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TRANSFORMER DIAGNOSTICS

JUNE 2003

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FIST 3-31 provides guidance to Bureau of Reclamation (Reclamation) powerplant personnel in transformer diagnostics. Transformers rated 5,000 kilovoltamperes (kVA) and above are considered power transformers. All generator step-up (GSU) transformers, and may station service and excitation transformers are considered power transformers because they are rated 500 kVA or larger.

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VOLUME 3-31

TRANSFORMER DIAGNOSTICS

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TECHNICAL SERVICES GROUP

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1. INTRODUCTION

This document is intended to establish recommended practice as well as to give general advice and guidance in testing and diagnosing oil-filled power transformers to establish their condition, identify problems, and provide potential remedies. This document applies to oil-filled power transformers (500 kilovoltamperes [kVA] and larger), owned and operated by the Bureau of Reclamation (Reclamation). Specific technical details are included in other documents which are referenced in this document.

Guidance and recommendations herein are based on industry standards and experience in Reclamation facilities. However, equipment and situations vary greatly, and sound engineering and management judgment must be exercised when applying these diagnostics. All available information must be considered (e.g., manufacturer's and transformer experts' recommendations, unusual operating conditions, personal experience with the equipment, etc.) in conjunction with this document.

2. REFERENCE DOCUMENTS

[1] *Facilities Instructions, Standards, and Techniques (FIST) Volume 3-30, Transformer Maintenance*, October 2000, Bureau of Reclamation, available at <www.usbr.gov>, select Programs, Power, Reports and Data, Power Documents.

[2] "Transformer Condition Assessment," in *Hydro Powerplant Risk Assessment Guide*, a joint effort of Bureau of Reclamation, U.S. Army Corps of Engineers, Hydro Quebec, and Bonneville Power Administration (see appendix).

[3] "Mineral Oil-Impregnated Electrical Equipment" in *Service-Interpretation of Dissolved and Free Gas Analysis*, International Electrotechnical Commission (IEC) 60599, 1997.

[4] *Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers*, Institute of Electrical and Electronic Engineers (IEEE) C57.104™.

[5] *Transformer Maintenance Guide*, S.D. Myers, Joe Kelly, R.H. Parrish, 1991.

[6] *Standard Test Method for Interfacial Tension of Oil Against Water by the Ring Method,* American National Standards Institute/American Society for Testing and Materials (ANSI/ASTM) D 971-1991.

[7] *FIST Volume 3-5, Maintenance of Liquid Insulation: Mineral Oils and Askarels*, 1992.

[8] *Standard Test Method for Furanic Compounds in Electrical Insulating Liquids by High Performance Liquid Chromatography*, ASTM D 5837-1996.

[9] *Standard Specification for Mineral Insulating Oil Used in Electrical Apparatus*, ASTM D 3487-1988.

[10] *Reference Book on Insulating Liquids and Gases*, Reference Book for Insulating Liquids and Gases (RBILG)-391, Doble Engineering Company, 1993.

[11] *Guide for Diagnostic Field Testing of Electric Power Apparatus – Part 1: Oil-filled Power Transformers, Regulators, and Reactors*, IEEE 62-1995™.

[12] *Replacements*, Bureau of Reclamation and Western Area Power Administration, July 1995.

[13] *M5100 Sweep Frequency Response Analysis (SFRA) Instrument Users Guide*, Doble Engineering Company.

[14] *Electric Power Research Institute (EPRI) Guidelines for the Life Extension of Substations*. 2002 Update.

[15] *Recommended Practice for Electrical Equipment Maintenance*, National Fire Protection Association (NFPA) 70 B, 2002 Edition.

[16] *FIST Volume 4-1B*, Maintenance Scheduling for Electrical Equipment.

[17] *FIST Volume 4-13*, Thermographic Maintenance Program.

[18] *Proceedings: Substation Equipment Diagnostics, Conference IX*, Electric Power Research Institute (EPRI).

[19] *An Introduction to the Half-Century Transformer*, Transformer Maintenance Institute, S.D. Myers Co., 2002.

[20] *Transformer Nitrogen Advisory*, PEB 5.

3. TRANSFORMER DIAGNOSTICS AND TRANSFORMER MAINTENANCE

This volume addresses specific testing and diagnostic techniques and tools used to assess the condition of oil-filled power transformers. These processes are often above and beyond routine maintenance work completed on a regular basis to keep the transformer operational. Reclamation recommended practice for routine transformer maintenance is specified in *FIST Volume 3-30, Transformer Maintenance* [1]. Transformer diagnostics require specialized equipment and training. This expertise is not expected to be maintained in every office. In some cases, it may be necessary to contact diagnostics specialists, either inside Reclamation or out, who have the latest equipment and recent experience.

FIST Volume 3-30, Transformer Maintenance [1], contains some diagnostic information. In some cases, that information is repeated or amplified here for completeness and clarity. This volume and *FIST Volume 3-30* should be used jointly to provide the full range of transformer maintenance, testing, and diagnostics needed to extend the life of Reclamation power transformers.

Figures 1 and 2 show the overall transformer condition assessment methodology, linking routine maintenance and diagnostics.

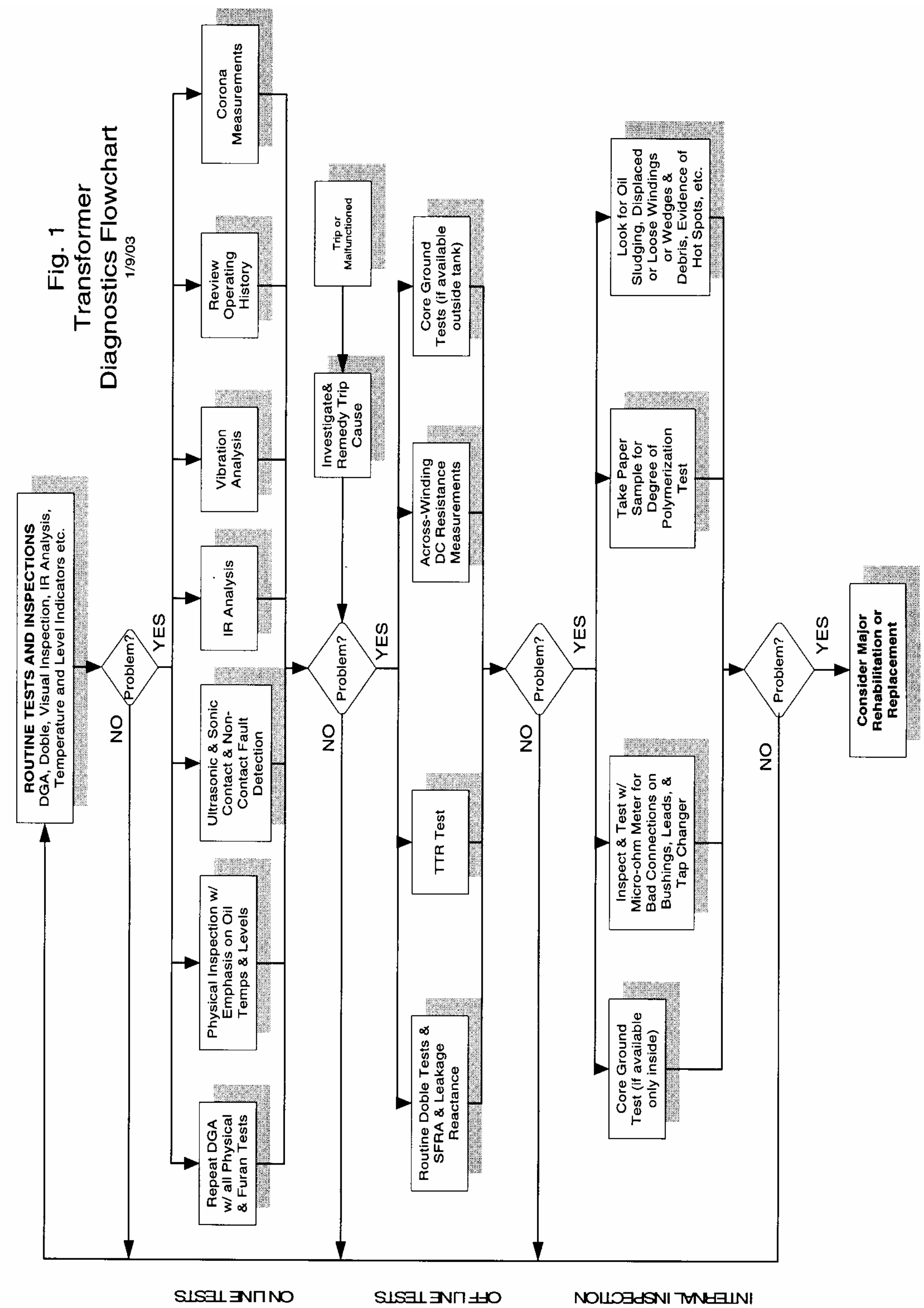

Figure 1.—Transformer Diagnostics Flowchart.

- **Windings**
  - DC Resistance
  - Turns Ratio
  - Percent Impedance/Leakage Reactance
  - Sweep Frequency Response Analysis (SFRA)
  - Doble Tests (for windings and oil)
    - Capacitance
    - Excitation Current and Watts Loss
    - Power Factor/Dissipation Factor
- **Bushings and Arresters**
  - Capacitance (Doble Tests)
  - Dielectric Loss (watts)
  - Power Factor
  - Temperature (infrared camera)
  - Oil Level (bushings only)
  - Visual Inspection for Porcelain Cracks and Chips
- **Insulating Oil**
  - Dissolved Gas Analysis
  - Dielectric Strength
  - Metal Particle Count (if transformer has pump problems)
  - Moisture
  - Power Factor/Dissipation Factor (Doble)
  - Interfacial Tension
  - Acid Number
  - Furans
  - Oxygen Inhibitor
- **Core**
  - Insulation Resistance
  - Ground Test
- **Conservator**
  - Visual (oil leaks and leaks in diaphragm)
  - Inert Air System (desiccant color)
  - Level Gauge Calibration
- **Tanks and Auxiliaries**
  - Fault Pressure Relay (functional test)
  - Pressure Relief Device (visual)
  - Buchholz Relay (visual check for gas)
  - Top Oil Temperature Indicator
  - Winding Temperature Indicator
  - Infrared Temperature Scan
  - Fault Analyzer (ultrasonic)
  - Sound Analysis (sonic)
  - Vibration Analyzer
- **Cooling System**
  - Clean (fan blades and radiators)
  - Fans and Controls (check fan rotation)
  - Oil Pumps (check flow indicators, check rotation)
  - Pump Bearings (vibration, sound, and temperature)
  - Check Radiator (valves open)
  - Check Cooling System with Infrared Camera

Figure 2.—Transformer Diagnostic Test Chart
(Adapted from IEEE 62-1995™ [11]).

4. TRANSFORMER DIAGNOSTICS AND POWERPLANT REHABILITATION

Determining transformer condition is useful in itself for making short-term decisions regarding operation and maintenance. Assessing transformer condition through diagnostic techniques is also important for conducting asset management studies for transformer replacement. Transformer condition is an important input to an engineering and economic model used to determine the most cost-effective alternative for power train rehabilitation (i.e., continued operation, refurbishment, or replacement). A methodology has been developed to use information derived from the diagnostics described in this document for rehabilitation purposes. For information on this methodology, see "Transformer Condition Assessment" in *Hydro Powerplant Risk Assessment Guide* [2], in the appendix.

5. DISSOLVED GAS ANALYSIS

5.1. Background

Dissolved gas analysis (DGA) is the most important tool in determining the condition of a transformer. It is the first indicator of a problem and can identify deteriorating insulation and oil, overheating, hot spots, partial discharge, and arcing. The "health" of the oil is reflective of the health of the transformer itself. Dissolved gas analysis consists of sending transformer oil samples to a commercial laboratory for testing. The most important indicators are the individual and total combustible gas (TCG) generation rates based on IEC 60599 [3] and IEEE C 57-104™ [4] standards.

CAUTION:

Information on DGA in this FIST volume is an incomplete summary. Transformer DGA theory and methodology is described in greater detail in section 4.4 of *FIST Volume 3-30, Transformer Maintenance* [1].

5.2. Transformer Diagnosis Using Individual and Total Dissolved Key Gas Concentrations

A four-condition DGA guide to classify risks to transformers with no previous problems has been published in the Standard IEEE Standard (Std). C57-104™. The guide uses combinations of individual gases and total combustible gas concentration as indicators. It is not universally accepted and is only one of the tools used to evaluate dissolved gas in transformers. The four IEEE® conditions are defined immediately below, and gas levels are in table 1 following the definitions.

Condition 1: Total dissolved combustible gas (TDCG) below this level indicates the transformer is operating satisfactorily. Any individual combustible gas exceeding specified levels in table 2 should have additional investigation.

Table 1.—Dissolved Key Gas Concentration Limits in Parts Per Million (ppm) [4]

Status	Hydrogen (H_2)	Methane (CH_4)	Acetylene (C_2H_2)	Ethylene (C_2H_4)	Ethane (C_2H_6)	Carbon Monoxide (CO)	Carbon Dioxide (CO_2)[1]	TDCG
Condition 1	100	120	35	50	65	350	2,500	720
Condition 2	101-700	121-400	36-50	51-100	66-100	351-570	2,500-4,000	721-1,920
Condition 3	701-1,800	401-1,000	51-80	101-200	101-150	571-1,400	4,001-10,000	1,921-4,630
Condition 4	>1,800	>1,000	>80	>200	>150	>1,400	>10,000	>4,630

[1] CO_2 is not included in adding the numbers for TDCG because it is not a combustible gas.

Table 2.—Actions Based on Dissolved Combustible Gas (Adapted from [4])

Conditions	TDCG Level or Highest Individual Gas (See table 1)	TDCG Generation Rates (ppm per day)	Sampling Intervals and Operating Actions for Gas Generation Rates	
			Sampling Interval	Operating Procedures
Condition 1	<720 ppm of TDCG or highest condition based on individual combustible gas from table 1.	<10	Annually: 6 months for extra high voltage transformer	Continue normal operation.
		10-30	Quarterly	
		>30	Monthly	Exercise caution. Analyze individual gases to find cause. Determine load dependence.
Condition 2	721–1,920 ppm of TDCG or highest condition based on individual combustible gas from table 1.	<10	Quarterly	Exercise caution. Analyze individual gases to find cause. Determine load dependence.
		10-30	Monthly	
		>30	Monthly	
Condition 3	1,941–2,630 ppm of TDCG or highest condition based on individual combustible gas from table 1.	<10	Monthly	Exercise extreme caution. Analyze individual gases to find cause. Plan outage. Call manufacturer and other consultants for advice.
		10-30	Weekly	
		>30	Weekly	
Condition 4	>4,639 ppm of TDCG or highest condition based on individual combustible gas from table 1.	<10	Weekly	Exercise extreme caution. Analyze individual gases to find cause. Plan outage. Call manufacturer and other consultants for advice.
		10-30	Daily	
		>30	Daily	Consider removal from service. Call manufacturer and other consultants for advice.

Condition 2: TDCG within this range indicates greater than normal combustible gas level. Any individual combustible gas exceeding specified levels in table 2 should have additional investigation. A fault may be present. Take DGA samples at least often enough to calculate the amount of gas generation per day for each gas. (See table 2 for recommended sampling frequency and actions.)

Condition 3: TDCG within this range indicates a high level of decomposition of cellulose insulation and/or oil. Any individual combustible gas exceeding specified levels in table 1 should have additional investigation. A fault or faults are probably present. Take DGA samples at least often enough to calculate the amount of gas generation per day for each gas.

Condition 4: TDCG within this range indicates excessive decomposition of cellulose insulation and/or oil. Continued operation could result in failure of the transformer.

CAUTION:

Transformers generate some combustible gases from normal operation, and condition numbers for dissolved gases given in IEEE C-57-104-1991™ [4] (table 1 above) are extremely conservative. Transformers can operate safely with individual gases in Condition 4 with no problems, provided they are stable and gases are not increasing or are increasing very slowly. If TDCG and individual gases are increasing significantly (more than 30 ppm per day [ppm/day]), an active fault is in progress. The transformer should be de-energized when Condition 4 levels are reached.

A sudden increase in key gases and the rate of gas production is more important in evaluating a transformer than the accumulated amount of gas. One very important consideration is acetylene (C_2H_2). Generation of any amount of this gas above a few ppm indicates high-energy arcing. Trace amounts (a few ppm) can be generated by a very hot thermal fault (500 degrees Celsius (EC) or higher). A one-time arc, caused by a nearby lightning strike or a high voltage surge, can also generate a small amount of C_2H_2. If C_2H_2 is found in the DGA, oil samples should be taken weekly or even daily to determine if additional C_2H_2 is being generated. If no additional acetylene is found and the level is below the IEEE® Condition 4, the transformer may continue in service. However, if acetylene continues to increase, the transformer has an active high-energy internal arc and should be taken out of service immediately. Further operation is extremely hazardous and may result in explosive catastrophic failure of the tank, spreading flaming oil over a large area.

NOTES:

1. Either the highest condition based on individual combustible gas or TDCG can determine the condition (1,2,3, or 4) of the transformer. For example, if the TDCG is between 1,941 ppm and 2,630 ppm, this indicates Condition 3. However, if hydrogen is greater than 1,800 ppm, the transformer is in Condition 4, as shown in table 2.

2. When the table says “determine load dependence,” this means try to find out if the gas generation rate in ppm/day goes up and down with the load. The transformer may be overloaded or have a cooling problem. Take oil samples every time the load changes; if load changes are too frequent, this may not be possible.

3. To get the TDCG generation rate, divide the change in TDCG by the number of days between samples that the transformer has been loaded. Down-days should not be included. The individual gas generation rate in ppm/day is determined by the same method.

Table 2 assumes that no previous DGA tests have been made on the transformer or that no recent history exists. If a previous DGA exists, it should be reviewed to determine if the situation is stable (gases are not increasing significantly) or unstable (gases are increasing significantly). See table 3 (following page) for generation rates to decide whether gases are increasing significantly.

5.3 Diagnosing a Transformer Problem Using Dissolved Gas Analysis and the Duval Triangle

CAUTION:

Do not use the Duval Triangle to determine whether or not a transformer has a problem. Notice, there is no area on the triangle for a transformer that does not have a problem. The triangle will show a fault for every transformer whether it has a fault or not. Use the above IEEE® method or table 3 to determine if a problem exists before applying the Duval Triangle. The Duval Triangle is used only to diagnose what the problem is. As with other methods, a significant amount of gas (at least L1 limits and G2 generation rates in table 3), must already be present before this method is valid.

5.3.1 Origin of the Duval Triangle. Michel Duval of Hydro Quebec developed this method in the 1960s using a database of thousands of DGAs and transformer problem diagnosis. More recently, this method was incorporated in the Transformer Oil Analyst Software version 4 (TOA 4), developed by Delta X Research and used by many in the utility industry to diagnose transformer problems. This method has proven to be accurate and dependable over many years and is now gaining in popularity. The method and how to use it are described below.

5.3.2 How to Use the Duval Triangle

1. First determine whether a problem exists by using the IEEE® method above, and/or table 3 below (see *FIST Volume 3-30* for an explanation of this table). At least one of the hydrocarbon gases or hydrogen (H_2) must be in IEEE® Condition 3, and increasing at a generation rate (G2) from the table below, before a problem is confirmed. To use table 3 below without the IEEE® method, at least one of the individual gases must be at L1 level or above and the gas generation rate at least at G2. The L1 limits and gas generation rates from table 3 below are more reliable than the IEEE® method; however, one should use both methods to confirm that a problem exists.

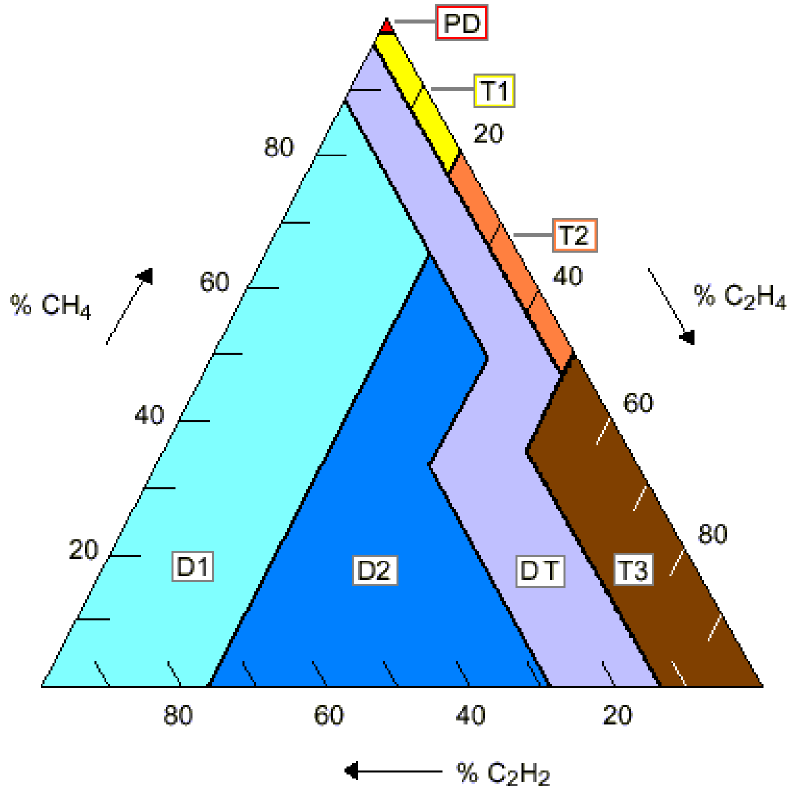

Figure 3.—The Duval Triangle.

Legend

PD = Partial Discharge
T1 = Thermal Fault Less than 300 °C
T2 = Thermal Fault Between 300 °C and 700 °C
T3 = Thermal Fault Greater than 700 °C
D1 = Low Energy Discharge (Sparking)
D2 = High Energy Discharge (Arcing)
DT = Mix of Thermal and Electrical Faults

Table 3.—L1 Limits and Generation Rate Per Month Limits

Gas	L1 Limits	G1 Limits (ppm per month)	G2 Limits (ppm per month)
H_2	100	10	50
CH_4	75	8	38
C_2H_2	3	3	3
C_2H_4	75	8	38
C_2H_6	75	8	38
CO	700	70	350
CO_2	7,000	700	3,500

If there is a sudden increase in H_2 with only carbon monoxide (CO) and carbon dioxide (CO_2) and little or none of the hydrocarbon gases, use section 17 (CO_2/CO ratio) below to determine if the cellulose insulation is being degraded by overheating.

2. Once a problem has been determined to exist, use the total accumulated amount of the three Duval Triangle gases and plot the percentages of the total on the triangle to arrive at a diagnosis. An example is shown below. Also, calculate the amount of the three gases used in the Duval Triangle, generated since the sudden increase in gas began. Subtracting out the amount of gas generated prior to the sudden increase will give the amount of gases generated since the fault began. Detailed instructions and an example are shown below.

   a. Take the amount (ppm) of methane (CH_4) in the DGA and subtract the amount of CH_4 from an earlier DGA, before the sudden increase in gas. This will give the amount of methane generated since the problem started.

   b. Repeat this process for the remaining two gases, ethylene (C_2H_4) and acetylene (C_2H_2).

3. Add the three numbers (differences) obtained by the process of step 2 above. This gives 100 percent (%) of the three key gases generated since the fault, used in the Duval Triangle.

4. Divide each individual gas difference by the total difference of gas obtained in step 3 above. This gives the percentage increase of each gas of the total increase.

5. Plot the percentage of each gas on the Duval Triangle, beginning on the side indicated for that particular gas. Draw lines across the triangle for each gas parallel to the hash marks shown on each side of the triangle. An example is shown below.

NOTE:

In most cases, acetylene (C_2H_2) will be zero, and the result will be a point on the right side of the Duval Triangle.

Compare the total accumulated gas diagnosis and the diagnosis obtained by using only the increase-in-gases after a fault. If the fault has existed for some time, or if generation rates are high, the two diagnoses will be the same. If the diagnoses are not the same, always use the diagnosis of the increase in gases generated by the fault which will be the more severe of the two. See the example below of a Reclamation transformer where the diagnosis using increase in gas is more severe than when using the total accumulated gas.

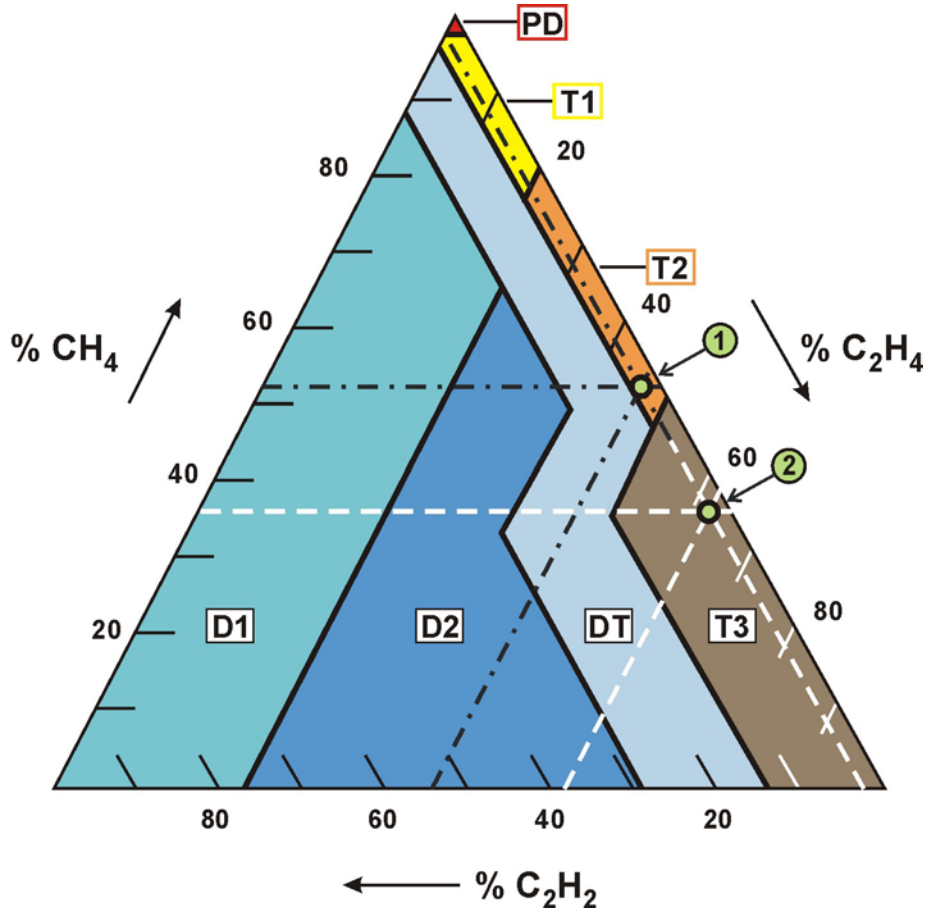

Figure 4.—Duval Triangle Diagnostic Example of a Reclamation Transformer.

Example: Using figure 4 above and the information below, two diagnoses of a Reclamation transformer were obtained. The first diagnosis (Point 1), was obtained using the total amount of the three gases used by the Duval Triangle. The second diagnosis (Point 2) was obtained using only the increase in gases between the two DGAs. CO and CO_2 are used to evaluate cellulose.

	DGA No. 1	DGA No. 2	Increase
CH_4	142	192	50
C_2H_4	84	170	86
C_2H_2	4	7	3
Total	230	369	139

DGA No. 1	DGA No. 2	Increase
CO = 176	199	23
CO_2 = 1,009	2,326	1,317

Steps to Obtain the First Diagnosis (Point 1) on the Duval Triangle (Figure 4)

1. Use the **total accumulated** gas from DGA 2 = 369

2. Divide each gas by the total to find the percentage of each gas of the total.

% CH_4 = 192/369 = 52%, % C_2H_4 = 170/369 = 46%, % C_2H_2 = 7/369 = 2%

3. Draw three lines across the Duval Triangle starting at the percentages obtained in step 2. These lines **must be drawn parallel** to the hash mark on each respective side. See the black dashed lines in figure 4 above.

4. Point 1 is obtained where the lines intersect within the T2 diagnostic area of the triangle, which indicates a thermal fault between 300 and 700 °C. See figure 3, Legend, above.

Steps to Obtain the Second Diagnosis (Point 2) on the Duval Triangle (Figure 4)

1. Use the **total increase** in gas = 139.

2. Divide each gas increase by the total increase to find the percentage of each gas of the total.

% increase CH_4 = 50/139 = 36%, % increase C_2H_4 = 86/139 = 46%,
% increase C_2H_2 = 3/139 = 2%

3. Draw three lines across the Duval Triangle starting at the percentages obtained in step 2. These lines **must be drawn parallel** to the hash mark on each respective side. See the white dashed lines in figure 4 above. Note that C_2H_2 was the same percentage (2%) both times; and, therefore, both lines are the same.

4. Point 2 is obtained where the lines intersect within the T3 diagnostic area of the triangle which indicates a thermal fault greater than 700 °C. See figure 3, Legend, above.

NOTES:

1. Point 2 is the more severe diagnosis obtained by using the increase in gas rather than the total accumulated gas. It is helpful to perform both methods as a check; many times both diagnoses will come out the same.

2. CO and CO_2 are included to show that the fault does not involve severe degradation of cellulose insulation. See section 17 for an explanation of CO_2/CO ratios.

The ratio of total accumulated gas CO_2/CO = 2326/199 = 11.7.

The ratio of increase CO_2/CO = 1317/ 23 = 57. Neither of these ratios is low enough to cause concern. This shows that the thermal fault is not close enough to the cellulose insulation to cause heat degradation of the insulation. The large increase in CO_2 could mean an atmospheric leak.

The fault is probably a bad connection on a bushing bottom, a bad contact or connection in the tap changer, or a problem with a core ground. These problems are probably all reparable in the field. Any of these problems can cause the results revealed by the Duval Triangle diagnosis above. These are areas where a fault will not degrade cellulose insulation which would cause the CO_2/CO ratio to be much lower than what was obtained. For information to arrive at a probable fault see *FIST Volume 3-30,* section 4.4.

5.4 Expertise Needed

A Transformer Expert should be consulted if a problematic trend is evidenced by a number of DGAs. The transformer manufacturer should be consulted along with DGA lab personnel as well as others experienced in transformer maintenance and diagnostics. Never make a diagnosis based on one DGA; a sample may have been mishandled or mislabeled either in the field or lab.

6. OIL PHYSICAL/CHEMICAL TESTS

When sending oil samples to a laboratory for DGA, one should also specify other tests that reveal oil quality.

6.1 Transformer Oil Tests That Should Be Performed Annually With the Dissolved Gas Analysis

6.1.1 Dielectric Strength. This test measures the voltage at which the oil electrically breaks down. The test gives an indication of the amount of contaminants (water and oxidation particles) in the oil. DGA laboratories typically use ASTM D-1816. **Using the D-1816 test, the minimum oil breakdown voltage is 20 kilovolts (kV) for transformers rated less than 288 kV and 25 kV for transformers 287.5 kV and above**. If a dielectric strength test falls below these numbers, the oil should be reclaimed. Do not base any decision on one test result, or on one type of test; look at all the information from several DGA tests and review trends before making any decision.

The dielectric strength test is not extremely valuable; moisture in combination with oxygen and heat will destroy cellulose insulation long before the dielectric strength of the oil has indicated anything is going wrong. See *Transformer Maintenance Guide*, by J.J. Kelly, S.D. Myers, R.H. Parrish, S.D. Myers Co 1981 [5]. The dielectric strength test also reveals nothing about acids and sludge. The tests explained below are much more important in that regard.

6.1.2 Interfacial Tension (IFT). This test, ASTM D-971-91, *Standard Test Method for Interfacial Tension of Oil Against Water by the Ring Method* [6], is used by DGA laboratories to determine the interfacial tension between the oil sample and distilled water. The oil sample is placed in a beaker of distilled water at a temperature of 25 EC. The oil will float because its specific gravity is less than that of water. There should be a distinct line between the two liquids. The IFT number is the amount of force (dynes) required to pull a small wire ring upward a distance of 1 centimeter through the water/oil interface. A dyne is a very small unit of force equal to 0.000002247 pound. Good clean oil will make a very distinct line on top of the water and give an IFT number of 40 to 50 dynes per centimeter of travel of the wire ring.

As oil ages, it is contaminated by tiny particles (oxidation products) of the oil and paper insulation. Particles on top of the water extend across the water/oil interface line which weakens the surface tension between the two liquids. Particles in oil weaken interfacial tension and lower the IFT number. IFT and acid number (see below) together are an excellent indication of when oil needs to be reclaimed. It is recommended the oil be reclaimed when the IFT number falls to 25 dynes per centimeter. At this level, the oil is very contaminated and must be reclaimed to prevent sludging, which begins around 22 dynes per centimeter. See *FIST Volume 3-5, Maintenance of Liquid Insulation: Mineral Oils and Askarels* [7]. If oil is not reclaimed, sludge will settle on windings, insulation, cooling surfaces, etc., and cause loading and cooling problems. This will greatly shorten transformer life.

There is a definite relationship between acid number, the IFT, and years-in-service. The accompanying curve (figure 5) shows the relationship and is found in many publications. Notice that the curve shows the normal service limits both for the IFT and the acid number.

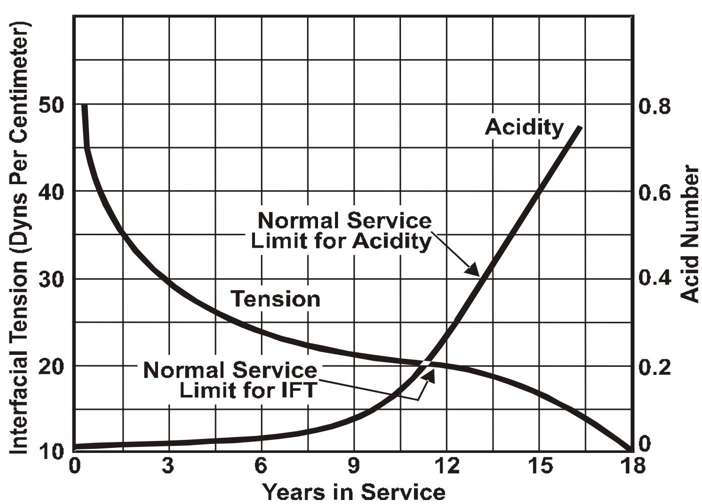

Figure 5.—Service Limits for Transformer Oil.

6.1.3 Acid Number. Acid number is the amount of potassium hydroxide (KOH) in milligrams (mg) that it takes to neutralize the acid in 1 gram (gm) of transformer oil. The higher the acid number, the more acid is in the oil. New transformer oils contain practically no acid. Oxidation of insulation and oils form acids as the transformer ages. Oxidation products form sludge particles in suspension in the oil which rains (precipitates out) inside the transformer. The acids attack metals inside the tank and form soaps (more sludge). Acid also attacks cellulose and accelerates insulation degradation. Sludging has been found to begin when the acid number reaches 0.40; it is obvious that the oil should be reclaimed long before it reaches 0.40. **It is recommended that the oil be reclaimed when the acid number reaches 0.20 mg KOH/gm [5].** As with all others, this decision must not be based on one DGA test; look for a rising trend in the acid number each year. Plan ahead and begin budgeting for reclaiming the oil before the acid number reaches 0.20.

6.1.4 Furans. Furans are a family of organic compounds which are formed by degradation of paper insulation [8]. Overheating, oxidation, acids, and decay caused by high moisture with oxygen accelerate the destruction of insulation and form furanic compounds. As with dissolved gases, increases in furans between DGA tests are important. When furans become greater than 250 parts per billion (ppb), the oil should be reclaimed; paper insulation is being deteriorated and transformer life reduced at a high rate. Look at the IFT and acid number in conjunction with furans. Furanic content in the oil is especially helpful in estimating remaining life in the paper insulation, particularly if several prior tests can be compared and trends established. Also see also section 17.3 for more on furans.

6.1.5 Oxygen. Oxygen (O_2) must be watched closely in DGA tests. Many experts and organizations, including EPRI, believe that above 2,000 ppm, oxygen in the oil greatly accelerates paper deterioration. This becomes even more critical with moisture above safe levels. See the Moisture section below and *FIST, Volume 3-30*, table 12 for moisture levels. Under the same temperature conditions, cellulose insulation in low oxygen oil will last 10 times longer than insulation in high oxygen oil [5]. It is recommended that if oxygen reaches 10,000 ppm in the DGA, the oil should be de-gassed and new oxygen inhibitor installed (see below). High atmospheric gases (O_2 and nitrogen [N_2]) normally mean that a leak has developed in a bladder or diaphragm in the conservator. If there is no conservator and pressurized nitrogen is on top of the oil, expect to see high nitrogen but not high oxygen. See *FIST Volume 3-30* [1] for how to check for leaks. Oxygen comes only from leaks and from deteriorating insulation.

6.1.6 Oxygen Inhibitor. Test for oxygen inhibitor every 3 to 5 years with the annual DGA test. Moisture is destructive to cellulose and even more so in the presence of oxygen. Acids are formed that attack the insulation and metals which form soaps and more acids, causing a viscious cycle. Oxygen inhibitor is key to extending the life of transformers. The inhibitor currently used is Ditertiary Butyl Paracresol (DBPC). This works similar to a sacrificial anode in grounding circuits; oxygen attacks the inhibitor instead of the cellulose insulation. As this occurs and the transformer ages, the inhibitor is used up and needs to be replaced. Replacement of the inhibitor generally requires that the oil also be treated [5]. The ideal amount of DBPC is 0.3% by total weight of the oil, which is given on the transformer nameplate [9].

6.1.7 Oil Power Factor. Power factor indicates the dielectric loss (leakage current associated with watts loss) of the oil. This test can be performed by DGA laboratories. It may also be done by Doble testing in the field. A high power factor indicates deterioration and/or contamination from byproducts such as water, carbon, or other conducting particles, including metal soaps caused by acids attacking transformer metals, and products of oxidation. DGA labs normally test oil power factor at 25 EC and 100 EC. Information in Doble Engineering Company *Reference Book on Insulating Liquids and Gases RBIL-391*, 1993 [10] indicates the in-service limit for power factor is less than 0.5% at 25 EC. If the power factor is greater than 0.5% and less than 1.0%, further investigation is required; the oil may require replacement or Fuller's earth filtering. **If the power factor is greater than 1.0% at 25 EC, the oil may cause failure of the transformer; replacement or reclaiming of the oil is required immediately.** Above 2%, oil should be removed from service and replaced because equipment failure is imminent. The oil cannot be reclaimed.

6.1.8 Moisture. Moisture, especially in the presence of oxygen, is extremely hazardous to transformer insulation. Recent EPRI studies show that oxygen above 2,000 ppm dissolved in transformer oil is extremely destructive. Each DGA and Doble test result should be examined carefully to see if water content is increasing and to determine the moisture by dry weight (M/DW) or percent saturation in the paper insulation. When 2% M/DW is reached, plans should be made for a dry out. Never allow the M/DW to go above 2.5% in the paper or 30% oil saturation before drying out the transformer. **Each time the moisture is doubled in a transformer, the life of the insulation is cut by one-half.** Keep in mind that the life of the transformer is the life of the paper, and the life of the paper is extended by keeping out moisture and oxygen. For service-aged transformers rated less than 69 kV, results of up to 35 ppm at 60 °C are considered acceptable. For 69 kV through 230 kV, a DGA test result of 20 ppm at 60 °C is considered acceptable. For greater than 230 kV, moisture should never exceed 12 ppm at 60 °C. However, the use of absolute values for water does not always guarantee safe conditions, and the percent by dry weight should be determined. See table 12, "Doble Limits for In-Service Oils," in section 4.6.5 of *FIST, Volume 3-30* [1]. If values are higher than these limits, the oil should be processed. Reclamation specifies that manufacturers dry new transformers to at least 0.5% M/DW during commissioning. In a transformer having 10,000 pounds of paper insulation, this means that 10,000 x 0.005 = 50 pounds of water (about 6 gallons) is in the paper. This is not enough moisture to be detrimental to electrical integrity. When the transformer is new, this water is distributed equally through the transformer.

When the transformer is energized, water begins to migrate to the coolest part of the transformer and the site of the greatest electrical stress. This location is normally the insulation in the lower one-third of the winding [5]. Paper insulation has a much greater affinity for water than does oil. Thus, insulation acts just like blotting paper or paper towels; it soaks up water superbly. The water will distribute itself unequally, with much more water being in the paper than in the oil. **The paper will even partially dry the oil by absorbing water from the oil.** Temperature is also a big factor in how the water distributes itself between the oil and paper; see table 4 below for comparison. The ppm of water in oil shown in the DGA is only a very small part of the water in the transformer.

Table 4.— Comparison of Water Distribution in Oil and Paper [5]

Temperature (degrees C)	Water in Oil	Water in Paper
20E	1	3,000 times what is in the oil
40E	1	1,000 times what is in the oil
60E	1	300 times what is in the oil

The table above shows the tremendous attraction that paper insulation has for water and how the water changes in the paper with temperature. **It is important when an oil sample is taken that the oil temperature from the top oil temperature gauge be recorded.**

It is critical for life extension to keep transformers as dry and as free of oxygen as possible. Moisture and oxygen cause paper insulation to decay much faster than normal and to form acids, metal soaps, sludge, and more moisture. Sludge settles on windings and inside the structure, causing transformer cooling to be less efficient, and slowly, over time, temperature rises. Acids cause an increase in the rate of decay, which forms more acid, sludge, and moisture at a faster rate [5]. This is a vicious cycle of increasing speed with deterioration forming more acid and causing more decay. The answer is to keep the transformer as dry as possible and free of oxygen as possible. In addition, oxygen inhibitor should be watched carefully in DGA testing. Oil should be dried when moisture in oil reaches values given in table 12 of *FIST, Volume 3-30* [1].

How much moisture in insulation is too much? When the insulation gets to 2.5% M/DW or 30% oil saturation (given on some DGAs), the transformer should have a dry out with vacuum if the tank is rated for vacuum. If the transformer tank is not rated for vacuum, do not pull a vacuum. In this case, it is better to do round-the-clock re-circulation with a Bowser drying the oil as much as possible, which will pull some water out of the paper. At 2.5% M/DW and above, paper insulation is degrading much faster than normal [5]. As paper is degraded, more water and oxygen is produced from the decay products, and the transformer becomes even wetter and decays even faster. When a transformer gets above 4% M/DW, it is in danger of flashover if the temperature rises to 90 EC.

7. AGE

Transformer age is an important factor to consider when identifying candidates for replacement or rehabilitation. Age is one indicator of remaining life and upgrade potential to current state-of-the art materials. During transformer life, structural strength and insulating properties of materials used for support and electrical insulation (especially paper) deteriorate. Although actual service life varies widely depending on the manufacturer, design, quality of assembly, materials used, maintenance, and operating conditions, the expected life of a transformer is about 40 years (*Replacements*, July 1995, Bureau of Reclamation and Western Area Power Administration [12]).

8. DOBLE TESTS ON INSULATION

Doble testing is important to determine the condition of a transformer, because it can detect winding and bushing insulation integrity and problems in the winding and core. Doble tests are conducted in the field on de-energized transformers using special test equipment. Generally, a Doble M-4000 test set is used along with accompanying software. The software automatically performs analysis of test results and responds with a four letter code: G = Good, I = Investigate, D = Deteriorated, and B = Bad. These codes refer to insulation quality. If a "D" or "B" code is encountered, the insulation should be re-tested, carefully investigated, and the problem definitely explained before re-energizing. Other tests may have to be performed and, perhaps, an internal inspection should be considered before the unit is re-energized. The Doble Company should be consulted, along with the transformer manufacturer, and other transformer experts. If the problem is severe, the unit may have to be taken out of service.

8.1 Insulation Power Factor Test

The purpose of this test is to determine the state of dryness of the windings and insulation system and to determine a power factor for the overall insulation, including bushings, oil, and windings. It is a measure of the ratio of the power (I^2R) losses to the volt-amperes applied during the test. The power factor obtained is a measure of watts lost in the total transformer insulation system including the bushings. The power factor should not exceed 0.5% at 20 EC. Temperature correction of test results can be done automatically on the Doble test set. The watts loss should not exceed one-half of one percent of the total power input (volt-amps) from the test. The values obtained at each test are compared to previous tests and baseline factory tests, and a trend can be established as the insulation system ages.

8.2 Capacitance Tests

This test measures and records the capacitance (including bushings) between the high and low voltage windings, between the high voltage winding and the tank (ground), and between the low voltage winding and the tank (ground). Changes in these values as the transformer ages and events occur, such as nearby lightning strikes or through faults, indicate winding deformation and structural problems such as displaced wedging and winding support.

8.3 Excitation Current Test

CAUTION:

Perform the excitation test before any direct current (dc) tests. Excitation Current Tests should never be conducted after a dc test has been performed on the transformer. Results will be incorrect because of residual magnetism of the core left from the dc tests.

The purpose of this test is to detect short-circuited turns, poor electrical connections, core de-laminations, core lamination shorts, tap changer problems, and other possible core and winding problems. On three-phase transformers, results are also compared between phases. This test measures current needed to magnetize the core and generate the magnetic field in the windings. Doble software only gives two indications on this test; one is “G” for good and “Q” for questionable. On a three-phase, wye/delta or delta/wye transformer test, the excitation current pattern will be two phases higher than the remaining phase. Compare the two higher currents only. If the excitation current is less than 50 milliampere (mA), the difference between the two higher currents should be less than 10%. If the excitation current is more than 50 mA, the difference should be less than 5%. In general, if there is an internal problem, these differences will be greater. When this happens, other tests should also show abnormalities, and an internal inspection should be considered. The results, as with all others, should be compared with factory and prior field tests.

8.4. Bushing Tests

For bushings that have a potential tap, both the capacitance between the top of the bushing and the bottom tap (normally called C1) and the capacitance between the tap and ground (normally called C2) are measured. To determine bushing losses, power factor tests are also performed. C2 capacitance is much greater than C1. Bushings without a potential tap are normally tested from the bushing top conductor to ground and "hot collar" tests. These test results are compared with factory tests and/or prior tests to determine deterioration. About 90% of bushing failures may be attributed to moisture ingress evidenced by an increasing power factor from Doble testing on a scheduled basis.

8.5. Percent Impedance/Leakage Reactance Test

This is normally an acceptance test to see that nameplate percent impedance agrees with the measured percent impedance when the transformer arrives onsite. Normally a 3% difference is considered acceptable. However, after the initial benchmark test, the percent impedance should not vary more than 2% from benchmark. As the transformer ages or suffers events such as through faults, nearby lightning strikes, and other surges, this test is used in the field to detect winding deformation. Winding deformation can lead to immediate transformer failure after a severe through fault, or a small deformation can lead to a failure years later.

Percent impedance/leakage reactance testing is performed by short circuiting the low voltage winding, and applying a test voltage to the high voltage winding. Reluctance is resistance to lines of magnetic flux. Reluctance to the magnetic flux is very high in spaces between the high and low voltage windings and spaces between the windings and core. Reluctance is very low through the magnetic core so that the vast majority of total reluctance is in the spaces. When winding movement (distortion) occurs, these spaces change. Therefore, the reluctance changes, resulting in a change in the measured leakage reactance. Changes in leakage reactance and in capacitance tests (explained above), serve as an excellent indicator of winding movement and structural problems (displaced wedging etc.). This test does not replace excitation current tests or capacitance tests, but complement them and they are used together. The excitation current test relies on reluctance of the core while the leakage reactance test relies on reluctance of the spaces. See Doble's *Leakage Reactance Instrument Users Guide*, and IEEE® *Guide for Diagnostic Field Testing of Electric Power Apparatus-Part 1: Oil-Filled Power Transformers, Regulators, and Reactors* (IEEE 62-1995™ [11]).

8.6. Sweep Frequency Response Analysis Tests

These tests show, in trace form, the winding transfer function of the transformer and are valuable to determine if any damage has occurred during shipping or during a through fault. Core grounds, core displacement, and other core and winding problems can be revealed by this test.

These tests should be conducted before and after the transformer has been moved or after experiencing a through fault. Results should be compared to baseline tests performed at the factory or as soon as possible after receiving the transformer. If the SFRA tests cannot be performed at the factory, they should be conducted as an acceptance test before energizing a new or rebuilt transformer to establish a baseline. A baseline should be established for older inservice transformers during a normal Doble test cycle. If at all possible, one should use the same test equipment for baseline and following tests, or the results may not be comparable.

For a delta/wye transformer, a test voltage of variable frequency (normally 20 hertz [Hz] to 2 megahertz [MHz]) is placed across each phase of the high voltage winding. With this set of tests, low voltage windings are isolated with no connections on any of the bushings. An additional set of tests is performed by short circuiting all the low voltage windings and again placing the test voltage on each phase of the high voltage winding. A third set of tests is made by isolating the high voltage winding and placing the test voltage across each low voltage winding. See the *M5100 SFRA Instrument Users Guide,* Doble Engineering Company [13] for connection details.

Figure 6 is a picture of test traces on a new three-phase Reclamation transformer. The top three traces were taken on the low voltage side, X1-X3, X2-X1, and

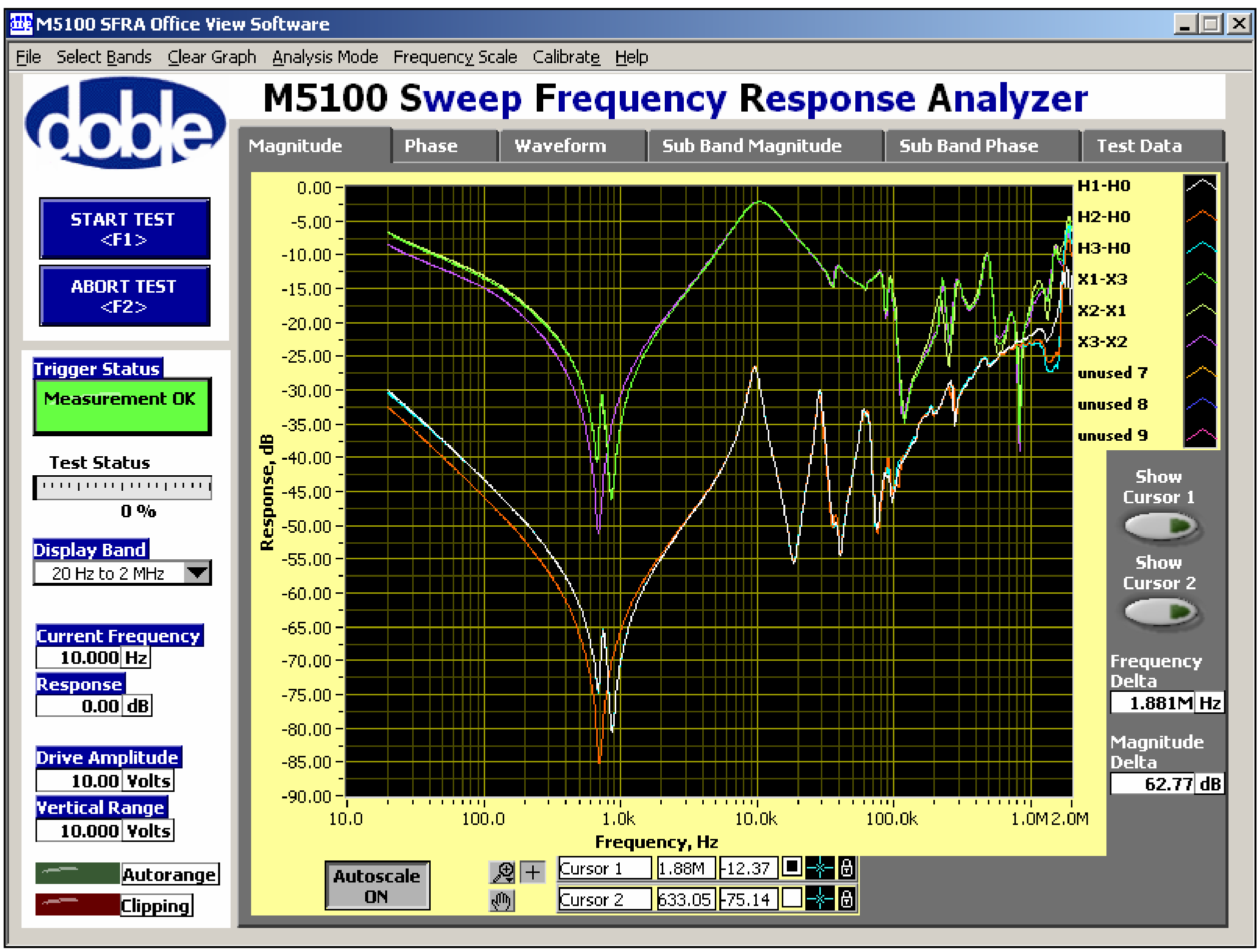

Figure 6.—SFRA Test Traces of a New Transformer.

X3-X2. The two outside windings (A and C phases) have the same general shape with a "W" at the lowest point of the trace, while the inside winding (B phase) has a "V" at the bottom. The high voltage traces (lower three) have the same characteristics. Note that, in both high and low voltage tests, the traces fall almost perfectly on top of each other for the outside windings (A and C), while the inside winding (B phase), is slightly displaced to the left. These are characteristic traces of a three-phase transformer in good condition; these traces will be the baseline for future tests on this transformer.

By comparing future traces with baseline traces, the following can be noted. In general, the traces will change shape and be distorted in the low frequency range (under 5,000 Hz) if there is a core problem. The traces will be distorted and change shape in higher frequencies (above 10,000 Hz) if there is a winding problem. Changes of less than 3 decibels (dB) compared to baseline traces are normal and within tolerances. From 5 Hz to 2 kilohertz (kHz), changes of + or – 3 dB (or more) can indicate shorted turns, open circuit, residual magnetism, or core movement. From 50 Hz to 20 kHz +/- 3 dB (or more), change from baseline can indicate bulk movement of windings relative to each other. From 500 Hz to 2 MHz, changes of +/- 3 dB (or more) can indicate deformation within a winding. From 25 Hz to 10 MHz, changes of +/- 3 dB (or more) can indicate problems with winding leads and/or test leads placement. The above diagnostics come from the EuroDoble Client Committee after much testing experience and analysis. Note that there is a great deal of overlap in frequencies, which can mean more than one diagnosis.

Figure 7 shows traces of a transformer with a problem. This transformer is not Reclamation-owned, and test results are used for illustration only. The traces have the same general positions on the graph as the good transformer. The lower traces are high voltage winding tests, while the upper traces are the low voltage winding tests. Note in the higher frequencies of the low voltage traces that "A" phase (X1-X0 green trace) is displaced from the other two phases more than 3 dB from about 4 kHz to about 50 kHz. With a healthy transformer, these would fall almost on top of each other as the other two phases do. Also notice that "A" phase (H1-H3Lsh) is displaced in the test with the low voltage winding shorted. There is an obvious problem with "A" phase on the low voltage side. After opening the transformer, it was found that the "A" phase winding lead had burned off near the winding connection and re-welded itself on the winding at a different location, effectively shorting out a few turns. The transformer was still working, but hot metal gases (ethylene, ethane, methane) were actively generating and showing up in the DGA. Although other tests could have revealed this problem, SFRA showed the problem was with "A" phase and, therefore, where to concentrate the internal inspection.

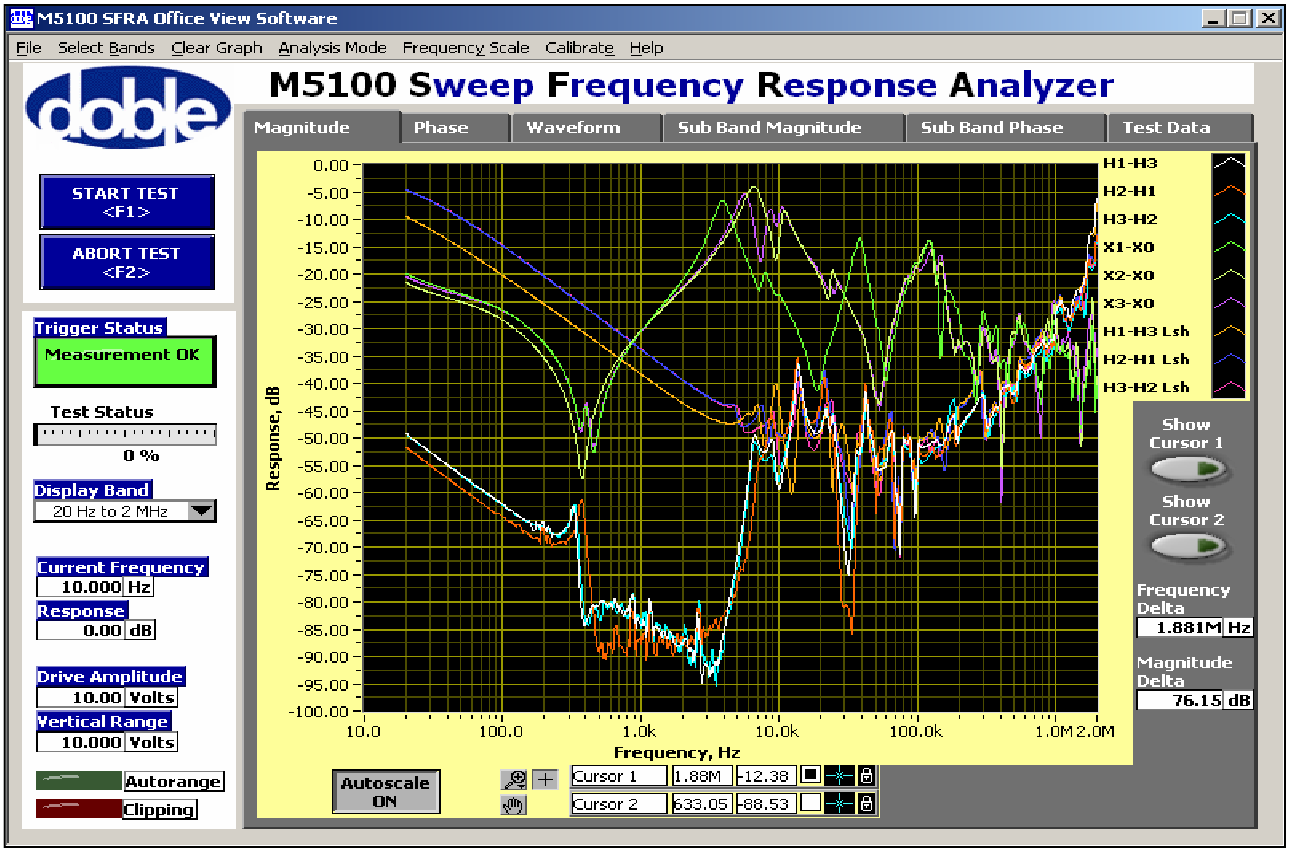

Figure 7.—SFRA Test Traces of a Defective New Transformer.

9. VISUAL INSPECTION

9.1 Background

Visual inspection of the transformer exterior reveals important condition information. For example, valves positioned incorrectly, plugged radiators, stuck temperature indicators and level gauges, and noisy oil pumps or fans. Oil leaks can often be seen which indicate a potential for oil contamination, loss of insulation, or environmental problems. Physical inspection requires staff experienced in these techniques.

9.2 Temperature Indicators Online

Check all temperature indicators while the transformer is online. The winding temperature indicator should be reading approximately 15 degrees above the top oil temperature. If this is not the case, one or both temperature indicators are malfunctioning. Refer to *FIST Volume 3-30* [1] for maintenance and testing of these devices. Check the top oil temperature next to the top oil indicator's thermowell with an infrared camera. Compare the readings with the top oil indicator. Reset all maximum indicator hands on the temperatures indicating devices after recording the old maximum temperature readings. High temperature may mean overloading, cooling problems, or problems with windings, core, or connections.

9.3 Temperature Indicators Offline

When the transformer is offline and has cooled to ambient temperature, check the top oil and winding temperature indicators; both should be reading the same. If not, one or both temperature indicators are malfunctioning. Check the calibration according to the proper procedure. Also compare these readings with the indicated temperature on the conservator oil level indicator; all three should agree. See *FIST Volume 3-30* [1] for details.

9.4 Conservator

Check the oil level gauge on the conservator. See figure 8 at right. This gauge indicates oil level by displaying a temperature. Compare the indicated temperature on the conservator level gauge with the top oil temperature indicator. They should be approximately the same. Calibrate or replace the conservator oil level indicator if needed, but only after checking the top oil temperature indicator as shown in the above section. See *FIST Volume 3-30* [1] for potential problems and testing this gauge. Reference also IEEE 62-1995™ [11], section 6.6.2. If atmospheric gases (nitrogen, oxygen, carbon dioxide) and perhaps moisture increase suddenly in the DGA, a leak may have developed in the conservator diaphragm or bladder.

Figure 8.—Conservator Oil Level.

With the transformer offline and under clearance, open the inspection port on top of the conservator and look inside with a flashlight. If there is a leak, oil will be visible on top of the diaphragm or inside the bladder. Reclose the conservator and replace the bladder or diaphragm at the first opportunity by scheduling an outage. If there is no gas inside the Buchholz Relay, the transformer may be re-energized after bleeding the air out of the bladder failure relay. A DGA should be taken immediately to check for O_2, N_2, and moisture. However, the transformer may be operated until a new bladder is installed, keeping a close eye on the DGAs. It is recommended that DGAs be performed every 3 months until the new bladder is installed. After the bladder installation, the oil may need to be de-gassed if O_2 exceeds 10,000 ppm. Also, carefully check the moisture level in the DGAs to ensure it is below recommended levels for the particular transformer voltage. Check the desiccant in the breather often; never let more than two-thirds become discolored before renewing the desiccant. All efforts should be made to keep the oxygen level below 2,000 ppm and moisture as low as possible. See *FIST Volume 3-30* [1] for details.

9.5 Conservator Breather

Check the dehydrating (desiccant) breather for proper oil level if it is an oil type unit. Check the color of the desiccant and replace it when approximately one-third remains with the proper color. See figure 9 for a modern oil type desiccant breather. Notice the pink desiccant at the bottom of the blue indicating that this portion is water saturated. Notice also that oil is visible in the very bottom 1-inch or so of the unit.

Figure 9.—Conservator Breather.

Many times, the oil is clear, and the oil level will not be readily apparent. Normally, there is a thin line around the breather near the bottom of the glass; this indicates where the oil level should be. Compare the oil level with the level indicator line and refill, if necessary. Note the 1¼-inch pipe going from the breather to the conservator. Small tubing (½ inch or so) is not large enough to admit air quickly when the transformer is de-energized in winter. A transformer can cool so quickly that a vacuum can be created from oil shrinkage with enough force to puncture a bladder. When this happens, the bladder is destroyed; and air is pulled into the conservator making a large bubble.

9.6 Nitrogen

If the transformer has a nitrogen blanket, check the pressure gauge for proper pressure. Look at the operators recording of pressures from the pressure gauge. If this does not change, the gauge is probably defective. Check the nitrogen bottle to insure the nitrogen is the proper quality (see PEB No. 5 [20]). Check for any increased usage of nitrogen which indicates a leak. See *FIST Volume 3-30* [1]. Smaller transformers such as station service or smaller generator-step-up transformers may not have nitrogen bottles attached to replace lost nitrogen. Be especially watchful of the pressure gauge and the operator's records of pressures with these. The pressure gauge can be defective for years, and no one will notice. The gauge will read nearly the same and will not vary much over winter and summer or night and day. Meanwhile, a nitrogen leak can develop; and all the N_2 will be lost. This allows air with oxygen and moisture to enter and deteriorate the oil and insulation. Watch for increased oxygen and moisture in the DGA. An ultrasonic and sonic leak detection instrument (P-2000) is used for locating N_2 leaks.

9.7 Oil Leaks

Check the entire transformer for oil leaks. Leaks develop due to gaskets wearing out, ultraviolet exposure, taking a "set," or from expansion and contraction, especially after transformers have cooled, due to thermal shrinkage of gaskets and flanges. See *FIST Volume 3-30* [1] for details. Many leaks can be repaired by applying an epoxy or other patch. Flange leaks may be stopped with these methods using rubberized epoxy forced into the flange under pressure. Very small leaks in welds and tanks may be stopped by peening with a ball-peen hammer, cleaning with the proper solvent, and applying a "patch" of the correct epoxy. Experienced leak mitigation contractors whose work is guaranteed may also be employed. Some leaks may have to be welded. Welding may be done with oil in the transformer if an experienced, qualified, and knowledgeable welder is available. If welding with oil in the tank is the method chosen, oil samples must be taken for DGA both before and after welding. Welding may cause gases to appear in the DGA and it must be determined what gases are attributed to welding and which ones to transformer operation. See also EPRI's *Guidelines for the Life Extension of Substations,* 2000 and 2002 update [14] section on "Transformers Leak Mitigation" that gives several materials and applications to stop transformer oil leaks. Copies of this literature are available at the Technical Service Center.

Figure 10.— Pressure Relief Device.

9.8 Pressure Relief Device

See figure 10 at the right showing a pressure relief device with the yellow indicating arm. With the transformer under clearance, check the pressure relief device indicating arm on top of the transformer to see if it has operated. If it has operated, the arm will be in the up (vertical) position, and alarm and shut-down relays should have activated. See *FIST Volume 3-30* [1] for details.

CAUTION:

Do not re-energize a transformer after this device has operated and relays have de-energized the transformer, until extensive testing to determine and correct the cause has been undertaken. Explosive, catastrophic failure could be the result of energization after this device has operated.

9.9 Oil Pumps

If the transformer has oil pumps, check flow indicators and pump isolation valves to ensure oil is circulating properly. Pump motor(s) may also have reversed rotation, and flow indicators may still show that oil is flowing. To ensure motors are turning in the proper direction, use an ammeter to check the motor current. Compare results with the full-load-current indicated on the motor nameplate. If the motor is reversed, the current will be much less than the nameplate full-load-current. See *FIST Volume 3-30* [1] for details. Check oil pumps with a vibration analyzer if they develop unusual noises. Have the DGA lab check for dissolved metals in the oil and run a metal particle count for metals if the bearings are suspect. This should be done immediately, as soon as a bearing becomes suspect; bad oil-pump bearings can put enough metal particles into the oil to threaten transformer insulation and cause flashover inside the tank. An explosive catastrophic failure of the transformer tank could be the result.

9.10 Fans and Radiators

Inspect all isolation valves at the tops and bottoms of radiators to ensure they are open. Inspect cooling fans and radiators for cleanliness and fans for proper rotation. Check for dirty or damaged fan blades or partially blocked radiators. Fans are much more efficient if the blades are clean and rotating in cool air. Normally, fans blow cool air through the radiators; they should not be pulling air through. Check to see if fans are reversed electrically (i.e., pulling air first through the radiators and then through the fan blades). This means the blades are rotating in warm air after it passes through the radiator which is much less efficient. Place a hand on the radiator opposite the fans; air should be coming out of the radiator against your hand. Watch the blades as they rotate slowly when they are starting or stopping to determine which way they should be rotating and correct the rotation if necessary. See *FIST Volume 3-30* [1] and IEEE 62-1995™ [11]. Also inspect radiators and fans with an infrared (IR) camera, see “Section 10.4, Infrared Temperature Analysis.”

Figure 11.—Buchholz Relay.

9.11 Buchholz Relay

Inspect the isolation valve on the Buchholz relay to ensure it is open. With the transformer offline and under clearance, examine the Buchholz relay by lifting the window cover (center in figure 11 at right) and looking inside. If there is gas inside, the oil will be displaced, and the gas will be evident as a space on top the oil. If sufficient gas is found to displace the upper float, the alarm should be activated. The small valve at the top left is to bleed the gas off and reset the relay. See *FIST Volume 3-30* [1] for details on this relay. If a small amount of gas is found in this relay when the transformer is new (a few months after startup), it is probably just air that has been trapped in the transformer structure and is now escaping; there is little cause for concern.

If the transformer has been on line for some time (service aged), and gas is found in the Buchholz, oil samples must be sent to the lab for DGA and extensive testing. Consult with the manufacturer and other transformer experts. A definite cause of the gas bubbles must be determined and corrected before re-energization of the transformer.

9.12 Sudden Pressure Relay

An example relay is shown in figure 12 at the right. The purpose of this relay is to alarm if there is a sudden pressure rise inside the tank. This relay is very sensitive and will operate if the pressure rises only a little. If a very small pressure change occurs caused by a small electrical fault inside the tank, this relay will alarm. In contrast, the pressure relief device (shown above in figure 11) operates if a large pressure builds inside the tank caused by heavy arcing and heating causing the oil to boil and bubble. Inspect the isolation valve to ensure it is open. With the transformer offline and under clearance, functionally test the sudden pressure relay by slowly closing the isolating valve. Leave it closed for a few seconds and reopen the valve very suddenly; this should activate the alarm. If the alarm does not activate, test the relay as specified in *FIST Volume 3-30*, section 4.1.6, and replace it with a new one if it fails to function.

Figure 12.—Sudden Pressure Relay.

9.13 Bladder Failure Relay

On newer transformers, a bladder failure relay may be found on or near the conservator top on the oil side of the bladder. This relay is near the highest point of the transformer. Its purpose is to alarm if the bladder fails and admits air bubbles into the oil.

The relay will also serve as a backup to the Buchholz relay. If the Buchholz relay overfills with gas and fails to activate an alarm or shutdown, gas will bypass the

Buchholz and migrate up into the conservator, eventually to the bladder failure relay. See figure 13. Of course, these gases should also show up in the DGA. However, DGAs are normally taken only once per year, and a problem may not be discovered before these alarms are activated.

Figure 13.—Bladder Failure Relay.

If the bladder failure alarm is activated, place the transformer under clearance and check the Buchholz for gas as mentioned in section 9.10. Open the conservator inspection port and look inside with a flashlight to check for oil inside the bladder. See section 9.4 above. Bleed the air/gas from the conservator using the bleed valve on top of the conservator. If the transformer is new and has been in service for only a few months, the problem most likely is air escaping from the structure as mentioned in section 9.11. With the transformer under clearance, open the inspection port on top of the conservator and look inside the bladder with a flashlight. If oil is found inside the bladder, it has developed a leak; a new one must be ordered and installed.

10. INFRARED TEMPERATURE ANALYSIS

Infrared analysis should be conducted annually while equipment is energized and under full load, if possible. IR analysis should also be conducted after any maintenance or testing to see if connections that were broken were remade properly. Also, if IR is done during factory heat run, the results can be used as a baseline for later comparison.

10.1 IR for Transformer Tanks

Unusually high external temperatures or unusual thermal patterns of transformer tanks indicate problems inside the transformer such as low oil level, circulating stray currents, blocked cooling, loose shields, tap changer problems, etc. Infrared scanning and analysis is required annually for trending purposes by NFPA 70B, *Recommended Practice for Electrical Equipment Maintenance* [25] and *FIST Volume 4-1B* [16]. See also *FIST Volume 4-13* [17] and IEEE 62-1995™ [11]. Abnormally high temperatures can damage or destroy transformer insulation and, thus, reduce life expectancy. Thermal patterns of transformer tanks and radiators should be cooler at the bottom and gradually warmer ascending to the top. See figure 14 for a normal pattern; the red spot at the top is normal showing a “hot spot” top of B phase about 110 degrees Fahrenheit (°F). Any departure from this pattern means a probable problem which must be investigated. An IR inspection can find over-heating conditions or incorrect thermal patterns. IR scanning and analysis requires trained staff experienced in these techniques.

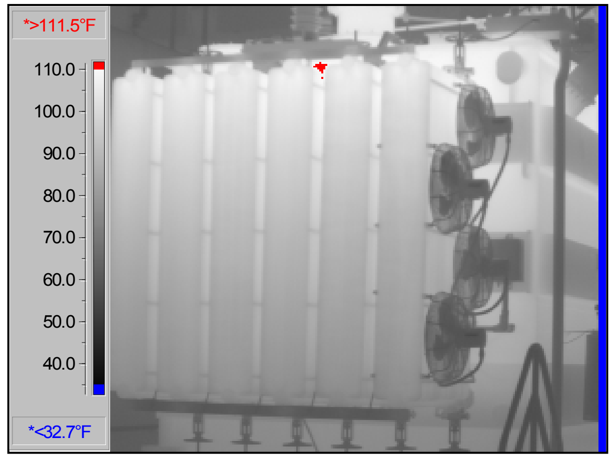

Figure 14.—Normal Transformer IR Pattern.

10.2 IR for Surge Arresters

Surge arresters should be included when infrared scanning energized transformers. Look for unusual thermal patterns on the surface of lightning arresters (see the arrester IR image in figure 15). Note that the yellow in the top right of the image is a reflection not associated with the arrester. A temperature profile of the arrester is shown as black lines. Note the hot spot (yellow) about a third of the way down from the top. This indicates that immediate de-energization and replacement must be undertaken. Catastrophic failure is imminent which can destroy nearby equipment and be hazardous to workers. Also compare thermal patterns to sister units or earlier scans of the same arrester. See the references indicated in section 10.1. Scan all high voltage connections and compare them to nearby connections for unusual temperatures.

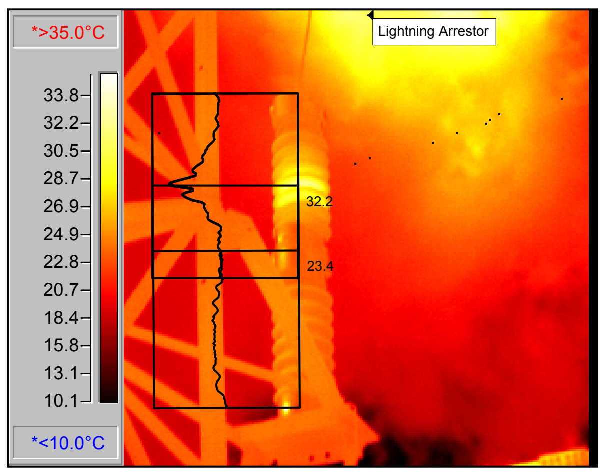

Figure 15.— IR Image of Defective Arrester.

10.3 IR for Bushings

IR scans of bushings can show low oil levels which would call for immediate de-energization and replacement. This generally means that the seal in the bushing bottom has failed, leaking oil into the transformer. The top seal has probably failed also allowing air and moisture to enter the top. Too high an oil level in a bushing generally means the seal in the bottom of the bushing has failed and oil head from the conservator, or nitrogen pressure, has pushed transformer oil up the bushing. Another reason a bushing can exhibit high oil level is the top seal leaking, allowing water to enter. The water migrates to the bushing bottom displacing the oil upward.

Remember, over 90% of bushing failures are attributed to water entrance through the top seal. Bushings commonly fail catastrophically, many times destroying the host transformer or breaker and nearby equipment and causing hazards to workers. Figure 16 shows low oil level in a high voltage transformer bushing. Compare previous IR scans of the same bushing with the current scan. Doble hot-collar testing possibly may show this problem. However, Doble tests are run infrequently, and the transformer has to be out of service, under clearance, and both primary and secondary conductors removed, while an IR scan can be easily done at any time.

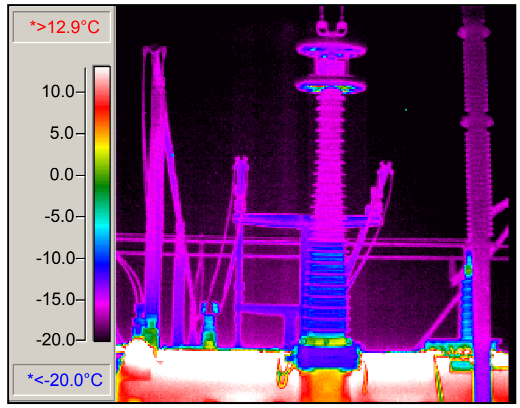

Figure 16.—IR Image of Defective Bushing.

10.4 IR for Radiators and Cooling Systems

Examine radiators with an IR camera and compare them with each other. A cool radiator or segment indicates that a valve is closed or the radiator or segment is plugged. The IR image (figure 17) at right shows that the cold left radiator section is valved off or plugged. If visual inspection shows the valves are open, the radiator or segment must be isolated, drained, and removed and the blockage cleared. Do not allow a transformer to operate with reduced cooling which drastically shortens transformer life. Remember, an increased operating temperature of only 8 to 10 °C will reduce transformer life by one-half. IR scan all cooling systems, including heat exchangers, fans, pumps, motors, etc. Check inside control panels for overloaded wiring, loose connections, and overheated relays. Look for unusual thermal patterns and compare similar equipment.

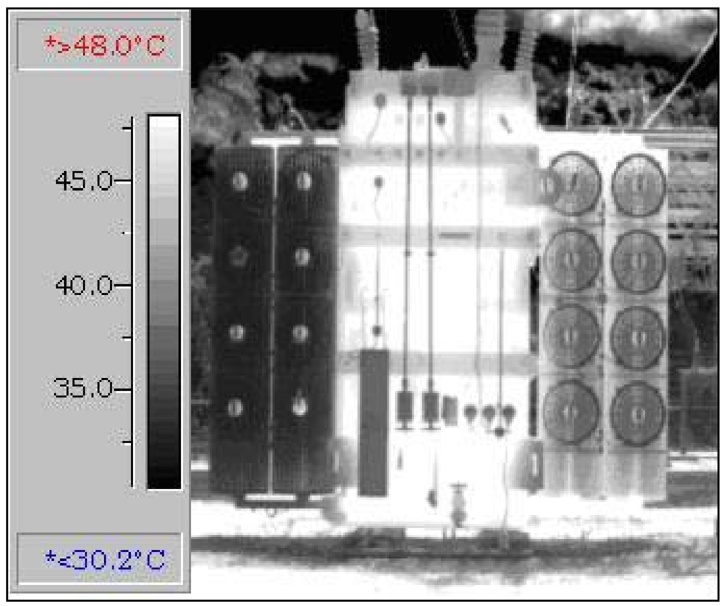

Figure 17.—IR Image Showing Blocked Radiators.

11. CORONA SCOPE SCAN

With the transformer energized, scan the bushings and surge arresters and all high voltage connections for unusual corona patterns. Corona should be visible only at the top of bushings and arresters, and corona at connections should be similar to sister connections. As a bushing deteriorates due to physical defects, the corona pattern will grow progressively larger. When the corona pattern reaches a grounded surface (i.e., the tank or structure) a flashover will occur destroying the bushing or arrester and perhaps the transformer. The corona scope will reveal this problem long before a flashover.

12. ULTRASONIC AND SONIC FAULT DETECTION

12.1 Background

This test should be applied when hydrogen is increasing markedly in the DGA. High hydrogen generation indicates partial discharge occurring inside the transformer. Other gases such as methane, ethane, and ethylene may also be increasing. Acetylene may also be present if arcing is occurring and may also be increasing.

Ultrasonic contact (in contact with the tank), fault detection can detect partial discharge (corona) and full discharge (arcing) inside the transformer. This test can also detect loose parts inside the transformer. Partial discharges emit energy in the order of 20 kHz to 200 kHz. These frequencies are above levels that can be detected audibly. The test equipment receives the signals and converts them electronically into audible signals. Headphones are provided to eliminate spurious noise from the powerplant and other sources. The equipment logs data for future reference. A baseline test should be conducted and compared with future test data. This test method has some limitations; if a partial discharge is located deep within the windings, external detectors may not be sensitive enough to detect and locate the problem. However, partial discharges most often occur near the top of the transformer in areas of high voltage stress which can readily be located by this method. These defects can sometimes be easily remedied extending transformer service life.

12.2 Process

Magnetic piezoelectric crystal transducers, sized and tuned to the appropriate frequencies, are placed on the outside of the tank, and signals are recorded. If discharges are detected, the location is triangulated so that during an internal inspection, the inspector will know the general area to search for a problem. Likewise, sonic (audible ranges) fault detection can find mechanical problems such as noisy bearings in pumps or fans, nitrogen leaks, loose shields, or other loose parts inside the transformer tank, etc. See EPRI's *Guidelines for the Life Extension of Substations* [14], section 3. See also IEEE 62-1995™ [11], section 6.1.8.4.

13. VIBRATION ANALYSIS

13.1 Background

Vibration analysis by itself cannot predict many faults associated with transformers, but it is another useful tool to help determine transformer condition. Vibration can result from loose transformer core segments, loose windings, shield problems, loose parts, or bad bearings on oil cooling pumps or fans. Extreme care must be exercised in evaluating the source of vibration. Many times, a loose panel cover, door, or bolts/screws lying in control panels, or loose on the outside have been misdiagnosed as problems inside the tank. There are several instruments available from various manufacturers and the technology is advancing quickly. Every transformer is different; therefore, to detect this, baseline vibration tests should be run and data recorded for comparison with future tests.

For a normal transformer in good condition, vibration data is normally 2 times line frequency (120 Hz) and also appears as multiples of 2 times line frequency; that is, 4 times 60 (240 Hz), 6 times 60 (360 Hz), etc. The 120 Hz is always the largest and has an amplitude of less than 0.5 inch per second (ips) and greater than 0.1 ips. The next peak of interest is the 4 times line frequency or 240 Hz. The amplitude of this peak should not exceed 0.5 ips. None of the remaining harmonic peaks should exceed 0.15 ips in amplitude. See EPRI's *Proceedings: Substation Equipment Diagnostics, Conference IX* [18] section on "Vibration Analysis."

14. TURNS RATIO TEST

14.1 Background

This test only needs to be performed if a problem is suspected from the DGA, Doble testing, or relay operation. The turns ratio test detects shorted turns which indicate insulation failure by determining if the correct turns ratio exists. Shorted turns may result from short circuits or dielectric (insulation) failures.

14.2 Process

Measurements are made by applying a known low voltage across one winding and measuring the induced voltage on the corresponding winding. The low voltage is normally applied across a high voltage winding so that the induced voltage is lower, reducing hazards while performing the test. The voltage ratio obtained by the test is compared to the nameplate voltage ratio. The ratio obtained from the field test should agree with the factory within 0.5%. New transformers of good quality normally compare to the nameplate within 0.1%.

For three-phase delta/wye or wye/delta connected transformers a three-phase equivalency test should be performed. The test is performed and calculated across corresponding single windings. Look at the nameplate phasor diagram to find out what winding on the primary corresponds to a particular winding on the secondary. Calculate the ratio of each three-phase winding based on the line to neutral voltage of the wye winding. Divide the line-to-line winding voltage by 1.732 to obtain the correct line-to-neutral voltage. Check the tap changer position to make sure it is set at the position on which the nameplate voltage is based. Otherwise, the turns ratio test information cannot be compared with the nameplate. Nameplate information for Reclamation transformers is normally based on the tap 3 position of the tap changer. See the manufacturer's instruction manual for the specific turns ratio tester for details. See IEEE 62-1995™ [11].

15. DC WINDING RESISTANCE MEASUREMENT

CAUTION:

Do not attempt to run an excitation current test immediately after any dc test. Energizing with dc will leave a residual magnetism in the core and will ruin the results of the excitation current test.

15.1 Background

If generation of ethylene, ethane, and perhaps methane in the DGAs indicates a poor connection, winding resistances should be checked. Turns ratio, SFRA, Doble tests, or relay operations may give indications that dc testing is warranted. Winding resistances are tested in the field to check for loose connections on bushings or tap changers, broken strands, and high contact resistance in tap changers. Results are compared to other phases in wye connected transformers or between pairs of terminals on a delta-connected winding to determine if a resistance is too high. Resistances can also be compared to the original factory measurements or to sister transformers. Agreement within 5% for any of the above comparisons is considered satisfactory. If winding resistances are to be compared to factory values, resistance measurements will have to be converted to the reference temperature used at the factory (usually 75 °C). To do this, use the following formula:

$$Rs = Rm\left(\frac{Ts + Tk}{Tm + Tk}\right)$$

Rs	=	Resistance at the factory reference temperature (found in the transformer manual)
Rm	=	Resistance actually measured
Ts	=	Factory reference temperature (usually 75 °C)
Tm	=	Temperature at which you took the measurements
Tk	=	A constant for the particular metal the winding is made from: 234.5 °C for copper; 225 °C for aluminum

It is very difficult to determine actual winding temperature in the field, and, normally, this is not needed. The above temperature corrections are necessary only if resistance is going to be compared to factory values. Normally, phase resistances are compared to each other, or sister transformers at the same temperature, and actual winding temperatures and corrections are not needed. The most accurate method is to allow the transformer to sit de-energized until temperatures are equalized. This test can reveal serious problems. If the DGA indicates this test is necessary, it's worth the effort.

15.2 Process

Winding resistances are measured using a Wheatstone Bridge for values 1 ohm or above and using a micro-ohmmeter or Kelvin Bridge for values under 1 ohm. An instrument made by AVO is available for loan to facilities.

Take readings from the top of each bushing to neutral for wye connected windings and across each pair of bushings for delta connected windings. If the neutral bushing is not available on wye windings, take each one to ground (if the neutral is grounded), or take readings between pairs of bushings as if it were a delta winding. Be consistent each time so that a good comparison can be made. The tap changer can also be changed from contact to contact, and the contact resistance can be checked. Make sure to take the first test with the tap changer "as found." Keep accurate records and connection diagrams so that later measurements can be compared.

16. CORE INSULATION RESISTANCE AND INADVERTENT CORE GROUND TEST (MEGGER®)

CAUTION:

Do not attempt to run an excitation test on a transformer immediately after using dc test equipment. Residual magnetism will remain in the core and ruin the excitation current test results.

16.1 Background

Core insulation resistance and core ground test is used if an unintentional core ground is suspected; this may be indicated by the DGA. Key gases to look for are ethane and/or ethylene and possibly methane. These gases may also be present if there is a poor connection at the bottom of a bushing or a bad tap changer contact. Therefore, this test is only necessary if the winding resistance test above shows all the connections are good and if tap changer contacts are in good condition.

16.2 Process

The intentional core ground must be disconnected. This may be difficult, and some oil may have to be drained to accomplish this. On some transformers, core grounds are brought outside through insulated bushings and are easily accessed. A standard dc Megger® (1,000-volt Megger® is recommended) is then attached between the core ground lead (or the top of the core itself and the tank [ground]). The Megger® is used to place a dc voltage between these points and the resistance measured. A new transformer should read greater than 1,000 megohms. A service-aged transformer should read greater than 100 megohms. Ten to one hundred megohms is indicative of deteriorating insulation between the core and ground. Less than 10 megohms is sufficient to cause destructive circulating currents and must be further investigated. See IEEE Standard 62-1995™ [11]. A solid unintentional core ground may read zero ohms; this, of course, causes destructive circulating currents also and must be corrected before energization.

17. ESTIMATE OF PAPER DETERIORATION (ONLINE)

NOTE:

The two methods below should be used together.

17.1 CO_2 and CO Accumulated Total Gas Values

IEEE Standard C57.104™ *Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers* [4] gives status conditions based on accumulated values of CO_2 and CO. Accumulated dissolved gas levels provide four status conditions: Normal Operation, Modest Concern (investigate), Major Concern (more investigation), and Imminent Risk (nearing failure). The CO_2 and CO levels in ppm for each status are given below.

Table 5.—Paper Status Conditions Using CO_2 and CO

		CO_2	CO
Condition 1	Normal	0 - 2,500	0- 350
Condition 2	Modest Concern	2,500 – 4,000	351– 570
Condition 3	Major Concern	4,001 – 10,000	571 – 1,400
Condition 4	Imminent Risk	> 10,000	>1,400

CAUTION:

The status from the table above should be at least in the Condition 2 or 3 from one or both gases before a detailed investigation is begun. There is no need to look at the ratios from section 17.2 below unless a substantial amount of these gases have already been generated. If the transformer is relatively new, CO_2 and other atmospheric gases (N_2, O_2, and even some CO) may be migrating out of the paper into the oil because the paper was stored in air prior to transformer assembly. If the paper was stored in a polluted city atmosphere, a considerable amount of CO may show up in the DGA. This may look like the transformer has a problem and is generating a lot of CO. However, if the transformer has a real problem, H_2 and perhaps other heat gases (CH_4, C_2H_6, C_2H_4) should also be increasing.

17.2 CO_2 /CO Ratio

Calculate a normal operating CO_2 /CO ratio at each DGA, based on the total accumulated amount of both gases. Look at several DGAs concentrating on CO_2 and CO. Experience has shown that with normal loading and temperatures, the rate of generation of CO_2 runs 7 to 20 times higher than CO. With a CO_2 /CO ratio above 7, there is little concern. With some transformers, ratios down to 5 times more CO_2 than CO might be considered normal. However, be careful with a ratio below 7. If H_2, CH_4, and C_2H_6 are increasing significantly as well as CO and the ratio is 5 or less, there is probably a problem. Take time to know the particular transformer by carefully checking all prior DGAs and establish a normal operating CO_2 to CO ratio.

CAUTION:

After a suspected problem (a substantial increase in the amount of CO), the ratio should be based on the gas generation of both CO_2 and CO between successive DGAs and not on accumulated total CO_2 and CO gas levels

If a problem is suspected, take another DGA sample immediately to confirm the problem. Take the amount of CO_2 generated between the DGAs and divide it by the amount of CO generated in that same time to establish the ratio. An excellent indication of abnormally high temperatures and rapidly deteriorating cellulose insulation is a CO_2/ CO under 5. If the ratio is 3 or under, severe and rapid deterioration of cellulose is certainly occurring. In addition to DGAs, perform the Furans test explained below. Extreme overheating from loss of cooling or plugged oil passages will produce a CO_2/CO ratio around 2 or 3 along with increasing Furans. If this is found, de-energization and internal inspection is recommended; the transformer is in imminent danger of failure.

17.3 Furans (See Section 6.1.4 for More on Furans)

When cellulose insulation decomposes due to overheating, chemicals, in addition to CO_2 and CO, are released and dissolved in the oil. These chemical compounds are known as furanic compounds or furans. The most important one, for our purposes, is 2-furfuraldehyde. When DGAs are required, always request that furans testing be completed by the laboratory to check for paper deterioration. In healthy transformers, there are no detectable furans in the oil, or they are less than 100 ppb. In cases where significant damage to paper insulation from heat has occurred, furan levels have been found to be at least 100 ppb and up to 70,000 ppb. Use the furan numbers in table 6, below, for assessment; do not base any evaluation on only one test; use several DGAs over a period of time to develop trending. See *An Introduction to the Half-Century Transformer* by the Transformer Maintenance Institute, S.D. Myers Co., 2002 [19]. The first column in table 6 is used for transformers with nonthermally upgraded paper, and the second column is for transformers with thermally upgraded paper.

Table 6.—Furans, DP, Percent of Life Used, of Paper Insulation

55 °C Rise Transformer 2FAL (ppb)	65 °C Rise Transformer Total Furans (ppb)	Estimated Degree of Polymerization (DP)	Estimated Percentage of Remaining Life	Interpretation
58	51	800	100	Normal Aging Rate
130	100	700	90	
292	195	600	79	
654	381	500	66	Accelerated Aging Rate
1,464	745	400	50	
1,720	852	380	46	
2,021	974	360	42	
2,374	1,113	340	38	Excessive Aging Danger Zone
2,789	1,273	320	33	
3,277	1,455	300	29	
3,851	1,664	280	24	High Risk of Failure
4,524	1,902	260	19	
5,315	2,175	240	13	End of Expected Life of Paper Insulation and of the Transformer
6,245	2,487	220	7	
7,337	2,843	200	0	

Testing is done for five different furans which are caused by different problems. The five furans and their most common causes are listed below:

5H2F (5-hydroxymethyl-2-furaldehyde) caused by oxidation (aging and heating) of the paper

2FOL (2-furfurol) caused by high moisture in the paper

2FAL (2-furaldehyde) caused by overheating

2ACF (2-acetylfuran) caused by lightning (rarely found in DGA)

5M2F (5-methyl-2-furaldehyde) caused by local severe overheating (hotspot)

18. ESTIMATE OF PAPER DETERIORATION (OFFLINE DURING INTERNAL INSPECTION)

18.1 Degree of Polymerization (DP)

Do not open a transformer for the sole purpose of doing this test. Perform this test only if the unit is being opened for other reasons. See the reasons for an internal inspection in section 19.

18.2 Background

One of the most dependable means of determining paper deterioration and remaining life is the DP test of the cellulose. The cellulose molecule is made up of a long chain of glucose rings which form the mechanical strength of the molecule and the paper. DP is the average number of these rings in the molecule. As paper ages or deteriorates from heat, acids, oxygen, and water, the number of these rings decrease. When the insulation is new, the DP is typically between 1,000 and 1,400. As paper deteriorates, bonds between the rings begin to break. When the DP reaches around 200, the insulation has reached the end of life. All mechanical strength of the insulation has been lost; the transformer must be replaced.

18.3 Process

When doing an internal inspection, or if the transformer is opened and oil is fully or partially drained for any reason on a service aged transformer, perform a DP test. Remove a sample of the paper insulation about 1 centimeter square from a convenient location near the top of center phase with a pair of tweezers. In general, in a three-phase transformer, the hottest most thermally aged paper will be at the top of the center phase. If it is not possible to take a sample from the center phase, take a sample from the top of one of the other phases. Send this sample to an oil testing laboratory for the DP test. Analyze results of the DP test with the table below taken from EPRI's *Guidelines for the Life Extension of Substations,* 2002 Update, chapter 3. Table 7, below, has been developed by EPRI to estimate remaining life.

Table 7.—DP Values for Estimating Remaining Paper Life

New insulation	1,000 DP to 1,400 DP
60% to 66% life remaining	500 DP
30% life remaining	300 DP
0 life remaining	200 DP

19. INTERNAL INSPECTION

19.1 Background

If an internal inspection is absolutely necessary, it must be completed by an experienced person who knows exactly what to look for and where to look. Many times, more damage is done by opening a transformer and doing an internal inspection than what is gained. There are very few reasons for an internal inspection; some are shown below:

— Extensive testing shows serious problems.

— Unexplained relay operation takes the transformer offline, and testing is inconclusive.

— Acetylene is being generated in the DGA (indicates active internal arcing).

— Ethylene and ethane are being generated in sufficient quantities to cause grave concern. This generally indicates a bad connection on a bushing bottom or tap changer, circulating currents, additional core ground, or static discharges.

— A core ground must be repaired, or an additional core ground has developed which must be removed.

— Vibration and ultrasonic analysis indicate loose windings that are generating gases from heat caused by friction of the vibrating coils; loose wedges must be located and replaced.

— CO_2/CO ratio are very low (around 2 or 3), indicating severe paper deterioration from overheating. Cooling must be checked carefully before opening the transformer.

— Furans are high (see section 17.3), indicating excessive aging rate; a DP test must be completed.

— The metal particle count is above 5,000 in 10 milliliters of oil taken specifically for detecting metal particle count. (See EPRI's *Guidelines for the Life Extension of Substations,* 2002 Update [14] for exact procedures for detecting and correcting metal particle contamination).

NOTE:

If a service-aged transformer is opened for any reason, a sample of the paper should be taken for DP analysis. If possible, take the paper sample from the top of the center phase winding because this will be near the hot spot. If it is not possible to get a paper sample from the top of B phase, take a sample from the top of one of the other windings.

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20. TRANSFORMER BORESCOPE

A new technology has been developed for internal transformer inspections using a specifically designed borescope. The borescope can be used with oil inside the transformer; core, windings, connections, etc., can be examined and photographed. If it is necessary to go inside the transformer for repairs, workers will possibly know exactly what is defective and exactly what must be done. This technology, used properly, can save generating time and repair dollars.

Currently, this technology is available only as a contracting service. However, plans are being made by the developing company to make the instrument available for sale.

21. TRANSFORMER OPERATING HISTORY

21.1 Background

One of the most important transformer diagnostic tools is the operating history including temperatures, overload history (especially through faults), relay operations, and nearby lightning strikes. Many times, a though fault or nearby lightning strike will generate acetylene or ethylene and other gases, and these will remain in future DGAs. Through faults (i.e., where fault current passes through the windings) subject a transformer to severe electrical and mechanical stresses which can degrade insulation and mechanical strength. Likewise, close-in lightning strikes subject the transformer to stresses. Excessive heating caused by sustained overloads or loss of cooling will degrade insulation. The damage may not be immediately evident but can show up years later. Through faults, overload history, and temperatures should be in operations records, and a review of these is required when diagnosing a transformer problem.

22. TRANSFORMER DIAGNOSTICS/CONDITION ASSESSMENT SUMMARY

A summary of diagnostic techniques is given below in table 8.

Table 8.—Reclamation Transformer Condition Assessment Summary

Tests	Detects	Tools
Online Tests		
Dissolved Gas Analysis (Laboratory and Portable)	Measures dissolved gasses: to detect, arcing, bad electrical contacts, hot spots, partial discharges, overheating of conductors, oil, tank, cellulose (paper insulation).	Portable Gas -In - Oil Analyzer with software[1] (e.g., Morgan Schaffer P200 and Transformer Oil Analyst software). Note: The P200 does not measure oxygen and nitrogen. Or send to an oil testing laboratory for DGA.
Oil Physical and Chemical Tests	Moisture, interfacial tension, acidity, furans, dissolved metals, and metal particle count (indicates pump problems). Analyzes paper and oil condition.	Requires laboratory analysis.
Physical Inspection - External	Oil leaks, broken parts, worn paint, defective support structure, malfunctioning temperature and level indicators, cooling problems, pump and radiator problems, bushing and lightning arrester porcelain cracks, etc.	Experienced staff, binoculars for bushing, and lightning arrester porcelain cracks and loose bolts.
Infrared Scan	Hot spots, localized heating, bad connections, circulating currents, blocked cooling, tap changer problems, bushing and lightning arrester problems.	Trained and experienced staff with Thermographic Camera and Analysis Software.[1]
Ultrasonic and Sonic Contact Fault Detection	Internal partial discharge, arcing, sparking, pump impeller and bearing problems. Mechanical noises, loose parts (blocking, deflectors, etc.).	Fault detector with data logger.[1]
Ultrasonic Non-Contact and Contact Fault Detection	Nitrogen leaks, vacuum leaks, corona at bushings, pump mechanical and bearing problems, cooling fan problems.	Ultrasonic probe and meter (e.g., UltraProbe 2000).
Vibration Analysis	Internal core, shield problems. Loose parts vibration.	Vibration data logger.[1]
External Temperatures (Main Tank)	Temperature monitoring with changes in load and ambient temperature.	Portable temperature data loggers and software. [1]
Sound Level	Internal and external noises to compare to baseline and other vibration tests.	Sound level meter[1] (e.g., Quest 2400 Sound Meter).
Corona	Compare bushings and lightning arresters and all high voltage connections with sister units.	Corona Scope,[1] Model CS-01-A.

Table 8.—Reclamation Transformer Condition Assessment Summary (continued)

Tests	Detects	Tools
OFFLINE TESTS		
Doble Power Factor	Loss of winding insulation integrity. Loss of bushing insulation integrity. Winding moisture.	Doble test equipment.
Excitation Current	Shorted turns in the windings.	Doble test equipment.
Turns Ratio	Shorted windings.	Turns ratio tester (e.g., Biddle 55005).
Leakage Reactance	Measures percent impedance, to be compared to name plate after moving or through fault.	Doble test equipment.
Sweep Frequency Response Analysis	Structural problems, core and winding problems, movement of core and windings. Run this test before and after moving and after a through fault.	Doble M5100 sweep frequency response analyzer.
Across Winding Resistance Measurements	Broken strands, loose connections, bad contacts in tap changer.	Wheatstone Bridge (1 ohm and greater). Kelvin Bridge (less than 1 ohm).
Winding DC Resistance to Ground	Winding low resistance to ground (leakage current).	Megger®.[1]
Core to Ground Resistance[2]	Bad connection on intentional core ground or existence of unintentional grounds.	Megger®.[1]
Internal Inspections and Tests	Oil sludging, displaced winding or wedging, loose windings, bad connections, burned conductors.	Experienced staff, micro-ohm meter and/or Foster Miller Borescope.
Degree of Polymerization	Insulation condition (life expectancy).	Laboratory analysis of paper sample.

[1] This equipment is available from the Hydroelectric Research and Technical Services Group.

[2] External test may be possible depending on transformer construction.

APPENDIX

HYDRO PLANT RISK ASSESSMENT GUIDE

Transformer Condition Assessment

1. GENERAL

Power transformers are key components in the power train at hydroelectric powerplants and are appropriate for analysis under a risk assessment program. Transformer failure can have a significant economic impact due to long lead times in procurement, manufacturing, and installation in addition to high equipment cost. According to the Electric Power Research Institute (EPRI): "Extending the useful life of power transformers is the single most important strategy for increasing life of power transmission and distribution infrastructures starting with generator step-up transformers (GSU) at the powerplant itself"(EPRI Report No. 1001938).

Determining the existing condition of power transformers is an essential step in analyzing the risk of failure. This chapter provides a process for arriving at a Transformer Condition Index. This condition index may be used as an input to the risk-and-economic analysis computer model where it adjusts transformer life expectancy curves. The output of the economic analysis is a set of alternative scenarios, including costs and benefits, intended for management decisions on replacement or rehabilitation.

2 SCOPE/APPLICATION

The transformer condition assessment methodology outlined in this chapter applies to oil-filled, power transformers (> 500 kilovoltampere [kVA]) currently in operation.

This guide is not intended to define transformer maintenance practices or describe in detail transformer condition assessment inspections, tests, or measurements. Utility maintenance policies and procedures must be consulted for such information.

3. CONDITION INDICATORS AND TRANSFORMER CONDITION INDEX

This guide describes four Condition Indicators generally regarded by hydro powerplant engineers as a sound basis for assessing transformer condition.

— Insulating Oil Analysis (Dissolved Gas Analysis [DGA] and Furan)

— Power Factor and Excitation Current Tests

— Operation and Maintenance (O&M) History

— Age

These indicators are based on "Tier 1" inspections, tests, and measurements conducted by utility staff or contractors over the course of time. The indicators are expressed in numerical terms and are used to arrive at an overall Transformer Condition Index.

The guide also describes a "toolbox" of Tier 2 inspections, tests, and measurements that may be applied, depending on the specific problem being addressed. Results of Tier 2 may modify the score of the Transformer Condition Index.

After review by a transformer expert, the Condition Index is suitable for use as an input to the risk and economic analysis model.

4. INSPECTIONS, TESTING, AND MEASUREMENTS

The hierarchy of inspections, tests, and measurements is illustrated in figure 1 (Transformer Condition Assessment Methodology). Table 14 (Transformer Condition Assessment Summary) summarizes these activities.

Inspections, tests, and measurements ("tests") performed to determine transformer condition are divided into two tiers or levels. Tier 1 tests are those that are routinely accomplished as part of normal operation and maintenance or are readily discernible by examination of existing data. Results of Tier 1 tests are quantified below as Condition Indicator Scores that are weighted and summed to arrive at a Transformer Condition Index. Tier 1 tests may indicate abnormal conditions that can be resolved with standard corrective maintenance solutions. Tier 1 tests results may also indicate the need for additional investigation, categorized as Tier 2 tests.

Tier 2 tests are considered nonroutine. Tier 2 test results may affect the Transformer Condition Index established using Tier 1 tests but also may confirm or disprove the need for more extensive maintenance, rehabilitation, or transformer replacement.

Inspection, testing, and measurement methods are specified in technical references specific to the electric utility.

This guide assumes that Tier 1 and Tier 2 inspections, tests, and measurements are conducted and analyzed by staff suitably trained and experienced in transformer diagnostics. In the case of more basic tests, this may be qualified staff who are competent in these routine procedures. More complex inspections and measurements may require a transformer diagnostics "expert."

This guide also assumes that inspections, tests, and measurements are conducted on a frequency that provides accurate and current information needed by the assessment. In some cases, it may be necessary to conduct tests prior to this assessment to acquire current data.

NOTE:

A severely negative result of ANY inspection, test, or measurement may be adequate in itself to require immediate de-energization, or prevent re-energization, of the transformer regardless of the Transformer Condition Index score.

Transformer condition assessment may cause concern that justifies more frequent monitoring. Utilities should consider the possibility of taking more frequent measurements (e.g., oil samples) or the installation of online monitoring systems (e.g., gas-in-oil) that will continuously track critical quantities. This will provide additional data for condition assessment and establish a certain amount of reassurance as transformer alternatives are being explored.

5. SCORING

Transformer Condition Indicator scoring is somewhat subjective, relying on transformer condition experts. Relative terms such as "results normal" and "degradation" refer to results that are compared to:

— Industry accepted levels

— Baseline or previous (acceptable) levels on this equipment

— Equipment of similar design, construction, or age operating in a similar environment

6. WEIGHTING FACTORS

Weighting factors used in the condition assessment methodology recognize that some Condition Indicators affect the Transformer Condition Index to a greater or lesser degree than other indicators. These weighting factors were arrived at by consensus among transformer design and maintenance personnel with extensive experience.

7. MITIGATING FACTORS

Every transformer is unique; therefore, the methodology described in this chapter cannot quantify all factors that affect individual transformer condition. It is important that the Transformer Condition Index arrived at be scrutinized by engineering experts. Mitigating factors specific to the utility may determine the final Condition Index and the final decision on transformer replacement or rehabilitation.

8. DOCUMENTATION

Substantiating documentation is essential to support findings of the assessment, particularly where a Tier 1 Condition Indicator score is less than 3 or where a Tier 2 tests result in subtractions from the Transformer Condition Index. Test results and reports, photographs, O&M records, or other documentation should accompany the Transformer Condition Assessment Summary Form.

9. CONDITION ASSESSMENT METHODOLOGY

The condition assessment methodology consists of analyzing each Condition Indicator individually to arrive at a Condition Indicator Score; then the score is weighted and summed with scores from other condition indicators. The sum is the Transformer Condition Index. Apply the Condition Index to the Alternatives table (table 15) to determine the recommended course of action.

Reasonable efforts should be made to perform Tier 1 inspections, tests, and measurements. However, when data is missing to properly score the Condition Indicator, it may be assumed that the score is “Good” or numerically some mid-range number such as 2.

CAUTION:

This strategy should be used judiciously to prevent deceptive results.

10. TIER ONE – INSPECTIONS, TESTS, MEASUREMENTS

Tier 1 “tests” inspections, tests, and measurements routinely accomplished as part of normal O&M are readily discernible by examination of existing data. Tier 1 test results are quantified below as Condition Indicators that are weighted and summed to arrive at a Transformer Condition Index. Tier 1 inspections, tests, and measurements may indicate abnormal conditions that can be resolved with standard corrective maintenance solutions. Tier 1 test results may also indicate the need for additional investigation, categorized as Tier 2 tests.

Condition Indicator 1 – Insulating Oil Analysis

Dissolved gas analysis is the most important factor in determining the condition of a transformer because, being performed more frequently than other tests, it may be the first indication of a problem. Insulating oil analysis can identify internal arcing; bad electrical contacts; hot spots; partial discharge; or overheating of conductors, oil, tank, or cellulose. The “health” of the oil is reflective of the health of the transformer itself. DGA consists of sending transformer insulating oil samples to a commercial laboratory for analysis. The most important indicator is the individual and total dissolved combustible gas (TDCG) generation rates, based on International Electrotechnical Commission (IEC) and Institute of Electrical and Electronic Engineers (IEEE®) standards. Although gas generation rates are not the only indicator, they are reasonable for use in determining the Condition Indicator Score.

Furanic analysis may indicate a problem with the paper insulation which could affect transformer longevity. A baseline furanic analysis should be made initially and repeated if the transformer is overheated, overloaded, aged, or after changing or processing the oil.

Physical tests such as interfacial tension (IFT), acidity, moisture content, and dielectric strength usually indicate oil conditions that can be remedied through various reclamation processes. Therefore, they are not indicative of overall transformer condition that would lead to replacement. Such tests do not affect the Insulating Oil Condition Indicator score.

Results are analyzed and applied to table 1 to arrive at a Condition Indicator Score.

Table 1.—Insulating Oil Analysis Scoring

Results	Condition Indicator Score
TDCG Generation Rate Less Than 30 parts per million per month (ppm/month) and: * All individual combustible gas generation less than 10 ppm/month * Exceptions: carbon monoxide (CO) generation less than 70 ppm/month and acetylene (C_2H_2) generation rate 0 ppm. (See Note below) **AND** Furans 150 parts per billion (ppb) or less.	3
TDCG generation rate between 30 and 60 ppm/month and: * All individual combustible gas generation rate less than 15 ppm/month. * Exceptions: CO generation rate less than 150 ppm/month and C_2H_2 generation rate 0 ppm. (See Note below.) **OR** Furans between 150 ppb and 200 ppb.	2
TDCG generation rate between 50 and 80 ppm/month and: * All individual combustible gas generation rates less than 25 ppm/month. * Exceptions: CO generation rate less than 350 ppm/month and C_2H_2 generation rate less than 5 ppm/month. (See Note below.) **OR** Furans between 200 ppb and 250 ppb.	1
TDCG generation rate greater than 80 ppm/month and: * Any individual combustible gas generation rate more than 50 ppm/month. * Exceptions: CO generation more than 350 ppm/month and C_2H_2 generation rate no more than 10 ppm/per month. (See Note below.) **OR** Furans above 250 ppb.	0

The above DGA numbers are based on dissolved gas in oil generation rates and come from a combination of IEEE C57-104™, IEC 60599, and Delta X Research's Transformer Oil Analysis (TOA) software.

NOTE:

Any ongoing acetylene (C_2H_2) generation indicates an active arcing fault, and the transformer may have to be removed from service to avoid possible catastrophic failure. A transformer may be safely operated with some C_2H_2 showing in the DGA. C_2H_2 sometimes comes from a one-time event such as a close-in lightning strike or through fault. However, if C_2H_2 is increasing more than 10 ppm per month, the transformer should be removed from service. Because acetylene generation is a critical indicator of transformer internal condition, each utility should establish practices in accordance with published standards and transformer experts to monitor any increases in gas generation and take corrective action. Increasing the frequency of DGA analysis and de-gasifying the transformer oil are potential alternatives to consider.

Condition Indicator 2 – Power Factor and Excitation Current Tests

Power factor insulation testing is important to determining the condition of the transformer because it can detect winding and bushing insulation integrity. Power factor and excitation current tests are conducted in the field on de-energized, isolated, and properly grounded transformers. Excitation current tests measure the single-phase voltage, current, and phase angle between them, typically on the high-voltage side with the terminals of the other winding left floating (with the exception of a grounded neutral). The measurements are performed at rated frequency and usually at test voltages up to 10 kilovolts (kV). The test detects shorted turns, poor tap changer contacts, and core problems.

Results are analyzed and applied to table 2 to arrive at a Condition Indicator Score.

Condition Indicator 3 – Operation and Maintenance History

O&M history may indicate overall transformer condition. O&M history factors that may apply are:

- Sustained overloading.
- Unusual operating temperatures indicated by gauges and continuous monitoring.
- Abnormal temperatures indicated by infrared scanning.
- Nearby lightning strikes or through faults.

Table 2.—Power Factor and Excitation Current Test Scoring

Test Results[1]	Condition Indicator Score
Power factor results normal (Good - G) **AND** Normal excitation current values and patterns compared to other phases and prior tests.	3
Power factor results show minor degradation. (Deteriorated - D) **OR** Minor deviation[2] in excitation current values and patterns compared to other phases and prior tests.	2
Power factor results show significant deterioration. (Investigate - I) **OR** Significant deviation[2] in current values and patterns compared to other phases and prior tests.	1
Power factor results show severe degradation. (Bad –B) **OR** Severe deviation[2] in current values and patterns compared to other phases and prior tests.	May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.

[1] Doble insulation rating in parentheses.
[2] Be sure to account for residual magnetism and load tap changer (LTC).

— Abnormally high corona detected.

— Abnormally high external temperatures detected.

— Problems with auxiliary systems (fans, radiators, cooling water piping, pumps, motors, controls, nitrogen replenishment system, and indicating and protection devices).

— Deteriorated control and protection wiring and devices.

— Increase in corrective maintenance or difficulty in acquiring spare parts.

— Anomalies determined by physical inspection (external inspection or internal inspection not requiring untanking) (e.g., incorrectly positioned valves, plugged radiators, stuck temperature indicators and level gauges, noisy oil pumps or fans, oil leaks, connections to bushings).

— Previous failures on this equipment.

— Failures or problems on equipment of similar design, construction, or age operating in a similar environment.

Qualified personnel should make a subjective determination of scoring that encompasses as many O&M factors as possible under this Indicator.

Results are analyzed and applied to table 3 to arrive at a Condition Indicator Score.

Table 3.—Operation and Maintenance History Scoring

History Results	Condition Indicator Score
Operation and maintenance are normal.	3
Some abnormal operating conditions experienced and / or additional maintenance above normal occurring.	2
Significant operation outside normal and/or significant additional maintenance is required; or forced outage occurs; or outages are regularly extended due to maintenance problems; or similar units are problematic.	1
Repeated forced outages; maintenance not cost effective; or major oil leaks and/or severe mechanical problems; or similar units have failed.	0

Condition Indicator 4 – Age

Transformer age is an important factor to consider when identifying candidates for transformer replacement. Age is one indicator of remaining life and upgrade potential to current state-of-the-art materials. During the life of the transformer, the structural and insulating properties of materials used for structural support and electrical insulation, especially wood and paper, deteriorate. Although actual service life varies widely depending on the manufacturer's design, quality of assembly, materials used, operating history, current operating conditions, and maintenance history, the average expected life for an individual transformer in a large population of transformer is statistically about 40 years.

Apply the transformer age to table 4 to arrive at the Condition Indicator Score.

Table 4.—Age Scoring

Age	Condition Indicator Score
Under 30 years	3
30 – 45 years	2
Over 45 years	1

11. TIER 1 - TRANSFORMER CONDITION INDEX CALCULATIONS

Enter the Condition Indicator Scores from the tables above into the Transformer Condition Assessment Summary form at the end of this chapter. Multiply each Condition Indicator Score by the Weighting Factor, and sum the Total Scores to arrive at the Tier 1 Transformer Condition Index. This index may be adjusted by the Tier 2 inspections, tests, and measurements described below. Suggested alternatives for followup action, based on the Transformer Condition Index, are described in the Transformer Condition-Based Alternatives at the end of this chapter.

12. TIER 2 - INSPECTIONS, TESTS, MEASUREMENTS

Tier 2 inspections, tests, and measurements generally require specialized equipment or training, may be intrusive, or may require an extended outage to perform. Tier 2 assessment is considered nonroutine. Tier 2 inspections may affect the Transformer Condition Index number established using Tier 1 but also may confirm or refute the need for more extensive maintenance, rehabilitation, or transformer replacement.

For each Tier 2 inspection, test, or measurement performed, subtract the appropriate amount from the appropriate Tier 1 Condition Indicator and recalculate the Transformer Condition Index using the Transformer Condition Assessment Survey Form at the end of this document.

Test T2.1: Turns Ratio Test

The transformer turns ratio (TTR) test detects shorts between turns of the same coil, which indicates insulation failure between the turns. These tests are performed with the transformer de-energized and may show the necessity for an internal inspection or removal from service.

Results are analyzed and applied to table 5 to arrive at a Transformer Condition Index score adjustment.

Table 5.—Turns Ratio Test Scoring

Test Results	Adjustment to Transformer Condition Index
Less than 0.20% difference from nameplate V_1/V_2 and compared to previous readings.	No change
0.20% to 0.50% difference compared to nameplate V_1/V_2.	Subtract 1.0
Greater than 0.5% difference compared to nameplate V_1/V_2.	May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.

Test T2.2: Short Circuit Impedance Tests

Sometimes called Percent Impedance or Leakage Reactance, these tests are conducted in the field and compared to nameplate information, previous tests, and similar units to detect deformation of the core or windings caused by shipping damage, through faults, or ground faults. Some difference may be expected between nameplate and field test results because factory tests are conducted at full load current, normally not possible in the field. Field connections and test leads and jumpers also play a significant role in test results, and it is impossible to exactly duplicate the factory test setup. Therefore, the I^2R losses may be different and cause different test results. By comparing percent-reactance to nameplate impedance, the differences caused by leads and connections can be eliminated. Because reactance is only the inductive component of the impedance, I^2R losses are omitted in the test results.

Results are analyzed and applied to table 6 to arrive at a Transformer Condition Index score adjustment.

Table 6.—Short Circuit Test Scoring

Test Results	Condition Indicator Score
Less than 1% difference from nameplate impedance.	No change
1% to 3% difference from nameplate impedance (minor degradation).	Subtract 0.5
3% to 5% difference from nameplate impedance (significant degradation).	Subtract 1.0
Greater than 5% difference from nameplate impedance (severe degradation).	May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.

Test T2.3: Core-to-Ground Resistance Megger® Tests

The transformer core is intentionally grounded through one connection. The core-to-ground resistance test can detect if this connection is loose. It can also detect whether there are other, undesired and inadvertent, grounds. If the intentional core ground is intact, the resultant resistance should be very low. To check for unintentional core grounds, remove the intentional ground and Megger® between the core and the grounded transformer tank. This test should produce very high resistance indicating that an unintentional ground is not present. This test is to supplement DGA that shows generation of hot metal gases (methane, ethane, ethylene) and to indicate if a spurious, unintentional core ground is the problem. Experience can help locate the source of the problem.

Results are analyzed and applied to table 7 to arrive at a Transformer Condition Index score adjustment.

Table 7.—Core-to-Ground Resistance Test Scoring

Test Results[1]	Adjustment to Transformer Condition Index
Greater than 1,000 megohms[1] (results normal)	3
600 to 900 megohms	2
200 to 500 megohms	1
Less than 200 megohms	May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.

[1] With intentional ground disconnected.

Test T2.4: Winding Direct-Current Resistance Measurements

Careful measurement of winding resistance can detect broken conductor strands, loose connections, and bad contacts in the tap changer (de-energized tap changer [DETC] or LTC). Results from these measurements may indicate the need for an internal inspection. This information supplements DGA and is useful when DGA shows generation of heat gases (ethane, ethylene, methane). These tests are typically performed with a micro-ohmmeter and or Wheatstone bridge. Test results are compared between phases or with factory tests. When comparing to factory tests, a temperature correction must be employed (IEEE P62™). This test should be performed only after the rest of the routine electrical tests because it may magnetize the core, affecting results of the other tests.

Results are analyzed and applied to table 8 to arrive at a Transformer Condition Index score adjustment.

Test T2.5: Ultrasonic and Sonic Fault Detection Measurements

These assessment tests (sometimes called Acoustic Testing) are helpful in locating internal faults. Partial discharges (corona) and low energy arcing/sparking emit energy in the range of 50 megahertz (ultrasonic), well above audible sound. To make these measurements, sensors are placed on the outside of a transformer tank to detect these ultrasonic emissions which are then converted electronically to oscilloscope traces or audible frequencies and recorded. By triangulation, a general location of a fault (corona or arcing/sparking) may be determined so that an internal

Table 8.—Winding Direct-Current Resistance Measurement Scoring

Measurement Results[1]	Adjustment to Transformer Condition Index
No more than 5% difference between phases or from factory tests.	No change
5% to 7% difference between phases or from factory tests.	Subtract 0.5
7% to 10% difference between phases or from factory tests.	Subtract 1.0
More than 10% between phases or from factory tests.	May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.

inspection can be focused in that location. These devices also can detect loose shields that build up static and discharge it to the grounded tank; poor connections on bushings; bad contacts on a tap changer that are arcing/sparking; core ground problems that cause sparking/arcing; and areas of weak insulation that generate corona. Sonic testing can detect increased core and coil noise (looseness) and vibration, failing bearings in oil pumps and fans, and nitrogen leaks in nitrogen blanketed transformers.

Information gained from these measurements supplements DGA, and provides additional support information for de-energized tests such as core ground and winding resistance tests. In addition, these tests help pinpoint areas to look for problems during internal inspections.

Performing baseline tests may provide comparisons for later tests. Experience can help locate the source of the problem.

Results are analyzed and applied to table 9 to arrive at a Transformer Condition Index score adjustment.

Test T2.6: Vibration Analysis

Vibration can result from loose transformer core and coil segments, shield problems, loose parts, or bad bearings on oil cooling pumps or fans. Vibration analyzers are used to detect and measure the vibration. Information gained from these tests supplements ultrasonic and sonic (acoustic) fault detection tests and DGA. Information from these tests may indicate maintenance is needed on pumps/fans mounted external to the tank. It may also show when an internal transformer inspection is necessary. If wedging has been displaced due to paper deterioration or through faults, vibration will increase markedly. This will also

Table 9.—Ultrasonic and Sonic Measurement Scoring

Measurement Results	Adjustment to Transformer Condition Index
Results normal	No change
Low level fault indication	Subtract 0.5
Moderate level fault indication	Subtract 1.0
Severe fault level indication	Subtract 2.0

show if core and coil vibration has increased compared to baseline information. Experience can help locate the source of the problem.

Results are analyzed and applied to table 10 to arrive at a Transformer Condition Index score adjustment.

Table 10.—Vibration Analysis Scoring

Analysis Results	Adjustment to Transformer Condition Index
Results normal	No change
Low level fault indication	Subtract 0.5
Moderate level fault indication	Subtract 1.0
Severe fault level indication	Subtract 2.0

Test T2.7: Frequency Response Analysis (FRA)

Frequency Response Analysis (or Sweep Frequency Response Analysis) can determine if windings of a transformer have moved or shifted. It can be completed as a factory test prior to shipment and repeated after the transformer is received onsite to determine if windings have been damaged or shifted during shipping. This test is also helpful if a protective relay has tripped or a through fault, short circuit, or ground fault has occurred

A sweep frequency is generally placed on each of the high voltage windings, and the signal is detected on the low-voltage windings. This provides a picture of the frequency transfer function of the windings. If the windings have been displaced or shifted, test results will differ markedly from prior tests. Test results are kept in transformer history files so they can be compared to later tests.

Results are determined by comparison to baseline or previous measurements or comparison to units of similar design and construction.

Results are analyzed and applied to table 11 to arrive at a Transformer Condition Index score adjustment.

Table 11.—Frequency Response Analysis Scoring

Test Results	Adjustment to Transformer Condition Index
No deviation compared to prior tests.	No change
Minor deviation compared to prior tests.	Subtract 2.0
Moderate deviation compared to prior tests.	Subtract 3.0
Significant deviation compared to prior tests.	Subtract 4.0
Severe deviation compared to prior tests.	May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.

Test T2.8: Internal Inspection

In some cases, it is necessary to open, partially or fully drain the oil, and perform an internal inspection to determine transformer condition. These inspections must be performed by experienced staff with proper training. Sludging, loose wedges, loose coils, poor electrical connections on bushing bottoms, burned contacts on tap changers, localized overheating signified by carbon buildup, displaced wedging or insulation, and debris and other foreign material are general areas of concern. Photographs and mapping problem locations are good means of documenting findings. Before entering and while inside the transformer, the Occupational Safety and Health Administration, State, local, and utility safety practices must be followed (e.g., "permitted confined space" entry practices).

Results are analyzed and applied to table 12 to arrive at a Transformer Condition Index score adjustment.

Table 12.—Internal Inspection Scoring

Inspection Results	Adjustment to Transformer Condition Index
Conditions normal	No change
Minimal degradation	Subtract 0.5
Moderate degradation	Subtract 1.5
Severe degradation	May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.

Test T2.9: Degree of Polymerization

Winding insulation (cellulose) deterioration can be quantified by analysis of the degree of polymerization (DP) of the insulating material. This test gives an indication of the remaining structural strength of the paper insulation and is an excellent indication of the remaining life of the paper and the transformer itself. This requires analyzing a sample of the paper insulation in a laboratory to determine the deterioration of the molecular bonds of the paper.

Results are analyzed and applied to table 13 to arrive at a Transformer Condition Index score adjustment.

Table 13.—Degree of Polymerization Scoring

Test Results	Adjustment to Transformer Condition Index
900 or higher no polymerization decrease (results normal)	No change
800-700 (minimal polymerization decrease)	Subtract 0.5
600-300 (moderate polymerization decrease)	Subtract 1.5
$\leq$200 (severe polymerization decrease—insulation has no mechanical strength; end of life)	May indicate serious problem requiring immediate evaluation, additional testing, consultation with experts, and remediation prior to re-energization.

13. TIER 2 – TRANSFORMER CONDITION INDEX CALCULATIONS

Enter the Tier 2 adjustments from the tables above into the Transformer Condition Assessment Summary form at the end of this chapter. Subtract the sum of these adjustments from the Tier 1 Transformer Condition Index to arrive at the total Transformer Condition Index. Suggested alternatives for followup action, based on the Transformer Condition Index, are described in the Transformer Condition-Based Alternatives located at the end of this chapter.

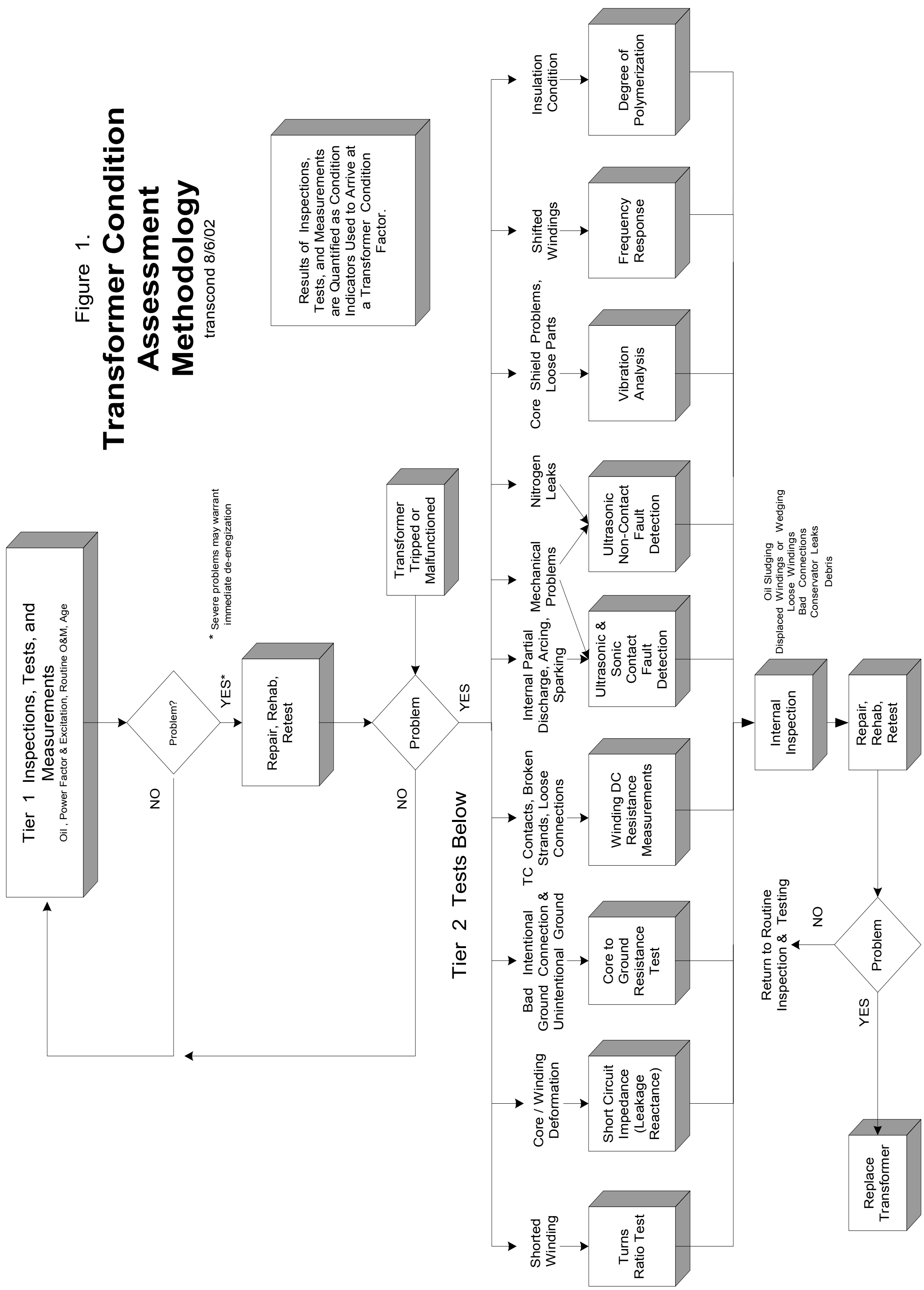
Figure 1.
Transformer Condition Assessment Methodology
transcond 8/6/02
Results of Inspections, Tests, and Measurements are Quantified as Condition Indicators Used to Arrive at a Transformer Condition Factor.
Tier 1 Inspections, Tests, and Measurements
Oil , Power Factor & Excitation, Routine O&M, Age
Problem?
YES*
NO
Repair, Rehab, Retest
* Severe problems may warrant immediate de-energization
Transformer Tripped or Malfunctioned
Problem
YES
NO
Tier 2 Tests Below
Shorted Winding
Turns Ratio Test
Core / Winding Deformation
Short Circuit Impedance (Leakage Reactance)
Bad Intentional Ground Connection & Unintentional Ground
Core to Ground Resistance Test
TC Contacts, Broken Strands, Loose Connections
Winding DC Resistance Measurements
Internal Partial Discharge, Arcing, Sparking
Ultrasonic & Sonic Contact Fault Detection
Mechanical Problems
Nitrogen Leaks
Ultrasonic Non-Contact Fault Detection
Core Shield Problems, Loose Parts
Vibration Analysis
Shifted Windings
Frequency Response
Insulation Condition
Degree of Polymerization
Oil Sludging
Displaced Windings or Wedging
Loose Windings
Bad Connections
Conservator Leaks
Debris
Internal Inspection
Repair, Rehab, Retest
Problem
NO
Return to Routine Inspection & Testing
YES
Replace Transformer

Table 14.—Transformer Condition Assessment Summary

Test	Detects	Tool
Online Tests		
Dissolved Gas Analysis	Internal arcing; bad electrical contacts; hot spots; partial discharge; and overheating of conductors, oil, tank, and cellulose insulation.	Requires laboratory analysis.
Oil Physical and Chemical Tests	Moisture, degraded IFT, acidity, furans, dielectric strength, and power factor.	Requires laboratory analysis.
External Physical Inspection	Oil leaks, broken parts, worn paint, defective support structure, stuck indicators, noisy operation, loose connections, cooling problems with fans, pumps, etc.	Experienced staff and binoculars.
External Temperatures (Main tank and load tap changer)	Temperature monitoring with changes in load and ambient temperature.	Portable temperature data loggers and software.
Infrared Scan	Hot spots indicating localized heating, circulating currents, blocked cooling, tap changer problems, and loose connections.	Thermographic camera and analysis software.
Ultrasonic (Acoustic) Contact Fault Detection	Internal partial discharge, arcing, sparking, loose shields, poor bushing connections, bad tap changer contacts, core ground problems, and weak insulation that is causing corona.	Ultrasonic detectors and analysis software.
Sonic Fault Detection	Nitrogen leaks, vacuum leaks, core and coil vibration, corona at bushings, and mechanical and bearing problems in pumps and cooling fans.	Ultrasonic probe and meter.
Vibration Analysis	Internal core, coil, and shield problems; loose parts and bad bearings.	Vibration data logger.
Offline Tests		
Doble Tests (bushing capacitance, insulation power factor, tip up, excitation current)	Loss of winding insulation integrity, loss of bushing insulation integrity, and winding moisture.	Doble test equipment.
Turns Ratio	Shorted windings.	Doble test equipment or turns ratio tester.
Short Circuit Impedance	Deformation of the core or winding.	Doble or equivalent test equipment.
Core to Ground Resistance (External test may be possible depending on transformer construction)	Bad connection on intentional core ground and existence of unintentional grounds.	Megger®.
Winding Direct Current (dc) Resistance Measurements	Broken strands, loose connections, bad tap changer contacts.	Wheatstone Bridge (1 ohm and greater). Kelvin Bridge micro-ohmmeter (less than 1 ohm).
Frequency Response Analysis	Shifted windings.	Doble or equivalent sweep frequency analyzer.
Internal Inspection	Oil sludging, displaced winding or wedging, loose windings, bad connections, localized heating, debris and foreign objects.	Experienced staff, micro-ohmmeter.
Degree of Polymerization	Insulation condition (life expectancy).	Laboratory analysis of paper sample.

TRANSFORMER CONDITION ASSESSMENT SUMMARY FORM

Date: ______________________ Transformer Identifier: ______________________
Location: ______________________ Manufacturer: ________ Yr. Mfd: __________
No. of Phases: _________ MVA: _________ Voltage: ______________________

Tier 1 Transformer Condition Summary

Indicator No.	Indicator	Score	X Weighting Factor =	Total Score
1	Oil Analysis		1.143	
2	Power Factor and Excitation Current Tests		0.952	
3	Operation and Maintenance History		0.762	
4	Age		0.476	
	Tier 1 Transformer Condition Index (sum of individual Total Scores)			(Between 0 and 10)

Tier 2 Transformer Condition Summary

Tier 2 Test	Adjustment to Tier 1 Condition Index
T2.1 Turns Ratio Test	
T2.2 Short Circuit Impedance Test	
T2.3 Core-to-Ground Resistance Megger® Test	
T2.4 Winding DC Resistance Measurement	
T2.5 Ultrasonic and Sonic Fault Detection Measurement	
T2.6 Vibration Analysis	
T2.7 Frequency Response Analysis	
T2.8 Internal Inspection	
T2.9 Degree of Polymerization	
Tier 2 Adjustments to Transformer Condition Index (Sum of individual adjustments)	

To calculate the net Transformer Condition Index, subtract the Tier 2 Adjustments from the Tier 1 Condition Index:

Tier 1 Transformer Condition Index __________
minus **Tier 2 Adjustments** __________ = _____________
Net Transformer Condition Index

Evaluator: ___________________________
Technical Review: ___________________________ Management Review: ___________
Copies to: ________________________________

Forward completed form, including supporting documentation, to agency transformer expert.

14. TRANSFORMER ALTERNATIVES

After review by a transformer expert, the Transformer Condition Index—either modified by Tier 2 tests or not—may be sufficient for decisionmaking regarding transformer alternatives. The index is also suitable for use in the risk-and-economic analysis model described elsewhere in this guide. Where it is desired to consider alternatives based solely on transformer condition, the Transformer Condition Index may be directly applied to table 15.

Table 15.—Transformer Condition-Based Alternatives

Transformer Condition Index Range	Suggested Course of Action
8-10 (Good)	Continue O&M without restriction. Repeat this condition assessment process as needed.
4-7 (Fair)	Continue operation but re-evaluate O&M practices. Consider using appropriate Tier 2 tests. Conduct full Life Extension risk-economic assessment. Repeat this condition assessment process as needed.
0-3 (Poor)	Immediate evaluation including additional Tier 2 testing. Consultation with experts. Adjust O&M as prudent. Begin replacement/rehabilitation process.

Acronyms and Abbreviations

AC	alternating current
ANSI	American National Standards Institute
ASTM	American Society for Testing and Materials
C1	Capacitance between the bushing top and the bottom tap
C2	Capacitance between the bottom tap of a bushing and ground
CH_4	methane
C_2H_2	acetylene
C_2H_4	ethylene
C_2H_6	ethane
CO	carbon monoxide
CO_2	carbon dioxide
°C	degrees Centigrade
dB	decibel
DBPC	Ditertiary Butyl Paracresol (oxygen inhibitor for transformer oil)
dc	direct current
DETC	de-energized tap changer
DGA	dissolved gas analysis
DP	Degree of Polymerization (measure of mechanical strength and remaining life of paper insulation).
EHV	extra high voltage (higher than 240,000 volts)
EPRI	Electric Power Research Institute
FIST	Facilities Instructions, Standards, and Techniques
FRA	Frequency Response Analyses
gm	gram
GSU	generator step up
H_2	hydrogen
Hz	hertz (cycles)
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronic Engineers
IFT	Interfacial Tension (between transformer oil and water; this is a measure of the amount of particles and pollution in transformer oil)
ips	inches per second
IR	infrared
I^2R	watts (watts loss measured by Doble testing)
kHz	kilohertz (kilocycles)
KOH	potassium hydroxide (used to determine acid number of transformer oil)
kV	kilovolts
LTC	load tap changer
kVA	kilovoltampere
mA	milliampere
M/DW	moisture by dry weight (percent of weight of water in paper insulation based on dry weight of paper given on transformer nameplate)
Mg	milligram
MHz	megahertz
NFPA	National Fire Protection Association
N_2	nitrogen
O&M	operation and maintenance
O_2	oxygen
PEB	Power Equipment Bulletin
ppb	parts per billion
ppm	parts per million
ppm/day	parts per million per day
RBILG	Reference Book for Insulating Liquids and Gases, Doble Engineering Co.
SFRA	Sweep Frequency Response Analysis
TCG	total combustible gas
TDCG	total dissolved combustible gas
TOA 5	Transformer Oil Analysis Software, version 5
TTR	transformer turns ratio
°C	degree Celcius
°F	degree Fahrenheit
%	percent