

Transformer Oil Sampling



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In dealing with the various firms that perform laboratory testing of transformer oil samples, I have noticed different recommended tests and different threshold levels associated with the results. Therefore, I thought it might be useful to discuss what is considered to be the more useful tests that need to be performed and the acceptable results associated with those tests. It is highly recommended that transformer oil sample tests be performed at least on an annual basis with results compared from year to year. In this article, I will discuss transformer oil sample tests other than dissolved gas analysis (DGA). We will leave the DGA discussion for another day.

Transformer oil sample tests can be separated into two general categories, those that assess the immediate acceptability of the insulation system and those that assess the degree of aging or degradation of the insulation system.

Insulation System Acceptability

To evaluate the immediate acceptability of the insulating system, three important oil sample tests should be carried out:

1. dielectric breakdown voltage
2. moisture content
3. power factor

These test measurements should be reviewed to verify that there are no sudden changes that would indicate the possibility of the entrance of moisture or other contaminants. If there is a sudden change, the transformer should be carefully inspected for leaks, and the oil processed if the dielectric is below an acceptable level or water content is above acceptable levels. A description of these tests is provided below:

Dielectric Breakdown Voltage – The dielectric breakdown voltage is a measurement of electrical stress that an insulating oil can withstand without failure. It is measured by applying a voltage between two electrodes under prescribed conditions under the oil. The dielectric test measures the voltage at which the oil breaks down, which is indicative of the amount of contaminant (usually moisture) in the oil. For mineral oil, a generally accepted minimum dielectric strength is 30 kV

for transformers with a high-voltage rating of 230 kV and above and 27 kV for transformers with a high-voltage rating below 230 kV. New oil should have a minimum dielectric strength of 35 kV by ASTM methods of testing. Oil is not necessarily in good condition even when the dielectric strength is adequate, because this tells nothing about the presence of acids and sludge. Lower values are indicative of damp or dirty oil.

Moisture Content – Moisture in oil is measured in parts per million (ppm) using the weight of moisture divided by the weight of oil. Water can be present in oil in a dissolved form, as tiny droplets mixed with the oil (emulsion), or in a free state at the bottom of the tank holding the oil. Demulsification occurs when the tiny droplets unite to form larger drops which sink to the bottom and form free water. When the moisture in oil exceeds the saturation value, there will also be free water precipitated from the oil in suspension or drops. In general, the moisture content in the oil lowers the insulating system dielectric strength and allows flashover that can damage a transformer. Moisture can also accelerate paper-insulation aging rates that will reduce the expected useful life of equipment. For mineral oil, a generally accepted maximum moisture content is 35 ppm.

Power Factor - The power factor of insulating oil equals the cosine of the phase angle between an ac voltage applied and the resulting current. Power factor indicates the dielectric loss of the insulating oil and, thus, its dielectric heating. The power-factor test is widely used as an acceptance and preventive maintenance test for insulating oil. A high power factor in service-aged oil indicates deterioration, contamination, or both with moisture, carbon, or deterioration products. For mineral oil, the power factor of new oil should not exceed 0.05 percent at 25°C. Service-aged oil with a power factor in excess of 0.5 percent should be further analyzed in a laboratory to determine the cause of the high power factor. Oil with a power factor in excess of 2.0 percent may be an operational hazard. It should be investigated and either reconditioned or replaced.

Insulation System Aging/Degradation

The principal indicators to assess the degree of aging or degradation of the insulation system (lead conductor insulation, winding insulation, core insulation, and the fluid insulation) are:

1. interfacial tension
2. acid neutralization
3. color

These indicators should be reviewed for any abrupt changes as they would normally change very little from year to year. A significant change in these values may indicate overheating of all or part of the insulation system. The transformer should be scheduled for acceptance tests as soon as possible if these results are verified.

Interfacial Tension -The interfacial tension (IFT) test is employed as an indication of the sludging characteristics of power transformer insulating oil. It is a test of IFT of water against oil, which is different from surface tension in that the surface of the water is in contact with oil instead of air. The attraction between the water molecules at the interface is influenced by the presence of polar molecules in the oil

Insulating Oil Quality Limits							
Test	ASTM Test Method	Mineral Oils	Silicone	Wecosol	FR3	R-Temp	Askarel
Visual	D1524 D2129	Clear free of particles	Clear free of particles	Clear free of particles	Clear free of particles	Clear free of particles	Clear free of particles
Dielectric Breakdown Voltage, kV	D877 D1816	≥ 26	≥ 25	≥ 26	≥ 34	≥ 24	≥ 30
Water Content Maximum, ppm	D1533	≤ 35	≤ 100	≤ 35	≤ 400	≤ 35	≤ 50
Power Factor max @ 25 Deg C, %	D924	≤ 0.5	≤ 0.2	≤ 12	≤ 1.0	≤ 1.0	-
Interfacial Tension, dynes/cm or mN/m	D971 D2285	≥ 25	-	-	≥ 18	≥ 22	-
Acid Neutralization number max, mg KOH/gm	D974	≤ 0.2	≤ 0.2	≤ 0.25	≤ 2.5	≤ 0.25	≤ 0.25

in such a way that the presence of more polar compounds causes lower IFT. The test measures the concentration of polar molecules in suspension and in solution in the oil and thus gives an accurate measurement of dissolved sludge precursors in the oil long before any sludge is precipitated. Typically for mineral oil, new oil has a minimum reading of 36 dynes/cm and an in-service oil is generally considered good until a reading of less than 25 dynes/cm is reached. It has been established that an IFT of less than 0.015 N/m (15 dyne/cm) almost invariably shows sludging. An IFT of 0.015 to 0.022 N/m (15 to 22 dyne/cm) shows an uncertain condition, and an IFT value of more than 0.022 N/m (22 dyne/cm) is generally indicative of no sludging. If there is an interfacial tension decrease of 20 percent or more (with a change in the color between annual readings), the oil should be resampled and tested for confirmation of the results. A significant change denotes an accelerated aging of the insulation system, which would be indicative of overheating of the insulation. The transformer should be scheduled for winding insulation tests as soon as possible if these results are verified.

Acid Neutralization Number - The acid neutralization number, or acid number, is the amount of potassium hydroxide (KOH in mg) required to neutralize the acid in one gram of oil. It is indicative of the acid content in the oil. With service-aged oils, it is also indicative of the presence of contaminants, like sludge. It should be recognized that the acidity test alone determines conditions under which sludge may form but does not necessarily indicate that actual sludging conditions exist. New transformer oils contain practically no acids. The acidity test measures the content of acids formed by oxidation. The oxidation products polymerize to form sludge which then precipitates out. Acids react with metals on the surfaces inside the tank and form metallic soaps, another form of sludge. For mineral oil, sludging has been found to begin when the acid number reaches or exceeds 0.4 mg KOH/gram. New oil has an acid number of less than 0.05 mg KOH/gram. Oil showing an acid number of 0.15 or larger can be expected to show accelerated acid formation. Typically, results of 0.10 mg KOH/gram of oil or less are considered good. Higher values are indicative of a problem. If there is an acidity increase of 25 percent or more (with a change in the color between annual readings), the oil should be resampled and tested for confirmation of the results. A significant change denotes an accelerated aging of the insulation system,

which would be indicative of overheating of the insulation. The transformer should be scheduled for acceptance tests as soon as possible if these results are verified.

Color – The color of an insulating oil is determined by means of transmitted light and is expressed by a numerical value based on comparison with a series of color standards. It is recognized that color by itself could be misleading in evaluating oils for service quality. The primary significance of color is to observe a change or darkening of the oil from previous samples of oil from the same transformer. Noticeable darkening in short periods of time indicates either contamination or that arcing is taking place. A darkening color, with no significant change in neutralization value or viscosity, usually indicates contamination.

The acceptable levels provided for the above parameters are for cases when mineral oil is used as the insulating oil. Below is a table which includes a compilation of suggested acceptable levels for other insulating oils:

The above levels are consistent with NETA/ANSI MTS-2007, Standard for Maintenance Testing Specifications for Electrical Power Distribution Equipment and Systems and the IEEE C57 series of specifications on transformer fluid testing. Additionally, I am sure that tests other than those shown above could be recommended based on conditions and results. My suggestion is that the above recommended tests and results should provide the minimum requirements for a condition-based, transformer oil analysis program. As suggested above, transformer fluid sample tests should be performed at least annually, with more frequent testing performed if issues arise.

As Operations Manager of ESCO Energy Services Company, Lynn brings over 25 years of working knowledge in design, permitting, construction, and startup of mechanical, electrical, and instrumentation and controls projects as well as experience in the operation and maintenance of facilities.

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