WHAT MEANS AND TOOLS WOULD BE NECESSARY TO MAINTAIN AGED TRANSFORMER POPULATION

(PAPER PREPARED ON BEHALF OF SC A2)

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Introduction

It was commonly considered that transformer active life should last for 25-30 years. Relevant calculations and life-tests models research based on simulation of rated stresses and reasonable high voltage and through fault circuit stresses, e.g.[1, 2] supported anticipated life span. However a huge number of equipment shows no symptoms of significant insulation deterioration and a low failure rate after 50 and even after 60 years. The question comes: why they live such a long life? One explanation is that only a small percent of population operates continuously under rated stresses. Really if average load doesn't exceed 70% (50 % losses) one can reasonable expect doubling of calculated life.

However it might be another scenario: process of degradation is progressing but only by different manner than just thermal deterioration of cellulose insulation, and diagnostic tools available are not effective to some aging –mode defects.

Apparently, deteriorating of transformer fleet is growing significantly with years and without proper actions it would really threaten with fatal consequences. What tools and methods are available to mitigate aging phenomena and prevent snow-ball mode failures?

Technical Life of a transformer may be determined by several components:

- "Thermal Life"-time up to critical decomposition of winding (conductor) insulation, which in its turn is considered as mechanical life of paper, e.g. DP≤200;
- "Dielectric Life"-life span up to critical reduction of dielectric margin of major and minor insulation;
- "Mechanical life" of winding under impact of though fault currents, vibrations, etc;
- "Life of accessories", especially bushings and LTC.

CIGRE is trying to contribute to all aspects of transformer life.

"Thermal Life"

Recently CIGRE WG D1.01.10 presented a brochure "Ageing of cellulose in mineral-oil insulated transformers" [3]. The results of sophisticated studies allow better understanding processes of insulation decomposition under impact of realistic range of operating temperature (70 - 130 °C) and associated degradation factors. It was confirmed that state of cellulose decomposition might be characterized with "aging factor", which is equal to number of scissions of cellulosic molecule, and expressed through cellulose polymerization degree (DP) in a hot spot area.

It was suggested three dominating processes of cellulose decomposition: hydrolysis, pyrolysis and oxidation. In a real transformer all these processes act simultaneously being accompanied with oxidation of oil. Which process will dominate depends on the temperature and the condition.

The results allow distinguishing between abnormal overheating of cellulose when pyrolysis is dominating, and "normal" aging, when basically hydrolytic destruction is progressing and "life of paper" may be introduced though exponential function of temperature and pre-exponential coefficient, which depends on moisture and acids contamination.

It was also highlighted low-temperature cellulose decomposition, which acts basically through oxygen in oil and trough oxidation products in the oil – free radicals and peroxides and requires minimum activation energy.

A number of postmortem inspections that have been performed recently on scrubbed and repaired transformers presented clear evidences of strongly non-uniform deterioration of winding insulation e.g.[4]. Apparently temperature profile has been a major factor highlighting that thermal life is limited basically with state of insulation in a hot test zones (e.g Table 1). However there also have been evidences of determinative effect of oil oxidation products of insulation aging state (e.g. Table 2). Number of service years looks as secondary factor.

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Table 1: Aging state of LV winding in 133.3 MVA, 220/11 kV transformer after 30 years.

Sampling point	Temperature rise above ambient	DP
Top coil, paper	85	**280**
Middle coil, paper	53	447

Table 2: Aging decomposition of top coils conductors insulation in 800 MVA 400/275/22 kV, ONAN/ODAF after 24 years in service.

Winding	DP
Tertiary Never loaded, affected only by oil temperature and by-products	390
Tap	350
Common	275
Series	280

There has been some uncertainness in application of typical tools, namely insulation pattern DP tests and furans-in- oil analysis in real transformers.

In large power transformers hot spot area typically is not accessible for sampling being situated ether on inner winding or restricted with top winding insulating collar. Hence only indirect way may be used to anticipate DP in hot spot area.
Effectiveness of furans analysis is mitigated by a small amount of cellulose involved if intensive deterioration process in real transformer. Practically only 2-5% of total amount of cellulose contribute to "diagnostic basket" depending on winding temperature profile.
Elaboration of "thermal" life assessment technology should be a subject of priority.
Apparently "thermal life" span of a transformer should consider: temperature profile, time of operation, moisture and acids content as well as other oil degradation products particularly of polar and conductive nature.
Assessment of "thermal life» seems as a complex program including extension of oil test scope with measurement of oxidation products that can accelerate cellulose deterioration, e.g low molecular acids, methods based on extraction of by-products from insulation patterns, and vacuum extraction of acids and furans from cellulose; DP profile vs temperature, and post-mortem inspection during refurbishment. Detection of deterioration and overheating of CTC wire (continuously transposed conductor) using specific by-products would be a particular task-as CTC wire more susceptible to mechanical weakness of insulation being subjected to high local compressive stress. . It would be important to elaborate on the base of CIGRE Guide[3] on insulation condition assessment including recommendation on places and procedures of sampling insulation patterns for DP test. It's also the time to re-work method of DP measurement considering possible errors[6] particularly while low values are measured.

Dielectric Life

It has been generally considered, that aging deterioration of cellulose does not lead to substantial loss of its dielectric properties. This statement may be valid to some extent for non-impregnated insulation but is not the case for oil impregnated oil-barrier and oil-paper systems.
In fact insulation properties are subjected to a complex impairment including increasing dissipation factor and conductivity of paper and pressboard due to adsorption of polar oil aging products by the surface of the barriers and conductor insulation (Table 3).

Table 3: Change of oil and paper parameters after aging on service condition[5]

Parameter		Transformer No 1		Transformer No 2	
		prior	after	prior	after
Oil	Acidity (mg KOH/g)	0.06	0.58	0.01	0.1
	Water soluble acids (mg KOH/g)	0.01	0.21	0.003	0.04
	Tan delta at 20 °C (%)	0.14	0.71	0.14	0.26
Kraft paper	Tan delta (%)	0.6	**14.5**	0.6	**12.3**
	Permittivity (-)	3.3	**4.9**	3.3	**3.7**

Electrical field attracts predominantly conductive mode particles that reduce surface resistance and stability of pressboard to withstand PD activity as well as impulse strength of oil-barrier system.

Recent studies associated with formation and deposit on insulation copper sulphide have brought out clearly possibility of full loss of dielectric properties of contaminated insulation. Similar effect can be expected from deposit of oil sludge, carbon, and metal wearing-mode particles.

There have been several documented cases associated with a deposit of carbon on the lower porcelain of bushings and winding insulation, which originated from the localized overheating of the core, and with deposits of iron particles on the porcelain surface, which originated from pump bearing wear.

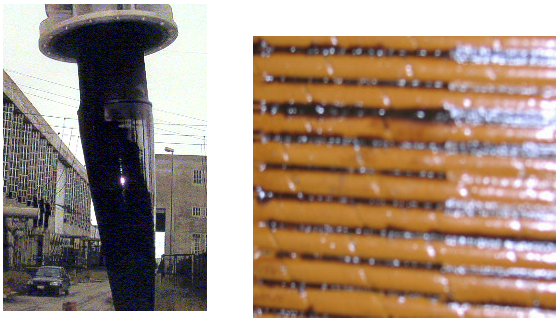

Fig 1: Sludge deposit of bushing porcelain (left) and winding (right)

Methods assessment of insulation condition

Traditionally identification of moisture content is considered as a preferential target of insulation condition assessment. Studies of WGA2.30 have shown that insulation moisture profile is strongly non-uniform depending on temperature profile. Moisture ingressed from atmosphere is distributed basically between pressboard barriers. However significant destruction of cellulose results in producing large amount of “aging“ water, which would contaminate turns and coils insulation directly.
Thus new diagnostic challenges are approaching: local contamination of barriers with conductive particles and contamination of winding turn-to-turn insulation with aging by-products should be task of priority.
One way to assess possible contamination of insulation would be analysis of oil, which is a transfer media for contaminants. Special attention should be paid to identification of conductive particles, namely carbon, metallic particles including dissolve ones.
Existing system of dielectric characteristics measurement as traditional R_{60} or R_{600}, tanδ, R_{60}/R_{15} or R_{600}/R_{60}, as well as novel RVI, PDC and FDS are focused on assessment of insulation in major clearances (winding-to winding, winding- to – ground) . Due to much greater capacitance of thin conductor insulation in comparison with capacitance of oil-barrier structure contamination of turn insulation negligibly contributes to change of measured characteristics.
As alternative capacitive component of on-load current and capacitive fraction of FRA could serve to assess the condition of longitudinal winding insulation. Another opportunity would be direct e.g. FDS measurement of winding insulation when oil is drained.

Role of fluids in reliability aspect of transformer equipment

Many maintenance guides still consider the insulating fluid as 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. Dielectric withstands strength of the oil and the level of oil contamination determines the dielectric safety margin of both new and service aged transformer insulation systems.
International standards specify rise of top oil temperature above ambient 60 °C allowing maximum temperature app. 100 °C at rated load and 115 °C during overloading. However a few types of mineral oils retain useful life at 100 °C for reasonable operation period.
Oxidation stability test and specified oil parameters allow distinguishing between the oils quality but gives poor idea what’s the life of the oil on given conditions in terms of temperature and electrical field intensity. Stability test does not consider impact of electrical field and cellulose materials on oxidation process.
Different oils that meet ASTM and IEC Specifications show drastically different picture of forming conductive by-products during aging under effect of electrical field (Fig.2).

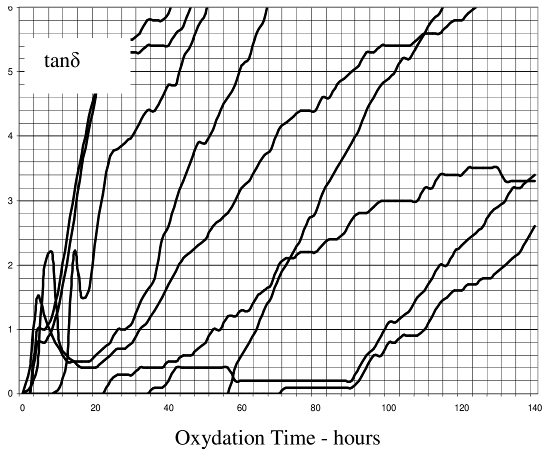

Fig. 2: Doble Free Life Test Behavior of different non-inhibited oils under operating temperature 95 °C. Rise of tanδ characterized the rate of producing conductive and polar by-products [5]

Experience has shown that some non-inhibited oils, which retain specified acidity and Interfacial Tension on the level of new oils, in fact exhibits very short induction period with formation of volatile acids just in 0,5-1 hour after applying temperature (Fig.3). Final decay products: sludge and acids are not the final decay products of the insulation integrity due to adsorption with cellulose and attracting conductive and polar by-products by electrical field.

Localized high temperature can accelerate oil aging process forming by-products locally, which being adsorbed with insulation or attracted with electrical field make weak effect on oil bulk specified parameters. Fig 4 shows an example of critical local oxidation of oil with formation of substantial amount of sludge while bulk oil parameters conformed to "good" state according to IEC 60422.

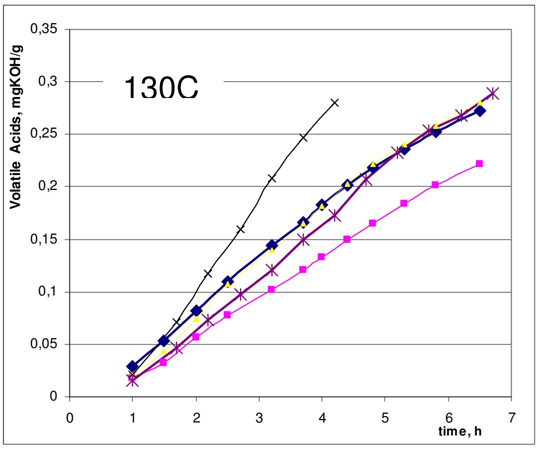

Fig 3: Oxidation Life test of oil from four GSU Transformers after 17-20 years of service Acidity <0.01 mgKOH/g, IFT≈38 mN/m

We presume that future CIGRE studies and relevant re-consideration of IEC 60296 and 60422 standards should include additionally the following:

- Oxidation stability of oil - in order to classify oils, and to determine useful life (induction period) within the certain range of temperature as well as rate of deterioration after the end of useful life, and relevant recommendation for application of the oil at certain range of maximum temperature.
- Oxidation stability of the system (oil, cellulose) including effect of electrical field with determination of impact of by-products of characteristics of cellulose).
- The rate of oxidation characteristic e,g, peroxide number.
- Temperature dependences of oil density (ρ), specific heat (c), and interfacial tension (IFT) as main parameters responsible for heat exchange, gas solubility (ρ) and insulation impregnation-de-impregnation with oil (IFT).
- Understanding of oxidation by-products though visible and infrared spectra.
- Recommendation on particles-in oil classification and measurement including aging submicron particles, methods of counting and identification by means of microscopic analysis.
- Information on solubility gases and water in particular type or class of oils. Aging leads to formation of significant amount of dissolved water adsorbed by oil oxidation by-products, specifically, of anionic surfactants and polar-mode aromatics. Unfortunately commonly used methods cannot measure added water unless preliminary heating of oil performed [7]. Hence reconsidering of moisture-in-oil test methods is becoming a task of importance

Rehabilitation of insulation system

Traditionally insulation drying out and degassing are considered as most important procedure to improve insulation condition and extend the life. However removing of moisture and oxygen is only a part of insulation restoration program, which as a whole should include also, removing particles as major measure to increase oil dielectric strength and mitigate effect of water, and regeneration insulation structure and active part in integrity

Changing of oil and flushing insulation with oil are not sufficient procedures because they do not allow removing by-products out-of cellulose macrospores. Retained by-products would accelerate further degradation. On the other hand it has been very positive experience with restoration and oil quality by means of treatment of transformer-in integrity in service [8].

Oil degassing destroys typically diagnostic media in oil bringing uncertainness in condition assessment. It has been also a positive experience with extraction of by-product accumulated in winding insulation using

Fig 4: Hot spot area of winding of shell form transformer. Max. temperature at 50 °C ambient and 60 °C of top oil above 130 °C. All area contaminated with oil sludge

LFH technique [9]. The latter allows also advising the rate of insulation deterioration.

Complex treatment including dissolving by-products, removing of submicron particles (e.g. carbon) and regeneration of insulation integrity would be the most appropriate solution to extend the life.

There have been experienced several techniques of removing oil-aging products out of insulation:

- Use special cleaning fluid during complex treatment of insulation (drying, regeneration and cleaning);
- Improve the detergency of operating oil: by means of establishment of special condition, namely, maintaining a low concentration of oil decay by reclaiming and a high temperature of oil to improve its solubility.

The subject of priority seems to be elaboration of Guide on on-line transformer processing, technique for removing reactive sulphur components, techniques for removing of oxidation by-products that adsorbed with insulation and hopefully copper sulphide deposit using cleaning fluids and vapor-phase solvent treatment.

Postmortem inspection as diagnostic tool

Factual information about real changes in transformer can be obtained only my means of direct study of the condition of aged material, what unfortunately possible only after disassembling of transformer active part. Thus, any or post mortem inspection is becoming a vital procedure.
Failed unit may become a powerful teaching aid, which would save a number of sister units and suggest an efficient strategical program for life assessment and life extension of operating population. Post-mortem inspection permits detailed investigation of insulation condition including the following:

- Understanding Insulation contamination and aging profile, which may be specific for the family.
- Measurement of water content in samples of conductor insulation and pressboard (aging water profile).
- Extraction and measurement of furans and acids in insulation, measurement of dielectric loss factor.
- Resistivity of insulation (surface resistance of pressboard) particularly in area of visible discoloration.

Elaboration of CIGRE Guides on post-mortem inspection might be a task of priority.

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