ASSESSMENT OF OIL ANALYSIS DATA FOR MEDIUM VOLTAGE DISTRIBUTION TRANSFORMERS

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Abstract: To ensure a safe and secure operation of transformers various diagnosis techniques are known. A lot of them are only applied to large power transformers regarding the costs. But distribution transformers can also benefit from the knowledge. In this contribution the results from 37 oil analyses of medium voltage distribution transformers with different load history and age are presented. The considered transformers are 10 to 55 years old. The rated power varies between 160 kVA and 1250 kVA. All transformers are oil immersed. The objects of investigation are the physio-chemical properties of the observed oils. In addition to routine tests for distribution transformers like breakdown voltage, water content and acid number some extra tests were also performed: for example the loss factor respectively the oil conductivity and the dissolved gases in oil. Also the transformers' main data e.g. rated power and ages are considered. Aim of the investigation is to improve the evaluation of the results and to show their physical or statistical correlation. The analysis of the results also considers effects of parameters e.g. oil temperature at sampling time. Finally, in the conclusion a suggestion of diagnostic techniques and sampling intervals is proposed.

1 INTRODUCTION

In this contribution the results from many oil analyses of medium voltage distribution transformers with different load history and age are presented. The oil samples were taken during a routine test of University of Stuttgart's distribution transformers. These transformers are sampled once a decade which was the reason to analyse the physio-chemical properties of the used oils. Aim of the investigation is to improve the evaluation of the results and to show their physical and statistical correlation. Thus several routine oil tests are performed, including colour number, breakdown voltage, water content and total acid number. In addition loss factor respectively oil conductivity and dissolved gases in oil were measured.

In this contribution also a short survey of the used measuring apparatuses with their advantages and disadvantages as well as accuracies and possible error sources are given.

2 MEASUREMENT EQUIPMENT

In the following sections the measurement methods and equipment are presented.

2.1 Breakdown voltage measurement

This measurement is an integral oil examination. It shows effects on oil quality caused by several sources. Obviously, an increase of the water content will decrease the breakdown voltage. Particles and other aging products have an influence too. With this quick measurement method it is possible to get a rough overview of the oil condition and decide further tests.

The presented tests follow IEC 60156. The setup uses a 2.5 mm gap distance between two calotte electrodes (VDE). The test cell is filled with approximately 400 ml oil. It is important to follow at least the waiting times recommended by the standards (5 min) because of air bubbles resulting from the filling process. Six breakdowns are produced (pause and stirring of 2 min). The result is the mean breakdown voltage with a standard deviation. Typically, the relative standard deviation for mineral oil is between 10 % and 20 %. A steady increase in breakdown voltage during the test indicates that the waiting times could have been too short. This is often the cause when a dielectric fluid has a higher viscosity than usual (e.g. natural esters). Depending on the transformer's rated voltage the measured value has to satisfy 30 kV, 40 kV or 50 kV for the highest voltages [1, 2].

2.2 Determining total acid number

The total acid number (TAN) of the oil gives some information about the aging of the oil-paper insulation system. It is determined by titration and is defined by how many milligrams of KOH solution are needed to neutralize the acid in 1 gram of oil. New oils can have a TAN of 0.01 whereas for aged oil 0.25 is already an alarming value and 0.50 is critical. The typical absolute measurement accuracy is +/- 0.01 for titration of about 10 g oil. As the name total acid number implies, this parameter shows a super-imposition of several aging products from oil aging and paper aging. Normally, it cannot distinguish between them, for example low and heavy molecular weight acids. Still an elevated TAN indicates aging. Especially for overloading and high operating temperatures over longer periods of time a rise in TAN should appear [3].

2.3 Determination of water content with coulometric Karl-Fischer titration

The water content in oil is used for two diagnostic methods. Firstly, it is directly connected to the breakdown voltage and thus is important for the safe operation of a transformer. Secondly, it is used for estimating ageing progress and remaining lifetime of the transformer. In this case the interesting part is the moisture content of the solid insulation which is estimated indirectly with moisture equilibrium diagrams from water in oil or dielectric spectroscopy of the whole insulating system.

The absolute moisture content in oil is measured with coulometric Karl-Fischer titration. In mineral oil the water content is very low, so it is common to use ppm values, which are defined by µg of water per gram oil. Obviously, the determination of very small amounts of water is difficult. Satisfying results can be achieved with direct injection of oil in the Karl-Fischer reagent. It is also necessary to take into account the sensitivity limits of the titrator. An acceptable repeatability has been obtained with water amounts greater than 10 µg, which can be achieved by injecting larger volumes of oil into the titrator. Additionally a display of double exponential titration curves helps defining titration stop criteria and simplifies quality control [4].

2.4 Loss factor measurement of the oil

The dielectric loss factor can be measured with a Schering bridge or more recently with the vector impedance method. It is convenient to use test cells defined for conductivity measurement. As the measurement frequencies and polarisability of the oil are very low, the loss factor is proportional to the conductivity. A combination of ageing products and water can have an influence on the conductivity and thus on the loss factor. Also the measurement temperature has to be considered as conductivity is exponentially temperature dependent [5].

2.5 Dissolved gas analysis

The Dissolved gas analysis (DGA) is a well known and accepted diagnostic method for oil immersed electrical equipment. Especially for power transformers it is a common routine test. This measurement is based on the fact that electrical or thermal failures in transformers generate various gases which then dissolve in the surrounding oil. After taking an oil sample and analysing it in the laboratory, it is possible to ascertain the transformer's internal error. Typically 11 fault gases are measured: H_2, CH_4, C_2H_2, C_2H_4, C_2H_6, C_3H_6, C_3H_8, CO, CO_2, O_2 and N_2.

The measurement is done according IEC 60567 [6] using a gas chromatograph (GC) linked with a degassing system. To degas oil samples several techniques are available: vacuum degassing, headspace sampling and stripping. Each method has advantages and disadvantages. For this contribution headspace method is used. In a small vial (volume 20 ml) 10 ml of oil is in contact with headspace filled with argon. After 30 min of shacking at 70 °C equilibrium is reached. Afterwards a gas sample is automatically injected in the GC. After the analysis it is possible to calculate the fault gas concentration in oil using the Ostwald-coefficients.

In the GC's columns the injected gas mix is separated to its components. The individual gas components are measured by two detectors: a flame ionization detector (FID) and a thermal conductivity detector (TCD). The FID only measures combustible gases with high accuracy. The TCD can measure all gases with a different thermal conductivity than the carrier gas. A methanizer is used to convert CO and CO_2 to methane and thus these gases can be detected more precisely in the FID.

The detection limit of the whole analysing system should be 5 µl/l for hydrogen and 1 µl/l for the hydrocarbons according IEC 60567 with good reproducibility.

For the analysis in this contribution a Siemens Sichromat 2/8 GC (2 columns in independent ovens, FID, TCD, methanizer, argon as carrier gas) with a Hewlett Packard HP 7694 headspace sampler is used.

3 TRANSFORMERS UNDER SURVEY

3.1 Technical specifications

The results from 37 oil analyses of medium voltage distribution transformers with different load history and age are determined. The oil samples are taken during a routine test of University of Stuttgart's distribution transformers. The considered transformers are 10 to 55 years old, see Figure 1.

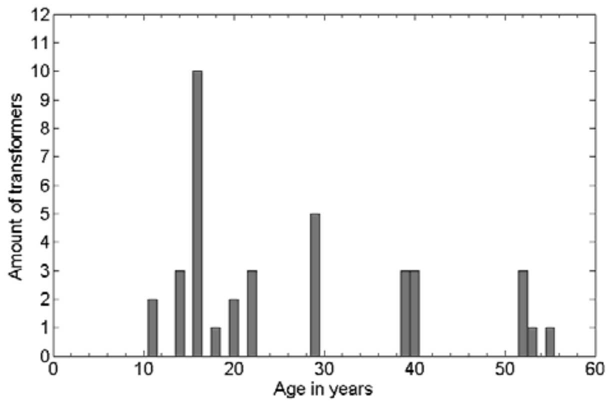

Figure 1: Transformer fleet age distribution

The rated power varies between 160 kVA and 1250 kVA, see Table 1.

Table 1: Transformers power ratings

Power rating	≤ 400 kVA	> 400 and ≤ 800 kVA	> 800 kVA
quantity	11	14	12

The rated voltage is 10 kV / 400 V for all transformers. All transformers are oil immersed; 34 of them are equipped with a free breathing oil conservator, 3 are hermetically sealed transformers.

3.2 Oil Sampling

Correct sampling is very important for an accurate measurement of all oil diagnosis values. For sampling a sealed aluminium bottle is recommended. Normally two bottles are needed: one for oil characteristics determination (min. 500 ml) and one for DGA (100 – 1000 ml according degassing technique). Because of the small oil volume of distribution transformers only one sample bottle (625 ml) is used.

Before sampling it is important to be sure that the transformer is offline or that it is possible to take samples safely. It is very important to fill the sample bottle carefully. The bottle should be absolute full without headspace or any air bubbles. It should be quickly sealed to avoid contamination (e.g. water or gases from ambient air) [6]. After sampling it is necessary to write down the top-oil temperature of the transformer. The sample bottles should be stored dry and protected from sunlight and analysed as fast as possible.

In the laboratory it is recommended to measure the water content and the dissolved gases first because of cross contamination with ambient air.

4 RESULTS

4.1 Oil characteristics

Figure 2 shows the average breakdown voltage over all investigated transformer oils. It is evident that they are generally in a good condition for medium power voltage transformers regardless the age, which can be up to 55 years.

As mentioned the total acid number is one indicator for ageing. In Figure 3 the acid number is plotted over the age of the respective transformer. A significant variation of the total acid number exists, but it does not depend on the service years. One could speculate that the influence of the transformers' load is dominating. TAN does not change much over time, but at elevated temperatures its trend could give useful information about the accelerated thermal degradation and thus the structural condition.

A more difficult interpretation is the assessment of water content in oil and its implications. Figure 4 shows the absolute water content plotted against service years. As the paper insulation ages the water content should be increasing. A tendency can be recognized, but the value depends on many factors like oil temperature or equilibration time. Therefore the next section discusses the temperature dependence of the measured values.

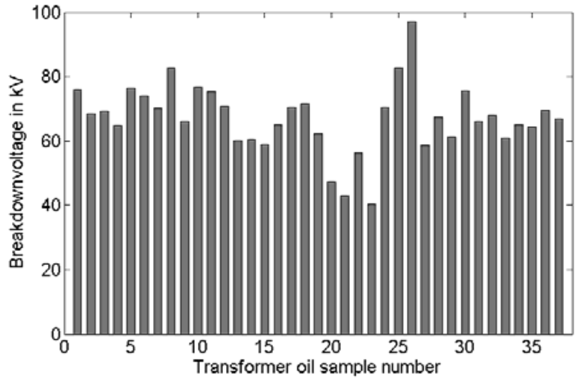

Figure 2: Transformer oil breakdown voltages

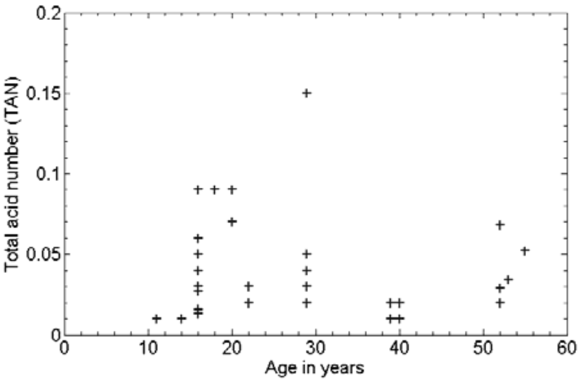

Figure 3: Total acid number depending on age

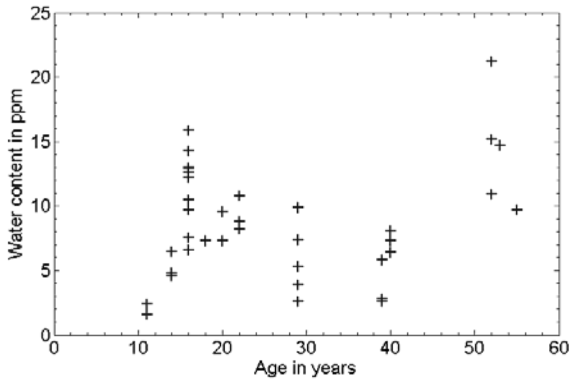

Figure 4: Water content in oil depending on age

4.2 Sampling temperature dependence

It is well known that water migrates between solid and liquid insulation. This process is governed by the oil temperature as the water saturation limit of oil changes drastically with temperature. For cold transformers water migrates into the paper. For hot operating temperatures the water content of the oil rises. Therefore ppm values of the hot oil seem to be higher. Figure 5 illustrates the effect, even if the transformers have unknown and possibly different moisture contents in the solid insulation. The consequence is that the oil from the warmer transformer, which therefore has to be more wet, will have a worse breakdown voltage, which normally is measured at ambient temperature. Three solutions can overcome this problem:

- Sampling the oil only at a well-defined oil temperature, e.g. 20°C top oil.
- Heat the breakdown voltage test cell up to the sampling temperature for measurement.
- Use a temperature correcting formula for the breakdown voltage and water value, which is already suggested in some standards.

As oil and paper age, not only water is produced, but also organic acids, which is reflected in the total acid number. Here also an investigation is made to see if acids migrate between solid insulation and oil like water does. Figure 6 shows TAN against sampling temperature. A dependency can not be observed. It seems that the acids do not behave as dynamically as water. Additionally their composition of weak or strong polar molecules is unclear.

The temperature dependent loss factor, respectively the oil's conductivity is measured at room temperature. An exact relationship between high TAN and water content to high loss factors could not be found. In some cases the conductivity was very high – in some cases still low.

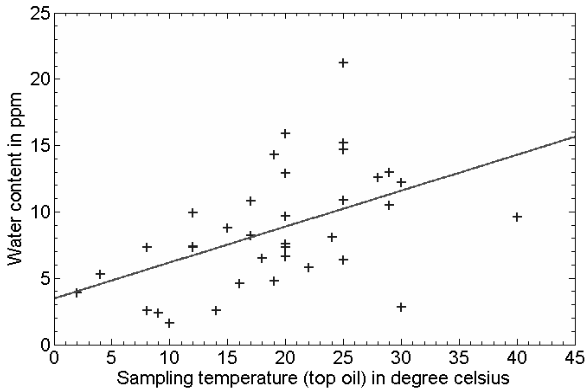

Figure 5: Water content vs. sampling temperature

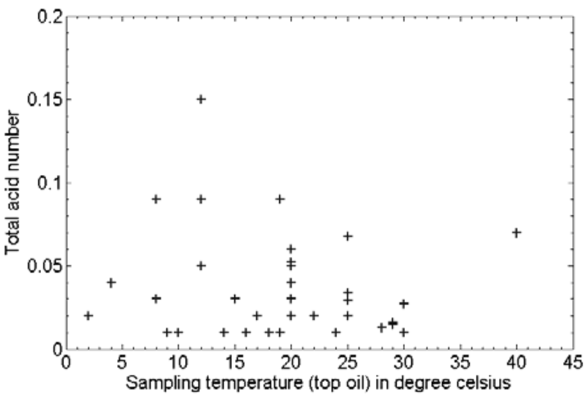

Figure 6: TAN vs. sampling temperature

4.3 Dissolved gas analysis

In Figure 7 the concentration of total dissolved combustible gases (TDCG, here: H_2, CH_4, C_2H_2, C_2H_4, C_2H_6 and CO) are plotted over transformers' age. The TDCG concentration is normally a hint for an ongoing fault in the transformer. However, the transformers' fault gas concentrations are in a typical range [7]. In this case the observed transformers only accumulated fault gases over the years.

The CO_2/CO ratio is known as an indicator of the decomposition of cellulose [8]. In Figure 8 the ratio is printed over transformers' age. In the diagram transformers between 10 and 30 years have a variable ratio between 5 and 48. This distribution may result from various load situations of the considered transformers. In comparison the older ones' ratio (> 35 years) is smaller. The older transformers have a smaller CO_2/CO ratio by trend then younger ones. As a conclusion a fix CO_2/CO ratio as diagnostic indicator is problematical because the ratio changes over the years.

In Figure 9 the concentrations of CO_2 and CO are plotted over transformers' age. In the diagram CO_2 concentrations vary over their age. But a concentration maximum can be seen at an age of around 20 years. Older and younger ones have a lower CO_2 concentration. It is unclear if a correlation can be found without the knowledge of the loading. In comparison the CO concentration is slightly increasing over the years.

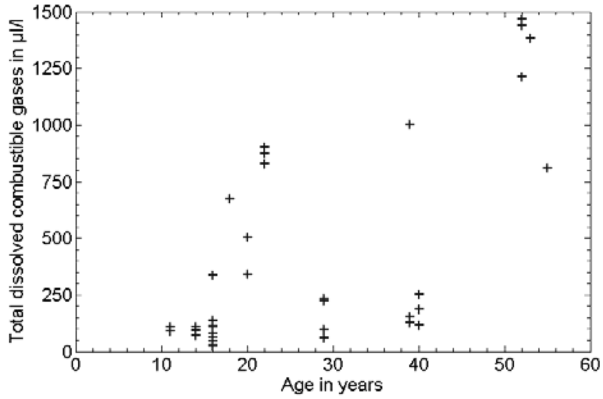

Figure 7: Combustible gases produced over years

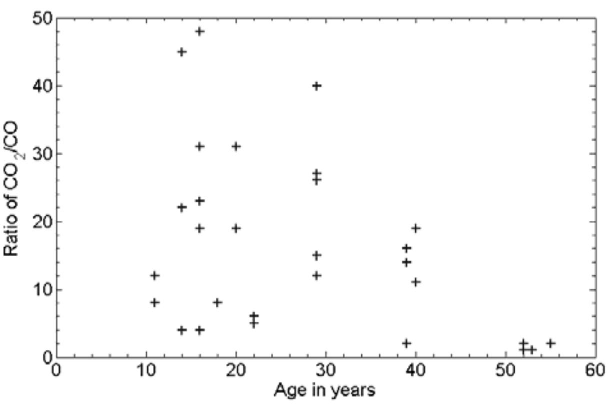

Figure 8: CO_2/CO ratio over transformer age

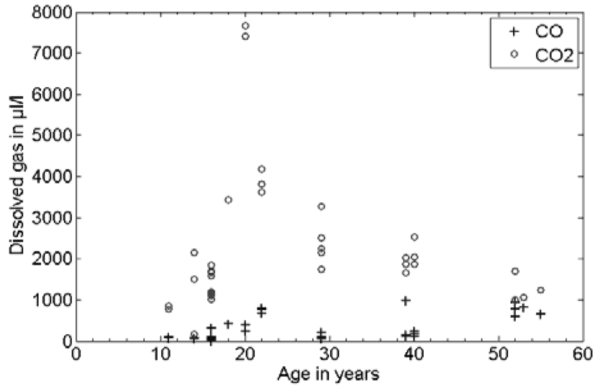

Figure 9: CO_2 and CO development over age

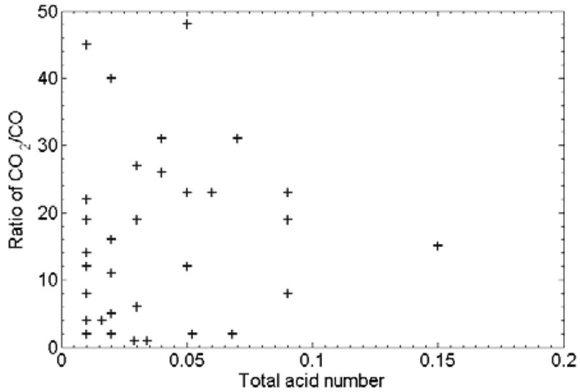

Figure 10: CO_2/CO ratio over total acid number

In Figure 10 the CO_2/CO ratio is displayed over the total acid number. As mentioned the total acid number is one indicator for ageing. However, in the diagram no correlation between the ratio and total acid number can be seen. So maybe CO_2/CO ratio could be time and load dependent. The ratio interpretation could be improved by considering the origins of the gases like oil ageing and cellulose ageing.

5 CONCLUSION

In this contribution the results from 37 oil analyses of medium voltage distribution transformers of different age were presented. Also a short survey of the used measuring apparatuses considering advantages and disadvantages as well as accuracies and possible error sources were discussed.

As the analysed transformers are mainly operated at lower partial load the measured values can be seen as a reference for regular ageing. For water content assessment the oil sampling temperature is of crucial importance. Neglecting this fact could lead to an erroneous diagnosis. For ageing assessment it seems that load history has a higher influence than normal natural ageing.

In case of higher loading or even overloading a transformer, the interval for oil sampling should be reduced in order to get better trend information. Eventually, the chosen interval depends on the importance of the electric equipment. Useful data can be gained from total acid number, water content and CO_2/CO ratio as ageing indicators.

A quick overview of the insulating system condition can already be obtained by measuring breakdown voltage. Hereby, it is possible to get information about safety of operation, but is highly dependent on oil sampling temperature.

6 REFERENCES

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