TRANSFORMER AND CAPACITOR DIELECTRIC FLUIDS

INTRODUCTION

Property Risk Consulting Guideline PRC.5.9.1 provides general guidance for setting up a transformer preventive maintenance (PM) program. It describes inspection, servicing and testing activities for both dry-type and liquid-insulated transformers. It identifies specific transformer dielectric fluid tests and test frequencies.

This guideline describes the use and maintenance of the four basic types of dielectric fluids. Specifically, mineral oil, askarel, nonflammable fluid and less-flammable liquid are discussed. The guideline assists working transformer dielectric fluid maintenance programs by guiding test methods and analyses. It also guides the maintenance and arrangement of capacitors based on the insulating fluid used in construction.

Polychlorinated biphenyls (PCBs) pose a risk to human health and the environment. Their manufacture, use and disposal are governed by 40 CFR part 761 of the Code of Federal Regulations (CFR). Transformer and capacitor dielectric fluids containing PCBs require special attention as outlined in PRC.5.4.5.1.

The type of dielectric in a transformer frequently determines what is necessary for effective loss control. PRC.5.2 and the PRC.5.9 series of guidelines assist loss control efforts by guiding the location, arrangement and protection of transformers based on transformer construction.

POSITION

Locate, arrange, protect and maintain fluid-insulated transformers as described in this and referenced supplementary Property Risk Consulting Guidelines.

For liquid-insulated transformers rated over 75 kVA, include dielectric fluid testing in the PM program, as follows:

- Schedule the listed routine tests no less frequently than as identified in PRC.5.9.1:
    - Dielectric strength (all fluids);
    - Acidity (all fluids);
    - Dissolved gas analysis (DGA) for oil and less-flammable fluids used in transformers rated above 2500 kVA;
    - Interfacial tension (IT) for oil and high molecular weight hydrocarbons.
- Employ accepted sampling and testing procedures and use reliable test equipment as described in this guideline.

- Analyze test results and take corrective actions where necessary to prevent electrical breakdown.
- Retain test records for insurance company review.
- Handle PCBs in accordance with the CFR. If appropriate, employ a qualified transformer servicing organization to sample, test and dispose of dielectric fluids containing PCBs.

Perform capacitor PM as recommended by the manufacturer, and include:

- Inspection of the tank for bulging, discoloration and leaks.
- Check of the operating temperature using an infrared measuring device.
- Review of environmental conditions such as ambient temperature and ventilation.
- Metering of applied voltage.

Enclose capacitors in a vault if located indoors and containing more than 3 gal (11.4 L) of a Non-PCB dielectric liquid when:

- The fire point of the dielectric fluid is less than 572°F (300°C),

OR

- A fire involving the capacitor could ignite significant quantities of other combustible materials.

Provide special fire protection, such as an automatic carbon dioxide flooding system, in any vault containing both a capacitor containing more than 3 gal (11.4 L) of a Non-PCB dielectric liquid, and switchgear having a serious business interruption loss potential, particularly if a capacitor rupture and fire can expose the switchgear to burning fluid.

DISCUSSION

Dielectric Fluids - Purpose And Use

In general, dielectric fluids maintain electric fields, cool heated electrical components, and provide electrical insulation. They are used in power transformers, capacitors and other equipment where their specific properties are required.

A power transformer is basically a tank containing paper-wrapped conductors wound around a steel core and immersed in a dielectric fluid. The dielectric fluid circulates through the tank by convection or auxiliary pumping. This fluid picks up heat as it passes the transformer windings and core, and cools as it passes along the surface of the tank or through radiators. External fans may move air across the radiators and fins to force cool the fluid. Where a transformer nameplate has more than one kVA rating, the self-cooled rating which appears first applies to use of that unit without pumps or fans. Subsequent ratings are the forced-cooled ratings and are listed in the order of the forced cooling methods listed on the nameplate.

But the transformer dielectric does more than transfer heat. Essentially, each winding turn, the primary and secondary voltage connections, the core and the tank are at different voltage potentials. The dielectric provides the electrical insulation needed to minimize current flow between these points where air alone would not provide adequate insulation.

Oil transformer dielectric fluids usually serve one other important purpose. Both overly moist and excessively dry paper are poor electrical insulators. By saturating the paper insulation wrapped around the windings, oil improves the paper’s insulating characteristics and retards moisture penetration into the paper.

Similarly, a power factor correction capacitor can be a tank with internal components that include paper insulation immersed in a dielectric fluid. Or the capacitor tank can contain tightly packed layers of plastic film and aluminum foil sheets immersed in the dielectric fluid. Generally, the dielectric fluid in a capacitor serves the same insulating function as the dielectric in a transformer.

Even if a dielectric meets specification, a severe electric surge can cause electrical breakdown and tank rupture. Contaminated dielectrics break down more readily. A severely contaminated dielectric can break down at normal operating voltage and temperature. Gas bubbles, water, carbon particles and sludge are common contaminants.

Importance Of Testing

The condition of a dielectric in an operating transformer is an indicator of the condition of the transformer. Dielectric tests provide a ready means of evaluating the transformer’s condition and predicting its performance. Generally, fluid and gas samples can be drawn and tests can be performed without interrupting service. Analysis of a dielectric can identify corona, rusting, sparking, arcing, overheating, water content, impurities, changes in electrical properties and other problems that can lead to loss. The high energy components of electric power systems require predictive and preventive maintenance to maintain fluid characteristics and to prevent electrical breakdown, explosion and catastrophic loss.

The importance of dielectric fluid maintenance is emphasized by the great amount of material available on the subject. Some of the organizations publishing standards defining test procedures and setting limits for test results include: National Fire Protection Association (NFPA); ASTM International (ASTM); American National Standards Institute (ANSI); and The Institute of Electrical and Electronics Engineers, Inc. (IEEE). NFPA 70B prescribes tests and limits for oils and askarels. Manufacturers of transformers, test equipment and dielectric fluids also provide guidelines for fluid testing and the interpretation of test results. Also transformer service companies establish and distribute their own testing standards based on their own experience.

Types Of Fluids

The *National Electrical Code*® (NEC) describes the following four liquid filled transformer categories:

- Oil-insulated
- Askarel-Insulated
- Nonflammable Fluid-Insulated
- Less-Flammable Liquid-Insulated.

As described later, there are different types of fluids within some of these categories. The NEC describes protection requirements for transformers based on these four basic categories.

Dielectric fluids are not readily interchangeable. Viscosity, heat transfer and other fluid characteristics form a basis for the design of the electrical equipment. Where an equipment manufacturer authorizes a change to an alternate dielectric, derating the unit may be necessary. Gaskets and other transformer components will sometimes have to be replaced when a new type of fluid is used. However, replacement of dielectric fluids is not uncommon due to the PCB problem described in PRC.5.4.5.1.

Oil-Insulated Transformers

Transformer oil is a refined petroleum oil. It is typically referred to as mineral oil. It has high dielectric strength and low viscosity. Because is offers little resistance to flow, it is an effective heat transfer agent.

Mineral oil has a flash point of not less than 293°F (145°C). Of all types of transformers, mineral oil-insulated units offer the greatest fire threat due to the severity of the oil fire that can occur.

With aging, impurities accumulate in the oil. Its resistance to breakdown from voltage gradients decreases. It can sludge. Preventive and corrective measures include reconditioning or reclaiming the fluid, and using additives.

For most codes and standards, oil-insulated transformers are those which have been tested for PCB contamination and are rated and maintained as “Non-PCB.” However, mineral oil can be contaminated with PCBs through past practices involving poor handling and testing procedures, such as using common piping or the same test equipment with both askarel and oil fluids. Or oil may have become contaminated before PCB hazards were recognized and when manufacturers sometimes filled new transformers with askarel fluid for testing. Because PCB contaminated mineral oil has both the fire hazard of oil and the PCB hazard of askarel, both hazards should be recognized in the application of codes, standards and loss control programs.

Askarel-Insulated Transformers

"Askarel" was originally a trade name for a specific fluid. Common usage of the term changed its meaning. It became a generic term referring to nonflammable synthetic chlorinated hydrocarbons used as liquid insulations and coolants used in transformers and capacitors and typically containing PCBs. While some askarels do not contain PCBs, for the purpose of this guideline, the term refers to a nonflammable transformer dielectric containing PCBs.

Because PCBs are essentially non-biodegradable and deemed to be a health risk, the use of askarels and other fluids containing PCBs are regulated by the CFR.

Most codes and standards consider an askarel to be a noncombustible fluid. Askarels and other dielectric fluids contaminated by askarels should be tested for PCB content in parts per million and for fire point. Such information is needed with any loss control program to evaluate compliance with the various codes and standards.

Nonflammable Fluid-Insulated Transformers

Tetrachloroethylene is a solvent. It is a commonly used dry-cleaning fluid. Since the regulation of PCBs, tetrachloroethylene (perchloroethylene) has been used in transformers as a nonflammable dielectric fluid. It has a lower viscosity than mineral oil and has excellent electrical insulation properties. Both the fluid alone and a blend with mineral oil have been listed as noncombustible fluids.

However, concerns have been expressed over tetrachloroethylene's effects on the environment and on the transformer itself. Precautions are required with indoor use because the fluid is toxic. Corrosion is another concern with indoor installations. One of the high temperature decomposition products is hydrogen chloride which can combine with moisture in the air to form hydrochloric acid. In corrosion sensitive occupancies, the units should be enclosed and directly vented to the outdoors. Such occupancies include semiconductor manufacturing, precision machining and computers.

Use of a nonflammable transformer fluid is highly desirable. Currently there are several nonflammable fluids available. When one is proposed for use, its chemical makeup, toxicity and environmental hazards potential should be determined. Advantages, disadvantages and protection requirements should be weighed.

Nonflammable transformer fluids are used in transformers for retrofilling and reclassification. Therefore, nonflammable fluid-insulated transformers can also be rated PCB, PCB-contaminated and Non-PCB, depending on reclassification status.

Less-Flammable Liquid-Insulated (LFLI) Transformers

LFLI transformers use a dielectric fluid having a fire point of not less than 300°C (572°F). Less-flammable fluids are qualified by the Cleveland Open Cup Test (ASTM D92). Candidate liquids are heated by slowly increasing the temperature of the cup containing the liquid sample. The fire point is the lowest temperature at which the test flame will cause continued burning of the liquid for at least 5 seconds. The two major types of LFLI fluids are polydimethyl siloxane (PDMS) and high molecular weight hydrocarbons (HMWH).

PDMS is a silicone compound. Although used for years in electrical equipment, and not considered a detriment to the environment, silicones gained popularity for use in transformers only as the use of askarels declined. Silicones have a higher viscosity and less desirable heat transfer characteristics than either askarels or mineral oils. However, silicones are readily available and have excellent electrical insulating properties.

HMWH are chemically similar to mineral oils. These fluids have higher viscosities and fire points than do mineral oils. These materials burn at higher temperatures than silicones, and thus have a potential for greater fire damage.

LFLI fluids are also used in askarel-insulated transformers for retrofilling and reclassification. Thus a transformer may contain an LFLI dielectric fluid, and also be rated as PCB or PCB-contaminated, with the associated PCB concerns. If reclassification results in a "Non-PCB" rating, health and environmental hazards diminish.

LFLI transformers have a low incidence of rupture and the fluids are difficult to ignite. The prohibition of combustibles near the transformer, and containment for spill and spray control, are good loss control techniques for well maintained units.

Capacitors

Originally, large power capacitors were oil-insulated and posed a major fire threat. When noncombustible askarels were developed, askarels became the major dielectric fluid. Both the NEC and the CFR address capacitor requirements.

The NEC states "Capacitors containing more than 3 gal (11.36 L) of flammable liquid shall be enclosed in vaults or outdoor fenced enclosures." Although it specifically states "flammable liquid," the intent is to include any combustible liquid.

As required by the CFR, all large PCB capacitors must be replaced unless located in restricted access electrical substations or located in contained and restricted access indoor installations. Because PCB capacitors cannot be retrofilled, PCB units that are immediately exposed by potential fire sources, e.g., oil-filled equipment or concentrations of combustibles must be replaced. Also, those that serve as a contamination exposure to waterways, ducted air handling systems or processes producing items for human consumption (food, liquids, pharmaceuticals) require immediate replacement.

Reasons For Testing Dielectrics

The condition of a liquid-insulated device can be evaluated by drawing, testing and analyzing its dielectric fluid. When sampling and test methods follow established procedures, current test results can be compared with past results. Historical trends show the effects of deterioration from normal aging and uncommon stress. The rate at which insulation is deteriorating, and its condition, are identified. This type of maintenance is "predictive" in that analysis of the results can predict imminent electrical breakdown. When a maintenance program also directs follow-up actions to prevent or minimize the chances of unexpected electrical breakdown, it is also "preventive."

PM effects control over losses. Arcing, overheating, water content, impurities, changes in electrical properties and other problems incipient to loss can usually be detected and corrected early enough to prevent a major loss.

As examples, arcing from a minor fault deep in the windings of a transformer, overheating of cellulose (insulating paper) and overheating of insulating fluid can cause the formation of gases in a transformer. These gases build up and saturate the fluid before sufficient quantities are generated to reach the vapor space. A DGA of a fluid sample generally promotes the early detection of such problems, allowing actions to be taken to stop the slowly developing problem before it results in a catastrophic breakdown. Tests that analyze only the free combustible gases in the vapor space are less likely to provide such early warning.

Fluid Tests

More than 30 tests can be performed on samples of an insulating liquid. Normally however, several common, simple, benchmark tests are used during routine maintenance. Other tests are performed only when more data is needed, such as when the initial test results are borderline. These additional tests help to form a reliable analysis of the fluid's condition.

ASTM publishes the procedures for most tests. Many test equipment manufacturers also provide relevant instructions for tests using their equipment.

Common tests are described in PRC.5.0.1. PRC.5.9.1 recommends transformer fluid testing no less than every three months, annually or every two years, depending on the type of transformer fluid and its use. Further, AXA XL Risk Consulting specifies the following minimum testing for oils: Dielectric Strength (Breakdown Voltage); Acidity (Neutralization Number); Interfacial Tension; and DGA. DGA is also called Gas-In-Oil Analysis and Gas Chromatography. A Moisture Content (Karl Fischer) Test should be performed when there is suspicion of excessive water in the fluid.

Total combustible gas (TCG) tests, also called gas analysis tests, differ from DGA tests. TCG detects the total combustible gas in the gas or vapor space of a transformer. A fault or problem condition in a transformer forms gases. These gases are absorbed into the fluid. A DGA test can detect these gases as they become absorbed into the fluid. When the fluid saturates, continued gas generation produces gases that accumulate in the vapor space of the transformer. Only then can TCG tests detect this accumulation. TCG testing cannot detect problems as early as can DGA testing.

It is common practice to complete more than these identified minimum tests. Supplemental tests often include: Visual; Color; Specific Gravity; Viscosity; Refractive Index; Power (or Dissipation) Factor; and Pour Point Tests. Not all can be done on every type of transformer fluid. These and additional tests can fully document the condition and history of a fluid.

Predictive maintenance is stronger and more reliable when more than minimum testing is done. Since the costs of sampling and administration have already been incurred, supplemental tests usually contribute relatively small added cost.

Getting Help

In general, any company with strong maintenance, quality control and fluid test departments may test transformer fluids in-house. Test equipment at some of these facilities rival equipment used at major independent fluid testing labs.

However, handling and disposing of PCB fluids requires special expertise. Property Risk Consulting generally recommends PCB fluid maintenance be performed by qualified outside servicing organizations.

Outside services should also be contracted for any facility not having the expertise or equipment necessary for a good fluid testing program. Many transformer servicing and testing organizations exist for such purposes.

Some transformer manufacturers sell, repair and help maintain transformers. They offer various services to assist PM programs, including employee training and fluid testing programs, whether or not a transformer was purchased from them. Their chemical labs offer full electrical insulation testing services. A field staff provides on-site customer service that includes drawing samples for customers that do not have the appropriate expertise or staff to perform such work. For customers capable of drawing samples, the labs can provide kits containing the bottling and shipping material needed for mailing the samples to the lab for testing.

Many large and small testing labs are also capable of assisting with predictive maintenance. Many are reliable and knowledgeable of insulating fluid sampling procedures, handling requirements, test methods and evaluation standards. They can examine the quality of the fluid, evaluate its suitability for use, and make appropriate recommendations.

Some offer only mail-in service since they do not have a staff for on-site field services. Others provide not only the full scope of tests, evaluations and recommendations, they also offer on-site services that include fluid sampling and reconditioning. Some also provide transformer maintenance training for their customers.

Sampling Methods

Sampling procedures are an important part of a fluid testing program. Sampling is usually accomplished without de-energizing the transformer. Exposing a sample to light, drawing a sample into the wrong type container, taking a sample from the wrong part of the tank, exposing a sample to air, sampling when the fluid temperature is not normal, or delaying a test on a sample for a week can affect the results. Sampling must be done safely and must adhere to strict procedures deemed acceptable for the test being considered. A specific test may require a specific sampling procedure.

Where several sampling procedures are acceptable, one method should be selected for consistent test results.

ASTM D923 defines equipment and procedures for drawing samples for fluid tests. Samples must contain an adequate amount of fluid for the proposed tests, and must represent that portion of fluid in the transformer tank or compartment likely to have the greatest deterioration and contamination. Accurate sampling requires taking samples from a specific location where these conditions are likely to be found. Generally, sampling valves are provided at the bottom of the tank for oil-insulated units. Askarel, perchloroethylene (nonflammable fluid) and silicone samples are usually taken from sampling outlets provided near the top of the tank at the 25°C (77°F) liquid level. The same location should be used for all subsequent tests to authenticate historical comparisons.

ASTM D2759 and 3305 describe methods of sampling the gas from the vapor space above a fluid.

Sampling methods must not contaminate the samples. Samples must represent the true fluid or gas condition. Sampling conditions, e.g., the temperature of the fluid when a sample was drawn, the air temperature around the unit, and the relative humidity, must be documented. Good sampling and test methods are necessary to validate evaluations.

The method and location of sampling depends on the size and design of the transformer, the type of fluid and its viscosity, atmospheric conditions and tests to be performed. Generally, once drawn, samples should be tested as quickly as possible. Samples in storage should be shielded from light. Aging and exposure to light can affect test results.

ASTM D923 describes standard sampling methods appropriate for most fluid tests.

It identifies acceptable sampling equipment, its cleaning and preparation, and methods of handling the fluid, including drawing, packaging, labeling, storing and shipping. Glass bottles and tin cans are identified as suitable sample containers. Rubber stoppers are not permitted. A glass bottle with an aluminum foil covered cork stopper, or a “perfect-fitting” glass stopper, or a screw cap having a suitable liner, is an acceptable container for a sample. A screw-capped tin can soldered with a suitable flux is also acceptable if the cap is appropriately lined.

Sample containers required by ASTM D613 are glass hypodermic syringes, stainless steel sampling bottles or flexible-sided metal cans. This procedure promotes special precautions required to prevent samples becoming exposed to the environment, including preventing the escape of gases entrained in the oil. The common test procedure for DGA specifies that the samples must be obtained using the ASTM D3613 sampling methods. Either ASTM D3613 or D923 may be used for drawing samples for moisture content tests.

Test Methods

Table 1 lists the ASTM references that describe common transformer fluid test procedures. While AXA XL Risk Consulting recommends that fluids containing PCBs be replaced following federal guidelines, askarels are listed for tests because askarels containing PCBs are still used and must be maintained.

Analysis of Test Results

Once sampling and testing procedures are set, standards must be selected for analyzing the test results. Comparisons with both past results and “norms” are of value for analysis.

TABLE 1
ASTM References For Fluid Test Procedures

	Insulating Fluid				
Test	Oil	HMWH	Silicone	Askarels	Perchloroethylene
Dielectric Strength	D877 or D1816	D1816 or D877	D877*	D877	D877 or D1816
Acidity	D974 or D664	D664 or D974	D974	D974 or D664	D974
Interfacial Tension	D97	D971	***	...	D971
Dissolved Gas Analysis	D3612	D3612	D3612	...	...
Combustible (Free) Gas	D3284	D3284	...	...	...
Visual (Field Test)	D1524	D1524	...	...	D1524
Color	D1500 or D1524	D1500	D2129	D2129	D1500
Specific Gravity	D1298	D1298	D1298	…	…
Viscosity	D88 or D445**	D445** or D88	D445**	D88 or D445**	D88
Refractive Index	D1807	D1807	D1807	D1218	...
Power Factor	D924	D924	D924*	D924	D924
Pour Point	D97	D97	D97	D97	D97
Moisture Content	D1533	D1533	D1533	D1533	D1533
Specific Resistance	D1169	D1169	D1169*	D1169	...
Fire Point/Flash Point	D92	D92	D92	D92	...
Oxidation Stability	D2440	D2112	...	...	...
PCB Analysis	D4059	D4059	D4059	D4059	...
DBPC/DBP Inhibitor	D2668	D2668	...	...	...

* Modify in accordance with ASTM D2225
** Use with ASTM D2161
*** May be tested using D971, but not a commonly accepted test for this fluid.

A fluid's historical test record should start with "as received" and "before energized" tests, and continue on through the life of the equipment. Whenever a fluid is processed and returned to service, new baselines should be established.

If a complete historical record is maintained, fluid tests can be compared with prior tests performed throughout the period of equipment use. Generally, periodic testing allows deterioration and other changes to be monitored, and allows corrective action to be taken before major breakdowns occur. Changes from prior tests show the rate of deterioration. If the history shows that a borderline test result does not change over the years, the test result is not of major concern. But if the same test result is part of a continual series of fast-declining test results, immediate corrective action is needed.

Prior service use is important because some standards evaluate a test result differently under various conditions including: when the fluid has never been placed in electrical service; when the sample comes from a new transformer; when the fluid is service-aged; when it has been reconditioned; and when it comes from a transformer of a high voltage class. Some of these categories are controversial, however. The purpose of testing is to predict and prevent breakdowns. The acceptance of one fluid and rejection of another based on its past service use, when both test the same and can sustain the same stresses, appears unjustified.

As part of PM, "limits" must be set to trigger action plans when test results fall outside of acceptable ranges. Some limits are based on trends and deviations. Some are based on reaching specified values. There is no hard and fast rule that makes selection of limits easy. For some tests, there are about as many "acceptable test limits" and "norms" as there are different sources used for standards. Differences occur because there is no consensus on definitive limits. Some standards are more stringent than others. Generally, a more stringent standard provides greater safety and reliability. Transformer and fluid manufacturers can provide a good basis on which to judge the results of fluid testing. These manufacturers can recommend specific action when a fluid is found to be unsatisfactory for use. They have a vested interest in keeping the transformers operating and extending their service use. But while manufacturers are a primary source for setting limits, their limits should not be accepted blindly. By resetting limits closer to the test norm, breakdowns can be reduced.

Examples Of Limits

Manufacturers, IEEE, ASTM and other sources can be used to identify acceptable fluid test results. Some of these references are listed in this guide. The many considerations described in the references and in the other sources should be evaluated in setting up any program. However, in no case should test result limits be set outside of the range of acceptable values provided by the manufacturers of the transformer and the fluid.

Where test results do not meet set criteria, an immediate analysis should be made. Subsequent loss preventive actions should be immediate. This may include further testing, removing the unit from service for repairs or replacement, and fluid treatment or replacement. Where there is a good predictive maintenance program and a test result is suspect, it is generally **not** necessary to shut a unit down due to a single test result. Contamination of the test sample or a faulty procedure may be a cause. Any problem should, however, receive immediate attention and prompt resolution.

Examples of limits for key fluid test results are presented in Tables 2 & 3. Table 2 shows typical test limits for service aged fluid. Table 3 shows DGA test limits for oil and HMWH.

DGA analyses may also include evaluating specific gas to gas ratios and the rate of gas evolution. Amounts of specific gases are reported as a percentage of total gases present, and as parts per million of the oil volume. The combination and relative amounts of gases present can identify causes of insulation breakdown.

In an operating transformer, gas is generated as a result of natural aging, incipient problems and major problems. Operation of a gas alarm relay, or calculations showing the generation of more than 0.1 ft^3/day (2.8 l/day) of combustible gas, indicates an incipient or severe problem which should be corrected immediately.

TABLE 2
Service-Aged Fluid - Typical Test Limits (see text)

	Insulating Fluid					
Test	Oil - Typical	Oil - EHV Units	HMWH	Silicone	Askarels	Perchloroethylene
Dielectric Strength ASTM D877 (kV)	> 25	> 31	≥ 26	≥ 25	> 35	≥ 26
Acidity ASTM D664 (mg KOH/g)			≤ 0.2			
ASTM D974 (mg KOH/g)	≤ 0.35	≤ 0.28		≤ 0.2	< 0.09	≤ 0.25
Interfacial Tension ASTM D971 (dynes/cm)	≥ 23	≥ 31	≥ 28	≥ 35	N/A	N/A
Moisture Content ASTM D1533 (ppm)	≤ 25	≤ 15	≤ 45	≤ 100	≤ 70	≤ 35
Power Factor (60 Hz) ASTM D924 (% @ 25°C)	< 1.0	< 0.03	≤ 1.0	≤ 0.2		≤ 12
ASTM D924 (% @ 50°C)					≤ 1.2	
Viscosity ASTM D445 (25°C,cSt)	12	N/A	350	47.5-52.5	15	0.55

N/A = Limit Not Available

TABLE 3
Typical Limits (Maximums) For Gas-In-Oil (see text)

PPM*	Combustible Gas**	Cause Of Deviation
100	Hydrogen (H_2)	Corona; Rusting of the Core; Electrolysis; Sparking; Arcing
50	Methane (CH_4)	Overheated Oil; Sparking
25	Acetylene (C_2H_2)	Arcing
30	Ethylene (C_2H_4)	Overheated Oil
65	Ethane (C_2H_6)	Overheated Oil
350	Carbon Monoxide (CO)	Overheated Cellulose

* Parts per million by volume of the total gas present.
** Other analyzed gases in the oil sample include Carbon Dioxide, Oxygen and Nitrogen.

Two of the more common gas ratio analysis methods are the Rogers and Dornenberg ratio methods. These are described in IEEE C57.104. Analysis involves sampling the oil or gas space, determining ratios of specific key component gases, and diagnosing faults based on these results. These analyses cannot diagnose simultaneous faults.

Figure 1 shows the gas ratio methodology used by the Rogers gas ratio analysis. It is based on DGA results identifying relative amounts of gas in oil in parts per million. Unanticipated gas ratios and inconclusive combinations of ratios are represented in Figure 1 by boxes labeled “N/A.”

The Dornenberg gas ratio model is similar to the Rogers model. The Dornenberg model uses two of the gas ratios used in the Rogers model, and two that are not. The Dornenberg model also identifies dissolved gas concentrations that merit further investigation. Table 3 was developed from the Dornenberg model.

Gas ratio analyses purport to identify the most likely fault condition, but they are not infallible. Test results require professional interpretation.

No one gas test result or indicator automatically identifies an electrical fault. Even if a result leaves a strong suspicion of breakdown, other tests or observations are needed. Damaged test equipment, contaminated samples and improper test procedures can all produce errant results. A single test result should be analyzed along with other test results, or should, as a minimum, trigger further testing. A validation test can identify problems and guide appropriate corrective actions.

Actions Following Analysis

When problems are identified by tests, several options may be available. Mineral oil and HMWH fluids may be reconditioned, reconditioned and reclaimed, or replaced, depending on the degree of deterioration. For other dielectric fluids, manufacturers’ guidelines should be consulted when results indicate deterioration.

Reconditioning removes water and solid contaminants from an oil. It may use filters, centrifuges and vacuum dehydrators. Reconditioning usually starts off with filtering. The most widely used filter is a blotter press. A blotter press filters water and suspended solids from an oil, but increases the oxygen content of the oil. And oxygen causes sludging and acidity. Therefore, additives like ditertiary butyl paracresol (DBPC) are added after filtering to inhibit oxidation. In some cases, filtering and additives are sufficient to allow the oil to be reused.

Because filters frequently become “too wet” to sufficiently remove water, centrifuges are often used in combination with them. Centrifuges remove the remaining water suspended in oil, but cannot remove dissolved contaminants.

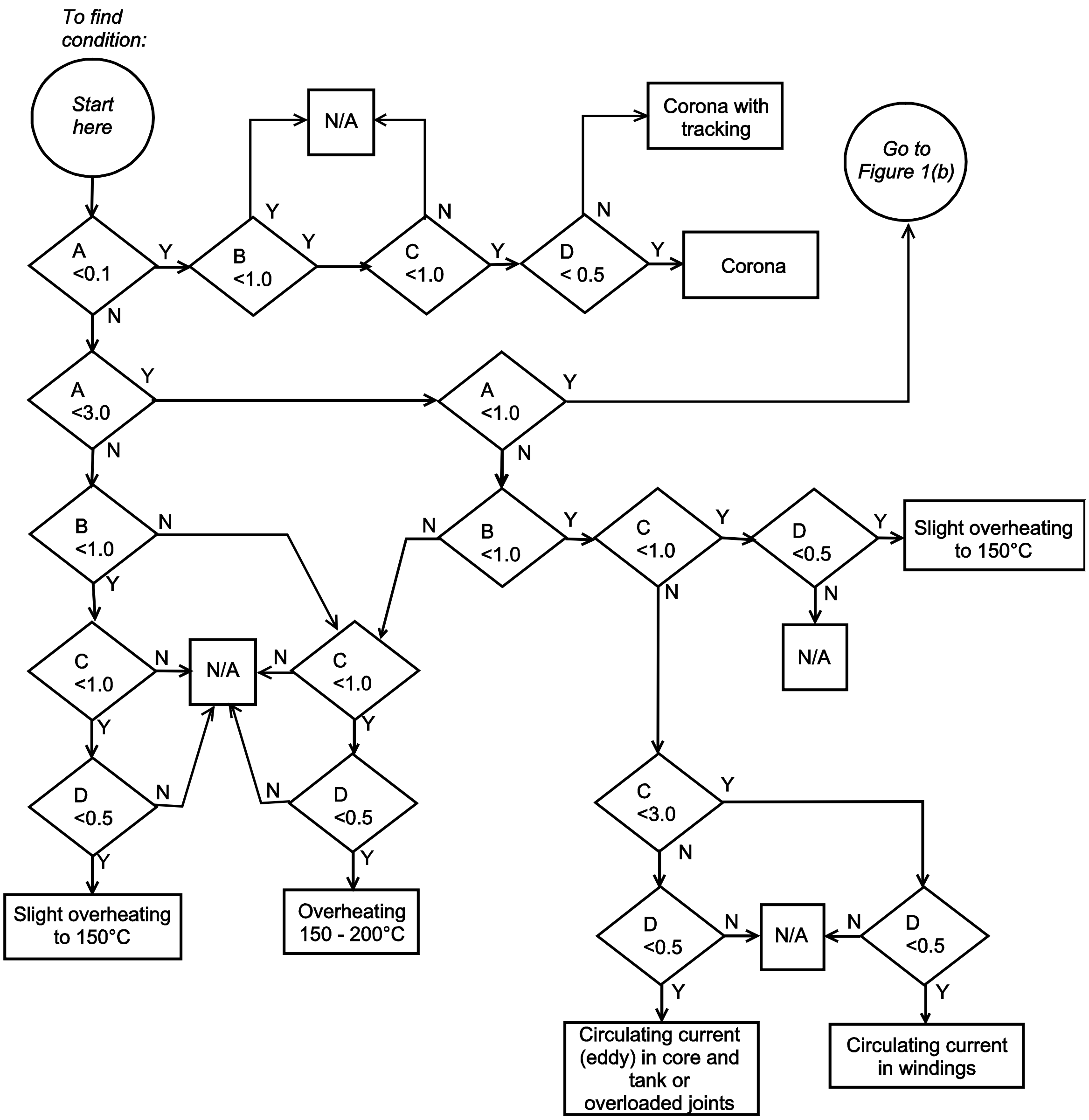
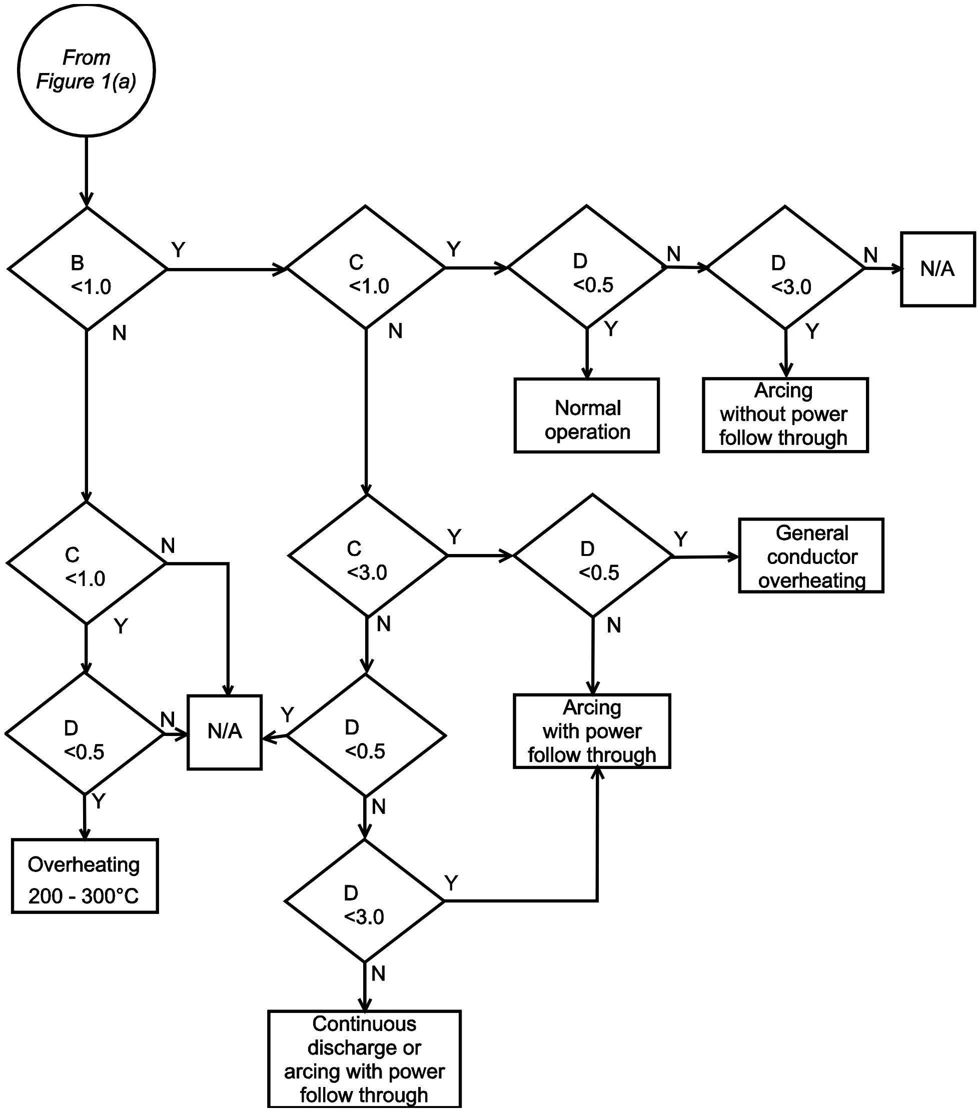


Figure 1(a). DGA Diagnosis Tree.



LEGEND FOR DGA DIAGNOSIS TREE

A = Volumetric ratio of methane to hydrogen gas = $\frac{CH_4\ (ppm)}{H_2\ (ppm)}$

B = Volumetric ratio of ethane to methane gas = $\frac{C_2H_6\ (ppm)}{CH_4\ (ppm)}$

C = Volumetric ratio of ethylene to ethane gas = $\frac{C_2H_4\ (ppm)}{C_2H_6\ (ppm)}$

D = Volumetric ratio of acetylene to ethylene gas = $\frac{C_2H_2\ (ppm)}{C_2H_4\ (ppm)}$

y = Yes

n = No

N/A = Not Available

Figure 1(b). DGA Diagnosis Tree.

Vacuum dehydrators are usually the final stage of reconditioning. Because vacuum dehydrators cannot be used where solids are suspended in an oil, filtering must take place first. Vacuum dehydrators remove gases and some acids from oils. Often, oil is suitable for reuse following this stage of reconditioning.

Oil reclaiming places oil in contact with Fuller's Earth (clay). Oil may percolate through a clay bed or may be mechanically mixed with clay. (Other methods of reclaiming also exist.) Water in an oil will impair the effectiveness of the reclaiming process. Therefore, reconditioning must be completed before oil can be reclaimed. Reclaiming removes the acids and contaminants not removed by reconditioning. IEEE 637 provides guidance for reclaiming hydrocarbon-based transformer fluids.

When oil is reconditioned or reclaimed on site, such as with the use of mobile units containing presses, tanks, generators and pumps, care must be taken to avoid severe fire hazards and loss potentials. If oil sprays from a ruptured oil line and is ignited by the mobile unit's power source or by other energized equipment, a severe fire can result. Separation, barriers and water spray should be incorporated into the design of the transformer and roadway area.