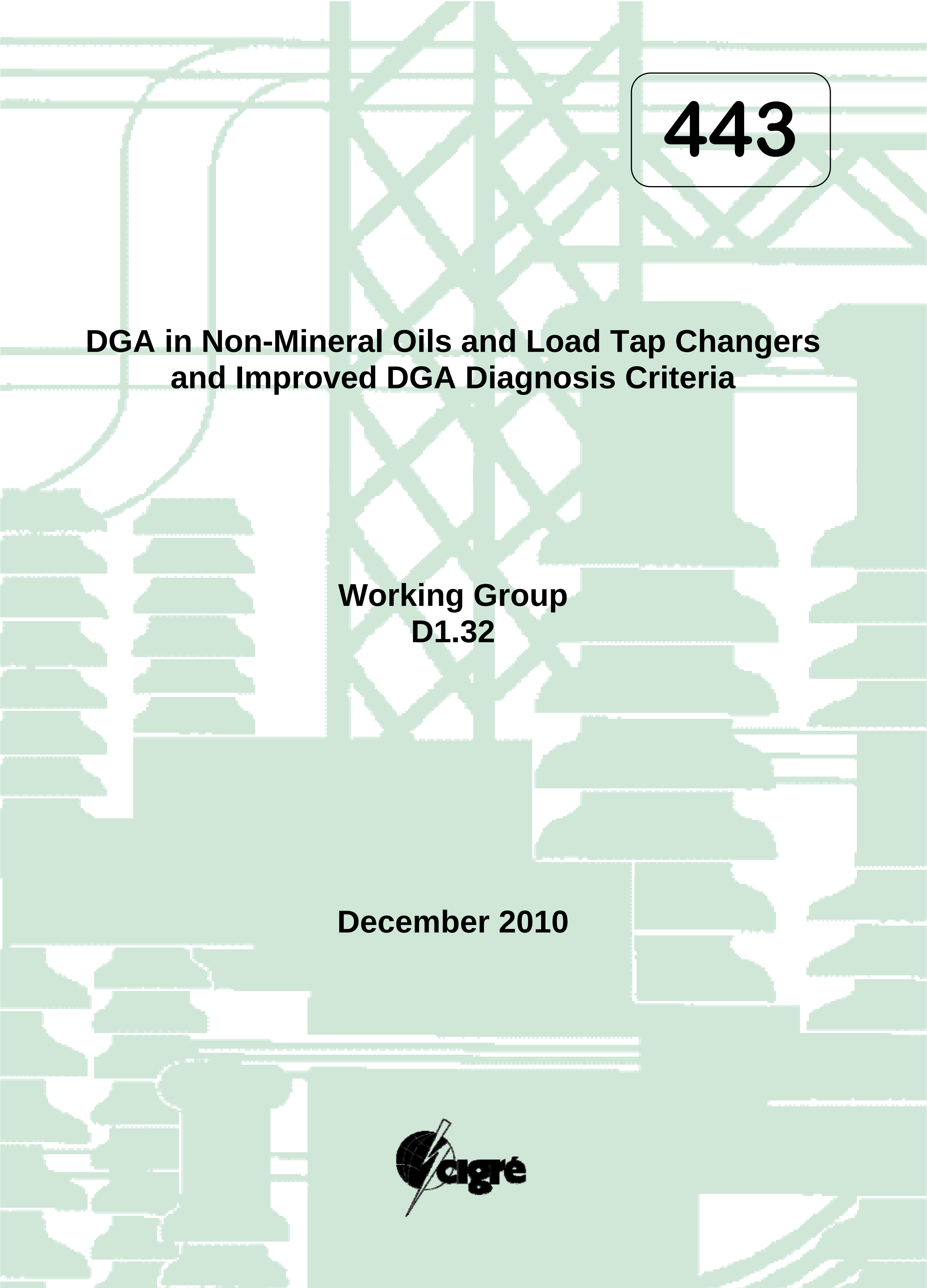

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DGA in Non-Mineral Oils and Load Tap Changers and Improved DGA Diagnosis Criteria

Working Group
D1.32

December 2010

WG D1.32

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ISBN: 978- 2- 85873- 131-2

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1 EXECUTIVE SUMMARY

1.1 Introduction

Dissolved gas analysis (DGA) is widely used for detecting faults in insulating fluid-filled, high voltage electrical equipment in service. Historically, DGA has been applied mainly to transformers filled with mineral oils. This report presents progress made by WG D1.32 (WG32) concerning:

-the application of DGA to non-mineral oils.
-the application of DGA to load tap changers.
-the effect of oil sampling on DGA results.
-the use of DGA during heat-run tests on repaired or upgraded transformers.
-gas losses from transformers of the open conservator-type.
-stray gassing of passivated oils.
-the use of DGA in continuously degassed transformers.
-the formation of carbon oxides in mineral oil-filled transformers.

1.2 Application of DGA to non-mineral oils

Non-mineral oils such as natural and synthetic esters are increasingly used for applications in transformers where less-flammable or environmentally-friendly oils are desirable. It has been evaluated by WG32 that the analytical techniques and interpretation methods used for mineral oils can be used with some adjustments for non-mineral oils.

On the analytical side, a significant difference concerns the partition coefficients used for calibrating the Head Space method with standard gas mixtures. These coefficients are quite different for non-mineral oils for some gases and are provided in this report at 20°C.

The recommendation of WG32, however, is rather to calibrate the Head Space method with gas-in-oil standards, for both mineral and non-mineral oils. This does not require the knowledge of partition coefficients.

Values of the solubility of air in the different oils are also indicated in this report.

The interpretation of DGA results is basically the same as for mineral oils, and the small adjustments to fault zone boundaries that are necessary for non-mineral oils are provided in this report.

Non-mineral oils appear to be more stray gassing than mineral oils, and tools are provided to distinguish this stray gassing from more serious faults in service such as carbonization of paper.

Typical concentration values in service are lower than with mineral oils, but this could be due to the relatively small number of DGA results available with non-mineral oils.

1.3 Application of DGA to load tap changers

DGA is often considered as difficult to apply to load tap changers (LTCs) because normal operation of this equipment involves arc-breaking between LTC contacts and/or resistor heating, which interferes with the identification of actual faults in the LTCs.

This report provides interpretation methods allowing the detection of faults in LTCs where arc breaking occurs:

- in oil (reactor and resistor types).
- in vacuum (reactor and resistor types)
- with commutation switches in the same or in separate oil compartments

A more precise classification of LTCs is given in the report.

Gas levels in LTCs depend very much on the number of operations. After a change of LTC oil, contamination by the previous oil must be taken into account before attempting a diagnosis.

An example of heavy coking on LTC contacts is shown in Figure 1.

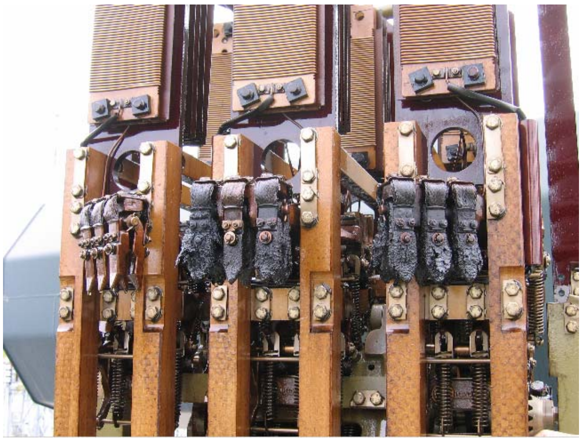


Figure 1: Example of heavy coking on LTC contacts [28]

1.4 Improved DGA diagnosis criteria

Recommendations are made by WG32 to minimize the effect of manual oil sampling on DGA results, concerning the quality of sampling devices used and procedures to avoid the formation of bubbles in oil.

Values of pre-failure gassing rates observed in transformers in service on different networks are provided, and recommendations made concerning the sampling intervals and levels of attention required as a function of gas concentrations, gassing rates and a combination of concentrations and rates in transformers in service.

It is shown that DGA can be used during heat-run tests on repaired or upgraded transformers which have been vapour-phase dried before the tests.

Gas losses from transformers of the open conservator-type do not appear to have a very significant effect on typical values and gas levels in service.

The addition of a passivator additive in oil to alleviate copper sulphide deposition in transformers in service increases the stray gassing of the oil.

When transformers are continuously degassed to remove oxygen from oil in service, an online gas monitor must be used to be able to detect faults by DGA.

High values of the CO_2/CO ratio in transformers in service are related to accelerated paper aging. Low values of this ratio in sealed transformers do not appear to indicate paper involvement in the faults as is usually the case in air-breathing transformers.

2 INTRODUCTION

Dissolved gas analysis (DGA) is among the most powerful tools for detecting faults in electrical equipment in service. For that reason, DGA analytical techniques and interpretation methods are continuously being investigated and improved.
CIGRE in particular has done a lot of work on DGA in the past decade. The new laboratory techniques of gas extraction developed during the late 90's have been evaluated by Task Force TF 15.01.07 [1] and introduced into IEC Standard 60567 in 2005 [2].
The typical gas concentrations and rates of gas increase observed in transformers in service worldwide have been surveyed by Joint Task Force JTF D1.01/A2.11 (TF11) [3] and have been introduced into IEC Standard 60599 in 2007 [4]. TF11 has also made significant progress concerning pre-failure concentrations in service, stray gassing of oils at relatively low temperatures, gas formation from paper, and gases trapped in paper insulation.
In 2008, TF D1-01-15 (recently renamed WG.D1.15 then WG D1.32 or "WG32") has prepared a CIGRE Brochure [5] on gas monitors, devices which are increasingly used to follow gas and fault formation in transformers on-line.
The present document reports the findings of WG32 on the other subjects it has examined:
-application of DGA to non-mineral oils and load tap changers.
-pre-failure rates of gas increase in service and oil sampling for DGA.
-heat-run tests on repaired transformers and on-line degassing.
-solubility of gases in oils and carbon oxide formation in service.

Note: superscripts in this report (from [1] to [27]) refer to members of WG32 who made specific contributions to the report (unpublished data or concepts). The list of superscripts and corresponding authors can be found in section 9. References to published documents (from [1] to [21]), are listed in section 7.

3 APPLICATION OF DGA TO NON-MINERAL OILS

Still today, most transformers and electrical equipment in service are filled with mineral oil. Non-mineral oils (such as natural and synthetic esters and silicone oils) are increasingly used, however, for special applications where less flammable or more biodegradable oils are desirable (such as indoors, in urban areas or in railway transformers).
The DGA analytical techniques and interpretation methods to use with such oils have been examined by WG32.

3.1 DGA analytical techniques for non-mineral oils

It has been evaluated by WG32 that the same basic techniques used for mineral oils can also be used for non-mineral oils with a few adjustments.

For the extraction of gases dissolved in oil, all the methods described in IEC 60567 [2] can be used (Toepler, Partial Degassing, Stripping, Head Space). A small adjustment in the case of non-mineral oils concerns the equilibrium time necessary for gas extraction. The more viscous the oil, the longer the equilibrium time, typically 10 to 15 minutes (or higher) for the more viscous silicone oils vs. 1 to 3 minutes for mineral oils (see section 7 of 60567 [2]).

A more important adjustment concerns the calibration of the Head Space method with gas standards (section 7.5.5.2 of 60567 [2]). This procedure requires knowing the partition coefficients of gases in oil, which are very different in mineral and non-mineral oils for several gases.

Round robin tests have thus been organized by WG32 to determine the partition coefficients of gases in non-mineral oils, using the two head space methods recommended in IEC 60567 [2]: gas-in-oil standards and the slope/intercept method (section 7.5.5.3).

Gas-in-oil standards have thus been prepared [4, 5], and analyzed by several experienced laboratories [2-5, 19], using the Head Space method. The corresponding partition coefficients k were then calculated using equation (2a) of IEC 60567 [2] (section 7.5.5.3), with C_L = known gas concentrations in the prepared gas-in-oil standard and C_G = gas concentrations in the gas phase of the vials measured by gas chromatography.

Examples of k values thus obtained for mineral oil are indicated in Table A1 of Annex A. The large dispersion of values suggests that the measurement of k values by head space is dependant on the analytical conditions used by individual laboratories and therefore not reliable. The same dispersion of results is observed with non-mineral oils. Laboratory procedures using the Headspace method must establish partition coefficients related to the analytical equipment used.

Partition coefficients also appear to be strongly dependant on gas concentrations, as illustrated with mineral oils in Table A2 of Annex A [2]. The same concentration dependence is observed with non-mineral oils [2].

The poor reproducibility of head space extraction efficiency between laboratories, especially for the less soluble gases, has been proposed to explain this large dispersion of results [4]. The non-linearity of the calibration curves used for the Head Space method at the phase ratios used in the vials, as shown for example in Figure A1 of Annex A[5], may also be a reason for the unreliable values also obtained when using the slope/intercept method.

As a result, the k values that have been published so far for non-mineral oils and determined by the head space method are uncertain and are not recommended for general use.

A more direct and reliable method for the determination of partition coefficients has been developed by WG32 [4]. It consists in bubbling in oil pure gases or 1% mixtures of these gases in air up to equilibrium, extracting these gases completely using Toepler or Partial Degassing with multiple cycles of vacuum extraction, then measuring the total volume of gas extracted. The k values thus obtained at equilibrium, also known as the solubility coefficients, are indicated at 20°C in Table 1 for different types of mineral and non-mineral oils [4], using 1% mixtures.

Table 1: Solubility/ partition coefficients k of gases in mineral and non-mineral oils at 20°C [4]

Gas:	H_2	O_2	N_2	CH_4	CO	CO_2	C_2H_2	C_2H_4	C_2H_6	C_3H_6
Oil type:										
Mineral	0.0504	0.172	0.091	0.423	0.125	1.10	1.25	1.81	2.88	9.64
FR3	0.0471	0.134	0.074	0.341	0.108	1.54	2.58	1.67	2.14	7.46
Midel	0.0479	0.152	0.091	0.378	0.130	2.08	4.26	1.85	2.20	7.67
Silicone	0.0869	0.267	0.155	0.580	0.189	1.63	2.04	2.18	3.10	9.91

It has been observed [4] that k values may vary depending on the matrix of gases present in oil. For instance, with all types of oils they are 10% lower for hydrogen when using 1% mixtures of hydrogen in air rather than pure hydrogen. With silicone oils they are 8% lower for carbon monoxide. They also depend on the high or low levels of air, nitrogen or fault gases present in oils, and may thus be different in sealed and air-breathing equipment. They depend on the chemical composition of oils and are different in oxidized oils [6] and in the presence in oil of chemicals such as acetone [2,4-6].

Calibrating the Head Space method with gas standards is thus considered by WG32 [2,5] as not reliable because of this uncertainty on k values. The procedure recommended by WG32 [2, 5] rather consists in using the calibration method described in section 7.5.5.1 of IEC 60567 [2] with several gas-in-oil standards at different concentrations. These oil standards can either be purchased or prepared in the laboratory according to section 6 of IEC 60567 [2]. With this procedure, k values do not need to be known.

The determination of k values at 70°C is in preparation[4], for those who would still want to use the procedure of calibration of the Head Space method with gas standards, even though it is not recommended by WG32. The experimental set-up necessary for this determination at 70°C is more complex and will be available only after this report has been completed.

The solubility of air in different types of mineral and non mineral oils has also been determined by WG32 [3], since it is an alternative method proposed in Annex D of IEC 60567 [2] for verifying the overall extraction efficiency of DGA analytical techniques. The method used consists in leaving a sample of degassed oil in contact with the atmosphere at a given temperature until air saturation is reached, then analyzing the air content by DGA. The values thus obtained are indicated in Table 2 [3].

Table 2: Solubility of air in mineral and non-mineral oils at 20°C [3]

Oil type	Density	ppm			Ostwald (k)		
		O_2	N_2	CO_2	O_2	N_2	CO_2
Mineral	0.8783	33480	64760	577	0.160	0.083	1.154
Mineral (aged)	0.8869	31893	61632	393	0.153	0.079	0.786
BioTemp	0.9158	24507	50177	625	0.117	0.064	1.250
FR3	0.9210	21995	49613	647	0.105	0.064	1.294
Midel	0.9197	21705	45268	555	0.104	0.058	1.110
Silicone	0.9645	54938	113078	763	0.263	0.145	1.526

The solubility of air in mineral oil at various temperatures has also been determined [3] and is indicated in Table 3. The concentration of nitrogen in oil at saturation can be seen to depend on temperature. It also depends on the amount of oxygen and fault gases in oil [4]. It therefore cannot be used as a universal “natural internal standard” as mentioned by one manufacturer of on-line gas monitors, since the temperature of oil varies inside transformers with time, climate, design and load.

Table 3: Influence of temperature on the solubility of air in mineral oil [3]

Temp. °C	O_2	N_2
13	32937	62798
21.5	32750	63728
25	32483	64061
50	31465	66141

The recommendations of WG32 reported in this section 3.1 have been proposed for the revision of IEC 60567 [2] presently in progress.

3.2 Identification of faults in non-mineral oils

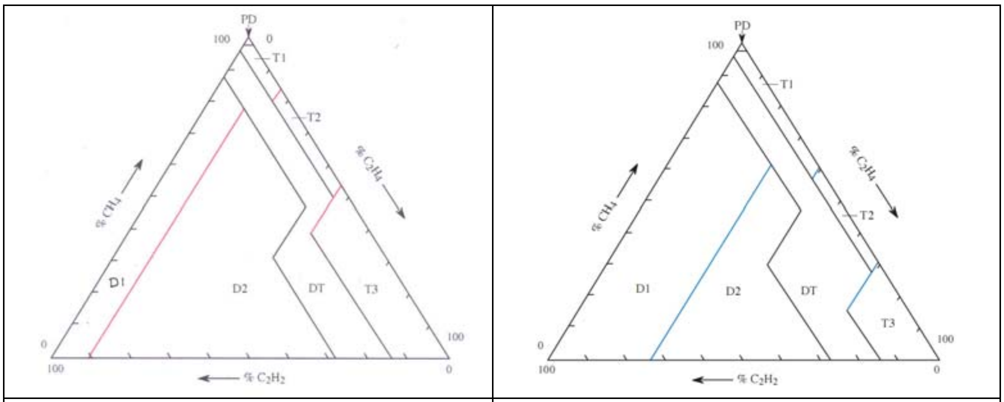
DGA interpretation methods for mineral oils are based on a large number of cases of transformers in service where gas formation could be attributed to a specific type of fault by visual inspection of the transformer. Very few such cases are available so far for non-mineral oils, because these oils have been used only recently and in a relatively small number of transformers. None has been reported to WG32.

By subjecting mineral and non-mineral oils to exactly the same thermal and electrical faults simulated in the laboratory, however, and by comparing gas formations in both oils, it is possible (with caution) to somehow predict the gas formation patterns which are likely to occur when non-mineral oils are subjected to actual faults in service.

A few such laboratory data comparing mineral and non-mineral oils have been published [6-12]. They indicate that gas formation patterns are basically the same in mineral and non-mineral oils (the same types of gases are formed for a given type of fault), but with some quantitative differences in the ratios of gases formed.

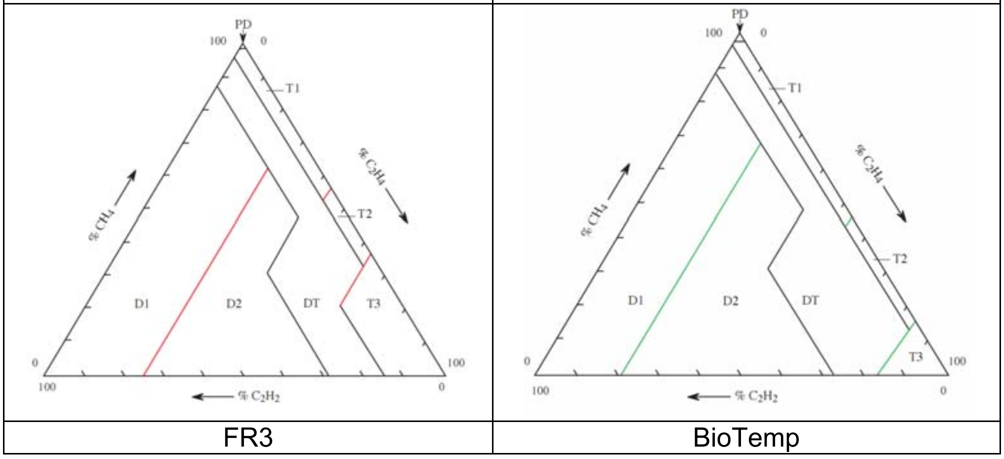
Figure B1 of Annex B indicates the differences observed between mineral oil and 4 different types of non-mineral oils. They occur mostly in the T1-T3 zones of thermal faults. From these differences, it is possible [13] to adjust zone boundaries for each type of non-mineral oil as indicated in Figure 1 and Table 4. Values in brackets in Table 4 are extrapolated and will need to be confirmed in the future. These zone boundaries for non-mineral oils, based on laboratory comparisons with mineral oils, may need some further adjustments when actual cases of faults are reported in transformers in service. Until then they can be used by default.

Fault zones in Figure 1 are the same as in the classical Duval Triangle for mineral oil: PD = Corona Partial discharges; D1 = Discharges of low energy; D2 = Discharges of high energy; T1 = Thermal faults of temperature < 300ºC; T2 = Thermal faults of temperature 300ºC < T < 700ºC; T3 = Thermal faults of temperature > 700ºC; DT = mixtures of electrical and thermal faults.



Silicone

Midel



FR3

BioTemp

Figure 1: Identification of faults in non-mineral oils

Table 4: Fault zone boundaries for non-mineral oils (when different from mineral oils), in % C_2H_4

Boundary between zones:	Mineral oils	Silicone	Midel	FR3	BioTemp
D1/ D2	23	9	26	25	20
T1/ T2	20	16	39	43	52
T2/ T3	50	(46)	(68)	63	(82)

Pyrolysis tests of the T3-type on mineral and non-mineral oils have also been performed at 700 and 1200 °C by WG32 [7] and are indicated in Table B1 of Annex B. They suggest that some small additional adjustments to the T2/T3 zone boundaries of Figure 1 may be necessary in the future, when inspected cases of such faults in transformers become available.

Laboratory test results should be used only with caution to predict the actual temperature of faults in transformers in service, because faults in transformers are more complex than faults in the laboratory in terms of paper-to-oil ratios involved, temperature gradients around the fault, and oil convection.
It has thus been observed with mineral oils (in Figures 3-5 of ref. [14]) that the same gas formation pattern may be related to different temperatures:
-measured in laboratory tests in oil only.
-measured in laboratory in paper only
-actually observed in transformers by visual observation of the damage done.
The actual temperature of insulation decomposed to form gases during laboratory tests may also be different from the measured temperature, because of temperature gradients.

When comparing two different oils (mineral and non-mineral oil) under exactly the same experimental conditions in the laboratory, however, it is not necessary to know for sure these actual temperatures.

Some non-mineral oils such as natural esters (e.g., FR3) are more stray gassing than mineral oils, producing significant amounts of gases such as hydrogen and ethane at relatively low temperatures of 90 to 200°C [12] which are considered only as mild overheating. Such stray gassing can be distinguished from more severe overheating or carbonization of paper by using the Triangle for low temperature faults in FR3 [15], indicated in Figure 2.

Fault zones in Figure 2 are identified as: S = Stray gassing of FR3; C = Hot spots with carbonization of paper (T >300°C); O = Overheating (T < 250°C).(zone PD = Corona Partial Discharges which occurs in the right upper part of the Triangle is not indicated in Figure 2).

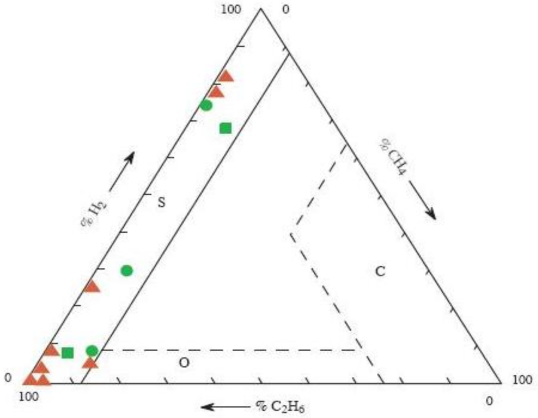


Figure 2: Identification of stray gassing in FR3 oils with the Triangle for low temperature faults

The higher stray gassing tendency of FR3 has tentatively been related to its higher viscosity [3] or to the additives it contains [8]. Very little stray gassing, however, has been observed at 250°C with silicone oils [5], despite their high viscosity.

3.3 Typical concentration values in non-mineral oils

Evaluating typical concentration values in transformers filled with non-mineral oils requires data banks of DGA results in service with such oils. Very few such data have been made available to WG32.

The 90% typical concentration values reported for non-mineral oils are indicated in Table 5. They appear to be lower than for mineral oil, possibly because it takes higher temperatures to form gases with such oils, or because too few data are available so far to be really representative of their actual behaviour in service.

Table 5: Examples of 90% typical concentration values observed in non-mineral oils

Ref.	Oil type	Network	Traction	H2	CH4	C2H4	C2H2	C2H6	CO	CO2	Population
[4]	Mineral	X		100	80	170	3	55	500	8900	> 20,000
[22]	Midel	X		37	68	70	1	50	1148	4120	138
[1]	FR3	X		35	12	12	1	20	400	3000	180
[14]	BioTemp	X		41	7	5	1	4	199		38
[2]	Silicones		X	25	28	1	1	0	405	2614	25
[2]	Midel		X	21	7	9	2	2	201	1536	38

3.4 Gas formation in hybrid systems

Only inconclusive laboratory DGA data concerning the decomposition of the high temperature-grade papers and boards (aramid based papers and boards such as Nomex®) used in "hybrid systems have been reported to WG32[7, 5].

Pyrolysis testing without the presence of oxygen indicated that up to 250°C only water is detected (equal to the moisture regain of the paper and board). Between 250°C and 350°C a small amount of DMAc (dimethyl acetamide) can be detected. The DMAc is from the manufacturing process and is not a degradation product. Degradation (under pyrolysis) of the aramid paper and board occurs between 450°C and 1000°C with major components being CO_2 and high molecular weight hydrocarbons[7].

4 APPLICATION OF DGA TO LOAD TAP CHANGERS

A high percentage of transformer failures are due to load tap changer (LTC) failures. However, because of the interference of gases produced by the normal operation of LTCs, DGA has long been considered as difficult to apply to LTCs, or even as not applicable to some types of LTCs [16].

To be able to detect abnormal faults in LTCs by DGA, their normal operation must first be identified precisely. Depending on the electrical components used and their operating conditions in service, normal operation in oil may involve various combinations of arcing between contacts and/or heating in transition resistors.

4.1 Classification of LTCs according to electrical components used and type of design

To evaluate the gas generation of tap-changers, it is necessary to distinguish between the different tap-changer types which are worldwide in service. The following classification of LTCs has been proposed[12] and is indicated in Table 6.

Table 6: Classification Scheme for LTCs

A	Arc-breaking in oil for breaking/making load current		
V	Vacuum interrupters for breaking/making load current		
	R	Bridging current through resistors (Resistor type)	
	X	Bridging current through reactances (Reactor type)	
		S	Diverter switch and Tap selector in different oil compartments (Separate)
		C	Diverter switch and Tap selector in the same oil compartment (Combined)

For example, an LTC of the vacuum interrupter type using reactance bridging, with all contacts in one compartment, will be classified as “VXC”. An LTC of the arc-breaking-in-oil type using resistor bridging, with the diverter switch and tap selector in separate oil compartments, will be classified as “ARS”. Such a classification of commercially available LTCs has been made [12] and is indicated in Table C1 of Annex C.

Note [12]: Investigations have shown, that, for diverter switches with vacuum interrupters, sparking or low-energy arcing can occur on commutation contacts (by-pass switches), which are present in the diverter switch oil compartment. This is independent of the behavior of the tap selector, which may show arcing on the change-over selector contacts. When reversing the regulating winding or adding a coarse-tap winding, the potential of the regulating winding is determined by the capacitive coupling of the regulating winding with the neighboured winding(s) and/or the core. The capacitive current and recovery voltage has to be borne by the change-over selector contacts.

4.2 Classification of LTCs according to gases formed during normal operation

Depending on the design, different gas-generating components contribute typical gas patterns. These gas patterns superimpose and form type-specific gas mixtures in the tap-changer oil.
Generally, the following gas sources can be present:

- Arc-switching contacts : arcing gases
- Commutation contacts, by-pass contacts : sparking gases
- Vacuum interrupters : no gases
- Transition resistors : heating gases ≤300°C (normal operation)
  heating gases >300°C (overload, fault case)
- Transition reactance (preventive autotransformer, inside transformer tank) : no gases

Normal operation of LTCs using arc-breaking contacts, by-pass switches or change-over selectors (components A) may produce arcing gases D1 in oil. Transition resistors (component R) may produce thermal gases (T3, T2 or T1). Vacuum interrupters and transition reactances (components V and X) cannot produce gases.

However, some of these components may or may not contribute gases during normal operation, depending on the design and how they are operated in service (transformer load), so that the gases formed during normal operation of complex LTCs (particularly of the ARS type) cannot be reliably predicted with the classification of Tables 6 and C1 alone.

For the purpose of fault identification by DGA, LTCs should rather be classified according to gases formed during normal operation, as indicated in Table 7, which is based on observations available so far [1].

Table 7: Classification of LTCs according to gases formed during normal operation

LTC type				Main gases formed during normal operation		
Classification acc. to Table 6		Compartment type	In-tank type	Arcing D1	Thermal T3/T2	Thermal T1
Arc-breaking-in-oil type	AXC, AXS	X		X		
	ARC, ARS	X		X		
	ARS type 1		X	X		(X)
	ARS type 2		X		X	
	ARS type 3		X	(X)	(X)	
	ARS type 4		X	X	X	
Vacuum type	VXC	X				
	VRC		X	(X)		(X)
	VRS		X	(X)	X	

(X): depending on the mode of operation

Compartment types indicated in Table 7 correspond to LTCs with similar gas formation during normal operation and manufactured for example by ABB, Allis Chalmers, Cooper, Federal Pioneer, GE, McGraw Edison, Moloney, Reinhausen, Siemens, Waukesha and Westinghouse.
In-tank types indicated in Table 7, as an example, correspond to LTCs of the OILTAP® and VACUTAP® series manufactured by Reinhausen.

Gas amount and gas composition depend on additional parameters, like:

- Number of operations/day
- Actual percentage load of the transformer
- Stray gassing behaviour of the oil
- Venting system (sealed/not sealed)

However, these will not significantly change the classification of Table 7.

4.3 Fault identification in LTCs

4.3.1 LTCs of the arc-breaking-in-oil compartment type

A large majority of the LTCs presently in operation are used in North America and are of the arc-breaking-in-oil compartment type ("conventional oil type"), as indicated in Table 7 (AXC, AXS, ARC and ARS). Specific methods of interpretation of DGA in these LTCs have been developed, such as the Stenestam code [14], the C_2H_4/C_2H_2 ratio and the Triangle method [13]. The coloured dots in Figure 3 using the Triangle method correspond to actual cases of faults or normal operation inspected in service in LTCs of these types.

The experience so far is that LTCs of the conventional oil-types have very similar gassing behaviour during normal operation, suggesting that the resistors used in LTCs of these ARC and ARS types do not contribute significantly to gassing during normal operation.

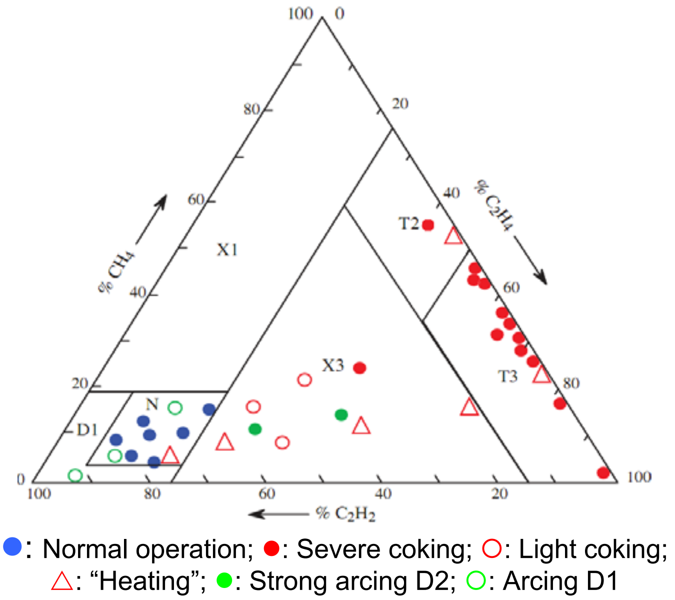


Figure 3: Identification of faults in LTCs of the arc-breaking-in-oil compartment type (conventional oil type)

Fault zones in Figure 3 are: N = Normal operation of the LTC; T3 = Severe thermal faults of temperature > 700 ºC; T2 = Severe thermal faults of temperature 300 ºC < T < 700 ºC; X3 = fault T3 in progress (in a majority of cases), or abnormal severe arcing D2; D1 = Abnormal arcing D1; X1 = possibly thermal fault T1 (T < 300 ºC) in progress.

The normal operation zone N indicated in Figure 3 applies to all LTCs of the conventional oil-types monitored by DGA so far. For specific individual types of such LTCs, the actual size of the N zone is usually smaller and should preferably be determined first in order to more precisely detect cases of abnormal operation occurring outside of the N zone.

In zone X3, to distinguish between faults T3 in progress and abnormal arcing D2, it is suggested to change the oil and run a few LTC operations (~ 100). If the DGA point moves towards the N zone, this may indicate a fault T3 in progress, since it takes some time for temperature to rise to T3 levels on LTC contacts. If the DGA point remains unchanged, it is more likely abnormal arcing D2.

The Triangle method of Figure 3 has been applied to DGA data in LTCs of the conventional oil-types provided by members of WG32. Results are indicated in Figure C1 of Annex C. They confirm the attribution of fault zones in Figure 3. Two examples of gas formation change with time in service are indicated in Figure C2 of Annex C.

4.3.2 LTCs of the arc-breaking-in-oil in-tank type ARS

The normal operation of LTCs of the ARS in-tank type may involve arc-breaking-in-oil but also current dissipation in the transition resistors [16]. Depending on the design of the contact system, actual load current and dimensioning of transition resistors, arcing gases or/and thermal gases may be formed, as can be seen in Table 7.

For example [1], as indicated in Figure C3(a) of Annex C, normal operation of LTCs of the in-tank ARS type 1 is observed first in the N (arcing) zone of Figure 3, then moves slowly towards the thermal zone T1, due to heating of oil at relatively low temperatures.

Two examples of gas formation change with time in LTCs of the in-tank ARS type 1 are indicated in Figure C4 of Annex C. Gas formation moving towards the T1 zone after an oil change corresponds to normal operation according to Figure C3(a) of Annex C, while gas formation moving towards the T3 zone might indicate some overheating.

In Figure C3(b) of Annex C, the normal operation of LTCs of the in-tank ARS type 2 involves heating of the resistors at high temperatures, so that their normal operation occurs in the lower part of zones T3 and X3.

4.3.3 LTCs of the vacuum type VXC

In LTCs of the vacuum reactor VXC type, normal operation involves only arc-breaking in a vacuum bottle. The change-over selector in the oil of such LTCs operates very seldom [12] and is not expected to contribute arcing gases in oil, or only very low insignificant amounts.

Any significant gas formation in the surrounding cooling oil therefore indicates some abnormal behaviour of the LTC (electrical or thermal), which can be identified using the same methods as for transformers, e.g., the general Triangle for transformers filled with mineral oils indicated in Figure C5 of Annex C. Gas levels in the oil of such LTCs are usually very low.

Figure C5 of Annex C also indicates a few cases of abnormal operation in such LTCs, which are mostly located in the thermal fault zones (T2, T3), with indeed no arcing gases observed.

4.3.4 LTCs of the vacuum types VRC and VRS

Normal operation of LTCs of the VRC and VRS types may involve current heating through transition resistors and/or sparking of commutation contacts (by-pass switches) immersed in the surrounding cooling oil [12]. In such LTCs, thermal and/or arcing gases may thus be formed during normal operation, as indicated in Table 7, and this appears to depend very much on the mode of operation of these LTCs.

For example, the gassing behaviour of two LTCs of the vacuum in-tank type VRC [12] is indicated in Figure C6 of Annex C. In service (Figure C6a of Annex C), normal operation occurs mostly in the N zone of Figure 3, suggesting that only sparking of the commutation contacts is involved, with no significant contribution from the resistors [1].
During power switching tests in the factory [12], however, normal operation occurs in the T2/DT zone (Figure C6b of annex C), suggesting that mostly heating of the resistors is involved, at relatively high temperatures T2, with only a minor contribution of the commutation contacts. Only the last part of the normal operation curve in blue is significant (gas levels are low and unreliable in the first parts).

In Figure C7 of Annex C, the normal operation of LTCs of the vacuum in-tank type VRS also occurs in the T2/DT zone [1, 12].

4.4 Gas levels in LTCs

A relatively constant amount of gas, which depends on the type of LTC, is formed per LTC operation during the normal operation of LTCs, as illustrated in Table 8 (in ppm of total dissolved combustible gases). Significantly larger amounts are formed in the case of abnormal operation.
Looking at gas levels in service without taking into account the number of operations may therefore be misleading. Furthermore, the number of operations is seldom available from LTC operators.

Table 8: Examples of normal gas formation per LTC operation

Ref.	LTC type	~ ppm/1000 operations
[1]	AXC and ARC	500
[1, 12]	VXC	0 -10
[12, 1]	ARS	6000
[12, 1]	VRC and VRC	10-30

4.5 Minimum gas concentrations for attempting diagnosis in LTCs

Identification of faults in LTCs should be attempted only when gases in oil are above a minimum level (~ >10 ppm of C_2H_2 and/or C_2H_4), because of laboratory uncertainty at low gas levels [17].

Furthermore, for LTCs where the oil has been removed and replaced by new oil, contamination by the previous oil may occur, especially if the LTC has been subjected to a large number of operations [1]. The amount of oil left on LTC surfaces after changing the oil has been evaluated at about 0.16% [6], and should be taken into account to determine the minimum level of gases above which this oil leftover may interfere with diagnosis. For example, if concentration of a gas in the previous oil was 10,000 ppm, only levels of this gas above 16 ppm in the new oil should be used for diagnosis.

5 IMPROVED DGA DIAGNOSIS CRITERIA

5.1 Oil sampling for DGA

It has been suggested, based on systematic differences between readings of some on-line gas monitors and the corresponding laboratory results, that manual oil sampling could lead to losses of gases from the oil (particularly the less soluble ones like H_2 and CO), and/or contamination of the oil with oxygen or air (in sealed equipment).

A survey has thus been organized by WG32 to investigate if and how oil sampling actually affects DGA results. The most frequently mentioned concerns related to oil sampling are the lack of training or experience of sampling personnel, standard sampling procedures not followed properly, need for more detailed sampling procedures, use of poor quality sampling equipment, formation of gas bubbles in syringes and contact of oil in bottles with atmospheric air when sampling.

It has been found by WG32 that bubbles are observed on average in only 20% of syringes received by laboratories, and large bubbles (of more than 0.3 ml or 5 divisions in a 25 ml syringe) in 2% of cases. These percentages are lower for some laboratories and higher for others, which would need to improve their sampling skills. The matter of bubbles in syringes therefore is not a general sampling problem but one limited to a relatively small number of laboratories. Using good-quality syringes with matched piston and barrel, priming the piston with clean oil before sampling and using well-trained and experienced sampling personnel are recommended by WG32 to avoid gas bubbles in syringes.

Gas bubbles in syringes do not affect DGA results using the Toepler and Partial Degassing methods, since the bubbles are injected in the extraction vessel with the oil. With the Head Space method, however, the bubbles are not injected with the oil and gas losses by diffusion from the oil to the gas bubbles should be calculated. A similar correction should be made for the air gap left in rigid (glass or metallic) bottles used for sampling for DGA.

Examples of calculated and measured gas losses from oil to bubbles of two different sizes (small and large) in syringes are indicated in Table 9 [4]. The air gap left in rigid sampling bottles is the equivalent of a medium-sized bubble in syringes.

Table 9: Gas losses (in %) from oil to bubbles in syringes [4]

Bubble size	Syringe divisions	Bubble volume, ml	H_2	CO	C_2H_2
small	1	0.05	-3	-1	-0.1
large	5	0.3	-15	-6	-1

H_2 losses have been found to be higher when the syringe has its tip 30° down and the gas bubble is in contract with the piston of the syringe [3]. Gas losses are also higher in case of an air bubble in air-saturated oil, since the bubble cannot redissolve in oil [3].
In the absence of a gas bubble in oil, no significant gas loss from the oil is measured after a few weeks of storage of the syringe in darkness [4].

Bubbles are often formed in syringes (and probably also in sampling bottles) when oil temperature in the transformer is high [8]. Placing the syringe in its protective box in the vertical position, standing on the piston and with the syringe tip upwards, until the oil has slowly cooled down, efficiently prevents such bubble formation [1].

Bubbles are also formed during air transportation of oil samples because of the reduced pressure inducing over-saturation of air or nitrogen in oil. Specially sealed boxes have been developed to eliminate this problem [4].

Appropriate septa of the butyl rubber type should be used with vials [2, 27], since silicone septa are not gas-tight [2, 21]. No gas losses or air contamination have been observed when using 3-way plastic valves on syringes [4, 10].

It has been reported [3] that dissolved gases reach the bottom oil much more rapidly than usually assumed, and therefore that DGA results obtained from this location are in general quite representative, except in cases of very rapid gas formation.

The recommendations of WG15 in this section 5 have been proposed for the revision of IEC 60567 [2] presently in preparation.

5.2 Gas levels in service

The 90% typical gas concentrations (TGC) and typical rates of gas increase (TRGI) observed in power transformers in service have been determined previously by CIGRE JTF D1.01/A2.11 (TF11) [3].
Since then, it was reported to WG32 [10] that in UK TGC values are lower because transformers are operated at only 60% of nominal load, resulting in lower operating temperatures and therefore less gassing in service. Similarly, in Belgium TGC values are higher [19], probably because transformers there are mostly of the shell-type. The oil to paper ratio is lower in such equipment, so that the same amount of gases formed is dissolved in a smaller volume of oil, resulting in higher typical values in ppm.
Above typical values, it is recommended in IEC 60599 [4] to increase the frequency of oil sampling for DGA.

Pre-failure gas concentrations (PFGC) in service have also been determined by TF11.
PFGC values are the values above which the probability of having a failure-related event in service (such as fault gas alarm, tripping or failure requiring repairs or replacement) increases dramatically. They were found by TF11 to be surprisingly close on different network, suggesting that failure occurs when a critical amount of insulation is destroyed [3].

The pre-failure rates of gas increase (PFRGI) in service have similarly been determined by WG32 [1, 3, 6] and are indicated in Table 10 (“NS” means that no PFRGI values are observed in service for these gases). They are also observed to be surprisingly close on different networks, and relatively similar in sealed and air breathing equipment.

Table 10: Pre-failure rates of gas increase in service, in in µl/l /day

Ref.	C_2H_2	H_2	CH_4	C_2H_4	C_2H_6	CO	CO_2
[1]	0.5	3	5	5	11	NS	NS
[6]	0.3	1.3	4.6	3.9	8.8	NS	NS
[3]	0.2	3.3	2.5	1.4	7.9	NS	NS

In-between typical and pre-failure values, it is possible to calculate the oil sampling intervals and levels of attention required as a function of gas concentration and rate of gas increase in service [18]. For gas concentrations, the extrapolation method used is illustrated in Figure 4 and the numerical values are given in Table 11. The curve and values for CO_2 were obtained by analogy with those of total dissolved combustible gases (TDCG), since no PFGC value is observed for this gas.

For rates of gas increase, numerical values are given in Table 12. The corresponding curves can be obtained by replacing the typical and pre-failure concentrations of Figure 6 by the typical and pre-failure rates of gas increase given in Table 10. The curves and values for CO and CO_2 were obtained by analogy with those for TDCG since no PFRGI values are observed for these gases.

Typical values in Tables 11 and 12 are the average values surveyed by TF11. The actual ranges of individual typical values on different networks are indicated in [3-4].
To calculate rates of gas increase in service, more than two successive DGA concentration values should preferably be used for a better accuracy [17].

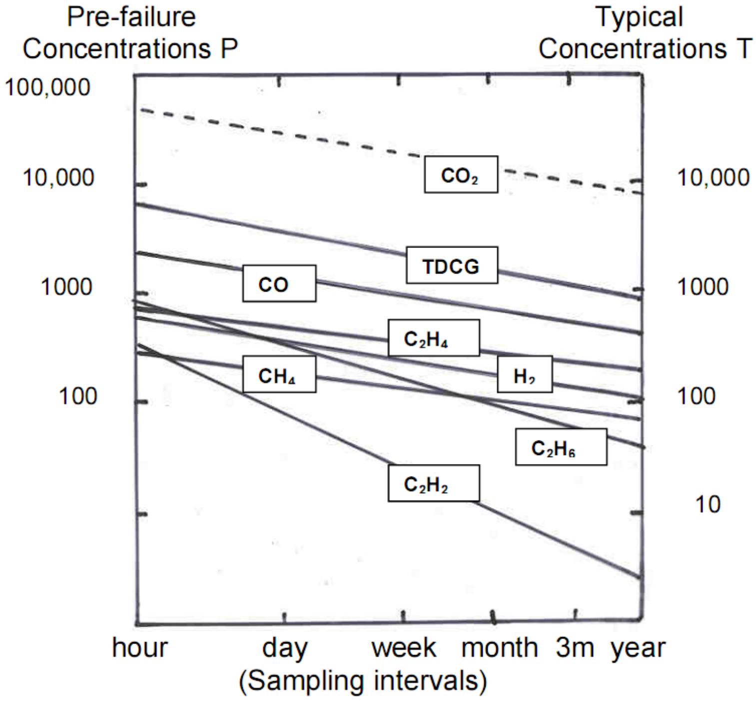


Figure 4: Oil sampling intervals versus gas concentrations in CIGRE power transformers in service

Table 11: Oil sampling intervals versus gas concentrations in CIGRE power transformers in service, in µl/l

Concentration	H_2	CH_4	C_2H_4	C_2H_6	C_2H_2	CO	CO_2	TDCG	Sampling intervals
Typical	100	80	170	55	3	500	8900	908	Yearly
Level 2	180	129	270	126	13	766	14885	1542	Monthly
Level 3	254	170	352	205	32	983	20084	2101	Weekly
Level 4	403	248	505	393	102	1372	29980	3175	Daily
Pre-failure	725	400	800	900	450	2100	50000	5380	Hourly

Table 12: Oil sampling intervals versus rates of gas increase in CIGRE power transformers in service, in µl/l/year

Rate	H_2	CH_4	C_2H_4	C_2H_6	C_2H_2	CO	CO_2	TDCG	Sampling intervals
Typical	83	65	89	47	2	660	5850	946	Yearly
Level 2	179	175	218	176	7	1737	15382	2539	Monthly
Level 3	280	313	369	382	17	3054	27012	4513	Weekly
Level 4	509	679	745	1074	47	6491	57351	9738	Daily
Pre-failure	1095	1825	1825	4015	182	17000	150000	26000	Hourly

It may happen in service that different oil sampling intervals and levels of attention are required by gas concentrations and by rates of gas increase. In such cases, the oil sampling intervals and levels of attention corresponding to a combination of concentrations and rates can be used, as indicated in Table 13 [1].

Table 13: Oil sampling intervals versus a combination of rates of gas increase and gas concentrations in CIGRE power transformers in service [1]

		Sampling intervals based on combined gas rate levels and gas concentration levels				
Gas rate level #	Gas conc. level #	Daily	Weekly	Monthly	Quarterly	Yearly
4	4	X				
4	3	X				
4	2		X			
4	1		X			
3	4	X				
3	3		X			
3	2		X			
3	1			X		
2	4		X			
2	3			X		
2	2			X		
2	1				X	
1	4			X		
1	3			X		
1	2				X	
1	1					X

Values in Tables 11-13 correspond to the average typical values observed by CIGRE in transformers worldwide and can be used by default. Typical values on individual networks may be slightly different, however, depending on operating conditions, types of transformers used and climate. Individual networks are therefore encouraged to calculate their actual typical values in service as indicated in [18], and to use them in Tables 11-13 instead of the average CIGRE typical values.

5.3 Heat run tests on repaired transformers

Factory acceptance tests (heat-run tests) are routinely performed on newly-built transformers, and maximum gas formation limits during these tests have been specified in IEC 61181 [19].

The use of DGA during heat-run tests on repaired or refurbished transformers is not recommended in 61181 [19], for fear that gases trapped in paper insulation before repair may interfere with gases formed during the tests. However, since such tests are quite useful and actually used to evaluate if the transformers have been repaired correctly, they have been revisited by WG32.

DGA results after heat-run tests on a number of repaired or upgraded transformers [3,5] is indicated in Table 14. All transformers had been vapour phase-dried before the tests. Before tests # 10 and 11, new windings had been installed. Tank and radiators were upgraded before tests # 1-9. CO_2 could not be measured during tests # 1-9 because of analytical calibration problems.

Gas formation during the tests remains below the limits of 61181 [19], meaning that any gases left in transformers after repair do not interfere with the tests, and therefore that heat-run tests can be used for repaired transformers, provided they have been vapour-phase dried before the tests.

Table 14: Gas formation after heat run tests on repaired transformers, in ppm/ hour

		H_2 + Cn	CO	CO_2		
	IEC 61181 gas limits:	0.1-1.6	0.4-2	5-18	Passes test	Gassing back in service
Ref.	Transf. # ::					
5	1	0.08	0.17	-	x	
	2	0.25	0	-	x	
	3	0	0.04	-	x	
	4	0.04	0.37	-	x	x
	5	0.70	0	-	x	x
	6	1.70	0	-	~	x
	7	0.12	0.37	-	x	x
	8	0.29	1	-	x	x
	9	0.50	0	-	x	x
3	10	0.31	2.63	3.56	~	
	11	0.33	1.92	3.08	x	

This lack of interference is possibly due to the fact [5] that the test duration is short as compared to the time needed for gases left in the repaired transformers to diffuse out of paper.

The accuracy of DGA results during factory acceptance tests, a concern of CIGRE A2 [9], has been evaluated by IEC 61181 [19] as acceptable if analytical procedures are followed correctly.

5.4 Gas losses from transformers of the conservator-type

Gas losses from transformers of the open conservator-type are often assumed to be higher than from transformers of the sealed-type, because of the diffusion of gases from the oil to the conservator and from there to the atmosphere.

Typical gas concentrations in the two types of transformers, however, have been observed by TF11 to be quite similar [3], suggesting that gas losses in transformers of the air breathing-type may not be as high as thought.

This has been investigated by WG32 [11], using a de-energized transformer of this type containing significant amounts of fault gases, and following the decrease of gas content in oil during several months with an on-line Transfix monitor. The results are indicated in Table 15.

Table 15: Gas losses from a de-energized transformer of the conservator-type [11]

	Initial conc. in	Gas losses in:	
	ppm	ppm/year	%/month
H_2	75	52	6
CH_4	370	520	12
C_2H_4	810	780	8
CO_2	1,600	1210	6

Gas losses are proportional to the initial gas concentration in oil, which is consistent with the general laws of mass transfer. They are of about 10 % per month on average, and it takes about one year for gases to escape totally from the transformer.

A possible reason for these lower than expected gas losses is that diffusion of gases though the very long (more than 1 m) piece of piping connecting the main tank to the conservator is very slow (a few cm per day).

When the transformer is in operation, temperature variations between day and night transfer some volume of oil back and forth between the tank and the conservator, because of oil expansion/contraction. Only about 1 % of the total oil volume is involved in such transfers, however, (based on a 15°C difference between day and night and a coefficient of oil expansion of 0.00078 ml/ml/°C), which corresponds to about 15 % per month (assuming that half of dissolved gases in the conservator are lost to the atmosphere during the day) [1]. This is only marginally higher than the losses by diffusion indicated above.

According to this calculation, above the typical rates of gas increase of Table 12 [4] gas losses are compensated by gas formation. They indeed do not appear to have a very significant impact on typical values and gas levels in service [3]. However, actual losses may be higher than calculated above because of thermo-siphon effects in oil [14], and would need further experimental investigation.

In a transformer equipped with a membrane in the conservator, it has been observed [14] that the loss of H_2 was about 2% per month, which will not affect the typical values observed in such equipment in service.

5.5 Stray gassing of passivated oils

Metal passivator additives are routinely added to transformers filled with oils containing corrosive sulphur compounds such as DBDS, in order to alleviate potential problems of copper sulphide deposition in paper in service. It has been suggested that passivated oils are more stray gassing than non-passivated ones, possibly interfering with DGA diagnosis. Stray gassing is the unexpected gassing of oil at relatively low temperatures of 90 to 200°C [3].This has been investigated by WG32.

It was found [3] that if the transformer has been filled with passivated oil from the beginning, very little or no stray gassing is observed. If passivator is added to a non-passivated oil already in a transformer for some time, increasing amounts of H_2 and CO are formed, in correlation with the decrease in passivator content in the transformer. Gas formation occurs in the stray gassing zone of mineral oils, and might be due to the degradation of the passivator [3].

A steep increase in the formation of H_2 has also been observed [6] when the amount of passivator additive starts to decrease in oil as a result of oxidation. Significant increases in H_2 formation have also been observed at higher contents of passivator additives (500 ppm) [11].

Further investigations on the use of passivator and associated effects have been started in 2009 within CIGRE SC A2 (WG A2 40).

5.6 On-line continuous degassing of transformers

Some transformer users [11] favour the on-line continuous degassing of free-breathing transformers in order to reduce the oxygen content of oil and therefore the long-term degradation of paper and oil. Others [3, 14, 16] consider that this will result in the loss of DGA diagnosis and therefore is not advisable.

Using an on-line gas monitor appears to somehow alleviate this concern [1]. It has been shown (see Fig.11 of [20]) that new faults can thus be detected as spikes on the continuous background of dissolved gases, allowing to calculate the rate of fault gas formation and to identify the type of fault. Information about the accumulated gas concentrations formed, however, will likely be lost. Further investigation would be needed, however, to evaluate the accuracy of such a calculation.

An alternative to continuously degassing is of course to use transformers with air preservation systems (nitrogen blankets or membranes).

5.7 Formation of carbon oxides in transformers

It has previously been shown by TF11 (see Table 19 of ref. [3]) that CO_2/CO ratios of 20 to 50 are formed when overheating prototype transformers at 160 to 130°C, respectively.

Additional observations made by WG32 [2] indicate that there is a correlation in transformers in service between degrees of polymerization of paper DP of 200 to 400, CO_2/CO ratios in oil of 20 to 55, respectively, and high concentrations of CO_2.

The distribution of CO_2/CO ratios in open and closed-type transformers for different types of applications (distribution, transmission, generation and power level) on different networks has therefore been evaluated by WG32 [1, 3, 8] and is indicated in Table 16.

Table 16: Distribution of CO_2/CO ratios on different networks

Ref.:	1	3					8		
Open	x	x	x	x					
Closed					x	x	x	x	x
CO_2/CO:	% of DGA cases:								
> 50	2	1	1	1	0	0	8	4	17
50-20	10	1	5	9	9	5	15	18	25
20-4	80	95	88	83	87	81	63	64	48
< 4	10	3	5	7	4	15	14	14	8

High CO2/CO ratios (>20) are observed mostly in the closed-type transformers of one network. There is no correlation between high ratios and the amounts of the other hydrocarbon gases formed.

On the other hand, it has been pointed out [2] [21] and confirmed [5, 20, 16] that low values of the CO2/CO ratio (<3) are often observed in sealed transformers, which do not appear to be related to an actual fault or to paper involvement as indicated in IEC 60599 [22] for mostly air-breathing equipment. This will have to be investigated further by WG32 and indicated in the IEC document when it comes under revision [2].

6 CONCLUSIONS

6.1 Application of DGA to non-mineral oils

It has been evaluated by WG32 that the analytical techniques and interpretation methods used for mineral oils can be used with some adjustments for non-mineral oils.
The partition coefficients used for calibrating the Head Space method with standard gas mixtures are significantly different for non-mineral oils. The recommendation of WG32, however, is rather to calibrate the Head Space method with gas-in-oil standards, which does not require the knowledge of partition coefficients, for both mineral and non-mineral oils.

The small adjustments to fault zone boundaries which are necessary for non-mineral oils are indicated in this report, as well as tools to distinguish the stray gassing of some non-mineral oils from more serious faults in service.
Typical concentration values in service appear to be lower than for mineral oils.

6.2 Application of DGA to load tap changers

Interpretation methods are provided in this report for the detection of faults in LTCs where arc breaking occurs:
- in oil (reactor and resistor types).
- in vacuum (reactor and resistor types)
- with commutation switches in the same or separate oil compartments

After a change of oil in the LTC, contamination by the previous oil must be taken into account before attempting a diagnosis.

6.3 Improved DGA diagnosis criteria

Recommendations are proposed to minimize the effect of oil sampling on DGA results (quality of sampling devices used and procedures to avoid the formation of bubbles in oil).

The pre-failure gassing rates observed in transformers in service are indicated in this report, as well as recommendations concerning the sampling intervals and levels of attention required as a function of gas concentrations and gassing rates in service.

DGA can be used during heat-run tests on repaired or upgraded transformers which have been vapour-phase dried before the tests.

Gas losses from transformers of the open conservator-type do not appear to have a very significant effect on typical values and gas levels in service.

The addition of a passivator additive in oil to alleviate copper sulphide deposition in transformers in service increases the stray gassing of the oil.

DGA can be used to detect faults in continuously degassed transformers in service only with the help of an on-line gas monitor.

High values of the CO_2/CO ratio in transformers in service appear to be related to accelerated paper aging and are observed mostly in transformers of the closed-type. Low values of this ratio in sealed transformers do not necessarily indicate paper involvement in the faults as in the case of air-breathing transformers.

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8 TRADEMARKED PRODUCTS

BioTemp : ABB
FR3 : Cooper Power Systems
Midel : M&I Materials
Nomex: E.I. du Pont de Nemours
OILTAP, VACUTAP: MR Reinhausen

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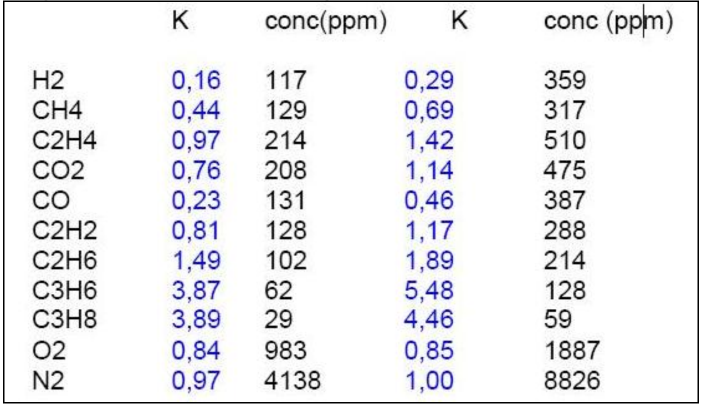
[1] M.Duval, [2] I.Atanassova-Hoehlein, [3] F.Scatiggio, [4] M.Cyr, [5] M.Grisaru, [6] M.Martins, [7] L.Bates, [8] P.Boman, [9] A.C.Hall, [10] G.Wilson, [11] L.Arvidsson, [12] R.Frotscher, [13] M.Szebeni, [14] K.Carrander, [15] H.Athanassatou, [16] A.M.Haug, [17] A.Moellmann, [18] H.J.Knab, [19] J.VanPeteghem, [20] G.Buchgraber, [21] S.Tenbohlen, [22] R.Maina, [23] B.Pahlavanpour, [24] P.McShane, [25] R.Martin, [26] Z.Wang, [27] C.Myers, [28] M.Foata.

ANNEX A – MEASUREMENT OF PARTITION COEFFICIENTS BY HEAD SPACE METHOD

Table A1: Dispersion of values of partition coefficients measured by the head space method

Method used:	Gas-in oil standard			Slope/Intercept
Laboratory:	[19]	[3]	[2]	[2]
H_2	0.19	0.02	0.077	0.03
CO	0.16	0.04	0.07	0.09
N_2		0.07		0.25
O_2		0.13		0.33
CH_4	0.40	0.17	0.23	0.33
CO_2	0.77	0.37	0.83	0.76
C_2H_2	1.00	1.16	1.31	0.72
C_2H_4	1.41	0.95	1.78	1.20
C_2H_6	2.07	2.19	2.4	1.50

Table A2: Concentration dependence of partition coefficients measured by the head space/ gas standards method [2]



	K	conc(ppm)	K	conc (ppm)
H2	0,16	117	0,29	359
CH4	0,44	129	0,69	317
C2H4	0,97	214	1,42	510
CO2	0,76	208	1,14	475
CO	0,23	131	0,46	387
C2H2	0,81	128	1,17	288
C2H6	1,49	102	1,89	214
C3H6	3,87	62	5,48	128
C3H8	3,89	29	4,46	59
O2	0,84	983	0,85	1887
N2	0,97	4138	1,00	8826

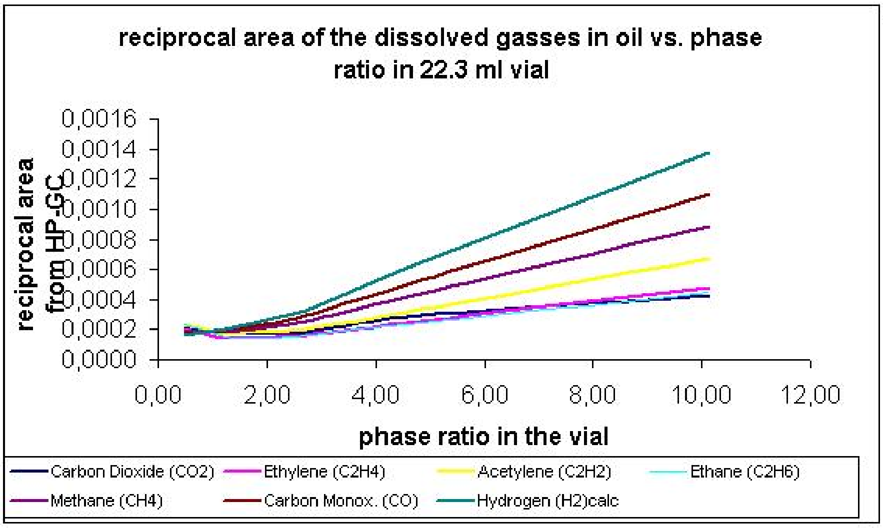
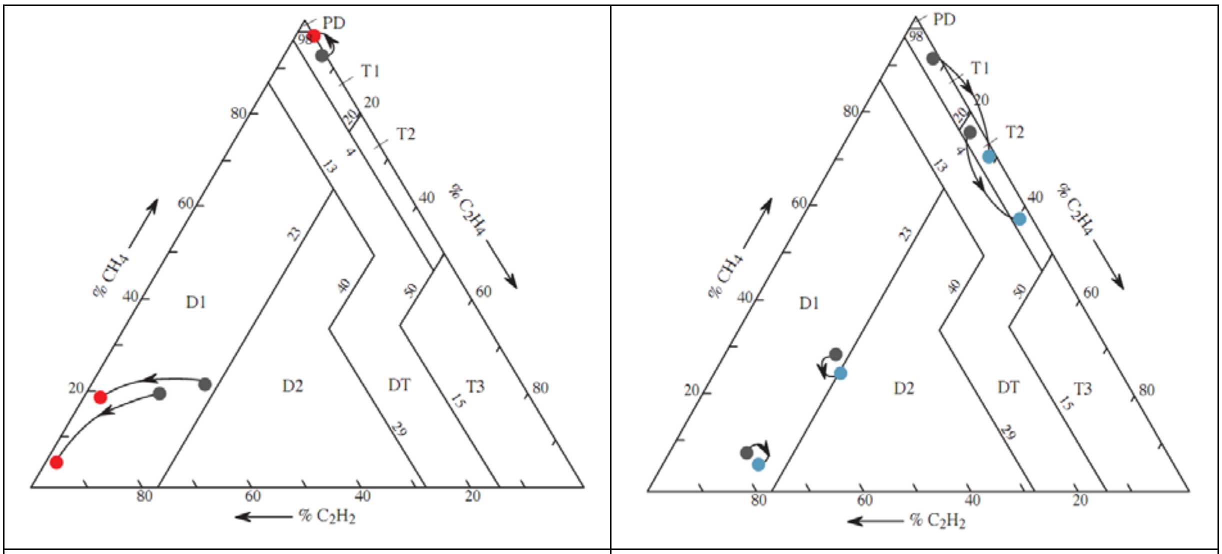


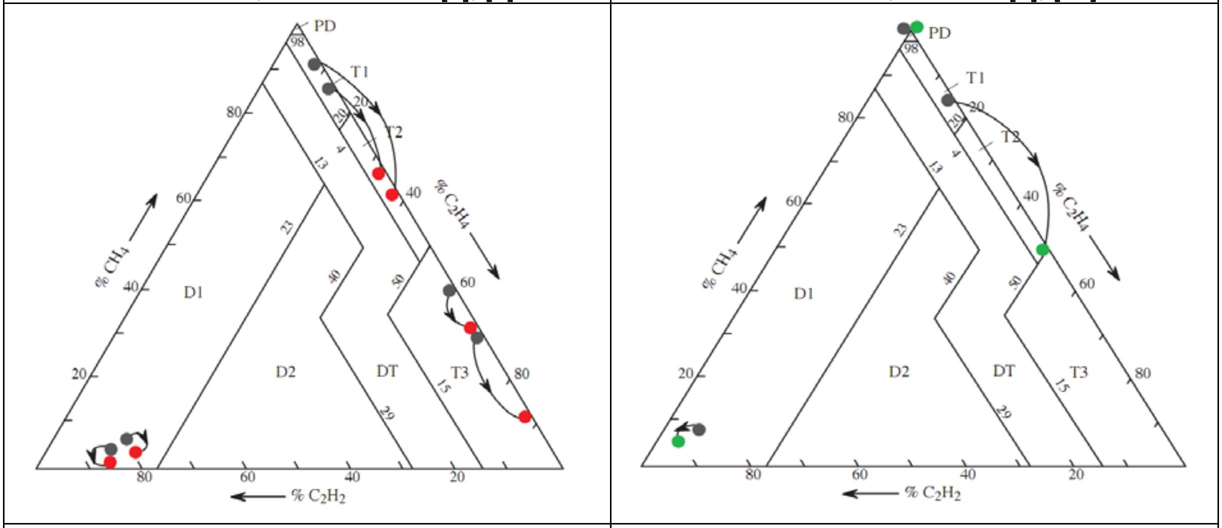
Figure A1: Non linearity of the measured amounts of dissolved gases vs. the gas/oil phase ratio value in the vial [5]

ANNEX B: LABORATORY TESTS ON NON-MINERAL OILS



●: Mineral oil; ●: Silicone oil [6], [7]

●: Mineral oil; ●: Midel [9], [12]



●: Mineral oil; ●: FR3 [10-12]

●: Mineral oil; ●: BioTemp [8], [10]

Note: zone boundaries indicated in Figure B1 are those of mineral oils.

Figure B1: Comparison of published DGA results of mineral and non-mineral oils subjected to the same faults (PD, D1, T1, T3) in the laboratory

Table B1: Gas formation from laboratory pyrolysis tests on mineral and non-mineral oils performed by WG32 [7] (arbitrary units)

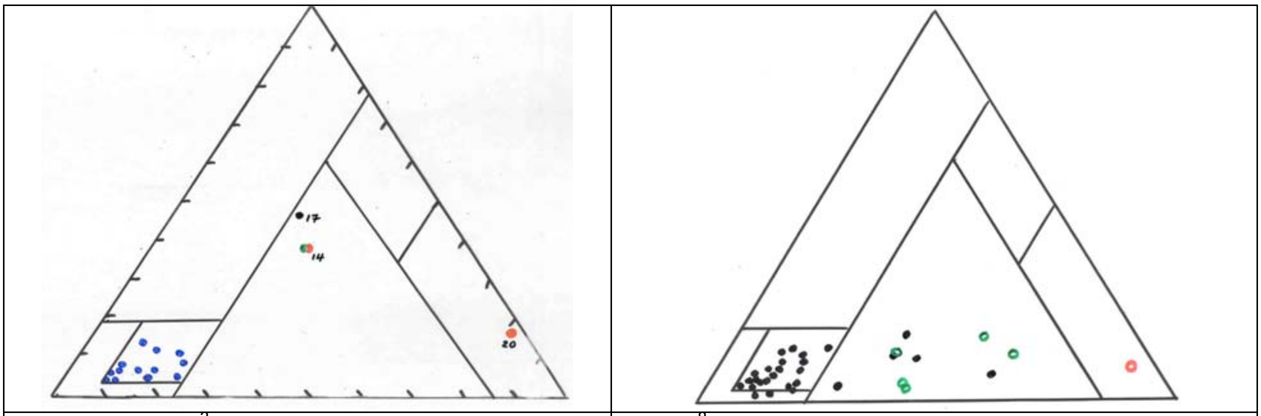
	Mineral	Midel	Silicone	FR3	BioTemp
1200 °C					
CH_4	2.72	3.14	1.51	2.80	3.36
C_2H_4	12.5	17.8	1.59	6.14	10.71
C_2H_6	1.61	2.2	0.13	0.65	1.16
C_2H_2	1.61	3.2	0.26	0.96	2.43
700 °C					
CH_4	0.73	1.07	0.13	1.41	1.34
C_2H_4	2.57	5.15	0.30	4.09	5.17
C_2H_6	0.99	2.13	0.04	1.28	1.82
C_2H_2	-	-	-	-	-

ANNEX C: DGA RESULTS OF WG32 IN LOAD TAP CHANGERS

Table C1: Classification of commercial LTCs according to Table 6 [12]

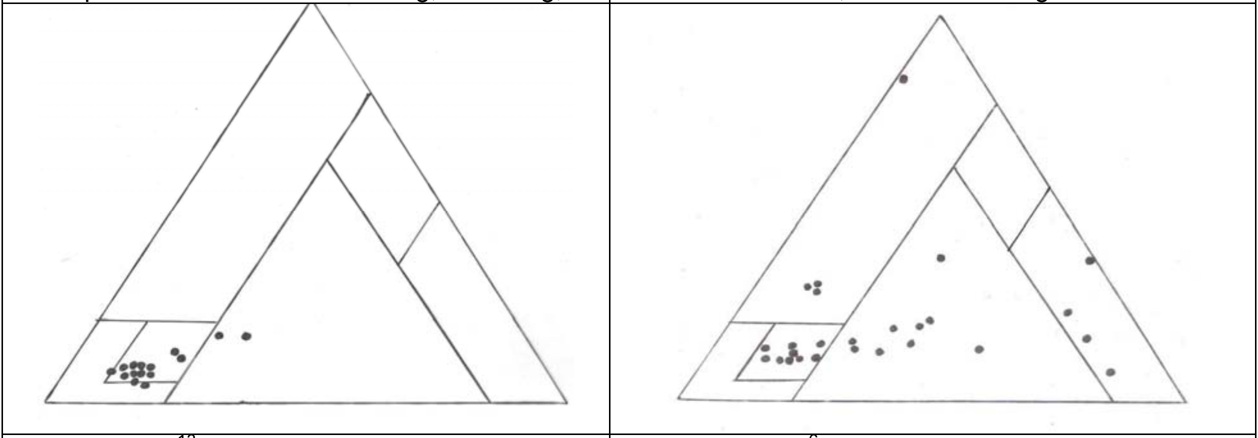
Manufacturer	Type	Classification
Reinhausen	OILTAP® V, H, C	ARC
	OILTAP® R, M, D, G, MS, F, T	ARS types 1, 2, 3, 4
	VACUTAP® VV	VRC
	VACUTAP® VR	VRS
	VACUTAP® RMV-I, RMV-II, RMV-A	VXC
	RMT, RMS	AXC
ABB	UZB.., UZC.., UZD.., UZE.., UZF..	ARC
	UBB	ARC
	UCB, UCC, UCD, UCG, UCL	ARS
	UVT	VXC
	VUCG	VRS
Westinghouse	URS, UTN, UTS, UNR, UTT	AXC
	URT	AXS
	UVT, UVW	VXC
	UTH	ARS
Cooper, McGraw Edison, Pennsylania	550, 995	AXC
	394, 494, 396B, 996	AXS
Allis-Chalmers	TLH-xx	AXC
Federal Pacific	TC-515, TC-525	AXC
	TC-34, TC-46, TC-546	AXS
Ferranti	RT	ARC
GE	LR-25, LRT-38, LRT-48, LRT-68, LRT-72, LRT-65, LRT-83, LRS-83	AXC
	LRT-45, LRT-59, LRT-85	AXS
	LRT-200, LRT-300, LRT-400, LRT-500, LRT-700	VXC
Huaming	SYZZ, CV, SV	ARC
	CM, CMB, CMD	ARS
	HDK	VXC
	HWV	VRC
	VCV, SHUV, SHJV	VRC
	SHZV	VRS
Hyundai-Elprom	RS4, RS5, RS6, RS7, RS9, RS18, RS12, RS16, RS19	ARS
	RSV5, RSV19	VRS
ATL (UK)	AT, ATV, AE	ARC

Note 1: the 3 gases used in the triangles of Figures C1 to C7 are CH_4, C_2H_4 and C_2H_2 as for the general interpretation of DGA in transformers.



Ref: [3]; 🔵: Normal operation;
Inspected faults: 🔴: Overheating; 🟢: Arcing;

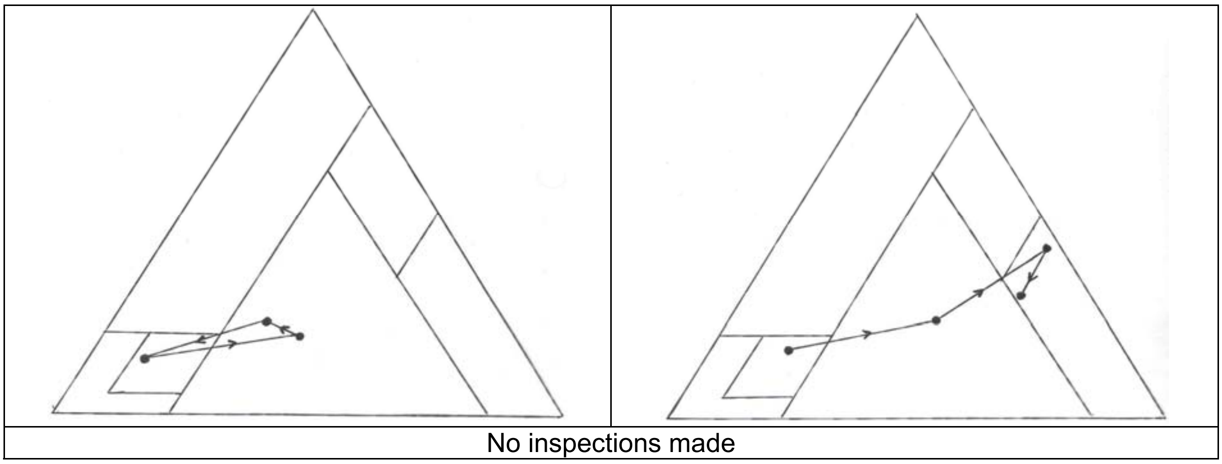
Ref: [8]; ●: no fault suspected, no inspection made;
🟢: arc burns, debris 🔴: damaged contact



Ref: [13]; ●: no inspections made

Ref: [6]; ●: no inspections made

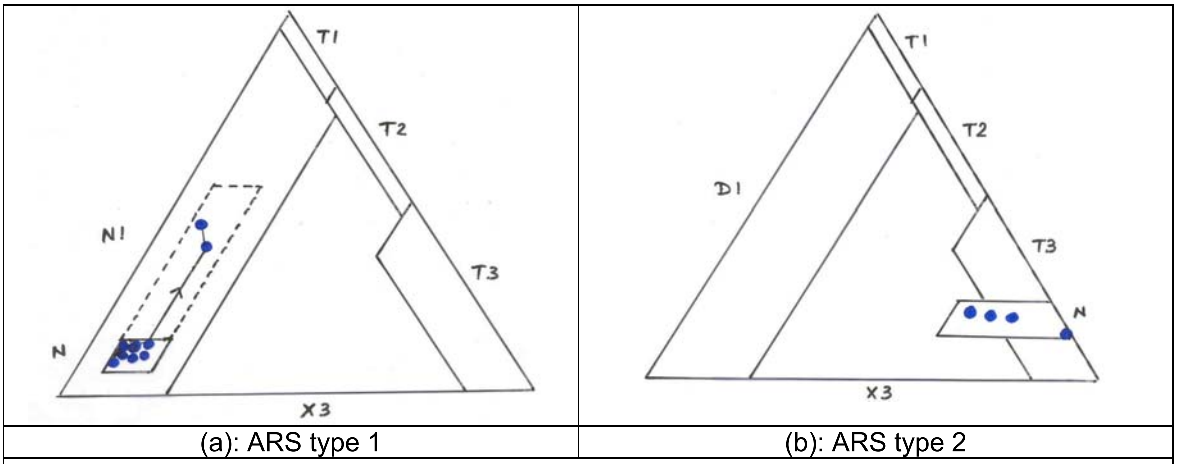
Figure C1: Normal and faulty operation of LTCs of the arc-breaking-in-oil compartment type (conventional oil type AXC, ARC)



No inspections made

Figure C2: Gas formation change in two LTCs of the arc-breaking-in-oil compartment type (conventional oil type AXC, ARC) [6]

Note 2: in Figures C1 and C2, fault zones and zone boundaries are as in Figure 3 of section 4.3.1.

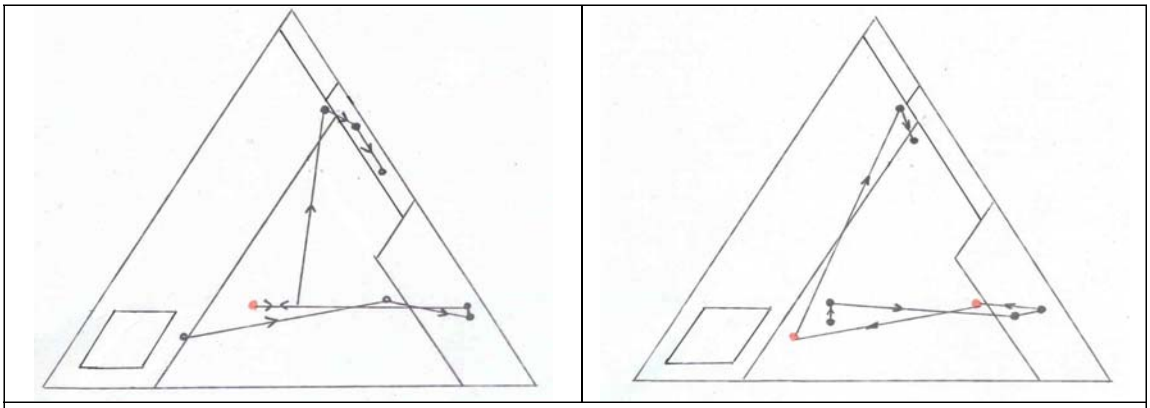


(a): ARS type 1

(b): ARS type 2

●: Normal operation

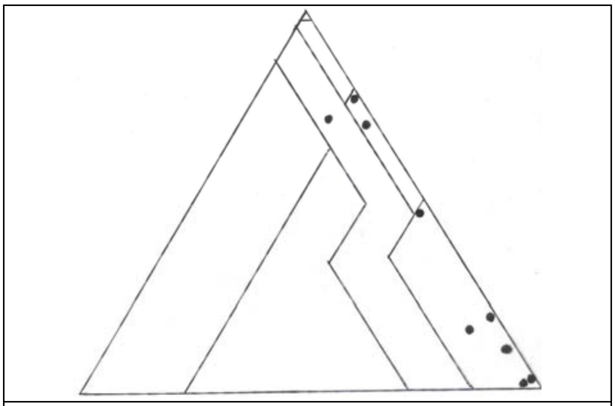
Figure C3: Normal operation of LTCs of the arc-breaking-in-oil in-tank type (ARS types 1 and 2) [1]



●: no inspection made; ●: oil change

Figure C4: Gas formation change in two LTCs of the arc-breaking-in-oil in-tank type (ARS type 1) [6]

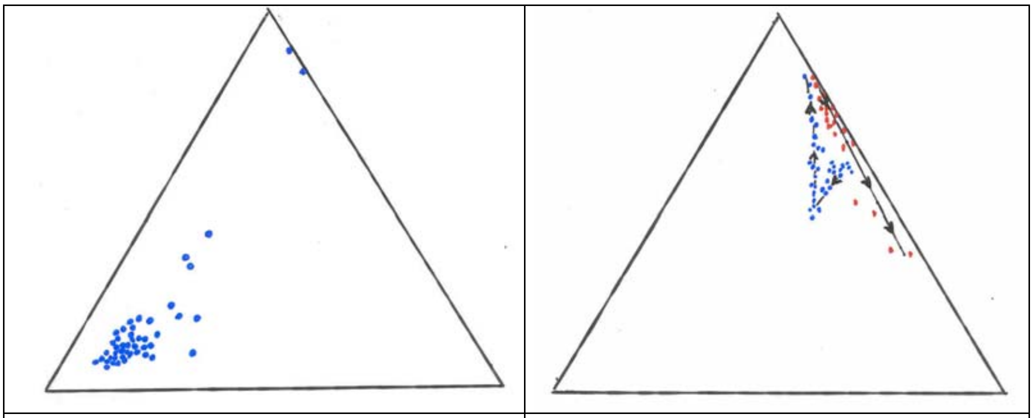
Note 3: in Figures C3, C4 and C7, fault zones T1, T2, T3 and D1 are those used for the general interpretation of DGA in transformers (see Figure 1 of section 3.2 for identification). Zones N and N1 correspond to normal operation. X3 is an intermediate zone.



●: no inspection made

Figure C5: LTCs of the vacuum compartment type (VXC)[8]

Note 4: in Figure C5, fault zones are those used for the general interpretation of DGA in transformers (see Figure 1 of section 3.2 for identification).



(a): in service

(b): during power switching tests

●: Normal operation; ●: formation of a very high temperature hot spot

Figure C6: Two different modes of operation of LTCs of the vacuum in-tank type VRC[12, 1]

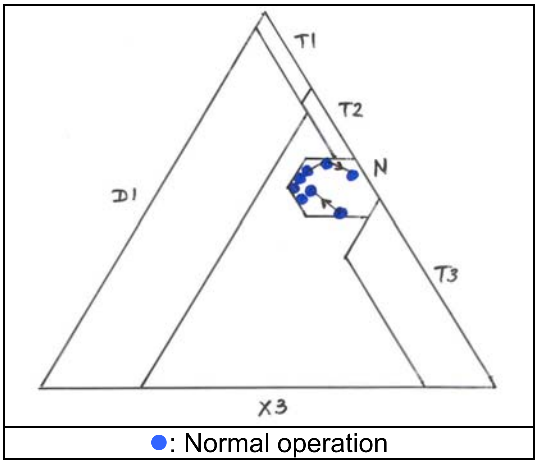


Figure C7: Normal operation of LTCs of the vacuum in-tank type VRS [12, 1]

(see Note 3 for the identification of fault zones)