TRANSFORMER FLUID: A POWERFUL TOOL FOR THE LIFE MANAGEMENT OF AN AGEING TRANSFORMER POPULATION

Victor Sokolov
ZTZ Service

Armando Bassetto
Bassetto and Mak

T.V. Oommen
Consultant

Ted Haupert
Dave Hanson
TJ/H2b Analytical Services, Inc.

Abstract

It has been estimated that transformer fluids contain about 70% of the diagnostic information available for transformers. The challenge is to access and use this information effectively. Historically, testing programs have been developed that evaluate separate facets of the transformer condition. This paper considers the dynamics of transformer components considered together as a system leading to a comprehensive testing program for determining transformer condition. Particularly with the changing needs of the electric power industry, optimized testing and diagnostic protocols will be fundamental to transformer life management in the future.

Introduction

The global task of the electric power industry in the first quarter of the 21st century will be to manage the serviceability of a huge transformer population that has already been in service for 25-40 years. Concurrent with this task will be meeting the fundamental objective of transformer life management, defined simply as "getting the most out of the asset". One way to accomplish this is to ensure that appropriate actions are taken to promote the longest possible service life under any operating conditions. It is also possible that within this definition taking no action and assuming an economically justified risk of failure could be acceptable.

In order to make the best decisions, it is imperative to understand the condition of the equipment. Without sufficient information the likelihood of no action leading to a failure may only appear to be acceptable and the cost of appropriate actions may only appear to optimize performance.

In recent years there has been considerable interest in the life management of transformers. One can easily observe this in the rapid development of economic based maintenance concepts such as Reliability Centered Maintenance, Condition Based Maintenance, and Comprehensive Life Extension as well as in such accompanying techniques as On-line Monitoring and On-line Processing. All of these developments reflect a changing view of asset management and implicit in each of them is the need for and use of a greater amount of information. In order to meet the developing needs of the asset managers, there will continue to be a high demand for new technologies and new diagnostic tools to fulfill the requisite need for information.

The most easily accessible and efficient way to determine transformer condition is to use the fluid as the diagnostic medium. It has been estimated that transformer fluids contain about 70% of the available diagnostic information for transformers. The challenge is to access and use it effectively. Traditional oil test programs utilize only a few diagnostic parameters leaving a myriad of important oil-based information unused.

The goal of this work is to present ways to realize the potential benefits of oil testing and to suggest some algorithms to assess the condition of a transformer not as a characterization of symptoms but as a comprehensive evaluation for life management.

Characterizing the Fluid

Functionally, most electrical insulating fluids are considered to be equivalent and they are handled as such. It is common to see transformer fluid levels adjusted using available fluid stocks and used oils combined for processing and reuse. The only fluids that are typically managed separately are either specialty fluids or contaminated fluids.

Chemically, most electrical insulating fluids are not equivalent. While the differences normally do not defeat the prescribed functions of the fluids, they do affect the way they function.

Transformer fluids vary in composition from nearly pure compounds to mixtures that are too complex to fully describe. The measurable chemical features of these fluids vary in concentration from percent, which is parts per hundred, to parts per trillion. Those components in the percent range, both major and minor, describe the basic chemical composition and determine the basic fluid properties and reactions involving the fluid. The effects of composition can vary widely. The examples shown in Tables 1, 2 & 3 demonstrate variations in properties produced by variations in composition and illustrate the importance of determining fluid composition.

Table 1
Gas Solubility Properties of Insulating Fluids†

Oils	**Properties**	**Ostwald Coefficients at 20°C**				
		H_2	N_2	air	C_2H_2	CO_2
I-hydro-refined	C_A=1.6% Sp.Gr.=0.856	0.05	0.089	0.103	1.02	1.1
II	C_A=14% Sp.Gr.=0.869	0.044	0.085	0.091	1.1	1.1
III-synthetic	C_A=66% Sp.Gr.=0.968	0.034	0.061	0.061	1.92	1.71

† Provided by Prof. Lipstein

Table 1 illustrates that significant differences in aromatic carbon content, C_A, and specific gravity result in significantly different gas solubilities, as indicated by the Ostwald coefficients.

Table 2
Solubility of Water in Oils with Different Aromatic Content

Oils	Aromatic Content C_A, %	Water Solubility, ppm		
		20 °C	40 °C	70 °C
1	5	42.8	97.5	279
2	8	46.8	108	316
3	16	56.2	128.3	369.2
4	21	75	162	436
5	Silicone-oil	174	314.7	675.4

Table 2 illustrates the importance of aromatic carbon content, C_A, for determining the solubility of water in mineral oils.

Table 3
Gas Evolution in Different Oils at Selected Temperatures†

Type of oil	Temperature (°C)	Time (hours)	Gas Concentration (ppm)					
			H_2	CH_4	CO	CO_2	C_2H_4	C_2H_6
ГК	Initial	0	0	1	0	212	0	0
	100	6	5	1	41	408	0	0
	120	6	35	42	190	931	2.6	43
	120	+16	78	66	283	1772	2.6	62
Nytro-11GX	Initial	0	0	0	0	246	0	0
	100	6	31	0	55	413	4.8	0
	120	6	79	39	222	833	10	9
	120	+16	116	39	227	1068	10	14
YPF-64	Initial	0	0	0	0	297	0	0
	100	6	5	1	73	439	0	0.5
	120	6	31	23	282	898	3.8	0.5
	120	+16	31	39	298	1392	3.8	7.8
	140	6	55	22	358	961	2.6	0.5
Y-3 (Technol)	Initial	0	0	0	0	547	0	0
	100	6	5	1	16.2	611	3.2	0
	120	6	47	1	63	1076	3.2	0
Shell Diala Ax	Initial	0	0	0	0	642	0	0
	100	6	0	1	26	797	0	0
	120	6	0	3.9	130	1471	0	0

† Tests performed in the ZTZ – Service Material Lab

Table 3 illustrates some of the variability found in gas generation. A study by Cigre WG 15.01 has shown that some oils may produce hydrogen at low temperatures (below 130°C). A possible explanation may be that the catalysts used today are sufficient to produce "over-hydrogenated oils". It has been proposed that these oils contain some molecules where hydrogen atoms occupy an unstable position. A mild heating could release such atoms. A similar effect may occur with partial discharge. Typically, the rate of gas generation during partial discharge varies in the range of 5-50 μl per joule of dissipated energy. However, some hydro-refined oils have rates of gas generation up to 200 μl per joule of dissipated energy. It has also been shown that some fluids may have substantial production of CO, CO2 and hydrocarbons at the operating temperatures of a transformer.

It is important to note that the parameters treated in these tables are all fundamentally important for any diagnostic assessment. Because the magnitude of the variations is sufficient to confuse or misdirect the diagnostic process, it is important to characterize those aspects of the basic chemical composition that define these fundamental fluid properties. Fortunately, once they are known, the basic composition and the associated properties will generally not change unless substantial mixing with another fluid occurs.

In addition to the major and minor fluid components, there are a number of important components found at low levels. The reasons for their importance are diverse. For example, consider components such as sulfur, silicon, 2,6-ditertiary-butyl para-cresol or poly-aromatic hydrocarbons.

Sulfur in transformer oil is usually kept below 1%. Cigre WG 15.01 has suggested that heat and electrical stress may change the sulfur in the oil to a form of corrosive sulfur, which has a detrimental effect on copper. Sulfur may also be introduced from other transformer components and similarly changed to form a corrosive sulfur. Recently**,** one utility reported failures of several shunt reactors where the suggested failure mechanism was a short-circuit between adjacent turns due to corrosion caused by copper sulfide. Utilities typically specify oil with a low corrosive sulfur content but do not have any specification for the total sulfur content.

Silicon in transformer fluid, with the obvious exclusion of silicone fluid, is usually found as an additive at less than 5-10 parts per million. At these low concentrations silicon contributes antifoaming properties which aid processing under vacuum. At higher concentrations silicon enhances foaming and can severely interfere with vacuum processing operations.

2,6-Ditertiary-butyl para-cresol (DBPC) or 2,6-ditertiary-butyl phenol (DBP) is sometimes added to transformer oil at concentrations as high as 0.3 percent to act as an oxidation inhibitor. Presence of the inhibitor can enhance insulation life. It also changes the relationships of the oxidation products found in the oil.

In addition to their influence on basic fluid properties, poly-aromatic hydrocarbons or PAH's, may present a health concern. Recent study suggests naphthenic base oils with more than 2 percent PAH are potentially carcinogenic.

Characterization of the transformer fluid is the defining process that sets the stage for all future assessments by:

1. Determining how the fluid will interact with the rest of the system and establishing the basis for diagnostic evaluations.

2. Identifying residues of equipment manufacturing, fluid production, transformer processing and handling which provides source information for contamination and its potential consequences.

3. Identifying baseline values for the components that will change.

4. Confirming the condition of the fluid with regard to functionality as well as health, safety and environmental concerns.

The use of this information in conjunction with the information from an ongoing fluid testing program provides the basis for transformer life management.

The Fluid as a Part of the System

Many maintenance guides still consider the insulating fluid to be a separate component that can be monitored and treated separately from the fluid-paper insulation system or from the transformer as a whole. In fact, the fluid is an integral part of the transformer playing a dynamic role in the condition of the entire system.

Consider the role the fluid plays in the serviceability of the dielectric system. Aging tests were performed on transformer models in the Transformer Research Institute at Zaporozhye, Ukraine to evaluate the dielectric life and the mechanical life of the insulation system. These studies demonstrate that the dielectric life of the insulation system can be shorter than its mechanical life due to deterioration of the oil-paper system and the consequential deterioration of the dielectric withstand strength of the coil-to-coil insulation. As shown in the Table 4, at 100°C the conductor insulation life is 50 years based on mechanical properties and only 22 years due to deterioration of dielectric strength.

Table 4
Estimated Life of Transformer Winding Insulation Under the Influence of Temperature, Electrical and Mechanical Stresses†

Hot Spot Temperature, °C	Estimated Mechanical Life (Reduction of DP to 200), Years	Estimated Dielectric Life (Reduction of dielectric strength by 40%), Years
80	6229	124
100	**50**	**22.1**
110	**17**	**10**
125	4	3.3
140	1	1.16
160	0.19	0.32

† Tests performed in ZTZ – Service Material Lab

Water created from the degradation of the paper interacts with the paper-oil system to produce this effect. The increase of water available from the paper leads to an increased relative saturation of water in the oil and a reduction in dielectric strength. This in turn leads to an increased adsorption of water on particles that adsorb water, further reducing the dielectric strength of the fluid. When the relative saturation is sufficient, emulsion formation in the vicinity of surface-active substances further reduces the dielectric strength of the insulation. Studying the electrical models of the transformer paper-oil insulation system has shown that the dielectric safety margin of both the major and minor insulation contaminated with water is still determined by the dielectric withstand strength of the oil.

Water is usually present in the oil in a soluble or dissolved form but also may present as a form adsorbed by "polar" aging products and called "bound water". It has been found that as temperature increases, some bound water can be converted into soluble water. Test results of the water content of aged oil sampled from two current transformers are shown in Table 5. After heating the oil at 100°C for 5 hours the water content in oil increased significantly. A similar phenomenon has been observed in bushing oils. Most likely, the dissolved polar compounds in the oil are the source of this additional water.

Table 5
Transformation of Bound Water to Soluble Water from Aged Oil
Not in Contact with Paper†

Type of oil	Properties	Water content ppm	
		Before heating	After heating at 100°C for 5 hours
Used oil from 750 kV CT	Acidity=0.064mg KOH/g IFT=32 dynes/cm PF_{90} =5.32%	26.3	85
Used oil from 750 kV CT	Ca=18% Acidity=0.064mg KOH/g IFT=32 dynes/cm PF_{90}=6.1%	23.5	132

† Tests performed in ZTZ – Service Material Lab

There are also other temperature driven dynamics of water including “bubble formation” and “rain”. EPRI sponsored projects in the late 1980s and early 1990s confirmed prior observation that bubbles could be generated from a sudden overload of the transformer. This type of bubble generation has been studied in more detail, and it now appears that these bubbles consist mostly of water vapor released from the cellulosic paper wraps on the hot conductor. The hot spot temperature is a critical factor, but the water content of the paper insulation is also important. Oil preservation systems, such as nitrogen-blanketed and conservator systems, showed very little difference at low moisture levels in the paper. If the insulation is very dry, eg., with 0.5% moisture, virtually no bubbles are formed. Aged transformers with 2.0% or more moisture could release bubbles at hot spot temperatures greater than 140°C. Since the dielectric strength of the bubbles is significantly less than the insulation system, their formation can result in discharge events ranging from partial discharge to flashover.
When a temperature drop within the transformer is sufficient to change the relative saturation of water from less than 100 percent to greater than 100 percent, an emulsion of oil and water will form. If an appropriate surface is available or the temperature drop is extreme enough, further condensation will occur forming water drops or “rain”. Both emulsified water and free water substantially reduce the dielectric strength of the insulation system. Transported by the fluid their movement through the transformer can cause numerous dielectric and mechanical problems both with the insulation system and adjacent cellulosic materials.

Finally, the presence of water in the cellulose participates in the degradation of the cellulose. Each doubling of moisture concentration doubles the rate of degradation. This process reduces the degree of polymerization (DP) of the cellulose thereby reducing its mechanical strength.

Like water, fluid oxidation products are instrumental in the degradation of the insulation system. The oxidation process culminates with the formation of sludge which:

- As a suspended impurity, reduces the fluid dielectric withstand strength in a manner similar to particles.

- As a semi-conductive sediment, reduces the insulation dielectric withstand strength and may provide for tracking.

- When extremely acidic, will aggressively age both the oil and the cellulose insulation.

The conditions under which sludge will form are not always readily apparent. In the presence of a strong electrical field sludge may form even though the acidity is low. A number of sludge deposits have been found on local insulation zones where the electric field strengths are quite high. These deposits were not apparent until the windings were dismantled.

The correlation between traditional aging characteristics such as color, acidity, interfacial tension, dielectric breakdown voltage, dissipation factor, resistivity and sludge appearance during oil stability tests may be quite different for different oils. These differences increase significantly when the fluids are aging in transformers, due to the effects of transformer materials, operating temperatures, dielectric stress and interaction of aging products with cellulose (See Table 6).

Table 6
Relationships of Aging Characteristics of Service Aged Oils
from Service-Aged Power Transformers

Sample	**Acidity**	**IFT**	**Color**	**Infrared Absorbance**	**PF_{90}**	**SN**	**Sludge**
1	0.081	22.0	3.5	3	3.65		0.018
2	0.035	25.9	2.5	2	2.25		0.014
3	0.124	23.1	3.0	8	4.09		0.017
4	0.154	21.9	6.5		11.69		0.015
5	0.109	28.6	5.0	8	8.84		0.010
6	0.151	23.0	4.5		5.84	0.577	0.012
7	0.111	25.9	4.0	11	15.40	0.310	0.016
8	0.098	26.1	4.0	11	15.61	0.312	0.011
9	0.098	27.2	4.0	11	21.89	0.313	0.013
10	0.193	26.3	4.5	9.5	4.01		0.014

Figure 1 shows a correlation between acid number and interfacial tension test results of oil samples obtained from 25 power transformers, rated 138-13.8 kV, 12-60 MVA. The best correlation occurs in the least oxidized fluids. As the oxidation proceeds, the correlation begins to diverge.

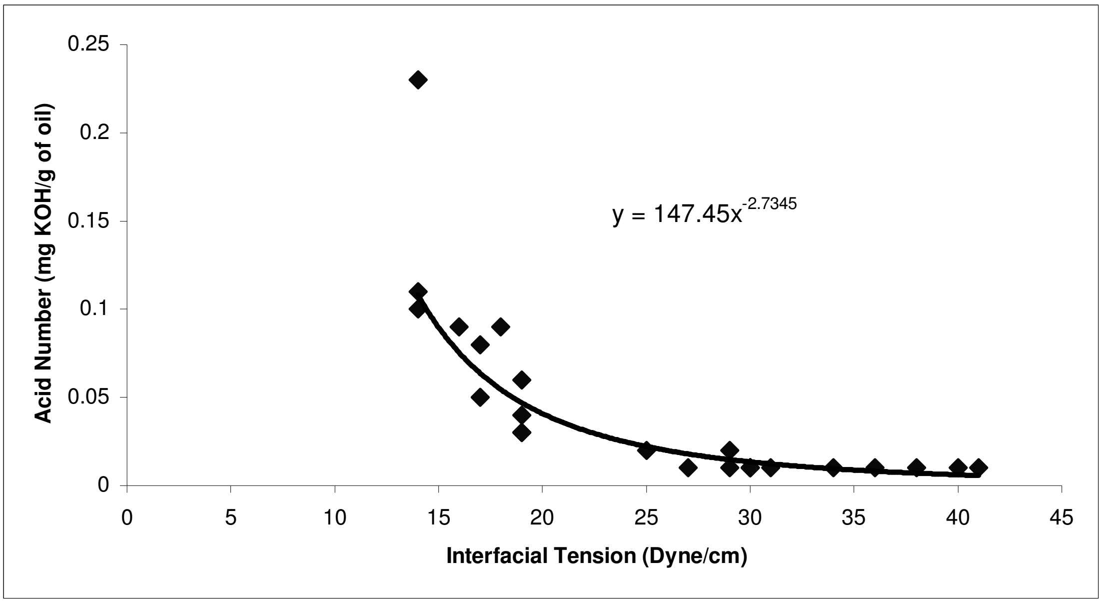


Figure 1
Correlation between acid number and interfacial tension test results.

Figures 2 and 3 show the correlation between the differential infrared absorbance of fluids at 1710 cm^{-1} versus their acid number and their interfacial tension, respectively. The discrepancy is more significant for acid numbers higher than 0.05 mg KOH/g and for IFTs lower than 20 Dynes/cm. The practical importance of such a discrepancy is that there may be oils in service with fairly acceptable IFT's and acid numbers that may contain a significant amount of non-acidic polar compounds detected by infrared spectroscopy.

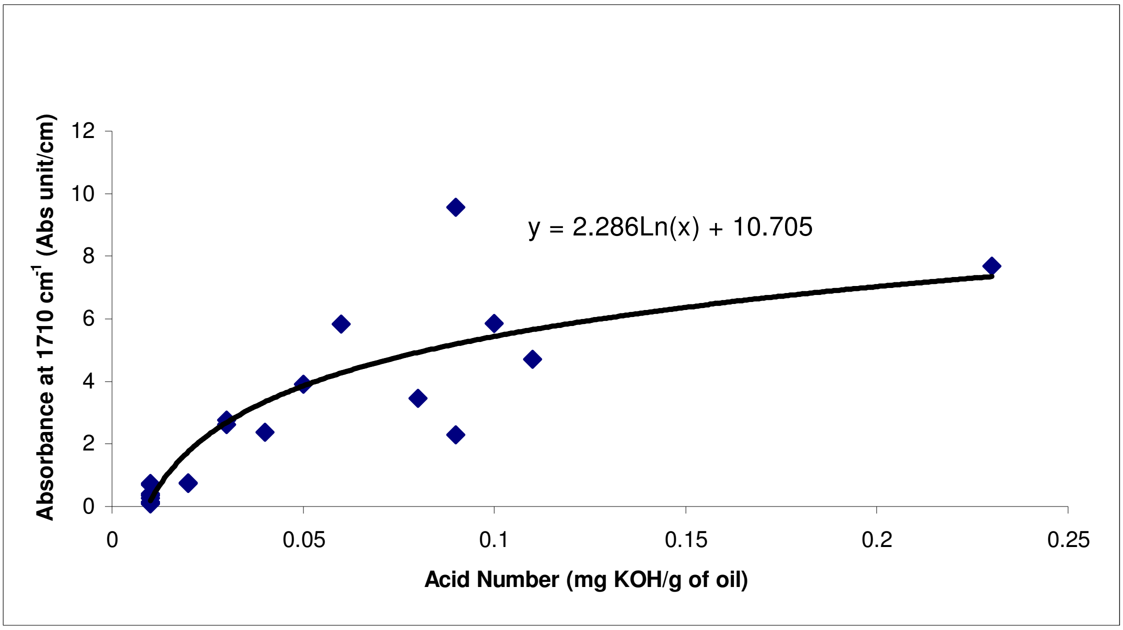


Figure 2
Correlation between the differential infrared absorbance at 1710 cm^{-1} and the acid number

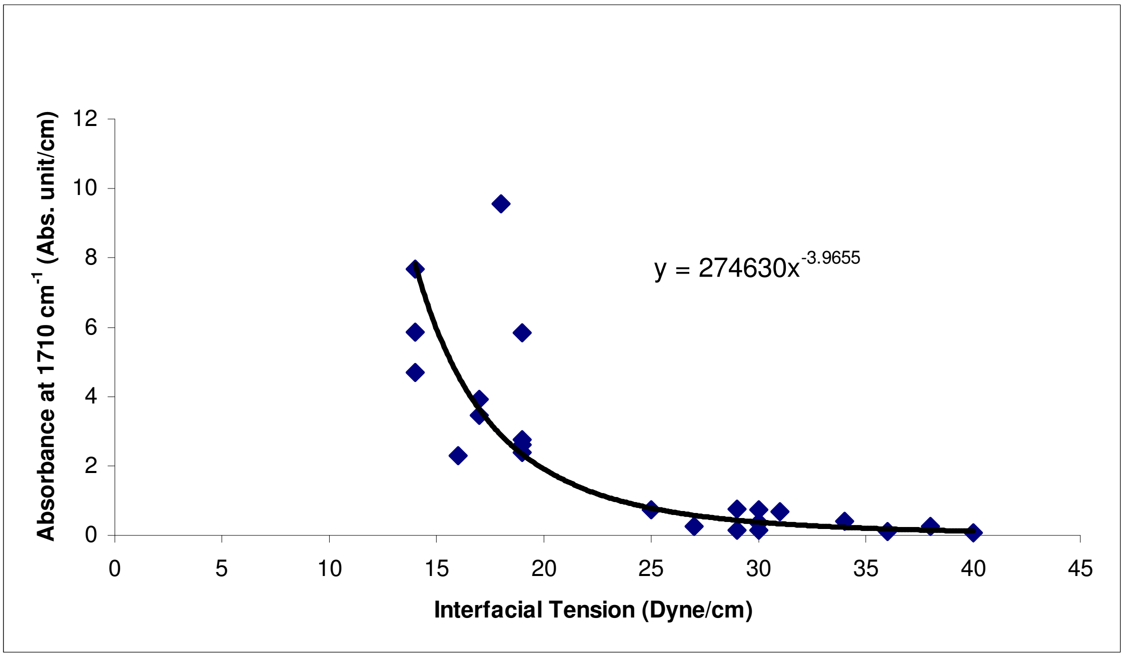


Figure 3
Correlation between the differential infrared absorbance of oils at 1710 cm^{-1} and the interfacial tension

These examples demonstrate that the typical oil tests do not completely assess the progress of oil aging.

Gas formation occurs primarily in the oil. With the exception of bubble formation, gases are dissolved directly into the oil and distributed throughout the transformer. Changes in temperature will induce migration of gases between oil, cellulose and any gas spaces and may significantly change gas-in-oil concentrations, especially when the temperature changes are large (See Table 7).

A 750 kV Shunt Reactor with a source of localized overheating was stored for 1 year. Tests were performed before and after heating the unit for 3 days

Table 7
Effect of Temperature Distribution of Gases

	H_2 ppm	CH_4 ppm	C_2H_4 ppm	C_2H_2 ppm	C_2H_6 ppm	CO ppm	CO_2 ppm	O_2 %	N_2 %
20 °C, before heating	trace	172	78	ND	56	923	1929	0.08	2.9
64 °C, after heating	56	269	147	1.3	90	1163	2654	0.09	5.5

Gas bubbles may be produced in transformers from severe fault conditions, a sudden release of pressure in gas saturated systems or an overload condition. Only a serious fault condition is expected to release large quantities of fault gases that do not get absorbed into the oil immediately. Nitrogen or air blanketed transformers may develop negative pressure in the gas space during rapid cool down. If the pressure differential between the gas in the oil and gas in the gas space is appreciable, spontaneous release of bubbles is possible. Transformer failures from a “cold start” of a stagnant transformer from bubble release in the supersaturated oil is one of the causes of sudden transformer failures. Therefore, it is necessary to ensure that such extreme pressure differential does not occur. Modern transformers with conservator tanks avoid this problem. As mentioned earlier, an overload condition with sufficient moisture and heat will produce bubbles of water vapor. Bubbles from any of these phenomena can lead to discharge events ranging from PD to flashover.

All of these examples illustrate that obtaining the best information from oil testing requires an understanding of the dynamics of the transformer as a system including the distribution of water, gases, contaminants and decomposition products between the fluid, solid insulation and gas spaces.

The Fluid as the Diagnostic Field

The possible benefits from using oil testing are indicated on Table 8, the Transformer Functional Failure Model suggested by the Cigre workgroup on Transformer Life Management, Cigre WG12.18. One may observe that for this collection most of the problems indicated could, in principle, be detected by means of oil analysis.

Table 8
Functional Failure Model
Possible detection of typical defects and faults through oil tests.

SYSTEM, COMPONENTS	DEFECT	Detection Through oil	FAULTS	Detection Through oil
Dielectric Major Insulation Minor Insulation Leads	Excessive water Oil contamination Surface contamination Abnormal aged oil cellulose aging static electrification PD of low energy	Yes Yes No Yes Yes Yes Yes	Destructive PD Localized tracking Creeping discharge Heated cellulose Flashover	Yes No Yes Yes Yes
Magnetic circuit Core insulation Clamping Magnetic shields Grounding circuit	Loosening clamping Short/open-circuit in grounding circuit circulating current Floating potential Aging lamination	No Yes Yes Yes No	Localized hot spot Sparking/ discharges Gassing	Yes Yes Yes
Mechanical Windings Clamping Leads support	Loosening clamping	No	Winding distortion radial axial twisting Insulation Failure	No Yes
Electric circuit Leads Winding conductors	Poor joint Poor contacts Contact deterioration	Yes Yes Yes	Localized hot spot Open-circuit Short-circuit	Yes No Yes

A selection of parameters to achieve the information goals is suggested in Table 9. The diagnostic use of oil-based information may be assisted by creating functional test/information groups such as:

- Characterization – which gives parameters that can be used to identify the oil
- Aging status – which gives parameters relevant to the aging process
- Dielectric status – which gives parameters used to determine the dielectric safety margin and dielectric characteristics of the insulation spaces.
- Degradation status – which gives parameters relevant to faults, failure and wear.

Table 9
A Functional Classification of Oil-Based Information

Classification of Oil-Based Information for Transformer Life Management			
Characterization	**Aging Status**	**Dielectric Status**	**Degradation status**
Fluid Composition Carbon Types Specific Gravity Viscosity Refractive Index Permittivity PAH content Inhibitor Content Total sulfur Corrosive Sulfur PCB Content BTA Content	Free Radicals Visible Spectrum Acidity Saponification Number Inhibitor contents IFT IR spectroscopy Dissipation factor Resistivity Polarization Index Turbidity Insoluble sludge Sludge content Oxidation stability tests Furanic compounds	Water content Percent saturation Bound water Particle profile Breakdown voltage Impulse strength Charging Tendency Resistivity Dissipation factor Insoluble sludge Gas tendency PD intention voltage	DGA Extended DGA Furanic compounds Phenols Cresols Dissolved metals Particle profile

Assessing the Transformer Condition for Life Management

The assessment begins with a compilation of information about the transformer. This includes information about the ratings, the core and coil such as their weights and configuration, the preservation system, the cooling system, the presence and configuration of a load tapchanger, the presence of a no-load tapchanger, and the full characterization of the fluid. This information should be collected and compiled in a manner that allows it to be available whenever an assessment is performed.

Summary operation, event, and maintenance activity data should also be compiled and available for assessments. As was illustrated above, isolated test data may imply one cause but be the result of a different one. Only with a completely integrated set of information can a thorough assessment be achieved.

We are proposing, for functional purposes, that the commentaries on the assessment address the topics of aging, dielectric and degradation. Note that there is an overlap of information between these topics and that these functional groupings are not intended limit a diagnostic testing program.

Assessing the Ageing Status of a Transformer

The test information for aging status specified in Table 9 was chosen to answer the following questions:

- What is the remaining inhibitor content?
- What is the non-acidic polar content?
- What is the acid content?
- What is the water content?
- What is the amount of esterification?
- What is the amount of sludge?
- What is the amount of insoluble sludge?
- What is the degree of polymerization of the paper?

The answers to these questions integrated with the compiled transformer information provides the basis for assessing the stages of aging and potential consequences. From the assessment a set of conditions such as:

- Presence of water, acids and non-acid polars which accelerate cellulose decomposition
- End of the induction period indicating a trend of accelerated degradation
- Appearance of sludge

may be chosen to initiate a course of actions like those shown in Figure 4.

Assessing the Dielectric Status of a Transformer

The condition assessment of the dielectric system of a transformer incorporates quantification of those factors that may reduce the dielectric safety margin of insulation under operating and through fault conditions. This information is used to answer the following basic questions:

➡ *What is the contamination with water, particles, acid, sludge?*
➡ *Will there be a substantial reduction in the dielectric margin at operating temperatures?*
➡ *What is the dielectric withstand capability?*
➡ *What is the amount of water in the solid insulation?*
➡ *Will there be bubble evolution at any allowable amount of loading?*
➡ *What is the amount of insulation surface contamination?*
➡ *What is the remaining mechanical strength of the solid insulation?*
➡ *Does this provide adequate withstand capability?*

Similar to the aging status, the answers to these questions integrated with the compiled transformer information provide the basis for assessing the stages of dielectric strength and withstand potential. From the assessment a set of conditions such as:

- Potential reduction of dielectric strength from conductive particles
- Potential reduction of dielectric strength from sediment or surface active substances
- Potential reduction of dielectric strength from water

- Potential reduction of mechanical withstand capability may be chosen to initiate a course of action.

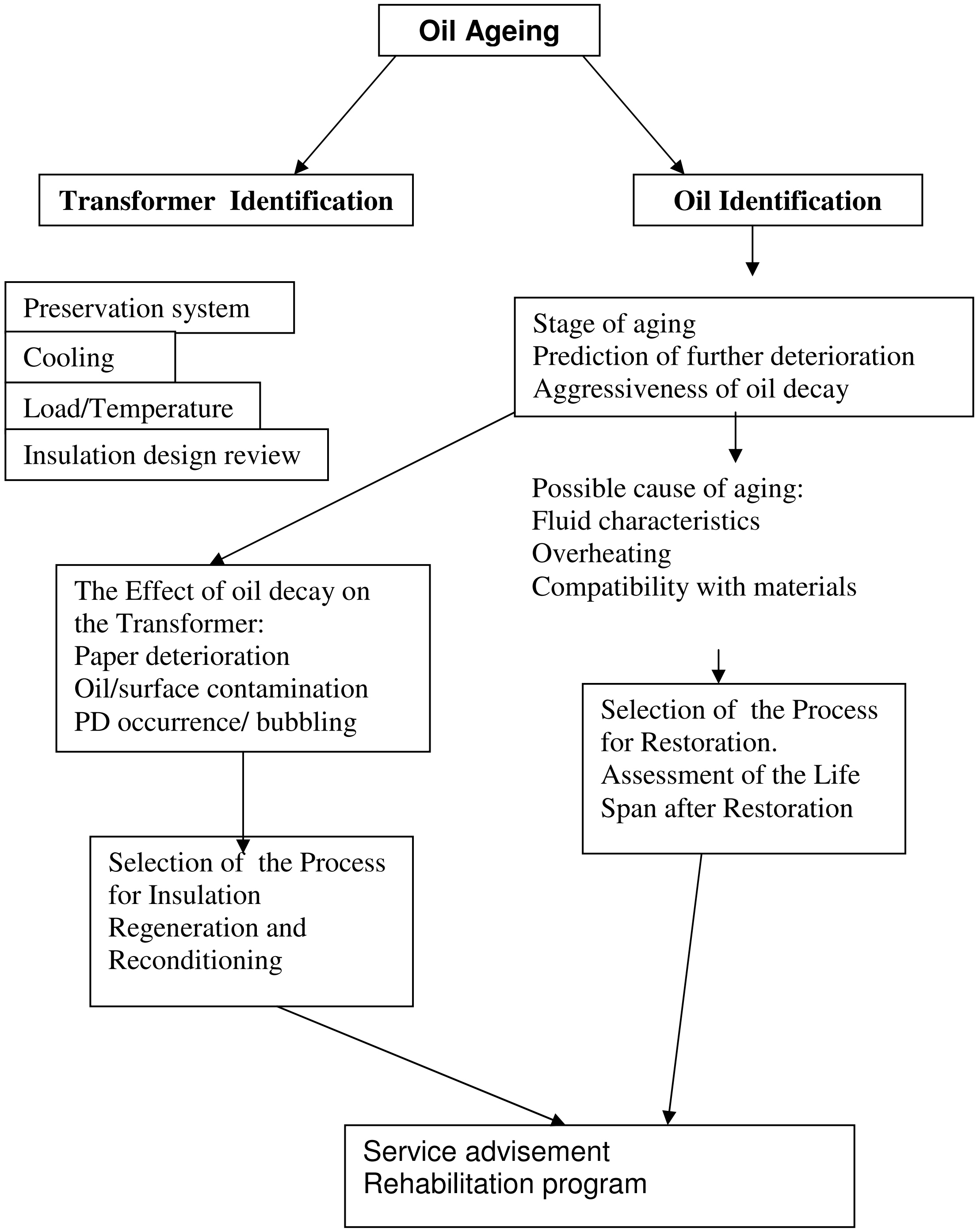


Figure 4
A flow chart of actions for fluid ageing

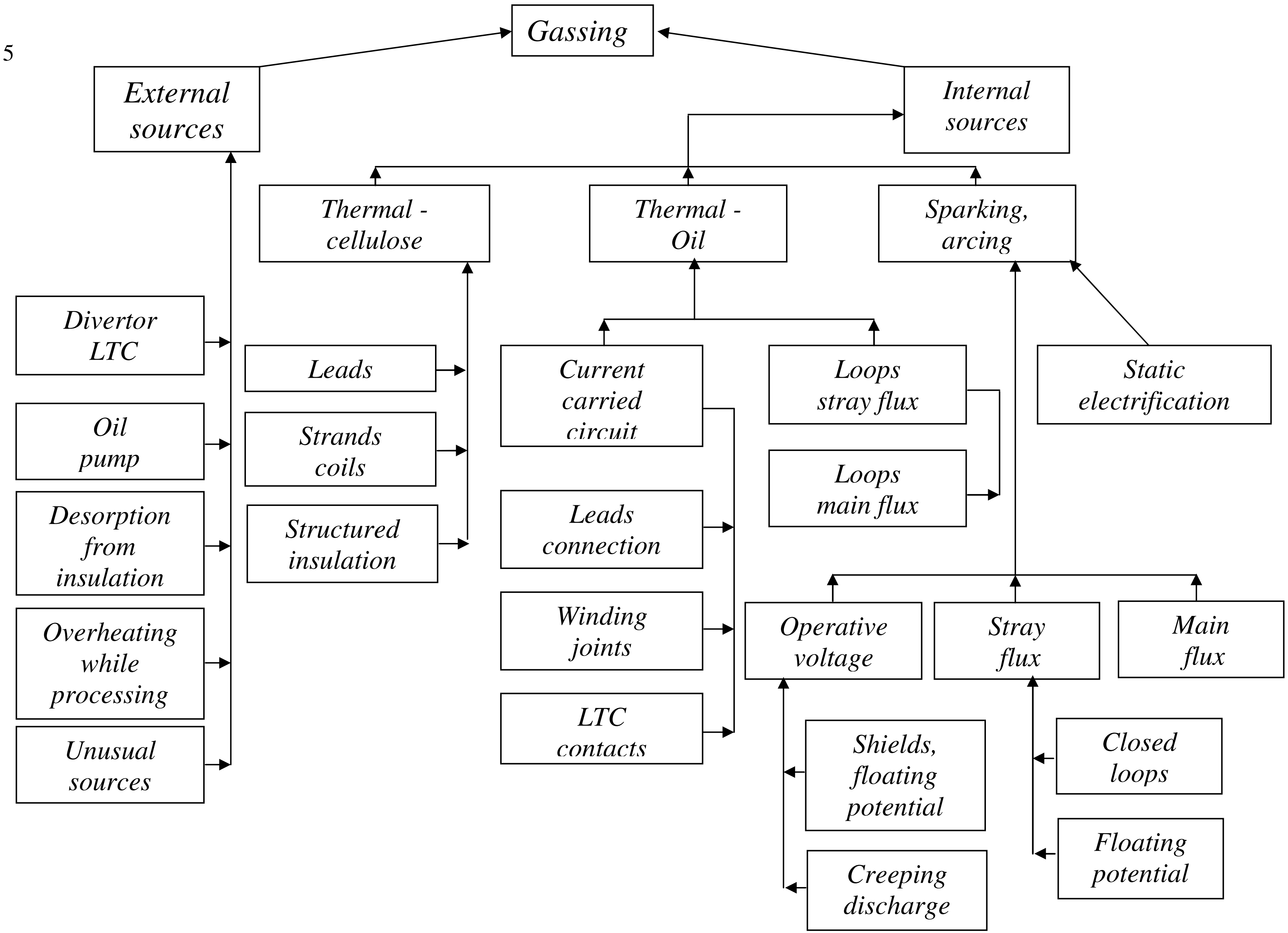
Assessing the Degradation Status of a Transformer

Degradation by-products such as gases, furans, phenols, cresols, dissolved metals, and metal particles are effective indicators of degradation processes. Once indicated, the challenge is to identify the source and seriousness of the process. The scheme in Figure 5 shows how gas information can be used to begin to locate the source of several degradation processes. Combined with the additional information available for the transformer, the success of identifying the source and severity is greatly enhanced.

Conclusion

Transformer life management requires comprehensive condition assessments to be made from a system's perspective. Because the transformer fluid is systemic, a large amount of this requisite information is available from fluid testing. In order to obtain the most complete and therefore useful information from fluid testing, an understanding of the dynamics of the transformer as a system, including the distribution of water, gases, contaminants and decomposition products between the fluid, solid insulation and gas spaces, is required. Using this understanding and the test information obtained, a diagnostic assessment can be made. This diagnosis coupled with an effective set of action plans provides the asset manager with the ability to choose the course of action best suited to the utility's needs.

Fig. 5



Gassing
External sources
Internal sources
Thermal - cellulose
Thermal - Oil
Sparking, arcing
Divertor LTC
Oil pump
Desorption from insulation
Overheating while processing
Unusual sources
Leads
Strands coils
Structured insulation
Current carried circuit
Leads connection
Winding joints
LTC contacts
Loops stray flux
Loops main flux
Static electrification
Operative voltage
Stray flux
Main flux
Shields, floating potential
Creeping discharge
Closed loops
Floating potential

References

1) John Sabau, Rolf Stokhuyzen, "Aging and Gassing of Mineral Insulating Oils", Proceedings of TechCon 2000

2) Dr Bruce Pahlavanpour, National Grid Company plc, "UK Insulating Oil Aging: Reclamation or Replacement"

3) Dr Bruce Pahlavanpour & Gordon Wilson, National Grid Company plc*, Kelvin Avenue, Leatherhead, Surrey, KT22 7ST* Insulating Oil Management Services

4) W.Tumiatti and B. Pahlavanpour "Condition Monitoring by Oil Chemical Analysis"

5) T. V. Oommen* Bubble Evolution from Transformer Overload Paper for presentation at the IEEE Insulation Life Subcommittee, Niagara Falls, Canada,October 17, 2000.

6) CIGRE WG 12.18 "Life management of Transformers, Draft Interim Report", *CIGRE SC12 Colloquium, July 1999, Budapest.*

7) E. Savchenko and V. Sokolov "Effectiveness of Life Management Procedures on Large Power Transformers", *CIGRE SC12 Colloquium, 1997, Sydney.*

8) IEEE "Guide for Diagnostic Field Testing of Electric Power Apparatus-Part 1 : Oil Filled Power transformers, Regulators and Reactors", IEEE Std 62-1995.

9) V.V. Sokolov, Z. Berler, V. Rashkes "Effective Methods of the Assessment of the Insulation System Conditions in Power Transformers: A View Based on Practical Experience", *Proceedings of the EIC/EMCWE'99 Conference, October 26-28,1999,Cincinnati,OH*

10).V. V. Sokolov and B. V. Vanin "Experience with In-Field Asseeement Of Water Contamination of Large Power Transformers", *EPRI Substation Equipment Diagnostic Conference VII, 1999.*

11) V.V. Sokolov Consideration on Power Transformer Condition based Maitenance, EPRI Substation Equipment Diagnostic Conference VIII,February 20-23, 2000, New Orleans, LA

12) W.Mcnutt, A,Bassetto, P,Griffin. Tutorial on Electrical-Grid Insulating Papers in Power Transformers. *1993 Doble Clients Committees Fall Meeting.*

13) T. V. Oommen, EPRI Report EL-7291 'Further Experimentation on Bubble Generation During Transformer Overload' March 1992

14) T. V. Oommen, 'Particle Analysis on Transformer Oil for Diagnostic and Quality Control Purposes' Doble Conf. Paper, 1984

15) T. V. Oommen, 'Update on Metal-in-Oil Analysis As It Applies to Transformer Oil Pump Problems' , Doble Conf. Paper, 1984

16) Sakkie vanWyke, "The Ever-Aging Power Plants in South Africa: Analyzing the Current Scenerio and Establishing Effective Management Strategies", Proceedings of TechCon 2000 Aus-NZ.

17) V.G.Davydov, O.M.Roizman, "Moisture Phenomena and Moisture Assessment in Operating Transformers", Proceedings of TechCon 2000 Aus-NZ.