from separated water may float on oil of high density and lead to flashover on subsequent melting. However, density is not significant in comparing the quality of different samples of oil. There is no evidence to suggest that density is affected by normal oil deterioration. The fluid density is compared to the density of water. The specific gravity gives an indication of the oil type or whether there has been severe contamination with another liquid.

Viscosity

Viscosity is an important controlling factor in the dissipation of heat. Oil viscosity tends to increase with ageing and oxidation of the oil. Viscosity is also affected by temperature. Normal ageing and oxidation of the oil will not significantly affect its Viscosity. Only under extreme conditions of corona discharges or oxidation may this occur.

5.3.4 Oil Tests Group 3

Polychlorinated Biphenyls (PCBs)

These are a family of synthetic chlorinated aromatic hydrocarbons, which have good thermal and electrical properties. These properties, combined with their excellent chemical stability, made them useful in numerous commercial applications. However, their chemical stability and resistance to biodegradation makes them a potential environmental pollutant. Increasing concern on the environmental impact of PCBs has progressively restricted their use since the early 1970s and their use in new plant and equipment was banned by international agreement in 1986. Unfortunately, the use of common handling facilities has led to widespread contamination of mineral insulating oil. The PCB content of the oil in new equipment should be measured to confirm that the oil is PCB free. Furthermore, whenever there is a risk of potential contamination (for example oil treatment and oil handling), the oil should be analyzed and if the PCB content is found to exceed defined limits, then appropriate action should be taken.

Corrosive Sulphur

Sulphur is present in refined oils depending on the degree of refining and the crude oil used. Some sulphur compounds act as natural antioxidants, and their presence in the oil is useful. At high temperature, sulphur decomposes on hot metal surfaces to produce metal sulphides that can affect the conductivity of metal contacts of the switching equipment. Although uncommon, sulphide formation may also occur at lower temperatures, especially on silver plated surfaces. The determination of corrosive sulphur in the oil in service is seldom necessary. Tests such as DIN 51353 (silver strip) and ASTM D1275 (copper strip) may be used to ensure freedom from corrosive attack on bare metal surfaces under normal conditions. Recent international experience [CIGRE Technical Brochure 378] indicates that in special circumstances, such as high operating temperature, high load and low oxygen content (sealed/nitrogen blanket equipment), copper sulphide (Cu₂S) has been formed in the solid insulation. The presence of this conducting compound in the insulation may lead to failures. It has been demonstrated that existing test methods (DIN51353 and ASTM D1275 B) for detecting corrosive sulphur, are often unable to detect the specific sulphur compounds that may cause this phenomenon. Accordingly, a new test method has emerged, IEC62535 “Test method for detection of potentially corrosive sulphur in used and unused insulating oil”.

5.3.5 Oil Tests Results Management

Evaluation of Oil in Service

Insulating oil is subject to heat, oxygen, water and other catalysts, all of which are detrimental to the properties of the oil. In order to maintain the quality of the oil, regular sampling and analysis should be performed. Often the first sign of oil deterioration may be direct observation of the oil clarity and colour through the sight glass of the conservator oil level indicator. From the viewpoint of environmental impact, this basic inspection can also detect oil smears, dripping oil and ground contamination. The interpretation of results, in terms of the functional deterioration of the oil, should be done by experienced personnel based on the following elements of Risk Management and Life Cycle Analysis:

- Characteristic values for the type and family of oil and equipment, developed by statistical methods
- Evaluation of trends and the rate of variation of the values for a given oil property
- Normal, or typical values, for “fair” or “poor” for the appropriate type and family of equipment

In the case of oil contaminated with PCB, environmental impact is a critical factor to consider, as well as the local regulations. If it is suspected that oil has become contaminated with PCB, specific analyses should be undertaken. Based on the results, a risk assessment will be required to quantify the risk, identify appropriate risk prevention measures, but also find ways to mitigate potential damage to the environment and to eliminate unreasonable risks to staff and the public.

Classification of Oil in Service

As it is virtually impossible to set hard and fast limits for the evaluation of oil in service, the classification of the quality of oil in service into good, fair and poor, and decisions on any consequential corrective action, should only be made after due consideration of the results of all tests. The trending of the oil results over a period of time provides clear evidence and a sound basis to substantiate the need for corrective action. Oil may be classified as “good”, “fair” or “poor” based on the evaluation of significant properties and their ability to be restored to the characteristics desired. The following classification is suggested:

- Good:* Oil in normal condition, continue normal sampling
- Fair:* Oil deterioration detectable, more frequent sampling recommended
- Poor:* Oil deterioration abnormal, immediate action advisable

Table 46 shows the relationship between some examples of a transformer problem and its corresponding influence on parameters for the main oil.

TRANSFORMER PROBLEM									
OIL PARAMETER	OVERHEATING			PARTIAL DISCHARGE			DAMAGE TO HERMETIC SEAL		
	In Core	Connection	Winding / Cooling Problem	Oil	Paper	Oil / Paper Surface	Membrane Break	Oil Leakage	Water Ingress
Acidity / IFT	H 1,2	H 1,2	H 1,2	L	L	L	L 2	L	H 2
Colour	H 1,2	H 1,2	H 1,2	L	L	L	L 2	L	L
Water Content	L	L	H 5,6	L	H 5,6	H 5,6	L-M 6	M	H 8
Breakdown Voltage	L	M 3,12	H 4,6,12	H 11	M	H 5,6,12	M 6	M 7	H 8
Dissipation Factor	H 1,2	H 1,2	H 1,2	L	L	L	L 2	L	H 9
Gas Content	H 1,10	H 1,10	H 1,10	H 1,10	H 1,4,10	H 1,4,10	H 7	M 10	L 7

LEGEND			
Influence of Problem on Oil Parameter	Transformer Problem		
H = High influence	1- Oil Destruction	5- Paper Ageing	9- Water, Sediment, Emulsion
M = Medium influence	2- Oil Ageing	6- Water Production	10- Gas Production
L = Low influence	3- Oil Carbonization	7- Dissolved Air	11- Bubble
	4- Paper Destruction	8- Free Water	12- Particles

Table 46: Relation between Transformer Problems and Main Oil Parameters

5.3.6 Tests on Paper

Cellulosic insulating paper must have good electrical properties to withstand electrical stress, as well as good mechanical properties to survive the static and dynamic forces that are applied while in service without rupture. However, different mechanical properties may have quite different behaviours during ageing.

Tensile Strength of Paper

A measure of the mechanical strength of paper is determined by measuring its tensile strength. Most of the early studies on transformer ageing were based on the use of the tensile strength as a measure of paper degradation, taking the reduction of the tensile strength to 50 % of its original value as being the end of life criterion. Importantly, it is known that the tensile strength of paper decreases in a linear relationship with the diminution of the degree of polymerisation, and reaches about half of its original value when DP is about 200-250.

Degree of Polymerisation

Another measure of the mechanical strength of paper is derived from the degree of polymerisation (DP) of the cellulose natural polymers that make up its paper fibres. Paper with an initial DP value of approximately 1000 is expected to last the lifetime of the transformer (25-40 years), but a DP of 150-250 is regarded to be end of life criterion for the transformer insulation because the paper is also at risk of mechanical failure. Degradation of the paper can cause the transformer to fail by a number of mechanisms:

- The brittle paper can break away from the transformer windings and block ducts.
- Water is a product of degradation and builds up in the paper, reducing its resistivity.
- Local carbonising of the paper increases the conductivity and may lead to discharges and breakdown.

The DP of insulating paper can be determined from the viscosity of dilute polymer solutions according to IEC 60450 or ASTM D4243. It is noteworthy that insulating papers in transformers in service are inaccessible for sampling, thus direct measurement of the degradation of their properties is impossible. For this reason, there is general agreement in using the degree of polymerisation of the paper as marker property to assess the cellulosic paper condition.

Furans and Other Ageing Products

Furan products are measured in oil, but they originate from cellulose degradation. High Performance Liquid Chromatography (HPLC) analysis enables the separation and quantitative measurement of furan products. 2-Furaldehyde is the most common product of ageing. But 2-furfuryl alcohol (2FOL), 2-methyl-furfural and 5-hydroxy-2-methyl-furfural (5-HMF) are also detected. Furan products are generally relatively stable at temperatures up to 140°C, though notable exceptions are 2-furfuryl alcohol and 5-HMF. In a newly filled transformer, the furan concentration in oil increases initially, levels off, and then increases exponentially with ageing to a maximum value. Cellulosic degradation of thermally upgraded paper produces much less furans than standard kraft paper.

It is important to realise that quantitatively, water and carbon dioxide are the main by-products of the thermal degradation of cellulose. Furans and carbonyl derivatives are the second major degradation products, whereas alcohols, acids and aromatic and aliphatic hydrocarbons are minor products. It is also very important to realize that cellulosic paper is not a reclaimable material. The oil reclamation techniques, described later, are not able to restore the paper properties, although oil reclamation will have a highly beneficial effect by removing the carboxylic acids and sludge that promote and speed up paper degradation. However, in this way it is possible to indirectly increase the residual lifetime of the paper in the transformer.

5.4 On-Load Tap Changer Tests

In recent years, a number of on-line condition assessment tools have emerged for On-Load Tap Changers (OLTC). Table 47 gives an overview of the detection capabilities of five of the diagnostic methods and thereafter they are discussed in more detail.

DIAGNOSTIC METHOD	OLTC TYPE										
VIBRO-ACOUSTIC	Vacuum										
	Reactor										
	Resistor										
MOTOR TORQUE	All										
DISSOLVED GAS ANALYSIS	Vacuum										
	Reactor										
	Resistor										
IR THERMOGRAPHY	In-Tank										
	Compartment										
DYNAMIC RESISTANCE	All										
PROBLEMS											
	Linkage/Gears							G	G	G	G
	Timing/Sequence	G							E	E	E
	Control/Relays							E			
	Motor							G			
	Brake							E			
	Lubrication							E			
	Contacts alignment							G	G	G	G
	Arcing				M	G	E		E	E	E
	Overheating/Coking		G	L	M	E	E		L	M	L
	Contact wear	M							E	M	L
	Transition	E							E	E	E

L-Low
M-Moderate
G-Good
E-Excellent

Table 47: Diagnostic Capabilities of Different OLTC Tests

From this summary, it appears that any Condition Based Maintenance program for OLTCs would have to rely on the implementation of more than one technique to cover the widest possible range of failures. These could include DGA, Motor Torque Measurement and Vibro-Acoustic Signature depending on the OLTC type. Although this maintenance approach is attractive, difficulties in the interpretation for all three techniques still need to be resolved and more industry experience is to be gained before relying on it for CBM purposes.

5.4.1 Dynamic Resistance Measurement

Dynamic Resistance Measurement can be regarded as an enhancement of the winding resistance test. By introducing a known resistor value into the test circuit, then supplying the tapped winding with a continuous DC current, the transient test current fluctuations can be recorded during the OLTC switching process. The response is recorded with an oscilloscope, transient recorder or a specialised instrument. By analyzing the current response, both the timing sequence and the value of the transition resistors can be calculated and compared to the OLTC specifications.

Typical transient current responses are illustrated in Figure 18.

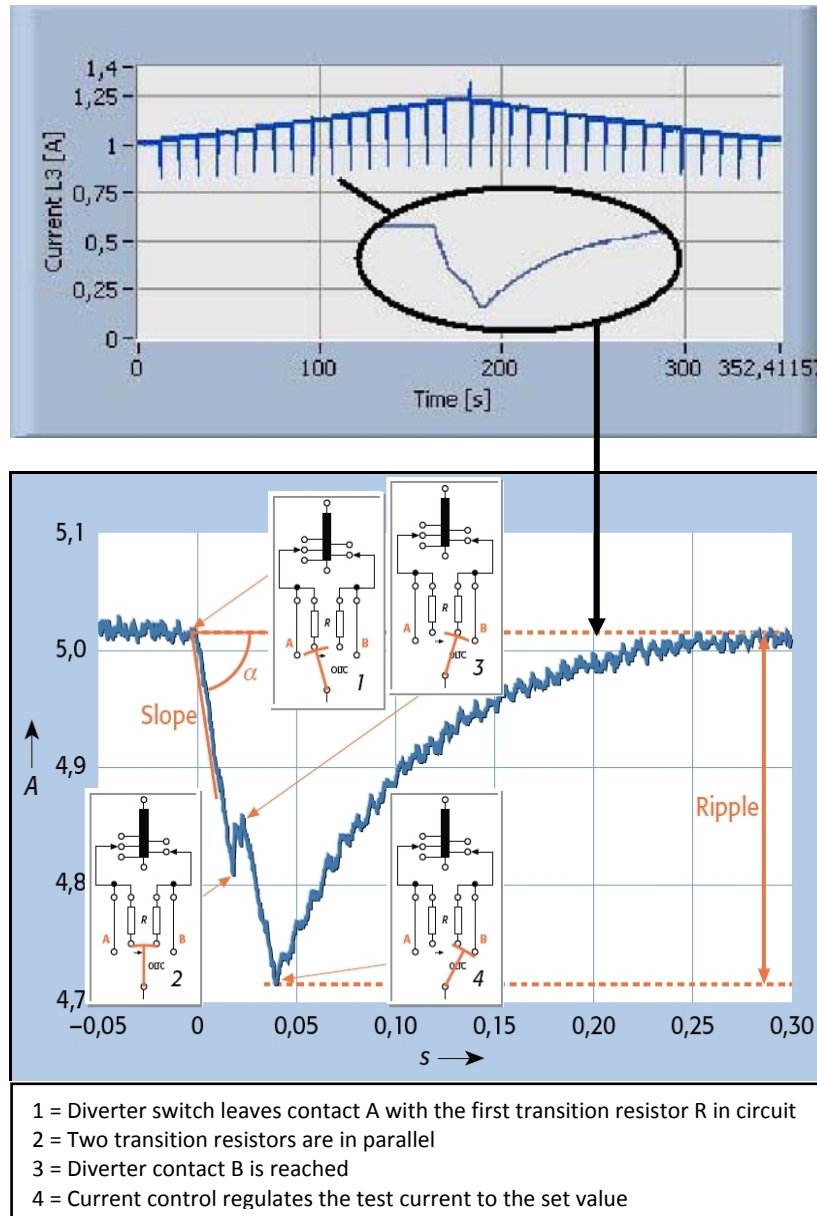


Figure 18: Typical Dynamic Resistance Measurement Response for a 33 Position OLTC with a Change-Over Selector

The interpretation of the recordings requires some skill and experience. A basic analysis can be made by comparing the Ripple and the Slope of the transient current curves of each phase, or with fingerprint measurements.

In complementing "static" winding resistance measurements, the Dynamic Resistance Measurement offers diagnostics for a number of diverter switch malfunctions such as:

- Contact problems on the diverter switch
- Broken springs
- Broken transition resistors
- Poor contact pressure
- Inadequate transition time

The dynamic measurement may also detect selector switch contact problems or a synchronism issue with the selector switch motion, the latter represented by a momentary open circuit during the tap change sequence. Because Dynamic Resistance Measurement can only be applied off-line and requires the line terminals to be disconnected, it is usually limited to quality control of the OLTC at commissioning or after a revision, or to ensure proper OLTC condition after a transformer trip.

Literature:

[1] J J Erbrink et al. "Advanced On-Site Diagnosis of Transformer On-Load Tap Changer", IEEE International Symposium on Electrical Insulation, June 2008, Vancouver, Canada
 [2] M Kruger et al. "New Tools for Diagnostic Measurements on Power Transformers", 2008 International Conference on Condition Monitoring and Diagnosis, Beijing, April 2008
 [3] Brendan Diggin, Hannes Malan "Condition Assessment of On Load Tap Changers using Static and Dynamic Contact Resistance" Doble International Conference 2004.

5.4.2 Dissolved Gas Analysis of Tap Changer Oil

A number of investigations have been made, mainly in the USA, to use the Dissolved Gas Analysis (DGA) of the tap changer oil as a diagnostic tool. These investigations focus on the detection of oil carbon and carbon coking of contacts in Reactor Type OLTCs of predominately older manufacture. On those OLTCs which are installed at the low voltage side of the transformer and which have to carry a high current accordingly, contact heating and coking seems to be a common problem.

CIGRE Task Force D1-01-15 (TF15) started investigating DGA in OLTCs in 2005. The main emphasis has been on the interpretation of DGA results in order to obtain reliable fault diagnosis. DGA results from several networks with OLTCs of the arc-breaking-in oil-type have thus been examined using the ABB Stenestam Code and a modified version of the Duval Triangle. Zones of normal operation, severe coking, light coking and abnormal arcing, together with recommended procedures to formally identify the fault (hot spot or electrical) have been defined, taking into account the fact that the normal operation of these OLTCs produces a background of arcing gases in oil. Examples of such cases investigated by TF15, mostly reactor types, are presented below.

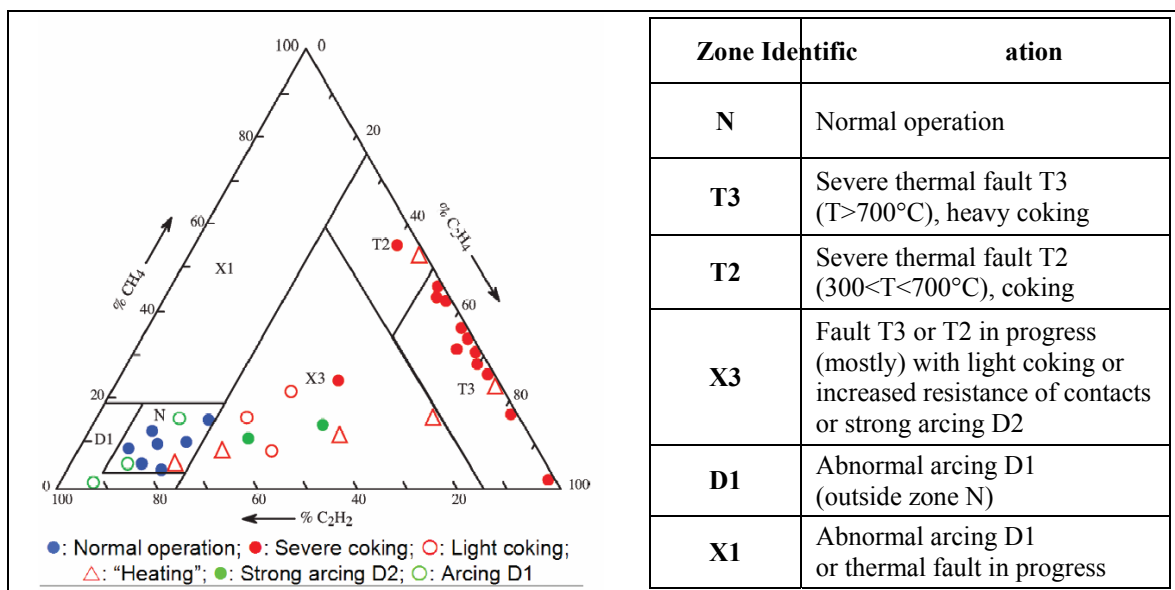


Figure 19: Modified Duval Triangle for OLTCs

High-speed resistor type OLTCs are usually installed at the high voltage side of a transformer. On diverter switches of this OLTC type, contact coking problems are much less common. However, the presence of the transition resistors in diverter oil introduces additional difficulty with interpretation as significant amounts of thermal overheating gases are produced by the hot resistors during normal tap change operation. Accordingly, interpretation schemes need to be adapted to each OLTC type and model, and are exemplified by the unique interpretation required for OLTCs employing vacuum bottle switching technology. These issues will be addressed in the proposed IEEE standard C57.139.

Other factors required for an accurate diagnosis are:

- Number of operations since oil has been last degassed or changed
- Average number of hourly operation (resistor type)
- Average and peak loads
- Use of sealed versus free-breathing compartments

Minimum gas concentrations for attempting a fault diagnosis have also been defined by TF15, especially after the oil has been changed in the OLTC. Typical oil sampling intervals implemented for the monitoring of DGA in OLTCs are:

- 6 months to 1 year in cases of normal operation and normal gassing of the OLTC
- 1 to 2 months in cases of abnormally high gassing units
- Weekly (or even daily) in cases where a serious fault is suspected, up until an internal inspection can be performed

A pipe connection to take oil samples from the OLTC oil should be installed on the transformer. It is recommended that the pipe connection ends with a drain valve at the side of the transformer tank at operating height. This enables oil samples to be taken while the transformer is in service.

References:

- [1] *M Duval "The Duval Triangle for Load Tap Changers, Non-Mineral Oils and Low Temperature Faults in Transformers", IEEE Electrical Insulation Magazine, November-December 2008, Volume 24*
- [2] *ABB Technical Bulletin IZSC000498-AAA en "Dissolved gas analysis in on-load tap-changer oil", COM/TK 2004-06-21.*
- [3] *IEEE C57.139 - Guide for Dissolved Gas Analysis Of Load Tap Changers*
- [4] *P Griffin et al. "Load Tap Changer Diagnostic Using Oil Tests – A Key to Condition-Based Maintenance", Doble Users' Conference, 2005.*
- [5] *Rick Asche "Dissolved Gas Analysis of Load Tap Changers Field Guide and Subcommittee Report ", Doble International Conference 2010*

5.4.3 Motor Torque Measurement

Motor Torque Measurement can provide valuable information on the drive assembly condition (links and gears, lubrication), the selector switch alignment and the diverter switch operation. The measurement is relatively simple and usually does not rely on a torque meter but rather uses motor supply parameters (current and voltage) to calculate motor power throughout the OLTC operation. With trending and comparisons, abnormal effects can be easily detected. A simpler measurement using only motor current will basically give the same indications but the abnormal deviations will sometimes not appear so clearly. An example of the detection of a lubrication problem is shown in Figure 20 below:

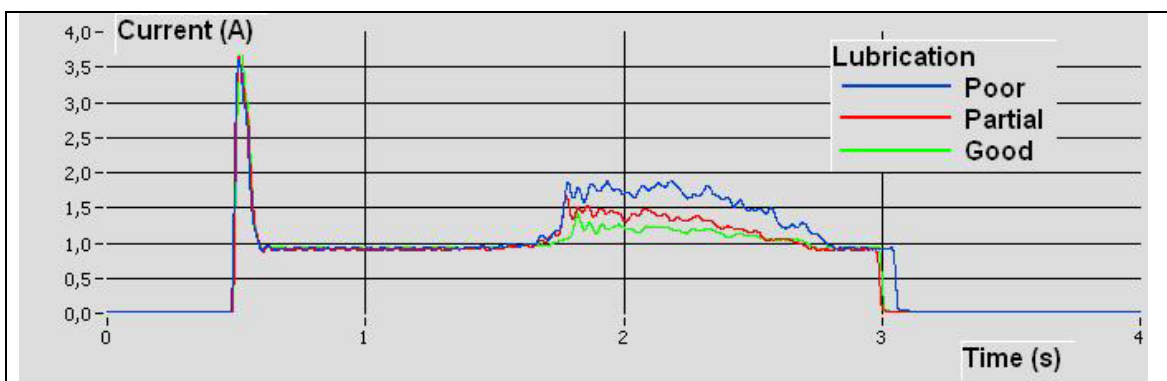


Figure 20: OLTC Drive Lubrication Problem Detected by Motor Current Measurement

5.4.4 Vibro-Acoustic Signature

The Vibro-Acoustic Signature is obtained by a vibration probe, or more precisely a wide frequency band accelerometer, applied to the wall of the transformer to collect the acoustic waves emitted by the mechanism, similarly to a stethoscope. The method is not to be confused with acoustic (ultrasonic) measurements for PD detection which use resonant sensors. The Vibro-Acoustic Signature is usually complemented by the measurement of the motor current, both to control the recording period (to start and end the operation) and to identify the different steps in the OLTC operation.

Each tap change operation produces characteristic pressure and vibration waves that transmit through the oil and to the tank structure. It has been shown by numerous investigators, both for laboratory and in service operations, that any degradation in the condition of the tap changer will involve a detectable change of the acoustic signature. Conversely, it has been observed that this same signature varies only slightly in the case of a stable apparatus. Figure 21 below shows the influence on contact wear on a Diverter Switch vibration signature.

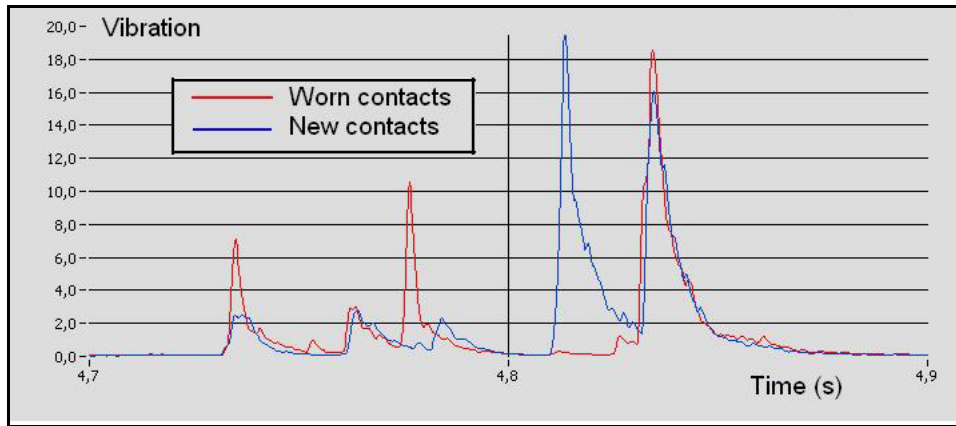


Figure 21: Evidence of Contact Wear on the Vibro-Acoustic Signature of a Diverter Switch

The main difficulty with this methodology is to establish for each OLTC type, make and operating principle, the respective criteria or deviation thresholds for a normal operating condition, outside which the OLTC condition should be considered abnormal. Nonetheless, the method has proven effective in the detection of a wide spectrum of anomalies. The whole test procedure is non invasive and can be performed while the transformer is in service.

Literature:

[1] *M Foata. et al. "Field Experience with the Implementation of a New On-Line Vibro-Acoustic Diagnostic for On-Load Tap Changers", Doble Users' Conference, 2005.*
 [2] *F Simas et al. "Vibration Monitoring of On-Load Tap Changers Using a Generic Algorithm", Instrumentation and Measurement Technology Conference, 2005. IMTC 2005. Proceedings of the IEEE, Volume 3, Issue , 16-19 May 2005 Page(s): 2288 – 2293*
 [3] *P Kang, and D. Birtwhistle, "Condition monitoring of power transformer on-load tap-changers II. Detection of ageing from vibration signatures", IEE Proc. Gen. Trans. and Distrib. 148,307-311 (2001).*
 [4] *K Williams, "Condition monitoring of OLTCs using vibration analysis", TechCon Asia 2006.*

5.4.5 OLTC Oil Tests

Breakdown voltage and water content are two parameters that may affect OLTC reliability. The following criteria are suggested:

		U_d [kV] VDE 0370 / IEC 60156	H ₂ O [ppm] ASTM D1533-88
New Mineral Oil prior to Energization		> 60	< 12
After end of Maintenance	New oil	> 50	< 15
Service-Aged Mineral Oil	Service oil	>30	< 30

Table 48: OLTC Oil Tests

5.5 Maintenance Inspection Tasks

Despite there being many tests available to evaluate transformer condition, experience shows that visual inspection is very effective, and sometimes the only way, to detect certain transformer problems. This section provides a list of the various inspections that may be applied to a transformer, either in or out of service.

5.5.1 Thermography

Infrared thermography is a technique that provides an image of invisible infrared light emitted by objects due to their thermal condition without any direct contact with the scanned object. This technique can be used to detect a defective connection on transformer bushings, hot spots on surge arresters, blocked cooling systems, and circulating currents affecting localized overheating of the tank wall, or to confirm oil level.

For compartment type OLTCs, infrared thermography can sometimes detect abnormal heating of degraded contacts (coking, low pressure) or other malfunctions that cause temperature rise on the compartment. Such problems are easily discerned on these OLTC designs because the OLTC compartment is normally cooler than the main tank, and any IR scan that shows to the contrary should trigger investigation.

5.5.2 Main Tank and Conservator

The tank contains the transformer active element (core and coil assembly) and its insulating fluid. An on-load tap changer compartment can also be included in the assessment of tank condition. The integrity of the tank is dictated primarily by its mechanical characteristics. The tank must hold pressure and should not leak. The integrity of the tank depends primarily on the condition of gasket containing surfaces, the hand hole, manhole, and tap changer door gaskets, and the integrity of tank welds. Deficiencies are detected by observing oil leakage.

The inability to adequately seal a tank may render a tank environmentally unacceptable for its current installation. External sealant repair systems, involving specialty sealants and unique hardware containing gasket provisions, may also prove effective in stopping leaks. The tank should also be inspected for indications of deformation. Tank deformation may result from extreme pressure or electrical arc experienced during a fault, improper foundation support, and for spare transformers, frequent installation and removal.

The integrity of a bladder may be checked in service by inserting a swab stick with a cotton cloth on the end through the bladder access port in the top of the conservator tank and gently swabbing the inside of the bladder. If the cotton swab becomes saturated with oil, this indicates that there is a leak in the bladder, and it must be replaced. Transducers that can detect rupture include:

- A capacitive transducer that detects contact with oil
- A gas collection relay mounted in the head of the conservator to detect air

The oil level in the conservator system should be checked regularly to make sure that it is at the proper level and to verify there is no undetected oil leak in the transformer. There is normally a 25°C gradation mark on the oil level gauge to use in adjusting the proper oil level.

In the past, conservator tanks were not necessarily designed to withstand full vacuum. In these designs, whenever vacuum is applied to the main tank, the valve between the main tank and the conservator tank must be closed. However, most modern conservator tanks are designed for full vacuum and the valve should be left open. In all cases, the transformer manual or manufacturer should be consulted. The desiccant for the bladder type conservator system should be checked regularly and replaced when it reaches the end of its moisture removal capability. Operating such a system with a non-functioning desiccant, (especially in a humid environment) can allow moisture to enter the tank, or cause the bladder to age prematurely.

The following actions can be performed on the main tank:

- Check for oil leaks, re-seal if necessary
- Check for paint damage and corrosion, repair if necessary
- Check oil levels in all compartments
- Check air drier and main conservator bladder - refill or replace if necessary
- Check air freezer – if installed
- Check grounding of main tank and neutral terminals
- Check electrical insulation for tank base where fitted
- Check status of all valves before putting back into service

Where silica gel is used for air drying, the colour change in the silica gel indicates that the silica gel is saturated with water and that the air passing through the breather will remain humid. During inspection, silica gel replacement should be done when more than 50% of the material has changed colour. Moreover, the colour change should be observed to start from the fresh air input side only (where air first enters the breather on its pathway toward the conservator). If the silica gel changes colour on the conservator side of the breather, or if the colour of the silica gel remains unchanged after several months, then this indicates there is air leakage in the connection piping allowing air to bypass the breather.

5.5.3 Cooling System

Oil Pumps

Visual inspection of the transformer oil cooling circuit components should be performed regularly and usually not exceeding every 12 months. Oil Pumps should be manually energized to ensure proper operation. Any significant noises (grinding, rubbing, scraping, oil flow cavitation) should be noted, investigated further and corrected. Flow gauges should indicate full flow without fluctuation. All areas including piping, valves and the surrounding ground area must not show evidence of oil leakage. Pumps equipped with a bearing condition monitor should have readings taken annually to ensure bearing integrity. Pumps with ball bearings are particularly vulnerable to in-service failure. Therefore, their replacement by pumps with sleeve bearings should be considered.

Radiators and Fans

Fans should be manually energized to ensure proper operation. Similarly to the oil pumps, significant fan motor noise or fan imbalance shudder should be noted, investigated further and corrected. Fan blade guards must be maintained for safety of personnel. Obvious obstructions to the through airflow caused by debris should be noted and cleaned. Periodic infrared imaging of the radiators should be made to ensure proper oil flow and heat transfer. All areas including piping, valves and surrounding ground area must not show evidence of oil leakage. Typical oil leakage points include pipe work flange joints, valve stems, oil pump electrical connections, radiator headers, and air bleed plugs.

Forced Oil-Air Coolers

Forced Oil-Air Coolers are used on many generator step-up transformers and mobile transformers, and some substation transformers. These coolers depend upon both the full airflow from their fans and full oil flow from their associated pumps, in order to provide the amount of cooling required to dissipate the transformer losses. Without both the fans and pumps operating, these coolers are essentially non-functional. Depending on the environmental conditions where the transformer is in service, after several years the coolers may deteriorate to the extent that they approach their end of life. One or more of the following conditions may cause premature end of life for these coolers.

Air flow gradually becomes impeded because the intricate finned surfaces on the cooling tubes are easily fouled or clogged with debris and accumulated deposits of air borne particles. This condition may be remedied with the use of high-pressure spray cleaning. However, extreme care is required to avoid deformation of the cooling tube fins by high pressure spraying, because this too will be detrimental to cooler performance. Cooler performance is impaired by any mechanical damage or any deformation of the fins, or if there is a general deterioration of the fins due to corrosion (which then helps to hold debris inside the tube bundle). The end result is that any of these conditions reduces the air flow and heat transfer capability of the coolers, causing the transformer to operate at higher temperatures. Overheating of the transformer windings, resulting from fouled coolers, causes excessive thermal aging of the insulation, which reduces the overall life of the transformer.

Corrosion due to galvanic action of dissimilar metals is a function of the metals used in the construction of the cooler and the ambient conditions in which the coolers are operated. The corrosion usually occurs between dissimilar metals in the

lower portion of the cooler at the juncture of the tubes and the tube sheet, and is readily seen when oil leaks are observed. In aggressive environments, the fins on the cooling tubes can corrode and disintegrate. Some field repairs have prolonged the life of forced oil and air coolers, however, this is considered to be a short-term correction. Left unattended, the oil leaks could eventually cause an environmental concern.

Oil leaks may occur where the tubes meet the tube sheet and can be attributed to thermal expansion and contraction that deforms the relatively soft tubes and allows oil to leak from this joint. Cooler designers usually take thermal expansion and contraction into account to prevent such leaks. Nevertheless, the installation instructions from the cooler manufacturer should also be followed to avoid exacerbating these thermal stresses.

In summary, in order to extend their efficiency, forced oil and air coolers should be maintained over their lifespan. However, when indications show that they are at the end of their life, plans should be made to replace them in order to extend the reliability and the life of the power transformer. The following actions can be performed on cooling system:

- Check functionality of cooling control system; local, remote, automatic cooling control, back-up cooling
- Check signalling of pumps, fans and flow-meters
- Check mechanical condition of pumps and fans, service times, wear of bearings
- Check cooling efficiency and clean coolers and radiators

5.5.4 Accessories

Liquid and Winding Temperature Indicators

The temperature recording for top oil and winding temperatures will vary depending on the transformer application and design. Normal readings may be obtained from site maintenance personnel. Top oil temperatures normally do not exceed 80°C and winding temperatures are normally less than 100°C. Any reading above these values may be an indication of cooling problems or loading beyond nameplate rating.

Liquid Level Indicator

If the oil level gauge gives erratic readings, the float inside the conservator tank should be checked for proper operation or damage. The liquid level indicator lens should be clear, legible and free of scratches. There should be no signs of moisture condensation on the lens. All labels should be clearly legible and visible. The pointer should travel freely when checked with a magnetic drive source. If any sticking is detected, replace the gauge. The switch should operate at the appropriate set point as shown on the dial or drawing when the pointer is moved by the magnetic drive. The operation of the switch should be a clear change of state from normally open to normally closed. There should be no non-contacts, commonly referred to as dead spots, or simultaneously normally open and normally closed contacts. The oil level indicator usually indicates where the 25°C oil level should be. Compare the reading of this indicator with the top oil temperature indicator. If the transformer is fully loaded, the top oil temperature will be high, and the level indicator should be closer to the high level mark. If the transformer is de-energized and the oil temperature gauge reads around 25°C, the oil level pointer should be near 25°C.

Liquid level indicators in the main tank of a conservator type transformer have a demonstrated propensity to seize up, due to infrequent movement. Since the main tank on such a transformer normally remains full of oil, the level indicators remain stationary for months or years. Whenever the oil is lowered for maintenance activities, these indicators should be carefully examined for proper functionality. Defective gauges should be repaired or replaced.

Rapid Pressure Rise Relay

The manufacturers of these relays publish testing methods to ensure that they function within calibrated parameters. Several factors affect the performance and long term life of these relays, including but not limited to, excessive vibration, moisture, and corrosive environments. Due to their design, it is not easy to detect signs of wear other than to conduct the performance tests recommended by the manufacturer. The operation of the relay switch should have a clear change of state from normally open to normally closed. There should be no non-contacts, commonly referred to as dead spots, or simultaneously normally open and normally closed contacts.

In addition to a performance check, it is also important to perform a visual inspection of the relay. Look for signs of corrosion in and around the connector location and around the top cover. Check that flange mounted style relays have smooth, even flanges and clean gasket sealing surfaces. Thread mounted styles should have smooth threads and any old

sealant material should be cleaned before reinstalling. The condition of the isolation valve should be checked to determine that it is functioning properly, in case the relay needs to be removed from service.

Gas Accumulation Relay

The tubing from the source to the Gas Accumulation Relay should be checked for crimping and plugs. Replace the tubing if any damage is detected. The relay gauge lens should be clear and free of scratches. There should be no signs of moisture condensation on the lens. The dial should be legible and free of paint flaking and chips. All labels should be legible and clearly visible.

The pointer should travel freely when checked with a magnet drive source. If any sticking is detected, replace the gauge. The switch should operate at the appropriate set point as shown on the dial or drawing when the pointer is moved by the magnetic drive. The operation of the switch should be a clear change of state from normally open to normally close. There should be no non-contacts, commonly referred to as dead spots or simultaneously normally open and normally closed contacts.

There are some transformers fitted with conservators that do not have any provision for detecting the production of free gas. Consideration should be given to having some form of Gas Accumulation Relay added for fault detection. Options include the installation of a Gas Accumulation Relay on the top of the main tank and tapping into the highest point of the tank top. As an alternative, a Buchholz relay can be installed in the piping between the main tank and the expansion tank for gas detection.

Pressure Relief Devices

The actual operating pressure for this device is determined by the transformer manufacturer and should not be changed without consultation with the transformer manufacturer. The operation of the device is such that the sealing valve opens when the internal tank pressure is sufficient to overcome the force of the hold down springs. These springs contain a tremendous amount of stored energy when assembled and should never be disassembled without taking the proper safety precautions.

The Pressure Relief Device (PRD) sealing valve gaskets are typically coated with a special lubricant to minimize sticking and long-term vulcanization to the sealing valve due to pressure, vibration and temperature. This lubricant may break down after long-term exposure to transformer oil and should be checked. The lubricant may also diminish after multiple operations, so any device that has seen more than a few operations in the field needs careful inspection to ensure the gasket is not sticking due to lack of lubricant.

Visual inspection of the spring cover for signs of corrosion, primarily at the sharp bend radii, is important. If any sign of cracking or pitting is noted, the device should be replaced. Check also that the springs have not corroded beyond light surface rust.

Check the condition of the attached operation indicating alarm switch, if so equipped. Any signs of corrosion or contamination, especially around the connector area, require the switch to be replaced. Most switches are designed with a manual test lever to allow users to verify proper operation. If the switch does not function and reset properly, it should be replaced. The operation of the switch should be a clear change of state from normally open to normally closed. There should be no non-contacts, commonly referred to as dead spots, or simultaneously normally open and normally closed contacts.

Cooling Equipment Controls

Cooling Equipment Controls comprise those devices that are interposed electrically or mechanically between the liquid/oil temperature indicator (LTI/OTI), or preferably the faster acting winding temperature indicator (WTI), the forced cooling fans and pumps, and the oil-filled cooling circuit (tanks, radiators and pipe work). Typical controls include bypass, bank selector and mode switches, interposing contactors, and shut-off valves.

Bypass switches turn cooling apparatus on and off independent of the LTI/OTI or WTI. Bank selector switches select the order in which cooling stages are operated, such that operating times may be equalized. Mode switches have manual and automatic positions that determine the source of control. These switches may be rotary or toggle type switches. They may, or may not, have a locking feature. Switches should operate freely without binding or sticking. Making and breaking of the circuit(s) under control should be instantaneous, discounting the action of any delay devices that may modify the action of the switch. Locking mechanisms should have the unlocking means available and functional. There should be no signs of corrosion, overheating, or discoloration on the switch case, actuators, connections, or associated wiring.

Interposing contactors should be examined for evidence of deterioration, which could shorten their life. On open frame types, pivot points should be examined for excessive wear and contacts should exhibit no excessive pitting. Coils should show no signs of overheating or insulation deterioration. If doubt of continued reliable operation exists, the contactor should be replaced. Mechanical delay devices should be operated over the full range of delay settings to ensure adjustability and delay period accuracy. At the expiration of the set delay period, interruption or making of the circuit should then be instantaneous. Contact resistance should be checked when visual inspection of contact condition is not possible.

In some cooling control schemes, an over temperature station trip control is also provided. This tripping scheme is typically actuated by the winding temperature indicator through an interposing contactor, which operates load shedding breakers.

Surveillance of Accessories

The following task list is a part of accessories maintenance:

- Check all current carrying connections, tighten screws, clean insulating parts (bushing porcelains)
- Check oil level in bushings, quality of the oil, and its colour
- Check Buchholz relay functionality and signalling, clean sight glasses
- Check the tank-conservator valve, position signalling
- Check all thermometers, locally and remotely measured temperature values
- Check winding temperature thermometer if installed
- Check high temperature signalling
- Check pressure relief valves for main tank and OLTC, including signalling
- Check and clean all monitoring and measuring sensors

5.5.5 Transformer Cabinets

As most accessories are connected through the Transformer Cabinet, this component requires special attention. The following inspection tasks are suggested:

- Check power supply, back-up feed and its signalling
- Check functionality of anti-condensation heaters
- Tighten screws and clean contacts on all current carrying parts
- Check service hour counter, if installed

5.5.6 On-Load Tap Changer

The OLTC requires special attention due to its mechanical moving parts, contact wear and attendant reliability issues. The following inspection tasks are suggested:

Diverter Switches

- Investigate whether upgrades are available to improve the operating reliability of the OLTC. These upgrades can be easy to install during routine maintenance
- Withdraw the diverter or selector switch insert (in tank type)
- Access diverter switch through inspection covers (bolt on type)
- Clean the diverter switch and the oil compartment
- Inspect and check its mechanism
- Measure contact wear on diverter and selector switch insert contacts. Compare the measured wear with the OLTC manufacturer's limit values
- Replace parts that exceed the limit values given by the manufacturer's manual
- Replace gaskets on all seals opened during maintenance
- Check the drive shafts and the tolerances of the drive shaft couplings
- Perform additional checks in accordance with the manufacturer's manual

Normally for vacuum switches used in a network transformer, no maintenance is necessary as they have greatly extended maintenance intervals. If maintenance becomes necessary, refer to the manufacturer's manual.

Motor Drive

- Perform visual checks
- Test sequence of the step to step operation
- Check the end position blockings (if available)
- Check the anti-condensation heater and cubicle door seals
- Check the remote control position indicator
- Perform additional checks according to the manufacturer's manual

Tap Selector

- Normally no maintenance is necessary in network applications
- If the number of operations exceeds the maintenance free interval contact the OLTC manufacturer
- If the OLTC is an older type, with no silver-plated selector contacts, then annual switching operations for cleaning purposes are recommended. Operate the OLTC 20 times over the regulating range and an additional 20 times over the reversing switch or coarse selector

Oil Replacement

- Oil replacement should be carried out during the maintenance. The mineral oil should not be replaced by oil of a different class or by an alternative liquid. If replacement by a different liquid is planned, the OLTC manufacturer should be consulted. Viscosities and dielectric characteristics might vary and need the approval of the manufacturer

Accessories

- Check the breather for the OLTC expansion tank at regular intervals, usually with the transformer breather
- Check at regular intervals the function of the protective devices (flow relay) together with those for the transformer

5.5.7 Buchholz Relay Operation and Recommended Actions when It Operates

This section provides guidance on the possible causes of Buchholz relay operation and recommends actions following the receipt of a Buchholz surge trip or gas collection alarm. It covers both operational situations and situations that arise during commissioning of new transformers. Buchholz relays installed on the transformer main tank have two elements described in more detail below:

Gas Collection Element

This element collects any gas escaping from the transformer and closes a contact when the gas volume reaches a certain limit. If gas continues to be produced after this limit is reached, it will escape out of the relay into the conservator and no further operation will take place. The transformer should have been carefully designed to avoid any internal pockets where gas can collect, so that any gas bubbles will rise through the pipe work to be collected in the relay. The gas collection element operates when a certain volume of gas is collected. Therefore it gives no direct indication of the rate of gas production.

Oil Surge Element

Primarily, this element is pre-set to operate and close a contact at a certain oil velocity through the relay. This will correspond to the oil flow expected during an arcing fault where oil surges from the main tank towards the conservator. However, this element will not operate on gas collection because the relay is designed to accumulate only a set volume of gas before allowing all excess gas to pass on to the conservator. This releases the excess gas before it can reach the level of the surge element float, allowing an oil surge event to be discriminated from a gas collection event. Secondly, if for any reason the oil level in the relay should drop (for example if oil is escaping from the transformer and the oil level drops below the level of the relay), then this element will also operate.

Possible Reasons for Operation of the Gas Collection Element

If gas is actually found in the relay following an indicated operation, then the following possible causes need to be considered.

Low Oil Level. If the oil level has dropped below the Buchholz relay, then first the alarm and then the trip elements will operate. This condition will also be confirmed by the oil level indicator on the conservator. Care needs to be taken to ensure that a residual mark on the sight glass is not obscuring the fact that the oil level has actually dropped. Low oil level must be investigated to determine the cause. A low oil level alarm commonly manifests as the combination of two effects; a slow oil

leak causing subtle diminution of the oil level, together with an unusually low ambient temperature. However, it is possible that oil has escaped from explosion vents or damage to the tank following a major internal failure. The latter possibilities should be investigated before concluding that a benign slow leak is the cause.

Partial Discharge (Sparking) within the Transformer Energy released from electrical discharges in the oil, causes the oil to decompose into hydrocarbon gases. Normally these gases are absorbed into the oil, but if the activity is severe then these gases can form bubbles.

Overheating Overheating of the windings, either caused by an internal fault or overloading, can lead to decomposition of the oil and gas production. Overheating of steel parts is possible as a result of overfluxing either from excessive voltage or geomagnetically induced DC currents (solar flares). Some other faults, such as core to earth insulation failure, will also cause gas production. All these conditions need to be investigated before a transformer is returned to service.

Air Trapped in the Transformer Following Oil Handling This commonly occurs where oil filling is attempted without applying a vacuum, or with only partial vacuum applied. In contrast, proper vacuum oil filling procedures ensure that wherever-trapped air bubbles or air spaces do form during an oil fill, that these rarefied gas volumes must reduce to very small air bubbles when they are finally compressed under static oil head following the release of vacuum. These residual gas bubbles are usually fine enough to be easily absorbed by the de-gassed oil. Nevertheless, gas bleed points are sometimes provided to bleed residual air pockets in larger trapped volumes such as bushings, oil pumps and pipe work, and should be bled immediately after any oil filling activity, and re-bled after the recommended stand time that follows an oil fill. Any need for repetitive bleeding of air puts the integrity of the vacuum oil fill into doubt. In all cases, adhere to the OEM instructions when vacuum oil-filling the transformer.

Gas collected in the Buchholz relay of a transformer should always be thoroughly investigated. The gas should never be assumed to be just air and dismissed, even after recent oil filling activity.

Air Entering the Transformer from Outside This is very unlikely to occur because all parts of the oil circuit are normally under positive pressure. The only potential area where air may be drawn in is at the inlet side of an oil pump. If this is occurring, it is a very dangerous condition for the transformer as air bubbles in the winding will cause failure.

For those circumstances where there is no gas found in the relay and there is no possibility that any gas could have leaked out of the relay or petcock connection pipe work, then the following causes should be considered.

Vibration or Shock If the operating element of the Buchholz relay is a mercury tilt switch, then these switches are susceptible to momentary operation if they experience very high levels of vibration or more likely a significant mechanical shock. This explanation for Buchholz operation should only be considered if the contact operation was momentary and coincided with an identifiable event and no gas was found in the relay.

Light Current Faults It is possible for wiring or relay faults to cause spurious operation of the alarm circuit. This possibility should only be considered once the causes set out above have been dismissed. This is especially important during commissioning when on occasion, damaged transformers have been re-energised because a wiring fault was assumed and the other possibilities were not examined.

Possible Reasons for Operation of the Oil Surge Element

The following causes of oil surge element operation need to be considered.

Electrical Breakdown A power arc within the tank will produce gas quickly enough to cause an oil surge. This surge can cause the surge element to operate. Normally, disruptive damage of this type will result in sufficient gas being produced to operate the gas collection element as well. Surges, produced by this type of failure, are also likely to have operated pressure relief devices.

Low Oil Level Low oil level operation of the oil surge element arises for the same reason discussed above for the gas collection element.

Pump Operation Some designs of transformer are susceptible to creating an oil surge through the Buchholz pipe when the pumps are started or stopped. The phenomenon is due to slight flexibility of the coolers causing volume changes, which in turn cause oil flows to and from the conservator. Generally pumps sucking oil from the coolers will cause a surge on start-up and pumps delivering oil to the cooler (normally mounted at high level) will cause a surge at shut down. The surges will

be worse if both pumps start simultaneously in a dual cooler (50% plus 50%) configuration. This is normally prevented by a delay relay in the pump control circuit, but supply interruptions and repeated operation of manual control have been known to cause spurious operation of the relay surge element even though the transformer is specified and tested to try to ensure this does not happen. Pump starting or stopping will not result in gas production so it is important to check that no gas is present in the Buchholz before considering this cause as a possibility. Excessive air in the coolers can increase the magnitude of the oil surge on pump start, bleeding the coolers can help to solve the problem, but again it must not be assumed that this is the cause of the Buchholz trip unless the DGA is clear. On very old transformers with a bursting disk type of pressure relief system situated above the level of the oil in the conservator, a failure of the disk for some reason, such as being knocked with a ladder during maintenance, can allow oil surges to occur when the pumps start.

Buchholz Mounted Incorrectly The Buchholz relay is designed to be mounted in sloping pipe work inclined 3° from the horizontal to facilitate gas collection. This means the gas oil surge element is designed to operate with the Buchholz mounted in a slightly inclined attitude, and furthermore, is calibrated to operate for unidirectional expulsion of oil. Accordingly, it is very important to mount the Buchholz relay correctly with its indicating arrow on the side of the relay pointing towards the conservator. Inadvertent reversal of the relay (during maintenance) could make the oil surge element unduly sensitive to pump start or pump stop.

Vibration and Shock Vibration or shock may affect the surge element in the same way as the gas collection element. Again this cause should only be considered if the contact operation was momentary and coincided with an identifiable event and no gas was found in the relay.

Actions to be Taken Following a Buchholz Alarm or Trip Operation

Buchholz Alarm The transformer must be switched out as soon as possible. If the transformer cannot be immediately switched out, then it must be considered to be at risk of failure and a minimum 20m exclusion zone established preferably by evacuating the compound. On no account must the transformer be approached for oil sampling, or for any other reason, until it is known to be de-energised. If the transformer is not switched out immediately, investigation actions which do not require the transformer to be approached, can be carried out. On transformers with a tap changer, no further tap changing operations should be carried out.

Buchholz Trip or Once the Transformer is De-Energized Following a Gas Alarm Once the transformer has tripped, or been switched out, a decision has to be made as to the next actions. This section is intended to help guide that decision. At all times the precautionary principle must be applied. Until it can be conclusively proved otherwise, the transformer must be assumed to have suffered an internal failure and should therefore not be re-energised. The following investigation actions are required to gather the information needed to make a decision on the next operational action. The list may not be exhaustive for a particular situation.

- Take oil samples from the main tank, all selectors and any other oil filled compartments containing high voltage parts (except diverter switches) and send them for urgent laboratory DGA.
- Check for the presence of gas in all Buchholz relays and record the volume of any gas found.
- Sample any collected free gas and send the sample for laboratory analysis.
- Check all pressure relief devices, either check for operation of the button indicator in spring operated types or check for rupture of the diaphragm in explosion vent types.
- Check for leakage of oil particularly around pressure relief devices but also at tank joints.
- Check for signs of distortion of the tank including tap changers.
- Check and record oil levels in all conservator tanks. Care is needed to ensure that tide marks are not disguising the fact that the conservator is empty.
- Check and record the level of oil in bushings.
- Check and record the level of oil in tap changer diverters.
- Check electrical protection for operation.
- Check fault recorders for operation.
- Check and record tap-position and times of tap changer operation from data logger.
- Note the position of cooler and tap changer controls including maximum temperature indications on WTI dials and whether the electrical protection on any of the auxiliary motors is tripped.

5.6 Insulation Drying

5.6.1 Introduction

Drying out a transformer, either for maintenance purpose or after a repair, is an important operation that consists of drawing out the water both for the liquid insulation (oil) and solid insulation (paper and board). Thorough drying will extend the life time of the oil-paper insulation system as well as improve the reliability of the transformer. Several drying techniques can be used. The drying time and the degree of dryness will depend on the different techniques used as well as the temperature of the process and the level of vacuum that can be applied on the units (the design of the tank needs to be checked since some units do not withstand vacuum). Drying the active part of a transformer is a long process. Reducing the time would have a direct impact on the quality of the drying.

Table 49 provides examples of the drying time needed to dry two different transformer with an hot oil and vacuum system. The initial moisture in the solid insulation was assessed to be around 3% (based on Karl Fischer tests in oil and moisture equilibrium curves as well as with Dielectric Response measurements). The remaining moisture was assessed to be around 1%.

Transformer	Hot Oil and Vacuum
40 MVA / 63 kV	5 days (24h per day)
400 MVA / 400 kV	30 days (24h per day)

Table 49: Transformer Drying Time

The number of days presented in this table are indicative only. This refers to the experience from one service provider. Other cases and drying with different conditions (oil temperature, ambient temperature, level of vacuum) might show different drying times. The drying time for the units mentioned above will normally stand within a range of plus or minus 30%. This means drying takes 3 to 7 days for the 40 MVA unit and 20 to 40 days for the 400 MVA unit.

The moisture in a transformer is generated by several sources:

- Remaining moisture in insulation during manufacturing
- Humid air from outside during transportation or/and assembling in substation
- Humid air from outside through the breather (non sealed)
- Moisture ingress through gaskets
- Chemical decomposition of cellulose
- Moisture absorption from outside during some maintenance operations, such as on-site control of active part, bushing replacement
- Topping-up of oil level made with humid oil (non dried)

It is important to reduce the exposure time of the active part to ambient (moisture) or to use a tent with dry air when the transformer tank is opened (for example bushing replacement). Maintaining low levels of humidity while repairing a transformer on site involves taking great care to prevent moisture ingress during the repair process. It is advisable to build around the transformer, a tent filled with pressurised dry air. During visual inspections or maintenance activities, when the oil must be partially or completely drained, it is important to limit the time that the solid insulation is exposed to air and this work should always employ purging with dry air into the free space of the tank during the entire period.

More than 99% of the moisture remains in the solid insulation (cellulosic parts) while less than 1% remains in the oil. This means that the quantity of water inside the solid insulation of a large power transformer can reach several hundred litres while it would not exceed a few litres in the oil itself. For example, a 300 MVA transformer, with 10000 kg of solid insulation, having an average moisture level of 3 %, represents 300 L of water. In the same transformer, 60000 kg of oil with a water content of 10 ppm at 30°C would hold only 0.6 L of water.

Literature:

Cigré Technical Brochure 349, "Moisture Equilibrium and Moisture Migration within Transformer Insulation Systems"

5.6.2 Risks and Consequences of Not Drying Insulation

Moisture in insulation represents risk to transformers in three ways. It accelerates depolymerisation of paper, reduces the breakdown voltage of oil and increases the risk of bubbling during sudden overload or thermal stress.

Cellulose is a natural polymeric material and the molecular chains making up the cellulosic polymer will break when exposed to high temperatures. This depolymerisation of cellulosic solid insulation is accelerated in the presence of moisture, oxygen and oil decay acids. 1% increase in the moisture content of the paper has the same effect as an increase of the operating temperature of 6-8°C (doubling the rate of depolymerisation). The aged paper will then become brittle and will lose its tensile strength. In cases of short-circuit fault or transportation movement, the insulation may tear, split or even fall off leading to serious dielectric failures.

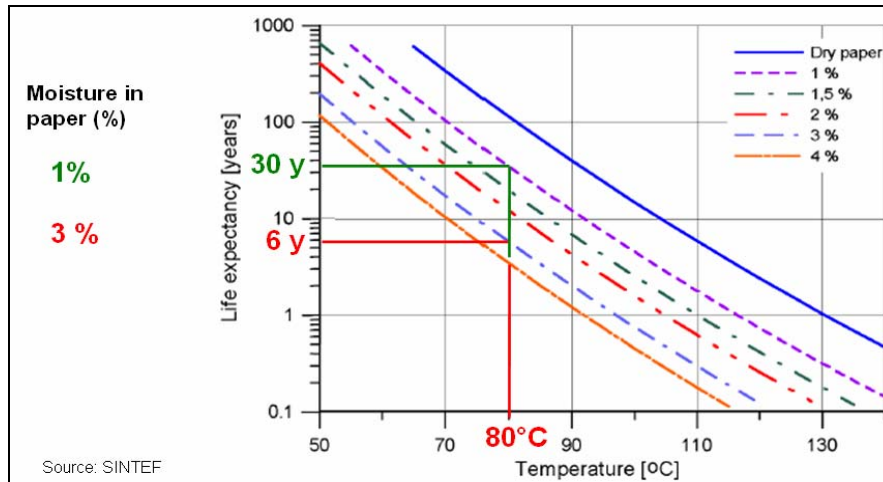


Figure 22: Influence of Temperature Combined with Water on Solid Insulation Life Time
(Laboratory experiment on a kraft paper sample)

Figure 22 illustrates how the maintenance action to dry a wet transformer could increase its life expectancy. This has possible financial benefits. Despite the fact that a transformer might fail for several different reasons, ageing of the insulation is the main parameter determining its life expectancy, and drying a transformer from 3% average moisture in the solid insulation down to 1% could extend the life time by about 20 years.

Moisture in the oil especially when combined with particles, will significantly reduce the breakdown voltage of the oil and increases the risk of static electrification, partial discharge activity and tracking.

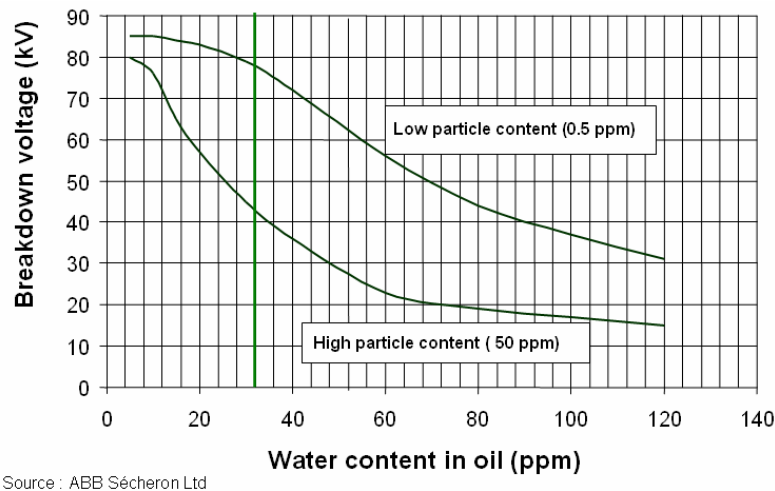


Figure 23: Impact on Breakdown Voltage of Water Content in the Oil Combined with Particles

High water content in the cellulose reduces the reliability of the unit because of the risk of bubbling in situations of overload or sudden loading where large increases in heat flux produce a sudden increase in temperature.

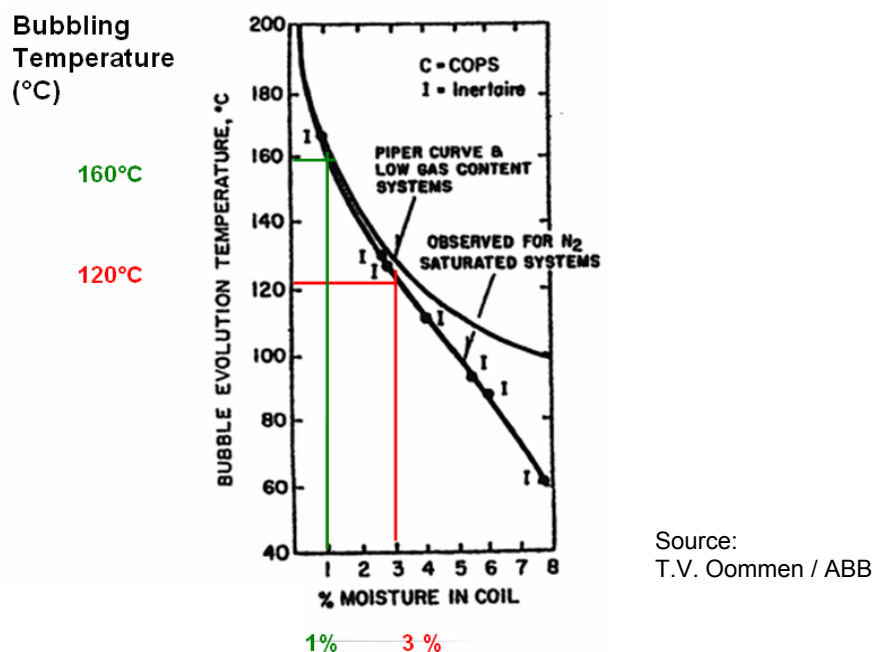


Figure 24: Bubbling Temperature as a Function of Moisture Content in the Solid Insulation

In order to reduce the ageing of the insulation system and to keep a high reliability of the transformer, it is mandatory to dry both the oil and the active part of the transformer after each action that requires the opening of the tank (maintenance, replacement of bushing or tap changer, repair of connections of or the active part) or as a maintenance action on wet transformers.

A dry transformer can then be more loaded for a given ageing rate, or the life time of its insulation system can be extended for a given load.

5.6.3 Factors Driving the Drying Time and Quality

Drying is characterized by moisture-moving forces helping the diffusion of the moisture through a porous material. The rate of diffusion is strongly dependent on temperature, the moisture content, the pressure gradient over the diffusion path and the physical properties of the material. This is an especially important consideration for drying pressboard that is already oil impregnated (for example during refurbishment and repair), as the diffusion coefficient compared to non-oily pressboard is approximately in the range of 1/10-1/20.

Temperature and vacuum are the main controlling factors for the drying speed and quality. For optimized drying, the transformer should be heated at the same time as vacuum is applied. The speed of the moisture diffusion through the insulating parts is multiplied by 10-20 if a vacuum of 1 mbar can be reached. Also, increasing the drying temperature by 10°C approximately doubles the rate of water vapour diffusion and accordingly the drying speed.

5.6.4 Different Drying Techniques

Drying of transformers can be achieved either through on-line or off-line techniques. On-line techniques have the advantage that the transformer remains in service all along the drying process (several weeks, months or possibly during the remaining life time of the transformer). Also it provides a method of drying on transformers with tanks that do not withstand vacuum. Off-line techniques have the advantage of providing a better drying quality of the solid insulation within a relatively short time (a few days/weeks).

Molecular Sieves

Among the on-line drying techniques, Molecular Sieves are well established. These devices are normally installed on the transformer wall, and have columns or cartridges filled with molecular sieve material. Molecular Sieve materials have the characteristic of binding dissolved water from the transformer oil and gradually drying the oil. Through the tendency to maintain equilibrium between the moisture in oil and in cellulose, a very limited drying effect will also be noticed in the solid insulation. A relatively small amount of oil (60-100 l/h) is constantly pumped through the Molecular Sieves, bypassing the normal main oil flow. The typical drying capacity is approximately 9 litres of water per year. Once the cartridges are saturated, they must be reactivated in a special plant. Some systems feature reactivation of the cartridges. A side effect of using a molecular sieve dryer is the reduction of the dissolved gas concentrations in the oil. Special care should be taken with selecting the oil sampling point and, whenever possible, oil should be sampled upstream of where the oil enters the absorbent cylinders.

Due to the limited drying effect on the solid insulation, it is usually advised to use molecular sieves to keep transformer dry (new transformers or old transformers after an off-line drying) rather than drying out a wet transformer. On wet transformers however, molecular sieves have the advantage to control the moisture in the oil and therefore avoid condensation/free water and a low breakdown voltage of the liquid insulating medium.

Hot Oil Circulation

In this method, the oil is constantly drawn off through the lower tank valve, passes through an oil processing plant, then returns into the upper part of the transformer through upper valve. The advantage is that it could be applied on each type of transformer even if the tank does not withstand the vacuum. The disadvantage of this process is that it requires a great deal of time, and the degree of dryness achieved in the solid insulation of the active part is not adequate for demanding applications.

Vacuum Drying Techniques

Several techniques are used including:

- Hot oil plus vacuum
- Hot oil plus vacuum plus hot oil spray
- Hot oil plus vacuum plus a cold trap

Insulation drying in the field using the hot oil circulation method, in conjunction with vacuum applied to the transformer, is very well known and has been practised for many years. In this process, the hot dry oil circulates through the tank to heat up the active part. Once a sufficient temperature is reached (70-85°C) in the core and windings, the oil is drained and full vacuum is applied. Due to the evaporation of water, the temperature in the insulation parts will drop and a new heating cycle with hot oil is required. This method is used in all parts of the world and much experience has been accumulated. The simplicity of the method is an advantage. The drying speed and quality can be improved by using a cold trap to freeze water vapour, thereby reducing the water vapour partial pressure in the vacuum space.

The main disadvantages for all these methods are that the tank must be able to withstand vacuum, relatively low process temperatures are achievable, and there are difficulties in countering heat loss during the vacuum period, resulting in long drying times.

In the hot oil plus vacuum dry out process, where the transformer core and windings are heated using hot oil, it is also possible to use supplementary heating such as a DC or AC source, to elevate the winding temperature to approximately 90 – 95°C. The transformer is maintained at this temperature for 72 to 120 hours to obtain uniform temperature in the core and windings, after which the oil is quickly drained and full vacuum applied to the transformer tank. Again, due to the evaporation of water, the temperature of the insulation will decrease. The speed of this temperature decrease is typically about 5 °C per day in the first two days and 3 or 2 °C per day thereafter, but can easily exceed this due to cold weather and heat loss. To maintain the temperature of the transformer windings above 60 °C during the drying period, supplementary heating techniques are sometimes necessary. One method involves circulating 5000 to 7000L of heated transformer oil (at about 90 °C) around the bottom of the transformer tank.

Low Frequency Heating / Low Frequency Heating plus Hot Oil Spray

The low frequency heating (LFH) technique requires the transformer's low voltage winding to be short-circuited and the high voltage winding to be connected to the LFH unit. During the initial heating phase, the oil is heated as it circulates through the oil treatment plant, whilst the windings are heated by means of the LFH heating. The combination of the hot oil and the current heating ensures that all parts of the transformer attain the required temperature levels in short time. Once the

target temperature is reached and the temperatures inside the transformer are stabilized, the oil is drained into a separate tank and vacuum is applied.

For the next temperature step, only LFH is used to heat the windings. During the electrical heating, the vacuum level is kept at approximately 30 mbar. If the temperature reaches the set point, the current heating is automatically stopped and a vacuum is applied down to <1 mbar. During this period, most of the water will evaporate. The vacuum level is then automatically brought up to 30 mbar again and the current heating is started again. This cycle is repeated as long as the moisture extraction rate is higher than a set point. The moisture extraction rate is used to determine the end of the drying process. Once the desired drying quality is reached, the transformer is filled again with oil.

The LFH technology needs a specific electrical source and some specific knowledge regarding the preparation of the drying equipment. The advantage is that it permits heating of the insulating parts to 90-110 °C instead of 60-75°C with the conventional technique. This higher temperature allows an acceleration of the speed of moisture diffusion by a factor of between 3 and 5 times, depending on the original moisture content. The drying time can be further reduced by coupling the LFH process with hot oil spray. This is well suited for shell type transformers. For example, the approximate time needed to dry a transformer from initial moisture in the solid insulation of 3% to remaining moisture of 1% is shown in Table 50.

Transformer	Hot Oil plus Vacuum (24 h / day)	LFH plus Oil Spray
110 MVA / 70 kV	8 days	4 days
400 MVA / 400 kV	20-30 days	9 days

Table 50: Time to Dry a Transformer

The number of days presented in this table are indicative only. They refer to the experience of one service provider. Other cases of drying, with different conditions (oil temperature, ambient temperature, level of vacuum), might show different drying times (ranging plus or minus 30%). When using this method, the following aspects must be taken into consideration:

- There are reduced possibilities to monitor and control the local temperatures of the transformer windings (whilst transformer is in vacuum, but connected to a power supply).
- It is impossible to control the heat transfer process from the winding conductor to the solid insulation, especially in the areas with thick insulation and the attendant risk of it cracking.
- There is a non uniform temperature in the transformer, especially in the absence of any heat transfer fluid (when the transformer is on vacuum, but connected to a power supply) This mainly concerns the heat transfer from the winding conductor to the distant thick end insulation pieces, which are not in direct contact with the winding conductor.
- The hot oil spray process is only effective if direct contact can be made between the hot oil and the transformer insulation. Indirect heat transfer by heat conduction or thermal radiation is ineffective in heating the insulation. Core form construction proves the most difficult to achieve uniform heating. The result is non uniform drying of the transformer insulation.
- The high temperature is critical in achieving both a low insulation equilibrium moisture content and rapid diffusion of moisture from oil-impregnated cellulose. It also partly compensates for the non uniform heating.

Vapour Phase

Vapour phase drying provides the fastest drying process. It has the added advantage to clean the active part efficiently. The disadvantages when used at site are the major logistics, high costs and the great care needed in order to ensure a safe process.

Actions before Applying Vacuum to a Transformer

Applying vacuum on the transformer tank (if the tank is designed for it) requires taking the following actions in order to reduce the risks of damage during the insulation drying process:

- Provide a connection that equalizes the vacuum in the transformer tank and the OLTC diverter tank
- Provide a connection that equalizes the vacuum in the transformer tank and the oil-oil bushing chambers
- Obtain data regarding the admissible pressure (during the insulation drying process) in the transformer for tank and transformer accessories (bushings, coolers, oil conservator, tap changers, barrier boards)

5.6.5 Remaining Relative Moisture Level

Table 51 below indicates the relative moisture level that could be achieved as criteria to stop the drying.

	Remaining moisture level (%)	
	Critical application	Normal application
Remanufacturing	0.5 – 0.7	0.7 – 0.8
Repair / Refurbishment	0.7 – 0.8	1.0 – 1.5

Table 51: End of Drying Criteria

The following table gives the definitions of the terms used in Table 51.

Remanufacturing:	New winding and insulation kit as well as new core and accessories (including bushing and OLTC) if this is considered from an ageing/reliability stand point. The transformer could be considered as new.
Repair	Partial replacement of the active part (one winding) or no winding replacement (shielding, core, OLTC or bushing replacement)
Refurbishment (mid-life)	Important overhaul of the transformer including active part cleaning, checking of connections, repressing/reblocking the windings
Critical application	HVDC, Rectifier, Furnace and industrial transformers, GSUs or grid transformers with HV>220 kV or high load
Normal application	Grid transformers with HV < 220 kV or low load (< 60% of nominal load)

Table 52: Definition of Terms Used in Table 51

Figure 25 summarizes performance in terms of drying time for the different drying methods.

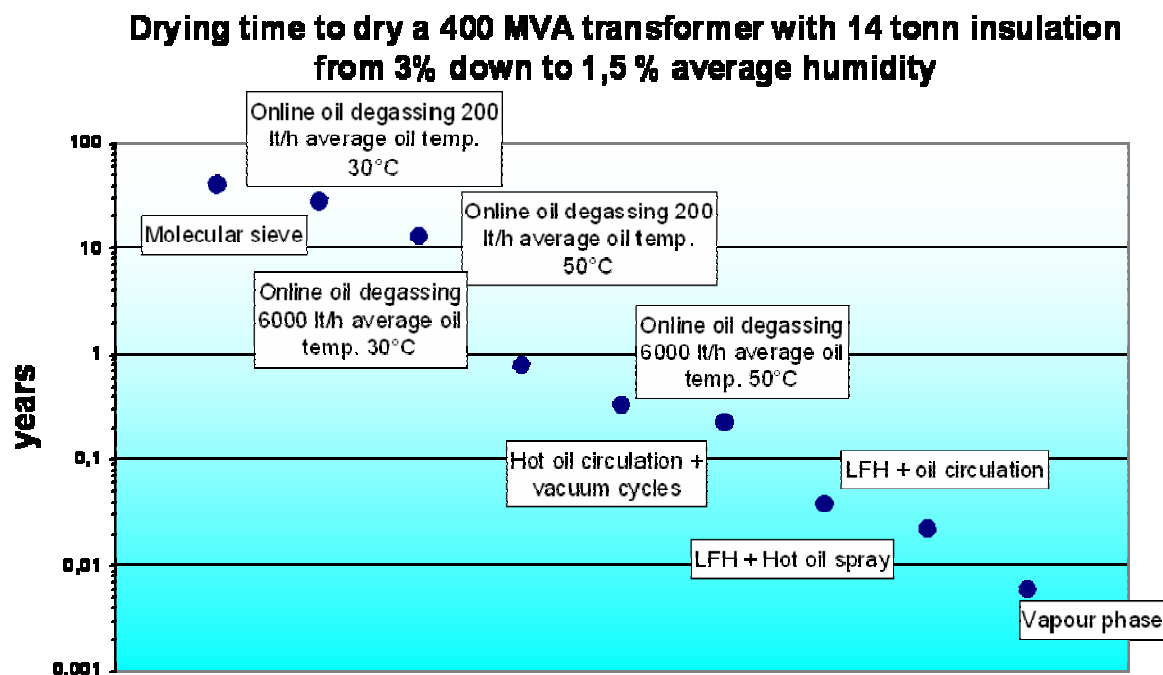


Figure 25: Performance in Terms of Drying Time for Different Drying Methods. (Source: ABB)

Literature:

[1] P. Koestinger and al. "Practical experience with the drying of power transformer in the field, applying the LFH technology", CIGRE Session 2004

5.7 Physical and Chemical Oil Treatments

This section is mainly based on the work of TF D1.01.12. Refer to CIGRE Brochure #413 for further information.

5.7.1 Reclamation of Transformer Oil

Reclamation is defined by the IEC as "a process that eliminates or reduces soluble and insoluble polar contaminants from the oil by chemical and physical processing". These contaminants are mostly oxidation products from the solid insulation, and especially the oil. Chemical and physical processing is typically a combination treatment using sorbent material and oil filters. Often degassing is performed at the same time, at least for on-line reclaiming.

The expected outcomes for oil reclamation depend on whether inhibited or uninhibited oils are treated. In general, uninhibited oil may have a shorter life after reclamation, if inhibitor is not added. This is dependent on the degree of oil oxidation prior to reclamation. Heavily oxidised oils will have relatively short lives, after reclamation, if they effectively remain as uninhibited oil.

When initially refined, the uninhibited oils are allowed to retain some of their aromatic content. Many oxidation inhibitors in naturally inhibited oil are aromatic in origin, with slightly polar functional groups capable of radical chain termination and other antioxidant functions. Due to this natural inhibitor content, the uninhibited oils have very different aging characteristics to the artificially inhibited oils. Unfortunately, the aromatics and their natural inhibitors are readily removed by the reclamation process (or over processing the oil with vacuum reconditioning for that matter). Adding an artificial inhibitor then becomes necessary.

In contrast, the ageing characteristics of inhibited oils rely on a single chemical, its artificial inhibitor, being added in large quantities as a measured dose, and thereafter carefully monitored and controlled. For best performance, the oil quality of artificially inhibited oils should be controlled very strictly at all stages of the life of the oil. The same applies to passivated oils, which have had a metal passivator artificially added to reduce or eliminate its potential corrosion activity. As oil reclamation processes may partially or totally remove antioxidants and passivators, it is usually necessary to add them after the treatment.

The reclamation process is essentially the same for both inhibited and uninhibited oil. Transformers may be regenerated off-line or on-line using a mobile unit containing a Fuller's Earth mixture, or clay. The oil is warmed and pumped through this media. The clay is a highly polar, granular matrix made from natural bentonite, sepiolite or montmorillonite, mixed with metal oxides, and "activated" (which may involve thermal dehydration and partial dehydroxylation) in order to increase the polarity, surface area and catalytic activity of the material. Other reclamation materials have been tried, such as carbonaceous charcoals, sands, and other clays. Each has different properties and these affect the reclamation process in varying ways. Hereafter, only Fuller's Earth based clays are discussed.

During oil reclamation, the material removed from the oil in approximate order, are any solids, polar material such as acids, then alcohols, aldehydes, ketones, esters, soaps and aromatic material. As outlined above, removal of the aromatics is not so important for artificially inhibited oil, but is critical when considering reclaiming uninhibited oil. Their partial or complete removal will result in reclaimed oil satisfying many of the physical and electrical properties recommended for re-used oils, but cannot satisfy prolonged use inside the oxidising environment of a transformer.

Literature:

[1] *O Berg et al, "Experiences from On-Site Transformer oil reclaiming", CIGRE Paris Conference Paper 12-103, 2002.*

5.7.2 Reclamation Processes

Oil Reclamation Processes involve oil contact with a sorbent material, from which the oil is separated after a suitable treatment period. There are two basic approaches. The first approach involves the sorbent being suspended in the oil while stirring, and is subsequently separated from the oil by filtration. This practice is sometimes referred to as contact processing. The second approach involves running the oil through percolating columns filled with the sorbent, either by gravity or by pumping the oil. International standards IEC 60422 and IEEE Standard 637 describe in some detail several of the systems used.

Usually the process of oil reclaiming is performed using the percolation method and can either be carried out batch-wise, with disposal of the sorbent when it has been saturated, or in a semi-continuous mode, with in-situ reactivation of the sorbent. The main advantage of the latter is that it facilitates on-line processing. Typically, the on-line process is run in two alternating modes; treatment mode and reactivation mode. In the treatment mode, the oil is drawn from the bottom of the transformer tank, heated and pumped through the sorbent columns. Before it is returned to a top valve or the expansion vessel, the oil passes through a filter and degasser. The treatment stage may continue until the effectiveness of the sorbent starts to deteriorate, or until it is convenient to switch to the reactivation stage. In this latter stage, the sorbent columns are by-passed, and the oil is led directly to the filter-degasser. The sorbent is then reactivated, usually by in-situ incineration. After reactivation, the process switches again to the treatment mode.

5.7.3 Sorbent Materials

The Sorbent Material used mostly is Fuller's Earth. The term Fuller's Earth refers to a class of naturally occurring adsorbent clays of varying mineral composition, and not a specific chemical. Fuller's Earth clays may be used as bleaches, adsorbents, or oil reclamation compounds. The following table shows the typical composition of Fuller's Earth:

SiO ₂	66.1%
Al ₂ O ₃	12.6%
Fe ₂ O ₃	5.1%
MgO	9.8%
CaO	1.4%
K ₂ O	1.3%
TiO ₂	1.0%
Other	2.7%

Table 53: Typical Composition of Fuller's Earth

5.7.4 Oil Reclamation Arrangements

When oil degradation reaches the stage where it begins to deleteriously affect paper insulation, or is deemed to be no longer fit for purpose, then the oil must be changed or regenerated. There are several arrangements available for performing oil reclamation. The choice of arrangement depends on the type of oil filled electrical equipment, cost, environmental considerations and local regulation.

On-Site On-Line

This arrangement for oil reclamation is performed On-Site using live transformers. It is a preferred method as it can clean the solid insulation utilizing the internally produced heat from the core and conductors. The heated oil provides for better removal of oil oxidation product from the solid insulation. Extreme care should be taken to avoid air entering the system as it may destroy the transformer. The usual method is to drain the oil from the bottom of the main tank, and return the clean, hot reclaimed oil to the top of the transformer.

On-Site Off-Line

It is similar to the above, but performed on the transformer while de-energized. This technique is more advantageous when it is performed together with hot oil cleaning of the insulation (at temperatures above the aniline point). This ensures desludging of the active part, because the oil decay products and precipitated sludge are re-dissolved and dealt with more effectively by the oil reclamation process.

Tank to Tank

This technique is usually employed for process economy when dealing with a number of small quantities of oil. A number of oxidised oil volumes are collected and transported to the treatment site and stored in a tank. When enough oil has accumulated, the oil reclamation process can begin. The reclaimed oil is then stored in clean tanks until it is used.

Large Scale Reclaiming

This is reclamation on an industrial scale and usually performed by a service provider that collects used oil from asset owners and stores it at their site in large tanks for reclamation. In general, oil reclamation should be conducted as stated in the Standard IEEE C57.140.

5.7.5 Risks and Consequences of Not Applying Oil Reclamation

The decision on when to reclaim oil is not straightforward. There are two important considerations involved that usually require a compromise.

The first consideration is to examine the short-term risk of transformer failure by assessing whether the oil is in such poor condition that it poses a threat to the safe operation of the equipment during the next few months or years. Taking this perspective, there are no stringent requirements on oil condition and the oil could continue to perform in the short term without reclamation. The limits set in IEC 60422 provide a guide, though in different countries the limits applied may vary slightly.

The second consideration is for the longevity of the transformer insulation by assessing what steps are needed to maintain the oil and paper in good condition to fulfil asset life expectations. Taking this perspective is likely to involve oil reclamation. In the latest editions of oil maintenance guides from the IEEE and IEC, there is a shift towards the longer term perspective with much more stringent requirements for several oil condition parameters. This is very much more the case with the IEC guide, and the same view is shared by many equipment users and service providers. Oil should be reclaimed without unnecessary delay when the test results for acidity, dissipation factor or interfacial tension are outside the limits in IEC 60422. However, it is more beneficial to reclaim the oil before it reaches an unacceptably poor condition, and for this there are at least two reasons. It has been shown that the less degraded the oil is at the time of treatment, the better is the oil quality that can be obtained after treatment. Furthermore, to fully realize the potential of oil reclaiming, to prolong life of paper insulation, the oil should be reclaimed before the increase in acidity accelerates the ageing.

Also, there are additional benefits with oil reclamation that should be considered, such as the reduced risk of static electrification or the removal of corrosive sulphur by some of the sorbents used for oil reclamation.

5.7.6 When to Reclaim Oil

As a guide, oil reclamation should be considered when any of the following criteria are applicable to the degraded oil:

- Acidity 0.10 mg KOH/g or higher
- Interfacial tension lower than 32mN/m (this is also the IEEE limit for the highest voltage class)
- Dissipation/power factor higher than 5% @ 90°C (this is also the IEEE limit for the highest voltage class)
- When the "Oxidation Index" (interfacial tension divided by acidity) is below 300

Note: Oxidation Index is based on the ratio of IFT over acidity. This figure is used as an indication of oil deterioration and action for oil reclamation since there are two factors involved (acidity and IFT). This figure is based on recommendation of IEEE for IFT and of IEC60422 for oil acidity.

When it is known that a transformer is planned to be in service for many years more, it may be necessary to reclaim the oil even before any of these criteria are reached. This especially applies where reclaiming means that the oil condition will be satisfactory for the remaining planned service life of the transformer.

5.7.7 Which Oils are Reclaimable

Even severely aged oil can be restored to an acceptable condition, provided that the oil was of good quality from the beginning. However, very acidic oils may require very long treatment times in order to get good long-term results. This particularly applies in the case of on-line treatment. Large amounts of oxidation products may be absorbed by paper and board, and there may even be sludge deposits. It may take a long time to re-dissolve the sludge and for the complete removal of harmful oxidation intermediates from the cellulose materials. In the end, it will be a question of economics. The cost to obtain an acceptable oil quality may become prohibitive. As a guide, for oils with acidity higher than 0.5 mg KOH/g, it should be carefully evaluated if on-line reclaiming will really be a cost-efficient option. This applies also to oil exchange, because new oil will also become contaminated by residual oxidation products in the transformer.

If the addition of an oxidation inhibitor after reclaiming is not allowed, then the treated oil can only be expected to have a short service life. Irrespective of whether the oil was originally inhibited or uninhibited, the natural inhibitor content will be depleted. After every use-reclaiming cycle the rate of oxidation escalates.

It is recommended that tests for the oil's suitability for reclamation be carried out. This usually consists of carrying out laboratory scale oil reclamation, followed by a check of all the usual oil quality parameters, including oxidation stability.

5.7.8 Requirements for Reclaimed Oil

It is expected that the requirements for reclaimed oil should be the same as those for new oil, in seeking to maintain and fulfil the oil's functional specification. On-site reclaiming ought to attain the same qualities as new oil (IEC 60422). With the exceptions of water content and oxidation stability, they are usually accomplished.

It should be noted that with respect to oil samples taken from the main tank, there are some oil quality parameters that are beyond the control of the on-site oil reclamation process. These include water content, PCB content and particle count which are all dependent on the existing state of the in-service transformer. The bulk of the transformer's water content resides in the solid insulation. Even if oil reclaiming temporarily dries the oil, at best it can only achieve superficial drying of the solid insulation.

Further study is needed on whether the oxidation stability of all oils after reclaiming, fulfils the requirements for new oil in IEC 60296. One study of reclaimed oils used the Rancimat method to measure oxidation stability. There is a general indication that the oxidation stability of reclaimed and re-inhibited oil is very good. However, the correlation of the Rancimat method with IEC 61125 method C (test specified by IEC 60296) is unknown. Furthermore, the oxidation stability of reclaimed oil depends partly on the composition of the oil when it was new. For this reason alone it may not be meaningful to apply, in every case, the same oxidation stability requirements as for new oil.

Experience in some countries does show that the acceptance criteria are in fact easily achieved, unless the oil is in very poor condition before treatment. There is little reason why an equipment user should accept poor results. Some operators of on-site reclaiming equipment guarantee values, such as those in IEC 60422, still hold for a certain period after the treatment. Therefore, having the same requirements as for new oil (with exceptions for PCBs, particles, water and oxidation stability) does seem realistic.

5.8 Treating Oil for Corrosive Sulphur Problems

Corrosive sulphur in oil has been a recognized problem for decades. However, the spate of recent transformer and reactor failures has renewed concern. In particular, there have been a number of failures occurring after the formation of copper sulphide in the winding insulation.

There are some oil treatments that can be performed to arrest any further formation of copper sulphide in the winding insulation. These should be considered when oil testing indicates the presence of corrosive sulphur in the oil. The oil treatments are briefly described in this section. Technical Brochure 378 (prepared by CIGRE WG A2.32) describes in more detail the problem, its detection and possible mitigation techniques.

Metal Passivator

Adding metal passivator is the most common technique used. Typically, toluotriazole passivator is added to the oil in concentrations varying between ten and several hundred parts per million. The passivator inhibits the reaction of copper with sulphur compounds. With oil in good condition, this may be the only action needed to prevent problems. However, it has been observed that with some aged oils the metal passivator is rapidly consumed. In extreme cases, more than half of the added passivator has been lost after a few months. It is therefore important to monitor the residual content of metal passivator in the oil, in order to detect its depletion.

Removal of Corrosive Sulphur

This treatment can be done three ways. Firstly, by removal of corrosive sulphur compounds, secondly by conversion of sulphur compounds, or thirdly a combination of the two techniques. There are probably several different methods that could be successfully applied. However, the ones mostly used on-site are either treatment with sorbents (single use or reactivating sorbents, some of them of the same type as used in regular on-line reclaiming) or a combination of reagents and sorbent. Although great care is needed because not all sorbents used for regular reclaiming are very efficient at removal of corrosive compounds. Furthermore, there are some reports of oil becoming more corrosive after reclaiming. The suitability of each type of reclaiming equipment needs to be evaluated for removing corrosive sulphur from the oil.

Oil Exchange

Another option is simply to replace the corrosive oil with non-corrosive oil. This technique has been successfully used in Brazil on many problematic units. However, it is very important to ensure that the oil exchange is as complete as possible, since even small amounts of corrosive sulphur from the original oil can cause enough contamination of the new oil to make it corrosive. Furthermore, it is strongly recommended to test beforehand a mix of old and new oil. If a mix with a 1:10 ratio performs well in lab tests (IEC 62535 and ASTM D1275B) it is assumed that oil exchange is suitable. Transformers with a high ratio of cellulosic insulation mass to the total oil mass will need extra caution because of their significant residual oil volume.

Literature:

M Dahlund, P Lorin, P Werle, "Effects of on-line reclaiming on the corrosive sulphur content of transformer oil", CIGRE Joint Colloquium, Cape Town, 2009

5.9 Static Electrification and Maintenance

Reference: *Cigre JWG 12/15.13 Technical Brochure 170 "Static Electrification in Power Transformers"*

5.9.1 Static Electrification

Transformers already identified to be subject to this phenomenon need further care in their maintenance activity. In performing maintenance activity, the possibility of creating conditions that are conducive to initiating the phenomena of Static Electrification should also be considered. In particular, this includes work that involves the circulation of oil through the transformer windings, or modifications to forced oil cooling.

Static Electrification arises through charge separation at the boundary surface between the insulation oil and the surrounding solid insulation in winding assemblies of the transformer, or the oil circuit of its cooling devices. A static charge accumulates on winding surfaces, oil pathways and surrounding solid insulation via relatively high velocity oil motion, and Static Electrification phenomena manifests with a significant potential increasing at certain positions, culminating in static discharge when the potential exceeds insulation breakdown limits.

Also aged, oxidized insulation oil has a higher electrostatic charging tendency (ECT) and therefore higher risk for static electrification. Oil reclamation is shown to have the additional benefit of reducing the ECT of the oil.

5.9.2 Mitigation of Static Electrification in Transformers

Since the propensity for the risk of Static Electrification is influenced by conditions such as flow rate of oil, temperature, being energized, materials in the oil flow pathway and the condition of insulation oil, the following measures can mitigate this risk.

Cooling Oil Flow Rate

Oil circulation or oil treatment, that involves oil being pumped through the windings, should limit oil flow so that it never exceeds that of the existing oil pumps. This applies to transformers employing directed oil flow. Similarly, any replacement, modification or upgrade of forced oil cooling pumps should also be limited in this same way, unless advised otherwise by a manufacturer. Appropriate selection of oil hoses with low static charge is also required.

Insulation Oil

The ECT of insulation oil increases as it oxidizes. The prevention of oil deterioration and exposure to air is important for all oil handling and oil treatment operations. The water content, particle content, and resistivity of the oil should be controlled. The Japanese experience, with the use of the oil additive benzotriazol (BTA) as a means of reducing oil ECT, also warrants consideration. Topping up oil needs to be checked for ECT.

In Service Monitoring

For units perceived to be at high risk, or require diagnostic surveillance, electrostatic charge detectors can be mounted on the transformer tank as an on-line monitor.

5.10 Precautions for Invasive Work

Work that requires oil to be partially or completely removed from the transformer may be regarded as invasive. Invasive work requires certain precautions to be taken because the transformer insulation is very sensitive to moisture, trapped air or gas bubbles, and particulate contaminants. Contaminants may easily be introduced either from airborne dust and humidity, or directly from people, tools and materials entering the transformer. This section provides a list of points for consideration when invasive work is carried out. However, the final set of detailed precautions for a specific work plan, or method statement, will be subject to the local situation, and recommendations from the manufacturer for the particular transformer, and the practices of the utility and maintenance contractor.

The following is regarded to be good practice when invasive work is carried out.

Planning the Work

- Generally only the minimum amount of oil required to carry out the work should be removed, but note that due to the low density of oil there is an extreme risk of drowning in oil and work over oil should be avoided or precautions must be taken to prevent any possibility of falling in.
- The job should be planned so that bodily access into the tank is not required unless absolutely necessary.
- If bodily access into the tank is unavoidable, proper confined space training and suitable plans and permits will need to be in place.
- Work should be planned so that the exposure time during which the tank is open should be as short as possible. The tank should be sealed whenever possible, for example during breaks in the work.
- Before a vacuum is applied to a tank, the ability of the tank to withstand vacuum must be verified. Additional time should be allowed for tracing and curing leaks that may prevent the maintenance of a vacuum, as leaks will reduce or negate the effectiveness of the process.

Draining the Transformer

- Air drawn into the transformer during oil draining must be dry (target dewpoint < -40°C).
- If the tank is left empty, or partially empty, it should be under positive pressure of dry air.
- Precautions must be taken to avoid loss of oil into the environment. Good practice is to use temporary bunding (oil containment barriers), drip trays under valves and hose couplings, and to have oil spill containment kits readily available.
- In order to avoid contact between the oil and oxygen, nitrogen may be used instead of air, but only if confined space access to the tank is not required.

Access to the Transformer

- Extreme cleanliness is required in order to avoid contaminating the transformer whenever an access hatch or hand-hole cover is removed. Before removing a cover loose paint, rust, gasket material must be removed and the area generally cleaned to prevent anything entering the tank.
- If access through a hand hole is needed, whether or not personnel access into the tank is involved, then a continuous flow of dry air should be used to prevent, as far as possible, ambient air entering the tank.
- If confined space working is required, then suitable safety precautions need to be taken, including specialist training, a permit system, air quality monitoring, an emergency plan, personal protective equipment and proper supervision.
- Gaskets that are disturbed during the course of the work should be replaced with new gaskets.
- All cleaning cloths and clothing should be lint free.
- Solvents, paints, glues and other chemicals should not be used unless specifically evaluated for compatibility with the transformer.
- Tools should be tethered if there is any chance that they could be dropped into the tank, and an inventory be kept to ensure nothing is left inside when the work is completed.
- If confined space access is required, special attention must be paid to contamination that could be introduced particularly on footwear. The use of dedicated boots and establishing a clean area at the point of entry are recommended.

Refilling the Transformer

- If paper pressboard or other porous insulation is exposed, then the transformer must be vacuum filled if the transformer was originally vacuum filled.
- Air leaks must be found and eliminated so that a good vacuum can be maintained. The leak rate should be measured at the start of the process with the vacuum pump off. See guidance in C57.93.
- The presence of free water on the tank should be avoided to prevent possible ingress during vacuum application.
- All oil introduced into the transformer must be dry <5ppm.
- Following refilling, the oil should be circulated through an oil reconditioning plant for filtering, degassing and drying, to achieve oil quality no worse than before the work was carried out and ideally <5ppm moisture.
- To avoid static electrification, oil flow velocities in excess of those produced by the normal flow rate of the cooling oil pump should be avoided and oil pipes should be of a type that will not cause static charging. Windings should be connected to earth during oil handling operations including running the oil cooling pumps.
- There must be a standing time allowed, following oil filling, to make sure that all air or gas is eliminated from the dielectric parts of the transformer. The time will depend on whether paper or pressboard has been exposed for a significant period, but should be of the order of 48 hours or more if the oil has been drained completely from a high voltage transformer. This standing time may be concurrent with oil reconditioning. Manufacturer's guidance must always be followed. See IEEE guide C57.93.

Chapter 6 Major Work – Transformer Repair

This section outlines the important considerations for performing major work on a transformer and shows how decision makers evaluate the possible repair either in a repair workshop or at site. An overview of current site repair practice is provided rather than a detailed description of the processes performed by the service provider. It is important to note that local standards, regulations and practice take precedence over this guidance.

6.1 On-Site Repair

On-Site Repair is regarded to be invasive work that has to be performed in-situ. It involves the repair or upgrade of a transformer where, at the very least, it is necessary to partly or completely drain the transformer of oil and remove its main covers. Depending on the complexity of the work, the level of expertise needed may vary. The need for high voltage tests will vary too. Repairs may be categorized as follows:

- Minor repairs such as replacement of bushings or tap changers, repair of connections
- Major repairs such as exchange of windings, repair of the core, upgrade

Literature:

J Mendes, R.A. Marcondes, J. Westberg, "On Site Repair of HV Power Transformers", Cigré Paris Conference Paper 12-114. 2002 Session

6.2 Advantages for On-Site Repair

Depending on specific constraints, an On-Site Repair might have clear advantages compared to an off-site, workshop repair. The main advantages considered by decision makers are:

- Transportation difficulties or impossibility: Disused railway tracks, changed axle loads for roads, bridges, changed road alignments
- High transportation costs
- High transportation risks (poor road conditions, heavily aged insulation)
- Reduced down-time on the units by avoiding long transportation time. Also minimizes higher losses in the network due to changes in optimum power flow, loss of energy sales, loss of water in a hydro plant, penalty for non delivery of energy. Typical time saving may be 1 to 3 months

Global experience with on-site repair includes Network and GSU transformers (up to 750 kV) as well as industrial units, reactors, HVDC transformers (up to 600 kV).

6.3 Process for On-Site Repair

The process for an on-site major repair is relatively similar from one transformer to another and with the appropriate resources can effectively emulate a workshop repair. However, some adaptations are needed depending on the site conditions.

The process should be documented with a procedure that outlines the individual tasks, material and equipment to be supplied to the site, quality control, cleanliness requirements, as well as the required human resources, competencies, and level of expertise for the different tasks. Because the process is performed outside the normal controls of an established workshop, quality control becomes more important. It should document the status and condition of received materials, the proper storage of materials, and the repair activity workflow along with exception resolution. Standards are required to define the initial cleanliness requirements, how to maintain this and the restoration measures in the event of contamination or exposure.

On-Site Repair requires excellent logistics, competent planning as well as the flexibility to adapt to the unforeseen (inherent to most repair situations) in order to minimize delays to the schedule.

Literature:

L Eklund et al, "Increase Transformer Reliability and Availability: from Condition Assessment to On Site Repair", Power Gen Middle East, Bahrain, Jan 2007

6.3.1 Logistics

Because on-site repair involves invasive work, there is specialised equipment, tools and consumables required that do not normally exist on the site. When the repair is made in a workshop situation, the most critical equipment such as cranes, winding machines, core stacking table, drying and testing equipment are immediately available. A key factor for successfully performing major repairs on-site is the Logistics required to secure the correct equipment at the right time in the repair schedule. By way of example, Logistics includes the provision of a suitable protective housing, the organising of cranes, skating equipment, lifting gear, scaffolding, oil handling and storage, and arranging transport of personnel, equipment and material to site. It is advisable to use checklists and Gantt charts to schedule these resources and material. Verifying that the equipment is in working order beforehand and using adequate shipment containers will prevent possible delays.

It is mandatory to create a clean environment to ensure that the transformer will not be exposed to moisture or contaminated by dust. Some sites have an existing high bay and access track to relocate the transformer to a protected environment. Where there is no adequate building, a temporary housing can be built instead. The area around the transformer should be equipped with a system to allow a positive over-pressure of dry filtered air. The building or housing should have sufficient lay-down area for the transformer disassembly and reassembly process.

Replacing the windings, without access to the original drawings, requires reverse engineering to produce a winding identical to the original winding design. In order to do that, the transformer needs to be partially disassembled in order to extract the failed winding for inspection and to take needed technical information and dimensions on the original design. Since the manufacturing of the new winding can take several weeks or months, it is important to take the necessary actions in order to keep the active part of the transformer away from any possible contamination (moisture, dust). The active part should then be put back in oil, in dry air or nitrogen.

Heavy lifting capabilities should be provided at site to lift the different components of the transformer. The total weight of the transformer and the weight of the active part can usually be found on the nameplate of the transformer.

The windings are usually wound in a factory, dried out and impregnated before shipment in sealed containers filled with dry air or oil. Adequate equipment to store and process the oil, as well as dry out equipment, are also needed. Finally, if high voltage testing is required, testing equipment should also be transported to the site. The heavy lift equipment test records should be reviewed to determine if it is adequate for the project.

A detailed plan for each activity will allow adequate time for the equipment and material to arrive at the proper phase of the repair. Planning should be updated daily by the site supervisor and reviewed periodically. Site personnel require regular contact with their service centre or factory for logistical, administrative and technical support.

Health and safety (H&S) requirements must be considered and followed during the planning and implementation of the repair process. The service provider company is usually obliged to train their own site personnel regarding H&S matters, but the site personnel might also be trained and certified by the company owning or operating the transformer. Because several companies could be working together, possibly including the customer's maintenance staff, it is recommended that one party has overall responsibility for H&S matters. Environmental aspects are also to be integrated at each phase of the project and especially at site (retention tanks, protection systems). The service supplier should follow a quality plan in line with the company quality policy and possible ISO 9000 / 14000 certifications.

The on-site repair process can require specific organisation depending on the type of technology to repair. For example, consider the different requirements when performing a major repair on a shell-form transformer versus a core-form transformer.

	Core-Form Transformer	Shell-Form Transformer
Workmanship	Skilled labour required for higher kV and MVA ratings	Higher labour hours due to handling of core steel while un-stacking and stacking
Capacity of lifting equipment	De-tanking of the active part needs heavy lift capability because the core and coils are lifted as a unit (except for bell type tank arrangement)	Heaviest part could be each shell winding phase assembly. Bell type tank cover to lift Heaviest lift is expected to be up to 50 tons
Drying time	Reasonable if the active part is kept under dry air during the whole repair process. Can be shortened if needed by using LFH	Larger quantity of paper and steel Hot oil spray plus vacuum recommended Possibly combined with LFH
Exposure time of windings to ambient	Minimal based on the time required to repair. Needs a controlled environment	Longer exposure time due to core un-stacking/stacking Needs a better controlled environment
Requirements in a temporary workshop	Awareness of extra space and height needed	Un-stacking of core laminations in a shell-form transformer requires a large lay down area. Special jigs and clamps for pancake windings are needed

Table 54: Different Requirements for Repairing Shell-Form and Core-Form

6.3.2 Disassembly, Assembly and Quality Control

The processes of disassembly and assembly are quite similar to the repair processes performed in a factory. The quality control process and procedures should be the same as the factory, except for necessary adaptations. Additional tests may be employed to confirm process quality specific to a repair at site.

6.3.3 Testing

Performing on-site testing involves significant cost, logistics and resources. Adequate testing equipment should be available, as well as a test procedure and an experienced site testing manager

High Voltage testing after repair is an important part of the quality control process. The IEC standard 60060, First Edition 2006-2 relates to the High Voltage site testing of electrical apparatus, but there are no standards that specifically cover HV testing for transformers repaired at site. IEC 60076-3 states that repaired units are tested at 80% of the nominal level performed on new units in factory acceptance tests (FAT), except for the long duration AC tests (ACLD) which are repeated at the 100% level. An important pre-requisite for testing the transformer at 100% of FAT is that bushings should be replaced by new ones, or be separately tested beforehand, and that the tap changer is completely overhauled. In cases where these pre-requisites for the bushings and tap changer are not met, it is advisable to test at 80% of FAT instead.

Transformer Categories

In the absence of any specific standard for on-site testing after transformer repair, there are a set of minimum testing requirements that can be recommended. There are four transformer categories defined with corresponding minimum test requirements to be applied for on-site testing. Each transformer category has related strategic importance to the owner, as well as technical risk, and this may need evaluating in an economic justification to perform any of the tests. Each case being different, with its own constraints, means that the user and the service provider need to agree at the contract stage on the scope of tests taking into account the requirements of the user (technical and economic) and the availability of adequate test equipment.

Defining the scope of testing is usually a difficult task since it extends the repair time and represents significant costs. On the other hand, tests will reduce the risk of an unexpected failure in operation with its associated safety issues, that would

otherwise extend the outage time. As a support to help agreement on the scope of test (Category 1-4) the following aspects can be considered:

- Type of repair and scope of work (for example bushing versus winding replacement)
- Possible consequences of a failure
- Stress from the network (lightning, short-circuit, overload)
- Urgency and loss of production related to the down-time
- Repair/refurbishment versus re-manufacturing (refer to definitions in Section 5.6.5 Table 52)

Table 55 gives an example of how to determine transformer categories for the purpose of on-site testing.

Ch	Characteristics
Category 1	<ul style="list-style-type: none"> - Nominal Voltage < 72.5 kV - Units with no critical loss of production, in case of failure, or with a good redundancy or a spare unit - Limited risk of fire in case of failure (collateral damages) - Repair of connections, replacement of bushing or OLTC - No expected overload. Good protection system. Low risk of short-circuit on the network - Urgency to put the units back in service to meet operation constraints - No availability of testing equipment
Category 2	<ul style="list-style-type: none"> - Nominal Voltage ≥ 72.5 kV and < 170 kV - Repair involving work on the active part
Category 3	<ul style="list-style-type: none"> - Nominal Voltage ≥ 170 kV and ≤ 300 kV - Transformers with severe consequences in case of failure and/or significant loss of production for example generation or industrial applications - Transformer with no spare unit
Category 4	<ul style="list-style-type: none"> - Nominal Voltage > 300 kV - Repair that incorporates a new winding design - Upgrade with new design to reach higher MVA / Voltage - Transformers with high lightning exposure

Table 55: Examples of Transformer Categories

For each transformer category, the following table indicates the recommended Post-Repair On-Site Testing.

Recommended Post-Repair, On-Site Tests for Different Transformer Categories

Recommended	Tests
Category 1	<ul style="list-style-type: none"> - Low voltage tests: Winding resistances, ratio, insulation resistance for windings and core, power factor - Functional tests and checks on indicators, control circuits, relays and OLTC - Dielectric Response (DR) and Frequency Response Analysis (FRA) might be considered as a fingerprint. - Continuous increase of voltage whenever possible (GSU) without any load: 20%–100% U_n - Connection to the network with no load at 100% U_n for 12 hours with monitoring of gas (preferably on-line or off-line after one hour and then every 3 hours). In any case, the results of the DGA should be analyzed before putting the transformer back under load - Incremental load rise (whenever possible) - Monthly follow-up of DGA over a 6 month period
Category 2	<ul style="list-style-type: none"> - Same tests as for Category 1 - Induced voltage tests with partial discharge (PD) measurement according to IEC 60076-3 or IEEE C57.12.00 standards. <i>(See remarks related to induced voltage tests following this table)</i>
Category 3	<ul style="list-style-type: none"> - Same tests as for Category 2 - In case of High Voltage Delta connected windings, separate source AC withstand voltage test (Applied voltage test) at 80% of the nominal voltage test according to IEC 60076-3 or IEEE C57.12.00 standard
Category 4	<ul style="list-style-type: none"> - Same tests as for Category 3 - Lightning impulse test, switching impulse test and chopped impulse test may be performed; nevertheless, the added value of these has to be evaluated (costs involved, availability of test equipments)

Table 56 – Recommendations for Post-Repair, On-Site Testing

Remarks Related to the Induced Voltage Test in Table 56

It is not advised to perform any short duration tests. Instead the following alternatives are proposed.

- For repairs where all the old insulation parts are replaced by new parts, bushings replaced with new ones, or existing bushings fully tested separately and OLTC fully overhauled, then perform a long duration induced test with PD measurement during 60 minutes at 150% of U_n (100% of FAT level).
- For repairs where only parts of the insulation system are replaced, or the existing bushings are not tested beforehand, then the PD test should be performed at 120% of U_n (80% of FAT level). The voltage test level should, in any case, be agreed upon by the owner of the transformer and the service provider.

Induced voltage tests with partial discharge tests, as described above, can also be used as a diagnostic method at site (preventive or troubleshooting) as well as for commissioning of new transformers at site after transportation and assembly.

HVDC Transformers and Shunt Reactors Tests

Tests recommended after the repair of HVDC transformers:

- Tests according to Category 4
- DC tests might also be applied, but are not regarded as a mandatory test

Test recommended after the repair of shunt reactors:

- Impulse test, when available, is the only high voltage test that is practicable on-site because of the imposing requirement for reactive power compensation during the induced test

Literature:

P. Werle, J. Szczechowski, "Experiences with On-Site Testing of Power Transformers - TrafoSiteTesting™, 16th International Symposium on High Voltage Engineering (ISH), Johannesburg, South Africa.

6.3.4 Competencies and Expertise

The repair of a transformer involves several forms of expertise at different stages of the repair process. An important part of the process is the preliminary investigation work to understand the scope of the repair and to identify the causal factors of the failure. Experience in diagnosis, analysis and troubleshooting is needed to define the scope of the repair and identify which parts will need to be replaced. Engineering resources are then required to control and modify the design of the unit if needed. Qualified repair personnel, with experience in field repair, are able to analysis the defects, propose new solutions using modern materials, tools and processes and incorporate them into the original internal assemblies despite their legacy technology. Accordingly, there is a need for ongoing training of all staff and a need to keep and monitor a register that records licences held, training expiry dates and attained qualifications and competencies.

Project personnel, especially the supervisor, must have experience in transformer manufacturing, repair and quality control. Working at site requires a degree of self-reliance and autonomy. Site personnel should be trained and certified for site repair work. Efficient communication tools are needed to get quick access to needed information and to access remote technical support. Moreover, Health & Safety guidelines need to be reviewed and the responsibility of all parties clearly understood. Each worker must hold a valid H&S certificate from their employer and where applicable, also receive a site induction from the asset owner.

Strong project management skills are required for the on-site transformer repair. Material supply and delivery, transportation of equipment, management of resources must be handled in a professional way. Potential difficulties should be anticipated as much as possible in order to stay in line with the agreed schedule.

6.4 Economics

The economic decision making for selecting between the options of transformer refurbishment, repair or replacement would normally involve some form of cost analysis. A comparative cost analysis cannot simply be reduced to a compilation of parts and labour expenses. Decisions will usually include other considerations, such as the respective core and winding loss costs, the relative transportation costs, and the cumulative business costs expected over the duration of outage.

Core and Winding Losses

Design enhancements and new materials have led to important transformer loss reductions over the last few decades. By example, Figure 26 shows how improvements in core steels and core assembly have reduced the per unit core loss in a transformer population belonging to a large North-American utility. It can be observed that in about 50 years, core losses have reduced by a factor of 10. When the costs of these losses are calculated over the expected lifespan of a refurbished transformer and converted into constant (actualized) expenses, they may amount to prohibitive levels. It is therefore essential that this consideration be taken into account early in the refurbishment decision of an older unit.

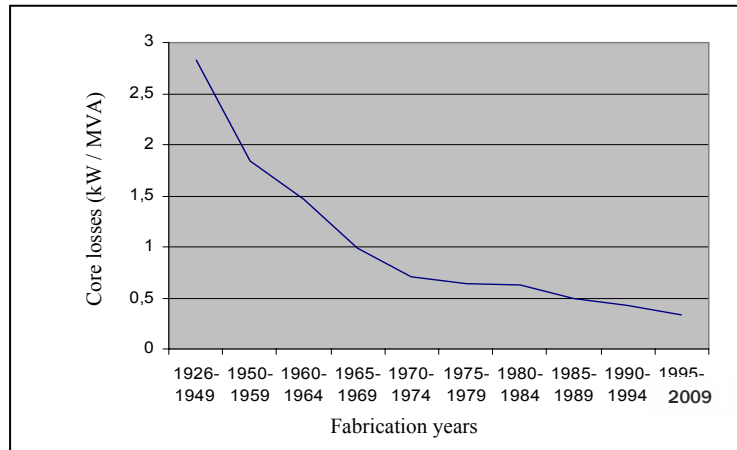


Figure 26: Reduction in Core Losses Over Time

Environmental regulations are changing rapidly and plant efficiency will receive greater scrutiny. These are likely to impact on the economic evaluations for all projects to be undertaken. This could make the core and winding losses even more costly to utilities that rely on fossil fuel generation.

Transportation

At the early stages of refurbishment planning, it is common to underestimate the round trip transportation costs to the repair shop. Many aspects are overlooked such as:

Management: Planning heavy lift transportation on public roadways often requires a fresh survey to identify a suitable route. Usually there have been major changes from the arrangement used at the time of initial installation. The original routes may no longer be available because of axle load restrictions or bridge height limitations. The preparation of the documents for the permits and supervision of the transportation may require work from an engineering firm.

Permits and Insurance: Local authorities along the way may require permits and charges can be important. Most will demand that the transportation be covered by liability insurance.

Civil Work: Road infrastructures may need to be temporarily reinforced or augmented at some locations. In some cases, new roads must be constructed. Also railroad sidings and branch lines may have been dismantled or fallen into disrepair.

Risks: The possibility of damaging the transformer during transportation is not negligible and must be factored into the project.

Outage Time

Outage costs are very sensitive to the time of year and outage duration and in most cases are very complex to evaluate. They must take into account contingency and spare availability. For facilities that operate with an N-1 contingency, it is an indirect risk-associated cost. For other facilities, outage penalties can be considerable and time for repair may become the unique criterion for the decision to replace, repair or refurbish.

Reliability and Tests

In principle, a refurbishment restores the reliability level to equal a new unit. Reliability costs should therefore be included, by default, in the overhaul costs through the necessary level of care and extent of the work. In theory, differential costs in testing could be discarded as both repaired units and new units would then go through very similar commissioning procedures. In practice, however, there are a number of instances where extra testing could be required. Reliability uncertainties have to be addressed, for example in cases where the refurbishment work is carried out by a new service provider. Therefore, in most cases, either testing costs or a reliability premium should be included.

Case Examples

To demonstrate the importance of a comprehensive economical evaluation in the on-site repair decision process, the following case examples have been included. Relative costs are expressed as percentages of the purchasing cost of a new unit. The numbers are actual figures from real cases and will exemplify the order of magnitude that each expense category can take.

Case 1: Problematic Transportation

The transformer is a 33MVA, 120 / 12 kV unit which was built in 1961. The active part was evaluated to be in very good condition but major work was required on the OLTC, bushings and accessories. The unit is located inside an underground substation in the middle of a dense business district served by a North-American utility.

- Transportation was problematic due to load restrictions and access limited by neighbouring buildings.
- No high voltage tests were deemed necessary since refurbishment would not involve any repair work of the active parts.
- Due to the location of the substation, special site related expenses were considered.
- Outage time was not an issue as the utility had sufficient contingency.

The comparative cost breakdown is summarized below expressed as a percentage of the supply cost of a new equivalent unit.

	New Unit	On-Site Repair	Factory Repair
Material and Labour			
New Transformer	100%		
Dismantling old unit	6%		
Refurbishment			
OLTC		16%	13%
Bushings		4%	4%
Cooling		7%	7%
Indicators, wiring and controls		9%	7%
Tank and sealing		7%	4%
Misc		6%	4%
Oil and drying		6%	2%
Subtotal A - Material and Labour	106%	55%	41%
Losses			
Core		24%	24%
Winding (50% average load)		6%	6%
Subtotal B = Subtotal A + Losses	106%	85%	71%
Site-related expenses			
Transportation	40%		65%
Other expenses (civil, lifting)	10%	12%	10%
TOTAL	156%	97%	146%

Table 57: Comparative Costs – Case 1

In subtotal A, only the material and labour costs are compiled and it can be seen that the on-site repair and the factory repair options appear the least expensive.

The contribution of core and winding losses, in subtotal B change the picture to a point where the on-site repair option is now marginal considering that the reliability and risks have not been factored in.

When transportation costs are finally considered, the on-site repair option clearly separates the other two options.

Case 2: Problematic Outage Time

A Generator Step-up Transformer 100 MVA, 140 / 10 kV failed after 15 years in service. Considering that there was no spare transformer, the replacement of the failed transformer with a new transformer in the shortest possible time was requested from several manufacturers.

One supplier volunteered to offer the repair of the unit in factory or on-site.

The cost evaluation shows that the least cost option also provides the fastest restoration to full capacity at the power generation plant.

	New Unit	On-Site Repair	Factory Repair
Material and Labour			
New Transformer ex works	100%		
Dismantling old unit	3%		
Metal recycling	-2%	-2%	-2%
Commissioning	3%	1%	3%
Repair			
Material, Assembly, Processing and Test		85%	70%
Losses	0%	10%	10%
Subtotal - Material and Labour	104%	94%	81%
Site related cost			
Transportation	15%	5%	30%
TOTAL COST	129%	99%	111%
Outage time of the Power plant (weeks)	52	30	40
Lost Net Earnings	600%	340%	450%
GRAND TOTAL (Repair cost & Loss of production)	730% 44	0%	560%

Table 58: Comparative Costs – Case 2

Case 3: Repair of a Faulted Unit Involving Core Repair and Winding Replacement

A 250 MVA, 13.8 / 315 kV generator step-up transformer located in a remote area had a core problem.

Because the unit had to be completely dismantled to repair the core, winding replacement was also considered to obtain the benefits of a complete overhaul and a copper loss reduction.

Transportation was problematic so alternatives to a factory repair were analyzed.

	New Unit	On-Site Repair	Factory Repair
Material and Labour			
New Transformer	100%		
Dismantling old unit	3%		
Metal recycling	-2%		
Commissioning	2%		
Refurbishment			
Core repair		55%	44%
New windings		16%	16%
Oil and drying		2%	1%
Tests		5%	3%
Subtotal A - Material and Labour	101%	73%	61%
Losses			
Core		31%	31%
Winding		0%	0%
Subtotal B = Subtotal A + Losses	100%	104%	92%
Site-related expenses			
Transportation	33%		60%
TOTAL	36%	109%	155%

Table 59: Comparative Costs – Case 3

6.5 Environmental Considerations

The environmental impact of transformers over their life cycle has become an important consideration in many countries. In order to evaluate the impact of an individual transformer on the environment, a methodology called a Life Cycle Impact Assessment (LCIA) can be used. The LCIA starts with a Life Cycle Inventory Analysis (LCI) to identify an inventory of the impacts on the environment of the main phases of the transformer during its entire life cycle. The impacts for each phase are then integrated and categorized as shown in Figure 27.

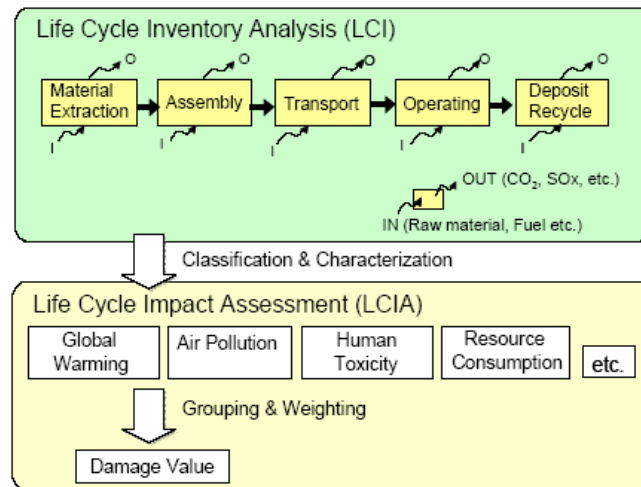


Figure 27: Framework of LCI and LCIA

The weighted sum of the impacts assessed for each of the four categories provides the overall Damage Value.

Many parameters are considered in such an evaluation in the case of a transformer:

- Design of the equipment
- Loss performance
- Quantity of all the different material used and their origin of production
- Transportation of raw material
- Semi-finished goods as well as the complete product
- Transformation of raw material
- Assembly of the different systems and sub-systems

International databases are available to evaluate the impact of each parameter.

When a transformer owner or operator needs to maintain, refurbish, repair or replace a transformer, it is recommended to perform such assessments in order to benchmark the different scenario. Generally speaking, such an analysis shows that more than 95% of the criteria "Climate Change" (CO₂ emission) is driven by the level of electrical losses (load and no-load). The impact might then be more or less important depending on the country where the transformer is operated (majority of hydro production, nuclear, fossil fuel). In any case, design improvements, either on a repair or on a new unit, reducing electrical losses will be one of the major factors to minimize the impact on environment. Recycling of material (reuse of old parts during a repair process, oil reclaiming) has a positive impact on the criteria "Resources".

It is important to note that this type of analysis and the benchmarking of several life cycle management decisions (maintain, upgrade, repair versus replace) can not be made in a generic way but must be performed for each specific case in order to integrate the frame conditions, constraints and company strategy of each owner/operator.

APPENDIX 1

SURVEY RESULTS

Systematic Preventive Maintenance (SPM) for GSU (page 1/2)

Maintenance tasks	"Task Interval" or "Conditional "																				Monitoring (m)	
	Basic Task Interval										Intensive Task Interval (if different from basic)										If "Conditional" on which conditions	which sensor
	A	B	C	D	E	F	G	H	I	J	A	B	C	D	E	F	G	H	I	J		
Type of Power Plant	N	H	N	Th	H	?	H	N	H	H	N	H	N	Th	H	?	H	N	H	H		
Inspections in service: - Visit (month – except D= daily) - Visual detailed inspection (month) - Infrared thermograph (month) - OLTC visual check (month) - silica-gel breathers check (month)	D ¹		D	D	2	½	1	D	1	1					1							
Oil tests (sampling in service) - Oil analysis, (year) - DGA- (year) - Furans (year) - additives	2	2	6	6	6	1	3	1	4	6	m ⁶	1	½		1		m ⁸		m ⁹	m ¹⁰		H2 or multi-gas
Oil treatment (in or out of service) - Oil filtering, - Regeneration,	c	c	c	D	-	D	D	c	c	-											Oil analysis Acidity, IFT, diel., PF	
Cleaning actions (out of service) - Fans cleaning, (year) - Radiators cleaning- (year)	1	1	1	6	c	6	c	c	c	c											Visual Inspection., current, temperature, ventilation	
Accessories verifications (out of service) - Gas relay functional test, (year) - Monitoring sensors verification, (year)	1	2	1	6	6	6	12	6	8	6												

¹ 3 time per day

² No OLTC

³ for 275kv and 500kV

⁴ 12 months or 24 months depending on the age of the transformer

⁵ first time after 12 year of operation, then conditionnal

⁶ multi-gas monitoring after protection action or periodic DGA

⁷ 1 month, 3 months or 6 months

⁸ multi-gas monitoring after protection action or periodic DGA

⁹ H2 for 120 kV and above

¹⁰ H2 for units identified as potential problems

Systematic Preventive Maintenance (SPM) for GSU (page 2/2)

Maintenance tasks	"Task Interval" or "Conditional "																				
	Basic Task Interval										Task Interval Intensive (if different from basic)										If "Conditional" Indicate conditions
	A	B	C	D	E	F	G	H	I	J	A	B	C	D	E	F	G	H	I	J	
Type of Power Plant	N	H	N	Th	H	?	H	N	H	H	N	H	N	Th	H	?	H	N	H	H	
Electrical tests : (out of service)																					
- Winding ratio (year)	c	c	c	c	c	c	c	c	-	6											DGA or protection action
- Winding resistance (year)	c	c	c	c	c	c	c	c	-	6											DGA or protection action
- Exciting current (year)	c	c	-	-	c	c	c	1	-	6											DGA or protection action
- AC insulation tests (year)	c	c	c	-	-	c	c	1	8	6											DGA or protection action
- Core Megger	-	-	-	-	-	-	-	-	-	6											
- DC insulation tests (year)	-	-	-	-	-	-	-	-	-	-											
Special tests ((out of service)																					
- Frequency response analysis (year)	c	-	-	-	-	-	-	c	c	c											DGA or protection action
- Partial discharges measurements	c	-	c	c	c	c	c	c	c	-											DGA or protection action
- Ultrasonic measurements	c	-	-	-	c	-	-	-	c	-											DGA or protection action
Bushings : (out of service)																					
- DGA, (year)	g	g	-	6	-	-	c ¹²	1	c	-									2 ¹³		Only some families with problems
- Power Factor (year)	g ¹¹		-	-	-	c	c	4	8	6											
OLTC : (out of service)																					
- Acoustic tests	-	-	-	-	-	-	-	-	-	-											
- Internal inspection (year)	-	-	-	g ¹⁴	6 ¹⁵	c ¹⁶	c ¹⁷	-	-	-											
Work inside the tank																					
- Connection inspection :	c	c	c	c	c	c	c	c	c	c											Fault, DGA, overhaul inspection
- Winding tightening	c	c	c	c	c	c	c	c	c	c											DGA, during repair

¹¹ Only performed when DGA is impossible (sampling impossible)

¹² Partial discharge detected by electromagnetic PD detector for bushing measured every 2 years

¹³ 2 years for 330-750 kv, and 4 years for 110kV-220kV

¹⁴ g : periodicity = half of Guarantee frequency of manufacturer

¹⁵ 6 years or 100 000 operations

¹⁶ 50 000 operations

¹⁷ every 12 years or 100 000 operations

Systematic Preventive Maintenance (SPM) for Transmission Transformer (1st part - page 1/2)

Maintenance tasks	"Task Interval" (y=year; m=month) or "Conditional "																				"Task Interval" or "Conditional " If "Conditional" on which conditions	Monitoring (m) which sensor
	Basic Task Interval										Intensive Task Interval (if different from basic)											
	A	B	C	D	E	F	G	H	I	J	A	B	C	D	E	F	G	H	I	J		
Inspections in service:																						
- Visit (month)	4	6	6	1	3	1	1	6	¼	D		2										
- Visual detailed inspection (month)	4	6	6	1	3	3	1	12	6	D		2							3 ¹⁸			
- Infrared thermograph (month)	24	24	36	?	12	12	-	24	12	24										12 ¹⁹		
- OLTC visual check (month)	4	6	6	?	12	3	1	6	¼	1		2										
- silica-gel breathers check (month)	4	6	6	?	3	1	1	6	3	D		2										
Oil tests (sampling in service)																						
- Oil analysis, (year)	2	2	1	2	1	1	-	2	1	1		m ₂₂	m ₂₃		m ₂₄	m ₂₅			m ₂₆			H2, water, multi-gas
- DGA- (year)	2	2	1	2	1	1	1	2	1	½												
- Furans(year)	2 ²⁰	2	-	-	-	1	-	-	-	12 ²¹												
- Additives	-	2	-	-	1	-	-	-	-	-												
Oil treatment (in or out of service)																						
- Oil filtering,	c	c	c	c	c	c	c	c	c	c												DGA, wet
- Regeneration,	c	c	c	c	c	c	c	c	c	c												DGA, acidity,
Cleaning actions (out of service)																						
- Fans cleaning, (year)	4	c	6	c	4	-	c	c	4	c		4										Visual Insp., refurbishment
- Radiators cleaning- (year)	4	c	-	c	4	c	c	c	4c	c												Visual Insp., refurbishment
Accessories verification (out of service)																						
- Gas relay functional test, (year)	4	c	6	6	4	6	4	-	4	6		4				4						Refurbishment works
- Monitoring sensors verification, (year)	4	c	-	6	4	-	4	6	4c	-												Suspect of malfunctioning

¹⁸ Plus on line monitoring of tap changer position, cooler control, temperature and electric parameters (partial for pre 2000 transformers, complete since 2000)

¹⁹ 12 months for 330-750 kV, 24 months for 220kV

²⁰ as required for DGA trending

²¹ after 12 years of operation, then conditional

²² strategic transformers (without criteria)

²³ strategic transformers (without criteria)

²⁴ New transformers 220kV, old T. with a known fault, strategic T, without spare

²⁵ moisture below 55kV breakdown, H2 or 8 gas DGA : new 330kV units and faulty transformers

²⁶ H2 and moisture

Maintenance tasks	"Task Interval" (y=year; m=month) or "Conditional"																				If "Conditional" Indicate conditions
	Basic Task Interval										Intensive Task Interval (if different from basic)										
	A	B	C	D	E	F	G	H	I	J	A	B	C	D	E	F	G	H	I	J	
Electrical tests : (out of service)																					
- Winding ratio (year)	4	c ²⁷	c ²⁸	c	c ²⁹	6	4	c	c	c											DGA or fault investigation or refurbishment work
- Winding resistance (year)	4	c"	c"	c	4c	6	4	c	7	c									4c		DGA or refurbishment work
- Exciting current (year)	-	c"	c"	c	c"	6	4	c	c	1											DGA or fault investigation or refurbishment work
- AC insulation tests (year)	4	c"	c"	c	4c	6	4	6	7	1									4c		DGA or fault investigation or refurbishment work
- DC insulation tests (year)	-	-	-	-	-	-	-	-	-	-											
Special tests ((out of service)																					
- Frequency response analysis (year)	c	c"	-	c	c"	6	c	c	7	c									4c		DGA, fault, transport damages
- Partial discharges measurements	c	c"	-	c	c"	-	-	c	c	c											DGA, fault investigations or after repair
- Ultrasonic measurements	c	c"	-	c	c"	-	-	c	-	-											DGA
Bushings : (out of service)																					
- DGA, (year)	-	-	-	-	-	-	4	-	-	1											
- Power Factor (year)	4	16	-	6	4	6	4	6	7	4					m ³⁰				4	2 ³¹	Power Factor if DGA or moisture high
OLTC : (out of service)																					
- Acoustic tests	-	-	-	-	-	-	-	-	-	-											Only to diagnose a problem
- Internal inspection (year)	4	12	6	6	4	6	c ³²	c ³³	4	c ³⁴	4 ³⁵	4			2						Years or operations nb, type of OLTC, or OLTC fault
- Oil analysis (year)																					
Work inside the tank																					
- Connection inspection :	c	c	c"	-	c	-	c	c	-	c											DGA, or mid life refurbishment, or after fault & FRA
- Winding tightening	c	c	c"	-	c	-	c	c	-	c											DGA, or mid life refurbishment, or after fault & FRA

Systematic Preventive Maintenance (SPM) for Transmission Transformer (1st part - page 2/2)

²⁷ If an internal fault is suspected or if an internal maintenance or OLTC maintenance operation is done

²⁸ after fault or for refurbishment work (" as above)

²⁹ performed if HV testing is required : pre-commissioning or after extensive internal work (" as above)

³⁰ new 330kV units

³¹ 2 years for 330kV-750kV, 4 years for 110-220kV

³² 2,4 or 6 y., 2000, 5000, 7000, 10000, 20000, 30000, 40000, 50000 or 90000 operations depending on the OLTC make and model

³³ 6years or 70000 operations

³⁴ 1 per year or after 5000 operations

³⁵ depends on type of OLTC, number of operations, normal loading, general past conditions

Systematic Preventive Maintenance (SPM) for Transmission Transformer (2nd part - page 1/2)

Maintenance tasks	"Task Interval" or "Conditional "																			Monitoring (m)			
	Task Interval Basic										Task Interval Intensive (if different from basic)									If "Conditional" on which conditions	which sensor		
	K	L	M	N	O	P	Q	R	S	T	K	L	M	N	O	P	Q	R	S	T			
Inspections in service: - Visit (month) - Visual detailed inspection (month) - Infrared thermograph (month) - OLTC visual check (month) - silicagel breathers check (month)	3	3	6	1	1	1	d	1	¼	3		1											
	12	3	6	12	1	1	¼	1	12	12		1 ³⁶											
	12	12	12	12	-	12	12	6	6	12		1"			12 ³⁷					m			
	3	3	1	12	1	1	¼	1	12	12													
	3	3	6	12	1	1	¼	1	12	6		1"											
												1"											
Oil tests (sampling in service) - Oil analysis, (year) - DGA- (year)	1	8	2	4	3	6	1	2	2	1		1	1 ³⁹		1	1	½	1					
	1	2	2	1	2	1	1	2	1	1	m ³⁸	1c	1"		m ⁴⁰	1 ⁴¹	1 ^{>42}	½	1c	m ⁴³	m ⁴⁴	Critical units,	H2 or multi-gas
Oil treatment (in or out of service) - Oil filtering, - Regeneration,	c	-	c	-	d ⁴⁵	d	d	c	c	-													
	c	c	-	c	-	-	-	c	c	c													
Cleaning actions (out of service) - Fans cleaning, (year) - Radiators cleaning- (year)	c	c	c	c	c	c	3	1	2	c									½				
	c	c	c	c	c	3	3	1	2	c									½				
Accessories verifications (out of service) - Gas relay functional test, (year) - Monitoring sensors verification, (year)	6	8	2	8	12	12	6	3	1	c													
	c	-	7	?	12	-	6	-	1	c					6 ⁴⁶								

³⁶ 1, 2 or 3 months depending on the importance of the station (" the same as above)
³⁷ for 275kV and above
³⁸ continuous DGA on worst transformers, H2 sensors on some with faults that need watching
³⁹ Sn > 600 MVA (" the same as above)
⁴⁰ H2 for 120kV and above
⁴¹ 1 year or 2 years, depending on the age of the transformer,
⁴² 6 month, 3 month or 1 month
⁴³ 40% of the transformers 400kV & 220kV with H2 and moisture monitoring
⁴⁴ H2 for 138kV & 240kV , multi-gas for 500kV or suspect units
⁴⁵ d: 1 day ?
⁴⁶ with OLTC

Systematic Preventive Maintenance (SPM) for Transmission Transformer (2nd part - page 2/2)

Maintenance tasks	"Task Interval" (y=year; m=month) or "Conditional "																				
	Task Interval Basic										Task Interval Intensive (if different from basic)										If "Conditional" Indicate conditions
	K	L	M	N	O	P	Q	R	S	T	K	L	M	N	O	P	Q	R	S	T	
Electrical tests : (out of service)																					
- Winding ratio (year)	c	8	7	-	c	c	c	5	2	c										3 ⁴⁸	DGA
- Winding resistance (year)	c	8	-	-	c	c	c	5	1	c				6 ⁴⁷						3"	DGA
- Exciting current (year)	c	8	-	-	c	-	c	5	1	c										3"	DGA
- AC insulation tests (year)	c	8	-	8	c	-	c	5	1	4				6"						3"	DGA
- DC insulation tests (year)	-	-	-	-	-	-	-	-	1												
Special tests ((out of service)																					
- Frequency response analysis	c	c	c	c	-	-	-	5c	c	c										3c	After commissioning, Fault,
- Partial discharges measurements	c	-	-	c	c	c	c	c	c	c											DGA
- Ultrasonic measurements	c	-	-	c	-	-	-	c	c	c											DGA
Bushings : (out of service)																					
- DGA, (year)	12	-	-	c	c	18	-	c	-	c											Bushing type, PD by e.m. detector, power factor
- Power Factor (year)	c	8	7	8	c	-	c	2	1	4		6		6 ⁴⁹						m ⁵⁰	
OLTC : (out of service)																					
- Acoustic tests	c	-	-	2	-	-	-	-	-	-											
- Internal inspection (year)	9 ⁵¹	8	12	6	12	c ⁵²	c ⁵³	5	7	4		4 ⁵⁴	4						3	m	LTC type, nb of operations (100 000) , DGA
- change of oil (year)									7											4	
Work inside the tank																					
- Connection inspection :	c	c	c	c	c	c	-	c	c	c										c	Fault, DGA, midlife overhaul
- Winding tightening	c	c	c	c	c	-	c	c	-	-											When inside (seldom)

⁴⁷ with OLTC

⁴⁸ if protection operation

⁴⁹ with OLTC

⁵⁰ online IDD for 138kV and above

⁵¹ 9 years inspection normally extended to 12 years for good service history and no problems

⁵² 100 000 operations

⁵³ 50 000 operations

⁵⁴ For OLTC Selective Intrusive mtce on a 6mo., 12mo., 4yr, 8yr, 12yr depending on the model type and usage

Appendix 2: SF6 Transformer Maintenance Particularities

1, GIT Construction

1-1 Basic Features The construction of a gas-insulated transformer (GIT) is basically the same as an oil-immersed transformer (OIT), with the exception of insulating material and cooling medium. Therefore, broad experience of OIT technology can be applied to GIT design, manufacturing and maintenance. Fig 1 shows an example of GIT structure, and Table 1 shows the basic feature comparison between OIT and GIT.

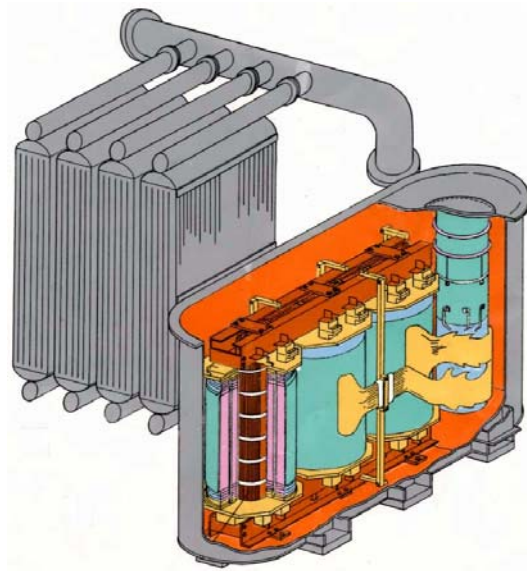
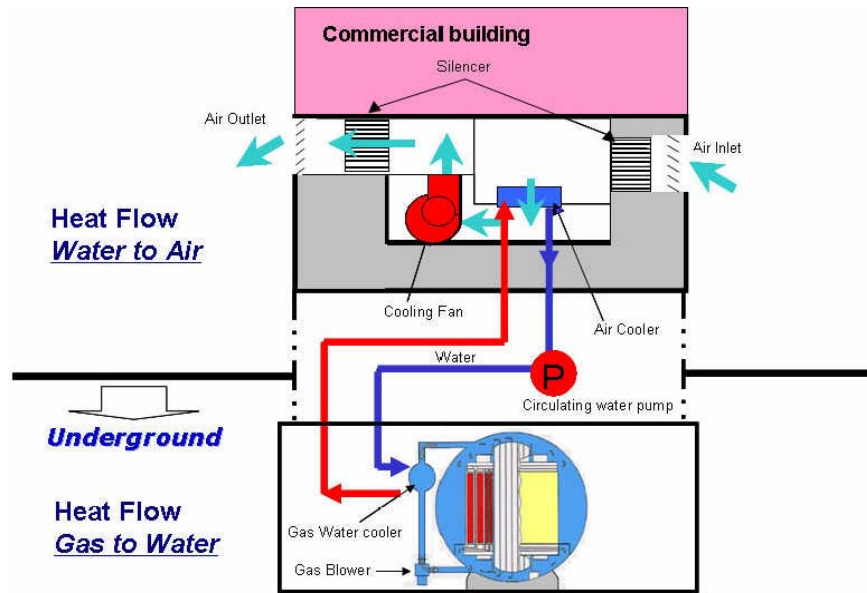
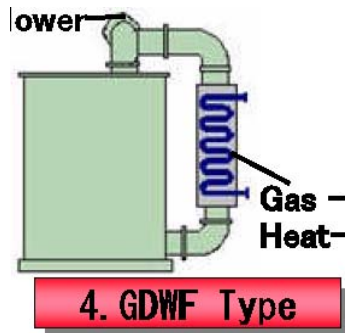
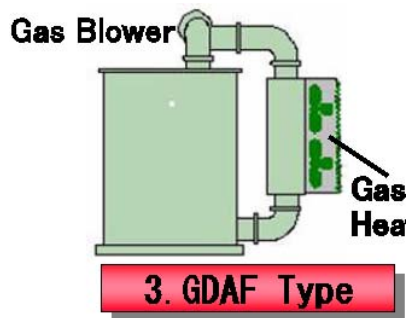
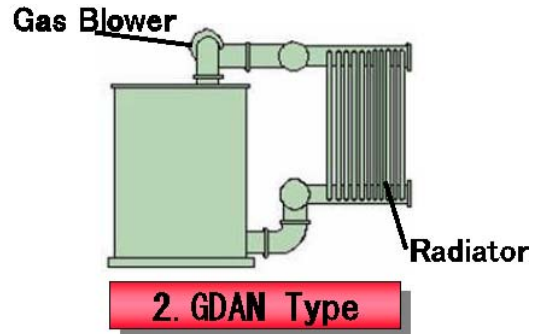
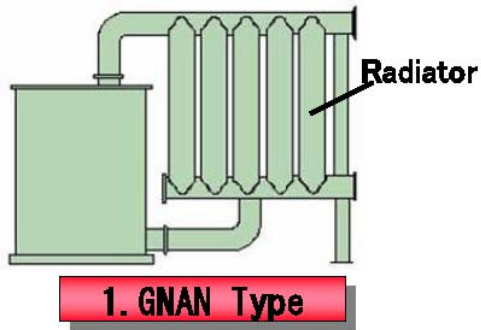


Fig 1. An example of GIT structure

	Oil Immersed Transformer (OIT)	Gas Insulated Transformer (GIT)
Insulation / Cooling	Insulation Oil	SF ₆ Pressure 0.14 or 0.43Mpa-g(20 √.)
Solid Insulation Material	Oil Impregnated Paper, Pressboard	PET film, PPS film, Aramide paper, Pressboard
Thermal Class	Class -A (Max 105 √.)	Class -E (Max 120 √.)
Conservator	Necessary	Unnecessary
On-Load Tap Changer	Divorter Switch	Arcing Switching in Oil
	Tap Selector	Slide Contact
		Vacuum Interrupter
		Roller Contact

Table 1. Comparison between OIT and GIT

1-2 Cooling design / Layout design for GIT The concept (1-5) of the external cooling design for a GIT is nearly the same as that for an OIT; for this reason various types of cooling method can be applied.



5. Water cooling system for urban substations

A water cooling system is widely used in large-capacity underground and/or indoor substations. The heat generated from a GIT is efficiently transferred to water-air heat exchangers by water flow. The cooling system is usually located on the top floor of the substation building.

1-3 Comparison between accessories for GIT and OIT Table 2. shows the comparison between accessories for GIT and OIT, which realizes that GIT is able to be properly protected in operating.

Item		GIT	OIT
Protective Device & Accessory	Temperature	Gas temperature indicator Winding temperature indicator	Oil temperature indicator Winding temperature indicator
	Leak	Gas density relay Compound gauge	Oil Level gauge
	Protection	Sudden gas pressure relay (OLTC)	Buchholtz relay, Gas detection relay Pressure relief device
	Others		Oil preservation system Dehydrating breather

Table 2. Comparison between GIT and OIT

2. Diagnosis & Maintenance

2-1 GIT Diagnostics The integrity of GIT can be checked and a failure cause analysis can be made using gas chromatography for the sampled gas. In addition, at site GIT integrity can be confirmed using a simple device of gas detective tube (gas checker set). Fig 2 shows Gas sampling using a gas sampling bag at site, and Fig 3. shows the gas checking set at site, same as that of GIS.

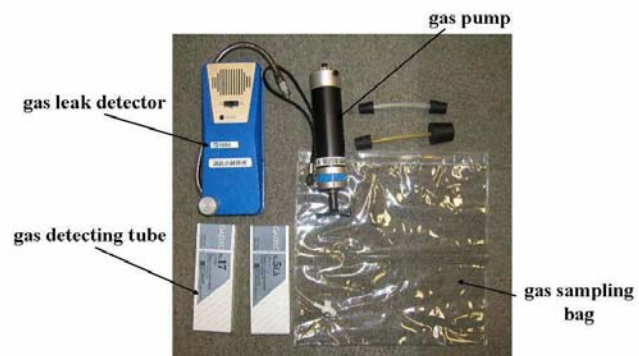
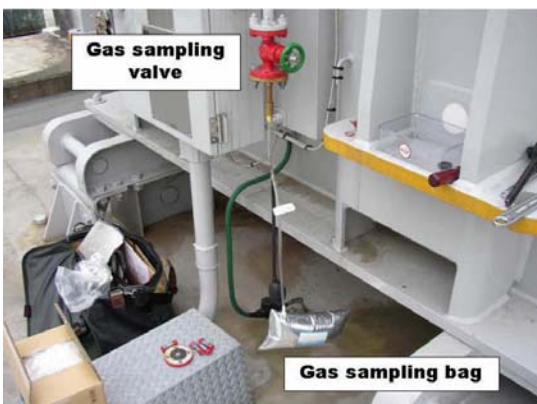


Fig 2. Gas sampling Fig 3. Decomposed Gas checker set

2-2 GIT Maintenance Table 3. shows one of examples for GIT maintenance program.

No.	Maintenance Item	Required maintenance period						
		Every 2 years	Every 3 years	Every 5 years	Every 10 years	Every 15 years	30 years	When failure occur
1	Gas analysis	✓						
2	Replenish the bearing grease of gas blower		✓					
3	Gas blower bearings				✓			
4	Exchange Gas blower					✓		
5	Indication and protection devices				✓			
6	Exchange Gas pressure sensor			✓				
7	Exchange Bushing						✓	
8	Exchange Control cable wiring						✓	
9	Inspection of OLTC			✓				
10	Exchange Cooler							✓
11	Exchange O-ring, Gasket							✓
12	Running repairs of small gas leakage							✓

Table 3. An example of GIT maintenance program

Appendix 3 - Operation and Maintenance Manual Content

The Operation and Maintenance Manual should include the following chapters:

- Transformer description
- Transportation and storage
- Erection and adjustments
- Commissioning
- Operation
- Maintenance and dismantling
- Spare parts
- Drawings
- Accessories
- Quality Control

The content of each chapter should include:

1. Transformer description

- Basic information: manual number, client name, substation where the transformer is installed, order number, manufacturer's name and the name and location of the factory, serial number, year of manufacture.
- Technical information: power and cooling mode, nominal voltages (primary, secondary, tertiary), frequency, number of phases, impedance, tap changer type and mechanism type, a copy of the nameplate

2. Transportation and storage

- All information necessary to transport and store the transformer
- Test and verification to do when the transformer and its accessory are delivered
- Maximum impacts that the transformer can support during transportation

3. Erection and adjustments

- All information necessary for the removal of blocking parts used for transportation
- All information presented in a logical order necessary to install accessories
- All information related to the resistance to vacuum of all compartment
- All the procedures for oil filling and oil treatment
- All information about the calibration of accessories (all setting values)

4. Commissioning

- All routine test results
- The list of the tests recommended before the energization of the transformer
- All precautions for the energization and first loading

5. Operation

- All information relative to the operation of the transformer in normal mode, overload or in case of a loss of a cooling stage

6. Maintenance and dismantling

- All information to access the bushing connections
- All information relative to all connections (windings, core, shield, etc.)
- All information to remove energy to all components
- The recommended procedure for inspection, calibration and test and proposed intervals
- The procedure to take an oil sample in bushings
- The list of the special tools requires, if any

7. Spare/replacement parts

- List of the recommended spare parts
- List of the parts for usury
- Recommendation for insurance parts

8. Photo and Drawings

- Photo of the core taken on the factory floor
- Photo of the windings taken from both sizes
- Drawing that shows access to different parts of the transformer
- Drawing of the electrical circuit of the windings, core, shield, etc.
- Description of all gaskets used in the transformer
- Brochures of all accessories

Appendix 4- Maintenance Recording

PROBLÈM	MAIN COMPONENT	SECONDARY COMPONENT
Low Oil Level	OLTC	Oil
Low Oil Level	Main tank	Oil
No heating	Control Cabinet	Heating Element
No heating	Control Cabinet	Wiring and Connections
No heating	Control Cabinet	Fuse
No heating	Control Cabinet	Thermostat
Breather failure	OLTC	Desiccant
Breather failure	OLTC	Desiccator
Breather failure	Main tank	Desiccant
Breather failure	Main tank	Desiccator
No Light	Control Cabinet	Bulb
No Light	Control Cabinet	Wiring and Connections
No Light	Control Cabinet	Fuse
No Light	Control Cabinet	Switch
Oil Leak	OLTC	Conservator
Oil Leak	OLTC	Desiccant
Oil Leak	OLTC	Pressure Relief Device
Oil Leak	OLTC	Gasket
Oil Leak	OLTC	Valve
Oil Leak	OLTC	Tubing
Oil Leak	Off Load Tap Changer	Gasket
Oil Leak	Off Load Tap Changer	Joint presse étoupe
Oil Leak	Main tank	Conservator
Oil Leak	Main tank	Desiccant
Oil Leak	Main tank	Pressure Relief Device
Oil Leak	Main tank	Garniture
Oil Leak	Main tank	Valve
Oil Leak	Main tank	Tubing
Oil Leak	Monitoring and indication	Oil Level Indicator
Oil Leak	Monitoring and indication	Gas Relay
Oil Leak	Monitoring and indication	Dissolved Gas detector
Oil Leak	Monitoring and indication	Winding Temperature Indicator
Oil Leak	Monitoring and indication	Winding Temperature Indicator
Oil Leak	Low Voltage Bushing	Gasket
Oil Leak	Low Voltage Bushing	Oil Level Indicator
Oil Leak	Low Voltage Bushing	Insulator
Oil Leak	Low Voltage Bushing	Capacitive Tap
Oil Leak	High Voltage Bushing	Gasket
Oil Leak	High Voltage Bushing	Oil Level Indicator
Oil Leak	High Voltage Bushing	Insulator
Oil Leak	High Voltage Bushing	Capacitive Tap
Oil Leak	Tertiary Voltage Bushing	Gasket
Oil Leak	Tertiary Voltage Bushing	Oil Level Indicator
Oil Leak	Tertiary Voltage Bushing	Insulator
Oil Leak	Tertiary Voltage Bushing	Capacitive Tap

PROBLEM	MAIN COMPONENT	SECONDARY COMPONENT
High Oil Level	OLTC	Oil
High Oil Level	Main Tank	Oil
High Resistance	OLTC	Diverter Switch Contact
High Resistance	OLTC	Reversing Switch Contact
High Resistance	OLTC	Selector Switch Contact
High Resistance	Off Load Tap Changer	Connection
High Resistance	Low Voltage Winding	Connection
High Resistance	High Voltage Winding	Connection
High Resistance	Tertiary Winding	Connection
High Resistance	High Voltage Bushing	Capacitive Tap
High Resistance	High Voltage Bushing	Connection
High Resistance	Low Voltage Bushing	Capacitive Tap
High Resistance	Low Voltage Bushing	Connection
High Resistance	Tertiary Voltage Bushing	Capacitive Tap
High Resistance	Tertiary Voltage Bushing	Connection
Damaged Insulator	High Voltage Bushing	Isolator
Damaged Insulator	Low Voltage Bushing	Isolator
Damaged Insulator	Tertiary Voltage Bushing	Isolator
Electrical Insulation	Tank	Oil
Electrical Insulation	High Voltage Winding	Isolation
Electrical Insulation	Low Voltage Winding	Isolation
Electrical Insulation	Tertiary Voltage Winding	Isolation
Electrical Insulation	High Voltage Bushing	Isolation
Electrical Insulation	High Voltage Bushing	Capacitive Tap
Electrical Insulation	Low Voltage Bushing	Isolation
Electrical Insulation	Low Voltage Bushing	Capacitive Tap
Electrical Insulation	Tertiary Voltage Bushing	Isolation
Electrical Insulation	Tertiary Voltage Bushing	Capacitive Tap
DC Ground	Electrical Control	Wiring and Connections
DC Ground	Monitoring and indication	Gas relay
DC Ground	Monitoring and indication	Winding Temperature Indicator
DC Ground	Monitoring and indication	Oil Temperature Indicator
Bad Cooling	Electrical Control	Main Relay
Bad Cooling	Electrical Control	Thermal Relay
Bad Cooling	Monitoring and indication	Winding Temperature Indicator
Bad Cooling	Cooling System	Pump
Bad Cooling	Cooling System	Radiator/Coolers
Bad Cooling	Cooling System	Tubing
Bad Cooling	Cooling System	Ventilator
Bad Indication	Monitoring and indication	Operation Counter
Bad Indication	Monitoring and indication	Oil Level Indicator
Bad Indication	Monitoring and indication	Gas Relay
Bad Indication	Monitoring and indication	Winding Temperature Indicator
Bad Indication	Monitoring and indication	Oil Temperature Indicator
Bad Indication	Bushing	Oil Level Indicator

PROBLEM	MAIN COMPONENT	SECONDARY COMPONENT
Bad Operation	OLTC	Cam
Bad Operation	OLTC	Diverter Switch
Bad Operation	OLTC	Inverter Switch
Bad Operation	OLTC	Selector Switch
Bad Operation	OLTC	Main Relay
Bad Operation	OLTC	Wiring and Connections
Bad Operation	OLTC	Break
Bad Operation	OLTC	Motor
Bad Operation	OLTC	Relay
Bad Operation	OLTC	Resistance
Bad Operation	Electrical Control	Wiring and Connections
Bad Operation	Electrical Control	Fuse
Bad Operation	Electrical Control	Relay
Bad Operation	Electrical Control	Voltage Relay
Bad Operation	Electrical Control	Parallelism Control

CAUSES

Deformed (mechanical)
 Unadjusted (mechanical)
 Destroyed (mechanical)
 Seized (mechanical)
 Worn (mechanical)
 Failed, Fissured(mechanical)
 Burned, Spotted (mechanical)
 Open Circuit (electrical)
 Short Circuit (electrical)
 Out of Tolerance (mechanical, electrical)
 Contaminated (chemical)
 Corroded (chemical)

REMEDIAL ACTION

Repair
 Replace

Appendix 5: Acronyms used in the brochure

AC:	Alternating Current
ACLD:	Alternating Current Long Duration
CBM:	Condition-Based Maintenance
CT:	Current Transformer
CTC:	Continuously Transposed Cable
DBP:	2,6-di-tert-butyl-phenol
DBPC:	2,6-di-tert-butyl-paracresol
DETC:	De-Energised Tap Changer
DF:	Dissipation Factor
DP	Degree of Polymerisation
DGA:	Dissolved Gas Analysis
ECT	Electrostatic Charging Tendency
EMC	Electrostatic Compatibility
FAT:	Factory Acceptance Test
FDS:	Frequency Domain Spectroscopy
FRA:	Frequency Response Analysis
FRSL:	Frequency Response Stray Losses
GIS:	Gas Insulated Switchgear
GIT	Gas Insulated Transformer
GSU:	Generator Step-Up (transformer)
H&S	Health and Safety
HPLC	High Performance Liquid Chromatography
HV:	High Voltage
HVDC:	High Voltage Direct Current
IED:	Intelligent Electronic Device
IFT:	Interfacial Tension
IP	Ingress Protection
LFH:	Low Frequency Heating
LTI:	Liquid Temperature Indicator
LV:	Low Voltage
MMS:	Maintenance Management System
MOA:	Metal Oxide Arrestor
OD:	Oil Directed
OEM:	Original Equipment Manufacturer
OFAF:	Oil Forced Air Forced
OIP:	Oil Impregnated Paper
OIT:	Oil Insulated Transformer
OLCM:	On-Line Condition Monitoring
OLTC:	On-Line Tap Changer
OTI	Oil Temperature Indicator
PCB:	Polychlorinated Biphenyl
PD:	Partial Discharge
PDC:	Polarization Depolarization Current (method)
PF:	Power Factor

PRD: Pressure Relief Device
RBP: Resin Bounded Paper
RCM: Reliability-Centred Maintenance
RIP: Resin Impregnated Paper
RPRR: Rapid Pressure Rise Relay
RTD: Resistance Temperature Detector
RVM: Recovery Voltage Method
SCADA: Supervisory Control and Data Acquisition
TBCM: Time-Based Condition Monitoring
TBM: Time-Based Maintenance
TV: Tertiary Voltage (winding)
UHF: Ultra High Frequency
WTI: Winding Temperature Indicator