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INTERNATIONAL STANDARD

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Mineral insulating oils in electrical equipment – Supervision and maintenance guidance

Huiles minérales isolantes dans les matériels électriques – Lignes directrices pour la maintenance et la surveillance

IEC 60422:2024-07(en-fr)

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INTERNATIONAL ELECTROTECHNICAL COMMISSION

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MINERAL INSULATING OILS IN ELECTRICAL EQUIPMENT – SUPERVISION AND MAINTENANCE GUIDANCE

FOREWORD

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IEC 60422 has been prepared by IEC technical committee 10: Fluids for electrotechnical applications. It is an International Standard.

This fifth edition cancels and replaces the fourth edition published in 2013. This edition constitutes a technical revision.

This edition includes the following significant technical changes with respect to the previous edition:

a) This new edition represents a major revision of the fourth edition, bringing this document in line with the latest developments in oil condition monitoring. New interpretation tables have been created, containing limits for oil parameters specific to plant type with suggested corrective actions in the tables and new test methods.
b) The action limits for all oil tests have been revised and changes made where necessary to enable users to use current methodology and comply with requirements and regulations affecting safety and environmental aspects.

c) Category O has been removed and is now incorporated within category A.

d) Online moisture interpretation is now incorporated.

e) More guidance on oil treatment (including reclamation criteria) is now available.

f) Guidance has been updated regarding corrosive sulphur.

g) In addition, this document incorporates changes introduced in associated standards since the fourth edition was published.

The text of this International Standard is based on the following documents:

Draft	Report on voting
10/1233/FDIS	10/1239/RVD

Full information on the voting for its approval can be found in the report on voting indicated in the above table.

The language used for the development of this International Standard is English.

This document was drafted in accordance with ISO/IEC Directives, Part 2, and developed in accordance with ISO/IEC Directives, Part 1 and ISO/IEC Directives, IEC Supplement, available at www.iec.ch/members_experts/refdocs. The main document types developed by IEC are described in greater detail at www.iec.ch/publications.

The committee has decided that the contents of this document will remain unchanged until the stability date indicated on the IEC website under webstore.iec.ch in the data related to the specific document. At this date, the document will be

- reconfirmed,
- withdrawn, or
- revised.

IMPORTANT – The "colour inside" logo on the cover page of this document indicates that it contains colours which are considered to be useful for the correct understanding of its contents. Users should therefore print this document using a colour printer.

INTRODUCTION

Insulating mineral oils are used in electrical equipment employed in the generation, transmission, distribution, and use of electrical energy.

Monitoring and maintaining oil quality is essential to ensure the reliable operation of oil-filled electrical equipment. Codes of practice for this purpose have been established by electrical power authorities, power companies and industries in many countries.

A review of current experience reveals a wide variation of procedures and guidance. It is possible, however, to compare the value and significance of standardized oil tests and to recommend uniform criteria for the evaluation of test data.

If a certain amount of oil deterioration (by degradation or contamination) is exceeded, there is inevitably some erosion of safety margins and the question of the risk of failure should be considered. While the quantification of the risk can be very difficult, a first step involves the identification of potential effects of increased deterioration. The philosophy underlying this document is to furnish users with as broad a base of understanding of oil quality deterioration as is available, so that they can make informed decisions on inspection and maintenance practices.

Mineral oils are valuable resources and should be utilised accordingly. Used mineral oils are, by most regulations, deemed to be controlled waste. If spills occur, this can have a negative environmental impact especially if the oil is contaminated by persistent organic pollutants such as polychlorinated biphenyls (PCBs).

This document, whilst technically sound, is mainly intended to serve as a common basis for the preparation of more specific and complete codes of practice by users in the light of local circumstances. Sound engineering judgement will have to be exerted in seeking the best compromise between technical requirements and economic factors.

Reference should also be made to instructions from the equipment manufacturer.

General caution

This document does not purport to address all the safety problems associated with its use. It is the responsibility of the user of this document to establish appropriate health and safety practices and determine the applicability of regulatory limitations prior to use.

The handling of mineral oils can be subject to local regulatory requirements and suppliers' safety datasheets.

Environment, health, and safety

This document is applicable to mineral oils, chemicals and used sample containers. The disposal of these items can be subject to local regulatory requirements regarding their impact on the environment.

Attention is drawn to the fact that, at the time of writing this document, some mineral oils in service are known to be contaminated to some degree with other liquids, for example, silicone oils and PCBs.

Because of this, safety countermeasures should be taken to avoid risks to workers, the public and the environment during the life of the equipment, by strictly controlling spills and emissions. The disposal or decontamination of these oils can be subject to local regulatory requirements. Every precaution should be taken to prevent release of mineral oil into the environment.

Typically, each country has specific regulations around health and safety. Safety Data Sheets (SDS) are normally used by the industry internationally and are usually written in accordance with an international regulation set (such as REACH [1][1]). Please consult the SDS from the suppliers of the insulating product that is used. These documents provide essential information regarding health, safety, and environmental impacts.

1 Numbers in square brackets refer to the Bibliography.

MINERAL INSULATING OILS IN ELECTRICAL EQUIPMENT – SUPERVISION AND MAINTENANCE GUIDANCE

1 Scope

This document provides monitoring guidance and procedures that are required for the use and maintenance of mineral insulating oils and other hydrocarbon-based liquids in transformers and other electrical equipment, including strategic spares and tanks for holding spare parts and components.

This document is applicable to mineral insulating oils, originally supplied conforming to IEC 60296, in transformers, switchgear and other electrical apparatus where oil sampling is reasonably practicable, and where the normal operating conditions specified in the equipment specifications apply.

This document is also intended to assist the power equipment operator to evaluate the condition of the oil and maintain it in a serviceable condition. It also provides a common basis for the preparation of more specific and complete local codes of practice.

The document includes recommendations on tests and evaluation procedures, and outlines methods for reconditioning and reclaiming oil, and the decontamination of oil contaminated with PCBs.

NOTE The condition monitoring of electrical equipment, for example by analysis of dissolved gases, furanic compounds or other means, is outside the scope of this document.

2 Normative references

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

IEC 60156, *Insulating liquids – Determination of the breakdown voltage at power frequency – Test method*

IEC 60247, *Insulating liquids – Measurement of relative permittivity, dielectric dissipation factor (tan δ) and d.c. resistivity*

IEC 60296:2020, *Fluids for electrotechnical applications – Mineral insulating oils for electrical equipment*

IEC 60475, *Method of sampling insulating liquids*

IEC 60666:2010, *Detection and determination of specified additives in mineral insulating oils*

IEC 60814, *Insulating liquids – Oil-impregnated paper and pressboard – Determination of water by automatic coulometric Karl Fischer titration*

IEC 60970, *Insulating liquids – Methods for counting and sizing particles*

IEC 61125:2018, *Insulating liquids – Test methods for oxidation stability – Test method for evaluating the oxidation stability of insulating liquids in the delivered state*

IEC 61619, *Insulating liquids – Contamination by polychlorinated biphenyls (PCBs) – Method of determination by capillary column gas chromatography*

IEC 62021-1, *Insulating liquids – Determination of acidity – Part 1: Automatic potentiometric titration*

IEC 62021-2, *Insulating liquids – Determination of acidity – Part 2: Colourimetric titration*

IEC 62535:2008, *Insulating liquids – Test method for detection of potentially corrosive sulphur in used and unused insulating oil*

IEC 62697-1, *Test methods for quantitative determination of corrosive sulfur compounds in unused and used insulating liquids – Part 1: Test method for quantitative determination of dibenzyldisulfide (DBDS)*

IEC 62961, *Insulating liquids – Test methods for the determination of interfacial tension of insulating liquids – Determination with the ring method*

ISO 2049, *Petroleum products – Determination of colour (ASTM scale)*

ISO 2719, *Determination of flash point – Pensky-Martens closed cup method*

ISO 3016, *Petroleum and related products from natural or synthetic sources – Determination of pour point*

ISO 3104, *Petroleum products – Transparent and opaque liquids – Determination of kinematic viscosity and calculation of dynamic viscosity*

ISO 3675, *Crude petroleum and liquid petroleum products – Laboratory determination of density – Hydrometer method*

ISO 6247, *Petroleum products – Determination of foaming characteristics of lubricating oils*

ISO 9120, *Petroleum and related products – Determination of air-release properties of steam turbine and other oils – Impinger method*

ISO 12185, *Crude petroleum and petroleum products – Determination of density – Oscillating U-tube method*

ASTM D971, *Standard Test Method for Interfacial Tension of Insulating Liquids Against Water by the Ring Method*

ASTM D7042, *Standard Test Method for Dynamic Viscosity and Density of Liquids by Stabinger Viscometer (and the Calculation of Kinematic Viscosity)*

DIN 51353, *Testing of insulating oils – Detection of corrosive sulphur – Silver strip test*

3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

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

- IEC Electropedia: available at https://www.electropedia.org/
- ISO Online browsing platform: available at https://www.iso.org/obp

NOTE ASTM and IEEE terminologies are available on:

- ASTM D2864: Standard Terminology Relating to Electrical Insulating Liquids and Gases [2]
- IEEE C57.12.80: Standard Terminology for Power and Distribution Transformers [3]

3.1
local regulations
regulations pertinent to the particular process in the country concerned

Note 1 to entry: Such regulations can include local, regional or national legislation or internal regulations set by the owner or operator of the equipment. Such regulations can refer to operational, environmental or health and safety issues. A detailed risk assessment, including consideration of such regulations, will usually be required.

3.2
routine tests (Group 1)
minimum tests required to monitor the oil and to ensure that it is suitable for continued service

Note 1 to entry: If the results obtained from these tests do not exceed recommended action limits, usually no further tests are considered necessary until the next regular period for inspection but, under certain perceived conditions, complementary tests can be deemed prudent.

3.3
complementary tests (Group 2)
additional tests, which can be used to obtain further specific information about the quality of the oil, and can be used to assist in the evaluation of the oil for continued use in service

3.4
special investigative tests (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

3.5
reconditioning
process that eliminates or reduces gases, water, solid particles, and contaminants by physical processing only

3.6
reclamation
process that eliminates or reduces soluble and insoluble polar contaminants from the oil by chemical and physical processing

3.7
PCBs decontamination
process that eliminates or reduces PCBs contamination from mineral oil

4 Properties and deterioration or degradation of oil

The reliable performance of mineral insulating oil in an insulation system depends upon certain basic oil characteristics that can affect the overall performance of the electrical equipment.

Certain properties of oil are necessary to accomplish its multiple roles of dielectric insulation, cooling, arc-quenching and lubrication. Oil needs to possess certain properties, in particular:

- high dielectric strength to withstand the electric stresses imposed in service;
- sufficiently low viscosity so that its ability to circulate and transfer heat is not impaired;
- adequate viscosity range and lubricity to ensure fault-free operation and endurance of mechanical equipment, such as tap-changers, over the whole temperature range;
- adequate low-temperature properties down to the lowest temperature expected at the installation site;
- resistance to oxidation and pyrolytic degradation (by switching arcs) to maximize service life;
- non-corrosive or detrimental to electrical plant construction materials that it is in contact with.

In service, mineral oil degrades due to the conditions of use. In many applications, insulating oil is in contact with air and is therefore subject to oxidation. Elevated temperatures accelerate degradation. The presence of metals, organo-metallic compounds, or both, can act as a catalyst for oxidation. Changes in colour, the formation of acidic compounds and, at an advanced stage of oxidation, precipitation of sludge can occur. Dielectric and, in extreme cases, thermal properties can be impaired.

In addition to oxidation products, many other undesirable contaminants, such as water, solid particles and oil-soluble polar compounds can accumulate in the oil during service, and affect its electrical properties. The presence of such contaminants and any oil degradation products are indicated by a change in one or more properties as described in Table 2.

Deterioration of other constructional materials, which can interfere with the proper functioning of the electrical equipment and shorten its working life, can also be indicated by changes in oil properties.

The decision on when to carry out an intervention is normally the responsibility of the asset owner and is usually part of a wider asset management strategy. When making intervention decisions, consideration should not only be given to the condition of the oil but also to the age and general condition of the plant item and its operational environment and duty. Carrying out an expensive intervention on an asset that is reaching end of life is not cost effective, alternatively not carrying out an intervention on a relatively new plant item even when certain intervention limits have not yet been reached can contribute to accelerated ageing and reduction in the projected asset life.

5 Categories of equipment

To take into account different user requirements, equipment has been placed in various categories, as shown in Table 1.

Table 1 – Categories of equipment

Category	Transformers and reactors
Category A	Power transformers and reactors with an U_m above 170 kV. Power transformers of any rated voltage where continuity of supply is vital and similar equipment for special applications operating under onerous condition.
Category B	Power transformers and reactors with an U_m above 72,5 kV and up to and including 170 kV (other than those in Category A).
Category C	Power transformers and reactors for MV/LV application, e.g. U_m up to and including 72,5 kV (distribution transformers) and traction transformers (other than those in Category A).
	Instrument and protection transformers
Category D	Instrument and protection transformers with an U_m above 170 kV.
Category E	Instrument and protection transformers with an U_m up to and including 170 kV.
	Tap-changers
Category F	Diverter tanks of on-load tap-changers, including combined selector and diverter tanks.
	Circuit breakers and switchgear
Category G	Oil-filled circuit breakers, oil-filled switches, AC metal-enclosed switchgear and control gear with an U_m exceeding 72,5 kV.
Category H	Oil-filled circuit breakers, oil-filled switches, AC metal-enclosed switchgear and control gear with an U_m up to and including 72,5 kV.
	Oil filled and OIP bushings
Category K	Bushings with an U_m above 170 kV.
Category L	Bushings with an U_m up to and including 170 kV.
NOTE 1 Separated selector tanks of on-load tap-changers belong to the same category as the associated transformer. NOTE 2 Regardless of size or voltage, a risk assessment can justify condition-monitoring techniques usually appropriate to a higher classification. NOTE 3 For practical and economic reasons, some electrical utilities can decide that their small transformers up to 1 MVA and 36 kV are not included in this classification. Routine monitoring programmes can be considered uneconomical for this type of equipment. Where a monitoring programme is required for these transformers, the guidelines given for Category C should be adequate. NOTE 4 U_m is the highest voltage for equipment. This was referred to as "nominal system voltage" in previous editions.	

6 Sampling of oil from equipment

Sampling in accordance with IEC 60475, shall be performed by an experienced person with adequate training, using approved sample containers or devices. Whenever possible, sampling from equipment shall be at normal operating conditions or very shortly after de-energisation. Whenever possible, Oil Directed or Oil Forced Air Forced (ODAF or OFAF) transformers should have their samples taken with pumps running.

Where available, manufacturer's instructions should be followed, and designated sample valves or points used.

It is essential that every effort is made to ensure that samples are representative of the oil in the equipment. Careless sampling procedures or contamination of the sample container will lead to erroneous conclusions concerning quality and incur wasted time, effort and expense involved in obtaining, transporting, and testing the sample.

During sampling, the temperature of the oil shall be recorded, see IEC 60475 for further guidance.

7 In-service oil diagnostic tests

7.1 General

A selection of tests can be applied to mineral oils in electrical equipment. The tests listed in Table 2 are considered sufficient to determine whether the condition of the in-service mineral oil is adequate for continued operation and to suggest the type of corrective action to be taken, if required.

The tests are not listed in order of priority within a grouping. When more than one test method is reported, the reference method is the first one listed. In case of dispute, this method shall be used.

Table 2 – Tests for in-service mineral insulating oils

Property	Group [a]	Subclause	Method
Colour	1	7.2	ISO 2049 or ASTM D1500
Appearance	1	7.3	Visual test
Breakdown voltage	1	7.4	IEC 60156
Water content	1	7.5	IEC 60814
Acidity (neutralization value)	1	7.6	IEC 62021-2 or IEC 62021-1
Dielectric dissipation factor (DDF) and resistivity	1	7.7	IEC 60247
Inhibitor content	1	7.8	IEC 60666
Sediment	2	7.9	Annex E of this document
Interfacial tension (IFT) [b, c]	2	7.11	IEC 62961 or ASTM D971
Particles (counting and sizing) [b]	2	7.12	IEC 60970
Sludge	3	7.10	Annex E of this document
Flash point	3	7.13	ISO 2719
Compatibility	3	7.14	See 7.14
Pour point	3	7.15	ISO 3016
Density at 20 °C	3	7.16	ISO 12185 or ISO 3675 or ASTM D7042
Viscosity	3	7.17	ISO 3104 or ASTM D7042
Polychlorinated biphenyls (PCBs)	3	7.18	IEC 61619
Corrosive sulphur [b]	3	7.19.2	DIN 51353
Potentially corrosive sulphur [b]	3	7.19.3	IEC 62535
Dibenzyl disulphide (DBDS) content	3	7.19.4	IEC 62697-1
Passivator content	3	7.20	Annex B of IEC 60666:2010

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

[b] Only under special circumstances, see applicable subclause.

[c] IFT can be considered as a Group 1 test (for inhibited oil only).

7.2 Colour

The colour of oil is determined in transmitted light and is expressed by a numerical value based on comparison with a series of colour standards. It is a general property, which can show significant degradation of oil. A rapid increase in colour of the in-service oil, relative to the original colour is an indication of degradation or contamination.

Colour shall be measured in accordance with ISO 2049. An alternative method is ASTM D1500 [4].

7.3 Appearance

A visual inspection of oil (oil sample in transmitted light under a thickness of approximately 10 cm and at ambient temperature) if showing cloudiness or sediment, can indicate the presence of free water, insoluble sludge, carbon particles, fibres, dust, or other contaminants.

7.4 Breakdown voltage (BDV)

Breakdown voltage is a measure of the ability of oil to withstand electric stress and has primary importance for the safe operation of electrical equipment. It is strongly dependent on the sampling temperature (7.5.1 to 7.5.5).

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, can reduce breakdown voltage dramatically. The effect of breakdown voltage reduction starts to accelerate with relative moisture saturation[2] (%RS) of over 20 %, which applies to different insulation fluid types [5]. 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.

Relative saturation, measured in an oil sample in the laboratory can be correlated to the measured value of breakdown voltage in the laboratory; while relative saturation measured by on-line monitoring reflects the condition of the combined insulation, acknowledging changes of water content in the oil induced by changes of transformer working temperatures and is a suitable parameter to correlate to breakdown voltage (dielectric strength of oil) under the operating conditions (see also informative Annex B).

The values of breakdown voltage are only significant when the oil has been sampled at the operating temperature of the transformer. Samples taken at < 20 °C (oil temperature) can give an optimistic view of the oil condition when analysed at room temperature, because almost all the water normally dissolved at temperatures above 20 °C has already migrated into the paper. On the other hand, samples taken at oil temperature near to the highest permissible top oil and analysed at room temperature can give too pessimistic a view on the dielectric strength of the oil than under the normal transformer operating condition, because relative moisture saturation (%RS) is temperature dependent. The breakdown voltage of spare units that have been out of service for a prolonged time should be monitored more frequently until the transformer has reached a steady state.

Breakdown voltage shall be measured in accordance with IEC 60156.

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2 %RS is the ratio of actual water content to maximum water content an insulating liquid can dissolve at a given temperature.

7.5 Water content

7.5.1 Water content in the oil and paper system

Transformers are dried during the manufacturing process until measurements or standard practices yield a moisture content in the cellulosic insulation of less than 0,5 % to 1,0 % depending upon purchaser's and manufacturer's requirements. After the initial drying, the moisture content of the insulation system can increase depending on either the environmental or operating conditions, or both. It is important that the transformer has adequate initial dryness and is kept in a dry state until put into service, since a high initial water content will increase the rate of degradation of the cellulosic insulation.

In a transformer, the total mass of water is distributed between the paper and the oil such that the bulk of water is in the paper.

Oil is a hydrophobic material with a very small capacity for water absorption (milligrams of water per kilogram of oil, mg/kg or parts per million, ppm). Conversely, cellulose material is hygroscopic with a huge water absorption capacity (parts per hundred, percent). Effectively this means that > 99 % of the water in such a system will be absorbed in the cellulose material. The exact distribution between these two materials is temperature dependent, but even at the highest operating temperatures, > 99 % of the water is in the cellulose material. Temperature fluctuation in a transformer drives the dynamic moisture exchange between oil and paper. The water distribution within the solid insulation is dependent on temperature gradients and the ageing condition of paper and other cellulose materials. Other polymer-based materials can also contain moisture in the bulk or on the surface. This shall be considered during oil handling, commissioning, and maintenance of the equipment.

When a transformer is working at a constant load, relatively elevated and stable temperature for a long period of time, thermodynamic equilibrium between water absorbed by the solid insulating materials and water dissolved in oil can be achieved.

All calculations and correlations of the water content in oil, and the water content in the oil and paper system, assume there is an equilibrium state between the insulating oil and the oil and paper system and vice versa. The equilibrium state is influenced by many factors, such as the difference in temperature between the oil and the cellulose and oil system, temperature gradient within the windings, composition of oil and paper and ageing status of paper and oil, insulation thickness etc.

The calculation of the water content in paper and pressboard by determination of the water in the oil has been examined in several studies and publications [5]. Nevertheless, practical results are often not in line with the theoretical predictions. In addition, please note that the drying process of the paper might not have removed as much water as calculated.

7.5.2 Influence of water on the solid and liquid dielectric system

Water influences:

- the breakdown voltage of the oil;
- the dielectric strength of the solid insulation;
- the ageing tendency of the liquid and solid insulation.

The water content in the liquid and solid insulation thus has a significant impact on the actual operating conditions and the lifetime of the transformer.

There are two main sources of water increase in transformer insulation:

- ingress of moisture from the atmosphere or through oil leakages;
- degradation of cellulose and oil.

Water is transferred in oil-filled electrical equipment by the insulating liquid. Water is present in oil in a dissolved form and can also be present as a hydrate adsorbed by polar ageing products (bonded water). Particles, such as cellulose fibres, sludge and soot in tap-changers can bind some water.

Age is not necessarily an indicator of high water content in solid insulation. Transformers up to 30 years old have been recorded to have water content in the solid insulation close to the "as new" factory condition.

7.5.3 Water in oil

The solubility of water in oil, given in mg/kg, depends on the condition of the oil, the temperature and type of oil. In an insulating liquid sample, the absolute water content (W_{abs}) is independent of the temperature, type and condition of the oil and the result given in mg/kg. W_{abs} shall be measured according to IEC 60814. The relative water content, called relative moisture saturation (RS) is defined by the ratio W_{abs}/S (where S is the moisture saturation in the insulating liquid) and the result is given in percent. The relative saturation can be evaluated by use of a suitable method such as those described in [5]. Since moisture saturation (S) is temperature dependent, the relative saturation is therefore also temperature dependent.

Relative saturation can be measured directly by techniques using capacitive sensors.

Usually, the temperature is determined directly in the oil stream of the sample taken. In cases where top oil indicator readings or corrections for Oil Natural Air Natural (ONAN) or Oil Forced Air Forced (OFAF) cooling mode are used, this should be recorded.

The water content in oil is directly proportional to the relative moisture saturation (%RS) up to the saturation level (Formula (1)).

$$W_{abs} = \frac{RS}{100} \times S \tag{1}$$

The temperature dependence of the moisture saturation in insulating liquid (S) is expressed by Formula (2):

$$S = e^{A_e - B_e/T} \tag{2}$$

Formula (2) has an Arrhenius form as the moisture saturation in insulating liquid (S) is temperature dependent. The natural logarithmic form can also be expressed in its decimal logarithm form for convenience as shown in Formula (3).

$$S = 10^{A_{10} - B_{10}/T} \tag{3}$$

where W_{abs} is the absolute water content in liquid (mg/kg), RS is the relative saturation (%), S is the moisture saturation level (mg/kg), T is the temperature in Kelvin, whereas A_e, B_e, A_{10} and B_{10} are moisture saturation coefficients in natural or decimal logarithm forms that depend on liquid characteristics, composition, and condition. As both natural logarithm and decimal logarithm forms of coefficients are used in the literature, Formulae (4) and (5) can be used to convert the moisture saturation coefficient values.

$$A_e = A_{10}\ln(10); B_e = B_{10}\ln(10) \quad (4)$$

$$A_{10} = A_e\log(e); B_{10} = B_e\log(e) \quad (5)$$

A and B together define the level of water content at a given temperature.

NOTE Online moisture sensors have the function of calculated conversion from relative saturation to absolute water content in ppm. Those ppm values obtained are likely to differ from the values determined from a sample with Karl-Fischer titration in a laboratory. This is because online monitoring is done at a different temperature or temperatures and most likely at a different sampling point in the transformer. Also, water solubility coefficients used for the calculations are usually generic, not defined for the specific oil sample.

As oils become very oxidized with increasing amounts of polar ageing by-products, their water solubility characteristics, which are also dependent on the type of the oil, also increase. The solubility of water in very aged oils can be much higher than that in unused oils (Figure 1). Each oil should be considered separately.

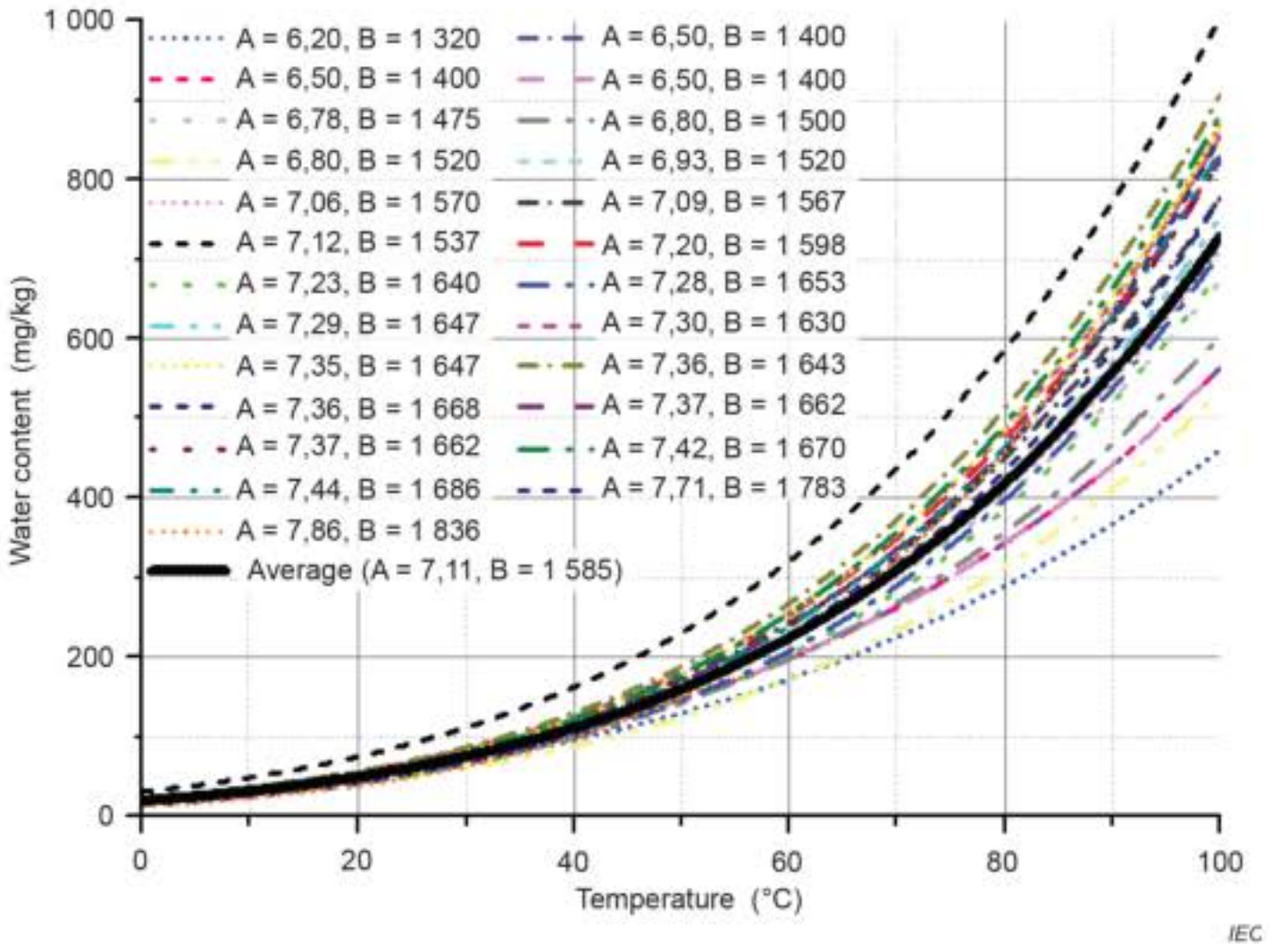

Figure 1 – Water solubility curves for unused mineral oil as adapted from literature [5] (according to Formula (3))

7.5.4 Water in the solid insulation

The estimation of moisture in the solid insulation is not a part of this document.

The so-called indirect methods for estimating moisture in the solid insulation are based on the water content measurement in the insulating liquid. Using the water content in liquid, temperature of insulation and by means of water sorption isotherms or moisture equilibrium curves, the water content in the solid insulation can be estimated.

The application of the moisture equilibrium curves, and water sorption isotherms requires consideration of the following:

- type and chemical structure of solid and liquid insulation;
- ageing condition of liquid insulation (e.g. high acidity);
- ageing condition of solid insulation;
- moisture equilibrium state (very rare, if at all possible);
- distribution of moisture in the solid insulation;
- temperature of insulation.

There are different moisture models, based on indirect methods. Some of them utilize normalized to 20 °C water content of the insulating liquid. The solubility coefficients A and B of the different liquids are different and the water exchange between solid and liquid insulation is a temperature triggered dynamic process. In a real transformer, there is not one single insulation water content – different parts of the solid insulation will hold different amounts of water, depending on the different temperatures, types and conditions of the solid materials involved.

7.5.5 Interpretation of results

Breakdown voltage and moisture are strongly interrelated. Both are temperature dependent, therefore it is most informative to measure them at different transformer temperatures to obtain a reliable assessment of moisture in the combined oil-paper insulation system. The interpretation of water content in oil is strongly related to the sampling temperature determined by measuring the temperature directly in the oil stream at the point of sampling. Where top oil temperature indicator (OTI) temperature corrections for oil natural (e.g. ONAN) or oil directed (e.g. ODAF) cooling mode are used, this should be explicitly noted.

The values for water content defining the condition Good, Fair and Poor in Table 5 to Table 9 of this document are based on 90 % statistical information from transformers in service. In cases of highly loaded transformers with oil temperature near to the highest permissible top oil temperature, the quick moisture exchange can lead to higher values of water in oil. Such cases shall be assessed carefully, investigating the possibility of reaching oil saturation, especially at steep temperature gradients. It shall always be kept in mind that:

– There is quite high uncertainty linked to measurement of water content from an oil sample (e.g. sampling technique, weather, oil condition).
– A single, high water content value should not be a reason for an immediate action. Repeated sampling is strongly recommended prior to considering corrective measures.
– Moisture levels in oil are highly dependent on the operating temperature of the transformer.
– Any short-term oil treatment or oil change will not solve a moisture problem in the transformer.
– For interpretation, the value shall come with recorded temperatures.
– High moisture in the oil is an indicator that there is too much moisture in the solid insulation.
– An online measurement of moisture on an in-service transformer will give a more accurate indication of the moisture situation than a single oil sample.

The use of on-line hysteresis curves of relative saturation at actual transformer operating temperature can be a useful tool for risk estimation [5]. See also informative Annex B.

Figure 2 shows online sensor data examples of hysteresis loops of %RS vs. temperature in transformers with 3 different water content levels.

1) Moist transformers: > 20 %RS

   Relative moisture saturation vs oil temperature hysteresis curve values exceed 20 %RS at operating transformer temperature all the time. The oils of these transformers have continuously significantly reduced dielectric strength due to high moisture.

   They also have a very broad hysteresis loop at 20 °C indicating there is potentially considerable water on paper surface for dynamic exchange of water between paper and oil. Such transformers can be at risk of dielectric breakdown due to moisture immediately after high loading where the oil cools rapidly or during cold start of the transformer, when water is pushed from the paper into the cold oil which results in a significant increase in %RS.

2) Transformers fit for service, but with elevated moisture in comparison to a new transformer. 10 % to 20 %RS

   Transformers, that have 10 % to 20 %RS moisture in oil can be at risk of reduced dielectric strength of oil due to moisture. This can occur during cold start or rapid cooling followed by higher than normal loading, because there is significant amount of water in the paper. In such conditions, the %RS increases significantly thus reducing the dielectric strength of oil.

3) Dry transformers: < 10 %RS

   Relative moisture saturation vs oil temperature hysteresis curve values are below 10 %RS and have a flat hysteresis loop. Such transformers are not at risk of reduced dielectric strength of oil due to moisture. There is very little water available on the paper surface for dynamic exchange of water between paper and oil.

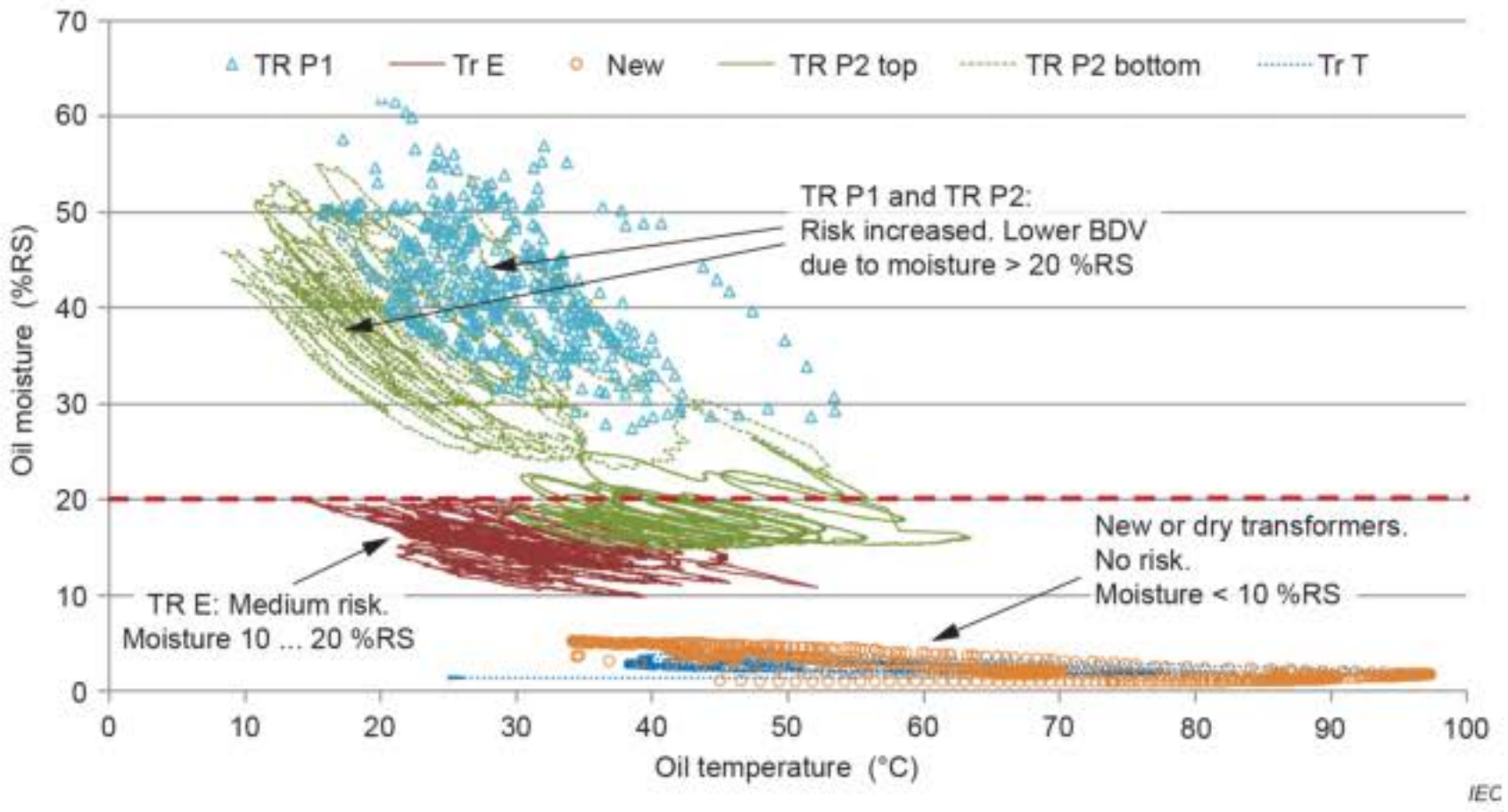

Figure 2 – Hysteresis loops of %RS vs. oil temperature in transformers with 3 different water content levels [5]

For general guideline on %RS for continuous online monitoring, refer to Table B.1.

7.6 Acidity

The acidity (neutralization value) of oil is a measure of the acidic constituents or contaminants in the oil.

Unused oil should be free from any acidic compound.

The acidity of used oil is due to the formation of acidic oxidation products. Acids and other oxidation products will, in conjunction with water and solid contaminants, affect the dielectric and other properties of the oil. Acids have an impact on the degradation of cellulosic materials and can also be responsible for the corrosion of metal parts in a transformer or similar equipment.

The rate of increase of acidity of oil in service is a good indicator of progressive ageing. The acidity level is used as a general guide for determining when the oil should be replaced or reclaimed.

Inhibited oils according to IEC 60296 will develop significantly lower amounts of acidic by-products in comparison to uninhibited oils, provided enough inhibitor is present.

Acidity shall be measured in accordance with IEC 62021-2 or 62021-1.

7.7 Dielectric dissipation factor (DDF) and resistivity

These parameters are very sensitive to the presence of soluble polar contaminants, ageing products, or colloids in 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.

Acceptable limits for these parameters depend largely upon the type of equipment. However, high values of DDF, or low values of resistivity, can either deleteriously affect the dielectric losses or the insulation resistance of the electrical equipment, or both.

There is generally a relationship between DDF and resistivity, with resistivity decreasing as DDF increases, as presented in Figure 3.

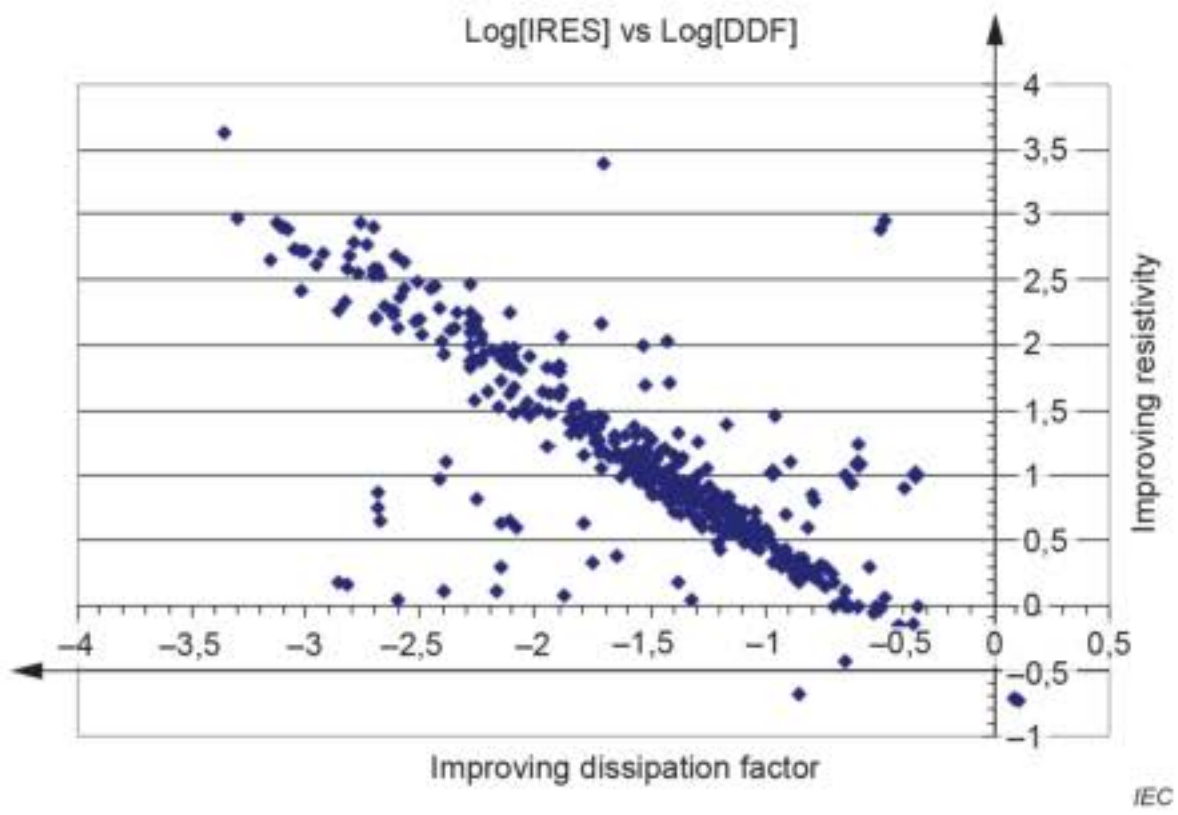

Figure 3 – Correlation between resistivity and dissipation factor [6]

It is normally not necessary to conduct both tests on the same oil and generally DDF is found to be the more common test.

In the case of very high voltage (VHV) and ultra-high voltage (UHV) instrument transformers and oil filled bushings, special attention shall be paid to DDF as it has been reported that a higher value of DDF can lead to thermal runaway leading to failure.

DDF shall be measured in accordance with IEC 60247. IEC 61620 can be used to check the results obtained with IEC 60247.

7.8 Inhibitor content

7.8.1 Oxidation stability

The ability of unused mineral insulating oil to withstand oxidation under thermal stress and in the presence of oxygen and a copper catalyst is called oxidation stability. It gives general information about the life expectancy of the oil under service conditions in electrical equipment. The property is defined as resistance to formation of acidic compounds, sludge and compounds influencing the dielectric dissipation factor (DDF) under given conditions. For unused oils complying with IEC 60296, these conditions are detailed in IEC 61125 and the limits of acceptable performance in IEC 60296.

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. These are known as natural antioxidants. Oils containing only natural antioxidants are designated as uninhibited oils.

Synthetic oxidation inhibitors can be added to enhance the oxidation stability. In mineral oils, mainly the phenolic type is used, and the common and generally accepted compounds are 2,6-di-tert-butyl-paracresol (DBPC) and 2,6-di-tert-butyl-phenol (DBP). The efficacy of added inhibitors will vary with the chemical composition of the base oil [7].

7.8.2 Monitoring of uninhibited and inhibited oils

Oxidation of uninhibited oils is normally monitored by the formation of acidic compounds and oil soluble and insoluble sludge. An increase in DDF and reduction in IFT are also signs of oxidation of insulating oils (see 7.6, 7.7 and 7.11).

Inhibited oils have a different oxidation pattern compared to 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.

The inhibitor content should be monitored at regular intervals; the frequency of which will depend upon operational temperature and load levels.

A decrease of IFT in inhibited (and uninhibited) oils can also be an early indication of initial formation of oxidation products.

Inhibitor concentration is measured according to IEC 60666.

7.9 Sediment

Sediment is insoluble material present in the oil.

Sediment includes:

- insoluble oxidation or degradation products of solid or liquid insulating materials;
- solid products arising from the conditions of service of the equipment; carbon and metal particles, metallic oxides and sulphides;
- fibres and other foreign matter of diverse origins.

The presence of sediment can change the electrical properties of the oil, and in addition, deposits can hinder heat-exchange, thus encouraging thermal degradation of the insulating materials.

Sediment should be measured according to the method E.1 described in Annex E.

7.10 Sludge

Sludge is a polymerized degradation product 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 sludge contents above this, the sludge is precipitated, contributing as an additional component to the sediment.

The presence of sludge can change the electrical properties of the oil, and in addition, deposits can hinder heat-exchange, thus encouraging thermal degradation of the insulating materials.

Sludge should be measured according to the method E.2 described in Annex E.

7.11 Interfacial tension (IFT)

The interfacial tension (IFT) between oil and water provides a means of detecting soluble polar contaminants and products of degradation. This characteristic can change rapidly during the initial stages of ageing but levels off when deterioration is still moderate.

The rate of decrease of IFT is strongly influenced by the type of oil; uninhibited oils usually show higher IFT rates of decrease than inhibited oils especially in free breathing transformers.

A rapid decrease of IFT can also be an indication of compatibility problems between the oil and some transformer materials (varnishes, gaskets), or of accidental contamination when filling with oil. However, oils with IFT values at or near the lower limit value given in Table 5 to Table 9 should be further investigated or reclaimed.

With overloaded transformers, the deterioration of materials is rapid and IFT is a tool for detection of deterioration.

The measurement of IFT of oil is strongly influenced by the relaxation time of the oil-water interface (dynamic interfacial tension). The reliability of the results can be improved when the duration of measurement is increased.

IFT shall be measured in accordance with IEC 62961 (reference method) and ASTM D971.

NOTE A drop in IFT is typical following the first fill of a transformer, see Table 3 for guidance.

7.12 Particles

The presence of particles in oil is known to impact breakdown voltage and DDF, especially in association with high moisture conditions.

Particles in the insulating oil of electrical equipment can have numerous possible sources. The equipment itself can contain particles from manufacturing and the oil can contain particles from storage and handling if not properly filtered before use. Mechanical wear and the ageing of oil and solid materials can produce particles during the service life of the equipment. Localized overheating above 500 °C can form carbon particles. Carbon particles are also produced by the normal switching operation of on-load tap-changers inside the tap-changer oil compartment. Where there are leaks, some particles can migrate into the transformer oil. Typical sources of metallic particles are the mechanical wear of tap-changer contacts, wear of pump bearings, and the wear of similar components.

Particle counting methods have been advised as a monitoring tool in [8] [9]. The impact of particles up to 14 µm (c) on the dielectric strength of the insulating system can typically be reliably detected by the commonly used BDV and DDF tests. Particles larger than 14 µm (c) can originate from the identified particle sources above and can be difficult to detect, due to their low number of occurrences. However, they shall be regarded as a possible risk for HV flashovers as bare metal electrode arrangements with small oil gaps are prone to be bridged by these particles. In some instances, this risk cannot be avoided by design, e.g. tap-changer contacts and additional advice and guidance on particles should be sought from the equipment manufacturer.

In most cases, knowledge on the type of particles (i.e. iron, aluminium, silver sulphide, fibres, carbon, etc.) will help to identify the particle source. Such analysis can provide more information on the wear status or possible mechanical defects than particle counting itself. When used in combination with an identification of the type of particles, Method B of IEC 60970 is applicable. If, for any reason, there is a requirement to code the level of contamination by solid particles in accordance with ISO 4406 [10], Method A of IEC 60970 shall be applied.

7.13 Flash point

The flash point of mineral oil usually does not vary with time and deterioration of the liquid however, a lowering flash point can indicate contamination. If the flash point is depressed, then this should be investigated to determine the cause and any required remedial action. In some critical applications or as determined by a risk assessment, the flash point should be measured to assure a satisfactory level of fire safety when required.

Flash point shall be measured in accordance with ISO 2719.

7.14 Compatibility

7.14.1 General

Compatibility can be defined as the ability of materials to be used together without deleterious changes in any of the materials.

Materials incompatibility can jeopardize the global efficiency of equipment with adverse consequences on materials performance, whether solids or liquids.

When required, end users should contact laboratories with experience in completing compatibility testing for details on testing and acceptable results. See Annex D for guidance.

7.14.2 Compatibility between different insulating mineral oils (miscibility)

When two or more different mineral oils for use in electrical equipment are mixed, a compatibility or miscibility issue can arise. The following recommendations provided some mitigation against the risk of poor compatibility.

Field experience indicates that problems are not normally encountered when unused oil is added in small percentages, i.e. < 10 %, to used oils classified as "Good" or "Fair" (see Table 5 to Table 9). In these cases, a compatibility test is usually not required.

NOTE 1 Where inhibited oil is used to top up an uninhibited oil, trace inhibitor can be detected in future oil samples.

Mineral insulating oils in the delivery state, complying with IEC 60296 and with the same classification (class, group, type, inhibition level and Lowest Cold Start Energizing Temperature (LCSET) as stated in IEC 60296) as that already in service should either be used for topping up or refilling electrical equipment, or both.

NOTE 2 For oils produced before 2021 (according to IEC 60296), new oil of Type B (according to IEC 60296) are suitable for mixing, provided they belong to the same inhibition level and LCSET.

In cases where a larger percentage is added, i.e. 10 % or more, or in cases where unused oil is added to heavily aged oil, a compatibility test can be necessary to determine the feasibility of mixing unused oils of different origins with oil in service.

For mixing used oils, a compatibility study is strongly recommended. Reference to the oil supplier is recommended in all cases but particularly where there are any doubts concerning compatibility.

In the compatibility study, as described below, the characteristics of the mixture should not be less favourable than those of the worse individual oil.

Oils should be mixed in the same proportions as in the application, or if not known in a 50/50 ratio.

The following functional tests are recommended for each individual oil and for the mixture:

- Foaming tendency according to ISO 6247
- Sediments and sludge
- DDF (tan delta) at 90 °C
- IFT

The following additional tests can also be carried out as investigatory tests if deemed required.

- Either corrosive sulphur (shall be according to DIN 51353) or potential corrosivity (shall be according to IEC 62535), or both.
- Oxidation stability shall be according to IEC 61125. Test duration shall be according to the oil class and type as stated in IEC 60296.

NOTE 3 Oxidation stability of in-service insulating liquid is not routinely measured nor are the test methods applicable (IEC 61125). To compare individual oils and the resulting mixture, it can be appropriate to measure oxidation stability to IEC 61125:2018, Annex B (induction period). Used oils typically do not have an oxidation stability comparable to unused oils.

Experience is very limited regarding the use of oil containing pour point depressants to top-up naturally low pour point oils. However, laboratory investigations suggest that no significant deterioration of low temperature behaviour is likely to occur.

Compatibility tests are particularly necessary in the case of oils containing additives. Again, reference to the oil supplier or to the equipment manufacturer is recommended.

7.15 Pour point

Pour point is a measure of the ability of the oil to flow properly at low temperature. There is no evidence to suggest that this property is affected by normal oil deterioration.

Pour point shall be measured in accordance with ISO 3016.

NOTE Slight changes in pour point can usually be interpreted as the result of topping-up with a different liquid or oil, though it can be the result of other sources of contamination.

7.16 Density

In cold climates, the density of the oil shall be low enough to prevent any ice resulting from the freezing of free water to float and possibly lead to fault conditions developing such as flashover of conductors. However, density is not significant in comparing the quality of different oils. Additionally, there is no evidence that density is affected by normal oil use or deterioration.

Density can be useful for discriminating mineral insulating oil from other liquid types or mineral oils of different chemical composition.

Density shall be measured in accordance with ISO 12185 (reference method); ISO 3675 and ASTM D7042 are acceptable.

NOTE 1 Changes in density can be interpreted as the result of topping-up with a different liquid or oil.

NOTE 2 Density is a consideration when designing protection flow and control equipment, for example devices which rely on buoyancy principles such as a Buchholz relay, this is to be taken into consideration in event of an oil change where the density of the new oil can be different.

7.17 Viscosity

Viscosity is a significant factor in heat transfer and can also influence the switching behaviour of on-load tap-changers (OLTCs) and similar equipment. If normal operation and maintenance practices are adhered to, then limited oxidation of the oil will not significantly affect its viscosity.

Viscosity shall be measured in accordance with ISO 3104 (preferred method) or ASTM D7042.

7.18 Polychlorinated biphenyls (PCBs)

Polychlorinated biphenyls (PCBs) are a family of synthetic chlorinated aromatic hydrocarbons, which have good thermal and electrical properties. These properties combined with excellent chemical stability made them useful in numerous commercial applications. However, their chemical stability and resistance to biodegradation has given cause for concern in terms of environmental pollution. This increasing concern over 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 PCBs content of oil in new equipment should be measured to confirm that the oil is PCBs free, i.e. below the detection limit. Thereafter, whenever there is a risk of potential contamination (oil treatment, transformer repairs, etc.) the oil should be analysed and if PCBs content is found to exceed defined limits, appropriate action should be taken (see 14.5).

PCBs shall be measured in accordance with IEC 61619 (identical to EN 12766-2 test method A:2001 [11]).

Testing for disposal can be subject to local regulations.

NOTE Limits can be subject to local regulations.

7.19 Corrosive sulphur in mineral insulating oil

7.19.1 General

Sulphur is always present in mineral insulating oils and some sulphur compounds can be corrosive to metal surfaces. When exceeding a minimum concentration level, sulphur compounds can form deposits which can cause failures in electrical equipment. It is required to differentiate between corrosive and potentially corrosive sulphur compounds:

- Corrosive sulphur compounds: elemental sulphur and mercaptans.
- Potentially corrosive compounds: disulphides, including DBDS, sulphides (rarely).

Table 2 recommends two methods for the assessment of corrosive sulphur in oil. Both methods can be used as complementary, and it should be considered that:

- IEC 62535 gives information on the oil’s corrosivity against copper and the oil’s tendency to deposit copper sulphide on paper. It will show positive results with corrosive sulphur but has been found to be especially reliable to detect potentially corrosive sulphur.
- DIN 51353 is suitable for silver corrosion assessment only. It has been found to be extremely sensitive and selective to detect corrosive sulphur substances such as highly reactive mercaptans and elemental sulphur, but it is insensitive to DBDS.

Both tests shall give a negative result to report an oil as "non-corrosive".

IEC 60296 provides specifications to ensure that deposition of copper and silver sulphides will not occur in service with unused and recycled oils, and so specifies the above-mentioned test procedures. Please note that these tests apply to oils that do not contain a metal passivator additive. When following the IEC 60666 test procedure, it shall be verified that the oil does not contain a metal passivator additive, before testing for corrosive sulphur. IEC 60296:2020, Clause B.3, provides a method for the removal of passivators where they are present.

7.19.2 Corrosive sulphur

The amount of sulphur in mineral oil depends on the quality of the crude oil, which determines the process and degree of refining. Sulphur in crude oil is usually present as organo-sulphur, but elemental sulphur contamination can also occur. The presence of reactive compounds causing corrosion at the normal operating temperatures of a mineral insulating oil is due to poor refining, contamination or, in the case of reclaiming, inappropriate materials or procedure.

At relatively high temperatures, sulphur-containing oil molecules can decompose and react with uncoated metal surfaces to form metal sulphides. Such reactions can take place in switching equipment and can increase the contact resistance. Another effect more frequently observed as occurring from corroded silver surfaces than from copper, is that sulphide deposits can flake off and cause flashovers in the equipment. Some sulphur containing molecules can also cause the formation of copper sulphide (Cu_2S) deposition in the paper insulation of electrical equipment. This phenomenon leads to a reduction of the electrical insulation properties and has resulted in several equipment failures in service [12].

7.19.3 Potentially corrosive sulphur

Where potentially corrosive sulphur compounds are present in oil, Cu_2S deposition occurs typically on paper insulated electrical conductors inside the paper layers, or on unvarnished or unprotected copper surfaces, when liquid temperatures are high.

Strongly aged insulating oils (e.g. oils showing high acidity), or oils with poor oxidation stability, can give ambiguous results on the paper wrapped copper strip under the conditions of IEC 62535, because of the formation of sludge. SEM-EDX analysis (as described in IEC 62535:2008, Annex B) is helpful to solve such ambiguous cases.

A combination of several factors, not only the potential oil corrosivity, can lead to a failure in electrical equipment. In this case, a risk assessment including design and operating conditions should be performed.

7.19.4 Dibenzyl disulphide (DBDS)

In the period between 1989 and 2006, DBDS had been widely added to mineral insulating oils as an antioxidant. Nevertheless, the oils passed the corrosivity tests of their time. In later years, DBDS was found to be potentially corrosive to copper surfaces at normal transformer operating temperatures, as it can form copper sulphide under certain conditions [12]. Additionally, DBDS can react with silver-coated contacts in switching equipment such as tap-changers, creating silver sulphide and causing an increase in contact resistance [13].

DBDS shall be measured in accordance with IEC 62697-1.

7.20 Metal passivator

The addition of a metal passivator is the mitigation technique that has been used to the greatest extent to minimize the risk of corrosive sulphur.

Three main types of benzotriazole derivatives are typically used as metal passivator additives:

N-bis(2-ethylhexyl)-aminomethyl-tolutriazole (TTAA), benzotriazole (BTA) and

5-methyl-1H-benzotriazole (TTA).

If a toluyltriazole derivative has been used[3], typically, 100 mg/kg (0,01 % by weight) of this substance is added to inhibit the reactions of copper with corrosive sulphur.

Metal passivators have a long history of use in mineral oil, mainly in lubricating oil but also, to a more limited extent, in insulating oil. They have been used not only to counteract corrosion, but also to improve oxidation stability and to suppress streaming electrification.

The passivator content shall be monitored during service.

Passivator content shall be measured in accordance with IEC 60666:2010, Annex B.

NOTE For additional guidance, see CIGRÉ Technical Brochure 625 [13].

7.21 Air release and foaming

Air release (shall be according to ISO 9120) and foaming tendency (shall be according to ISO 6247) are properties of the oil which can both be influenced by contaminants, such as silicone, phthalates or other surface-active chemicals or oils – see Annex F.

8 Evaluation of mineral insulating oil in new equipment

A substantial proportion of electrical equipment is supplied to the final user already filled with mineral oil. In such cases, as the oil has been in contact with insulating and other materials, it can no longer be considered as "mineral oil in the delivered state" as defined in IEC 60296. Therefore, its properties shall be regarded as those applicable to oil in service, even though the electrical equipment itself might not have been energized.

Oil properties should be appropriate to the category and functions of the equipment (see Table 3).

The extent of the changes in properties can vary with the type of equipment due to the different types of material and ratios of liquid-to-solid insulation; they should also be within the limits of Table 3. Properties not included in Table 3 (except for oxidation stability for which no in-service limits have been established) should be within the limits of IEC 60296.

As the characteristics of oil in new equipment are an integral part of that equipment design, the user can request these characteristics to be better than the minimum standards suggested in Table 3, which are based on the experience of many years of operating practice.

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3 Examples of commercially available TTAA and TAA are Irgamet® 39 and Irgamet® 30, respectively. This information is given for the convenience of users of this document and does not constitute an endorsement by the IEC of these products.

Table 3 – Recommended limits for mineral insulating oils after filling in new electrical equipment prior to first energization at site

Property	Highest voltage for equipment kV		
	< 72,5	**72,5 to 170**	**> 170**
Appearance	Clear, free from sediment and suspended matter		
Colour (on scale given in ISO 2049)	Max. 2,0	Max. 2,0	Max. 2,0
Breakdown voltage (kV)	Min. 55	Min. 60	Min. 60
Water content (mg/kg)	Max. 20 [a]	Max. 10	Max. 10
Acidity (mg KOH/g)	Max. 0,03	Max. 0,03	Max. 0,03
Dielectric dissipation factor at 90 °C and 40 Hz to 60 Hz [b]	Max. 0,015	Max. 0,015	Max. 0,010
Potentially corrosive sulphur and corrosive sulphur	Non-corrosive		
DBDS content (mg/kg)	Not detectable (< 5 mg/kg total)		
Interfacial tension (mN/m)	Min. 35	Min. 35	Min. 35
Total PCBs content (mg/kg)	Not detectable (< 2 mg/kg total)		
Particles	See 7.12 [c]		

[a] For use in transformers under 72,5 kV class; the maximum water content should be agreed between supplier and user depending upon local circumstances.

[b] Higher dielectric dissipation factor values can indicate excessive contamination, or the misapplication of solid materials used in manufacture, and should be investigated.

[c] A determination of particle size and quantity can be agreed between either the end user and the manufacturer, or service provider, or both. This information can be useful in situations where assets are critical.

Values in Table 3 are applicable to transformers factory filled or filled at site, samples can be taken shortly after filling (the appropriate time interval to sample should be agreed between the manufacturer and the end user).

9 Evaluation of oil in service

9.1 General

Insulating oil in service is subjected to heat, oxygen, water, and various catalysts; all of which are detrimental to the properties of the oil. To be able to maintain the condition of oil in service, it is necessary to perform regular sampling and analysis.

The interpretation of results, in terms of the functional deterioration of the oil, should be performed by experienced personnel based on the following elements of risk management and life cycle management:

- 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 PCBs, environmental impact is a critical factor to consider, as are local regulations. If it is suspected that oil has become contaminated with PCBs, specific analyses should be undertaken and interpretation of the results should be used in a risk assessment in advance of any works to avoid unreasonable risks for staff and the public or damage to the environment. Direct observation of the sight glass (if available), or oil level indicator can be used to monitor leakage and spills of oil.

9.2 Frequency of examination of oils in service

It is impossible to prescribe the frequency of examination of oils in service which will be applicable to all possible situations. Asset owners should set their frequencies based on a thorough risk assessment considering their own unique requirements and service conditions as well as the equipment manufacturer's maintenance guidance.

The optimum frequency will depend on the type, function, voltage, power, construction, and service conditions of the equipment, as well as the condition of the oil as determined in the previous analysis. A compromise will often have to be found between economic factors and reliability requirements.

Much greater difficulties exist in deciding frequency of testing and permissible oil deterioration levels which are acceptable for all applications of insulating oil in relation to differences in operating policies, reliability requirements and types of electrical system. For example, large power companies can find the full application of these recommendations to distribution transformers uneconomical. Conversely, the industrial user, whose activities depend on the reliability of his power supply, can institute more frequent and stricter controls of oil quality as a means of guarding against power failures.

By way of a guide, a suggested frequency of tests suitable for different types of equipment is given in Table 4. However, some equipment is designed having systems that are designed to control or prevent exposure of the oil to atmosphere. Where such systems are maintained in good condition, less frequent testing can be appropriate based on either life cycle analysis (LCA) or life cycle management (LCM) and risk assessment (RA), or both.

As some parameters such as water content and breakdown voltage can be subject to a rapid rate of change, they should be subject to an increased testing frequency and additional guidance on the required frequency should be sought from the relevant expert who can provide the required engineering judgement.

End users with liquid filled electrical equipment operating under special environmental or operating stresses such as solar, offshore, or highest voltage for equipment of ≥ 400 kV (Category O transformers in previous edition) should carry out an evaluation as per the guidance above and set sample frequency periods and limit values in accordance with their internal risk assessment and maintenance policy; this can result in more frequent testing or onerous limits than the guidance provided in Table 4 and Table 5 to Table 9.

Generally, check measurements should be carried out based on the following criteria:

a) Characteristics can be checked periodically, at intervals as suggested in Table 4, unless otherwise defined.

b) The frequency of examination can be increased where any of the significant properties indicates that the oil is in "Fair" or "Poor" condition, or when trend analysis indicates significant changes.

c) The oxidation of the oil will accelerate with increased temperature and in the presence of oxygen and water. Therefore, more frequent oil-sampling and complementary testing such as interfacial tension can be necessary for heavily loaded transformers.

d) The testing frequency should be established by means of a cost and benefit evaluation based on life cycle analysis and risk assessment. For some owners, this approach can indicate different testing frequencies from those suggested in Table 4.

Table 4 – Recommended frequency of testing [a]

Property [b]	Equipment category [c i]									
	A	B	C [d]	D [e]	E [e]	F	G	H	K [e]	L [e]
Group 1 (routine tests) [f] – years	1-2	1-4	1-12	1-2	2-6	2-6	2-6	2-12	3-12	3-12
Group 2 (complementary tests)	[g]									
Group 3 (special investigative tests)	[h]									
Group 3 (passivator content)	6 months or less, depending on the rate of decrease and the absolute value.									

[a] These proposed periods refer to a normal routine maintenance programme and for the tests detailed in this document. Should one or more of the measured properties indicate that the oil is in a "Fair" or "Poor" condition or if an abnormal ageing trend is observed, these periods should be shortened according to the importance of the equipment. These periods can also be shortened in the case of oils contaminated with PCBs to minimize any potential environmental impact caused by malfunctioning equipment.

[b] Groups 1, 2 and 3 are defined in Clause 3 and as a footnote to Table 2.

[c] Equipment categories are defined in Table 1.

[d] See 9.2 d).

[e] Categories D, E, K and L. After the first sample has been taken, the user, after consultation with either the manufacturer or laboratory, or both, can decide to lengthen the sampling period.

[f] Group 1 tests shall be performed after filling or refilling the transformer, prior to energizing.

[g] These tests can be done periodically but less frequently than routine tests. The frequency will depend upon the type of oil, age, and equipment. First (benchmark) measurements should be carried out in new or refurbished equipment prior to energization.

[h] These are very special tests that are carried out only under special circumstances.

[i] For traction transformers, sampling can be distance based rather than time based.

9.3 Testing procedures

9.3.1 General

The venue for testing and the number and type of tests that can be carried out on a given sample of oil can vary depending on local circumstances and economic considerations.

Oil in service varies widely in the extent of degradation and the degree of contamination. In general, a single type of test is insufficient to evaluate the condition of the oil sample.

Evaluation of the condition should preferably be based upon the composite evaluation of significant characteristics determined in suitably qualified and properly equipped laboratories. However, some users find it advantageous to carry out field screening tests.

9.3.2 Field tests

In some circumstances it is necessary to perform tests closer to the point of sampling rather in the laboratory. These are typically chosen to meet the following requirements:

- obtain a prompt estimation of oil condition;
- establish the classification of service-aged oils (see 9.4);
- eliminate any changes to the oil sample's properties due to transportation to either a laboratory or storage of oil samples, or both.

Field tests are typically done using mini mobile labs or robust transportable test equipment. Field tests can also be performed where there are on-site and on-line test instruments with an accuracy comparable to laboratory test instruments.

Field tests using mobile test equipment can provide results that are less accurate than laboratory tests due to a less controlled environment. Field tests are usually limited to visual inspection (colour and appearance), breakdown voltage, water content and acidity. These tests can sometimes be used for the assessment of service-aged oils in accordance with 9.4, though, more often, field tests are carried out to identify oil samples requiring laboratory evaluation.

9.3.3 Laboratory tests

A complete examination scheme includes all the tests listed in Table 2. However, these tests can be sub-divided into three groups and tests applicable to one or more groups can be required according to the specific requirements (see Table 2 and Table 4).

9.4 Classification of the condition of oils in service

9.4.1 General

It is virtually impossible to set rigid rules for the evaluation of oil in service or recommend test limits for all possible applications of insulating oil in service. The classification and any consequent corrective action should only be taken after due consideration of the results of all tests, the age and type of equipment. The trend of such results over a period of time is considered essential information when arriving at a final decision.

According to local or current industrial experience, oils in service can be classified as "Good", "Fair" or "Poor" based on the evaluation of significant properties and their ability to be restored to the characteristics desired. Table 5 to Table 9 provide asset specific guidance to assist in this classification process.

- Good

  Oil in normal condition; continue normal sampling.

- Fair

  Oil deterioration detectable; more frequent sampling recommended (see Table 5 to Table 9).

- Poor

  Oil deterioration abnormal; schedule effective actions.

For all asset types, always refer to the manufacturer’s Operations and Maintenance (O&M) manual for model specific information and guidance. Where the manufacturer has provided limit values, then they shall take precedence.

9.4.2 Transformers

See Table 5 for guidance.

9.4.3 Tap-changers

See Table 6 and Table 5 for guidance. Table 6 provides guidance for parameters specific to vacuum and non-vacuum on-load tap-changers (OLTCs). For vacuum type OLTCs and de-energized tap-changers (DETCs), further guidance on relevant parameters not detailed in Table 6 can be found in Table 5. Values might be different for different types of OLTCs, the manufacturers limits (where available) will prevail.

For vacuum type OLTCs, no regular time or condition-based oil replacement is generally required, and oil ageing should be similar to the oil in the transformer main tank. Therefore, monitoring of acidity, inhibitor content and passivator content is appropriate, as for transformers.

All OLTCs will present a certain amount of sediment in their oil compartment, due to normal abrasive wear. Non-vacuum models can show significant amounts of sediment and sludge, due to contact erosion and oil deterioration which are produced during their normal service life, therefore limit values for colour, appearance, dielectric dissipation factor, resistivity, sediment and sludge cannot be provided.

Vacuum type OLTCs should maintain a high level of oil quality during their whole service life, only particles from mechanical wear should be present. Non-vacuum type OLTCs can present high amounts of particles due to normal contact and mechanical wear; additionally, normal arc breaking activity can produce high levels of carbon within the oil.

9.4.4 Instrument and protection transformers

See Table 7 and Table 5 for guidance. Table 7 provides guidance for parameters specific to instrument and protection transformers. For guidance on parameters not detailed in Table 7, refer to appropriate category in Table 5.

Normally the amount of oil in instrument transformers is limited, therefore it is not usual to carry out routine sampling. Where sampling is carried out, the effect on the oil level and pressure should be taken into consideration.

9.4.5 Circuit breakers and switchgear

See Table 8 and Table 5 for guidance. Table 8 provides guidance for parameters specific to circuit breakers and switchgear. For other parameters not detailed in Table 8, refer to Table 5 Category C for guidance.

Based on knowledge and experience with their specific plant, asset owners operating large fleets can decide to apply different limit values to those detailed in Table 8 and Table 5, or they can opt to routinely change the oil in the equipment as they have determined that it is more economical than managing an oil testing regime, especially at distribution voltages.

9.4.6 Oil filled and OIP bushings

See Table 9 and Table 5 for guidance. Table 9 provides guidance for parameters specific to oil filled and oil impregnated bushings (OIP). For guidance on parameters not detailed in Table 9, refer to the appropriate category in Table 5.

Oil sampling is typically performed if other bushing diagnostic methods indicate a problem or have provided an inconclusive result.

Normally the amount of oil in bushings is limited, therefore it is not usual to carry out routine sampling. Users should refer to an approved sampling method before undertaking any sampling works. Where sampling is carried out, the effect on the oil level and pressure should be taken into consideration. Due to the low volumes of oil in bushings, topping up can be required following the taking of samples. Oil sampling from bushings without an oil level gauge is not recommended.

Where oil samples are taken for analysis, tests are typically limited to DGA and water content only.

Bushings flooded with the same oil as in the main tank of the transformer are not covered in Table 9, refer to the appropriate category in Table 5 for guidance.

9.5 Corrective action

In general, two types of contamination and deterioration of the oil can be considered: physical and chemical. Each one requires a different remedial action as described in Table 5 to Table 9 below. Summary of the remedial actions are detailed in Table 10.

Detailed guidance for plant types is found in the relevant table. Where indicated, additional guidance for all plant types can be found in Table 5. Refer to 9.4.2 to 9.4.6 for guidance on what tables and tests are applicable as well as additional guidance on testing considerations for each of the plant types.

The following recommendations should also be noted:

a) Where a test result is outside the limits recommended in Table 5 to Table 9, it should be compared with previous results and, if appropriate, a fresh sample obtained for confirmation before any other action is taken.

b) If rapid deterioration or acceleration in the rate of deterioration is observed, more frequent tests (see Table 4) should be instituted promptly and appropriate remedial action should be taken. It can be desirable to consult the manufacturer of the equipment.

10 Interpretation of results

Table 5 – Transformers and reactors – Application and interpretation of tests

Property	Category [a]	Conditions, limits and recommended actions [b, c]				Notes
			Condition: Good	Condition: Fair	Condition: Poor	
Colour	A, B, C	Limits >>	< 2	2 to 6	> 6	Typically, no action should be taken based on colour. Change, specifically rapid change in colour can indicate ageing and should be investigated utilising other tests. Some oils can be dark in colour but be in good condition therefore colour should not be used as an indicator of health.
		Actions >>	No action required, continue normal sampling.	As dictated by other tests.	As dictated by other tests.	
Appearance	A, B, C	Limits >>	Clear, free from sediment and suspended matter.		Either dull or turbid or both.	Dull appearance can be a symptom of chemical contamination. Turbidity is a symptom of high water content or indication of material incompatibility or severe contamination from non-soluble materials.
		Actions >>	No action required, continue normal sampling.		As dictated by other tests.	
Breakdown voltage (kV)	A	Limits >>	> 60	50 to 60	< 50	High sampling temperatures (> 50 °C) can lead to poor results when evaluated at ambient temperature in the laboratory. In these cases, repeat samples should be taken at lower temperatures. Alternatively, users can refer to Annex C for guidance on normalization of water content and how it can influence breakdown voltage.
	B	Limits >>	> 50	40 to 50	< 40	
	C	Limits >>	> 40	30 to 40	< 30	
		Actions >>	No action required, continue normal sampling.	More frequent sampling. Check other parameters, e.g. water, particle content.	Check the source of water or particulate contamination, resample. If high water content is confirmed, consider drying the solid insulation or filtering for removal and identification of particles.	

Property	Category [a]	Conditions, limits and recommended actions [b, c]				Notes
			Condition: Good	Condition: Fair	Condition: Poor	
Water content (mg/kg at transformer operating temperature)	A	Limits >>	< 15	15 to 20	> 20	The values of water content shall be always assessed together with the values for breakdown voltage. In case of suspicion of a moisture problem, sampling at different equipment temperatures is recommended. In the case of "Poor" condition due to high water content in the oil, online monitoring with relative saturation measurement is recommended. Guidance on limits for relative saturation are shown in Annex B.
	B	Limits >>	< 20	20 to 30	> 30	
	C	Limits >>	< 30	30 to 40	> 40	
		Actions >>	No action required, continue normal sampling.	More frequent sampling. Check other parameters, e.g. breakdown voltage, particle content and perhaps DDF or resistivity and acidity.	Check the source of water, resample. Consider monitoring with the transformer online (if possible) using fixed or portable equipment. Where further samples or online monitoring confirms high saturation values (see Annex B), drying of the solid insulation is recommended.	
Acidity [d] (mg_{KOH}/g_{oil})	A	Limits >>	< 0,10	0,10 to 0,15	> 0,15	
	B	Limits >>	< 0,10	0,10 to 0,20	> 0,20	
	C	Limits >>	< 0,15	0,15 to 0,30	> 0,30	
		Actions >>	No action required, continue normal sampling.	More frequent sampling. Check the presence of sediment and sludge. An inhibited oil that reached fair values has possibly lost its oxidation protection.	Starting from the limit value shown above, a decision can then be made at which point to reclaim the oil (see 14.4) or, alternatively, if more economical, replace the oil (see Clause 12).	

Property	Category [a]	Conditions, limits and recommended actions [b, c]				Notes
			Condition: Good	Condition: Fair	Condition: Poor	
Dielectric dissipation factor at 40 Hz to 60 Hz at 90 °C	A	Limits >>	< 0,10	0,10 to 0,20	> 0,20	
	B, C	Limits >>	< 0,10	0,10 to 0,50	> 0,50	
		Actions >>	No action required, continue normal sampling.	More frequent sampling. Check other parameters.	Consider reclaiming the oil (see 14.4) or, alternatively, if more economical, replace the oil (see Clause 12).	
Resistivity at 90 °C (GΩm)	A	Limits >>	> 10	3 to 10	< 3	
	B, C	Limits >>	> 3	0,2 to 3	< 0,2	
		Actions >>	No action required, continue normal sampling.	More frequent sampling. Check other parameters.	Consider reclaiming the oil (see 14.4) or alternatively, if more economical, replace the oil (see Clause 12).	
Inhibitor content (inhibited oils only)	A, B, C	Limits >>	> 60 % of original value.	40 % to 60 % of original value.	< 40 % of original value.	This guidance is applicable to originally inhibited oils and applicable to reclaimed uninhibited oils that have had inhibitor added. For further guidance, users can refer to the oil supplier.
		Actions >>	No action required, continue normal sampling.	More frequent sampling. Where acidity is ≤ 0,08 mg_{KOH}/g_{oil} and IFT ≥ 28 mN/m, consider re-inhibition to original base line level based on local experience.	More frequent sampling. Where acidity is ≤ 0,08 mg_{KOH}/g_{oil} and IFT ≥ 28 mN/m, consider re-inhibition to original base line level based on local experience. Where acidity is > 0,08 mg_{KOH}/g_{oil} or IFT < 28 mN/m, re-inhibition is not effective. Consider reclaiming (see 14.4) or change the oil (see Clause 12).	

Property	Category [a]	Conditions, limits and recommended actions [b, c]				Notes
			Condition: Good	Condition: Fair	Condition: Poor	
Passivator content (mg/kg)	A, B, C	Limits >>	> 70 mg/kg and stable, (rate of decrease < 10 mg/kg/year	50 to 70 mg/kg or > 70 mg/kg, with a significant rate of decrease of > 10 mg/kg/year	< 50 mg/kg	Aged oil, especially uninhibited oil, runs a greater risk of rapid depletion of passivator.
		Actions >>	No action required, less frequent monitoring acceptable.	Maintain regular monitoring.	Remove the source of corrosivity by changing the oil (see Clause 12) or by removing corrosive compounds by mean of suitable oil treatments, or as a short-term solution, top up with new passivator, to ≤ 100 mg/kg (see Clause 13).	
Sediment (%)	A, B, C	Limits >>	No sediment. Results below 0,02 % by mass can be neglected.		Sediment detected.	Not a routine test. Perform only when BDV, acidity and DDF values are near the limits.
		Actions >>	No action required.		Where sediment is detected, recondition oil or reclaim oil or both (14.3). Alternatively, if more economical, replace the oil (see Clause 12).	
Sludge (%)	A, B, C	Limits >>	No precipitable sludge. Results below 0,02 % by mass can be neglected.		Sludge detected.	Not a routine test. Perform only when BDV, acidity and DDF values are near the limits.
		Actions >>	No action required.		Where precipitable sludge is detected, reclaim oil (see 14.4). Alternatively, if more economical, replace the oil (see Clause 12).	

Property	Category [a]	Conditions, limits and recommended actions [b, c]				Notes
			Condition: Good	Condition: Fair	Condition: Poor	
Interfacial tension (mN/m)	A, B, C Inhibited Uninhibited	Limits >> Limits >> Actions >>	> 28 > 25 No action required, continue normal sampling.	22 to 28 20 to 25 More frequent sampling.	< 22 < 20 When poor results observed, refer to other tests such as acidity and DDF as well as other tests that can confirm ageing of the oil.	Can be a routine test for inhibited oil, typically not a routine test for uninhibited oil. This test is most useful during the early life as it can indicate early stage of oxidation or contamination.
Corrosive sulphur and potentially corrosive sulphur	A, B, C	Limits >>	Non-corrosive and not potentially corrosive.		Corrosive or potentially corrosive	The necessity of corrective actions is to be carefully evaluated following completion of a risk assessment study (see 7.19). After the addition of metal passivator to the oil, regular monitoring of the concentration of passivator is necessary. In case of continuous depletion of concentration of the passivator, remove the cause of corrosivity accordingly with recommended actions.
		Actions >>	No action required, continue normal sampling.		Conduct risk assessment – add a metal passivator (e.g. triazole derivatives). or – remove the source of corrosivity by changing the oil (see Clause 12) or by removing corrosive compounds by mean of suitable oil treatments. Measure DBDS See [e]	
Flash point	A, B, C	Limits >>	Decrease < 10 %		Decrease ≥ 10 %	Not a routine test. Can be required when an unusual odour is noticed, when an internal fault has occurred or when a transformer is refilled. Can be subject to local legislation and regulations.
		Actions >>	No action required.		Equipment can require inspection. Investigate.	

Property	Category [a]	Conditions, limits and recommended actions [b, c]				Notes
			Condition: Good	Condition: Fair	Condition: Poor	
PCBs	A, B, C	Limits >>	PCBs contamination not detectable.		PCBs detected Above limits subject to local regulations.	Can be subject to local legislation and regulations.
		Actions >>	No action required.		Can be subject to local regulations.	

[a] Category of equipment (see Table 1).

[b] Ensure sampling was properly done, sampling valve was properly cleaned before sampling (Clause 6) and transportation and storage periods in the laboratory were short.

[c] No action should be taken on the basis of one result and one property. All results shall be confirmed by a repeat sample especially if the result appears abnormal compared to the trend of the previous results obtained.

[d] Acidity values are typical for uninhibited oils. Inhibited oils with "Good" inhibitor content would have lower acidity values which are not expected to reach the "Poor" condition.

[e] If the oil test for corrosivity is positive and DBDS is present, follow the recommendations of CIGRÉ Brochures 378:2009 [12] and 625:2015 [13] for the appropriate mitigation actions.

Table 6 – Tap-changers – Application and interpretation of tests

Property	Category [a]	Conditions, limits and recommended actions [b, c]				Notes
			Condition: Good	Condition: Fair	Condition: Poor	
Breakdown voltage (kV)	F star point (Y)	Limits >>	≥ 30 kV		< 30 kV	If OLTC configuration is not known, then delta or line end guidance should be applied.
	F delta (Δ) or line-end	Limits >>	≥ 40 kV		< 40 kV	
		Actions >>	No action required, continue normal sampling.		Non-vacuum type – initiate maintenance including oil replacement. Vacuum type – Check the source of water or particulate contamination, resample. If contamination is confirmed, recondition or replace oil.	
Water content (mg/kg at transformer operating temperature)	F star point (Y)	Limits >>	< 15 mg/kg	15 to 40 mg/kg	> 40 mg/kg	The value of water content shall be regarded together with the value for breakdown voltage. The value of breakdown voltage is of overriding importance. When reconditioning the oil, consider residual humidity in the solid insulation which can require multiple drying process or repeated oil replacement.
	F delta (Δ) or line-end	Limits >>	< 15 mg/kg	15 to 30 mg/kg	> 30 mg/kg	
		Actions >>	No action required, continue normal sampling.	No action required, continue normal sampling. For vacuum tap-changers, consider more frequent sampling.	Check source of water. Non-vacuum type – Initiate maintenance including oil replacement. Vacuum type – Recondition or replace the oil.	

[a] Category of equipment (see Table 1).

[b] Ensure sampling was properly done, sampling valve was properly cleaned before sampling (Clause 6) and transportation and storage periods in the laboratory were short.

[c] No action should be taken on the basis of one result and one property. All results shall be confirmed by a repeat sample especially if the result appears abnormal compared to the trend of the previous results obtained.

Table 7 – Instrument and protection transformers – Application and interpretation of tests

Property	Category [a]	Conditions, limits and recommended actions [b, c]				Notes
			Condition: Good	Condition: Fair	Condition: Poor	
Water content (mg/kg at transformer operating temperature)	D	Limits >>	< 20	20 to 30	> 30	The value of water content shall always be assessed together with the value for breakdown voltage.
	E	Limits >>	< 30	30 to 40	> 40	
		Actions >>	No action required, continue normal sampling.	More frequent sampling. Check other parameters, e.g. breakdown voltage, particle content and perhaps DDF or resistivity and acidity.	Check the source of water, resample. Check seals and gaskets, if values are confirmed as above the limits then carry out a risk assessment to confirm if transformer can remain in service.	
Dielectric dissipation factor at 40 Hz to 60 Hz at 90 °C	D	Limits >>	< 0,01	0,01 to 0,10	> 0,10	
	E	Limits >>	< 0,10	0,10 to 0,30	> 0,30	
		Actions >>	No action required, continue normal sampling.	More frequent sampling. Check other parameters.	If values are confirmed as above the limits, then carry out a risk assessment to confirm if transformer can remain in service.	

[a] Category of equipment (see Table 1).

[b] Ensure sampling was properly done, sampling valve was properly cleaned before sampling (Clause 6) and transportation and storage periods in the laboratory were short.

[c] No action should be taken on the basis of one result and one property. All results shall be confirmed by a repeat sample especially if the result appears abnormal compared to the trend of the previous results obtained.

Table 8 – Circuit breakers and switchgear – Application and interpretation of tests

Property	Category [a]	Conditions, limits and recommended actions [b, c]				Notes
			Condition: Good	Condition: Fair	Condition: Poor	
Breakdown voltage (kV)	G	Limits >>	> 50	30 to 50	< 30	
	H	Limits >>	> 40	30 to 40	< 30	
			No action required, continue normal sampling.	More frequent sampling. Check other parameters, e.g. water, particle content.	For these switching equipment types, check the source of water or particulate contamination. Resample, if high water content is confirmed, change the oil and repair as required to prevent further occurrence.	
Water content (mg/kg)	G	Limits >>	< 20	20 to 40	> 40	The value of water content shall always be assessed together with the value for breakdown voltage. For these switching equipment types, the values of breakdown voltage are of overriding importance.
	H	Limits >>	< 30	30 to 45	> 45	
		Actions >>	No action required, continue normal sampling.	More frequent sampling. Check other parameters, e.g. water, particle content and perhaps DDF or resistivity and acidity.	For these switching equipment types, check the source of water. Resample, if high water content is confirmed, change the oil and repair as required to prevent further occurrence.	
Acidity [d] (mg_{KOH}/g_{oil})	G, H	Limits >>	< 0,10	0,10 to 0,2	> 0,2	
		Actions >>	No action required, continue normal sampling.	More frequent sampling. Check the presence of sediment and sludge. An inhibited oil that reached fair values has possibly lost its oxidation protection.	Starting from a value of 0,2 and if other tests indicate severe ageing, consider replacing the oil (see Clause 12).	

[a] Category of equipment (see Table 1).

[b] Ensure sampling was properly done, sampling valve was properly cleaned before sampling (Clause 6) and transportation and storage periods in the laboratory were short.

[c] No action should be taken on the basis of one result and one property. All results shall be confirmed by a repeat sample especially if the result appears abnormal compared to the trend of the previous results obtained.

[d] Acidity values are typical for uninhibited oils. Inhibited oils with "Good" inhibitor content would have lower acidity values which are not expected to reach the "Poor" condition.

Table 9 – Oil filled and OIP bushings – Application and interpretation of tests

Property	Category [a]	Conditions, limits and recommended actions [b, c]				Notes
			Condition: Good	Condition: Fair	Condition: Poor	
Breakdown voltage (kV)	K	Limits >>	> 60	40 to 60	< 40	
	L	Limits >>	> 50	30 to 50	< 30	
		Actions >>	No action required, continue normal sampling.	Check other parameters, e.g. water, particle content. Resample only if deemed required.	Check the source of water or particulate contamination. Resample. Based on all tests carry out risk assessment and remove bushing from service if required.	Consider electrical tests, capacitance and power factor to verify bushing condition. Frequent sampling of bushings is generally not recommended see 9.4.6.
Water content (mg/kg)	K	Limits >>	< 10	10 to 20	> 20	Consider electrical tests, capacitance and power factor to verify bushing condition.
	L	Limits >>	< 10	10 to 30	> 30	
		Actions >>	No action required, continue normal sampling.	. Check other parameters, e.g. breakdown voltage, particle content and perhaps DDF or resistivity and acidity. Resample only if deemed required.	Check the source of water, resample. Based on all tests carry out risk assessment and remove bushing from service if required.	
Dielectric dissipation factor at 40 Hz to 60 Hz at 90 °C	K	Limits >>	< 0,01	0,01 to 0,10	> 0,10	Consider electrical tests, capacitance and power factor to verify bushing condition.
	L	Limits >>	< 0,10	0,10 to 0,30	> 0,30	
		Actions >>	No action required, continue normal sampling.	Check other parameters. Resample only if deemed required.	If other tests indicate severe ageing, contact the manufacturer.	

[a] Category of equipment (see Table 1).

[b] Ensure sampling was properly done, sampling valve was properly cleaned before sampling (Clause 6) and transportation and storage periods in the laboratory were short.

[c] No action should be taken on the basis of one result and one property. All results shall be confirmed by a repeat sample especially if the result appears abnormal compared to the trend of the previous results obtained.

Table 10 – Summary of typical actions

Key factors	Symptoms	Corrective actions
Physical	High water content Low breakdown voltage value High particles content Turbid (not clear)	Either reconditioning (see 14.3) or drying of solid insulation if present, or both.
Chemical	High colour value Low IFT High acidity value High dissipation factor value Presence of sediments or sludge, or both	Reclaiming (see 14.4) or change the oil (see Clause 12).
	Low inhibitor content, for inhibited oil Low passivator content for passivator containing oil.	Restore original additive concentration according to recommendations in Table 5.
PCBs	PCBs contamination detectable.	Can be subject to local regulations (see 14.5).
Corrosive sulphur	Corrosive sulphur or potentially corrosive sulphur detected.	Perform risk assessment and carry out intervention as necessary: – add metal passivator (see Clause 13) – oil change (see Clause 12) – reclaiming (see 14.4)
In some cases, if the chemical contamination is extremely high, it can be more economical to replace the oil. A reclaiming viability test (see 14.4.1) is recommended. NOTE The more aged the oil is at the time of passivation, and the more severe the operating conditions, the higher is the risk that passivation is not a sufficient long-term remedy. A more detailed scheme for dealing with corrosive sulphur and copper sulphide formation is proposed in CIGRÉ, Brochure no. 378, 2009 [1].		

It is strongly emphasized that no action should be taken based on either one result or one property, or both. Where results appear abnormal compared to the trend of previous results it is recommended that an additional sample is taken and analysed to verify the results.

11 Handling and storage

CAUTION: Drum and container handling and environmental procedures can be subject to local regulations. Special attention shall be paid to avoid cross contamination by PCBs.

To ensure satisfactory service, the utmost care in handling the oil is essential. Drums and containers such as bulk containers should be clearly marked to indicate whether they are for clean or for used oil and should be reserved for the type indicated. Drums and containers and bulk tankers used for oil awaiting reclamation should not be used for any other product.

Drums and containers should preferably be stored in a temperature-controlled or stable temperature environment that provides protection from direct solar radiation. This minimises the expansion and contraction of the oil due to temperature fluctuations and will help to prevent the formation of condensation.

Drums should be stored horizontally and placed in such a position that there is a head of oil on the stopper or plug. They should be stored under cover to minimize the ingress of water and to reduce solar thermal cycling due to exposure to sunlight. The use of plastic sheeting is not recommended unless great care is taken to avoid the drums “sweating” with condensation.

During transportation, drums should be in the vertical position for stability and covered to prevent the ingress of water.

In practice, difficulty can be experienced in maintaining the purity of oil when it is transferred from one vessel to another due to the possibility of introducing contamination. Such practice is not recommended without strict adherence to quality control.

It is recognized that storage of oil in damaged drums and containers is not always satisfactory and the transfer of oil from such vessels to electrical equipment should be through a suitable treatment plant to remove water and dissolved gases.

In locations with fixed oil-handling equipment, the pipework from the clean oil tanks to the electrical apparatus should be kept clean and free from water. Dehydrating breathers should be regularly inspected and maintained. Where portable oil-handling equipment is used, flexible pipework and hand pumps should be carefully inspected to ensure that they are free from dirt and water and should be flushed with clean oil before use. If the clean oil is from drums, it should have been recently tested, and the filling orifices of the drums should be clean.

Hoses used for clean oil and hoses used for used oil should be clearly marked and provided with plugs for sealing the ends when not in use. Hoses shall be resistant to oil, as ordinary rubber contains free sulphur, which is corrosive. If wire braided hoses are used, the hoses shall be cross-bonded and properly grounded to prevent the build-up of any static charge. For specific problems, reference should be made to the equipment manufacturer's instructions.

12 Replacement of oil in electrical equipment

12.1 Replacement of oil in transformers with an U_m below 72,5 kV and in switchgear and associated equipment

A quantity of oil is necessary to rinse the interior of the tank and the immersed parts. It is essential that the tank and the surfaces of conductors and insulators be cleaned effectively and subsequently be kept free from fibres. Such fibres are readily introduced by the use of unsatisfactory cleaning materials during plant maintenance; in practice the only efficient and permissible materials are synthetic. It is also essential that the tank and other surfaces be kept free from water.

A final pressure flush with clean oil of known quality has proved beneficial in the removal of fibres and other extraneous material. It should be noted that possibly up to 10 % of the original oil might remain adsorbed in the solid insulation and its contaminants can take some time to migrate into the new oil.

Application of a vacuum extraction procedure has proved valuable in removing surface moisture, provided the equipment can withstand the vacuum and is warm.

Oil is normally reconditioned when filling the equipment. See 14.3.

There should be as little aeration as possible during the filling of tanks and as far as possible, the end of the delivery pipe should be held below the surface of the oil in order to avoid splashing; alternatively, the tanks should be filled from the bottom.

There should normally be a standing period ≥ 12 h to allow de-aeration before commissioning transformers (1 h is adequate for switchgear and 1 h to 2 h for power transformers with an U_m of < 16 kV).

12.2 Replacement of oil in transformers with an U_m of 72,5 kV and above

Reference should be made to the equipment manufacturer.

12.3 Replacement of oil in electrical equipment contaminated with PCBs

Reference should be made to the equipment manufacturer, and local regulations can apply. A full risk assessment should be carried out.

13 Addition of metal passivators to in-service oil

Metal passivator is added as a stock solution, dissolved in insulating oil. Such stock solutions are commercially available, but some service providers prepare the stock solution on-site, with oil from the actual unit. The stock solution can be added via an oil processing unit or other suitable equipment.

This treatment is recommended for corrosive oils which are otherwise in “Good” condition (see Table 5 etc.). For in-service oils that fall in “Fair” or “Poor” condition for acidity, a case-by-case study is recommended.

14 Treatment

14.1 Warning

The treatment of used oil shall be carried out with proper care and attention. All countermeasures should be taken to minimize any unreasonable risk to workers, public health, and the environment. All activities shall be undertaken by experienced and qualified personnel, fully aware of the health and environmental risks associated with oil treatment work. Local regulations can apply. In case of special oil treatments, where the related experience is poor, a risk assessment should be undertaken before commencing the treatment.

Strict control shall be undertaken to avoid possible cross contamination with polluted, contaminated, heavily aged and carbonized mineral oil or other types of liquids. Treatment plants and machines previously used for reconditioning and reclamation of PCBs contaminated transformers can induce cross contamination in another unit. The verification of the PCBs content in the residual oil retained in the treatment machine (prior to use for a new treatment) can avoid this risk.

Even the case of cross contamination by other insulating liquids (esters, silicones) should be considered. The use of the same treatment unit for different types of liquid is not recommended. In these cases, the reconditioning and reclaiming unit should be carefully drained, rinsed with unused mineral oil and either all filters or sorbent materials, or both should be replaced.

It is common practice in many countries to certify a container clean prior to filling it with mineral insulating oil; local regulations and practices can apply.

Strict control shall be undertaken to avoid accidental spills to the environment. Pipes, pumps, and hoses shall be carefully inspected for tightness. Piping used for on-line treatments (see 14.2.2) should be designed to prevent accidental emptying of the apparatus undergoing treatment.

As oil treatments are usually carried out under vacuum, special attention shall be paid to avoid emissions to the atmosphere. If applicable, equipment owners should verify the vacuum withstand capability of the electrical equipment (i.e. transformer) before undertaking work which will subject the equipment tank to vacuum.

Oil treatments produce waste, such as spent filters, oil-contaminated absorbents etc. The disposal of waste can be subject to local regulations regarding their impacts on the environment.

If the treatment is performed on-line on energized electrical equipment, strict safety measures shall be taken to avoid risks to the workers. Also, safety measures shall be taken to avoid any damage to the electrical equipment undergoing treatment.

Due care should be taken when working with hot oil. Personal protective equipment and relevant risk assessments can be subject to local regulations.

The oil cannot be considered totally separated from the solid insulation in the electrical equipment. Some of the ageing products and contaminants that treatments aim to remove reside within and on the surfaces of the oil-impregnated cellulosic (or similar porous) insulation. The practical implication of this is that when a reclamation treatment is carried out, after one circulation for example, such contaminants that are in solution in the oil will be removed and the oil condition, if sampled immediately thereafter, will have improved properties. However, should there still be significant ageing products and contaminants in the solid insulation, they can diffuse or dissolve into the oil within a short period thereafter. It is therefore important for good long-term results, that the treatment is carried on until the extraction is so complete (enough circulations through the reclamation equipment) that a significant bounce-back effect is avoided. Maintaining a high enough oil temperature to achieve this in a reasonable time is facilitated when the equipment is on-line while the treatment is carried out. To check that good, long-lasting results are acquired, follow-up sampling of the oil should be carried out after a few months in service following the treatment.

The properties of the oil after any treatment should be agreed between the service provider and the customer. Annex A provides a guideline for setting reclamation criteria.

In this document, reference is made in some places to the original electrical equipment manufacturer's instructions. In cases where manufacturer's instructions are unavailable, case-by-case consideration with expert consultation is recommended.

14.2 Classification of treatment processes

14.2.1 General

Treatment processes, regardless to the specific technology used, can be classified as follows:

– Off-line (de-energized) *or* on-line (energized)
– Batch *or* continuous mode

14.2.2 Off-line (de-energized) *vs* on-line (energized) treatment

Off-line treatments are performed on completely de-energized electrical equipment, whose connections with the power supply, transmission or distribution network have been isolated. These types of treatments allow the partial or complete draining of the unit undergoing the activity.

On-line treatments are performed on energized and loaded electrical equipment, where it has been confirmed that they can be operated during the treatment. These types of treatments are not possible with any oil draining, even partial. During an on-line treatment, the oil-level in the electrical equipment shall be carefully controlled, ensuring it covers the active part sufficiently and ensuring safe operation. On-line treatments require some specific precautions:

– Electrical insulation between the treatment plant and the electrical equipment undergoing treatment.
– Piping able to avoid the accidental emptying of the electrical equipment undergoing treatment, even in cases of pipe breakage.
– Systems to prevent the ingress of air bubbles in the electrical equipment.
– Appropriate measures to prevent turbulence in the oil circulation of the electrical equipment.

NOTE 1 It is not recommended to disconnect transformer protections during on-line oil treatment (e.g. Buchholz relay).

NOTE 2 CIGRÉ Technical Brochure 413 [14] provides detail on related topics of oil treatment.

14.2.3 Batch *vs* continuous mode treatment

Batch treatments are made on the oil after removal from the electrical equipment (e.g. in a separate external tank). By definition, they cannot be performed on-line. They are usually applied to the reconditioning or reclamation of oils intended to be used in a transformer, or other similar electrical apparatus (e.g. a new oil to be used to fill a new transformer).

In the case of open cycle (batch or off-line reconditioning and reclamation units), oil draining and oil refilling of the transformer to be treated are required. These activities result in more complex site works including a full oil drain and re-filling of the equipment, usually under vacuum. Care should be taken to ensure sufficient insulation impregnation when re-filling equipment. Additionally, care should be taken to ensure the equipment can withstand vacuum. Refer to CIGRÉ TB 445 [15] for further guidance.

Continuous mode treatment is performed by circulating the oil through the transformer and the treatment plant, without emptying the transformer, not even partially. They are usually carried out to improve certain properties of oil in service and can in certain circumstances be applied on-line. On-line application depends upon many conditions (transformer design and voltage, oil connection points, protection devices, etc.), so it is not always feasible.

14.3 Reconditioning (degassing, drying and filtration)

14.3.1 General

Reconditioning, also sometimes referred to as “drying and filtration”, “vacuum degassing and filtration” or “physical treatment”, is a process that eliminates or reduces some contaminants (moisture, gas, suspended material, etc.) by means of physical or mechanical processes (filtration, dehydration, degassing by vacuum, etc.). Chemical and polar contamination (as well as ageing products) are not normally removed. For example, proxies for polar contamination such as interfacial tension (IFT) or acidity will not necessarily be improved by reconditioning alone.

Reconditioning is usually carried out at the user's site to remove the above-mentioned contaminants from the oil. Reconditioning can be performed on oil already filled or during filling on electrical equipment, as well as on oil in storage tanks and containers. Depending on the context of the reconditioning, certain factors should be considered, for example, there can be an oil-paper (solid-porous insulation) system to consider. Two documents that give information on reconditioning are CIGRÉ Technical Brochure 227, 2003 “Life Management Techniques for Power Transformer” [16] and CIGRÉ Technical Brochure 413, 2010 “Insulating Oil Reclamation and Dechlorination” [14].

Reconditioning reduces the particle, water, and gas content of the oil. This is normally done for first filling of oil in equipment, refilling of oil in equipment or on-site or online reconditioning. This normally achieves the desired reduction in total gas content, water content as well as the target breakdown voltage. Expected properties after reconditioning should always be contractually agreed between customer and supplier; requirements of “Good” condition in Table 5 and Table 6 can be taken as a guideline. The process can also reduce other components such as furanic compounds (see CIGRÉ TB 779) [17]. For future interpretation, new base-line levels for parameters such as DGA and furan levels, when on-site or online treatment is done, should be established after such a process.

When doing reconditioning on oil contained in storage tanks, iso-containers, and sometimes in electrical equipment themselves, where free water is present in the base of the tank, then the removal of the water from the oil using reconditioning (that being vacuum degassing and drying) will be highly inefficient and the possibility of removing the free water directly by draining should be investigated first.

Vacuum degassing in open systems, or in large tanks having a large headspace, can result in incomplete gas removal, leading to a residual final concentration of atmospheric gases (oxygen, nitrogen, and traces of carbon dioxide) higher than expected. To prevent loss of additives (such as most common inhibitors, 2,6-di-tert-butyl-paracresol and 2,6-di-tert-butyl-phenol) and undue loss of lighter liquid fractions, conservative conditions for heat and vacuum applicable to most mineral insulating oils are shown in Table 11.

Table 11 – Conditions for processing mineral insulating oils (both inhibited and uninhibited)

Maximum liquid temperature	Minimum pressure	
[°C]	[mbar]	[Pa]
40	0,08	8
50	0,15	15
60	0,3	30
70	0,8	80
80	2	200
85	2,8	280

Table 11 presents the limits for maximum temperature for a certain minimum vacuum. For example, for a vacuum treatment with a pressure (vacuum) of 80 Pa (0,8 mbar), then the oil temperature, into the vacuum chamber, should not exceed 70 °C.

NOTE in some countries, an oil treatment above certain temperatures (usually 80 °C) can be classified as distillation and can be subject to local regulations.

Temperature limits from reconditioning equipment manufacturers and oil suppliers shall be respected. Ensure that special care is taken when oil is heated by means of electrical heaters. As a lot of energy is accumulated in the heaters, it is necessary to switch them off well in advance before the oil flow is stopped. Otherwise, overheating and burning can occur in the heaters. In addition, the heat density in the heater modules shall be considered. Modern oil reconditioning plants work typically with a heat density of ≈< 1,5 W/cm^2.

14.3.2 Reconditioning equipment

14.3.2.1 Filters

Filtering equipment usually forces oil under pressure through material such as paper, glass fibre, mesh (steel), and combinations of these media. Filters of this type are normally used to remove contaminants in suspension. Such equipment alone does not de-gas the oil.

It should be noted that historically the nominal micron ratings, commonly used to characterize these filters, are based on gravimetric tests and applying efficiency, based on weight, which takes no regard of particle size. (The filter medium should be capable of removing particles larger than 10 µm although local regulations can specify a lower value e.g. 5 µm).

Nowadays it is more common to define the filter rating including filtration efficiency; for example, specifying the filter rating e.g. 5 µm with a specific efficiency e.g. 99,5 %.

Typically filter rating with high efficiency have become the industry standard and these filter media will capture more particles per filtration cycle.

Filter manufacturers often use “Beta-ratio”, at a given filter rating, to indicate the filter efficiency, see Table 12. This Beta ratio is the ratio of particle upstream versus downstream of the filter element.

Table 12 – Beta ratio related to filter efficiency

Typical wording efficiency	Efficiency in %	Beta ratio
Nominal	50	2
High (or absolute)	98,5	75
Very high	99,5	200

Care should be taken to ensure that filter media are of the correct grade, efficiency and integrity and do not either shed fibres or unload dirt, or both, especially during differential pressure and temperature fluctuations.

Typically, depth filter media with filter rating 1 µm and 99 % or higher efficiency are not only capable of capturing particles, but they can also collect insoluble sludge pollution. It is therefore important to use only moderate oil flows, to allow the insoluble sludge to adhere to the filter.

Filtration efficiency can be evaluated with particle counts. Normally, filtration occurs both before and after the vacuum stage (coarse and fine).

During service, filters can become contaminated with used oil and solid contaminants. The disposal of filters can be subject to local regulations. Special consideration shall be given to filters likely to be contaminated with PCBs.

14.3.2.2 Vacuum dehydrator (vacuum chamber)

The vacuum dehydrator is an efficient means of reducing the gas and water content of a mineral insulating oil to very low values. The principle is to reduce the boiling point of water to facilitate water removal from the oil.

The use of vacuum dehydrators to recondition the oil has a negligible effect on the water absorbed in the solid insulation (porous media, cellulose or paper). The reduction of significant moisture from “wet” solid insulation systems requires special techniques, which are out of the scope of this document.

There are various types of vacuum dehydrator; normally functioning at 50 °C to 70 °C (see Table 11). In one method, the treatment is accomplished by spraying the oil into a vacuum chamber: in another, the oil flows in thin layers over a series of baffles (e.g. Rashig rings) inside a vacuum chamber. There are also coalescer based methods. In all situations, the objective is to expose a maximum surface and minimum thickness of oil to the vacuum.

In addition to removing water, vacuum dehydration will de-gas the oil and partially remove volatile ageing products for example some of the furans such as 2-furfural. Even if some by-products of the paper decomposition are partly removed, vacuum degassing will have no significant effect in reducing or the slowing down of the degradation of the solid insulation. Should some 2-furfural be removed, a new baseline of 2-furfural and related compounds will be achieved, this baseline can return to pre-conditioning levels but is highly dependent on the equipment in question and could take months or years.

Silicone contamination, even at low levels, can cause undesired slow de-aeration or excessive foaming that can disrupt the vacuum dehydration process. Flow rate, vacuum reduction and temperature variation can assist in reducing foaming. However, should the foaming persist, some have reported success in reclamation to remove silicone. Examples of sources of silicone contamination are silicone insulating liquids as well as silicone-based greases.

In addition, the degree of foaming of oils in the vacuum chambers of reconditioning equipment is also influenced by the water content, acidity, and physio-chemical nature of the insulating oil.

14.3.3 Application to electrical equipment

14.3.3.1 Conditioning or re-conditioning the oil prior to filling electrical equipment

During maintenance, a common activity is to run either new or used oil through an oil reconditioning plant (and thus do reconditioning) to reduce gas, water, and particles to reach desired oil parameters (such as target water and breakdown voltage, see Table 3). This can occur either during filling (i.e. in line reconditioning) or can be done in an oil storage container (such as an iso-container), where the oil is reconditioned prior to filling, re-filling or top-up in the electrical equipment.

14.3.3.2 Filling procedures

The filling of oil into the electrical equipment is normally a complex process which often involves pulling vacuum on the equipment tank and the introduction of oil at the appropriate flow rate and temperature into the equipment, usually through a reconditioning unit. Consult the electrical equipment manufacturer's instructions for the detailed procedure for oil filling.

14.3.3.3 Reconditioning by circulation

The oil is circulated through the reconditioning equipment, typically being taken from the bottom of the tank of the electrical equipment and returned to the top. The return delivery should be made smoothly and horizontally at or near the top oil level to avoid, as far as possible, mixing cleaned oil with oil that has not yet passed through the reconditioning unit. The circulation method is particularly useful for removing suspended contaminants, but not all contaminants adhering to the inner surfaces (e.g. papers and pressboards) will necessarily be removed.

Experience has shown that it is generally necessary to pass the total volume of oil through the reconditioning unit multiple times; this depends on the target values for the relevant parameters (water, BDV, total gas content). Equipment able to provide a flowrate that can guarantee a multiple circulation in a reasonable time should be used for this purpose. The final number of cycles will depend on the specific condition of the oil and of the electrical equipment itself. It is recommended that a sample from the electrical equipment is taken after the treatment to check the relevant parameters. The relevance of the measured parameters will be dependent on the sampling point, time, and temperature. For example, a particle measurement conducted during oil flow is the most representative.

In all cases, the oil should be allowed to stand for some time in accordance with the manufacturer's instructions before the equipment is re-energized. Reconditioning by circulation is a continuous-type process (see 14.2), and can be operated on-load, provided that the requirements in 14.2 are respected. On-line treatment should be done only in case of necessity (when transformer operability cannot be interrupted), as off-line treatment is inherently safer.

Another technique which is sometimes used for transformers involves the continuous circulation of oil during normal service through an adsorbent, such as a molecular sieve (so called "on-line moisture filtering"). This technique is able to keep the oil dry, even in cases of continuous release of moisture from the wet solid insulation. However, there are some systems which remove moisture by physical means rather than by adsorption on molecular sieves. These systems can alter the dissolved gas content in the oil, potentially compromising their diagnostic role in Dissolved Gas Analysis (DGA). These are specialized methods for which details are not considered further in this document.

14.3.3.4 Sealed electrical equipment

This includes distribution transformers, hermetically sealed, nitrogen blanketed, instrument transformers, capacitors, and bushings. Free breathing units which make use of a rubber-bag (bladder) in the conservator require some additional considerations when performing an activity that changes the oil level significantly (e.g. the rubber bag shall be inflated, and the conservator bled of air).

To avoid the risk of introducing air into the equipment, which can lead to premature failure, oil reconditioning in hermetically sealed units is not normally done. In cases of nitrogen blanketed units, consult the manufacturer of the equipment for specific procedures.

Should reconditioning be desired to be done in cases of sealed equipment, proceed strictly in accordance with the manufacturer's instructions pertinent at the time of reconditioning. In cases where manufacturer's instructions are unavailable, case-by-case consideration with expert consultation is recommended.

14.4 Reclaiming

14.4.1 General

This is a process that eliminates or reduces soluble and insoluble polar contaminants and ageing products from the oil by chemical and physical processing. Reclamation processes require special competence, equipment, and experience. The resulting treated oil should be evaluated on critical parameters to achieve information about process efficiency and to be able to estimate remaining oil lifetime.

Reclamation usually results in oil (which originally conformed to IEC 60296) with properties being restored to an acceptable condition for service (see Table 5). The extent of improvement of oil properties, as well as the extent of resistance to oxidation in further service, will depend on several factors such as: the oil condition before reclamation (degree of degradation expressed by acidity and DDF values, among others), quality of the original base oil, condition and contamination degree of the solid insulation, and the response of the oil to added inhibitor after reclamation. The specific parameters of the reclamation process itself also have a significant impact.

Reclamation processes are also used for removal of corrosive sulphur compounds from oil, including both Cu_2S forming copper compounds (e.g. DBDS) and elemental ("free") sulphur. Reclamation processes have also been applied to the removal of silicone contamination of insulating oils.

Before performing a reclamation process, a laboratory feasibility test can be useful depending on the specific circumstances and is often used for optimizing the process based on the specific adsorbents and process type.

Modern reclamation processes are based predominantly on a percolation type process. This usually consists of passing the oil through adsorbents whereby ageing products and polar contaminants are removed.

When reclaiming, generally there are two main approaches:

- Single Use Sorbents – these often include traditional clays such as "Fuller's earth" where reactivation is not appropriate or efficient.
- Reactivating Sorbents – these often include materials with specific and well-defined chemical structure so that they are more effective and thermally stable (such as activated bauxite).

Efficacy of the specific sorbent (for example in removing acids or corrosive sulphur) can vary.

14.4.2 Reclaiming by percolation with single use sorbents

The full process consists of four consecutive steps which are often applied multiple times.

1) The oil, being taken from the bottom of the electrical equipment, is heated to a given temperature and passed through a coarse filter.
2) It is then passed through one or more cartridges containing Fuller's earth or other suitable material, to eliminate soluble polar contaminants.
3) The oil is finally passed through a reconditioning device (vacuum dehydrator or centrifuge) to eliminate water, gases and do fine filtration.
4) Oil is then returned to the top of the electrical equipment.

Fuller's earth is an active material containing both internal and external polar active sites, which allow the non-polar components of the oil to pass through without retention, but which retains the polar contaminants or degradation compounds dissolved in the oil.

Several different clays are available that have proven suitable for these purposes. The most widely used are of the sepiolite, bentonite, attapulgite or montmorillonite type of which Fuller's earth is the most commonly used. They are composed of silicate anions $[Si_2O_5]_n$ condensed with octahedral layers of the type $X(OH)_2$ where X can be magnesium, aluminium, etc.

Normally, Fuller's earth is treated to increase its specific surface area and the concentration and polarity of its Lewis acids. Fuller's earth can be used alone or in combination with other chemicals like trisodium phosphate, activated charcoal and sodium silicate. Some clays can be of poor quality and in some rare cases add contaminants to the oil during reclamation. Apart from other parameters measured after the reclamation (defined by the reclamation criteria) a DIN 51353 silver strip test shall be done on the treated oil to confirm non-corrosivity.

The retention of contaminants by adsorbent active sites is generally improved by temperature, thus the process normally takes place at 60 °C to 80 °C.

Experience has shown that it is usually necessary to pass the total volume of oil through the adsorbent multiple times, therefore, reclamation units of appropriate capacity should be chosen for this purpose. The final number of cycles will depend on initial oil condition (the degree of ageing and contamination) and the desired final level for properties.

Disposal of oil contaminated clay and sorbent after use can be subject to local regulations (whereby incineration is the most common disposal method).

14.4.3 Reclaiming process using reactivating sorbents

The full process consists of several consecutive steps, which are often applied multiple times, having many similarities with the process using single-use clays such as Fuller's earth, but includes a reactivating step:

1) The oil, being taken from the bottom of the electrical equipment, is heated to a given temperature and passed through a coarse filter.
2) It is then passed through one or more cartridges (or columns) containing a suitable sorbent material, to eliminate soluble polar contaminants. For the sake of simplicity, a single column system is described in the following, though it is more common to use several or many columns in parallel.
3) The oil passes through a reconditioning device (usually a vacuum dehydrator) to eliminate water, gases and do fine filtration.
4) Oil is then returned to the top of the electrical equipment.

5) When the sorbent material is getting close to saturation (after a treatment time that can vary between several hours to several days), then a reactivation cycle is started:
   a) The cartridge and column are drained of oil.
   b) While air is pushed or drawn through the column, the top of the column is heated, igniting the adsorbed polar contaminants and some of the oil trapped in the porous sorbent.
   c) A heated (burning) zone travels then down the column, leaving behind reactivated sorbent, and pushing out much of the oil remaining in the sorbent.
   d) After the entire column has “burnt” it is allowed to cool down.
   e) After cooling down, the column is refilled with oil, and after some internal recirculation (whereby oil is not entering the electrical equipment, and the contaminated residues are removed to a separate waste tank), the treatment of oil in the electrical equipment is then resumed (step 1 above).

Although it is commonly applied to transformers and related equipment in an on-site, on-line setting, the same process is also applicable to oil held in external tanks (batch mode).

The sorbent material used is most commonly thermally activated granular bauxite, or a mixture of this with other materials, but could also be granules of pure alumina.

The retention of contaminants by adsorbent active sites is generally improved by temperature, thus the process normally takes place at 60 °C to 80 °C. To maintain temperatures and attain maximum efficiency, it is normally preferred to do the treatment while the equipment, whose oil is being treated, is in on-line and loaded in regular service.

Experience has shown that when the treatment is done on-line, it is necessary to pass the total volume of oil through the adsorbent several times. The final number of cycles will depend on initial oil condition (the degree of ageing and contamination) and the desired final level for properties.

Some oil is lost in the reactivation process; thus, some unused oil can be necessary for topping-up the equipment at the end of the process.

Over time the adsorbent will lose some efficiency. After typically a few hundred reactivations, it will be necessary to exchange the sorbent and dispose of the waste sorbent. The disposal of sorbents can be subject to local regulations, and efforts to minimize the residual contaminants in the disposed sorbent should be made.

Some types of reclaiming plant and procedures that make use of the reactivating sorbents method can in some cases cause the oil to become contaminated with corrosive sulphur, most notably elemental (“free”) sulphur. The sulphur is formed mainly in the reactivation process, and depending on the design of the equipment, and operation and maintenance routines, the severity of the problem can vary. However, a properly carried out treatment, where contaminated residues are appropriately dealt with in the process, should not result in any significant contamination of free sulphur in the transformer oil. This should always be confirmed by a DIN 51353 silver strip test on the treated oil.

As mentioned, over time the adsorbent becomes contaminated with used oil and solid contaminants. The disposal, or re-activation, of the substance can be subject to local regulations. Special consideration will have to be given to adsorbent likely to be contaminated with PCBs.

NOTE If online reclamation using reactivating sorbents on oil containing PCBs (such as levels up to 50 ppm where in some countries this is allowed) is done, during the reactivation process the possibility exists to emit by-products such as Poly-Chlorinated-Dibenzo-Dioxins (PCDD) and Poly-Chlorinated-Dibenzo-Furans (PCDF). Local regulations can apply.

14.4.4 Renewal of additives

After reclamation, inhibitors and passivators are usually significantly removed and thus after any type of reclamation it is strongly recommended to add inhibitor to the agreed concentration after the reclamation process is completed. See 7.8, Clause 13 and Clause A.2.

14.5 Removal of PCBs using dehalogenation and related processes

14.5.1 General

As keeping in service electrical equipment containing PCBs-contaminated oil can be permitted by some local regulations, these devices are not always be considered waste. Should the oil become accidentally contaminated, there are several processes and techniques available for either on-site or off-site decontamination of PCBs contaminated oil. These processes are based on chemical reactions between PCBs and the reagent to remove the chlorine present. All PCBs decontamination methods, either off-site or on-site, shall be applied by skilled personnel. Local regulations can apply.

Off-site decontamination techniques are limited by considerations for the safe transportation of contaminated equipment and liquid to an authorized oil processing facility and can be subject to local regulations.

14.5.2 Dehalogenation processes using sodium and lithium derivatives

These processes are typically applied in batch and use reagents based on metallic sodium, sodium hydride, lithium hydride and additives, for the dehalogenation of PCBs in the oil. This type of process is typically run under pressure and medium to high temperature (150 °C to 300 °C). This temperature is higher than the flash point of the oil (140 °C to 150 °C) and therefore introduces subsequent safety risks.

WARNING: Proper measures shall be taken to minimize the risk of fire or explosion, especially in the presence of oil with high moisture.

14.5.3 Dehalogenation processes using polyethylene glycol and potassium hydroxide (KPEG)

This process, developed to overcome the problems associated with the use of metallic sodium, uses a liquid reagent based on polyethylene glycol (PEG) and an alkaline metal hydroxide such as potassium hydroxide (KOH). This type of processes typically runs at temperatures of 100 °C to 130 °C.

These processes usually imply that some oil is removed from the unit to put it in contact with the liquid reagents in a suitable reactor. With adequate techniques (e.g. using auxiliary tanks), the process can be comparable to a continuous mode, closed circuit process (see 14.5.4).

14.5.4 Dehalogenation in continuous mode by closed circuit process

This process uses a solid reagent consisting of a high molecular weight glycol mixture, a mixture of bases and a radical promoter or other catalyst for chemical conversion of organic chlorine to inert salts, on a high surface area particulate support.

This process normally runs at 110 °C to 130 °C and has the capability to decontaminate equipment on-site, through continuous circulation of the oil in a closed system (without draining the oil or using auxiliary tanks), using the solvent capability of the oil for continuous extraction of PCBs from solid materials inside the equipment. This makes these processes suitable for on-line application.

14.5.5 Corrosive sulphur removal using KPEG

KPEG and continuous mode processes can be used for on-site treatment of aged and corrosive oils, being proven as very efficient in the removal of DBDS. They usually also improve the parameters of the oil linked to the presence of polar compounds, such as DDF, IFT and acidity.

These technologies can be applied in the removal of DBDS even at lower temperatures (80 °C to 100 °C) compared to those necessary for the efficient removal of PCBs. Simultaneous removal of PCBs and DBDS (in the cases when PCBs are present in the corrosive oil) is also possible using these methods.

14.6 Criteria for oil reclamation and treatments

See Annex A for recommendations on setting a criterion for oil reclamation and similar treatments.

Annex A
(normative)

Criteria for reclamation and treatments

A.1 General

Before proceeding with a reclamation process on an in-service insulating oil, it is recommended that there is a written agreement between the asset owner and the service provider regarding the measurable parameters and target values of the oil after the reclamation is completed. There are several aspects to consider, some of which are outlined below.

A.2 Key parameters to measure before and after reclamation

The parameters listed in Table A.1 are regarded as important and should be measured when carrying out a reclamation process. All the parameters shall be measured in accordance with the methods detailed (refer to Table 2 and Clause 7). This list is not prescriptive, and an asset owner can choose to include differing or additional parameters in their specific specification document. When deciding target values, it is important that baseline values are determined on the insulating liquid in question before the reclamation, and that these are used to define the intended target values.

Table A.1 – Parameters where limits should be agreed upon

Parameter	Recommended usage	Comments
Acidity (mg KOH/g)	Agreed maximum target value.	
Dielectric dissipation factor (DDF)	Agreed maximum target value.	
Interfacial tension (IFT)	Agreed minimum target value.	
Inhibitor content	Agreed minimum and maximum after inhibitor addition.	See Clause A.3.
Corrosive sulphur	All reclamations: DIN 51353 (Silver Corrosion) should have “corrosive sulphur absent”. If the purpose of the treatment is to remove potentially corrosive sulphur, then requirements for either potentially corrosive sulphur or DBDS content, or both, should be agreed upon.	See 14.4.3.
PCBs content	Measure and report for reference in general cases. If the purposes of the reclamation are to remove PCBs, then requirements for total PCBs content should be agreed upon.	Local regulations can apply. PCBs content should never be increased by a reclamation process, within the uncertainty of the method.

The parameters listed in Table A.2 have no limits but are recorded for trending purposes.

Table A.2 – Parameters where limits should not necessarily be set but should be measured for baseline and trending

Parameter	Recommended usage	Comments
Colour	Measure and report for reference.	
Breakdown voltage	Measure and report for reference. In cases where batch mode treatments are done, limits should be agreed prior to filling the electrical equipment.	BDV is a property that can rapidly change in the oil depending also on the temperature dependent water equilibrium between oil and solid insulation. It should be measured just after the treatment to ensure that no moisture ingress occurred, but it can change quite rapidly when the unit is returned to service, see 7.4.
Water	Measure and report for reference. In cases where batch mode treatments are done, limits should be agreed prior to filling the electrical equipment.	Water content is a property that can rapidly change in the oil depending also on the temperature dependent water equilibrium between oil and solid insulation. It should be measured just after the treatment to ensure that no moisture ingress occurred, but it can change quite rapidly when the unit is returned to service, see 7.5.

Asset owners can consult Table 3 or Table 5 as a guideline to decide the required target values. When ageing or contamination is extremely severe (one or more of the oil's properties largely over the "Poor" condition according to Table 5), the viability of doing reclamation should be evaluated.

Some of the above parameters are known to change with time (usually after days to weeks following treatment) after the reclamation is concluded, for example, due to ageing products and contaminants in the solid insulation which dissolve back into the insulating liquid. For this reason, the agreed end result can apply to a sample taken from the equipment immediately after reclamation in order to reflect either the efficiency of oil reclamation itself (for example using limit values of specified individual properties as given in Table 3) or can apply to a follow-up sample taken approximately 1 to 3 months after completion of treatment, or both, to reflect the real oil condition in service after conducted reclamation.

Oxidation stability of reclaimed in-service insulating liquid is not routinely measured nor are the test methods applicable (IEC 61125). For benchmarking and comparative purposes, it can be appropriate to measure oxidation stability to IEC 61125:2018, Annex B (induction period). Used oils subjected to reclamation typically do not have an oxidation stability comparable to unused oils.

A.3 Addition of inhibitor after reclamation

It is strongly recommended that inhibitor (see 7.8) is added to the insulating liquid after it has been reclaimed (this includes previously uninhibited oil). This is because the reclamation process removes both synthetic and natural occurring antioxidants, and the oxidation stability of the resulting liquid will typically be relatively poor. Therefore, inhibitor should be added or restored to the level of inhibited liquids as per IEC 60296 typically maximum 0,4 % by weight. If insufficient inhibitor is added, then the reclaimed oil ageing rate might be unacceptably high, thus it is recommended that a minimum inhibitor level (typically for aged oils in the range of 0,25 % to 0,35 %) be agreed between asset owner and service provider.

If the original inhibitor amount of the specific unused insulating oil type is known, it is recommended to dose to this point, and this can be below 0,25 %.

A.4 Time and location of sampling

A key aspect of the reclamation processes is that, depending on the electrical equipment in question, the solid insulation system might contain ageing products and contaminants that will migrate back into the insulating liquid post treatment. This means that if the main tank of the electrical equipment is sampled directly (i.e. hours) after the reclamation, the parameter's value will typically be better than if the sample is taken, for example, some weeks or months after the treatment.

It is recommended that target values are specified according to the main tank sampling point of the electrical equipment and that the asset owner agrees how long after the treatment samples should be taken, and which ones correspond to their target values.

Annex B
(informative)

General guideline for moisture %RS for continuous online monitoring

Table B.1 – Moisture %RS, continuous online monitoring, general guideline

Property	Category [a]		Recommended action limits			Notes
			Good	Fair	Poor	
Moisture (%RS when measured online at transformer operating temperature) **	All	Limits >>	< 10	10 – 20	> 20	The follow-up period shall be long enough under normal operating transformer conditions, at least one month. Broad hysteresis curve indicates potentially wet insulation. Flat hysteresis is indication of dry insulation.
		Actions >>	No action required.	Follow the %RS level during varying temperature, especially after high loading.	Consider drying solid insulation.	

[a] Category of equipment (see Table 1).

** The sensor being used shall have good sensitivity at very dry conditions and supplied with calibration at close to 0 %RS. The sensor shall have no temperature dependency i.e. be temperature compensated over the whole operating range. The sensor location should be in representative and flowing oil [5].

Annex C
(informative)

Normalizing water in oil for comparison and trending (historical practice)

C.1 General

Changes in a transformers operating temperature will result in water migration between the oil and any cellulose insulation. Therefore, normalisation for comparison and trending purposes is applied by some asset owners. The tools presented in this annex for interpreting the results are applicable only in the presence of cellulosic insulation in the equipment. Typically, this will be the active parts of power transformers and reactors. The basic idea is to normalize the measured water content of an oil sample from its sampling temperature always to the same reference temperature. Results of normalized water content should be used for moisture trending purposes to evaluate the need for additional tests or corrective actions. Additionally, normalization helps in evaluating the quality of sample taking, as normalized results should usually be similar from one year to the next.

When the normalized water content shows an increasing trend over a longer period (months), other tests as described in Table 5 are recommended to assess the moisture content of the insulation system.

The following guidance can be applied to obtain reliable results:

a) Sampling temperature ≥ 35 °C
b) Variation in operation temperature ±10 °C (max ±15 °C) within the last 12 h to 24 h before sampling
c) Accurate reading of oil temperature (always use the same measuring point)
d) Oil not treated during last 90 days
e) Unit in operation for at least one week after energizing

C.2 Sampling temperature at or above 35 °C

For a more realistic interpretation of water content and for trending purposes, the analytical result of water content of the oil at a given sampling temperature is normalized to a defined standard temperature. For practical reasons, the defined temperature is set at 20 °C. But normalization should only take place when the operating temperature is at or above 35 °C at the time of sampling; as below 35 °C, the rate of diffusion of water is too slow to achieve a state close to equilibrium in operational equipment within a reasonable time.

Normalized water content is expressed by Formula (C.1), which utilizes the normalization formula expressed by Formula (C.2) that is also shown in Figure C.1.

$$w_n = w_m \times f \tag{C.1}$$

$$f = 2{,}24\ \exp^{(-0{,}04\,Ts)} \tag{C.2}$$

Where w_n is the normalized water content, w_m is the measured water content at the time of sampling, f is the normalization factor and Ts is the transformer oil sampling temperature in Celsius.

When using the formula at temperatures below 35 °C, care should be taken with regards interpretation of the results. This is because at lower temperatures such as between 20 °C and 35 °C, the uncertainty is increased significantly due to the difficulty of achieving equilibrium.

The transformer oil sampling temperature for normalization should always be measured at the same location. Otherwise, comparison with previous results is not possible. Always using the top oil temperature can be the easiest solution.

NOTE 1 Normalized values are valid only for comparing results obtained at different oil temperatures. Actual values of water in oil at sampling points are the measured values, not the corrected ones.

NOTE 2 Some studies like CIGRÉ TB 738 [18] or TB 779 [17] show slightly different factors in the formula.

NOTE 3 These coefficients can change in the cases of severely aged oil caused by a change in partition of water in the paper and oil system.

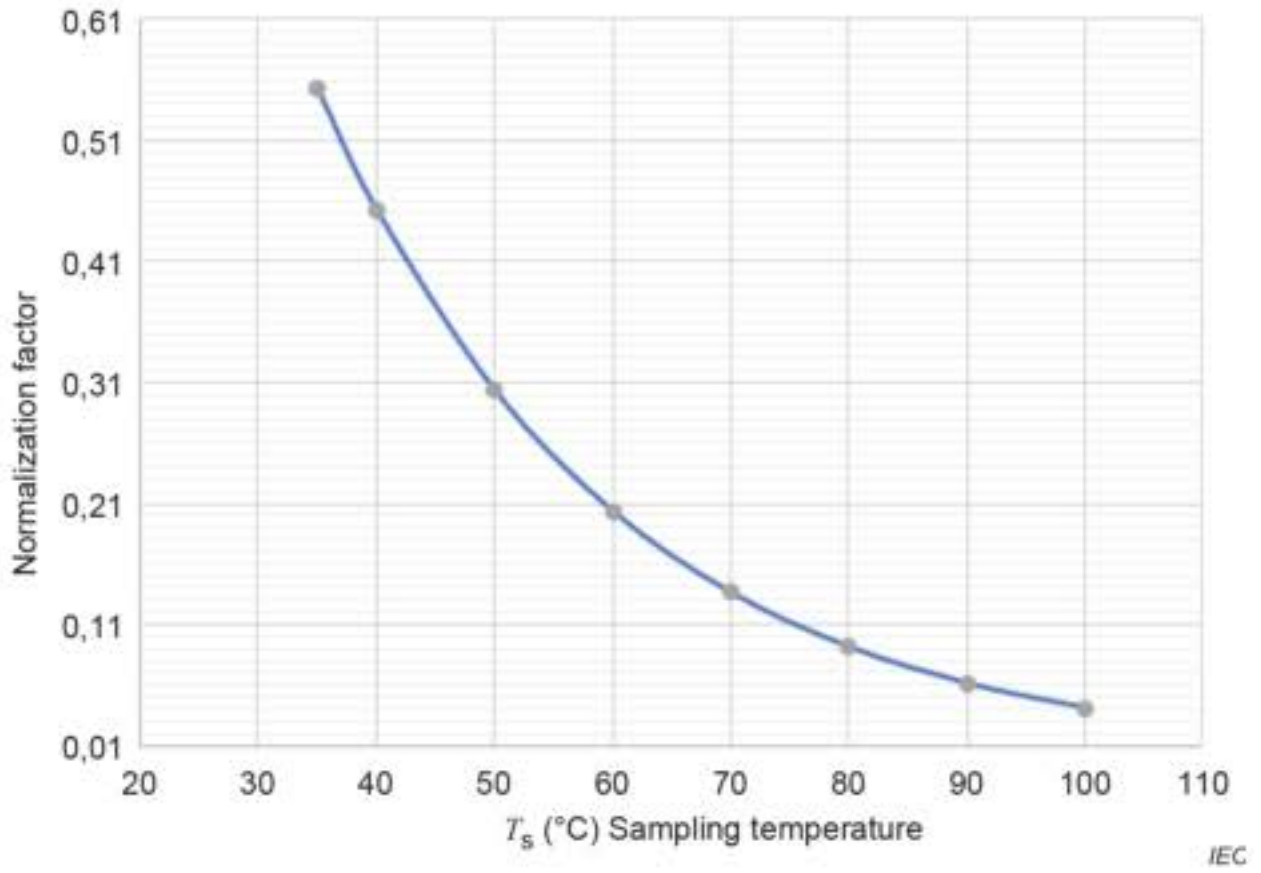

Figure C.1 – Normalization factors according to Formula (C.2)

EXAMPLE

Measured water content	10 mg/kg
Sampling temperature	40 °C
Normalization factor (from Formula (C.1))	0,45
Normalized water content (10 × 0,45)	4,5 mg/kg

Annex D
(informative)

Material compatibility

Materials incompatibility can have significant adverse consequences on a materials performance, whether solid or liquid which can ultimately impact the operability of an electrical asset.

Electrical properties (dielectric dissipation factor (DDF) and breakdown voltage (BDV)) of the oil can be negatively influenced by dissolution of the solid components (elastomers, resins, polymers, paints, etc.). Additionally, the solid materials used in the winding insulation or in gaskets can suffer dimensional changes (swelling, shrinking), therefore losing their original functionality.

Some guidelines are available in ASTM D3455 [19] but limited to the procedure for testing the compatibility.

Compatibility tests between the oil and other materials used in the apparatus (and in contact with the oil) are usually performed during the apparatus design process.

For oils in service, a problem with compatibility can arise in cases where replacement of one or more of the components (e.g. the oil, gaskets, etc.) involved has been carried out. If the replaced components are of different materials from the original ones, a compatibility check shall be required.

If the in-service mineral oil is replaced with a new one (fulfilling the requirements of IEC 60296), it can be assumed that materials compatibility is fully respected.

In cases of retro-filling with a liquid different from a mineral oil (or not fulfilling IEC 60296), or replacement of parts in contact with the oil with new ones of different material, the manufacturer of the equipment should be contacted for additional guidance.

As a confirmation of materials compatibility for equipment in service, it is a good practice to visually inspect all material surfaces accessible during maintenance activities for signs of deterioration, leakage, discoloration, or deformation.

When compatibility is to be checked between the materials and a new insulting liquid used in the equipment, tests of short duration at low temperature as detailed in IEC 63177[4] and ASTM D3455 [19] can be performed but can only reveal macroscopic incompatibilities.

Realistic, long duration tests are recommended in all cases but especially for high voltage application.

An increased temperature in the compatibility test can accelerate the reaction reducing the test duration, but caution should be taken to prevent changes in either reaction thermodynamic or kinetics, or both, that can lead to overstated degradation of the material.

A proper materials ratio in terms of volume or area or weight should be chosen between liquid and solid for simulating a real transformer design.

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4 Stage at the time of publication: IEC FDIS 63177:2024.

At the end of the test, the relevant properties of the constituents should be measured:

- for oil, e.g. colour, DDF, BDV, water content, acidity, interfacial tension, dissolved gases, etc.
- for solid materials, e.g. tensile strength, dimension, weight, elastic modulus, etc.

A blank test using the same ageing conditions but without solid material shall be carried-out for reference. The acceptance limits should be expressed, where possible, in terms of variation from the blank values (oil) or the initial value (solid).

Annex E
(informative)

Test method for determination of sediment and sludge

E.1 Sediment determination

To determine sediment:

a) weigh a P 10 glass filter or a suitable 8 μm membrane filter to the nearest 0,1 mg;
b) filter 100 g of a homogenized sample of the oil through the glass filter;
c) flush the filter with 100 ml of n-heptane in portions until the filter is free from oil;
d) dry the filter at 105 °C, weigh the filter and calculate the amount of sediment in %.

E.2 Sludge determination

To determine sludge:

a) take 25 g of the filtered oil from the sediment determination;
b) follow the procedure for sludge precipitation and calculation described in IEC 61125:2018, 4.8.1.

Annex F
(informative)

Contamination of oils with silicone

Mineral insulating oils accidentally contaminated with silicone, phthalates or other surface-active chemicals or oils can cause undesired slow de-aeration or excessive foaming in oil when trying to degas the transformer, thus making it difficult or impossible to fully degas the mineral insulating oil. The air release test of ISO 9120 and foaming tendency test of ISO 6247 can be used to indicate such contamination. Oil change or reclamation can be a solution to such a problem. This can be accompanied by the cleaning of contaminated parts.