

Power Transformer Maintenance and Application Guide



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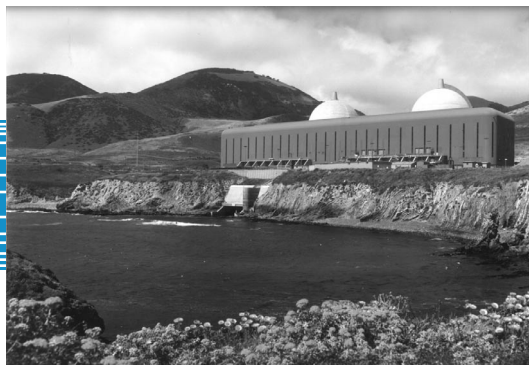
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Technical Report

Reduced
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Maintenance
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Power Transformer Maintenance and Application Guide

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Final Report, September 2002

EPRI Project Manager
W. E. Johnson

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REPORT SUMMARY

Background

Transformers are essential for power transmission and distribution. Without them, the modern transmission of electric power would not be very efficient. Transformers enable electric generating stations to supply power to the electric grid; they also enable plants to have access to an off-site power source for startup and refueling periods. They are very reliable pieces of equipment with many operating well beyond 20 years.

Many nuclear power plants have experienced failures with and/or damage to one or more of their large power transformers. Some of these failures can be tied directly to the lack of proper monitoring and maintenance of these transformers.

Objectives

- To provide maintenance guidance for power transformers at nuclear power plants, such as the generator step-up, unit auxiliary, and startup transformers
- To provide insight into the principal components used to make power transformers as well as the operating principles for transformers
- To cover maintenance on several key accessories such as the bus duct, cooling system, and transformer protection
- To provide the nuclear power plant maintenance and engineering personnel with comprehensive reliability, performance, and maintenance practices for power transformers

Approach

An analysis of industry failures, maintenance problems, and stressors such as temperatures, atmospheric conditions, and operating parameters, along with aging mechanisms, potential failure modes, and effect of degradation on components was performed. This information was used to better understand transformer failure mechanisms.

The team took advantage of the considerable amount of work done to identify phenomena associated with transformer failures, such as static electrification and geomagnetically induced currents, to identify the failure causes. Extensive work was been done to address condition monitoring techniques for transformers. The guide includes condition monitoring and preventive maintenance (PM) recommendations. Also, developing monitoring and diagnostic technologies were reviewed during this project.

Results

EPRI has developed this guide to provide a technical overview of transformers and a solid maintenance program that should help plants avoid untimely transformer failures. The design and construction of transformer components, such as tank, inert gas system, cores, insulation materials, oils, and instrumentation, are covered in this guide. This information should provide a basis for all plant personnel involved with transformers to build on. Certain support systems, for example, fire protection, inert gas, cooling, tap changers, lightning arrestors, bushings, bus duct, and current and potential transformers, are essential for reliable transformer operation. Warnings and precautions related to temperature rise, loss of cooling, low oil level, low gas pressure, and static electrification mitigation are some of the items that are provided to assist with understanding the impact on transformer operability and life.

Maintenance recommendations including condition assessment tests such as oil testing, insulation power factor, infrared thermography, routine inspections, cleaning, functional tests, and the recommended frequencies are provided. The storage and maintenance of spare transformers are addressed in this guide.

EPRI Perspective

With proper care, power transformers can provide reliable service well beyond their design life. The work that has been done to identify phenomena associated with transformer failures such as static electrification and geomagnetically induced currents have given transformer owners valuable tools for avoiding one set of operationally induced failures and one problem brought on by environmental concerns. Also, considerable work has been done to address condition monitoring techniques for transformers such as oil analysis. The guide presents a comprehensive collection of condition monitoring and PM recommendations; it also provides insight into the application of these techniques for the transformer owner. The information should assist users in avoiding untimely transformer failures and developing a solid maintenance program.

Keywords

Power transformer
Generator step-up
Startup transformer
Bushings
Bus duct

ABSTRACT

The increase in failures of main transformers at power plants has contributed significantly to plant unavailability across the industry. Many of these failures are caused by transformer components and support systems, such as fire protection spray system. Main transformers as defined by this report include generator step-up transformers (GSU), unit auxiliary (UAT) and station auxiliary transformers (SAT) [also known as reserve auxiliary transformers (RAT)].

This guide was developed based upon the operating experience at nuclear plants, vendor input, and other industry experience. This guide addresses power transformers and associated accessories including:

- Bus ducts
- Lightning arresters
- Tap changers
- Instruments
- Oil pumps
- Current and potential transformers
- Bushings
- Radiators
- Control panel components (for example, breakers, relays, terminal blocks, and heaters)

The information presented in this guide is intended to provide the nuclear power plant maintenance and engineering personnel with reliability, performance, and maintenance practices for power transformers. This guide should provide the reader a reasonable understanding of power transformers in the following areas:

- Design, construction, and operation
- Industry failure data
- Failure mechanisms and their causes
- Failure modes and effects analysis
- Accessories that can cause transformer outages and failures
- Recommended predictive (diagnostic), preventive, and corrective methods of maintenance to optimize component life and system operation
- Troubleshooting and problem resolution
- Training recommendations for plant personnel on power transformer maintenance

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1

INTRODUCTION

1.1 Purpose

The guide is intended to provide insight to experienced personnel as well as basic information to personnel newly assigned to power transformer operation and maintenance responsibilities.

This is a reference guide that provides background information for engineers assigned the responsibility of inspecting, testing, and maintaining large power transformers in generating stations. Although this guide covers the generator main transformer and the auxiliary power transformers, its content is applicable to most large power transformers.

Since the generator and transformers are interconnected through bus ducts, a brief section has been developed to cover the basic information on bus duct enclosures.

Transformers can vary in type depending on their particular application. Depending on their use in the industry, they are designed and built in different sizes, shapes, and core material. There are single-phase, three-phase, or poly-phase transformers, dry-type, air core, metering transformers, and so on. Metering transformers step down voltage and current values that can be used in metering and control operations.

Transformers included in this guide are large units, located outdoors, forced liquid cooled and insulated. They are used primarily for bulk power transformation of electrical energy.

1.2 Pop Outs

Throughout this guide, key information is summarized in “Pop Outs.” Pop Outs are bold lettered boxes that succinctly restate information covered in detail in the surrounding text, making the key point easier to locate.

The primary intent of a Pop Out is to emphasize information that will allow individuals to take action for the benefit of their plant. The information included in these Pop Outs was selected by FMAC personnel and the consultants and utility personnel who prepared and reviewed this guide.

The Pop Outs are organized according to three categories: O&M Costs, Technical, and Human Performance. Each category has an identifying icon, as shown below, to draw attention to it when quickly reviewing the guide.

Introduction



Key O&M Cost Point

Emphasizes information that will result in reduced purchase, operating, or maintenance costs.



Key Technical Point

Targets information that will lead to improved equipment reliability.



Key Human Performance Point

Denotes information that requires personnel action or consideration in order to prevent injury or damage or ease completion of the task.

Appendix F contains a listing of all key points in each category. The listing restates each key point and provides reference to its location in the body of the report. By reviewing this listing, users of this guide can determine if they have taken advantage of key information that the writers of the guide believe would benefit their plants.

2

TRANSFORMER FUNDAMENTALS

2.1 Typical Power Plant Transformer Layout

Power transformers are used in generating stations to connect the main generator to the high voltage transmission system. They also connect the plant and off-site sources of electrical power to distribution subsystems for operation of plant auxiliary electrical equipment at medium and low voltages.

The generator step-up (GSU) transformer normally requires no voltage regulating winding, since the field of the generator regulates the voltage. The secondary winding of the GSU is high voltage and requires large internal clearances, which requires the transformer tank to be large. On large generator mega-volt ampere (MVA) output, some utilities choose multiple single-phase transformers.

The unit auxiliary transformer (UAT) is tapped off the isophase bus duct to feed the plant auxiliary equipment through a segregated or non-segregated bus duct. Its load may vary during start-up and shutdown switching operations. The UAT primary and secondary voltages may be in the medium range and the transformer tank is normally smaller than the GSU with very small internal clearances.

A second power supply for the plant auxiliary equipment is provided from the preferred power supply (off-site source) through the reserve or system auxiliary transformer (RAT or SAT). The RAT/SAT provides power to the station equipment when the generating unit is off line, and serves as a backup power supply when on line. It feeds the plant auxiliary equipment through a segregated or non-segregated bus duct. The primary side of this transformer (off-site source) is high voltage and requires large internal clearances.

Figure 2-1 depicts a one-line diagram of a typical generating station. The primary winding of the GSU is connected by flexible links to the isophase bus duct, which connects to the terminals of the generator (see Figure 2-2.)

Transformer Fundamentals

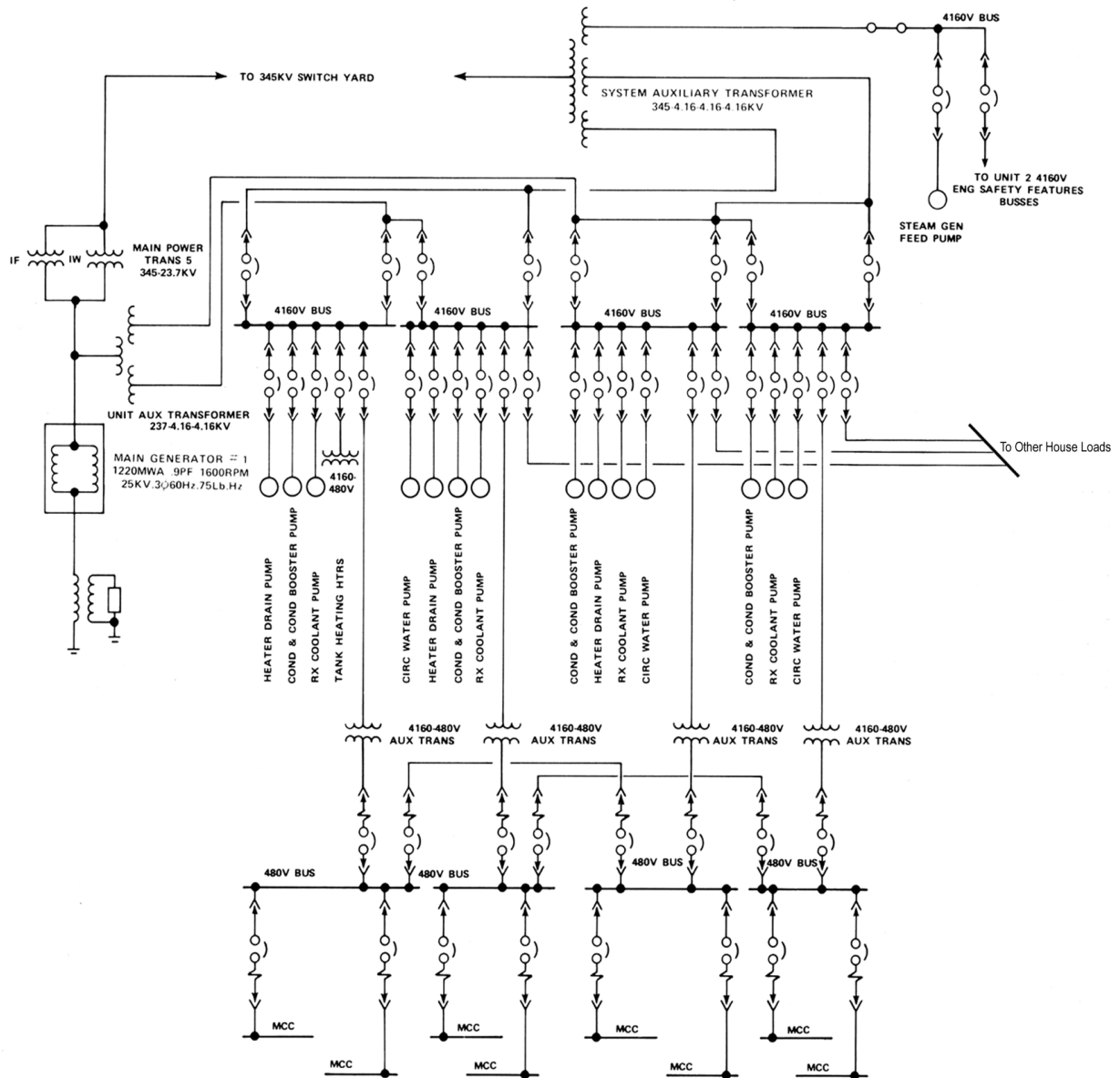


Figure 2-1
Typical Generating Station One-Line Diagram

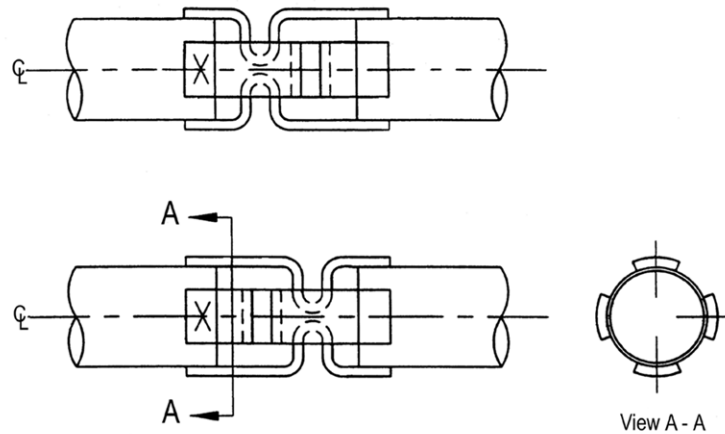


Figure 2-2
Laminated Flexible Connections

Typical power transformers (GSU and/or RAT or SAT) are liquid filled. Figure 2-3 is a cutaway view of a typical three-phase oil filled transformer, showing the tank, internal connections, typical windings, and the installed bushings. Figure 2-4 is a picture of a pancake coil and assembly.

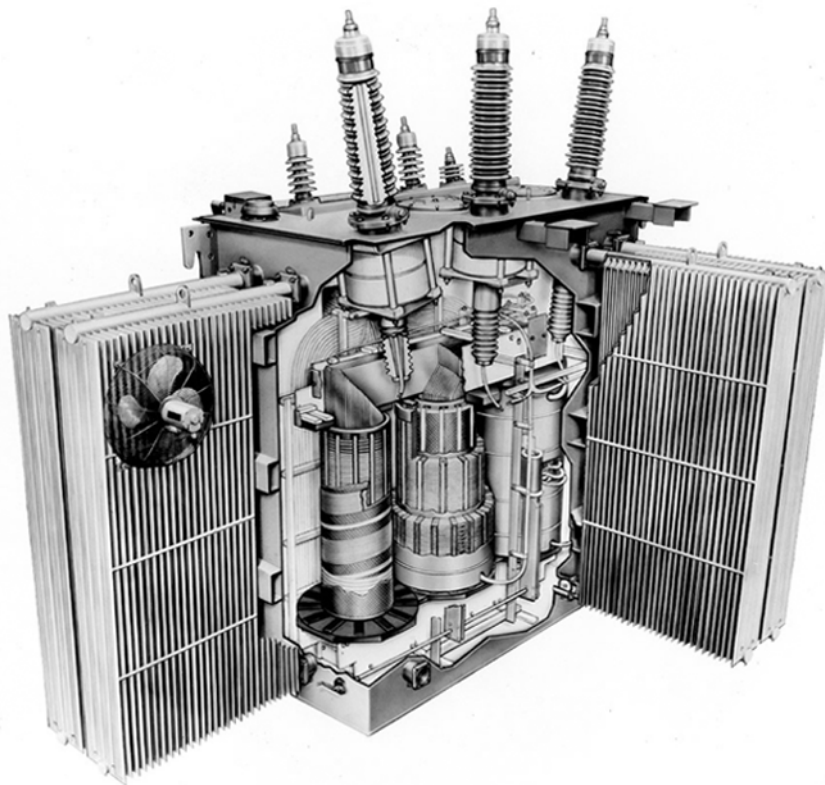


Figure 2-3
Cutaway Illustration of Power Transformer
(Courtesy of Waukesha Electric Systems)

Transformer Fundamentals

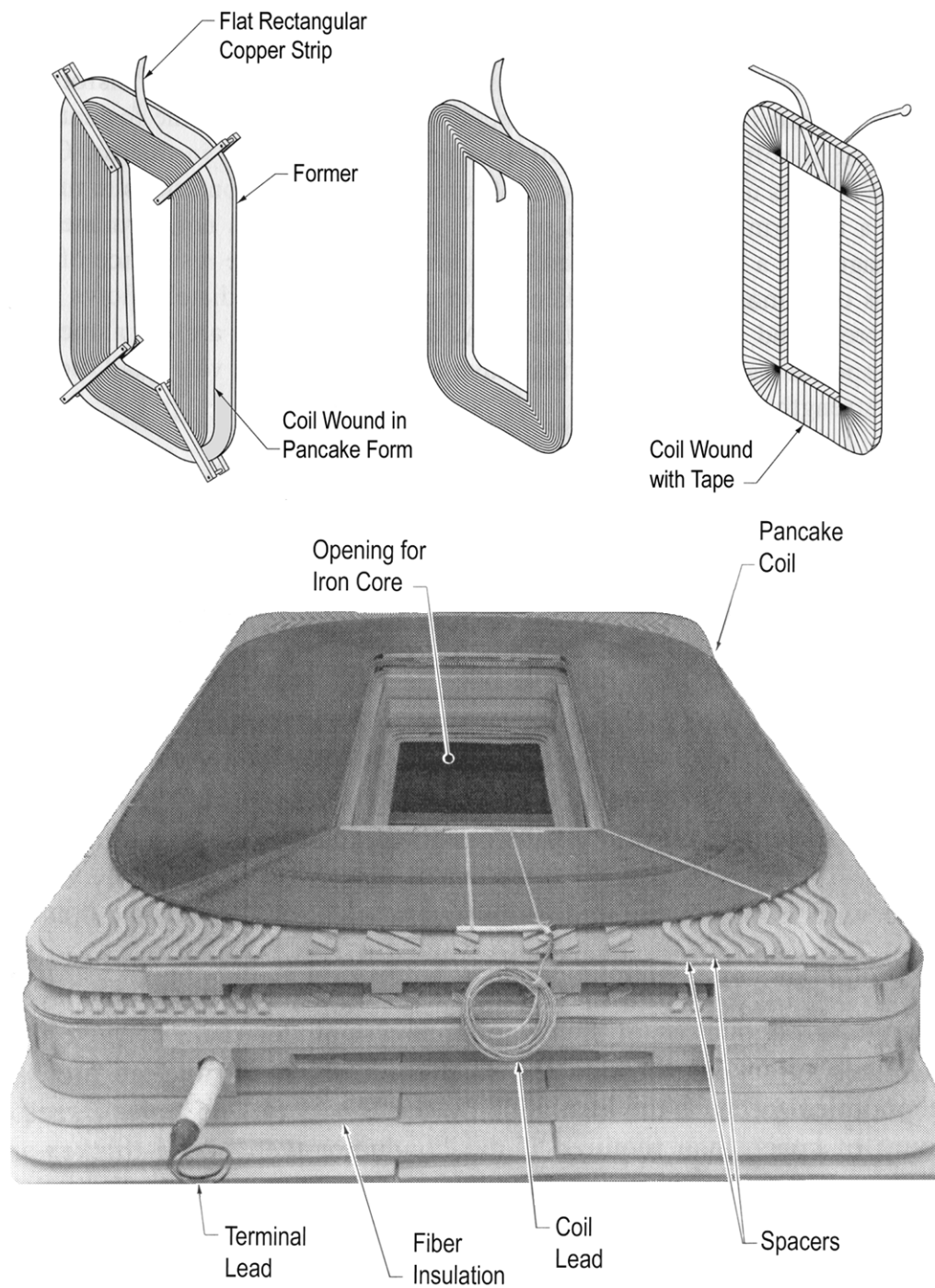


Figure 2-4
Example of Coil Assembly
(Courtesy of ABB)

2.2 Basic Transformer Design

The transformer information in this section is intended to offer a brief and basic overview theory on transformers. More detailed information can be found in textbooks and other publications.

The operation of the transformer is based on electromagnetic theory proposed by Lenz and further developed by Maxwell. When a current flows through a conductor, a magnetic field will be produced. By placing another conductor within that magnetic field, a voltage will be “induced” in that conductor. This principle provides the basis for transformer action. The transformer transfers power by electromagnetic induction between circuits at the same frequency, but at different voltage and current.

Transformers consist of two or more windings linked by a mutual magnetic field. When one of the windings (primary) is connected to an alternating voltage source, an alternating flux is produced. The amplitude of the flux depends on the primary voltage and number of turns in the windings. The mutual flux links the other winding (secondary) and induces voltage in that winding. The value of the induced voltage depends on the number of secondary turns.

The transformer is unique because, except for equipment that cools the oil, it has no continuously moving mechanical parts. The generation of electricity requires relative motion between a magnetic field and a group of conductors. In power plants, the turbine supplies the motion that drives the rotor magnetic field through the stator winding of the generator. In the transformer, this mechanical motion is replaced with a magnetic field that oscillates back and forth (magnetic flux) when the wires are connected to an alternating current voltage. Alternating current is required in order to produce a changing magnetic field that will in turn induce a voltage.

The following are some of the parameters for the basic transformer principles:

N = Number of turns of a non-magnetic metal, such as copper or aluminum

I = Current in amperes

E = Voltage in volts

ϕ = Flux or magnetic lines of force produced by current flow through the winding measured in ampere-turns (NI)

The transformer consists of two “circuits”, the electrical circuit and the magnetic circuit. The electrical circuit is the current flow through the primary winding and the secondary winding to the load. The primary winding is considered to be that which has the current applied to the transformer. The secondary winding is that winding that takes current away from the transformer. The magnetic circuit in a transformer provides a path for the flow of the magnetic flux produced by the primary windings to the secondary windings.

The magnetic circuit is described by the flux flow through the iron core of the transformer. Following are some of the parameters used to calculate the flux flow through the core.

Transformer Fundamentals

μ = Permeability of the material in the magnetic circuit

l = mean length of the magnetic path

A = cross sectional area of the magnetic path

The flux passing through the iron core is proportional to the current flow through the number of primary winding turns and inversely proportional to the ratio of the length of the magnetic path and permeability of the core with the cross sectional area of the core. This provides the coupling between the primary current and the secondary current through the transformer core. The fundamental relationship describing the magnetic flux within the transformer core is described by the following equation:

$$\phi = \frac{.4\pi NI}{l / \mu A}$$

For the electrical circuit of the transformer, when an alternating voltage E_1 is applied to the primary winding of a transformer, a current I_1 will flow through the primary coil of the winding. This current will produce an alternating magnetic field with a flux of ϕ magnetic lines of force as described above (see Figure 2-5 for the basic transformer configuration).

The magnetic flux ϕ will flow through the core and through the secondary winding coils to produce the secondary current in the secondary coils and voltage across the coils.

The flux that does not pass through the windings is called “leakage flux,” which causes heating of the core and it represents transformer loss.

Power transformers operating at full load or near full load transform a large amount of electric power that generates large amounts of heat. Transformers covered in this guide require some type of cooling to mitigate the consequences of excessive heat. A fluid such as oil is used as a cooling medium to remove excess heat from the transformer core and windings. The transformer cores and windings are designed to permit the flow of the oil around and through all coils. This provides a method to remove heat generated internally. The oil is then typically circulated through air-cooled radiators by oil circulation pumps. To increase radiator cooling capacity, fans may be used to increase air flow across the radiator.

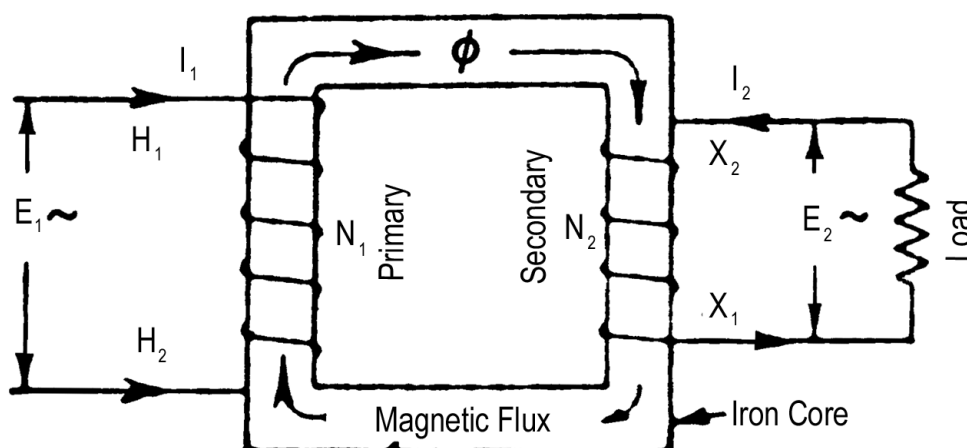


Figure 2-5
Basic Transformer Configuration

2.2.1 Voltage(E)—Current(I)—Turn(N) Relationships

The transformer primary and secondary coils are wound around an iron core. Once an alternating voltage E_1 is applied to the primary winding, a current I_1 called the exciting current, will flow in the primary winding and a voltage E_2 will be induced in the secondary winding. As the current flows through the winding, it will produce an alternating magnetic field with a flux of ϕ magnetic lines of force through the core. Magnetic flux ϕ in the iron core will always flow over the path of least resistance [1].

The voltage induced by the rate of change of flux in each turn of the transformer will be the same. Therefore, the voltage ratio between the two windings will be the same as the ratio of the number of turns (N):

$$\frac{E_1}{N_1} = \frac{E_2}{N_2} \text{ or } \frac{E_1}{E_2} = \frac{N_1}{N_2}$$

Thus, the fundamental relationship is established as the ratio of the primary and secondary voltage is equal to the ratio of the primary and secondary winding turns.

Since power is the phaser product of voltage and current and the primary power is equal to the secondary, that is $P_1 = P_2$ or $E_1 I_1 = E_2 I_2$

$$E_1 I_1 = E_2 I_2 \text{ or } \frac{E_1}{E_2} = \frac{I_2}{I_1}$$

Therefore,

$$\frac{N_1}{N_2} = \frac{I_2}{I_1}$$

Hence, the primary to secondary voltage ratio is inversely proportional to the current ratio.

2.2.2 Single-Phase Versus Three-Phase Power Transformers

Large power transformers, such as generator step-up transformers, are usually built as three-phase units in one tank. Because of the large electromagnetic field and the smaller stressed volume of insulation in the tank, some utilities prefer the single-phase (that is, three-single phase units with a separate tank and bus duct). Other utilities prefer to divide the large transformer capacity into two-half three-phase units with a separate tank and bus duct.

Electrically, either one of the three types is the same. Preference of one versus the other depends on the manufacturer's recommendation and the utility's choice.

2.3 Transformer Nameplate Information

Nameplate data provides important information for the proper operation and maintenance of each transformer. Transformers are expected to operate within their normal designed and operating rating.

- **MVA Rating**—The output that can be delivered by a transformer at rated secondary voltage and rated frequency without exceeding the specified temperature rise.
- **Cooling Class**—Type of insulating medium and the type of cooling medium to dissipate the heat generation in the transformer.
- **Winding Temperature Rise**—The difference between the average winding temperature or the hottest-spot winding temperature and the ambient temperature.
- **Voltage**—The primary and secondary voltage to transform electrical energy from primary voltage to secondary voltage.
- **Insulation Levels**—Indicates the ability of the transformer to withstand lightning strikes and other system over-voltages.
- **Impedance**—Expressed as a percentage and interpreted as percentage voltage drop in the transformer at full-load current.
- **Basic Impulse Level (BIL)**—The crest value of the impulse voltage during factory testing that the transformer is required to withstand without failure.
- **Polarity**—The relative instantaneous direction of the currents entering the primary terminals and leaving the secondary terminals of the transformer. The polarity is fixed by the lead connections inside the transformer.

Figure 2-6 depicts typical nameplate information, which covers the parameters previously listed.



2.4 Transformer Losses

An ideal transformer would be 100% efficient, or, the ratio of power output to power input would be 1. Most power transformers are about 97% to 99% efficient. About 1% to 3% of the power is attributable to transformer losses.

Although newer transformers operate at very high efficiencies, there is no such thing as an ideal transformer. Transformers develop substantial heat internally from resistive heating due to flow of current in the windings (load losses) and internal heating due to variations of flux in the iron core (core losses). The load losses are about three to six times higher than the core losses at nameplate load. Core loss is a function of voltage; load loss is a function of current.



Key Technical Point

Core loss is a function of voltage; load loss is a function of current.

In large capacity transformers, leakage flux (that is, any magnetic flux produced by the primary current that does not link all turns of all windings) is a major design concern. A portion of the flux produced by the primary current not constrained to the core becomes a stray loss (see Figure 2-7) and it can cause localized overheating and eddy-current losses discussed further in Sections 2.4.1.1 and 2.4.1.2.

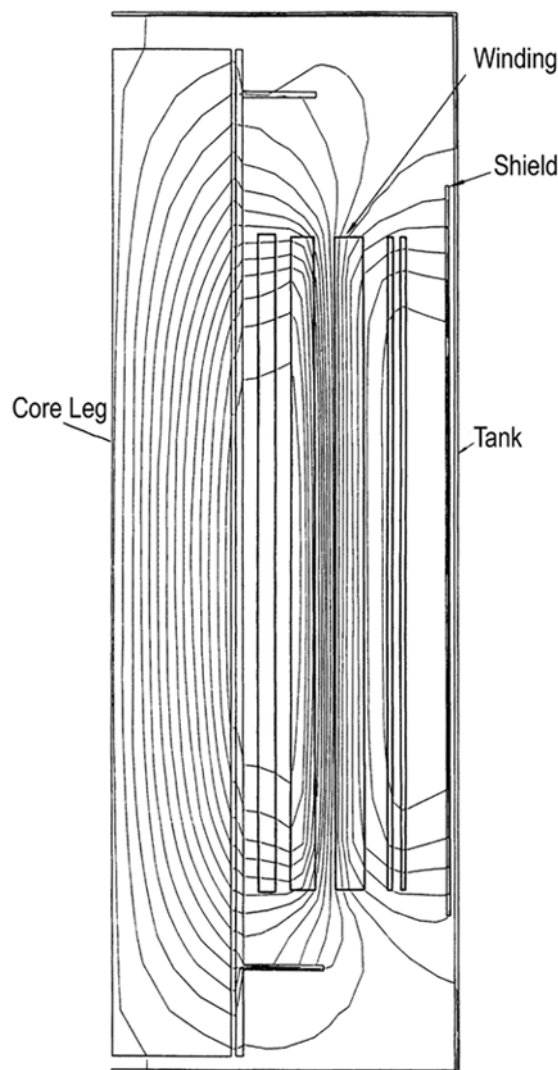


Figure 2-7
Example of Leakage Flux Distribution Analysis by Computer
(Courtesy of Toshiba)

When the transformer is energized, the no-load losses are core hysteresis and eddy-current losses.

2.4.1 No-Load (Iron) Losses

Certain losses occur in a transformer, regardless of the load, when the unit is connected to a source of voltage. These losses include core losses and copper losses in the primary winding due to the flow of no-load current (exciting current) and dielectric losses in the insulation. In practice, while the last two losses are very small, the iron or steel losses are significant. Thus, one of the no-load losses is commonly termed “iron losses.” The first major loss, known as “hysteresis,” is the power required to magnetize the core first in one direction and then in the other. As it is magnetized, the core actually expands and contracts ever so slightly producing the characteristic hum associated with transformers. The second major contributor to the no-load loss is the eddy-current loss or power loss due to the circulating current in the core iron.

2.4.1.1 Hysteresis Losses

The word “hysteresis” means “to be late” or “to lag behind.” Every time the current changes direction, the direction in which the core is magnetized changes. The molecules of iron constantly lag behind as the core changes its magnetic direction. The energy that has to be supplied to the molecules to reverse them and to get them oriented in the new direction of the field is called “hysteresis loss of the core.” In other words, the flux in the iron is always lagging the current in the coil; therefore, we say the iron has “hysteresis.” The amount of loss depends on the type of core material used. The molecules must reverse more often at higher frequencies. Therefore, more total energy is required. Higher hysteresis losses occur at high frequencies. The curve shown in Figure 2-8 is known as a hysteresis curve.

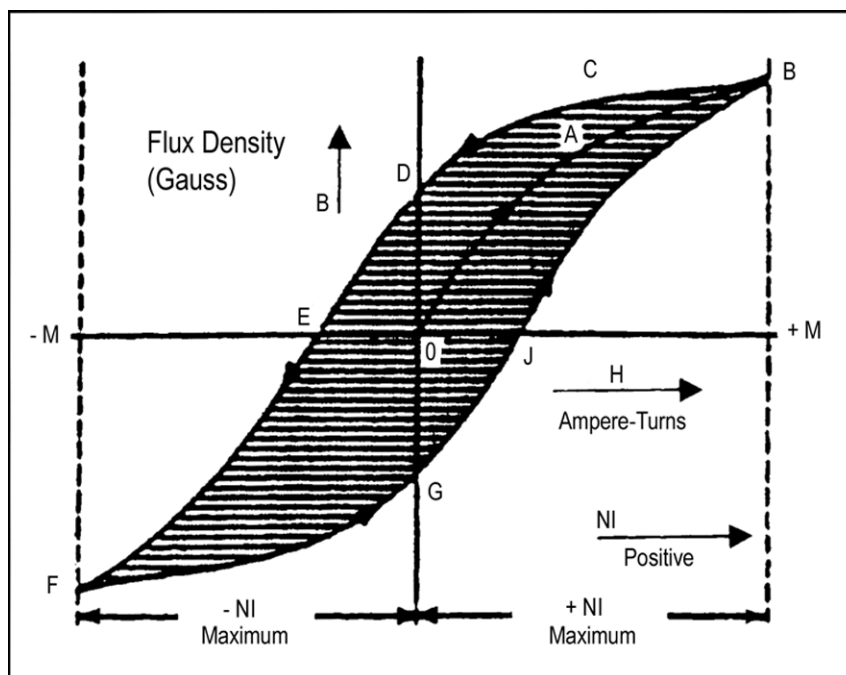


Figure 2-8
Hysteresis Loop

2.4.1.2 Eddy-Current Losses

A magnetic material that is used as a core for a transformer is by its nature also a conductor and is affected by the changing flux in the same manner that the windings on the core are affected; a voltage is induced that causes a current to flow in the core. This current is called an “eddy-current” and is the cause of the eddy-current losses. The eddy-currents are circulating currents with a direction of motion that is at right angles to the direction of the magnetic flux.

Eddy-current losses are reduced by using a core composed of thin laminated sheets of magnetic material that are coated with an insulating material and pressed or bolted together instead of a solid core. The laminations offer high resistance to current flow; hence, the eddy-currents and the resulting losses are reduced.

Figure 2-7 shows a portion of the flux that flows through the tank wall and the protective shield on the side of the wall. This leakage flux results in stray losses that can be reduced by shielding the tank wall. Stray losses are usually evident around the interior of the upper tank where bushings and secondary buses are located and certain structural parts.

**Key Technical Point**

Stray losses are usually evident around the interior of the upper tank where bushings and secondary buses are located.

During the design stage of the transformer, designers study the magnitude and direction of the stray losses and design magnetic steel/aluminum wall shields to direct stray losses. The shield draws leakage flux away from the tank wall, thereby reducing the stray losses. The shield is normally grounded to the tank in only one point. Accidental grounds to the shield will result in circulating currents and hot spots.

**Key Technical Point**

Accidental grounds to the shield will result in circulating currents and hot spots.

2.4.2 Load (Copper) Losses

Load losses are those that occur in a transformer when it carries load. Load losses are also called “copper losses” and are proportional to the square of the load current (that is, I^2R). The greatest part of the load loss is due to power lost when the current flows through the resistance of the windings.

2.5 Core Excitation

Figure 2-9 shows a saturation curve, which is a graph of flux density plotted against a steadily increasing direct current. At the knee of the curve, the linear increase in flux density ceases and there is little increase in flux density for a large increase in current. Thus, for a rise in current from O to A, the flux density rises for A to C, but for an equal rise in current from B to D, the flux rises only from E to F. By increasing current beyond the knee of the saturation curve, there are relatively minor changes in flux density, and conversely an increase in efficiency losses. Larger current can result in overheating and damage to the transformer. The same effect of magnetization could be obtained with a much smaller current before the core saturation. An increase in cross-sectional core area decreases flux density for a given current but increases weight, cost, and hysteresis losses of the transformer.

Because of this, most power transformers are designed to operate at or near the knee of saturation curve of the core material. Overexciting the transformer can greatly increase core losses and core temperature and, in extreme cases, can permanently damage the core, as explained in the following subsections.

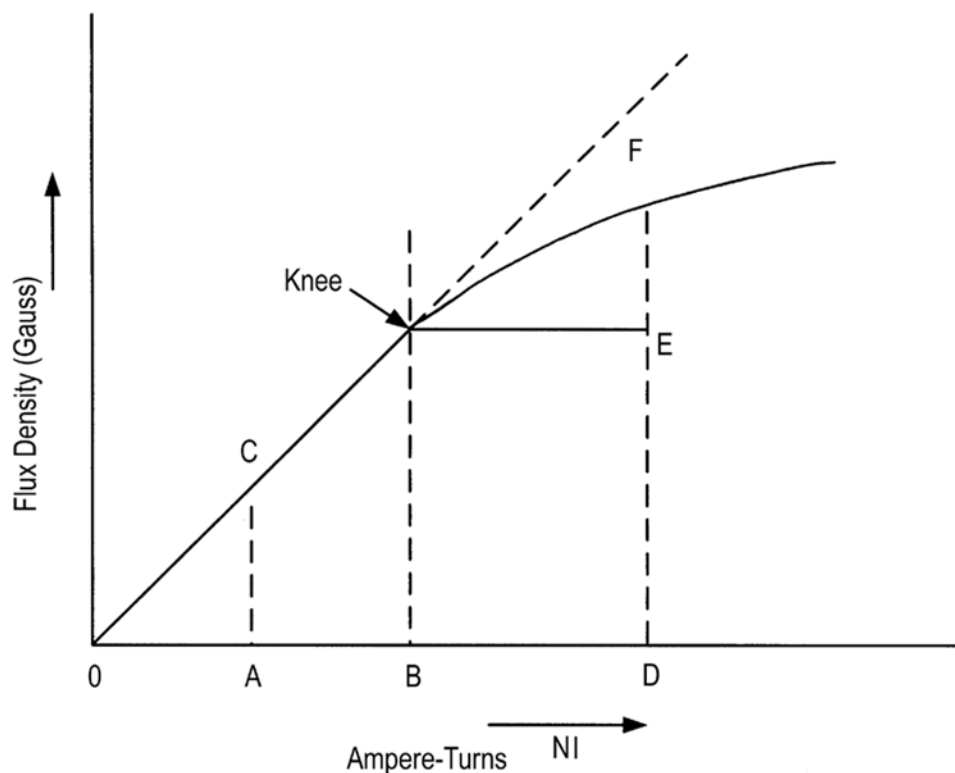


Figure 2-9
Saturation Curve



Key Technical Point

Overexciting the transformer can greatly increase core losses and core temperature and, in extreme cases, can permanently damage the core.

2.6 Overexcitation of Power Transformers

The information on overexciting a power transformer is corroborated by GE's technical information GET-3364 and ABB's instruction leaflet 48-50-13A. The following information on overexcitation of power transformers is provided.

Overexcitation describes a condition of excessive flux in a power transformer. A common measure of the flux is the per unit excitation which is defined as the per unit voltage divided by the per unit frequency (volts per hertz). The base quantities for voltage and frequency are the rated values.

Overexcitation exists when the limits specified by Section 4.1.6 of ANSI Standard C57.12.00-1998 are exceeded [2]. The standard can be summarized as follows:

A transformer shall be capable of:

- Operating at 105% of rated secondary voltage while delivering maximum rated output kva (≥ 0.80 pf lagging and frequency at least 95% of rated value).
- Operating at 110% of rated secondary voltage or volts per hertz at no load.

The limits apply to the rated secondary voltage or to the rated voltage and kva of any tap, only when operating at rated frequency. At other than rated frequency, the limits must be considered as applying to volts per hertz.

2.6.1 Causes

Power system operating conditions may cause overexcitation of a power transformer and other connected apparatus. Overexcitation can occur under circumstances such as:

- Regular system operating practices might allow the transformer voltage (at rated frequency) to exceed the limits permitted by standards.
- During generator start-up and shutdown, overexcitation can be caused by reduced frequency operation, if the voltage is not reduced proportionately.
- When a malfunction occurs in the controls of a generating station, a variation from the normal generator voltage and speed can produce damaging excitation levels.
- When various system regulators, breakers, and relays mis-operate, or when special tests are performed on parts of the system, overexcitation can occur.
- System emergency operation, particularly during and after a major power disturbance, can cause an unbalance between generation and load that could result in under-frequency and/or overvoltage operation.

Under-frequency operation can occur for the system as a whole, or for any subdivided component part of the system that encompasses at least one generator, during a period when load exceeds generation.

Overvoltage operation can occur during load rejection or when a system is being pieced together after having been split apart by a disturbance. A transformer at the end of a long unloaded line or cable can be subjected to abnormally high voltage because of the voltage rise along the line produced by the flow of the capacitive line charging current. Appropriate relaying devices must be provided to detect such overvoltages and to initiate corrective action.

2.6.2 Effects

The major concern relative to overexcitation of power transformers is thermal degradation of insulation resulting from stray flux heating rather than electrical breakdown of insulation due to overvoltage.

Excitation levels above those prescribed by the standards may result in more flux than the core steel can contain; thus the core becomes saturated. The overflow flux strays into winding conductors, leads, and structural parts, where eddy-currents produce losses and heating. Permanent damage to adjacent insulating materials may result if this heat cannot be readily dissipated.

Severe overexcitation can cause a transformer failure within a short time; however, less extreme overexcitation can occur without the operator being aware of its existence or consequences. Since the resulting thermal degradation of insulation is cumulative, the transformer may survive repeated instances of overexcitation, which are moderate in degree before an electrical breakdown occurs. A failure might be separated from the initiating incident by months of normal service operation.

**Key Technical Point**

Severe overexcitation can cause a transformer failure within a short time; however, less extreme overexcitation can occur without the operator being aware of its existence or consequences. A failure might be separated from the initiating incident by months of normal service operation.

2.6.3 Permissible Levels of Overexcitation

On a short-time basis, there is some capacity for excitation beyond the limits of the standards since the heating parts have finite thermal time constants. Because the damage is a function of both magnitude and duration of overexcitation, Figure 2-10 was developed to serve as a general guide for permissible short-time periods of overexcitation. The latitude for short-time overexcitation will be a function of each particular transformer design; therefore, any general guide, such as Figure 2-10, must be conservative.

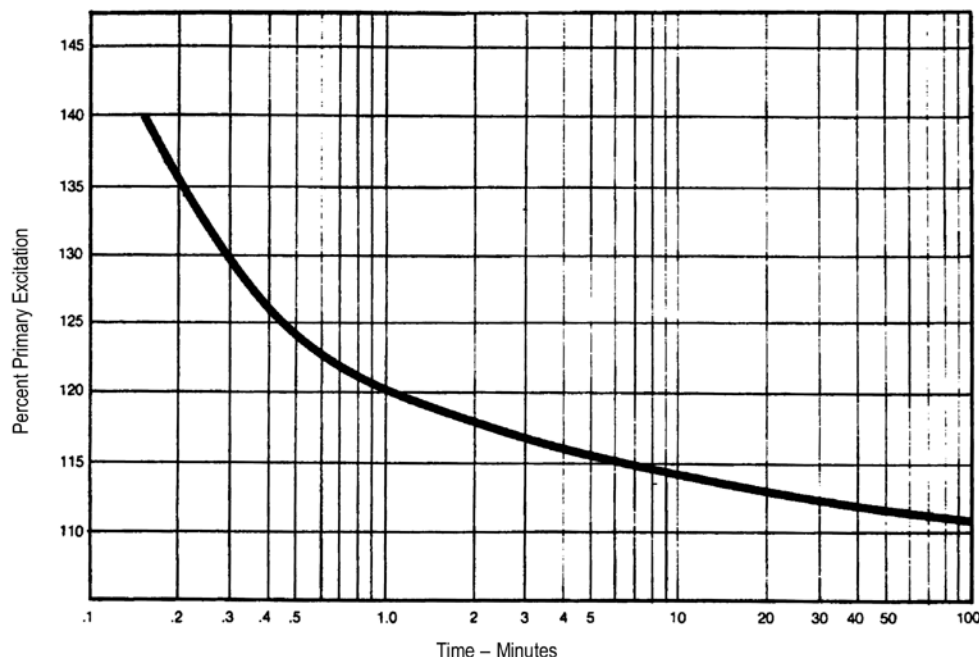


Figure 2-10
General Guide for Permissible Short-Time Overexcitation of Power Transformers

For transformers with high impedance, there is somewhat greater latitude for overexcitation than indicated in Figure 2-10 and the curve could be adjusted accordingly. As indicated in the first portion of this section, the transformer is designed to operate at 105% secondary voltage with rated 0.8 power factor lagging load. If the primary voltage (V_1) required for such operation is greater than 100% of rated, the ordinate scale of Figure 2-10 can be multiplied by $V_1 + 110$.

Operation anywhere on or below the curve of Figure 2-10 will not cause significant loss of transformer insulation life.

For example, a transformer could be operated at 120% excitation (1.2 times rated volts per hertz) for one minute without measurable damage. Then if the excitation was reduced to a level within the steady-state limits (specified by the standards) for a period of several hours, the temperature of the heated parts would return to normal; thus allowing the short-time overexcitation experience to be repeated without measurable damage. Any reasonable number of repetitions (during an emergency situation) would not be expected to affect the life of the transformer.



Key O&M Cost Point

During an emergency situation, short-time overexcitation may be allowed without causing measurable damage to the transformer.

On the other hand, operation above the curve shown in Figure 2-10, such as 120% excitation for two minutes, could cause the transformer to suffer permanent damage. Such damage is cumulative for repeated occurrences and would contribute eventually to a failure. In order to

make this determination, the magnitude of the overexcitation and its duration must be understood. In serious situations or where any doubt exists, the manufacturer of the transformer should be consulted.

It is recommended that an oil test be performed and that the transformer be inspected for possible damage any time it is known to have been overexcited beyond the limits such as those shown in Figure 2-10.

Sudden generator trip and load rejection can be an event that may be considered as a stressor on the transformer. In such a case, the system engineer should review operation of the protective scheme and request an oil sample and analysis for the GSU transformer.

**Key Technical Point**

After a generator trip or load rejection, a GSU oil sample and analysis should be done.

2.6.4 Detection and Correction

Protective devices should be used to detect excitation beyond acceptable limits and to initiate corrective action. In particular, separate volts per hertz detection should be installed on all unit-connected generator-transformer combinations to sense and control overexcitation. Past relaying practices have not recognized the overexcitation problem. Since damage can occur in such a short time, protective devices are needed to recognize abnormal conditions quickly and to initiate action to prevent damage to the transformers.

**Key Technical Point**

In particular, separate volts per hertz detection should be installed on all unit-connected generator-transformer combinations to sense and control overexcitation.

2.7 Geomagnetically Induced Currents (GICs)

Geomagnetically induced currents can result in severe over-saturation of a transformer core. A comprehensive explanation of GIC was presented in a paper presented at the EPRI Substation Equipment Diagnostics Conference in February 2000 [3]. A condensed version of that paper is presented here.

GICs are typically driven to or from various power system electrical ground points (transformer neutrals) by the voltages that are induced in transmission lines.

GICs are quasi-dc currents that have a very slow variation, usually in a frequency range much less than one Hz. GIC values of 130 amps in transformer neutrals have been measured. Severe GIC events can persist for periods of several hours, however, a large GIC with one polarity usually only lasts for a couple of minutes before changing polarity. GICs can occur for several days in succession and can be regional or continent-wide.

The factors that affect GIC are:

- The extent and strength of the horizontal electric field in the power system
- Ionospheric currents that vary as a function of time and space
- The earth's conductivity
- Proximity of the power system to the auroral zone

Electrical system characteristics:

- Power system orientation
- Lengths of transmission lines
- Electrical resistance
- Transformer type and grounding
- Station grounding

The geoelectric field is largest in areas of high earth resistivity near the auroral zone (55° to 70° latitude). Therefore GIC is more pronounced in northern latitudes in areas of igneous rock with high earth resistivity. Coastal areas are another region of high susceptibility to GIC because the induced current flowing in the ocean meets a higher resistance as it enters the land.

2.7.1 Effect of GIC on Power Systems

Past experience has proven that GICs can cause detrimental effects on power systems and power systems apparatus. These detrimental effects are:

- Transformer core half-cycle saturation resulting in an abnormal amount of stray flux impinging on the tank walls, flux shields, leads, and core clamps
- An increased amount of transformer var consumption resulting in potential system voltage collapse
- Generation of harmonics causing substantial transformer neutral currents
- Transformer heating caused by the excess flux external to the core flowing through adjacent paths such as the tank, clamps and leads
- Generator heating caused by harmonics and voltage unbalance from transformer half-cycle saturation
- Protective relay problems caused by the presence of harmonics
- Communications problems resulting from changes in the propagation characteristics of radio waves, and harmonics may cause disruption to land line systems.

2.7.2 Design Considerations

If possible, choose appropriate transformer types (for example, three phase, three leg core, and so on) that are more immune to the detrimental effects of GIC. The auxiliary legs of this design provide for symmetrical magnetic circuits of the core. This provides a flux sharing characteristic that allows a more uniform distribution of flux in the legs of the core.

The more uniform distribution of flux provides a lower harmonic content and distributes induced currents across the full circuit.

2.8 Observations

A transformer is a device that transforms an ac voltage and current to a higher or lower level. It is a device that transfers large or small amounts of energy by means of voltage and current transformation. It normally consists of two or more insulated windings on a common iron core immersed in oil or other insulating liquid (see Figure 2-11). Smaller transformers may not use oil for insulation (such as dry type).

In general, transformer losses are no-load losses and load losses. No-load loss is mainly hysteresis and eddy-current loss in the core. It is independent of load and exists when the transformer is excited. Load loss is the I^2R loss in the windings and stray losses caused by load current.

The no-load and load losses create heat that increases the temperature of the internal components, that is, oil, winding conductor, insulation, and core.

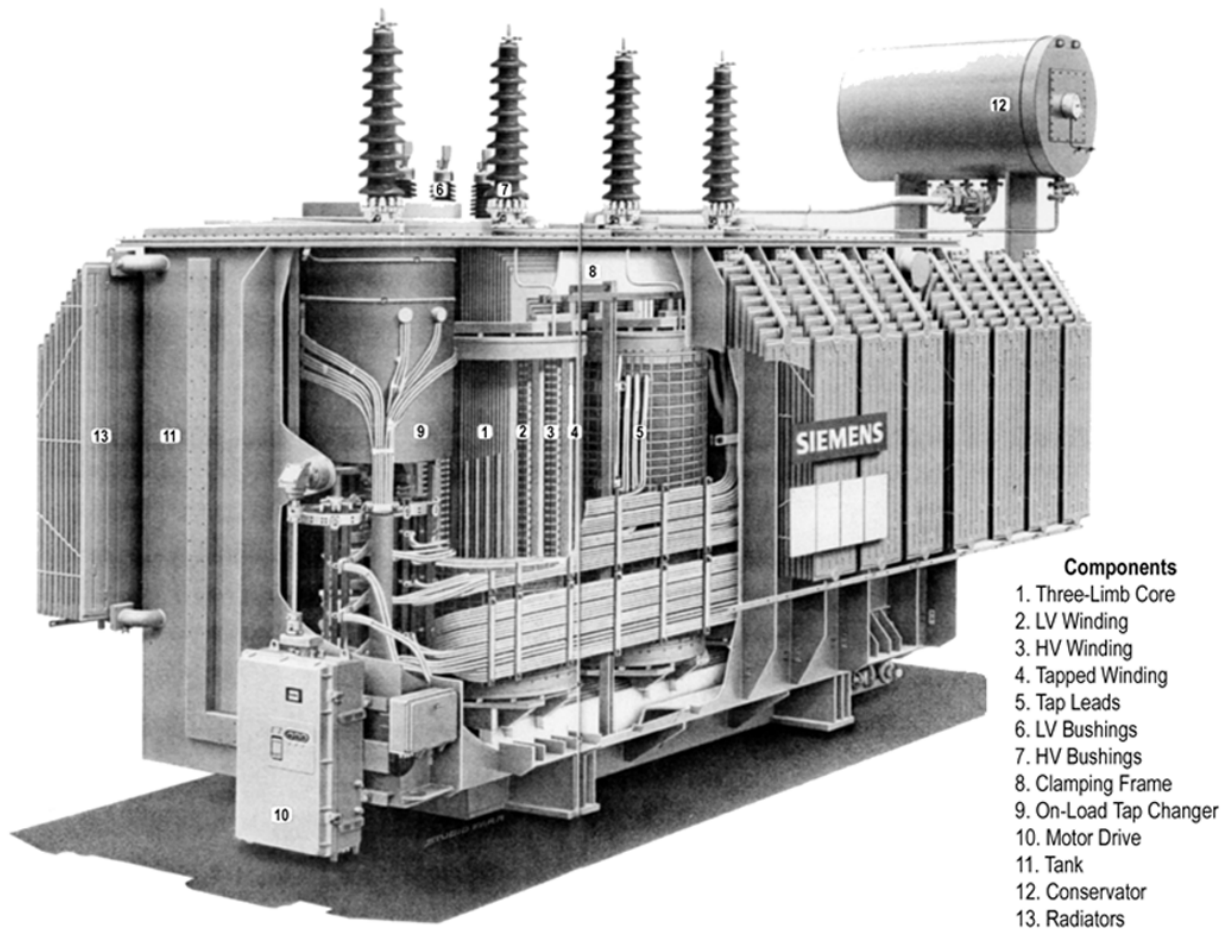


Figure 2-11
Internal View of a Large Power Transformer
(Courtesy of Siemens)

3

TRANSFORMER DESIGN AND CONSTRUCTION

3.1 Introduction

Large liquid-immersed transformers are typically designed, built, and operated according to the latest IEEE/ANSI Standard C57.12.00-2000 [4] or other similar standards.

The principal parts of a transformer include:

- Tank and oil preservation
- Magnetic core
- Windings
- Insulation windings
- Insulation system
- Insulating liquid
- Accessories

3.2 Tank and Oil Preservation

The transformer case or tank that houses the core and coil provides mechanical protection for the core and coil assembly. It is made of mild steel plates of appropriate thickness and contains the oil that is used to cool and insulate the core and coil assembly. The tank and its internal structural members are high in permeability and as a result are prone to leakage flux, especially in large capacity transformers. Therefore, it becomes important to control leakage flux, reduce eddy-currents, and avoid hot spots. Large tanks are designed with a leakage flux shield such as aluminum or non-magnetic steel. Figure 3-1 shows a typical transformer tank prior to inserting the core, with the flux shield seen on the inside wall.



Figure 3-1
Transformer Tank
(Courtesy of Smit)

Gaskets are used throughout the transformer to prevent the leakage of oil from pumps, manways, and accessory devices. Gaskets have several important jobs in sealing. A gasket must:

- Create a seal and hold it a long period of time
- Be impervious and not contaminate the insulating oil
- Be easily removed and replaced
- Be elastic enough to flow into imperfections on the mating sealing surface
- Withstand high and low temperatures and remain resilient
- Be of sufficient strength to resist crushing under applied load and resist blowout

Several types of gasket material are commonly used on large transformers and each has its particular application. The main influences on gasket material selection are design of the gasket joint, operating temperature extremes, type of fluid contained, and internal pressure of the transformer.

Cork-nitrile performs well at high temperatures, but should only be used if the joint does not have grooves or limits.

Cork-neoprene sets easily but should only be used if the joint does not have grooves or limits.

Nitrile performs better than cork-neoprene when exposed to higher temperatures. It should only be used if there are recesses or expansion limiting grooves. Nitrile is not sunlight resistant and will deteriorate even if only the edges are exposed.

Viton should be used only for gaskets and o-rings in temperatures higher than 65°C or for applications requiring motion (shaft seals, and so on).

Several types of oil preservation systems are used to protect the oil against air, moisture, contamination, and provide space for the expansion of the oil. Common oil preservation systems are described below.

3.2.1 Sealed Tank System

The sealed tank system (see Figure 3-2) maintains a constant overall fluid (oil) and gas (nitrogen) volume throughout the entire operating range of transformer temperature. The transformer tank and other components are tightly sealed, thereby allowing no air or moisture either in or out of the tank during normal circumstances. As the temperature of the fluid and void space gas increase, the fluid expands and the gas pressure within the tank increases; likewise, a decrease in temperature results in a drop in pressure. If the decrease in temperature is of sufficient magnitude, a vacuum (with relation to atmospheric pressure outside the tank) will be created, thereby potentially drawing outside air into the tank in the event of leakage.

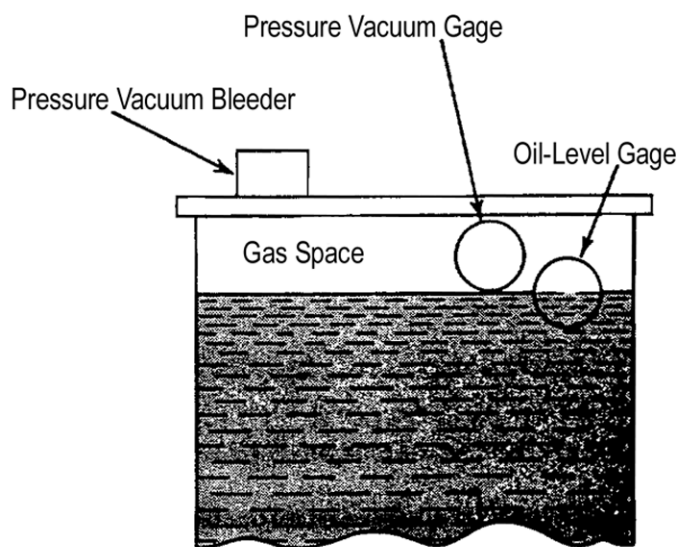


Figure 3-2
Sealed Tank

Transformers utilizing this type of oil preservation system are equipped with a pressure/vacuum bleeder to allow the nitrogen to be expelled if the internal pressure gets too high, and allows outside air to enter if the internal pressure gets too low, thereby protecting the main tank from possible damage. This type system could be used for some UAT or RAT.

3.2.2 Inert-Gas-Pressure System

The inert gas system uses a blanket of nitrogen to pressurize the void space above the oil volume to a pressure slightly greater than atmospheric (see Figure 3-3). Leakage occurring in the tank or other components will therefore occur only in the outward direction; this outward leakage prevents the induction of moisture or oxygen, and displaces any other gases that can accumulate over time. As indicated above, variations in loading and ambient temperature will result in changes in the volume of the oil fluid; this in turn will require either the addition or purging of the nitrogen in order to compensate for expansion.

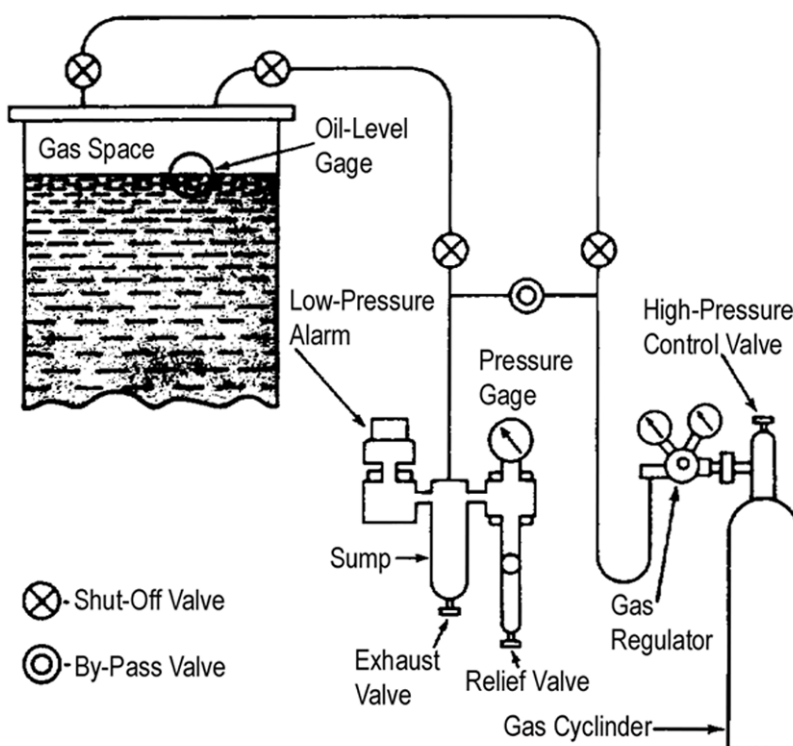


Figure 3-3
Inert-Gas-Pressure System

During periods of contraction, the nitrogen is supplied from storage bottles located near the transformer; a regulating valve maintains a slight positive pressure in the void space. During periods of expansion, another valve controls the venting of excess gas, thereby preventing over-pressurization. The regulating valves are calibrated so as to prevent simultaneous venting and charging of gas. Periodically, the gas bottle inventory must be verified, and empty bottles should be replaced or recharged. This system will most often be used on UAT and RAT.

3.2.3 Sealed Conservator System

The third type of oil preservation system is the sealed conservator. In this system, the entire volume of the tank is kept continually filled with fluid from a surge tank (conservator) mounted above the main tank. Figure 3-4 shows a typical sealed conservator preservation system. As the volume of the fluid decreases or increases, the surge is made up by or exhausted to the conservator tank. The void space (open to atmosphere) and fluid volume in the conservator are separated by a diaphragm (air cell or bladder), which prevents the contamination of the oil by moisture, gases, or other contaminants. The cycling of the air to the bladder may pass through an air dryer filled with desiccant. The desiccant serves to remove moisture from the air to minimize the flow of moisture through the bladder membrane into the transformer oil. A float-type level sensor measures the level of the conservator tank. The main tank is always completely filled. This system will most often be used on GSUs.

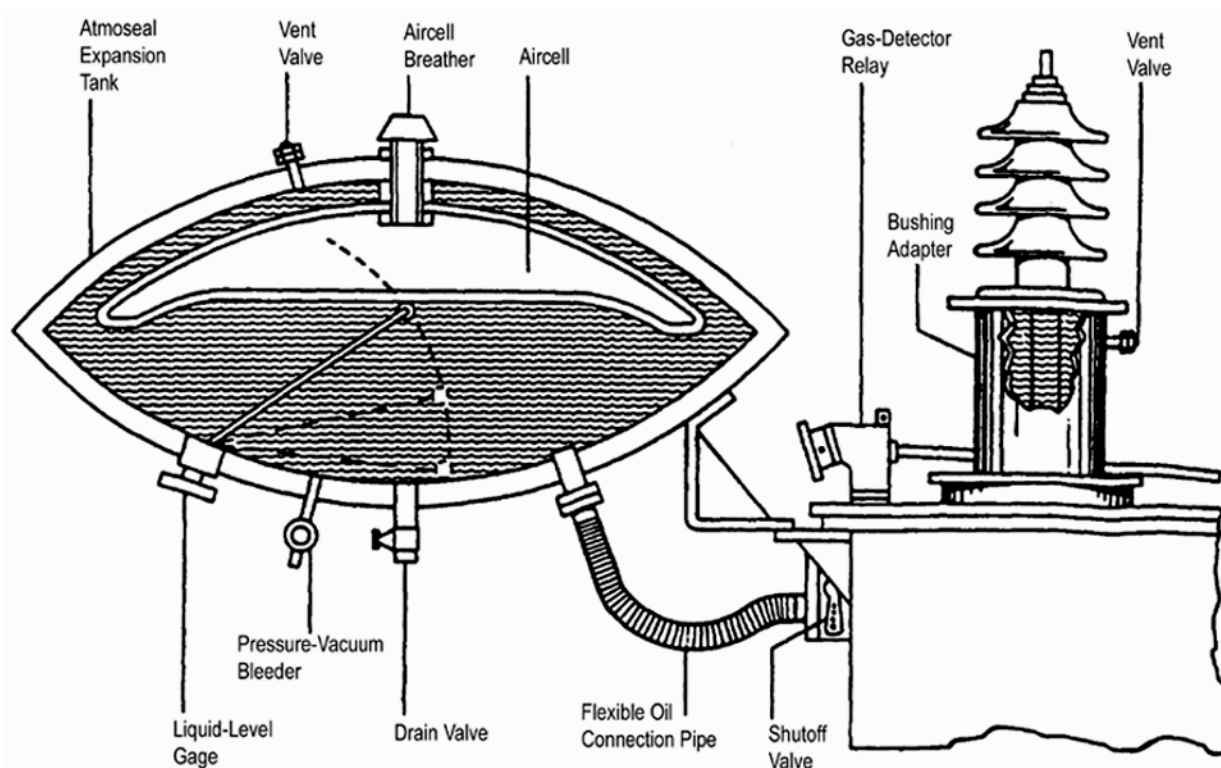


Figure 3-4
Typical Oil Preservation Sealed Conservator System

3.3 Magnetic Core

The core is that part of a transformer in which the magnetic field oscillates. It provides a low-reluctance path for the flux linking primary and secondary coils. The material is a very high grade of iron to which a small percentage of silicon has been added. The core is formed of thin sheets that are coated with an insulating material. The thin sheets form a high resistance path to eddy-currents. This material limits stray currents circulation in a transformer core. Without thin laminated sheets, the resultant heat and loss of power would be great.

Several years ago soft iron was used to manufacture transformer cores. Later on silicon alloyed with low carbon content was used with the soft iron to improve transformer losses. Further improvements were made over the years for maximum core magnetization and minimum core losses by introducing high-permeability grain-oriented silicon steel. Additional improvements were made in the industry with the introduction of laser cutting of the steel, which made possible the manufacture of laminations with minimal edge defects. This helps to prevent flux intensification on the edges of the laminations (see Figure 3-5).



Figure 3-5
Construction of Laser Cut Core Laminations
(Courtesy of SMIT)

Core laminations are properly secured by a clamping structure. The whole core assembly is clamped together by steel frames to hold the transformer windings together, and it braces them to withstand mechanical forces generated during normal operation or under fault conditions (see Figures 3-6 and 3-7).

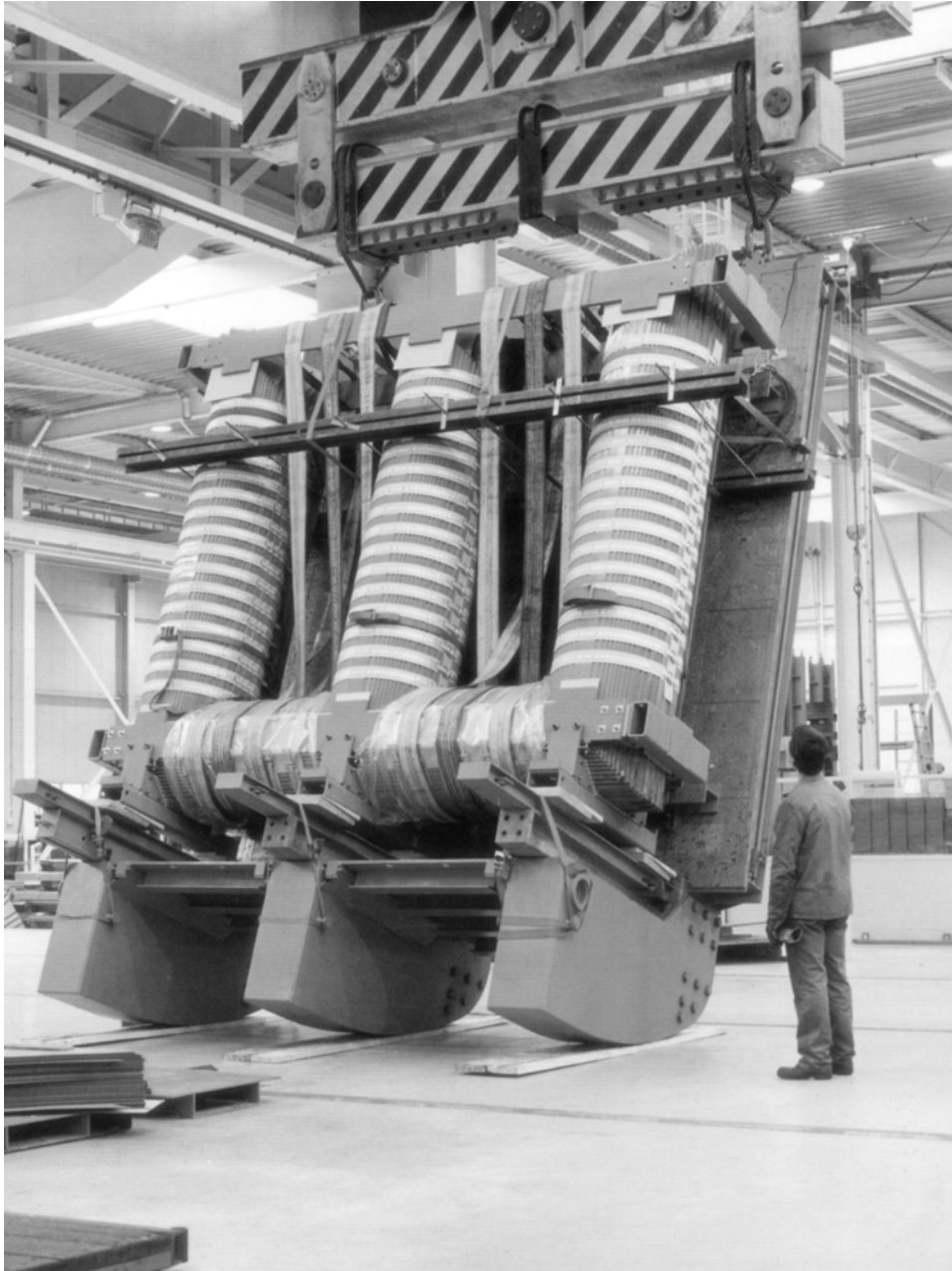


Figure 3-6
Clamping of Core Laminations
(Courtesy of SMIT)

Transformer magnetic cores are classified into two general forms: core form and shell form. These two types differ in the arrangement of the iron and copper with relation to each other.

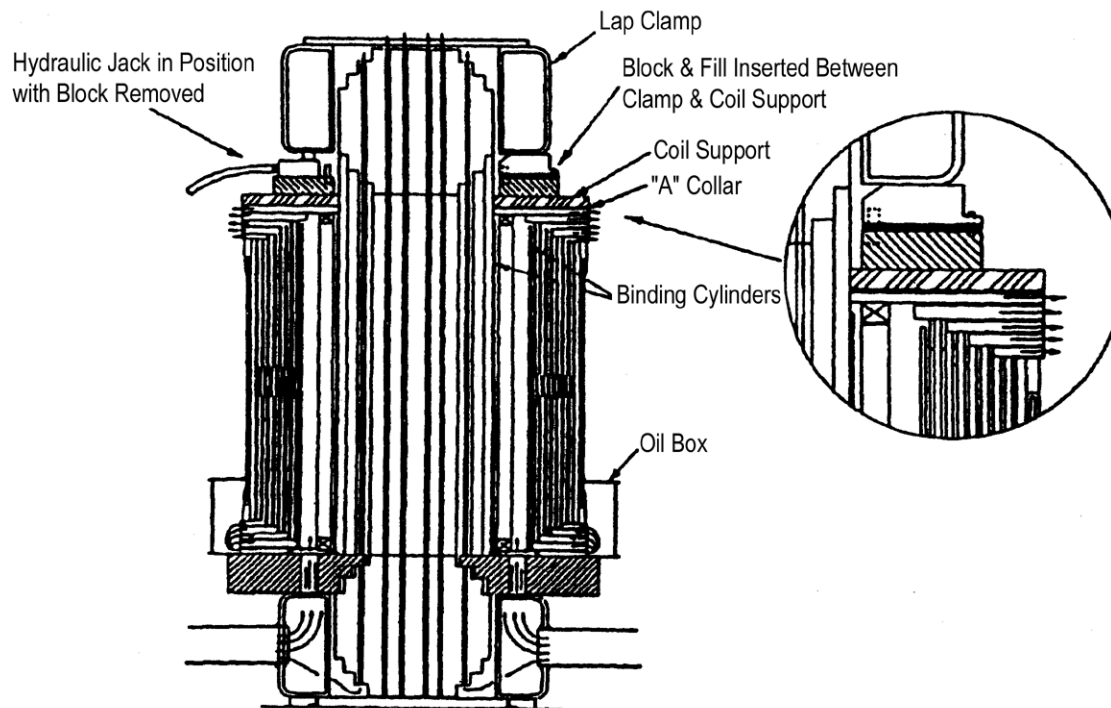


Figure 3-7
Clamping of Core Laminations
(Courtesy of GE)

3.3.1 Core Form

In the core form transformer, the windings surround the laminated core (see Figure 3-8). Three-phase transformers are usually designed as three-legged core. In cases of large capacity transformers, four or five-legged cores could be preferable to reduce overall physical dimensions of the transformer. This type is better suited to higher voltages, which require windings with many turns and heavy insulation. However, the size of the windings does require much more insulation. The core form design utilizes a multiple leg magnetic core that distributes flux more evenly which reduces the harmonics in the transformer. Also, this provides better distribution of induced currents across the full circuit.

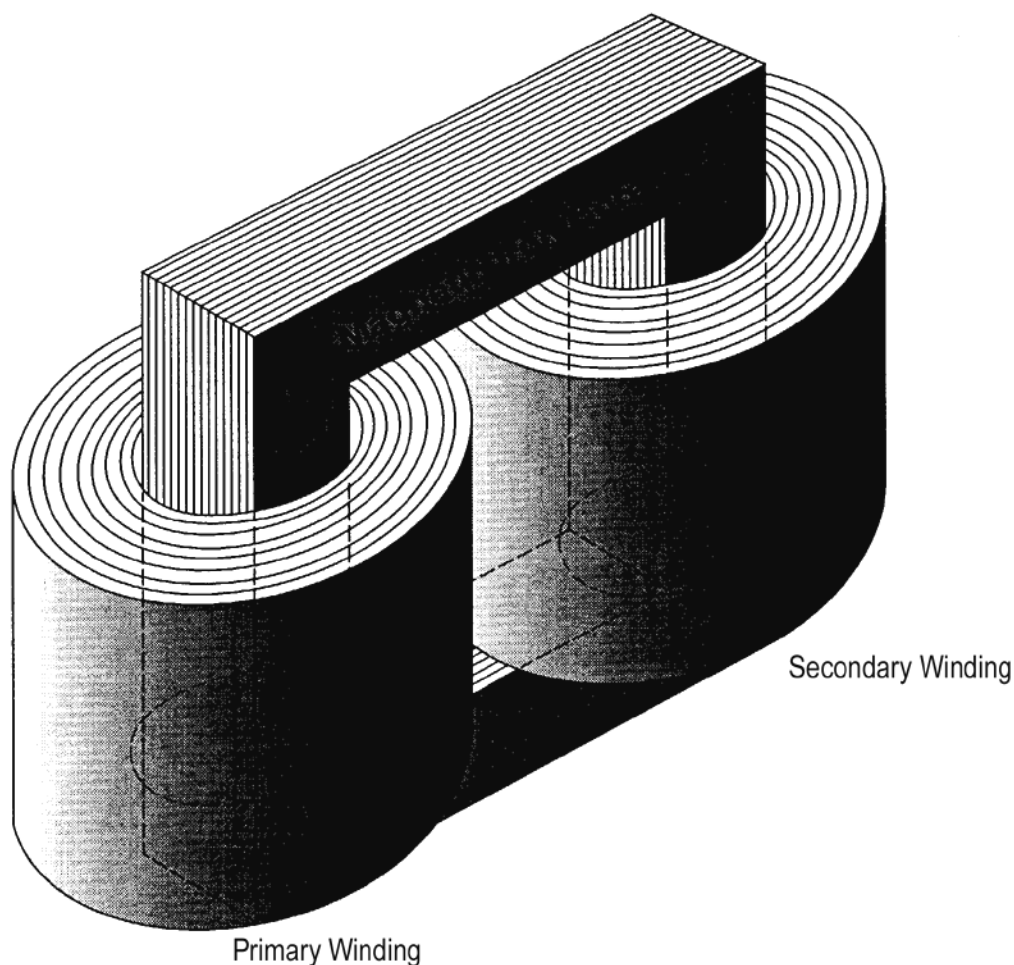


Figure 3-8
Core Form Transformer

3.3.2 Shell Form

In the shell form transformer, the magnetic core surrounds the windings (see Figure 3-9). The coils are typically disc or oblong-shaped and are stacked in the form of pancakes to form the winding configuration. The low voltage coils are normally located adjacent to the core iron to minimize the amount of high voltage insulation required to ground. In a shell form transformer the core leakage flux is reduced to a minimum because the coil windings surround the inner core and the outer core surrounds the coil. This type is suited for transformers of moderate voltage, requiring few turns and little insulation, large currents, and low frequency with corresponding magnetic flux. Use of the shell form may require a flux shield to be installed because the core is external to the windings.

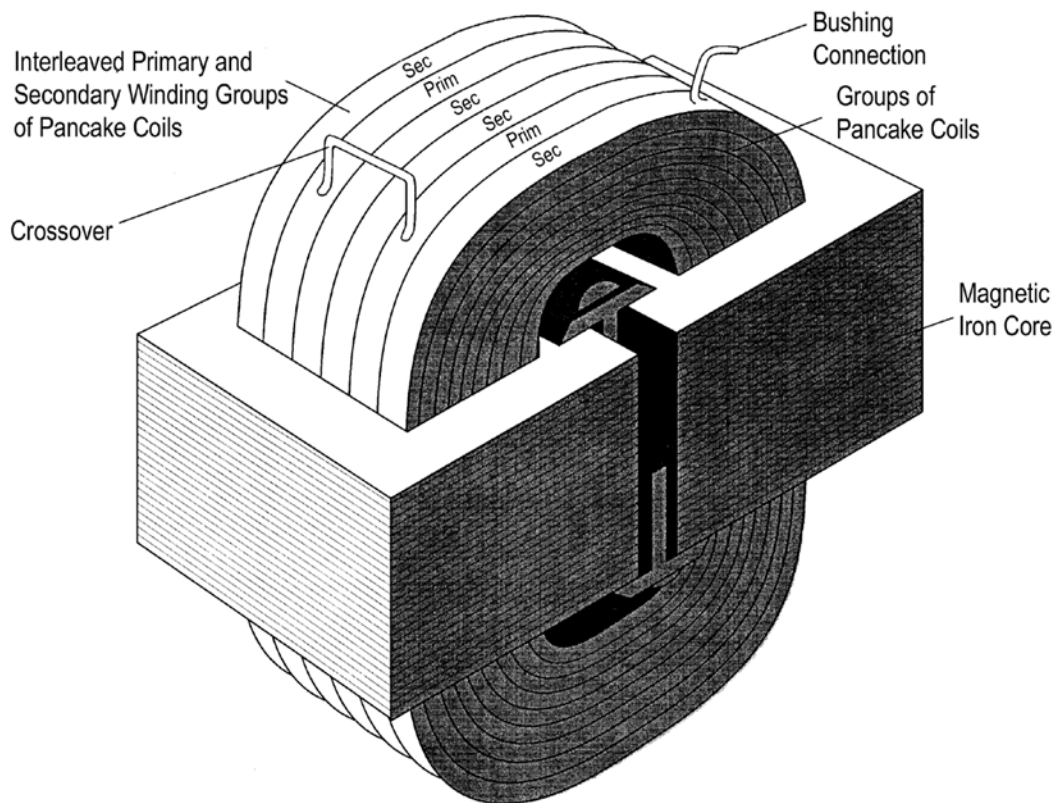


Figure 3-9
Shell Form Transformer

3.4 Coils/Windings

Transformer winding coils are designed and wound around the core according to the transformer ratio, that is, the number of turns. An individual coil turn can consist of many copper strands that are insulated individually. The entire turn is usually wrapped in paper insulation. A turn usually consists of several individually insulated copper conductor strands. The turns are constructed by winding them over a winding cylinder, which is mounted on a winding mandrel (see Figure 3-10).



Figure 3-10
Construction of Cylindrical Windings
(Courtesy of SMIT)

3.4.1 Coils

Some of the basic types of transformer coils are disk and helical. A disk coil consists of physically parallel winding sections that are connected electrically in series (see Figure 3-11). Each section of the winding contains one or more turns. Radial and axial spacers are placed between each section to provide insulation between sections and to allow oil to cool the copper conductors.

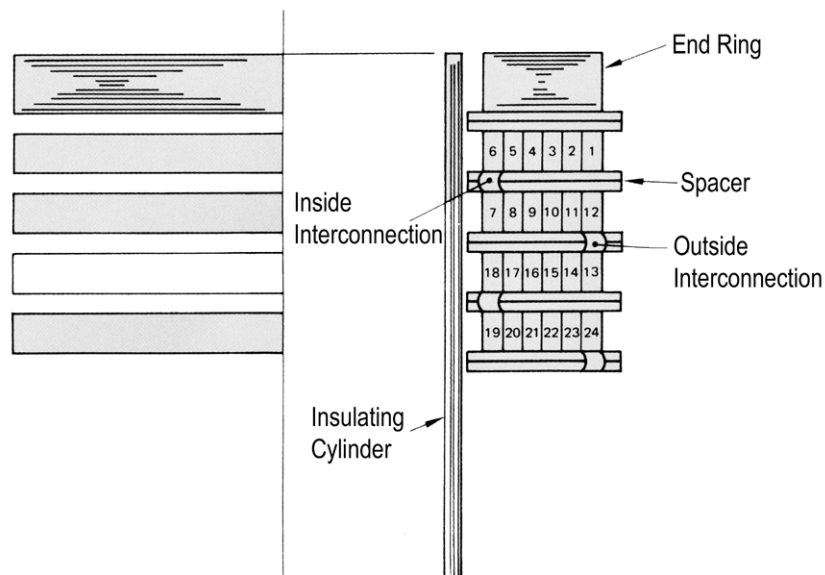


Figure 3-11
Disk Winding
(Courtesy of Waukesha)

A helical coil/winding is frequently referred to as a screw winding because of its shape and the way it is constructed (see Figure 3-12). Radial and axial spacers are placed between turns of a helical coil/winding for insulation and cooling purposes.

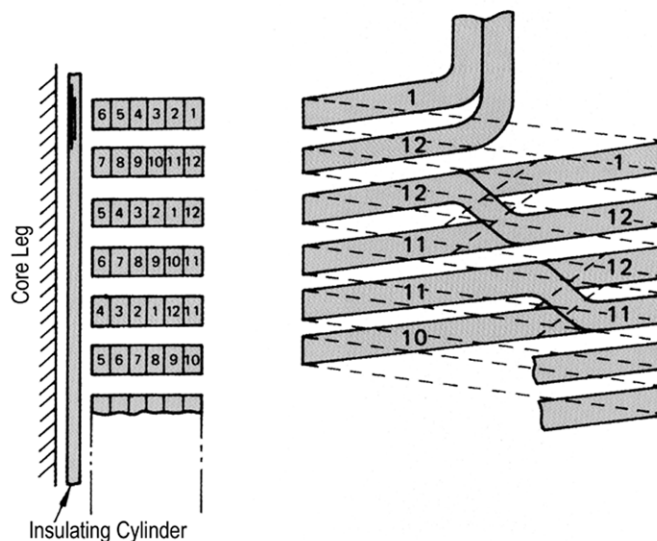


Figure 3-12
Helical Winding
(Courtesy of Waukesha)

A layer winding consists of one or more layers of coils that are placed on top of each other, but separated from each other by paper or pressboard insulation.

3.4.2 Number of Windings; HV, LV, and TV

The generator step-up transformer is usually a two winding transformer with primary and secondary windings. The primary winding is usually connected in delta (Δ), while the secondary is the high voltage and is wye (Y) connected. Figure 3-13 shows various transformer primary and secondary phase relationships.

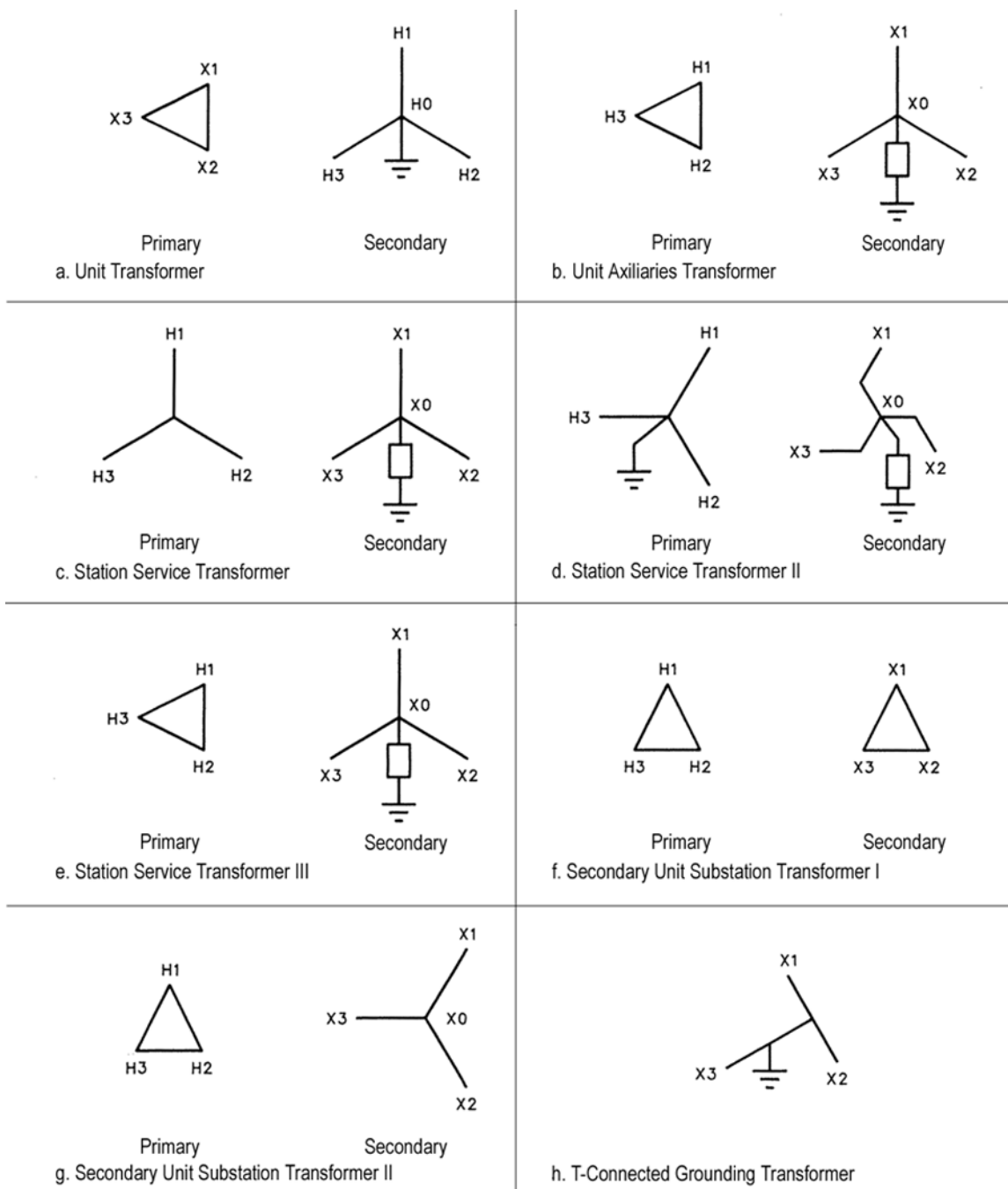


Figure 3-13
Transformer Primary and Secondary Phase Relationships

The delta-to-wye connection is often used for distribution when a four-wire secondary distribution is required. The delta-connected primary permits single-phase line loads to be connected between the secondary neutral and the line leads.

The wye-to-wye connection is used when tying together two high voltage transmission systems of unequal voltage. The configuration allows grounding of the neutral on either the primary or secondary side.

The wye-to-delta connection may be used for power distribution and transmission. This permits single-phase and three-phase loads to be drawn simultaneously from the delta-connected secondary at the same voltage.

Two winding transformers are designated as high voltage (HV or H) and low voltage (LV or X). When there are more than two windings, the windings are designated as H, X, Y and Z.

The auxiliary transformers in many cases have three or four windings. The UATs and RATs/SATs require two secondary windings to supply power to the plant's auxiliary loads. In addition to the two secondary windings, a delta tertiary may be added to provide a low impedance path for the zero sequence currents. The tertiary winding is normally internal to the tank without external connections and bushings.

3.4.3 Tertiary Windings

A number of large power transformers have been manufactured with a delta-connected stabilizing winding in wye-wye-connected transformers. The stabilizing winding is an auxiliary winding used particularly in wye-connected transformers for such purposes as the following:

- To stabilize the neutral point of the fundamental voltages
- To protect the transformer and the system from excessive third-harmonic voltages

The stabilizing winding provides an internally closed circuit for zero-sequence and third harmonic currents. The presence of a delta-connected, low impedance path, allows current to circulate around the delta in the event of unbalance in the loaded phases, so that this unbalance is reduced and not so greatly fed back through the system.

The tertiary winding must be strong enough mechanically, have the required thermal capacity, and have sufficient impedance with respect to the two main windings to withstand the effects of a short-circuit across the phases of the main windings.

3.5 Insulation System

Various types of materials have been used to insulate winding conductors from each other and from ground, but the most widely used, by far, is paper insulation. Electrical grade paper is made from high quality pulp that has been refined to remove chemicals found in ordinary paper. When dried and impregnated with good quality oil, electrical grade papers have high dielectric strength.

Other types of insulation, such as enamels, are commonly used to insulate the copper strands that make up a coil.

3.5.1 Paper Conductor Insulation

Paper insulation applied to winding conductors is from 0.002" to 0.005" thick. It is applied to the conductor by a taping machine using a spiral wrap. More than one thickness may be applied, depending on the dielectric requirements.

The thermal properties of paper insulation were improved in the early 1960s by treating them with certain chemicals. These thermally upgraded papers allowed the average winding temperature rise for a transformer to be increased from 55°C to 65°C. This made it possible to obtain more KVA from a transformer without increasing its physical size.

As paper ages, it becomes brittle. A measure of the brittleness can be determined by a test called degree of polymerization (DP). The cellulose molecules in paper consist of long chains of glucose rings. As the paper ages, the length of the glucose rings shorten which causes brittleness of the insulating paper. The DP test measures the average number of glucose rings in a paper sample. New insulating material has a DP of 1100 to 1200. Insulation end of life is generally considered to occur when the DP is reduced to a value of 200. To perform this test, it is necessary to remove a sample of paper from the transformer, usually from a lead because they are more accessible than winding insulation.



Key Technical Point

As paper ages, it becomes brittle. A measure of the brittleness can be determined by a test called degree of polymerization (DP).

3.5.2 Paper Barrier Materials

Besides the insulation that is applied to the windings, insulating barriers must be used between parts of the winding and between separate windings. Since these materials are not applied directly on the winding conductor, they do not need to be thermally upgraded. They are made in sheets with thicknesses from 0.015" (0.318 mm) to 0.25" (6.35 mm).

3.5.3 Insulation Coatings

Enamels are frequently used for strand insulation where the voltage between strands is low or for low voltage applications. One of the problems encountered when using synthetic insulating materials is that they may deteriorate over time when used in hot oil. Obviously, it is important that all enamel coatings be checked for compatibility with transformer oil.

One of the most widely used enamel insulation coatings is the formvar family of polyester resins. Epoxy resins are also used in some applications because they have higher temperature resistance than the formvars. However, the epoxy resins are more costly than the formvars.

3.5.4 High Temperature Materials

In certain applications, such as mobile transformers, it may be desirable to operate the transformer at higher temperatures. Nomex™ insulation films have been used for such applications. It consists of a polyester material that has a very high temperature characteristic and is compatible with transformer oil. Compared to paper insulation, it is quite expensive.

3.6 Insulating Liquid

The core losses and copper losses in the transformer are converted to heat. Unless some means is provided for continuously removing the heat from the core and windings, they would get progressively hotter, and eventually result in failure of the transformer.

Oil is used to provide heat transfer and improve insulation properties. Most insulating and cooling oils have several characteristics that are important to the function of power transfer in transformers. These characteristics are:

- *High dielectric strength*—a resistance to the flow of electric current.
- *Low viscosity*—flows easily, even at low temperatures, to provide good heat removal. Low viscosity also makes cooling oil better able to quench arcs and dissipate arcing products when the oil is used in circuit breakers and other arcing-contact equipment.
- *Purity*—essentially free from corrosive or damaging elements that could injure insulation or the materials of construction.

The oil used in transformers is a highly refined mineral oil. When new, its properties generally conform to ASTM D3487, which is the “Standard Specification for Mineral Insulating Oil Used in Electrical Apparatus” [5].

Transformer oil is a very good insulator when its moisture content and contamination level is very low. Besides being an excellent insulator itself, transformer oil causes the paper insulation used in transformers to also be a good insulator when it is impregnated with the oil.

In the past, transformer oil was produced from crude oils by the acid refining process. The present method used is the hydro-refining process. Although the processes are different, the oils being produced are, for all practical purposes, the same.

Transformer oil will maintain its maximum dielectric properties if the moisture content is kept low, such as between 5 ppm and 10 ppm (parts per million). The dielectric breakdown voltage of oil with 10 ppm of moisture is approximately 45 kV (when tested per ASTM D1816-1997) [6]. If the moisture content is increased to 25 ppm, the breakdown voltage is reduced to 35 kV. Another factor that will reduce the dielectric properties of transformer oil is the presence of particle contamination. More information is contained in Section 5.4.4.

In the past, transformers were built with Askarel rather than oil to eliminate the fire and explosion hazard caused by mineral oils, especially for indoor installations. Askarels, known as “polychlorinated biphenyls” (PCBs) were used as the predominant solid insulating material in

kraft cellulose-based paper. Askarel has been used in the past in combination with electrical grade trichlorobenzene (TCB).

In recent years, Askarel/PCBs have been banned in the U.S. (see Federal Register 40 CFR Part 761) because of their carcinogenic properties.

With the ban on Askarel, silicon liquids have been introduced for use in transformers instead of mineral oil. Silicon liquid is less flammable than conventional oil.

Nevertheless, most power transformers have been designed and built with mineral oil. Additives are inserted into the insulating fluid to improve long-term characteristics. These may include oxidation inhibitors and anti-sludging additives.

To improve cooling, heat exchangers are designed and installed on transformers that are located nearest the points where the internal heat is generated. Typically, on larger transformers, heat is transferred to and from the oil by pumping the oil through the heat exchangers. The transfer of heat through the heat exchangers by pumps is far more effective than the self-cooled or fan-cooled units.

The core, coils, and supports that make up the transformer solid insulation are impregnated with insulating liquid mineral oil. The primary functions of the insulating oil are to insulate the primary from the secondary windings and ground, and to transfer the heat from the windings to external cooling equipment. Oil penetrates and fills the spaces between the core and coils, thus maintaining the quality of paper and other cellulose-based insulation material.

3.7 Transformer Accessories

Transformers have various types of installed accessories that are used to monitor and/or provide protection for transformers. The chief components and how they operate are covered in the following sections.

3.7.1 Oil Level Indicator

The oil level indicator is a self-contained float-operated instrument and is used to indicate the level of the insulating fluid in liquid-immersed transformers (see Figure 3-14). A common design of indicator uses a pivoted float arm located in the tank. This arm is magnetically coupled to a shaft and pointer arrangement outside of the tank, thereby allowing a completely sealed interface. When the position of the float changes, the magnetic coupling is rotated; this moves the pointer a proportionate amount. In addition, the indicator includes alarm switches for monitoring functions.



Figure 3-14
Liquid Level Indicator
(Courtesy of Qualitrol)

3.7.2 Oil Temperature Indicator

The oil temperature indicator consists of a temperature-sensing bulb, indicating device, and a switch. The indicating device is connected through a capillary tube to the sensing bulb that fits into a well near the top of the transformer tank (see Figure 3-15). The indicating device has an analog scale, usually in degrees Celsius, and an indicating needle that is operated by the sensing element. Switches are actuated by the needle or the sensing element. These switches can be used to control fans, pumps, or annunciator circuits. The indicator has switches for automatic control of one or two stages of cooling fans, plus an alarm switch. These devices typically include an extra pointer that indicates the highest temperature reached for a particular period. This pointer will remain in place until manually reset.



Figure 3-15
Front View of a Liquid and Winding Temperature Indicator
(Courtesy of Qualitrol)

3.7.3 Winding Temperature Indicator

This device is supposed to indicate the hottest spot in a winding based on the manufacturer's heat run tests. For the most common type of winding temperature indicators, a simulated winding temperature is obtained by adding to the top oil temperature, a temperature increment that results from the heat produced by a current proportional to the load current flowing through a heating element. Earlier versions of these devices used a physical resistance, located in a well near the top of the tank, to create the additional heat, but new types can now do this through software.

In addition to the resistance temperature detector (RTD) type device described above, there are other electronic devices available that use fiber optics for high-accuracy temperature monitoring. These devices are user-friendly with computer-aided set-up software combining microprocessor technology and advanced digital signal processing.

3.7.4 Gas Detector Relay (Buchholz Relay)

A gas detector relay is used on transformers with a conservator tank. The relay and the indicator are mounted on top of the transformer. The relay is connected to a gas accumulator with tubing. The gas accumulator is under the top cover of the transformer (see Figure 3-16). Under normal conditions, the gas accumulator is filled with oil. During abnormal conditions in the transformer tank, gases are generated from the deterioration of insulation or decomposition of oil around hot spots. Gases will be generated by an incipient condition and rise to the center of the domed transformer cover passing through the gas collector to the gas relay. If a significant amount of gas is generated, an alarm will be actuated.

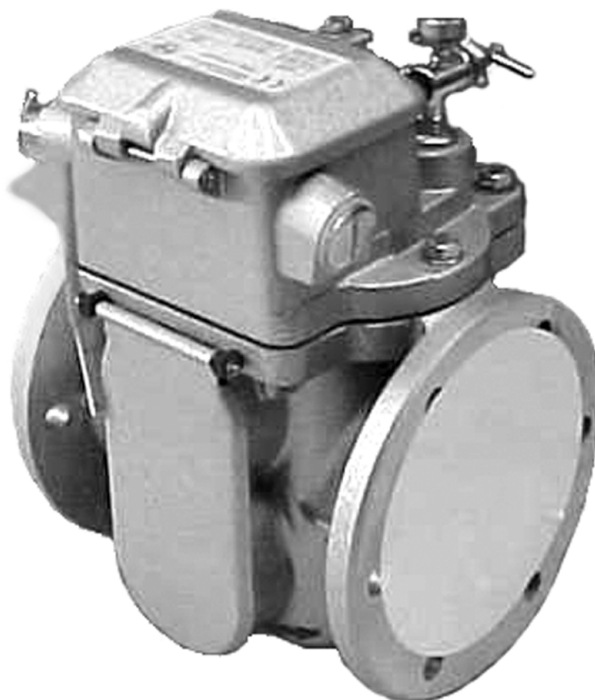


Figure 3-16
Gas Detector (Buchholz) Relay
(Courtesy of General Electric)

3.7.5 Pressure Relief Device

The pressure relief device mitigates the affects of large pressure changes in the transformer. The tank/enclosure design pressure [approximately 10 psig (0.69 bar)] is higher than the normal operating pressure but not sufficient to withstand pressures resulting from large internal faults. The pressure relief device utilizes one or more springs held in compression attached to a relief diaphragm (see Figure 3-17). When pressure on the diaphragm is sufficient to compress the springs, the diaphragm will move, thus relieving the pressure from the tank. The valve reseats after pressure is reduced.

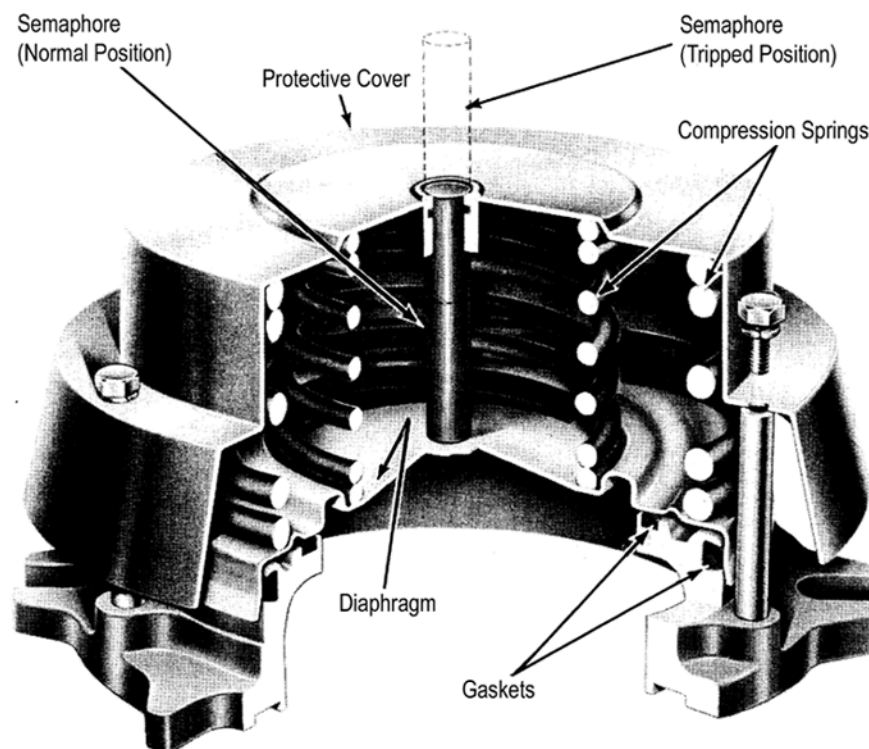


Figure 3-17
Pressure Relief Device
(Courtesy of Siemens-Westinghouse)

3.7.6 Sudden Pressure Relay

The sudden pressure or fault pressure relay detects sudden pressure transients produced within a transformer tank during operation. It senses the rate of change of pressure during internal faults. If the internal pressure exceeds the safe limits, the relay will activate the tripping scheme to de-energize the transformer. This relay does not act as a pressure relief device.

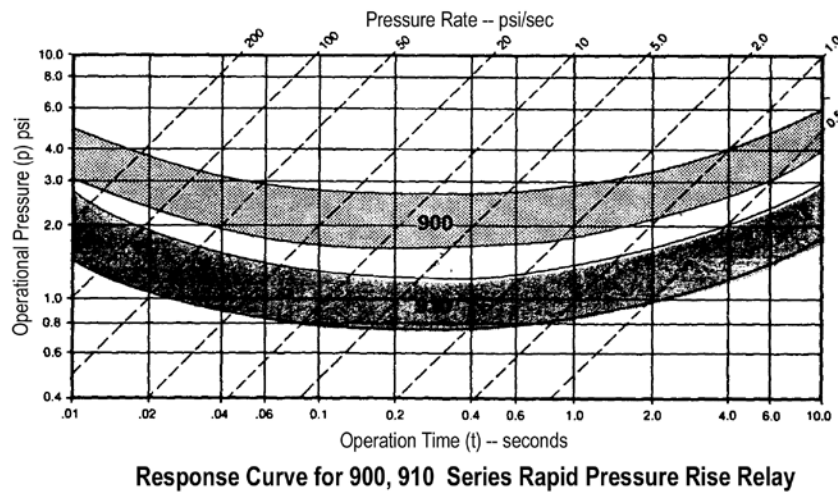
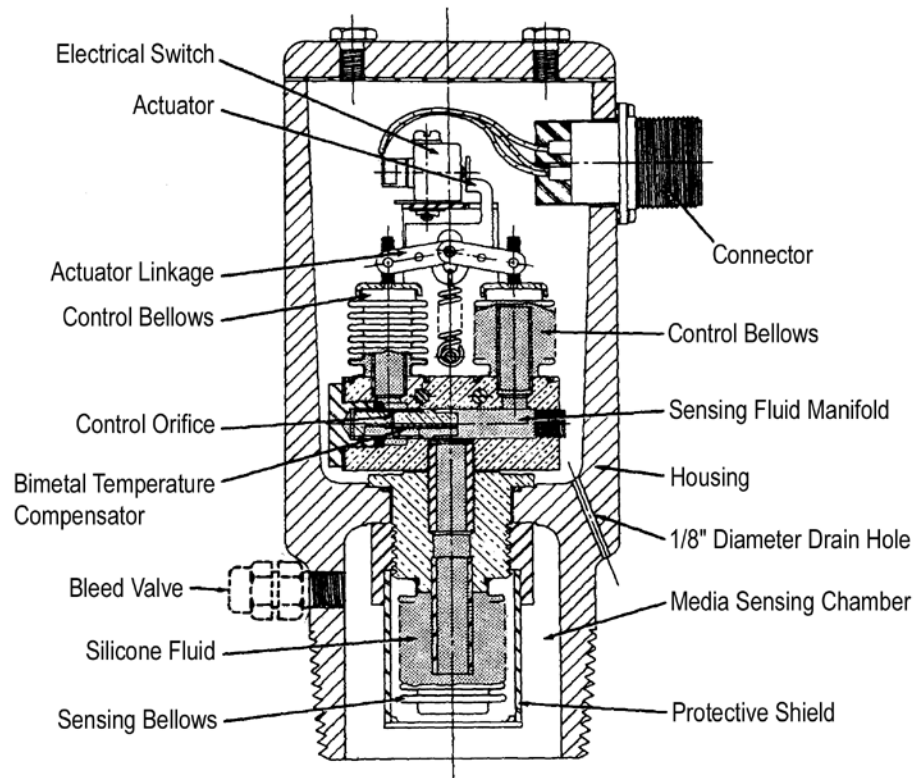


Figure 3-18
Response Curve for 900, 910 Series Rapid Pressure Rise Relay
(Courtesy of Qualitrol)

The Qualitrol 900, 910 series rapid pressure rise relay uses a series of bellows to mechanically determine the rate of fluid pressurization (see Figure 3-18). The 900 series models are designed for mounting under oil and the 910 series models mount in the gas space. Pressure transients applied to the sensing bellows result in the displacement of fluid of known viscosity (such as silicone oil) through various orifice channels. At low rates of pressurization, the fluid flows through the different size orifices at nearly equal rates thereby allowing force equilibration. At higher rates of pressurization, the smaller orifices create a significant pressure drop on the downstream side of the orifice, thereby resulting in a force imbalance with those orifices of larger diameter. This force imbalance is applied to a spring-loaded rocker arm assembly that actuates an electrical contact upon displacement from its null position. Depending on the configuration of the supporting wiring, this contact closure will either provide a remote alarm or cause the transformer to be de-energized.

Once the rate of pressure increase is reduced, and the differential fluid flow and resulting force imbalance will cease, the relay rocker arm returns to its null position and the relay resets. The sudden pressure relays are also usually temperature compensated to allow relatively stable pressurization rate detection throughout the design ambient temperature envelope.

3.7.7 Deluge/Fire Protection

Large power transformers can fail from either an internal or external electrical fault that results in over pressure of the tank. In cases where an internal pressure increase is rapid, the pressure relief device may not be adequate to prevent tank failure. Tank failure could release substantial quantities of insulating liquid and could initiate a fire.

National Fire Protection Association (NFPA) 70-1996, “National Electric Code” [7] and NFPA 850, “Fire Protection for Fossil Fueled Steam Electric Generating Plants,” [8] specify the type of protection required for oil-filled outdoor transformers. Protection includes the following:

- Separation
- Fire barriers
- Detection and water spray system
- Containment

According to NFPA requirements, a containment system must be provided for the GSUs and auxiliary transformers. The containment system should consist of a pit or a diked area and a drainage system for removal of rainwater. The pit or diked area should be of sufficient size to hold the oil contained in a large transformer.

Fire detectors are installed on top and around the transformer to activate the deluge systems in case of a fire. Because of false activation, thermal line wire, such as thermistor wire (or “protecto” wire), has been replacing fire detectors. The wire is installed like the detectors on top and around the transformer and is terminated at both ends in a control cabinet to activate the deluge system.

In addition to the transformer relay protection for large power transformers, the following are recommendations for relay and deluge activation:

1. Transformer differential relay operation should initiate the deluge system.
2. Transformer sudden pressure relay operation should initiate the deluge system.
3. Manual stations and the deluge valve weight switch (if installed) should initiate the deluge system only. The manual stations should be equipped with a protective guard to prevent accidental activation.
4. Thermal detection should be connected to alarm only.
5. Transformer oil cooling systems should not be tripped from the deluge system.
6. When possible the deluge system should be exercised regularly with the transformer de-energized to flush the piping system of impurities.
7. The direction of the spray nozzles should be such that the stream is aimed down at the transformer case and not directly at the bushings.
8. The deluge header pressure switch should be connected to alarm only.

3.7.8 Nitrogen Regulation System

The nitrogen regulation system is used to maintain positive pressure of nitrogen gas in the tank from an external gas cylinder. It prevents the oil from coming into direct contact with the surrounding atmosphere.

The gas regulation system consists of the gas cylinder, high and low pressure valves, by-pass valve, pressure bleeder, hoses, alarm contacts, and gages. A high-pressure regulator with an adjusting screw is connected between the high-pressure gage and low-pressure regulator and the piping to the tank. The nitrogen regulation hoses are connected to the top of the transformer tank. The gas cylinder is usually enclosed in a metal cabinet by the transformer.

The transformer is equipped with a nitrogen pressure indicator with a ± 5 psi (± 0.34 bar). The pressure indicator must be above zero and some positive pressure up to 5 psi. When the pressure in the tank drops below 0.5 psi (0.034 bar), gas is admitted into the transformer and is turned off as soon as the pressure rises above 0.5 psi. The nitrogen regulation is equipped with a bleeder valve device to expel gas when the internal tank pressure exceeds 8 psi (0.55 bar).

Alarm contacts are activated when the pressure in the nitrogen storage cylinder drops below 300 psi (20.68 bar) to warn personnel that a new gas cylinder is needed. The regulating system will continue to operate until the cylinder is emptied. Prompt action is required not to allow complete gas depletion. Additional alarms are provided to function when the transformer tank pressure drops below 0.25 psi (0.017 bar) or exceeds 8.5 psi (0.59 bar).

3.8 Cooling System

Many large power transformers are designed and built with a self-cooled rating and a cooling system to increase its rating by increments of one-third with the additional cooling. The self-cooled capacity is obtained by convection with radiators, while the forced-cooled ratings are obtained with fans and/or pumps.

The cooling process within the transformer is accomplished by cool oil flow through the radiators, then oil flows into the manifold, through the pump, and into the bottom of the transformer where it is distributed by a system of baffles. In some cases, the pump has adequate clearance around the impeller to permit free passage for self-cooling when not running.

3.8.1 Fans and Radiators

For oil filled transformers, fans and radiators are mounted at various locations around the transformer. Radiators are used to transfer heat from the oil to the surrounding atmosphere. Fans are usually mounted on the radiators to assist the radiators in heat removal. Fans for forced circulation increase the capacity by a single increment (Class OA/FA or ONAN/ONAF) or in two increments (Class OA/FA/FA or ONAN/ONAF/ONAF).

Fan assemblies are supplied with different motor hp ratings and fan blades depending on the transformer design. Fan motors are protected by a thermal element mounted inside the motor. Individual fan assemblies are connected to the power source with conduit and flexible cable to permit removal of a fan for repair work. The fan assemblies, motors, cables and conduit boxes are weatherproof design and are suitable for outdoor use. The correct fan rotation is when the airflow from the fan is through the radiator tubes and away from the transformer tank.

3.8.2 Oil Pumps

The transformer oil pump is an electrically operated pump that forces oil from the transformer tank through the radiators or heat exchangers (see Figure 3-19). The winding temperature device controls the pump.

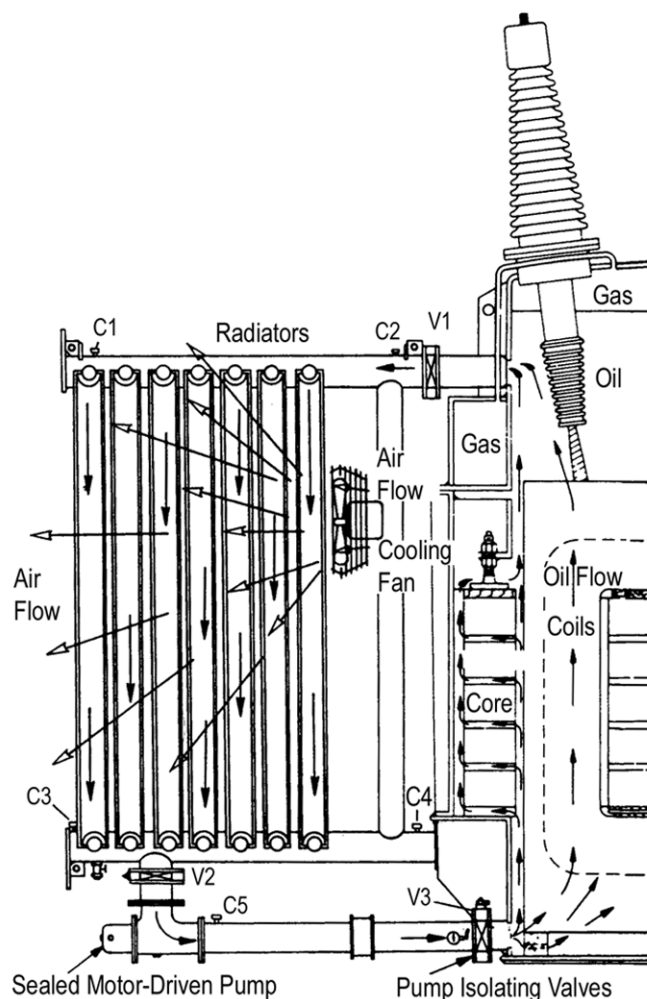


Figure 3-19
Typical Class OA/FOA/FOA Cooling System
(Courtesy of McGraw Edison)

Transformers equipped with oil pumps also have the means of indicating oil flow. A typical oil flow indicator is a vane-operated device that is found on either the suction or discharge pipes of the transformer oil pump. The flow indicator is designed to indicate by dial that the pump is on or if the oil flow is not sufficient, and then the alarm will be activated. The correct rotation is indicated on the pump with an arrow and the oil flow indicator.

3.9 Tap Changers

Transformers can be provided with a mechanical switching device to adjust the voltage ratio by means of adding or removing of voltage taps from the winding. The change is achieved either manually (no-load) or with load (LTC).

3.9.1 No-Load Tap Changers

No-load tap changers employ manually operated switching equipment that changes the turns ratio of the three phases simultaneously and by the same amount. In the case of single-phase transformers, each transformer has its own manually operated no-load tap changing switching device. The no-load tap changing switching device is located in the main tank along with the core and coils, and the operating handle is normally located externally on the side of the transformer tank.

The no-load tap changer can be operated only when the transformer is de-energized. Therefore the term “no-load” is really a misnomer because the transformer must not only be at no-load, it must also be de-energized. The IEEE standard term for the device is “tap changer for de-energized operation.”

Conventionally, a transformer has two full capacity $2\frac{1}{2}\%$ no-load taps above and two below rated voltage. In a step-down transformer, the taps above rated primary voltage are less likely to be used than those below it. For that reason, some transformers are purchased with one tap above and three taps below rated voltage. Also, the taps could be specified to be closer together than $2\frac{1}{2}\%$, or omitted altogether, particularly in power plant applications. If the taps are changed, the impedance of the transformer will also change and, in some cases, a short circuit study should be made.



Key Human Performance Point

Prior to initial energization or after the taps have been changed, the transformer turns ratio (TTR) test should be performed to check that the contacts have seated properly and, therefore, that each winding has the same ratio.

3.9.2 Load Tap Changers (LTC)

An LTC provides the mechanism to change taps without interruption of the load current. They are often used in distribution substations, but are relatively uncommon in power plants. A conventional LTC in the United States has 32 voltage taps at $\frac{1}{8}\%$ spacing, 16 above and 16 below rated voltage, to produce a voltage range of $\pm 10\%$.

When changing from one tap to the next, the present tap and the next tap must be switched from one to the other without causing an open circuit. Therefore, one contact will need to move and connect to the next tap position before the other contact moves off its tap position (make before break). This will result in an unacceptably high circulating current between the taps and in order to limit that current, transition impedance must be connected between the adjacent taps.

3.9.2.1 Resistance/Reactance

The two types of transition impedances used in LTCs are resistance and reactance. Resistance-type LTCs are characterized by short switching durations (40 ms to 180 ms) in order to limit resistor heating. This type of LTC is not able to operate continuously while bridging two

contacts. Since the transition resistance undergoes heating during the tap change operation, the transition resistance is susceptible to coking.

Resistance-type LTCs are normally located in the main tank of the transformer. This type of tap changer is mounted to the cover of the main tank and is suspended in the oil of the main tank. The usual configuration has the tap selector (non-interrupting) contacts sharing the main tank oil, but with the current interrupting contacts inside a separate cylinder containing its own oil.

Reactance-type LTCs utilize a center-tapped reactor, also known as a preventive autotransformer, which is capable of carrying full load current continuously. Therefore, LTCs of this type are capable of operating on the bridging, or half-cycle, tap positions, effectively doubling the number of voltage steps for a given number of physical taps. In addition, since this reactance does not experience significant heating during tap change operation, the rapidity with which the tap change must be completed is less than with resistance-type LTCs. Therefore, reactance-type LTCs can use slower, less complicated, and consequently more reliable drive mechanisms.

Reactance-type LTCs are normally located in compartments welded or bolted to the outside of the main tank. Tap leads are passed into the main compartment through an oil-tight tap board. LTCs of this type may be further divided into two separate oil-tight compartments to prevent oil degradation products resulting from arcing at the current interrupting contacts from contaminating the oil of the tap selector and contributing to the deterioration of the tap selector contacts.

3.9.2.2 Switching Oil/Vacuum

Three methods are used to interrupt the current and, thereby, accomplish switching in an LTC:

1. Selector switch (arcing tap switch) type. The selector switch, also called “arcing tap switch” type, is the simplest type of switching mechanism. This type of mechanism combines the duties of selecting tap position and interrupting current. In its simplest form, the selector switch type consists of a set of stationary contacts, with one for each tap position, and two moving contacts.
2. Diverter switch (arcing switch) type. The diverter, also called “arcing switch” type of switching mechanism separates the duties of tap selection and current interruption into two separate devices. The tap selector is similar to the selector switch described previously, however; it does not interrupt current. The tap selector generally consists of several stationary contacts and a set of moving contacts. To select the tap position, the moving contacts are simply moved from one stationary contact to the next. Current interruption is accomplished by a set of arcing contacts. These contacts are usually made of a material with high ablation resistance, such as silver tungsten, for higher current capacities, or copper for lower current interrupting duties.
3. Vacuum interrupter type. Electrically, the vacuum interrupter type of switch mechanism is the same as the diverter switch type. The difference lies in the mechanics of the diverter switch operation. In the diverter switch type outlined above, the arcing due to the opening

and closing of the diverter switch occurs in oil. In the vacuum interrupter type, the arcing occurs in a vacuum. The vacuum interrupter consists of a set of contacts sealed in a vacuum chamber. Usually, one of the contacts is stationary, while the other is a spring-loaded moveable contact. The vacuum serves to limit the arc duration and intensity, thereby limiting the damage and erosion of the contacts.

3.10 Lightning/Surge Arresters

Transformers are subject to surge voltage from switching operations, system disturbances, or lightning. Some of these disturbances may create abnormally high voltages that reach the transformer terminals.

Lightning arresters play a vital role in the protection of transformers against transient over voltages resulting from lightning surges due to lightning strikes and other system-switching transients. The proper selection and application of the surge arrester is an integral part of the selection and design of the transformer insulation. Figure 3-20 shows a cutaway of a typical lightning arrester. The arrester is composed of an external porcelain tube containing an arrangement of stacked discs (or valve blocks) that are composed of a silicon carbide material. Arresters are effectively switching devices that serve as an insulator under normal conditions and as a conductor under overvoltage conditions. Arresters are constructed of series repeating sections. When an overvoltage condition is cleared, the arrester must return to its normal insulating condition. Figure 3-20 shows spark gap material, metal-oxide varistor (MOV), and a typical arrester.



Figure 3-20
Typical Lightning/Surge Arrester and Internals

An arrester consists of an air gap in series with a resistor element. A common type of arrester in use is the valve type, which consists of one or more gaps in series with a dielectric element serving as a high resistance. Another name for this type of arrester is called spark gap type.

Another type of arrester is the MOV. The metal-oxide surge arresters are utilized under nominal power system frequency of 48 Hz–62 Hz. The ambient air temperature in the general vicinity can be between -40°C and $+40^{\circ}\text{C}$. Operating characteristics, performance characteristics, design testing, and other pertinent information can be found in the IEEE Standard C62.11-1999. Figure 3-21 depicts a typical transformer and lightning arrester installation.

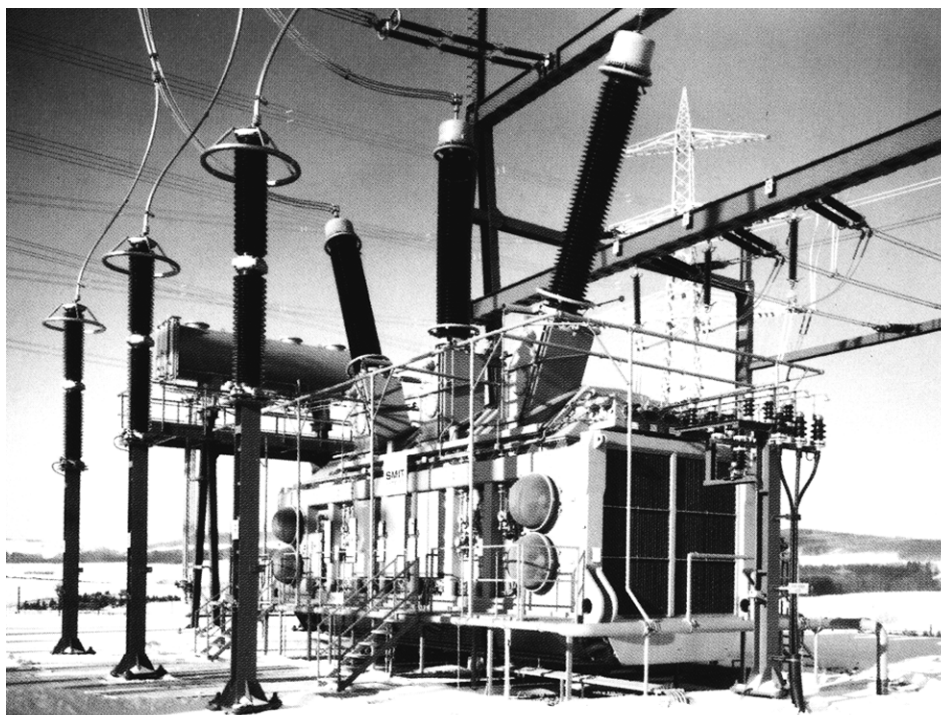


Figure 3-21
Typical Lightning Arrester Installation
(Courtesy of Smit)

A metal oxide arrester consists of a varistor being embedded in a ceramic insulator. In an overvoltage or other transient condition, the non-linear resistance lowers so that the excessive voltage is shunted to ground. With the nominal operating voltage, the metal oxide arrester has a very high resistance and therefore has only an insignificant leakage current. For that reason no additional spark gap is required. This allows for a faster reacting arrester than the spark gap type. MOVs will pass more leakage current as they age and degrade.

ANSI Standards C62.2 and C62.22 cover important considerations for selecting valve-type and oxide surge arresters.

For an optimum surge protection, the surge protection should be as follows:

- The voltage rating of the arrester should be equal to or greater than the normal line-to-ground voltage of the transformer.
- The arrester should be connected as close as possible to the transformer primary bushings.
- The arrester should be grounded to the tank and neutral ground.
- The resistance of the arrester ground connection should be a maximum of 5 ohms or less.

Use of in-service and out of service tests can be useful to assess the condition of arresters. Because arresters are resistive in nature and perform as insulators practically all of their service lives, tests normally performed are those that measure the ability of an arrester to act successfully

as an insulator. Only when arresters are removed from service and returned to a service shop might other tests for power-frequency withstand or sparkover be performed.

Field tests that are performed to check the insulating capability of an arrester can, to a greater or lesser degree, also indicate its internal condition. For example, an ac dielectric loss measurement that is significantly higher than measurements on similar units can be indicative of moisture and/or internal foreign particle contamination. If infrared readings are significantly higher than on similar units, these are usually indicative of excessive losses leading to abnormal heating. These two tests are the most commonly used as screening tests to detect any abnormalities in arrester condition. These tests are also considered to be indicative of conditions that may cause either the malfunction or failure of an arrester to operate properly under surge conditions. Note that the infrared test is performed with the arrester in service and that the ac dielectric loss test is performed with the arrester out of service.

In specific applications the arresters may have an arrester discharge counter and grading current instrument installed. The arrester discharge counter records on a cyclometer indicator the number of current discharges through the ground lead of the arrester. The arrester should be examined when the counter registers a discharge.

The arrester grading current instrument provides a continuous reading of the grading current and is typically connected with the discharge counter bypass. The grading current instrument provides information pertaining to degradation of the sealed arrester. Readings are noted on installation of the unit and the current is trended for variations. The meter will read both surface current and grading current so the readings should be taken with the arrester clean and dry under similar conditions.

An additional test applicable to those units in a SF₆ environment is the sparkover gap test. A spark gap is internal to the arrester and the purpose of the spark gap is to determine if SF₆ gas has leaked inside the arrester housing. SF₆ gas in the housing will cause the spark gap to increase. The sparkover of the gap should be monitored by sparking the gap (eight to ten times) to determine an average gap, with this test performed on a periodic basis through the life of the arrester.

3.11 Bushings

Bushings are insulating devices used on liquid-immersed transformers to insulate and seal the winding terminal connections through the grounded metal cover or sidewall of the tank. Bushings serve to insulate the primary and secondary windings from the tank. The bushing must provide sufficient dielectric strength to withstand the high voltages and is skirted to provide a long surface creepage path from the terminal to ground. A skirted non-conducting porcelain weather shield is used over the upper external portion to provide a long surface path from the terminal to the ground flange, as well as facilitate moisture run-off from the shield.

There are two primary types of bushings, based on how the bushing is connected to the winding: the fixed-conductor type where a central tube or rod conducts current from top of the bushing terminal to the bottom terminal which in turn is connected to the transformer winding; and the draw-lead type, in which case the winding lead is pulled through the central tube and connected to the top terminal.

Figure 3-22 shows a typical connection between transformer winding and bushings. These flexible connections should remain tightly clamped. If they are allowed to become loose, they could cause a short circuit; thus, causing a transformer failure.



Figure 3-22
Flexible Connections between Transformer Winding and Bushings
(Courtesy of Bob Beavers—Exelon)

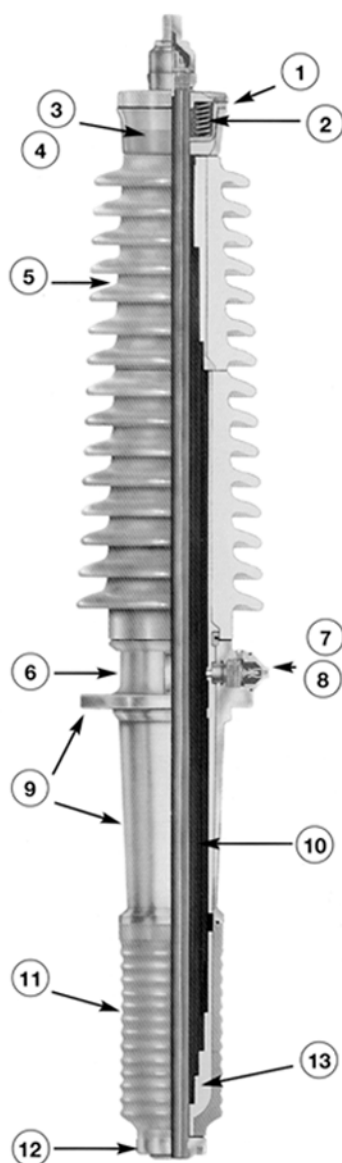
For power transformer high voltage applications, capacitor-type oil filled bushings are standard equipment (see Figure 3-23). These condenser types of bushings have layers of oil-impregnated kraft paper with aluminum or copper foil layers between them inside the porcelain cylinder. These foil layers form a series of condensers to equalize voltage distribution. Lower voltage bushings may or may not need to utilize the condenser-type design (see Figure 3-24).

Bushings can be equipped with either a power factor or a potential tap, depending on their voltage application. These taps are used during testing and grounded while the transformer is in service.

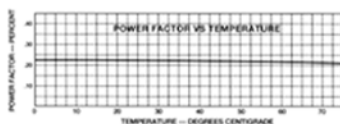
Bushings can be tested by utilizing the potential taps or power factor taps. The capacitance and power factor test results provide information that allows one to determine if there is a short-circuit in the condenser foils. An increase in the power factor is an indication of presence of moisture or other contaminants. Airborne contaminants (conductive and/or non-conductive), such as dust and salts, when combined with water can cause partial discharges and flashovers by providing a conductive coating on the surface of the bushing.

The hot collar test can be used to detect localized defects in bushings. The test is performed by energizing one or more temporary electrodes (collar of semi-conducting rubber) placed around the outside of the porcelain with the central conductor grounded. This test is useful when the

condition of a specified section of the bushing needs to be investigated for cracks in porcelain, degradation of fluid inside the bushing, or low liquid level.



The curve below shows typical power factor versus temperature relationship of Lapp POC bushings.



Lapp capacitor-graded bushings for transformer and oil circuit breaker applications are a proven design based on a capacitor core with aluminum foils and high dielectric paper impregnated with dried, degassed oil. Lapp POC bushings meet all ANSI/IEEE standards for outdoor apparatus bushings, where these standards apply for voltage classes 25 kV through 500 kV. When a transformer application results in overload above ANSI/IEEE standards, a bushing having a higher current rating is recommended. Lapp POC bushings for other applications (e.g., oil-to-oil, oil-to-gas, outdoor-to-indoor air, etc.) are available for various voltage classes and current ratings.

Design Features

1. Gaskets

Cork-nitrile rubber gaskets are designed to provide even loading and oil-tight seals with extended life.

2. High Compression Coil Springs

Multiple heavy-duty coil springs provide uniform, active compressive loading on gaskets to compensate for temperature variations and to assure oil-tight joints and reliable mechanical strength.

3. Clear-View Oil Reservoir (Medium and High Voltage Bushings)

The tinted glass oil reservoir filters damaging ultraviolet rays, preventing oil deterioration. The oil level and condition is clearly visible from any angle.

4. Magnetic Oil Gauge (Extra High Voltage Bushings)

The oil level is indicated by the pointer on the gauge.

5. Porcelain Housing

The outdoor porcelain housing has sturdy sheds to provide the required leakage and strike distance and has ground surfaces on top and bottom ends for oil-tight gasket seals.

6. Name Plate Data

The name plate affixed to the mounting flange identifies the bushing by catalog number, serial number and year of manufacture with electrical ratings and factory measurement data.

7. Power Factor Test Tap (Medium Voltage Bushings)

25 kV through 69 kV bushings have a power factor test tap. The test tap

is connected to the ground layer of the capacitor core. An aluminum cap covers the insulated test tap assembly and grounds the tap to the flange when energized.

8. Voltage Tap or Capacitance Tap (High and Extra High Voltage Bushings)

Bushings rated at 115 kV and above have a permanent internal ground. In addition, an insulated tap is connected to a floating capacitor layer. This tap, designated a capacitance tap or a voltage tap, is grounded except when used as a voltage source with a potential device. The voltage tap also serves as a means of measuring power factor and capacitance of the bushing core. The tap is ANSI standard type A, normally grounded.

9. Mounting Flange, Ground Sleeve Assembly

The mounting flange and ground sleeve assembly is made of aluminum and provides nonmagnetic, corrosion-resistant, high-strength service.

10. Paper-Foil Capacitor Core

Conductive layers of aluminum foil with high dielectric paper are wound around the conductor and into the bushing core to produce uniformly valued capacitors in series. This capacitance grading distributes the voltage and the electrical field uniformly throughout the core. The core is vacuum-dried and impregnated with dried, degassed oil.

11. Lower Porcelain Assembly

The lower porcelain has ground gasket surfaces on each end to facilitate alignment and maintain an oil-tight assembly.

12. Bottom Cap Assembly

A confined cork-nitrile rubber gasket provides a leak-proof seal between the porcelain and the cap. The end cap aligns the porcelain with the conductor. For bushings rated 115 kV through 161 kV, the bottom cap is adaptable for use in draw-lead and bottom-connected applications.

13. Dried, Degassed Oil

The internal space in the bushing between its exterior components and the core is filled with dried, degassed insulating oil.

Figure 3-23
Apparatus Bushing of the Paper-Oil Capacitor (POC) Type
(Courtesy of LAPP)

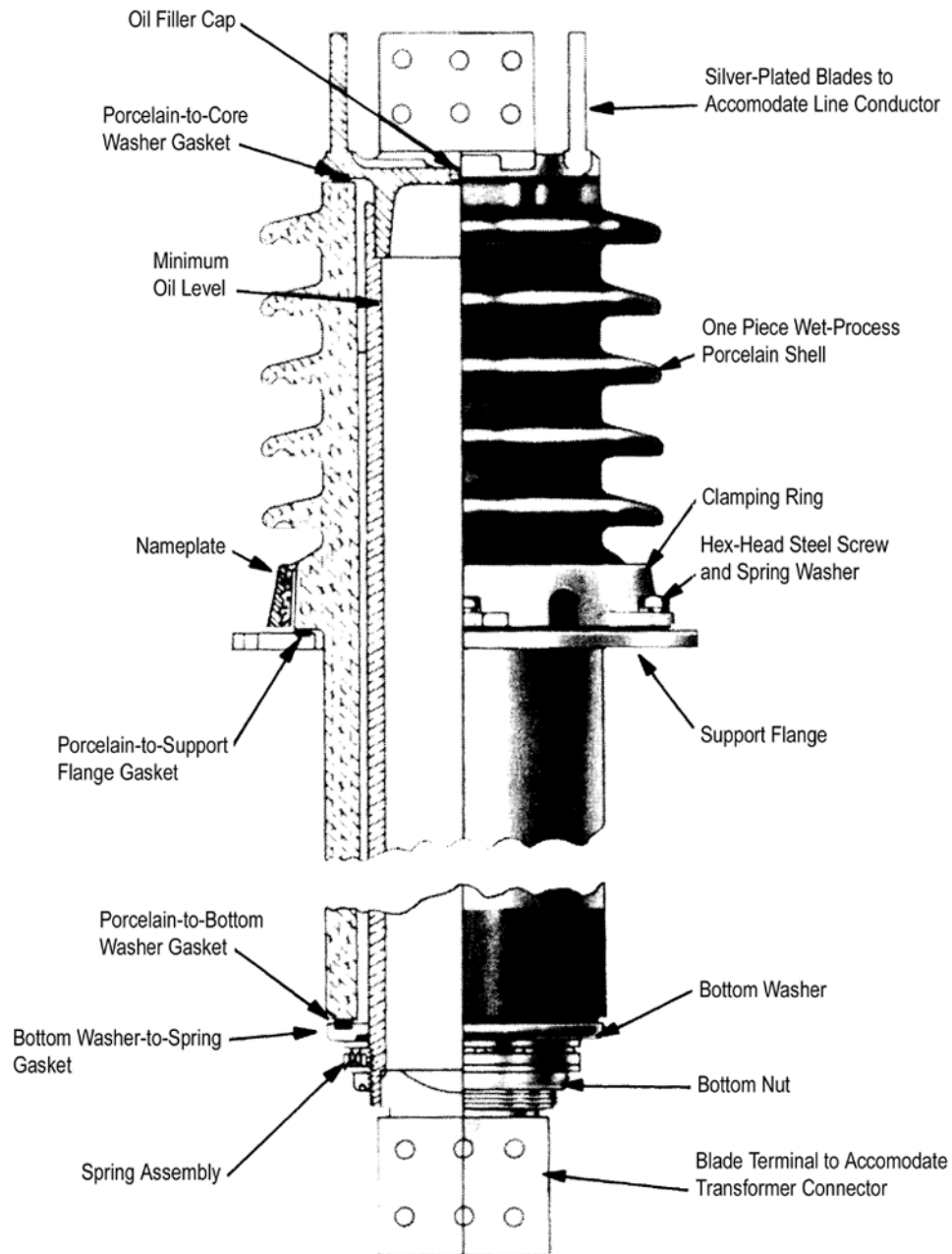


Figure 3-24
High-Current Type-A Bushing 25-kV, Class-4500 A and Above

3.12 Instrument Transformers

Instrument transformers are essential for measuring and controlling high voltages and high currents on electrical systems. These auxiliary devices change the magnitude but not the nature of the voltage and/or current that is being measured. There are two general types of instrument transformers: potential (voltage) transformers and current transformers.

Instrument transformers are most often deployed as single units but there are some units that are combined units—both PT and CT.

3.12.1 Potential Transformers (PTs)

Potential transformers (PTs) are also called voltage transformers (VTs) are used in the isophase bus duct to reduce the bus duct voltage to lower voltage for input to the relaying and metering protective scheme. Potential transformers consist of two separate windings on a common magnetic steel core and are similar to a basic transformer design. The primary winding consists of a large number of turns with a smaller size wire compared to the size of the secondary wire. The secondary winding has fewer turns of a heavier wire and the output is 120 volts as established by industry standards (see Figure 3-25).

Lower level potential transformers tap off the bus conductors and are usually enclosed in a metal compartment with the surge protection equipment. Typical PT compartments are the swing-out type to isolate the transformers and fuses. Swinging the unit out of the connect position, the transformer primary and secondary connections are isolated and the primary is momentarily grounded. Momentarily grounding the primary side allows personnel to pull out the primary fuses. Isolation is important for safety reasons to prevent accidental backfeeding from the secondary fuses.



Key Human Performance Point

Isolation of a PT by pulling primary fuses is important for safety reasons to prevent accidental backfeeding from the secondary fuses.

A potential transformer that is used for outdoor service is normally used on circuits 25 KV or greater. Potential transformers can be inductive (magnetic) or capacitive construction.

Inductive potential transformers are typically designed and constructed with similar insulation used in main power transformer windings—paper and oil insulation.

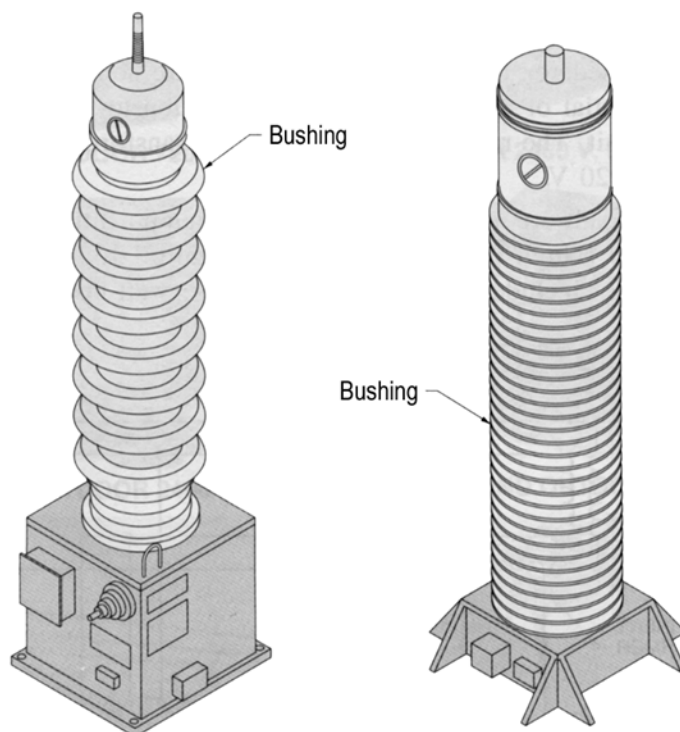


Figure 3-25
Inductive (Magnetic) Potential Transformer

The capacitive type potential transformer is typically used on systems with 100 KV or greater. It is often easier to design a capacitor type PT for higher voltage levels than a similar level of magnetic PT. A capacitor type PT is constructed by stacking a number of capacitors in series to be used with the applied voltage level. Capacitive PTs are more economical to manufacture for extra high voltage levels than magnetic PTs for similar voltage levels (see Figure 3-26).

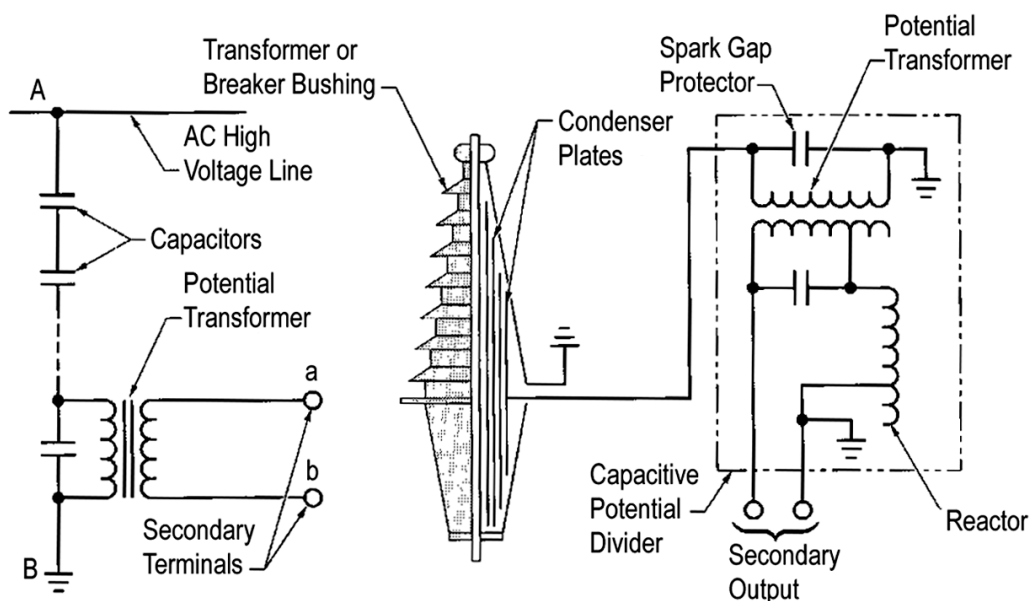


Figure 3-26
Capacitor Type Potential Transformer

3.12.2 Current Transformers (CTs)

Current transformers (CTs) are instrument transformers that are used to provide indication of the current that is flowing in the transformer and other conductors. CT lowers the secondary current to a safe level that can be used for control and metering. The secondary current is used for ammeters, wattmeters, varmeters, and relaying. The secondary output current for CTs has been standardized at 5 Amperes.

The ratio of the primary to the secondary is inversely proportional to the ratio of primary to secondary turns. For example, a current transformer with a ratio 800:5 has a load current of 800 Amperes and a secondary of 5 Amperes. Because the secondary current must be set, the secondary should never be open circuited because without the closed circuit path the CT would act as a step up transformer with a very high magnetizing current with an exceptional amount of flux in the magnetic core. Therefore, a CT should always have its secondary shorted when it is not connected to an external load in order to avoid dangerous and destructive arcing.

Most CTs are designed such that the primary winding consists of one or more turns of conductors with a large cross sectional area that is in series with the circuit that is being measured. The secondary of a CT is made of many small insulated conductors such that the output current is maintained at 5 Amperes. This design is known as a wound current transformer (see Figure 3-27).

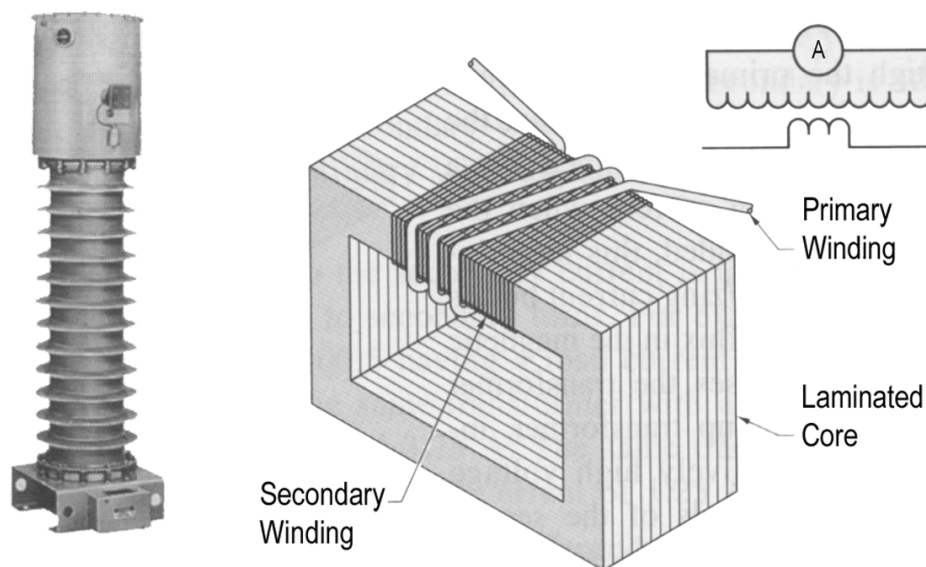


Figure 3-27
Wound Current Transformer

CTs can be classified as dry, compound-filled or oil. Dry-type or compound-filled CTs are used for voltages below 22,000 V. For voltages 22,000 V and greater, a compound-filled or oil-type CT will be used.

**Key Human Performance Point**

CT circuits should never be open while in service. Destructive arcing and a violent fireball will occur if the primary is energized.

**Key Human Performance Point**

Anyone working with CTs must always be sure that the secondary terminal points of the CT are in a closed circuit, and if not, they should be shorted together.

3.12.3 Rating of PTs and CTs

Besides the ratio of PTs and CTs, rating factor (RF) is another term that is used to specify this equipment. In the case of CTs, a rating factor is the number representing the amount of current increase beyond the nameplate current without exceeding the allowable temperature rise. The standard ambient temperature is 30°C and 55°C. For CTs, the ambient temperatures apply to both primary and secondary winding rating while for PTs the ambient temperatures apply to the secondary loading only.

As an example, a RF for a CT can be 2.0 at 30°C and 1.5 at 55°C, which means that the transformer will be able to carry 2 times the nameplate current at 30°C and 1.5 times the nameplate rating at 55°C.

Other important design and application parameters for CT and PTs are:

- Insulation class
- Polarity
- Accuracy classification and burden
- Excitation curves

Figure 3-28 shows some typical PTs and a CT with shorting bar. (Note that instrument transformers shown in Figure 3-28 are typically panel-type PTs and CTs).

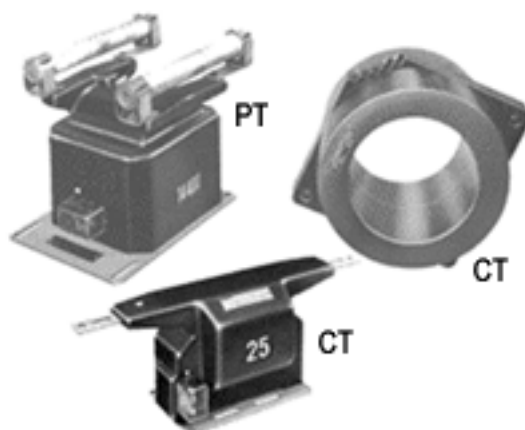


Figure 3-28
Panel-Type PT and CT

3.13 New Sensor Technology

Optical voltage and current sensors are being investigated as alternative to conventional instrument transformers. These new sensors offer many advantages such as improved accuracy, zero risk of explosion, lighter weight, and low to no ferro resonance.

Optical sensors use fiber-optic cabling to connect the actual sensor to electronics that process the signal and provide indication (see Figure 3-29). The sensor is a passive optical device that requires minimal maintenance. These devices are a foray into the world of digital technology. With these new devices, the output signal level can be changed to any level that would allow for more sensitive relaying and metering and avoid saturation issues associated with existing instrument transformers.

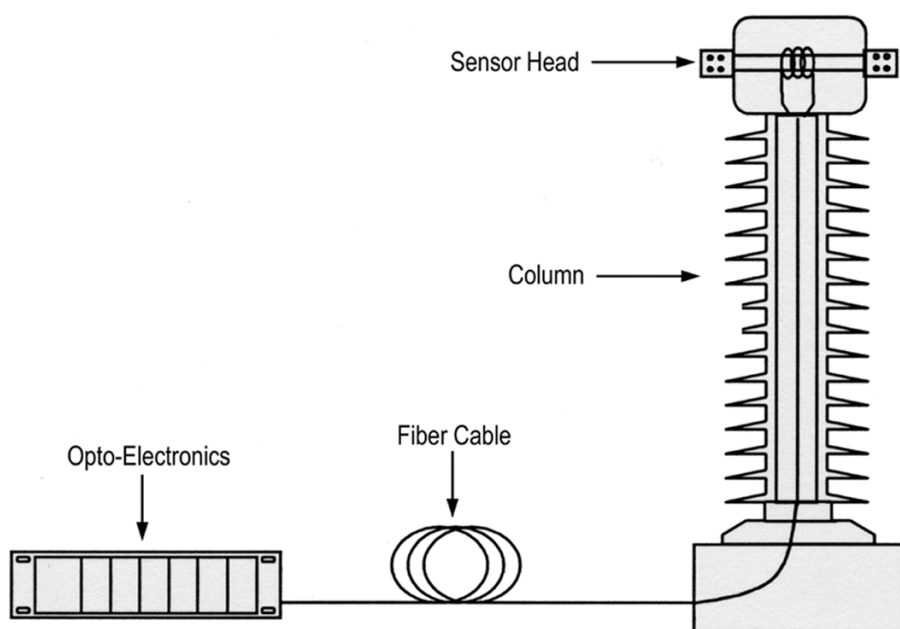


Figure 3-29
Typical Optical Current Transducer Setup

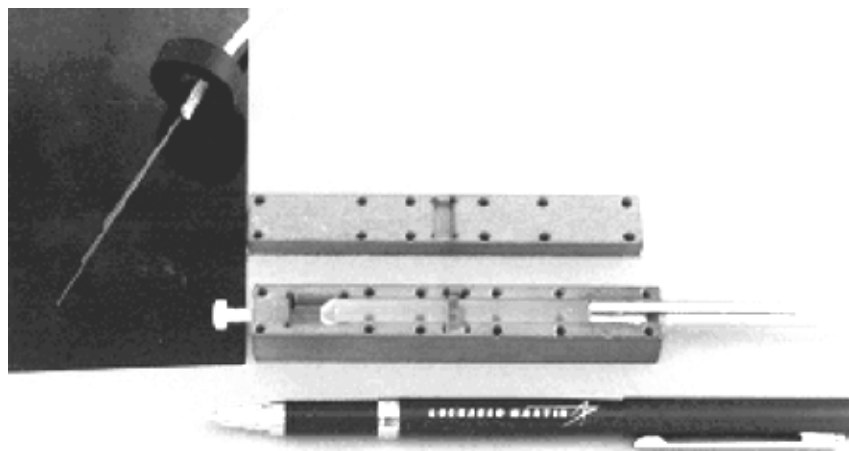


Figure 3-30
Example of Electro-Optic High Voltage (EOHV) Sensor
(Developed by G. Seifert, J. Davidson, and T. Crawford for INEEL)

3.14 Control Cabinet

The control cabinet is a weatherproof metal enclosure designed to prevent the accumulation and freezing of standing water along the panel doors. It houses all auxiliary devices except those that must be located directly on the transformer. Auxiliary devices in the control cabinet include fuses, breakers, control devices (relays and starters), alarm relays, and associated terminals for wiring and testing.

The control cabinet also houses the ac auxiliary power for pumps and fans, and dc control power. The ac auxiliary power normally has two sources of power and an automatic throw over scheme in case the normal feed fails to allow the emergency source to close in after a momentary interruption.

Figure 3-31 is a photograph of a typical control cabinet including the ability to switch between two control power supplies.

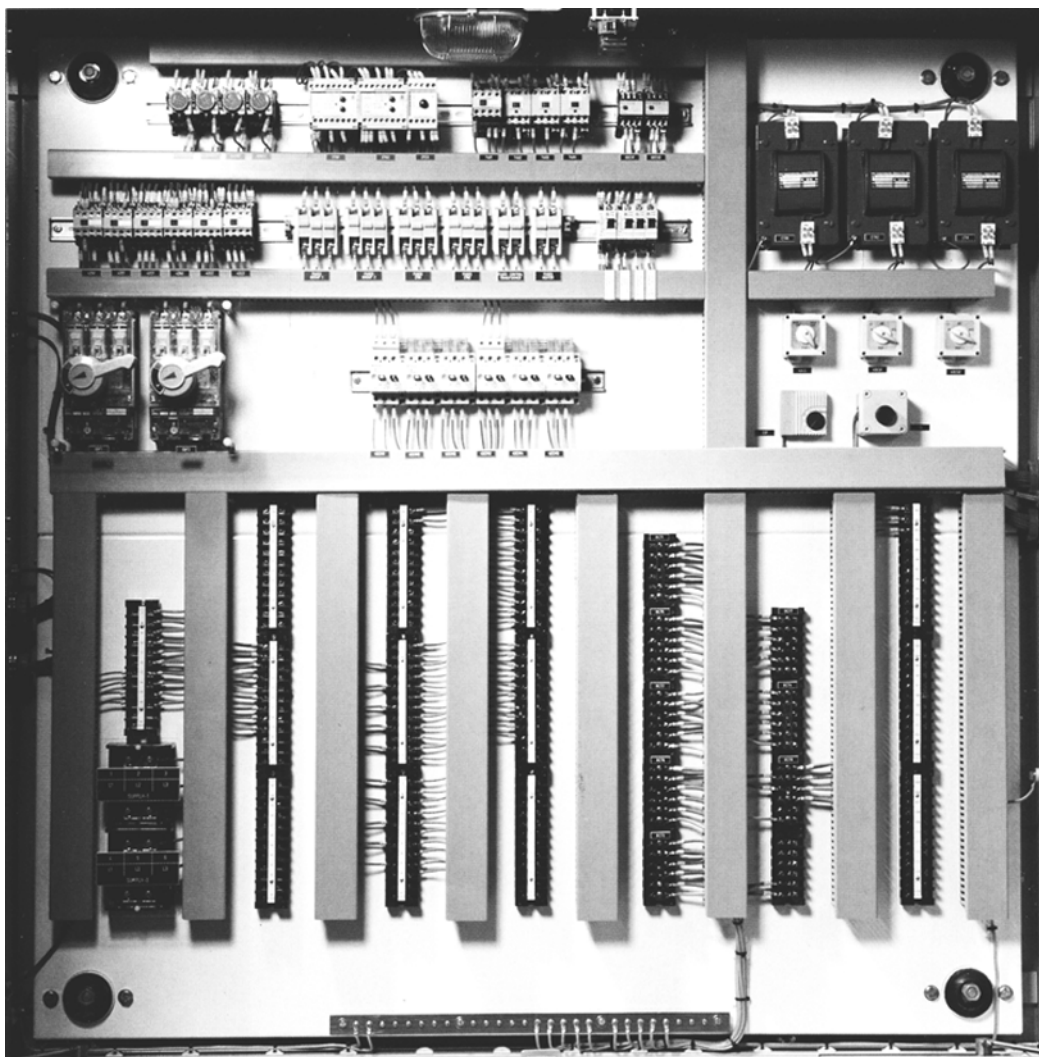


Figure 3-31
Typical Control Cabinet

3.15 Transformer Grounding

Transmission or distribution systems are grounded systems through a transformer with wye-windings and with the neutral point of the windings solidly grounded or connected through a non-interrupting, current-limiting device such as a reactor or a resistor. If the transformer neutral is not grounded, the neutral voltage could rise during fault and the neutral insulation could be overstressed. If neutral reactors are used in the transformer neutral, a system fault-study should be performed to size the reactor or resistor so that the neutral-to-ground voltage from a fault should not exceed the rated voltage of the transformer neutral. When a neutral is electrically tied down to ground, its potential can never rise or sink, and the transformer designer can determine the neutral insulation grading according to the system voltage.

3.16 Power Uprate

Utilities have been upgrading isophase bus ducts and in some cases rewound generators in order to produce 3%–5% (and even 12%) more power from their existing equipment. In some cases, more cooling was added to the isophase bus duct to raise its current carrying capacity by 3%. Since all the isophase bus duct current passes through the main power transformer primary winding, steps must be taken to ensure the transformer rating is adequate. The transformer nameplate should be used as a guide not to exceed the transformer current rating. If the transformer must be operated for additional current, the manufacturer should be consulted for possible modifications, such as modification of cooling equipment or other possibilities.

3.17 Observations

Liquid-immersed transformers consist of a magnetic core-and-coils assembly immersed in oil having good heat transfer and insulating properties. Transformers are insulated to withstand the voltages to which their windings and terminals may be subjected to in service. Large power transformers have a self-cooled rating and one or two additional forced-cooled ratings.

Transformers are designed for continuous operation above rated voltage or below rated frequency at maximum MVA rating specified by design and nameplate information. The average winding temperature rise above ambient temperature shall not exceed 65°C at rated MVA. The maximum (hottest-spot) winding temperature rise above ambient temperature shall not exceed 80°C at rated MVA per IEEE Std. C57.12.00.

Transformers are designed with insulation to withstand the voltages to which their windings and terminals might be subjected while in service. Impulse overvoltages can be produced by lightning strikes on their terminals or in connected transmission lines, or impulse overvoltages resulting from switching operations. The basic lightning impulse insulation level (BIL) of a transformer is the greatest value of voltage it can withstand as a “full wave” defined in ANSI/IEEE Std. C57.12.00 and C57.12.90.

4

TRANSFORMER OPERATION

4.1 Introduction

During normal operation, the bulk oil, the temperature of the winding conductors, the temperature of the metallic parts, and the ambient temperature affects the overall temperature of a transformer. The oil expands when it gets heated and space must be provided for expansion. The conductor temperature must be maintained within its design limits and its current carrying capacity. The temperature of the core and all other metallic parts must be limited so that the oil and insulation will not be degraded.

The oil circulation in the windings depends on the natural convection flow of the oil, or the forced (pumped) flow within the windings, and the heat exchangers. Natural convection oil velocities are very slow, and the difference in the temperature between the top of the oil and the bottom can be large. Forced flow, on the other hand, reduces the difference in temperature between the top of the oil and the bottom of the oil.

Transformers conforming to ANSI/IEEE Standard C57.12.00-2000, “General Requirements for Liquid Immersed Distribution, Power, and Regulating Transformers,” should be suitable for operation at the rated values specified in the nameplate data provided by the manufacturer [4]. When they are operated within their nameplate ratings, their life expectancy is normal. The manufacturers are to provide the rated MVA output at the rated primary/secondary voltages, average ambient temperature of 30°C, and an average winding temperature rise of 65°C (standard) or 55°C can be specified, but is not standard.

Operation of all transformer components or accessories (such as pumps, bushings, and so on) must be done according to manufacturer’s instructions and limitations based on the equipment rating.

4.2 Temperature Rise

Temperature rise (TR) is the difference between the transformer operating temperature and the ambient (surrounding) temperature. The transformer operating temperature may be any one of the following:

- Top oil temperature
- Average winding temperature
- Winding hottest spot temperature

Transformer Operation

For example, if the top oil temperature is 60°C and the ambient temperature is 10°C, then the $TR = 60^\circ - 10^\circ = 50^\circ\text{C}$. When evaluating temperature rise, the top oil temperature rise, winding hottest spot temperature and average winding temperature can be used to establish temperature trending of the operating transformer. These indicators provide temperature data based on their locations within the transformer. The winding hottest spot and top oil temperatures will indicate greater fluctuations than the average temperature over time.

Since transformers are rated for an average winding temperature rise of 65°C, continuous operation at loads higher than the nameplate rating can result in accelerated thermal degradation of the solid insulation and gassing of the insulating oil. An incidental operation above 65°C can be permissible if the transformer is normally operating for periods at loads below nameplate rating and at ambient temperatures lower than 30°C. However, such an incident requires an immediate review, response and, if required, derating of the transformer because of possible partial or total loss of cooling.

In the past, liquid-immersed transformers were designed with a 55°C average temperature rise at rated MVA. The average temperature rise is the temperature above ambient when the transformer is operating at full load. Newer transformers are designed with a 65°C average rise, although 55°C is still specified by some users.

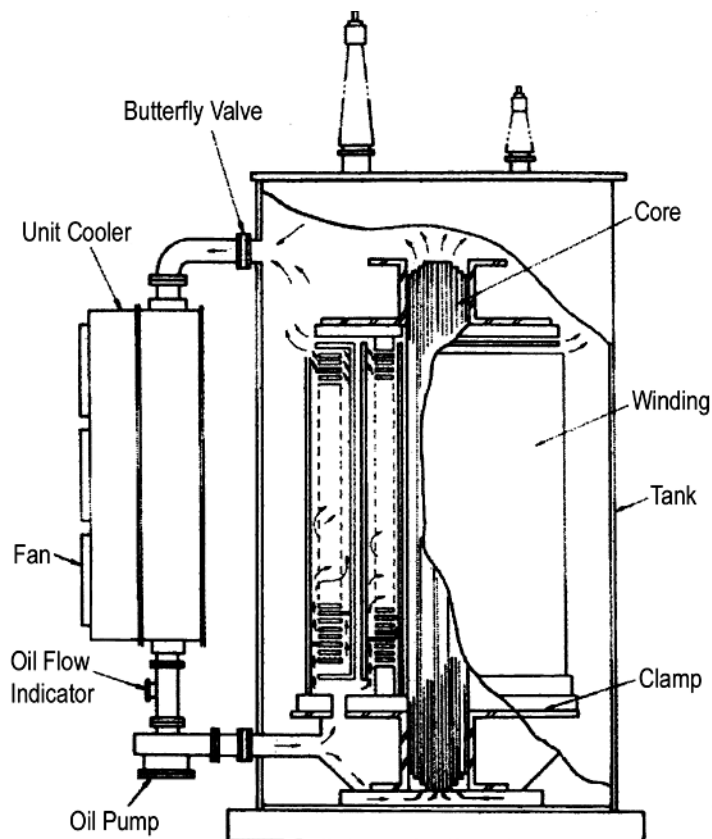


Figure 4-1
Forced-Oil, Forced-Air-Cooled Type Construction
(Courtesy of Toshiba)

4.3 Core Cooling and Cooling Classes of Transformers

Transformer cores and windings are normally designed to permit easy flow of oil inside the transformer tank throughout the core and coils. Insulating oil may be circulated throughout the transformer by pumps.

The cool oil moves from the oil ducts to the bottom of the tank, to be pushed again to the top of the transformer after it goes through the core and coils. The oil is then pumped through cooling fins located on the outside of the transformer, which radiate heat into the air. Air is drawn through the cooler/radiator by the fans, while a pump forces hot oil from inside the transformer through the oil ducts (see Figure 4-1).

Transformers are identified according to the cooling method employed. For liquid-immersed transformers, this identification is expressed by a four-letter code as described below. These designations are consistent with IEC 60076-2: 1993 and ANSI/IEEE C57.12.00, upon which the following material is based. The ANSI/IEEE cooling class designations have been changed in recent years to be consistent with the IEC designations. The ANSI/IEEE designations that were previously used for generating station transformers, and are shown on the vast majority of existing transformer nameplates, are described at the end of this subsection.

First Letter: Internal Cooling Medium in Contact with the Windings:

O—mineral oil or synthetic insulating liquid with fire point $\leq 300^{\circ}\text{C}$, normally used for transformers covered by this guide.

K—insulating liquid with fire point $> 300^{\circ}\text{C}$, would find application for indoor locations, but not for transformers covered by this guide.

L—insulating liquid with no measurable fire point would not find application for transformers covered by this guide.

Second Letter: Circulation Mechanism for Internal Cooling Medium:

N—natural convection flow through cooling equipment and in windings, sometimes called natural thermosiphon flow (no oil pumps)

F—forced circulation through cooling component (that is, oil pumps), natural convection flow in windings (non-directed flow)

D—forced circulation through cooling equipment, flow directed into at least the main windings (directed flow)

Third Letter: External Cooling Medium:

A—air

W—water

Fourth Letter: Circulation Mechanism for External Cooling Medium:

N—natural convection

F—forced circulation fans, pumps

Transformer Operation

A comparison of the cooling class designations used in IEEE Std. C57.12.00-1993 and in previous revisions, and the corresponding new designations, are provided in Table 4-1.

Table 4-1
Cooling Class Designation Examples for Typical Generating Station Transformers

Present Designations	Previous Designations
ONAN/ONAF/ONAF	OA/FA/FA
ONAN/ONAF/OFAF	OA/FA/FOA
ONAN/ODAF/ODAF	OA/FOA*/FOA*
OFAF	FOA
ODAF	FOA*

* Indicates directed oil flow.

Most in-service transformers have the previous designation of cooling class on their nameplates. For historical purposes, the information that follows provides further explanation about the previous cooling classes.

Many large liquid immersed transformers have a self-cooled rating and one or two additional forced-cooled ratings. The standard method of indicating these ratings is shown below:

- OA/FA/FA indicates that both the first stage and the second stage of forced cooling use forced air. The first stage uses half of the available fans (one bank); the second stage uses all available fans (both banks).
- OA/FA/FOA indicates that the first stage of forced cooling uses forced air and the second stage uses forced oil and forced air.
- OA/FOA/FOA indicates that both the first stage and the second stage of forced cooling use forced oil and forced air. The first stage uses half of the available fans and oil pumps (one bank); the second stage uses all available fans and pumps (both banks).

Transformers with a triple rating (OA/FA/FA, OA/FA/FOA, OA/FOA/FOA) have an increase of 33% MVA capacity for each cooling step. The 33% increased capacity is based on the first MVA base.

An example of how the transformer MVA rating is increased with the addition of cooling stages is shown in the following:

- Transformer rating at Full Load
- Self-cooled (OA) at 55°C rise 33 MVA
- First-stage cooling (FOA) at 55°C rise 44 MVA *
- Second-stage cooling (FOA) at 55°C rise 55 MVA *
- Second-stage cooling (FOA) at 65°C rise 61.6 MVA*

Note: * With 33% increase capacity

*At 65°C rise, the MVA capacity is increased by $55 \text{ MVA} \times 12\% = 6.6 \text{ MVA}$.

4.3.1 Loss of Cooling

Operation of transformers beyond their normal designed and operating rating causes loss of transformer life and should be avoided if at all possible. Operating temperatures exceeding the design temperatures and those recommended by the vendor could result in overheating that degrades the oil and paper insulation.



Key Technical Point

Operation of transformers beyond their normal designed and operating rating causes loss of transformer life and should be avoided if at all possible.

To deal with the possibility of unplanned loss of cooling, the manufacturer loading curves must be reviewed. These curves provide the transformer temperature rise versus per unit load and the violation area above 65°C.

According to IEEE C57.91-1995, Annex H, if partial cooling is available on OA/FA or OA/FA/FOA transformers, then the load rating should be based on the self-cooled (OA) rating. Section 4.3.3 of the standard provides guidance for permissible load in percent of nameplate rating versus percent of coolers in operation [9].

4.4 Oil Level/Expansion

Mineral oils have a large coefficient of expansion. Because of temperature variations due to ambient temperatures and loads, the oil level will vary. Therefore, space must be available for expansion, and on the other hand no moisture or air should be introduced into the tank.

In the sealed tank design, the space above the oil is filled with inert gas under pressure. The gas space on top allows for the variation in oil volume. The gas and oil volume remains constant over temperature variations.

In the inert gas-pressure design, the nitrogen blanket maintains constant positive pressure over the oil. It allows for any oil volume expansion since the nitrogen pressure is automatically regulated through a regulating valve. Nitrogen pressure setting maintains proper nitrogen blanket without allowing the oil to become super-saturated with nitrogen.

In a conservator system, the main tank is filled with oil while the expansion tank allows for oil volume variations. Its bladder connects with the main tank, while the rest of its tank allows the air to breathe in and out to make up for the oil expansion. The flow of air to and from the conservator above the bladder typically passes through a desiccant air dryer. The bladder is not totally impervious to air and small amounts of air pass through the bladder membrane over time. The desiccant serves to minimize the moisture in the air passing into the bladder, thus reducing moisture entrainment within the transformer oil.

4.4.1 Oil Level at 25°C

The transformer is filled with oil at the factory to the level that corresponds to oil temperature of 25°C. The oil level indicator is calibrated to this level. During the oil filling process in the field when the transformer is about filled, the oil level must be checked. The oil filling process must be stopped to measure the distance from the top of the flange to the top of the oil. If the temperature is not 25°C during the oil filling process, the correct dimension of the oil level at 25°C and the dimensional correction for temperatures other than 25°C must be adjusted according to the nameplate information. If the transformer is furnished with other compartments, the dimensioned correction for temperatures other than 25°C must be adjusted according to the nameplate and the temperature.

Once the transformer is in service, its normal oil level must be at 25°C. Therefore, oil filling of the transformer must be performed according to the vendor's manual and/or special oil filling procedures from the manufacturer to achieve the correct level.

4.4.2 Overfilling

In some cases, the transformer tank may be overfilled during the initial oil filling process or after an oil addition, especially during lower ambient temperatures. As the transformer gets loaded, the oil indicator would be beyond the normal 25°C indications. As the oil gets heated, the oil will expand. If no expansion space becomes available, the oil may be expelled through the pressure relief device.

4.4.3 Low Oil Level Consequences

Low oil level is very critical. Many transformers, and especially the ones with conservator tanks, have very little space between the core and windings and the top cover. Low oil level could endanger the transformer by exposing the core and windings. Partial exposure to nitrogen or to air could lead to insulation degradation and further complications.



Key Technical Point

Low oil level could endanger the transformer by exposing the core and coil.

A quick check of the oil level gauge could indicate a problem with the oil level. Oil weeping or leaks indicate a potential leak on the unit. Although the leak may not appear significant (for example, oil level gauge is acceptable), if left uncorrected, outside moisture could enter the unit under conditions of negative pressure. A high level of nitrogen gas usage would also indicate a leak. Rarely do leaks correct themselves. In contrast most get progressively worse—creating a situation where positive pressure might not be maintained. Nitrogen pressure setting is also important to avoid oil super-saturated with nitrogen.

4.5 Tank Gas Pressure

The transformer tank is typically designed to operate with a vacuum and a positive internal pressure of up to approximately 10 psi (0.69 bar). Tanks are welded steel construction, outdoor type, with bolted manhole covers and bushings on top of the tank or secondary bushing on the side. Tanks are made of several steel plates to accommodate the core and coil assembly and oil. Tanks are designed to withstand the following:

- Full vacuum
- Reasonable external (through) faults or internal faults
- Transportation

In general, the transformer tank is designed and built for long-term reliability with minimum maintenance.

The typical pressure range for a nitrogen blanketed transformer is from greater than 0 psi to 3.5 psi (0.24 bar). The original vendor recommendations for the subject transformer should be reviewed for specific vessel pressure limitations. When the transformer pressure is 0 psi or below, corrective action should be initiated and the cause identified to prevent the intrusion of moisture into the closed system. If the pressure exceeds the vendor recommended generator pressure, action should be initiated to identify the cause and the condition remedied.

The tank is protected from over-pressurization by the pressure relief device and from internal arcing fault by the sudden pressure relay. In some cases, a severe internal fault is impossible to be contained by the two relays, and a tank rupture occurs. According to EPRI report TR-104994, a tank rupture is defined as any event initiated by a fault internal to the transformer which results in a breach of the transformer casing and leakage of transformer oil. The subject transformers quite often are exposed to extreme temperatures, harsh weather conditions, and occasionally to abnormal operating conditions. The tank must be properly maintained to avoid metal corrosion, seal and gasketing deterioration, and metal fatigue.

EPRI report TR-111593, *Power Transformer Oil Leak Mitigation—Technology Assessment*, provides valuable material on current and developing technologies for sealing leaking transformers and a variety of commercial sealants; and specifically formulated high-performance gasket materials [10].

EPRI report TR-104994, *Power Transformer Tank Rupture: Risk Assessment and Mitigation*, investigates the rupture characteristics of power transformer tanks and provides recommendations and guidelines to designers and manufacturers for the mitigation of tank ruptures [11].

4.6 Static Electrification

The flow of insulating oil in large forced-oil-cooled power transformers may produce static electrification. Static charge build-up is created when cooler oil is pushed by the pumps from the bottom of the transformer to the top as it moves through the insulation of the windings and heat

exchangers. The ionization of the circulating oil builds up as a static charge which discharges through the cooling coil and creates a breakdown of the oil properties. Weakening of the oil dielectric strength could cause a flashover between the transformer windings.

4.6.1 Static Electrification Characteristics

Electrification characteristics have been documented as a function of flow, temperature, moisture, and the duct type and structure. Factors that influence the charging tendency of transformer oil are temperature, moisture content, oxidation, and presence of certain contaminants. Insulation paper wound coils and pressboard washers acquire a negative dc polarity while the oil that flows out becomes positively charged. Negative charge accumulation is observed in the lower parts of the insulation structure. The upper tank where the oil exists builds up a positive charge. Inspection of failed transformers has revealed that flashover usually occurs between a high voltage winding and a low voltage coil or bushing. Severe tracking has been observed in the lower parts of the insulation pieces. In all cases of catastrophic failures, the units were in the energized condition and the pumps were in operation.

4.6.2 Static Electrification Mitigation

Static electrification is a known cause of failure for transformers rated 345kV and above with forced-oil cooling. It can affect any EHV transformer, but most failures have occurred with the shell form design. Although static electrification mainly affects shell form transformers, the guidelines given in Table 4-2 are recommended to be used on core form transformers, since it is difficult to predict which core form designs are susceptible to this phenomenon. Documented static electrification events have occurred on transformers with large capacity oil pumps in the range of 800 gpm (50 L/s). However, data from tests suggests that the phenomena can be produced if a number of smaller pumps are discharging oil into the bottom of windings so that the total flow is the same.

Research sponsored by EPRI and other sources, such as transformer industry experts, have shown that the actions described below have a high probability of preventing failures from static electrification. Such a recommendation was presented by T. G. Lundquist, P.E., in the Static Electrification Failure at the Navajo Generating Station [12].

4.6.2.1 Control of Oil Flow

Flow of oil into the bottom of windings. It is important to change the sequence of pump activation so that there is never high flow into the bottom of any phase at low temperatures when the probability of static electrification is highest.

Staging of pumps on FOA transformers. Many FOA cooled transformers have only two stages of cooling such that the oil flow is high with only one group of coolers in operation. Pumps should be divided into three groups so that the oil flow will be low when the oil temperature is low. The following table can be used as a guide.

Table 4-2
Guide for Staging of Pumps on FOA Transformers

No. of Pumps	Group 1	Group 2	Group 3
3	1	1	1
4	1	1	2
5	1	2	2
6	2	2	2
7	2	2	3
8	2	3	3
9	2	3	4
10	3	3	4
11	3	4	4
12	3	4	5

4.6.2.2 Special Precautions after Drying, Oil Processing, or Long-Term Idle Periods

A significant percentage of failures caused by static electrification have occurred after transformers have been dried or the oil has been processed at the operating site. Research also found that discharge activity was the same after a long-term idle period as it was immediately after performing a field drying operation. The following special precautions are recommended for those situations:

If possible, take the transformer through a temperature cycle at reduced load with a limited number of pumps in operation.

Generator step-up transformers operate the transformer at reduced load and reduced flow with only part of the pumps in operation so that the transformer can be taken through a temperature cycle up through 60°C and hold at this temperature for a minimum of two hours. Reduce the temperature slowly by removing the load. Then initiate the pumps at full load in the normal manner with the temperature controls activating the pumps.

4.6.2.3 Control of Pumps as a Function of Temperature

The pumps must always be activated with the temperature controls:

- Never run all of the pumps before energizing the transformer. If the manufacturer's instructions specify running of oil pumps to remove gas bubbles, run the pumps in stages. Stop the pumps and let the unit set for a minimum of two hours before applying voltage.
- Never start operation of the transformer with the pumps in the manual mode. If there is an emergency in which the controls are inoperative, special precautions must be taken to bring the pumps on in stages commensurate with the temperature controls.

Transformer Operation

- It is recommended that lockout circuits be installed so that the pumps cannot be activated manually if the temperature is below the automatic activation temperature without special actions.
- It may be advisable to install a warning plate on the control cabinet door to warn operators that the pumps are not to be operated in the manual mode.
- Some of the failures appear to be the result of a lack of knowledge about the static electrification process. It may be advisable to add a section with instruction on this subject in operating manuals.

4.7 Observations

Liquid-immersed transformers have a self-cooled rating and one or two additional forced-cooled ratings. Heat generated internally within the transformer is removed by thermal circulation and by radiators, fans and/or oil pumps. Oil is moved by natural convection and by pumping oil through ducts, core, coils and then through the radiators/fans.

Power transformers operating at full- or near-full load process a large amount of electric power. The power flow in the primary and secondary windings develops extreme heat that requires a reliable system of cooling to distribute and dissipate the heat. Operation of transformers above their designed KVA rating causes loss of transformer life and should be avoided. Overheating degrades both the oil and paper insulation. Transformer manufacturers provide instructions and guidelines regarding the permissible load in percent of nameplate rating at 55°C /65°C average winding rise versus the percent of total coolers in operation during various ambient temperatures.

5

INDUSTRY FAILURE CAUSES AND MAINTENANCE PROBLEMS

5.1 Introduction

Industry reports were analyzed and the equipment failure history and the stressors that prevent this equipment from performing their intended functions were evaluated.

5.2 Component Stressors

Major transformer components such as tanks, cores, windings, insulation, radiators and bushings are relatively free from deterioration over a long period of time. Relative trouble-free operation requires proper operating limits on voltage, current and voltage surges, temperature and liquid levels, and maintenance of inert gas systems and corrosion prevention measures. The transformer internals depend largely on the normal transformer operation. Because of their frequent on/off operation, equipment such as pumps, and fans, require frequent maintenance to maintain operability.

Transformers located outdoors are subjected to severe weather conditions and often are subjected to heavy electrical and mechanical stresses. Components exposed to a number of elements/stressors over a long period of time affect the condition of the overall unit.

Some major elements or stressors that affect transformer condition are:

- Temperature and atmospheric conditions
- Operating parameters (such as voltage and current)
- Cycling of auxiliary equipment
- Vibration

5.2.1 Temperature and Atmospheric Conditions

Higher operating temperatures (due to loads) and ambient temperatures affect the overall condition of the transformer. Normal operating and ambient temperatures have been accounted for in the design and construction, but abnormal conditions could cause gradual deterioration of the transformer internals and the outside auxiliaries. Temperatures above those recommended by the vendor and the IEEE Std. C57.91-1995 could accelerate the deterioration of the insulating liquid and jeopardize the life expectancy of transformers.

Top oil temperature and winding hot spot temperature should be monitored for overload conditions or other abnormal operating conditions.

5.2.2 Operating Parameters and Transient Phenomena

Normal operating levels according to the transformer's rating have little or no effect on the transformer. But occasionally transformers are subjected to transient events. Transient events are abnormal conditions such as through-faults, overvoltage transients, spikes and fault interruptions that can lead to gradual deterioration and possible immediate failure depending on their magnitude. Over-voltage transients or spikes (such as lightning strikes) cause insulation breakdown or bushing flashover. The insulation breakdown occurs in the winding (solid) insulation and/or the liquid insulation. Severe cases may cause core loosening and/or dislocation.

5.2.3 Cycling of Auxiliary Equipment

Auxiliaries such as fans and pumps that are subjected to frequent cycling require frequent maintenance and either parts or total replacement. Frequent operations, inadequate design, environmental conditions, mechanical and vibrational stress cause deterioration and failures.

5.2.4 Vibration

The ac “hum” of the core and windings produce vibration and noise depending on how the transformer has been designed and built. In addition, the auxiliary equipment produces their own vibration and noise depending on how they have been manufactured and how they are mounted on the transformer.

High vibrations on a unit can also lead to solid insulation fretting and wear. If an abrasive point of contact exists from a high point on a conductor or some other manufacturing defect, then the effect of fretting from high vibrations is accelerated. As this fretting condition progresses, the localized insulation is deteriorated to a point where a turn-to-turn or strand-to-strand short can develop.

5.2.5 Loose Blocking

Spacing and geometry in a transformer are critical, especially with higher voltage units. The critical clamping pressure on coils is maintained by the use of a blocking and clamping system designed to withstand the mechanical forces generated by through-faults. However, if the blocking material itself changes in dimensions over time (for example, shrinking due to aging), these critical clamping pressures are not maintained. As looseness develops, the mechanical integrity of the overall unit is decreased.

**Key Technical Point**

Blocking material might shrink over time, thus requiring core reclamping.

During through-faults, very high mechanical stresses are created inside a transformer. While transformers are designed to withstand a number of through-faults, units exposed to high mechanical forces are subject to blocking problems and physical breakdown of the insulation. If blocking problems or insulation fretting already exist, then the unit might not be able to withstand through-faults.

5.2.6 Loss of Cooling

Loss of cooling might not be thought of as a mechanical failure mode since it rarely results in the immediate failure of a unit. Many units are designed with high temperature alarms that detect problems before they become “life threatening.” However, the temperature excursions produced by loss of cooling events have an accelerating deteriorating effect on insulation. Over extended periods of time, the higher temperatures rob the paper insulation of some of its mechanical strength.

Decreases in the strength of the paper will result in a shorter life. The paper insulation becomes less flexible and more brittle as the paper is exposed to increased temperature conditions, which results in a shorter life span. This deterioration effect is roughly doubled for every 10°C increase in temperature.

5.3 Stressors, Aging Mechanisms, Potential Failure Modes

The effect of the above elements/stressors are considered to be significant for the overall operating condition of the transformer and its components which can have significant affects on the tank, core, windings, insulation, and bushings.

Table 5-1, taken from SAND93-7068-UC-523, *Aging Management Guideline for Commercial Nuclear Power Plants—Power and Distribution Transformers*, summarizes the stressors acting upon power transformers and indicates the aging mechanisms, types of degradation, and failure modes that can result from exposure to these stresses [13].

Table 5-1
Stressors, Aging Mechanisms, Potential Failure Modes

Stressor	Intensifiers	Aging Mechanism	Age-Related Degradation	Potential Failure Mode	Comments
Temperature	Acidity of insulating fluid	Thermal deterioration	Loss of mechanical and electrical properties of solid insulation	Dielectric breakdown; flashover	Generally a slow process. Detected by periodic sampling and analysis. See Section 6.
	Ohmic heating; winding and core losses	Thermal deterioration; cracking	Loss of dielectric strength of organic winding and electrical connection insulation	Dielectric breakdown; flashover	Detected by periodic sampling and analysis. See Section 6.
	Contaminants	Thermal deterioration of lubricants	Binding and high friction; wear	Seized motor bearings, load tap changer components, valves, and enclosure door hinges	Detected by periodic sampling and analysis. See Section 6.
	Moisture and contaminants; dielectric stress	Thermal decomposition of insulating fluid	Loss of dielectric strength; sludge and/or gas formation	Localized breakdown and gas formation	Detected by periodic sampling and analysis. See Section 6.
Voltage	Contaminants; moisture	Accumulation of contaminants on bushing weather shield	Loss of surface insulating properties; surface tracking	External flashover of bushing between phase and ground	Accelerated in high dust, salt, and moisture environments. Detected by visual observation or bushing tests.
	Gas pockets or other low dielectric contaminants	Degradation of insulating fluid	Fluid decomposition and deterioration; gas formation	Localized breakdown of insulating fluid; eventual flashover and possible explosion	Detected by periodic sampling and analysis. See Section 6.

Table 5-1 (cont.)
Stressors, Aging Mechanisms, Potential Failure Modes

Stressor	Intensifiers	Aging Mechanism	Age-Related Degradation	Potential Failure Mode	Comments
	Low dielectric strength contaminants (such as gas or particulates)	Ionization and corona breakdown	Degradation of insulating materials	Dielectric breakdown; flashover	Detected by periodic sampling and analysis. See Section 6.
Current	External fault or surge conditions	Electro-magnetic forces on conductors/ core	Movement or dislocation of windings and/or core	Loss of spacing of windings; turn-to-turn shorts	Not significant at normal current levels. Detected by acoustics or relay activation.
Mechanical and Electrical Cycling	Deteriorated lubricants in auxiliary components	High friction between moving parts	Wear	Binding of tap changer, pump, or fan motor bearings, and valves	Increases with increasing duty cycle. Detected by vibration.
	Voltage; contaminants	Pitting or erosion of auxiliary device contact surfaces	Degradation of electrical components	Misoperation of load tap changer; loss of cooling components	Increases with number of make/ break operations. Detected by incorrect operating parameters or relay operation.
Non-Seismic Vibration	Loose internal components	Cyclic wear/ fatigue	Wear and possible cracking of components; loss of tolerances, misalignment	Binding; component deformation or breakage	Detected by vibration or acoustics.

5.4 Degradation Effect on Components

Understanding the manner in which components degrade is important for determining which monitoring methods can be used to detect which failure mechanisms that will result from the transformer degradation. Each principle component and the manner in which it is known to degrade is discussed in the following sections.

5.4.1 Transformer Tank and/or Bushing Compartment

The transformer tank is made of steel that houses the core and coil assembly, the insulation liquid, gaskets or other organic seals used in the construction of the enclosure, and the mounting of various parts and auxiliary equipment.

The transformer steel tank, gaskets, and seals are susceptible to abnormal or severe weather conditions such as heat, ultraviolet radiation and abnormal operating conditions. As a result, they suffer from aging degradation and create leaks. Gasket deterioration is more evident on transformers that have been subjected to overheating conditions. Gaskets might need to be replaced after being in-service for several years. Transformer and/or gasket vendors could provide information for shelf and service life of gaskets.

5.4.2 Core

The main degradation effect for a transformer core would be high circulating currents resulting from a core ground. High circulation currents can cause oil gassing as the result of overheated metal. Other core problems could be core bolt shorting, shorts between core laminations, core overexcitation, and loose laminations.

The maintenance practices related to transformer cores are the core-to-ground test (insulation resistance test), and verification of core mounting system integrity, and applicable tolerances. The core-to-ground test is used in core-form transformers to check the core-to-ground insulation level. In most dry-type transformers, the core is grounded by a single strap, which can be readily disconnected. In liquid units, tank entry may be required and core testing would be performed only at time of construction or after significant internal repairs. Low resistance readings are indicative of foreign material between the core and the tank or other problems with the core insulation system, and would require correction prior to return to service.

Verification of the core mounting system integrity helps control loosening or dislocation of the core due to non-seismic vibration during normal operation or forces generated by external electrical transients such as faults. Critical tolerances and dimensions may be checked to ensure no movement of the core or windings has occurred. However, these practices are not typically used except during periods when the core and windings are completely accessible (that is, major corrective maintenance or scheduled internal inspections). Core looseness is not a commonly expected condition.



Key Technical Point

Core looseness is not a commonly expected condition.

5.4.3 Windings (Conductor and Turn Insulation)

Degradation effects would include insulation damage from vibration, insulation aging from overheating combined with high oxygen and moisture, insulation degradation due to stray flux and winding insulation mechanical damage due to external faults.

During events such as lightning, fault interruptions and/or switching operations, windings can be subjected to severe dielectric stresses. The dielectric stress may occur during the initial peak voltage, which is usually of a short duration, followed by an oscillatory component which may last several cycles.

Abnormal currents may occur in the primary windings during switching operations, but currents are much heavier during a short-circuit event.

The current during transient conditions or abnormal events can result in severe mechanical and electrical stresses in the windings.

Visual inspection of the windings helps manage material degradation of the windings and insulation. In liquid immersed units, the windings are immersed in the insulating fluid, and thus may not generally be viewed unless the unit is drained or disassembled.

Electrical tests performed on the windings might include evaluation of the insulation resistance, winding ratio, and insulation power factor. Insulation resistance (megger®) testing is performed in the field on each winding with the other winding grounded, and from one winding to another. This test indicates the condition of the winding insulation as well as the presence of any moisture. Transformer winding ratio (or turn ratio test) is used to verify the transformation ratio of the primary to secondary windings at all tap settings. Power factor testing is used to detect insulation degradation. It measures the insulation power factor between the primary and secondary windings as well as each of the windings to ground. Generally speaking, a significant increase in the power factor (after correction for temperature) is indicative of substantial insulation degradation or the presence of moisture or other contamination.

5.4.4 Insulating Oil

Some moisture is always present in an insulating fluid or oil. At a given temperature, insulating fluid can absorb a specified amount of moisture before reaching a saturation point. As the amount of moisture approaches this saturation point, the dielectric strength of the fluid or oil will decrease. At saturation, this decrease can be rapid because free water is formed in the fluid. The dielectric strength of the fluid can decrease to a point where flashovers can occur. Good dielectric strengths (typically > 30 kV) can be maintained as long as relative saturations are kept very low.

Contamination in the form of particles will also degrade the dielectric strength of the fluid. Nonmetallic particles can enter the fluid through contamination with dirt and dust. Fibers can be released into the fluid from paper insulation and fiberboard, and metallic particles can be produced by pump wear or metal fretting as a result of vibration. At sufficiently high levels, these contaminants will degrade the dielectric strength to a point of failure.

Formation of bubbles is less apparent and harder to detect. Once formed, a stream of bubbles will quickly break down the dielectric strength of the fluid. Excess moisture in paper insulation that is released quickly by temperature excursions can produce bubbles of water vapor. Energetic formation of combustible gases at hot spots, at rates that exceed their ability to be quickly dissolved, will also produce bubbles. Finally, even the inert nitrogen gas blanket on various units

under some conditions could lead to the production of nitrogen bubbles. A unit running at very high oil temperatures, with a nitrogen supply set at high pressure, will absorb high levels of nitrogen in the oil. If this oil is then rapidly cooled, nitrogen bubbles could form.

**Key Technical Point**

Excess moisture in paper insulation that is released quickly by temperature excursions can produce bubbles of water vapor.

**Key Technical Point**

A unit running at very high oil temperatures with a nitrogen supply set at high pressure will absorb high levels of nitrogen in the oil. If this oil is then rapidly cooled, nitrogen bubbles could form.

5.4.5 Solid Insulation Breakdown

The solid insulation will also undergo breakdown by a number of methods. Overvoltage stresses, such as those produced by improper switching, can lead to flashovers across major insulation. Under some conditions, on units designed with high velocity oil flows, static charges can build up on the major insulation at voltages in excess of a million volts. This process is known as “static electrification” (see Section 4.6). These dc charges can produce tracking resulting in the physical breakdown of the surface insulation. Deterioration can continue until flashover and failure occur.

Other variables that affect the major insulation are temperature and moisture. Paper used in transformers typically contains 0.5%–1.0% moisture. Higher levels of moisture in combination with high levels of oxygen eventually accelerate the aging of the paper. In addition abnormally high levels of moisture in paper can be released into the oil at high temperatures. If not quickly absorbed back into the paper upon cooling, the amount of moisture transferred to the oil could cause bubbles and reduce the dielectric strength of the oil.

5.4.6 Bushings

Bushings must provide sufficient dielectric strength to withstand the high voltages and is skirted to provide a long surface creepage path from the terminal to ground.

Bushing flashover is a major concern for outdoor high voltage installations. Although bushings are designed and built to form a leakage surface that is open to cleaning action of wind and rain, airborne dust, dirt, and contaminants such as salt spray can accumulate on its exterior surface, which eventually creates a tracking path. If a bushing is damaged or heavily contaminated, leakage current becomes excessive, and visible evidence may appear as carbon tracking on the bushing surface. Current through the tracking path may be large enough to flash over to the ground. If flashover occurs (phase-to-ground fault), it could destroy the bushing and cause extensive transformer damage. Also, line-to-line faults can occur if all the bushings are contaminated, which could cause flashover.

Depending on the area and the surrounding atmosphere, the severity of this problem requires special attention and the necessary steps for prevention. In addition to periodic cleaning, some utilities apply special coatings such as silicon grease, wax, or elastomers on the surface of the porcelain.

**Key Technical Point**

Periodic cleaning and special coatings such as silicon grease, wax, or elastomers are used to limit the build up of contaminants on the surface of bushings.

Improvements have been made by the industry to improve the protective coatings of the bushings. Glaze is applied on the surface during the manufacturing process.

Materials used in bushing construction (such as, kraft paper, insulating oil, and gaskets) may be subjected to degradation by thermal aging, exposure to ultraviolet light, severe weather conditions and atmospheric contaminants. As a result the internal bushing insulation may be degraded from internal moisture caused by leaks, partial discharge, tracking and aging. Degradation can also occur from external physical damage, flashover, tracking and corona.

Bushing failures can be attributed to the following primary causes:

- Moisture ingress, leaks
- Internal partial discharge/tracking
- Overheating/thermal runaway
- External contamination
- System overvoltages
- Marginal designs
- Improper storage

5.4.7 Other Components

5.4.7.1 Instrument Transformers

Potential transformers (also called voltage transformers) are constructed of similar material as bushings and other main transformer internals. These devices are part of the protective scheme for the transformer and they provide a very important function. PTs are subject to similar failure mechanisms as bushings. PTs have oil for cooling and insulation. PTs tend to have a fairly long service life when compared to CTs.

Current transformers (CTs) monitor the current flow through the main power circuit. CTs can be classified as dry, compound-filled or oil. Dry-type or compound-filled CTs are used for voltages below 22,000 V. For voltages 22,000 V and greater, a compound-filled or oil-type CT is

typically used. CTs tend to fail catastrophically and have a higher failure rate than PTs. The oil in the CT can experience degradation overtime due to the heating cause by current.

The following failure causes for instrument transformers have been identified:

- The quality of the oil in some CTs
- The paper insulation may have been instrument transformers was of poor quality
- Contamination of the insulating oil
- Excess temperature that promotes dielectric breakdown of insulation and insulating oils
- Damaged by switching transients

5.4.7.2 Lightning/Surge Arrester

Arresters are constructed of series repeating sections. When an overvoltage condition is cleared, the arrester must return to its normal insulating condition. Lightning arrestors can use a spark gap material or a metal-oxide varistor (MOV). These devices are susceptible to similar failure as bushings and instrument transformers. As lightning arresters age, the leakage current tends to increase. This increase of leaking current is an indication of arrester degradation.

5.5 Transformer Failure Mechanisms

Transformer failures can be attributed to dielectric breakdown, short-circuit, deterioration of insulation properties, bushing failure mechanisms, and load tap changer failure mechanisms.

5.5.1 Dielectric Breakdown

Dielectric breakdown is one significant cause of failure. There are many reasons for such failures, including the following:

- Inadequate vacuum filling of the transformer both when new and when refilled in the field.
- Gas bubbles caused by saturation of the oil with nitrogen from the gas cushion oil preservation system.
- Gas bubbles caused by excessive water in the insulation when it is heated to high temperatures in the order of 150°C or greater by overload or by local hot spots.
- Inadequate insulation design for the voltages encountered in service.
- Static electrification caused by pumping the oil at high flow rates when the oil is cool.
- Significant overloading of transformer
- Aging of paper insulation

5.5.2 Short-Circuit Failure

Transformers are designed to more restrictive standards since the IEEE Std. C57.12.00-1993 requirements were initially approved in the mid-1970s. Some transformers designed and manufactured prior to that time may have questionable strength, and some designed afterwards may have design or manufacturing weaknesses. Some of the problems causing short-circuit failures are as follows:

- Loose windings caused by inadequate drying, inadequate compression in manufacturing, or improper support for the force in service.
- Inadequate strength in the windings including a variety of problems depending on the type winding used. Such problem areas are usually the result of poor design practice.
- Inadequate mechanical support for the short-circuit forces.

It should be noted that the actual failure might be dielectric in nature originating from damage caused during a short circuit, such as shearing of paper or shorting of turns. The failure may occur quite some time after the short circuit.

5.5.3 Deterioration of Insulation Properties from Oxygen and Water

Insulation can degrade more rapidly from exposure to high levels of oxygen (greater than 3000 ppm) and water (0.5% water in paper) at normal operating temperatures. This degradation can occur in older transformers due to:

- Oil expansion tanks with no rubber bags to prevent oxygen from entering the tank
- Failure to maintain the dehydrating breathers so that water also enters the oil through the expansion tank

Smaller transformers with open breathers are also subject to the same problem. If transformers with nitrogen blankets above the oil are not maintained, oxygen and water enter the system and degradation occurs, as follows:

- The paper becomes brittle the same as if thermally aged even though it has never been overheated.
- The paper in all windings becomes brittle such that they are susceptible to short-circuit failures such as turn-to-turn shorts.
- It is believed that the pressboard also becomes brittle and shrinks in the thickness dimension producing some looseness. However, the total thickness change may not be significant if the water content is high because water causes paper to swell.

5.5.4 Thermal Aging

The aging process is minimal if the oil and paper are kept dry, the oxygen content is nominal, and the hot-spot temperatures are not above standard allowances. If the transformer temperature does not exceed the rating of the paper, it is possible to load the transformer at or above its rating depending on the ambient temperature without significant loss of life.

Failure can result from thermal aging if the transformer is overloaded to the extent that hot-spot temperatures above the rating of the paper exist for long periods of time. Damage to the paper can also result from operation for long periods of time without cooling. A few such failures seem to occur each year from loss of cooling on major transformers.

5.6 Load Tap Changer Failure Mechanisms

The LTC compartment has current interrupting contacts and moveable taps that are moved frequently, for some transformers, depending on the voltage regulation requirements. The frequency of current interruption and tap movement is different from one transformer to another and depends on the voltage regulation requirements of the system. More frequent operation of the load tap changer will result in accelerated contact wear and higher gas generation in the oil. The load tap changer requires proper maintenance to avoid failures.

Load tap changer failure can be attributed to the following primary causes:

- Contact coking
- Localized oil overheating/oil contamination
- Deteriorated gaskets or seals
- Partial discharge/tracking
- Defective mechanical components
- Defective control system components

5.7 Observations

Several possible service conditions that can produce immediate degradation or aging degradation of a system or component were reviewed. Abnormal conditions and elements such as transients, atmospheric and temperature conditions, vibrations, mechanical and electrical cycling, and contaminants might deteriorate the overall transformer operating condition. When such degrading conditions are allowed to continue without the proper inspection and subsequent corrective steps, the results will be further equipment deterioration that eventually leads to failure.

Surveys conducted by insurers ranked lightening and other electrical disturbances as the key contributor to transformer failures. These causes were followed by inadequate maintenance, loose connections, and moisture contamination. It should not be surprising that most of these failures were seen at the transformer bushing with a few at the neutral grounding point.

Electrical tests performed on the windings might include evaluation of the insulation resistance, winding ratio, and insulation power factor. Insulation resistance (megger) testing is performed in the field on each winding with the other winding grounded, and from one winding to another. This test indicates the condition of the winding insulation as well as the presence of any moisture. Transformer winding ratio (or turn ratio test) is used to verify the transformation ratio of the primary to secondary windings at all tap settings. Power factor testing is used to detect

insulation degradation. It measures the insulation power factor between the primary and secondary windings as well as each of the windings to ground. A significant increase in the power factor (after correction for temperature) may indicate substantial insulation degradation, the presence of moisture, or other contamination.

Surveillance, condition monitoring, analysis of monitoring data and oil analysis, along with preventive and corrective maintenance, can provide an effective maintenance program to maintain reliable equipment in place.

6

TRANSFORMER TESTS AND ONLINE MONITORING

6.1 Introduction

Transformer testing is divided into two major categories: factory tests and field tests. The purpose of factory testing is to determine if a new transformer meets quality control and the specified design requirements. For full details on factory testing of transformers, refer to ANSI/IEEE C57.12.90-1993, “IEEE Standard Test Code for Liquid-Immersed Distribution, Power and Regulating Transformers.” The results of factory testing can be found on the certified test report provided by the manufacturer [14].

Field testing is performed to assess the condition of an operating transformer or to determine the cause of a tripout. The emphasis in this section will be on field testing.

6.2 Factory Routine Tests

Routine tests are made on completed transformers by the manufacturer as a quality control check and to verify that it meets the design specification. These tests are identified in Section 8, Table 17 of ANSI/IEEE Standard C57.12.00-1998 [2]. The following subsections provide a listing and a brief description of the routine factory tests for power transformers rated 115 kV and higher. Lower voltage power transformers and distribution transformers have similar, but different requirements. The ANSI standard referred to above details those requirements.

6.2.1 Winding Resistance

Winding resistance is measured and reported for the following reasons:

- It is used in calculations made at the factory to calculate the winding losses due to their resistance.
- It is needed in calculations made at the factory to determine if the guaranteed winding temperature rise has been met.
- It can be compared with later field measurements to detect potential winding abnormalities.

The resistance bridge method and the voltmeter-ammeter method are the two methods used to measure winding resistance. The actual resistance measurements are converted to a standard temperature (usually 85°C) and that is the temperature that is shown on the certified test report.

6.2.2 Core Insulation Resistance

The transformer core is insulated from the tank and other grounded parts. A single ground connection called a ground strap is installed to limit voltage rise on the core during operation. If an inadvertent ground occurs, a circulating current path is created that could damage the core. If this condition is allowed to persist, core damage will occur. In addition to the gases generated in the oil, under severe conditions, winding insulation can be damaged. In the absence of an inadvertent core ground, it is a good practice to measure the insulation resistance in order to determine the adequacy of the core insulation.

After a transformer is completely assembled, the insulation resistance between the core and ground is measured. The test voltage level is at least 500 volts dc and the duration of the test is one minute. The results are recorded in megohms.

6.2.3 Turns Ratio (TTR)

The turns ratio of a transformer is the ratio of the number of turns in the high voltage winding to that in the lower voltage winding. For example, if the number of turns in a high voltage winding is 150 and the number of turns in the low voltage winding is 10, the turns ratio is 15. If, at no load, 23 kV is applied to the low voltage winding, the voltage output of the high voltage winding would be 345 kV.

Voltage taps in a transformer are used to change the turns ratio. The taps within a winding are connected to either a tap changer for de-energized operation or to a load tap changer (LTC) (see Section 3.9). A tap changer for de-energized operation is sometimes called a “no-load tap changer,” but this term is a misnomer because this type of tap changer must be operated when the transformer is de-energized, not just carrying no load. A LTC is designed to operate while the transformer is in operation. Both devices can change the turns ratio, thereby, changing the transformer output voltage.

The turns ratio is checked at the factory for the rated voltage connection on all tap connections.

6.2.4 Polarity and Phase Relation

The polarity of a transformer terminal (bushing) indicates the relative instantaneous direction of the currents entering the primary terminals and leaving the secondary terminals (during most of each half cycle). The polarity of each terminal is checked during factory testing to confirm that the transformer has been assembled properly. It is essential to know the polarity of each of the transformer terminals if two transformers are to be connected in parallel. The polarity of each terminal is shown on the nameplate of the transformer.

For three-phase transformers, the primary and secondary windings might not have the same phase relationship, depending on how they are internally connected. The phase relationship between the different windings is checked during factory testing. Phase relationships have been standardized for two winding transformers with windings connected in either delta or wye, and are not normally a matter for concern.

6.2.5 No-Load Losses and Excitation Current

No-load losses (measured in watts) are those that occur when a transformer is energized, but not carrying any load. These losses are due primarily to losses in the transformer core.

Excitation current is the current that flows in a winding that excites the transformer while all the other windings are open-circuited. Excitation current is expressed in percent of the rated current of the exciting winding.

No-load losses and excitation current are measured during factory testing at 100% and 110% of rated voltage. The low voltage winding is the winding that is normally excited when performing this test.

6.2.6 Load Loss and Impedance Voltage

Load losses (measured in watts) are those that occur at a specified load, normally rated kVA, carried by the transformer. The load losses consist of two components:

1. Winding loss (I^2R) due to load current
2. Stray losses due to eddy-currents in the windings, core clamps, magnetic shields, tank wall, and other conducting parts

The test is performed by shorting one of the windings and applying sufficient voltage to the other winding to cause a specified amount of current to flow in both windings. The specified amount of current would normally consist of rated current plus a component of current needed to simulate the no-load loss, which is much less during this test because the voltage applied is also much less.

Both the I^2R and the stray losses vary with temperature and must be corrected to the standard temperature of 85°C. However, the I^2R losses increase with temperature and the stray losses decrease with temperature. Therefore, separate equations have been developed for the two types of losses to correct them to the standard temperature.

The impedance voltage is measured during the load loss test. It is the amount of voltage required to circulate rated current through one of the windings while the other winding is short-circuited. The percent impedance is the impedance voltage divided by the rated voltage times 100.

6.2.6.1 Applied Voltage

This test is sometimes called a hi-pot (high potential) test. It is a test of the ability of a transformer to withstand normal frequency (60 Hz) voltages to ground.

It consists of testing one set of windings while all of the other windings and the tank are grounded. For example, all of the low voltage bushings would be tied together and energized while all of the high voltage bushings are grounded. The amount of voltage that the particular set of windings should be able to withstand is covered by ANSI/IEEE standards. The duration of the test is one minute.

6.2.6.2 Induced Voltage

The induced voltage test stresses the insulation between turns, sections, and layers of a winding. Because the test is performed with voltages substantially higher than rated values, the frequency of the test voltage must be increased so as to not saturate the core of the transformer.

For a typical three-phase, two winding transformer, the test would consist of applying voltage to the low voltage winding with the high voltage winding open circuited. The test duration is one hour and consists of the following steps:

- The voltage level is increased for a short period of time to the level that will be maintained for the one-hour duration of the test. The voltage level is 150% of the maximum system operating voltage.
- The voltage is increased to 173% of the maximum system operating voltage for 7200 cycles.
- The voltage is reduced to the 150% level for the remainder of the test.
- Partial discharge (corona) levels are measured during the test. A successful test is indicated if:
 - The partial discharge level does not exceed 100 μV .
 - The increase in partial discharge levels during the one-hour test duration does not exceed 30 μV .
 - There is no steadily rising trend during the test, particularly in the last 20 minutes of the test.

6.2.6.3 Insulation Power Factor

Insulation power factor is the ratio of dielectric loss in an insulation system to the applied apparent power. It is measured at normal power frequency and the voltage test level is covered by ANSI/IEEE or other standards.

The power factor measurements made during factory testing can be compared later with field measurements to assess the probable condition of the insulation.

6.2.6.4 Winding Insulation Resistance

Tests of insulation resistance are made between windings to ground or between windings. The test is performed to determine if the state of dryness of the winding insulation is within acceptable values. The test results could vary when different types of equipment are used over a period of time. The temperature of the insulation system is a key factor regarding insulation resistance measurements. The results are recorded in megohms and the tests are commonly performed with a megohmmeter.

6.2.6.5 Auxiliary Devices, Control and Current Transformer Circuits

In addition to the factory tests, control and voltage transformer secondary circuits should be tested in the field for insulation resistance. The test can be performed with a 500 V megger and the acceptable value should be equal or greater than 2 MΩ.

6.2.7 Operation Test of All Devices

This test consists of operating devices such as fans, pumps, motors, LTC and others in both automatic and manual mode. Tests are performed to prove the wiring installation and proper function of all devices.

6.2.8 Auxiliary/Cooling Losses

The power consumption is measured for all cooling associated equipment, such as fans and pumps and other auxiliary equipment, such as the LTC drive motor. During the design stage of the transformer, the vendor calculates the transformer losses, which are verified during the factory tests.

6.2.9 Dissolved Gases in Oil Analysis

The criteria for interpreting the results of gas-in-oil analyses while other tests are being performed are still under development by the IEEE. Gas-in-oil testing will be most useful while other tests are being performed that cover significant time duration, such as a temperature rise test, or possibly a one-hour induced voltage test.

6.2.10 Mechanical Leaks



Key Technical Point

Oil leaks can originate from gas relay piping, valve packing, CT pockets, tap changers, radiators, and main tank covers. Covers are usually a major source of oil leaks if the installation is not done properly or materials are not compatible.

Prior to shipment of the assembled transformer, it is leak tested for at least eight hours at 125% of the maximum design operating pressure in order to detect the presence of leaks. Oil leaks can originate from gas relay piping, valve packing, CT pockets, tap changers, radiators, and main tank covers. Covers are usually a major source of oil leaks if the installation is not done properly or materials are not compatible. Leak repair of large transformers can be extremely costly especially if major gasket replacements become necessary.

**Key O&M Cost Point**

Leak repair of large transformers can be extremely costly, especially if major gasket replacements become necessary.

6.3 Factory Design Tests

Design tests are made by the manufacturer to determine the adequacy of a specific transformer design. Not all transformers are design tested. For example, if more than one transformer is purchased on an order, it would be necessary to design test only the first one. Design tests are identified in Section 8, Table 17 of ANSI/IEEE Standard C57.12.00-1998 [2]. The following subsections provide a listing and a brief description of the design factory tests for power transformers rated 115 kV and higher. Lower voltage power transformers and distribution transformers have similar, but different requirements. The ANSI standard referred to above details those requirements.

**Key Technical Point**

Design tests are made by the manufacturer to determine the adequacy of a specific transformer design.

6.3.1 Temperature Rise

The purpose of a temperature rise test is to determine if the thermal design of a transformer is adequate. The normal requirement is that the average winding temperature and the top oil temperature rises not exceed 65°C and that the maximum winding temperature (hottest-spot) temperature rise not exceed 80°C. The term “temperature rise” is defined as the difference between the temperature of the component being measured and the ambient temperature. For example, if the top oil temperature is measured to be 90°C and the ambient temperature is 30°C, the temperature rise is 60°C.

It is unusual for a transformer to fail a temperature rise test. If a transformer should fail this test, the usual reason would be that the losses are greater than calculated by the transformer designer.

In this case, the solution might be to add more cooling capacity to the transformer in order to meet the specified temperature requirement.

6.3.2 Audible Sound Level

Audible sound produced by a transformer comes primarily from its core. The sound is transmitted through the oil to the tank wall where it radiates as audible sound. An audible sound level test is performed at the transformer manufacturer's factory in a special room with a very low ambient sound level.

The audible sound level test is a design test that is performed to determine if a transformer meets the requirements specified in NEMA Standard TR1, Table 0-1 or as specified by the purchaser [15].

6.3.3 Mechanical Pressure

Tanks are designed to withstand a full vacuum. In addition, some manufacturers perform a leakage test with a liquid penetrant and pressure tests with 21.75 psi (1.5 bar). Other manufacturers test them to withstand full vacuum and 8.7 psi (60 kPa) overpressure. The mechanical strength of a power transformer and its tank is based on peak value of the short-circuit current and the calculated radial and axial electromagnetic forces that depend on the winding design and physical arrangement. EPRI TR-104994, *Power Transformer Tank Rupture: Risk Assessment and Mitigation*, has valuable information on mechanical pressure [11].

6.3.4 Dielectric Tests

Dielectric tests are voltage tests applied to a transformer to demonstrate that it has been designed and constructed to withstand the specified insulation levels.

Lightning impulse tests are performed to check the ability of a transformer to withstand high frequency voltage surges caused by lightning. System disturbances from lightning can be represented by three basic wave shapes: full waves, chopped waves, and front-of-waves [16]. Figure 6-1 illustrates a full wave with the approximate magnitude and time. Special equipment is required to perform these tests, and they are unsuitable for field testing.

The basis for these tests is a standard impulse wave shape that is applied to each transformer terminal. The wave rises to its highest (crest) voltage in 1.2 μ s and decays to half of the crest value in 50 μ s from the beginning of the wave. The crest value that a winding is successfully able to withstand is called the basic impulse insulation level (BIL).

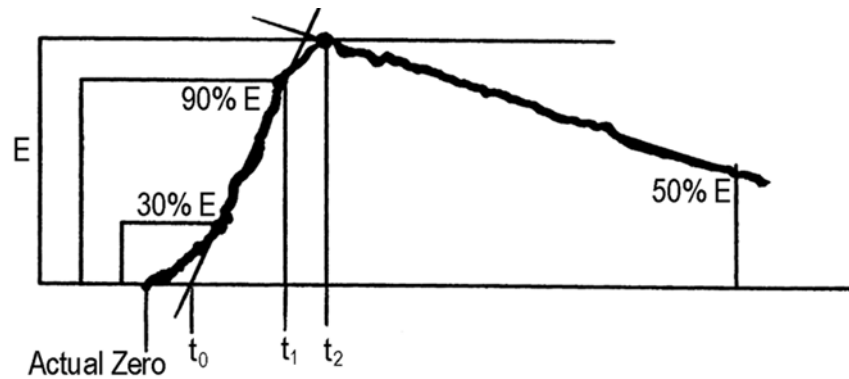


Figure 6-1
Graph of Standard Impulse Wave

Performing a lightning impulse testing is quite involved, but basically it consists of applying various lightning impulse voltages to each bushing on the transformer. Each winding and its bushing is tested as follows:

1. A standard impulse wave with a crest value of 50% of the full crest value is applied. This is called the “reduced full wave test.”
2. Two other waves, called “chopped waves” that simulate the voltage impulse, which results when a transmission line flashes over, are applied.
3. The standard impulse wave with a crest value of 100% of the full crest value is applied. This is called the “full wave test.”

The wave shapes of the reduced full wave test and the full wave test are compared. If they are identical, the test is successful. If the shape of the curve from the full wave test does not match the shape of the curve from the reduced full wave test, a problem has been detected. The types of problems that can be detected include internal flashovers and turn-to-turn faults.

6.4 Factory “Other” Tests

“Other” tests are those that may be specified by the purchaser in addition to routine and design tests. For transformers rated 115 kV and above, these tests are:

1. Zero-phase sequence impedance voltage
2. Single-phase excitation
3. Front-of-wave impulse
4. Switching impulse
5. Short circuit capability

6.5 Field Tests

The purpose of field testing is to determine if maintenance is required or to identify the cause of abnormal operation or trip-outs. The primary indicator of the internal condition of a transformer is the condition of the oil. Such tests can be performed while the transformer is in operation. Other tests can also be performed, but many of them require the transformer to be de-energized. On-line monitoring can be considered as a type of test and is coming into widespread use. A useful reference for performing field testing of power transformers is IEEE 62-1995, “Guide for Diagnostic Field Testing of Electric Power Apparatus, Part 1: Oil Filled Power Transformers, Regulators, and Reactors” [17].

6.5.1 Gas-in-Oil

The most useful and widely used field test involves the sampling and analysis of gases dissolved in the oil of a transformer. This technique is sensitive to a wide range of malfunctions, both thermal and electrical, which could eventually lead to failure of a transformer if corrective measures are not taken.

When taking oil samples, it is extremely important that such samples be taken carefully to avoid the possibility of contaminating the sample. The procedures for taking oil samples described in ASTM D923-1997 and/or D3613-1998 should be followed [18 and 19].



Key Human Performance Point

When taking oil samples, it is extremely important that such samples be taken carefully to avoid the possibility of contaminating the sample. The procedures for taking oil samples described in ASTM D923 and/or D3613 should be followed.

Never take an oil sample from a transformer under negative pressure. An air bubble could be drawn into the tank and cause a catastrophic transformer failure, possibly resulting in personal injury or death.



Key Human Performance Point

Never take an oil sample from a transformer under negative pressure. An air bubble could be drawn into the tank and cause a catastrophic transformer failure, possibly resulting in personal injury or death.

IEEE Std. C57.104-1991, “Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers,” is an invaluable aid for the interpretation of gas-in-oil test results. C57.104-1991 offers advice on both a simple, qualitative interpretation based on certain “key gases,” as well as a more detailed quantitative diagnosis based on absolute levels and ratios of gases. In addition, it provides a rational step-by-step action plan to carry the user from the first recognition of abnormal gas generation and trending, through an increased surveillance period, to possible removal from service [20].

6.5.1.1 Key Gases

Recognition of “key gases” is the first simple tool with which an investigator should be familiar. Experience and logic have led to the identification of the following relationships:

- **Carbon Monoxide and Carbon Dioxide (CO and CO₂).** Thermal decomposition of cellulose, even at normal operating temperatures, produces these carbon oxide gases. Thus, low rates of production are not a cause for alarm. However, production of such gases at an abnormally high rate is associated with over heated insulation. Both the rate of production and the ratio of the two gases can be indicative of the severity of the overheating.
- **Methane, Ethane, and Ethylene (CH₄, C₂H₆, and C₂H₄).** Thermal breakdown of mineral oil generates this family of gases, with certain ratios of the gases indicating the severity of the overheating.
- **Hydrogen (H₂).** Low-intensity electrical discharges in oil, sometimes referred to as corona, produce principally hydrogen, with some methane, but lesser quantities of the hydrocarbon gases.
- **Acetylene (C₂H₂).** High intensity electrical discharges or electrical arcs produce very high temperatures (over 600°C to 700°C), which cause the generation of small but significant quantities of acetylene. Little or no acetylene and a broad spectrum of the other gases usually is the result of metallic parts being overheated by stray flux or circulating currents, with no cellulose present. Acetylene is absent for other types of faults, so it is a reason for major concern when it is detected.

Since all normally operating transformers will have some levels of the above-mentioned gases dissolved in the oil (with the exception of acetylene), it is important to identify concentration levels for which the user should have concern. This has been done in IEEE Std. C57.104-1991. Table 6-1 has been extracted from that source.

Table 6-1
Dissolved Gas Concentration

Status	Dissolved Key Gas Concentration Limits (ppm)							
	H ₂ Hydrogen	CH ₄ Methane	C ₂ H ₂ Acetylene	C ₂ H ₄ Ethylene	C ₂ H ₆ Ethane	CO Carbon Monoxide	CO ₂ Carbon Dioxide	TDCG See notes
Condition 1	100	120	35	50	65	350	2500	720
Condition 2	101-700	121-400	36-50	51-100	66-100	351-570	2501-4000	721-1920
Condition 3	701-1800	401-1000	51-80	101-200	101-150	571-1400	4001-10000	1921-4630
Condition 4	> 1800	> 1000	> 80	> 200	> 150	> 1400	> 10000	> 4630

Notes:

TDCG = Total Dissolved Combustible Gas (excludes CO₂)

Condition 1 = Dissolved gas in this range indicates normal operation

Condition 2 = Begin analysis if dissolved gas indicates greater than normal gas generation.

Condition 3 = Dissolved gas in this range indicates a high level of insulation decomposition. Sample frequently to establish the trend of gas evolution and apply gas ratio analysis for diagnosis.

Condition 4 = Dissolved gas in this range indicates excessive decomposition. Continued operation could result in failure of the transformer.

Gas ratio analysis can be helpful in determining the source of abnormal gas generation. The CO₂/CO ratio might be an indication of abnormal insulation deterioration. Ratios of the hydrocarbon gases and hydrogen can indicate the temperature range of the heat source. It should be noted, however, that significant levels of dissolved gas must be present before this technique can be applied.

Experience has demonstrated that under normal operating temperatures, the rate of evolution of carbon dioxide is typically 7 to 20 times higher than that for carbon monoxide, but ratios down to 5 might be considered normal. The ratio is generally lower for sealed conservator type oil preservation systems than for inert gas (nitrogen bottle) systems. Thus, one indication of abnormally high temperature and insulation deterioration would be a CO₂/CO ratio under 5.

Other ratio and percentage indicators that are sometimes helpful are:

Hot Metal in Oil

Ethylene/methane—1 to 1.5

Ethylene/ethane—2 to 4

Ethylene/hydrogen—2 to 3

The ratio will sometimes vary from the above, but the general pattern is high levels of ethylene and methane with lesser levels of hydrogen and ethane. There are usually low levels of carbon monoxide, carbon dioxide and the other gases.

Partial Discharges in Oil

Hydrogen—80% to 85%

Methane—10% to 15%

Arcing in Oil

Hydrogen—60%

Acetylene—30%

These guidelines can be used to determine the general type of problem that is involved. Knowledge of the transformer design and its history in service is extremely important in the interpretation process. For example, one type of design during a certain time frame is known to have a gassing situation caused by hot metal. This kind of knowledge combined with the gas-in-oil history is valuable in the decision making process for this type of transformer.

A frequent question is: How long can a transformer be left on-line with a gassing problem? The answer depends on the type and quantity of gas being generated and, in many cases, the type and transformer operating history. For example, several of the transformers with the known hot metal problem have been in service for years with total hot metal gas contents of 1,000 ppm or more. In this case, the cause of the problem has been identified so that a reasonable assessment of the risks can be made. In general hot metal gases will not cause failure as long as they are stable. If the gas-in-oil indicates partial discharges or arcing, immediate investigation is obviously needed. Trend analysis is still the best method to use for making decisions on continued operation. Any sudden increase in trend is cause for serious concern.

6.5.1.2 Dielectric Strength and Water in Oil

Although the dielectric strength and water in oil tests are separate tests, oil samples for both tests are usually taken at the same time. There are two test methods for determining the dielectric strength of oil. In the main tank, the ASTM D1816 method should be used. This standard allows an electrode gap dimension of either a 0.040 inch (1.02 mm) or 0.080 inch (2.03 mm). Testing utilizing the 0.040 inch gap is more widely used and is, therefore, most often recommended.



Key Technical Point

There are two test methods for determining the dielectric strength of oil. In the main tank, the ASTM D1816 method should be used. Generally, the ASTM D1816 method is more responsive to dissolved water and particles in the oil.

If the transformer has a load tap changer, either the ASTM D877 [21] or the ASTM D1816 test method could be used. If the tap changer has sharp, uninsulated electrodes, the ASTM D877 method should be used. Otherwise, use the ASTM D1816 method, which is more suitable when insulated or well-rounded electrodes are used in the tap changer. Generally, the ASTM D1816 method is more responsive to dissolved water and particles in the oil.



Key Technical Point

If the tap changer has sharp, uninsulated electrodes, the ASTM D877 method should be used. Otherwise, use the ASTM D1816 method, which is more suitable when insulated or well-rounded electrodes are used in the tap changer.

ANSI/IEEE Standard C57.106-1991, “Guide for Acceptance and Maintenance of Insulating Oil in Equipment,” provides guidelines for the dielectric strength of oil in operating transformers which are shown in Table 6-2 [22].

Table 6-2
Oil Dielectric Strength for Service-Aged Oil

Test and Method	Minimum Dielectric Strength (kV)		
	< 69 kV	69 kV to 288 kV	> 345 kV
ASTM D1816, 0.040 inch gap	23	26	26
ASTM D1816, 0.080 inch gap	34	45	45
ASTM D877, 0.10 inch gap	26	26	26

The standards do not contain information on the recommended oil properties for load tap changers. However, the following guidelines can be used for general application. It is recommended that the manufacturer's information be checked carefully for this information before taking action, because it might be critical to the operation and life of the tap changer.

Typical oil dielectric characteristics for load tap changers are as follows:

- Compartments with no insulated parts or well rounded electrodes: ASTM D877 minimum dielectric = 25 kV
- Compartments with insulated components such as cables or all electrodes are well rounded: ASTM D1816 minimum dielectric = 20 kV

The maximum recommended moisture content in oil for different transformer voltage classes are taken from IEEE Std. 637-1985 [23] and ANSI/IEE Std. C57.106-1991 and shown in Table 6-3.

Table 6-3
Moisture Content in Oil for Service-Aged Oil

Test	Voltage Classes		
	< 69 kV	69 kV to 288 kV	> 345 kV
Moisture content, ppm (maximum) ASTM D1533 [24]	35	25	20

The water content in oil is a function of the water in the insulating paper. Since water is so detrimental to the dielectric strength of oil and paper, and can accelerate the aging of paper insulation, these values are very important.

6.5.1.3 Oil Power Factor

This test is used as a check on the deterioration and contamination of insulating oil because of its sensitivity to ionic contaminants. The current applicable ANSI/IEEE standard does not list minimum acceptable values for power factor. The applicable standard (IEEE Std. C57.106) is in

the process of being revised and should be consulted for limiting oil power factor values to use when it becomes available.

6.5.1.4 Interfacial Tension (IFT)

Interfacial tension is a measurement of the surface tension that an insulating fluid maintains against water. The test measures the forces of attraction between molecules of the two fluids. It is an excellent means of detecting oil-soluble polar contaminants and oxidation products in insulating oils.

If all the other oil parameters are normal, interfacial tension values below those shown in Table 6-4 are not of immediate concern. However, it is recommended that any downward trend be followed because it might indicate a deteriorating situation. The values shown in Table 6-4 are from the currently published version of IEEE Std. C57.106. The standard is in the process of being revised and should be consulted for any changes when it becomes available.

Table 6-4
Interfacial Tension

Test	Voltage Class		
	< 69 kV	69 kV to 288 kV	> 345 kV
Interfacial Tension, mN/m (maximum) ASTM D971 [25]	24	26	30

6.5.1.5 Color

The oil should be light in color and optically clear. Darkening of the color of the oil over a period of time can be an indication of deterioration or contamination of the oil.

6.5.1.6 Other Oil Tests

The following tests can also be performed on insulating oil, but are not usually done unless a determination is being made to replace the oil.

- **Acidity.** The acidity of insulating oil is measured by its neutralization number. It is a measure of the acidic by-products that are produced when oil oxidizes. It is used as a guide to determine when the oil should be reprocessed or replaced. Inhibitors are usually added to transformer oil to resist the tendency of insulating oil to oxidize and to create sludge. The tests that are used to evaluate the condition of oil in operating transformers are ASTM D664-2001 and ASTM D974-2001 [26 and 27].
- **Viscosity.** The viscosity of transformer oil might increase with age. If the viscosity increases, the cooling efficiency of the oil will be reduced.
- **Oxidation Stability.** Sludge and acid products are produced when oil oxidizes. The oxidation stability test measures the susceptibility of an oil to develop sludge and acid products. Oxidation stability tests are made when the oil is new. The tests used to evaluate oxidation stability are ASTM D2112-2001a and ASTM D2440-1999 [28 and 29].

6.5.2 Winding Resistance

Resistances are measured to determine if there are abnormalities such as open circuits, short circuits, or poor electrical connections in the windings. The measurements must be made with measuring equipment that has sufficient accuracy for the small values of resistance in some transformers. The values measured in the field are compared to factory values shown in the test report to determine if changes have occurred. Agreement within 2% is considered satisfactory.

To compare the field measurement of resistance with the factory measurement, the field measurement must be corrected to the standard reference temperature. The conversion equation is as follows for a standard reference temperature of 85°C:

$$R_{85} = R_m(85 + T_k)/(T_m + T_k)$$

where:

R_{85} = resistance at 85°C

R_m = measured resistance

T_m = temperature at which the resistance was measured

T_k = 234.5°C for copper or 225°C for aluminum

Determination of the transformer winding temperature is important in making a resistance measurement. However, it is very difficult to measure the temperature of the winding accurately under field conditions. Some methods commonly used include:

1. Placing a thermometer in contact with the tank wall. This will not give an accurate indication of the real winding temperature if the transformer has been recently removed from service.
2. Using values obtained from the permanently installed temperature indicators. If the transformer has recently been removed from service, this might be the only means available for estimating the winding temperature.
3. For nitrogen-blanketed transformers a thermometer can be placed in the main tank by inserting it in openings in the top of the tank or in the wells for the permanent temperature indicators. Inserting a thermometer into the main tank usually requires breaking the hermetic seal on the transformer, which will cause a loss of nitrogen pressure. This can introduce moisture into the transformer and carries a risk that a conductive object could accidentally be dropped into the winding. Mercury thermometers should not be used inside a transformer tank because, if broken, contamination will occur. Use of the wells for the permanent temperature indicators requires removal of the permanent sensor from the wells.

Normally there will be some variation in the values indicated by the different sensors. Because the transformer is not typically uniform throughout its mass, averaging of values from all the indicators might yield better results than using a single indicator.

Note that the transformer must be disconnected from all of the incoming connections to obtain accurate measurements. It could take some time for the measuring equipment to settle down if there is a delta winding in the transformer. Accurate resistance bridges are required to obtain acceptable measurements. It can be difficult to use such bridges in an energized substation unless they are shielded.

The interpretation of results is very dependent on the type of conductor being measured. Some conductors consist of several parallel paths of stranded wires and detecting a problem with only one strand might be beyond the resolution of the bridge or micro-ohmmeter. If more than one strand is broken or there is a high resistance internal connection, the Kelvin Bridge or micro-ohmmeter should detect the resulting higher resistance circuit.

Comparison of readings with other phases, duplicate transformers, or previous measurements under field conditions is recommended. Variations under field conditions should not exceed 5%.

6.5.3 Turns Ratio

The turns ratio of a transformer is the ratio of the number of turns in a higher voltage winding to that in a lower voltage winding. The voltage ratio of a transformer is the ratio of the rms terminal voltage of a higher voltage winding to the rms terminal voltage of a lower voltage winding under specified conditions of load. For all practical purposes, when the transformer is on open circuit, its voltage and turns ratios can be considered to be equal.

The polarity of a transformer is determined by the internal connections and is indicated by the nameplate markings. Polarity is of interest if the transformer is to be connected in parallel with one or more transformers.

Results of the polarity and transformation ratio tests are absolute and can be compared with the manufacturer's nameplate specifications.

Transformer winding ratios, polarity, and phase connections should be checked before energizing the transformer for the first time on site. The ratio in particular is checked during regular (for example, annual) inspections, and it is recommended that it be checked before returning the transformer to service if the unit has been subjected to a through-fault or if the setting of the de-energized tap changer has been changed.



Key Technical Point

The ratio in particular is checked during regular (for example, annual) inspections, and it is recommended that it be checked before returning the transformer to service if the unit has been subjected to a through-fault or if the setting of the de-energized tap changer has been changed.

**Key Human Performance Point**

Transformer winding ratios, polarity, and phase connections should be checked before energizing the transformer for the first time on site.

There are a number of commercial transformer turns ratio test sets available from manufacturers serving the power industry. These instruments, when operated in accordance with the manufacturer's instructions, provide convenient and accurate readings of ratio and polarity of power transformers,

The turns ratio tolerance should be within 0.5 percent of the nameplate specifications for all windings. For three-phase wye connected windings, this tolerance applies to the phase-to-neutral voltage. If the phase-to-neutral voltage is not explicitly indicated on the nameplate, then the rated phase-to-neutral voltage should be calculated by dividing the phase-to-phase voltage by 1.73.

From time-to-time, it might be observed that the measured ratios of the outer phases of a three-phase transformer will be slightly different. Unless the differences are greater than 0.5%, there is no cause for rejection of this transformer.

Infrequently, it will be found that the ratio will be different from that specified on the transformer nameplate. This condition can occur when a very large transformer is equipped with a low voltage winding having a relatively small number of turns. In this case, the turns ratio must be expressed to the nearest complete turn. This error is one of resolution, since the number of turns could be less than 200 turns (200 turns being required to provide 0.5% resolution).

Also, it should be noted that transformers with load taps in the low voltage winding, may not have an equal number of turns between taps due to the overall low number of turns in the LV winding. In such cases, the voltage variation with tap changer operation will not be uniform. All three phases should have the same measured ratio, although it might not be in exact agreement with the nameplate.

6.5.4 Low-Voltage Exciting Current

The single-phase exciting-current test is very useful in locating problems such as defects in the magnetic core structure, shifting of the windings, failures in the turn-to-turn insulation, or problems in the tap changing devices. These conditions result in a change in the effective reluctance of the magnetic circuit, which affects the current required to force a given flux through the core.

The test comprises a simple measurement of single-phase current on one side of the transformer, usually the high-voltage side, with the other side left floating (with the exception of a grounded neutral). Three-phase transformers are tested by applying a single-phase voltage to one phase at a time. The tests should be performed at the highest possible test voltage, without exceeding the voltage rating of the excited winding. The instrumentation should, whenever

possible, exclude from the measurement the capacitive currents between the excited winding and the other windings, the core, or the tank. For purposes of comparison, the subsequent tests should be performed at the same value of test voltage, and using the same test connections.

The usual approach to the analysis of the exciting-current test results is to compare the results with the previous tests, or between similar single-phase transformers, or between phases of a given three-phase transformer. For the great majority of three-phase transformers, the pattern is two similar high readings on the outer phases and one lower reading on the center phase. The exceptions are 4- and 5- legged core-type transformers, and shell-type transformers with non-delta secondary windings. These transformers give a pattern of three similar readings. If the transformer has a load tap changer, the recommended initial tests include measurements at half of the LTC positions, but the relationship between the phases is expected to remain unchanged. Certain problems can be detected on the basis of current change when the measurements are performed on different load tap changer positions. Consequently, understanding how the load tap changer affects the current magnitude of individual phases is essential for developing proper analysis.

The transformer core may have residual magnetism present as a result of being disconnected from the power line, or as is frequently the case, as a result of dc measurements of winding resistance. The residual magnetism results in the measurement of higher than normal exciting current.

There is no widely accepted field method for distinguishing between the effect of residual magnetism and the effect of a problem present in the transformer. However, experience shows the following:

- Although some residual magnetism is almost always present in the core, in most cases it has no significant effect on test results.
- The majority of problems detected had a much larger effect (more than 10%) on the test results than the residual magnetism does. (This is not to say that small changes in test results cannot be due to problems with the transformer.)
- It is recommended that the dc measurements of the winding resistance be performed after the exciting current tests.
- If a significant change in the test results is observed, the only known, reliable method of excluding the effect of residual magnetism is to demagnetize the transformer.

6.5.5 Insulation Condition Assessment

Once in-service, electrical equipment is subject to different ambient and operational conditions such as excess voltage, drastic temperature changes, moisture, environmental contamination, internal arcing, corona discharge, and age just to name a few. These factors eventually break down dielectric integrity, which manifest as small electrical power losses within the equipment. Insulation power factor testing is a universally accepted means of assessing insulation integrity. Since dielectric power losses are of concern, “power factor” is a term chosen to describe them. A perfect insulator has no losses and when a test voltage is applied to it, charging current is 90°

out-of-phase with voltage. Power factor is defined as the cosine of the voltage-current phase angle (cosine of the resistance-impedance phase angle).

The power factor test measures the “power factor” of the insulation that lies between the conductor and the outside of a coil (ground wall). Since insulation has capacitive behavior, the power factor should be very low. This test is often used in quality comparison testing of new coils rated 13.2 kV and higher. Dissipation factor and capacitance tests are similar to a power factor test. The dissipation factor test measures the tangent of the loss angle ($\tan \delta$) for certain levels of impedance and frequencies, is close in value to the power factor. The capacitance test measures the capacitance of the insulation that lies between the conductor and the outside of a coil, which is similar to what a power factor test does.

Dissipation factor ($\tan \delta$) is an inherent property of electrical insulation. It is a measure of the electrical losses in the insulation. Dissipation factor is defined as the reciprocal of the ratio between the insulating materials capacitive reactance to its resistance at a specified frequency. It measures the inefficiency of an insulating material (see Figure 6-2).

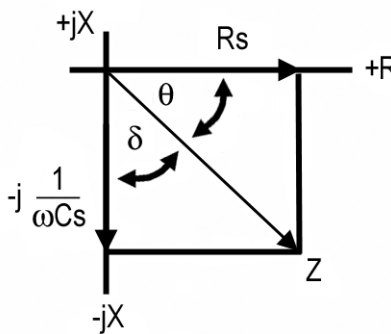


Figure 6-2
Power Factor Relationships

All real equipment has of course some inherent electrical losses, which should not increase significantly over time. As losses increase, the voltage-current phasor relationship, or power factor, changes (resistance-impedance phasor). These values, monitored over time, can be used to determine if insulation is deteriorating and to prevent future catastrophic failures or power outages. Parameters measured and recorded during testing include:



Key Technical Point

An insulation resistance test should be used to determine if the insulation is dry and clean before doing tests such as power factor, dissipation factor, or other tests.

- **Test Voltage:** Since dielectric loss (in milliWatts) is a function of test voltage, the test results should be recorded and same test voltage should be used during further tests to facilitate later comparison between test results.

- **Charging Current:** Current through test object displayed in RMS or vector quantity.
- **Capacitance (or Inductance):** Inherent capacitance of test object's insulation. This value is important and may indicate problems such as short circuits.
- **Power Factor:** A dimensionless quantity or factor. It is directly proportional to dielectric losses of insulation. It is defined as the cosine of the voltage-current phase angle (cosine of the resistance-impedance phase angle).
- **Tan-Delta or Dissipation Factor:** Also a dimensionless quantity, it is defined as the ratio between the insulation's resistance to its capacitive reactance at a specified frequency. It measures the inefficiency of an insulating material.
- **Dielectric (Power) Losses:** Active, Apparent, or Reactive Power in units of milliWatts, mVA, and mVAR, respectively, represent a combination of losses occurring due to dielectric absorption, ionization, and/or surface losses.

Similar to Test Voltage, **Temperature** and **Humidity** should be measured and recorded to facilitate better comparison of test results.

In the past, many utilities conducted power factor tests on a routine basis. Some utilities now perform power factor tests only when other tests indicate that a potential problem exists. Power factor testing requires the transformer to be taken off line, and test equipment and service personnel sent to the station. However, it should be noted that periodic power factor testing is recommended by most insurers even if the oil and other tests are satisfactory.

Key O&M Cost Point



The cost to conduct power factor tests is high because the transformer has to be taken off line. It should be noted that periodic power factor testing at prescribed intervals is done by most utilities. However, periodic power factor testing is recommended by most insurers even if the oil and other tests are satisfactory.

Power factor measurements are used for checking the condition of bushings. In fact, it might be necessary to perform power factor tests at more frequent intervals to check bushings that have a history of problems in service or that have a prompt increase in the power factor value between tests. It is important that a initial power factor reading be taken when the transformer is new, which should be used as a basis when subsequent measurements are made.

Key Technical Point



Power factor testing requires the transformer to be taken off line and test equipment and service personnel sent to the station.

6.5.5.1 Conduct of Tests

Insulation power factor is defined as the ratio of the power dissipated in the insulation in watts to the product of the effective voltage and current in volt-amperes when tested with a sinusoidal voltage. Special bridge circuits are used to make the measurements. The magnitude of the voltage used shall not exceed half of the low frequency test voltage in IEEE Std. C57.12.00 or 10,000 volts, whichever is lower. In the past, some low-voltage bridges such as 240 volts were

used. However, these bridges are not satisfactory for field-testing. The generally accepted method for performing power factor tests is Method II in IEEE Std. C57.12.90-1993 part 10.10 [14].

There are specialists in utilities that perform such tests and companies that furnish services for field testing of transformers, so those details will not be outlined here.

In general, the power factor of the insulation between windings and between the windings and ground are determined.

Two-winding transformers:

- High to low and ground
- High to ground, guard on low
- Low to high and ground
- Low to ground, guard on high

Three-winding transformers:

- High to low and ground, guard on tertiary
- High to ground, guard on low and tertiary
- Low to tertiary and ground, guard on high
- Low to ground, guard on high and tertiary
- Tertiary to high and ground, guard on low
- Tertiary to ground, guard on high and low
- High and low to tertiary and ground
- High and tertiary to low and ground

The measurements for these different combinations are compared to the original measurements when the transformer was installed and previous measurements to determine if changes have occurred.

6.5.5.2 Interpretation of Results

It is important to make corrections for temperature when performing these tests. There are recommended correction factors available in IEEE Std. C57.12.90-1993, and from companies that build test equipment and perform these tests.

The best interpretation tool is to trend the measurements. If there is an upward trend, some change has occurred in the system.

Water in the solid insulation can cause increases in power factor, and power factor measurements can be done as a check for increasing water in the paper. It should be noted that power factor will not always indicate high water content in insulation of some transformers. The reason is not well understood at this time.

Chemical contaminants can cause the power factor to increase. If the IFT and oil power factors indicate a possible contaminant in the system, insulation power factor tests are sometimes done to determine if power factor will also reflect the problem.

Failures within the insulation will usually cause the power factor to increase. Routinely, power factor tests are done when there is some indication that a failure has occurred in the insulation.

6.5.5.3 Bushings

Some bushing failures have occurred between power factor measurements done at periods such as one year, that is, the failure evolved after tests were made that had not indicated a problem.

There have been a number of bushing problems where deterioration in the insulation eventually caused bushing failure. The deterioration process usually causes the power factor of the bushing insulation to increase. It is important to note any increasing trends in bushing power factors since this might indicate deterioration in the bushing insulation.

Industry data has shown that some bushing designs are more susceptible to in-service degradation. Therefore, bushings with increasing power factor and/or dramatic increases (prompt increase) between tests should be tested more frequently.

6.5.5.4 Insulation Resistance

The measurement of insulation resistance is another way to determine if changes have occurred in service. However, this method is not used as frequently as insulation power factor. This method is also outlined in IEEE Std. C57.12.90-1993, Part 10.11, and is used to determine the insulation resistance between windings and from the windings to ground. In general, a dc voltage is applied to the insulation. Readings of the resistance are taken after the voltage has been applied for a specified time period. Instruments made for this purpose are made with variable dc voltage supplies such as 500, 1000, 1500, 2000, and higher volts.

6.5.5.5 Summary

Routine power factor tests are not recommended unless the oil tests and the water in insulation calculations indicate possible problems such as high water content or contamination in the insulation. However, power factor tests at intervals such as five to seven years are done by some utilities, even if the oil tests are normal, to detect incipient problems that might not have been indicated by the oil or other tests.

Trending power factor and insulation resistance are important when such measurements are taken. If there is an increasing trend, more investigation is usually needed. Power factor tests

could be needed at more frequent intervals on bushings that have a history of problems in service or that have an upward trend in the power factor.

Power factor and insulation resistance measurements do not always indicate high moisture content in some transformer designs. Off-line power factor tests on bushings might not always catch a defective bushing before it fails because the problem could evolve between measurement periods.

Power factor values at which the transformer should be dried or other actions taken should be obtained from the manufacturer or industry services companies, if possible. If the indicated water content is above the typical values, drying is usually performed.

6.6 On-Line Monitoring

The emphasis on reduced maintenance costs and life extension makes it desirable to have on-line monitoring systems that will provide improved information for determining when maintenance should be performed and for life extension. This subsection outlines the state-of-the-art for on-line monitoring systems. Such systems have become more common in recent years. Sensor development continues to be conducted in important areas such as gas-in-oil, moisture in oil and partial discharge measurements.



Key O&M Cost Point

The emphasis on reduced maintenance costs and life extension makes it desirable to have on-line monitoring systems that will provide improved information for determining when maintenance should be performed and for life extension.

6.6.1 Gas-in-Oil Sensors

Gas-in-oil sensors have been available for several years. When first introduced, these devices were essentially hydrogen sensors, although one such device did detect a small percentage of carbon monoxide, methane, and ethylene. These sensors are mounted so that they are exposed to the oil, and their performance appears to be somewhat better if they are mounted in a moving stream of oil that is representative of the oil that passes the windings and core. Although these gas-in-oil sensors detected primarily hydrogen, they do provide useful information in that hydrogen is generated by high partial discharges and is evolved by other processes, such as overheating of the oil.

Multiple gas sensors have been developed that can provide continuous monitoring and/or early warning of increased gas generation (see Section 6.7.6).

6.6.2 Temperature Sensors

Top oil thermometers that have been in use for many years are still being utilized. Some utilities use resistance temperature devices (RTDs) for improved accuracy and reliability. The output from both types is sometimes taken to remote control centers.

The so-called winding temperature devices are used on a large percentage of power transformers. The sensors are a simulation device that responds to the top oil temperature and the heat generated in a resistance element. A bushing current transformer provides current proportional to the load current to the heating coil. The current adds an increment of temperature to the coil that is equal to the winding temperature rise above the hot oil temperature. They have limitations in that the setting depends on the hot-spot temperature calculated by the designer, which might or might not represent the true hot-spot, and the time response of the winding may be different than that of the device.

Winding temperature devices now commercially available no longer use a resistor to determine the increment of temperature added to the top oil temperature. Instead, the increment is calculated by software.

Direct measurement of hot-spot temperatures using fiber optic technology was investigated in an EPRI project, and such sensors have been successfully installed in a number of operating transformers. The sensors are located in an area that is either the hottest spot location or is representative of the hottest spot temperature. Although the fiber optic cables are made from an insulating material, they are not suitable for installation in the higher voltage regions so that the sensors must be installed in a lower voltage area such as the low voltage windings or in leads. They can also be installed in the winding oil ducts to determine the hottest oil temperature since the winding oil duct temperature may be several degrees hotter than the bulk top oil temperature. The fiber optic cables are taken through pass-through devices to the outside of the tank where they are connected to read-out or recording equipment. The obvious advantage is that the actual hot-spot temperature can be determined for life extension considerations or for loading purposes.

6.6.3 Oil Level Gauges

An oil level indicator is another monitoring device that is used for online monitoring. Oil level gauges are used to detect the level under different temperature conditions and to alarm if the level is below the minimum. The gauges are set to maintain the transformer oil at a level such that the high-voltage parts might not be exposed. Section 3.7 has additional information on oil level gauges.

6.6.4 Rate of Pressure Rise Relays

Relays that respond to increases in pressure rise are installed in the gas space and under the oil of transformers having gas space oil preservation and in the oil for those having full tanks of oil. Both types respond to sudden increases in pressure that are caused by arcs under oil, which generate high pressures. These relays can be connected to breaker contacts for tripping since

sudden pressure increases are the results of serious arcs within the oil. These relays have been essentially trouble free after several years of correcting false alarms caused by different problems in the relays. It should be noted that installation on older transformers might require some study.

For example, some older transformers may have loose windings that cause hydraulic pumping of the oil under low-level short circuits or even magnetizing inrush, which can activate the relay. In such instances, persons familiar with the transformer design and these relays should be contacted.

6.6.5 Gas Detector Relays

These relays collect free gas bubbles in the oil. The relays are connected to high points on the cover, which collect the gas. If gas is generated by partial discharges or arcs within the oil, an alarm is initiated by the relay. Also, they will respond to air bubbles caused by leaks. Gas collector relays are another online monitoring device. More information is given in Section 3.7.4.

6.6.6 Oil Pump Performance Sensors

There are three types of devices in use:

- Differential pressure oil flow indicators are used to determine when the pumps are in operation.
- Vane-type oil flow indicators are used to determine when the pumps are in operation.
- Pump bearing wear detectors are available for pumps having sleeved bearings. These acoustic devices are used to determine any changes in the dimension of the gap between the shaft and the bearing surface. Base readings are obtained when the pump is new. A read-out device is then used periodically to determine if wear has occurred.

6.6.7 Water-in-Oil Sensors

Since water-in-oil is a key indicator of oil and paper insulation condition, considerable effort has been devoted to the development of practical on-line water-in-oil sensors. Such sensors are commercially available for installation on operating transformers.

In the past, utilities have assessed the dryness in the transformer by taking periodic samples to measure the moisture content in the oil. Taking samples at regular intervals as part of a scheduled maintenance routine is problematic compared to a continuous monitoring approach, since moisture content varies with the load. Therefore, the worst core condition might not be revealed by the sampling method.

Using online monitoring, a utility can monitor the moisture content in transformer oil on a continuous basis. An assessment can be made to determine the water in the insulation and what corrective actions might be necessary.

When the transformer insulation is exposed to the atmosphere, the rate of absorption of moisture depends on the relative humidity of the atmosphere. Moisture entering the transformer is absorbed by the oil and the cellular insulation material depending on the time duration of exposure.

The operation of moisture sensors is based on thin-film capacitive element technology. The capacitance measured will change proportionately to the change in the relative saturation of moisture in the oil. The output of these devices is the percent relative saturation of the moisture in the oil, which is dependant on the temperature of the oil and the amount of moisture in the oil. If the temperature of the oil is known, the parts per million (ppm) can be determined.

6.6.8 Load Tap Changer Monitors

A number of load tap changer monitors have been installed in service. The basic principle is that contacts that are nearing the end of their life or that are coking generate additional heat, which raises the temperature of the oil in the compartment. The tap changer diverter compartment usually runs cooler than the main tank and the selector compartment runs cooler than the diverter switch compartment. If the temperature of the diverter switch compartment starts to increase in comparison to the main tank or the selector compartment, there is usually a contact problem. If the selector and the diverter are in the same compartment, the temperature of the tap changer compartment must be compared to the main tank. Many such problems have been detected with infrared scanning.

The on-line monitors use temperature sensors located on the walls of the tap changer compartments and the main tank. The output is connected to recording and analysis equipment. Alarms can be activated if the temperature of the diverter compartment reaches a level indicating that the contacts should be inspected or changed. Other monitors that are available for load tap changers include:

- Timing circuits to determine if there has been a change in the operating time of the mechanical system.
- Measurement of the motor current including the starting current. Broken shafts or changes in the mechanical system might be detected.

Load tap changer monitors under development include:

- Use of ethylene gas analysis to determine contact wear. It has been found that the change in the ethylene is different when contact heating occurs compared to the other gases generated when the tap changer operates. Some utilities are already experimenting with ethylene detection using chromatograph data.
- Acoustic analysis is being used in much the same manner as is being applied to circuit breaker monitoring.

6.7 Developing Technologies

There are many technologies that have been developed and other are under development that are intended to help determine transformer condition. These technologies hold promise for improving transformer condition monitoring.

6.7.1 Frequency Response Analysis

Frequency Response Analysis (FRA) is a technique currently being used by many utilities to detect winding damage and winding looseness in power transformers. Winding damage and winding looseness can occur during transportation of a transformer or through the development of large mechanical forces as a result of through fault electrical currents which reduce the clamping pressure of the winding. This subsection describes the use of two known FRA techniques used to test the internal winding condition of power transformers.

A transformer winding consists of many winding turns inductively and capacitively coupled to each other. A capacitive coupling also exists between the windings and the grounded core and tank. Thus the equivalent circuit model of a transformer winding can be represented as a ladder network with series inductance and series capacitance, and parallel capacitance to ground (see Figure 6-3).

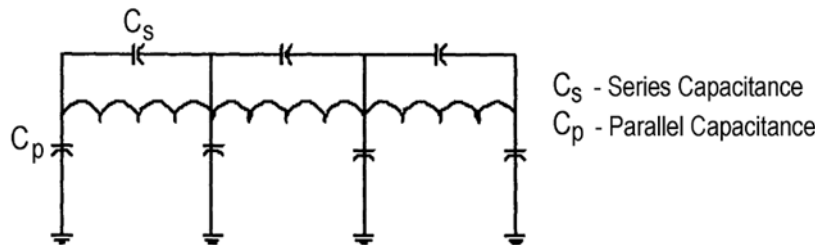


Figure 6-3
Equivalent Circuit of a Transformer Winding

6.7.1.1 FRA Test Methods

The interaction of the distributed capacitance and inductance of the windings generate a particular frequency response for that winding geometry. This provides the FRA signature for that particular transformer and winding, which can then be referenced during subsequent diagnostic testing. Any changes to the winding geometry, i.e., the inductance and capacitance of the winding, will cause a change in the frequency response of the transformer or the winding itself. The winding geometry changes when the windings are open-circuited, deformed by short circuits, or loose.

Currently, two excitation methods are used to conduct FRA measurements. They are the impulse method and the sweep frequency method. In the impulse method, a series of fast voltage/current transients from a recurrent surge generator are applied to HV terminal of the

transformer and the voltage/current response is measured on the LV terminal of the transformer or any other winding. In the sweep frequency excitation method a frequency source connected to a particular winding is swept over a range of frequencies and the attenuation from one end of the winding to the other end is measured. Care must be taken to ensure that the impulse and the frequency source contain the required energy over the frequency range of measurements and will not be affected by external noise sources found in the substation.

6.7.1.2 Impulse Test Method

The transformer is disconnected from the power system at all its terminals. Typically a short, low voltage impulse is injected on the HV terminal of the transformer with the neutral end of the winding being grounded (see Figure 6-4). The output voltage/current signal is measured on the LV terminal of the transformer. The applied voltage and output secondary voltage current are measured with the aid of a digitizer. A Fourier Transform is applied to the digitally recorded time data to obtain the frequency response. The transfer function is obtained by dividing the transformed output voltage/current by the transform of the input voltage. Changes in the winding can be detected by comparing the results obtained with previous recorded results of the transformer under test or results recorded on an identical transformer.

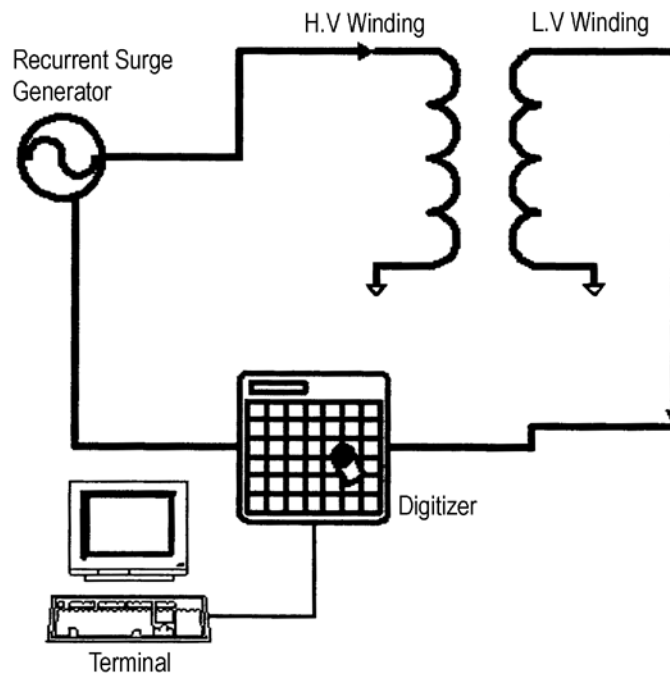


Figure 6-4
Impulse Measuring System

Figure 6-5 shows the FRA tests carried out on a 300 MVA, 345/138 kV transformer. The FRA of the transformer is compared with the results of a reference transformer that has a somewhat tightly clamped winding. The trace with the larger peak is from the transformer with a loose winding. The trace with the lower peak is from the reference transformer. As a result of this test, the utility decided to re-clamp the transformer windings.

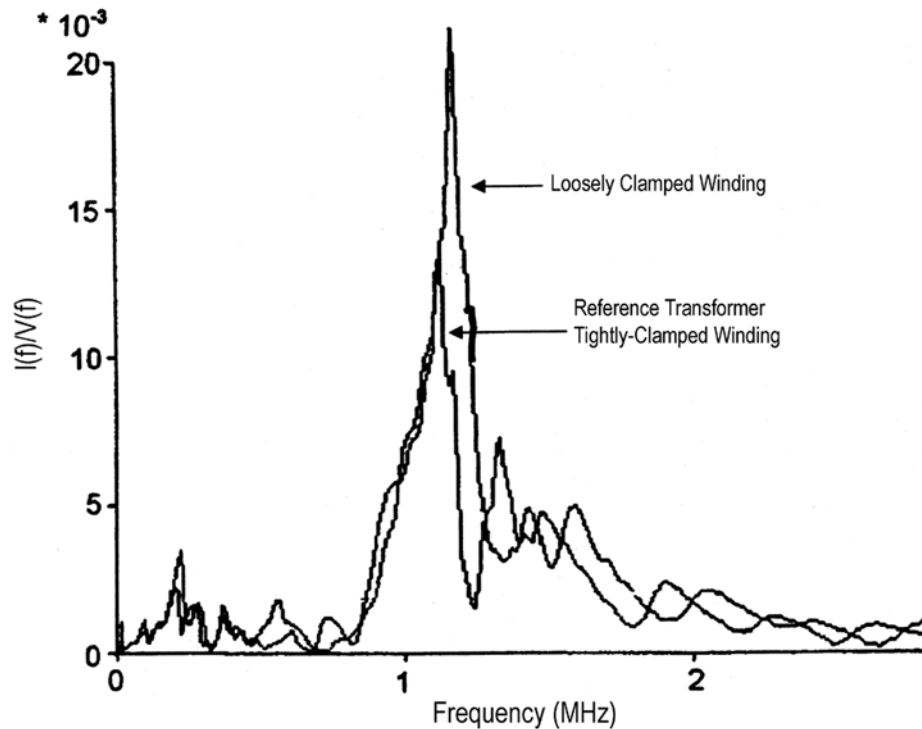


Figure 6-5
FRA Comparison of a Tightly-Clamped to Loosely-Clamped Transformer

Figure 6-6 shows the results of the FRA tests carried out on the same transformer before and after re-clamping. The trace with the larger peak is before re-clamping and the lower trace is after re-clamping.

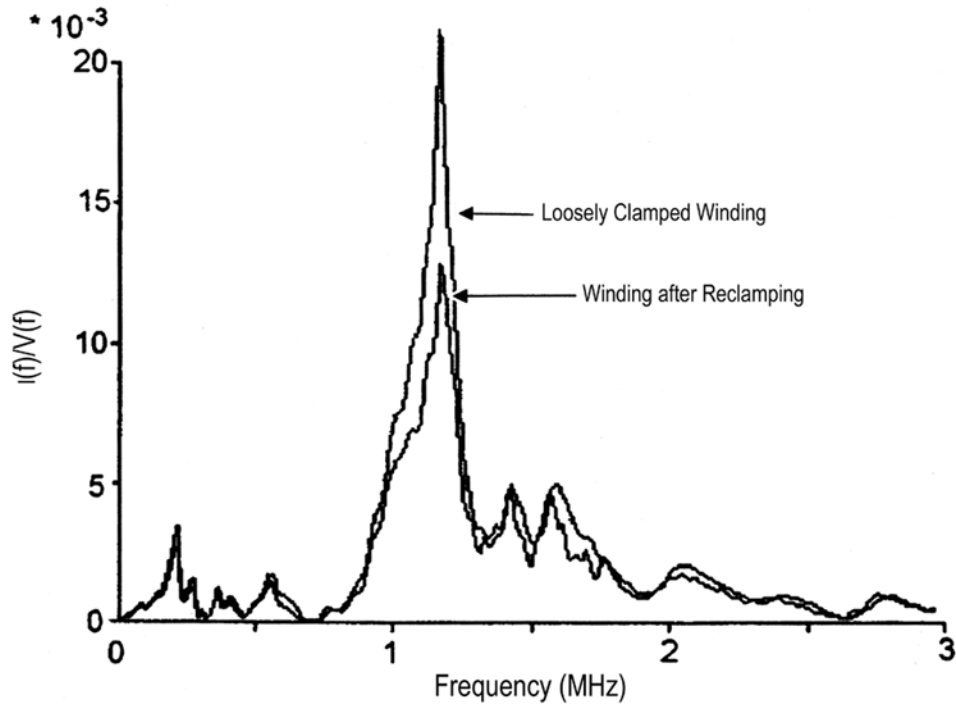


Figure 6-6
FRA Comparison Before and After Re-Clamping

6.7.1.3 Sweep Frequency Test Method

The transformer is disconnected from the power system at all terminals. Typically a Hewlett Packard HP 4195 Network/Spectrum Analyzer is used to inject a sweep frequency sinusoidal signal of approximately 2 V rms on one side of the winding under test (see Figure 6-7). The voltage is measured on the other side of the winding and a voltage transfer function is measured for the winding over the range of frequencies. The frequency range should typically be from 5 Hz to 10 MHz. The windings not under test are open-circuited and depending on the winding configuration, can be left floating or grounded at one terminal. Changes to the winding can be detected by comparing the response to previously recorded responses, by comparing the responses of each of the other windings, and by comparing the responses of other transformers of the same design.

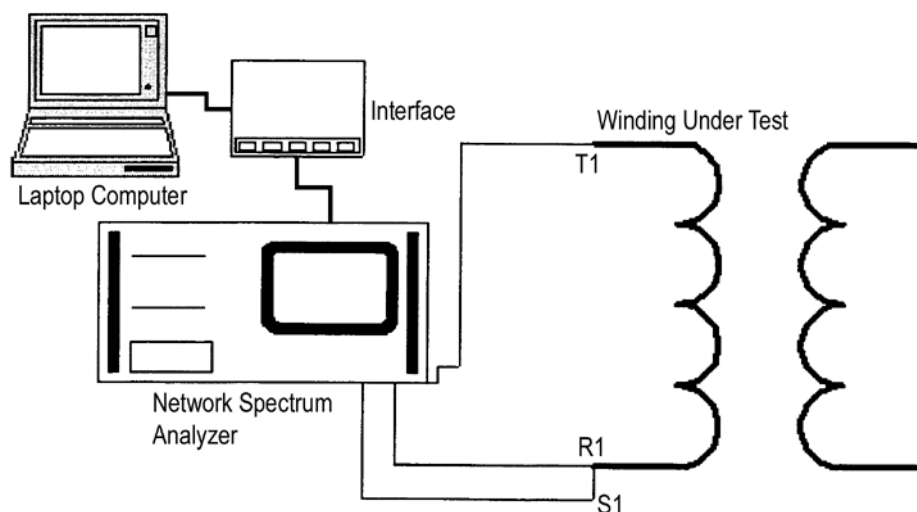


Figure 6-7
Sweep Frequency Measuring System

A typical low frequency response and high frequency response is shown in Figures 6-8 and 6-9. The point to note is that any shift in the response of a winding from the typical low frequency or high frequency response is an indication of winding movement or winding deformation.

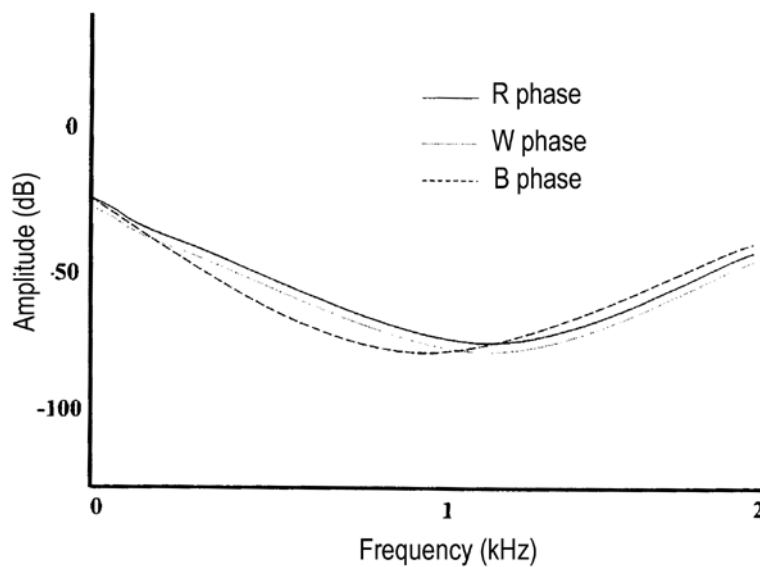


Figure 6-8
Typical Low Frequency Response

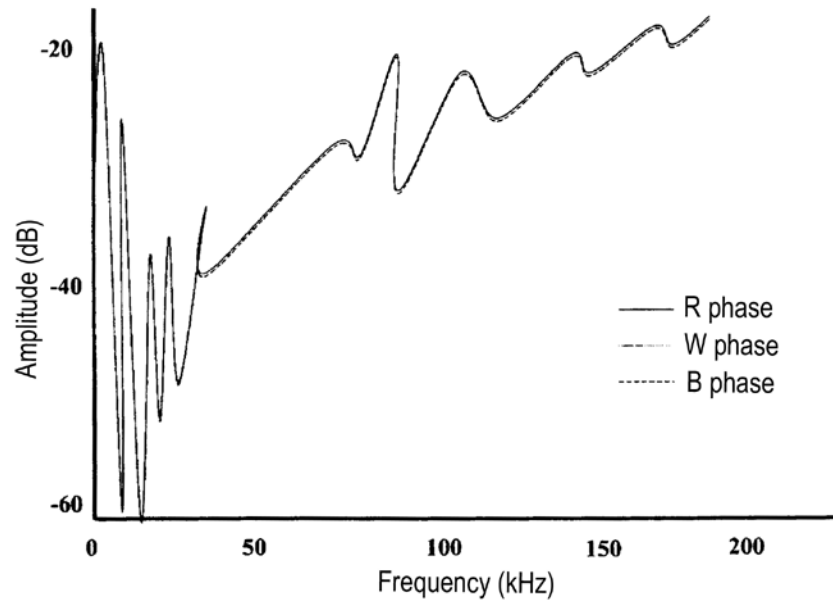


Figure 6-9
Typical High Frequency Response

6.7.1.4 FRA Summary

Various publications on FRA testing have concluded that both the impulse method and the swept frequency excitation method are reliable techniques for detecting winding movement and deformation in transformers.

It is relatively easy to perform both tests. However, it is important to ensure that the characteristic impedance of the test leads is matched to the input impedance of the measuring equipment to improve the repeatability, sensitivity and reliability of the detection of winding movement. Interpretation and assessments of the results are more conclusive if FRA reference or signature results are available, although for the sweep frequency method comparison between the different phases can be made.

Frequency response analysis testing is not the type of test that is performed periodically on a transformer. The test could be used to determine if winding movement has occurred due to a close-in through fault. Also, this test could detect loose windings on older core form transformers that do not have dynamic clamping systems. Its main use is to detect winding movement without actually going inside the transformer to make a visual determination.

6.7.2 Electrical Partial Discharge Protection

From the viewpoint of determining damaging conditions that could be remedied if detected early thereby reducing repair costs and preventing catastrophic failures, partial-discharge detection is of great interest. Partial discharge detection has been used in factories since about 1960 to determine the presence of damaging discharges during factory tests. It is recognized

that such detection has reduced the number of potential field failures by detecting incipient problems and taking corrective action in the factory.

The method used in the factory is to couple electrical detectors to the potential tap of the bushing so that discharges occurring during the test can be detected. The art has progressed to the point that readings taken at all terminals of the transformer under test can be used to locate the source of the discharge.

Such factory tests are performed in test bays where the high frequency background noise is relatively low. However, the background is quite high in a substation so that traditional electrical methods cannot be used. However, new approaches to electrical partial discharge measurement are being investigated.

An additional discussion on the use of partial discharge detection is presented in Section 6.7.3.

6.7.3 Acoustic Partial Discharge Detection

Acoustic partial-discharge detection is used in factories for location of discharges, and this technology has been developed for field detection. Acoustic signals are generated in the oil by partial discharges so this method involves sensing of the acoustic signals that are transmitted through the oil. Piezoelectric devices are used to detect acoustic emissions and have been installed on or in the transformer to obtain more data or as on-line monitors.

6.7.3.1 External Sensors

A number of sensors are attached at different locations on the tank wall. The output from the sensors can be taken to read-out devices or recorders. Data may be recorded and diagnosed using a computer system. If the signals appear in a transformer that has had no signal or if there is an increase such that there is an upward trend, an alarm is initiated (see Figure 6-10).

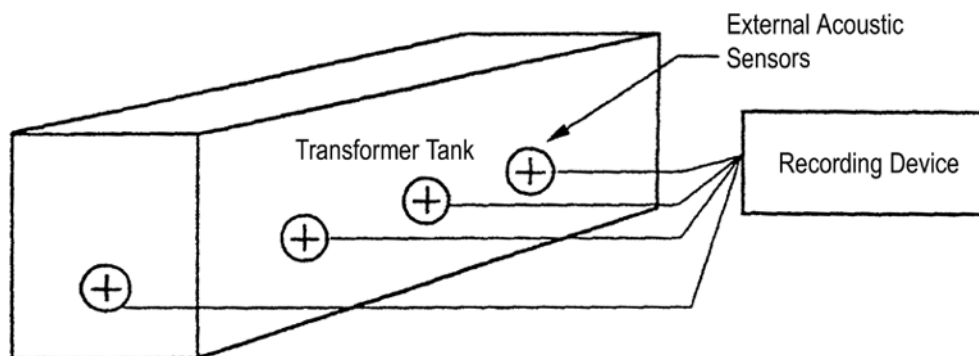


Figure 6-10
Location of External Acoustic Partial-Discharge Sensors on Tank Walls

6.7.3.2 Internal Sensors

The sensitivity can be increased if the sensors are located in the oil itself. However, the metal sensors cannot be located in areas of high electrical stress. One development is to attach the Piezoelectric sensor to the end of a fiberglass rod. The rod is installed in the oil through a gland as illustrated in Figure 6-11. Fiberglass is used because it is a reasonably good insulation material and glass is a good conductor of acoustic signals. This method was developed for factory location work, and it has been installed in a number of operating transformers.

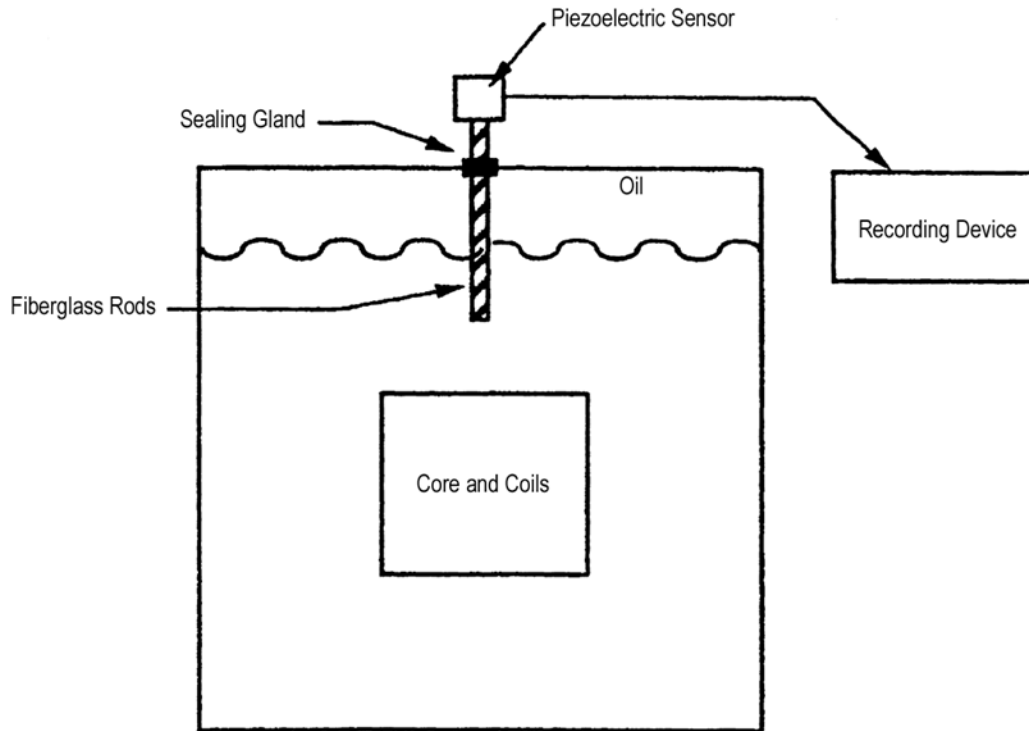


Figure 6-11
Internal Acoustic Partial-Discharge Sensor

There are several problems that had to be solved for use in energized substations. For example, the devices must operate in a rather hostile environment including high-frequency arcs, vibration in the tank walls, and external signals that are in the frequency response range of the sensors, such as rain or sleet impacting the cover of the transformer. It appears that these problems are being solved. Again, the output of these sensors is transmitted to a computer system for recording and analysis. Alarms are initiated when a signal originates in a transformer with no previous discharge history or if there is an upward trend.

In an EPRI-sponsored project, researchers recently designed and tested new fiber optic sensors capable of detecting partial discharges in power transformers. This research is described in EPRI report *Optical Fiber Acoustic Sensors for Inside-Transformer On-Line Detection of Partial Discharges*, 10000016 [30].

6.7.4 Furan Analysis

When paper decomposes thermally, some oil-soluble chemical compounds are released in addition to carbon monoxide and carbon dioxide gases. These are known as furanic compounds, the principal one being 2-furfuraldehyde. The preferred method of measurement of the furans is by HPLC (high performance liquid chromatography), although there are many other techniques. There is growing interest in developing diagnostic techniques based on the presence of these compounds to identify when an abnormal rate of insulation thermal decomposition exists because the test can be made on an oil sample taken while the transformer is in service.

Many investigators have hope that information can be derived from the rate of evolution of 2-furfuraldehyde, or some distinctive ratios can be identified between quantities of the less evident compounds. Unfortunately, at present there are no well-established guidelines for diagnostics, such as exist for gas-in-oil analysis. Furthermore, the prospect of establishing diagnostic techniques is dimmed by the fact that different types of cellulosic insulation seem to generate furans at different rates when heated and the generation rate is also influenced by moisture content.

Some utilities are performing furan analysis on transformer oil samples on a regular basis to gather information. The general result for normally operating transformers has been that there are either no detectable furans in the oil or the level is less than 100 ppb (parts per billion). In the numerous instances when significant thermal damage has been detected and confirmed by physical examination, the furan level has been at least 100 ppb and ranging upward to as much as 70 ppm (parts per million) in the most extreme case.

6.7.5 Static Electrification Detection

EPRI has sponsored research on static electrification in large power transformers since 1984. The culmination of this research was presented at a symposium in May 1999. As part of the research, tests were performed on a 500/345 kV, 333 MVA shell form transformer at the Ramapo Station of Consolidated Edison Company of New York. The transformer was operated in various ways (oil temperature, pump operation, and so on) to determine when static electrification would occur and what methods could be used to detect it. The types of sensors used for detection were:

- Internal acoustic partial discharge waveguides
- External acoustic partial discharge sensors
- Electrical partial discharge sensors, MIT
- EPRI “smart manhole” with Nilsson plate and MIT ACS sensors
- Leakage current measurements
- Pump oil flow
- Oil temperature
- Photo-diode and photo-multiplier partial discharge sensors

Transformer Tests and Online Monitoring

- Gas-in-oil sensors
- Water-in-oil sensors

The results of the test program demonstrated that diagnostic capability exists using sensors for the detection of static electrification discharges in operating transformers and discharges that occur as a result of other weakness or phenomena in the transformer system. A simple model could be developed using partial discharge sensors, oil temperature and pump oil-flow sensors. If discharges occur under the following conditions, the probability is very high that static electrification is the cause:

- The temperatures of the transformer insulation system are in the order of 15°C to 40°C.
- All pumps, or most of the pumps, are in operation with voltage on the transformer.

The discharges occur at intervals rather than on a continuing basis.

Partial discharge sensors have the capability for making on-line diagnostic tests on operating transformers. A summary of conclusions from the Ramapo tests are:

- The MIT Electrical System has demonstrated the sensitivity for detecting discharges in operating transformers.
- Internal waveguide acoustic rods installed into the oil have good sensitivity. They can be made to be largely insensitive to external noises such as ram.
- External acoustic sensors had good sensitivity.
- A number of sensors can be located around a transformer to increase the sensitivity and for location purposes.

The results of this research have demonstrated that technology and devices exist for making diagnostic tests on transformers in service. They could be installed as on-line monitors or used to make diagnostic tests on transformers that are suspected of having a partial discharge problem.

6.7.6 New Gas-in-Oil Sensors

There are now available gas-in-oil sensors that can detect other fault gases besides hydrogen. This is very important since gas-in-oil analysis is the primary method for determining the internal transformer condition. The objective is to employ on-line gas-in-oil measurement methods that will determine the amount of fault gases in the oil. If the cost of such devices is low enough, they could also be used to augment the present practice of taking samples and analyzing them in a laboratory, since the total cost for labor to take samples and analyze them is considerable. The gases that can be detected by these new gas-in-oil sensors generally include:

- Carbon monoxide
- Carbon dioxide
- Acetylene

- Ethylene
- Hydrogen
- Ethane
- Methane
- Oxygen

These devices may be more costly than hydrogen monitors, but will be able to provide more information about the condition of a transformer and could be cost effective for important transformers or for a transformer with a suspected serious problem. The long-term reliability of these new gas-in-oil sensors is as yet not known.

In addition to the gas-in-oil sensors described above, sensors are now also commercially available that can detect fault gases in the gas space above the oil in transformers with sealed tank or inert gas oil preservation systems.

6.8 Infrared Scanning

EPRI report “Guidelines for the Life Extension of Substations” includes detailed information on thermography infrared scanning [38].

Thermography was pioneered as an electrical preventive maintenance technique for the electric utility industry in the early 1960s. In recent years, due to advances in thermographic equipment design, thermography has become much more prevalent in substation maintenance, including transformers.

All objects emit heat in the form of infrared radiation, which is constantly being absorbed and re-emitted by humans and everything around them. Thermography, also called “infrared radiometry,” “infrared scanning,” or “temperature scanning,” is the term used to describe the process of making this thermal radiation visible to the human eye, thereby making interpretation and measurement of this radiation possible.

Thermography in electrical inspection is a non-contacting (non-destructive) operation, which is applied to in-service equipment while energized and carrying load. Problems are detected either as a function of excessive temperature rise (such as a poor connection) or a subnormal temperature (such as a cool transformer radiator fin signifying a blocked passage).

Infrared thermography can be used to measure the temperature of substation equipment without intrusive contact using infrared radiation to determine one of the following:

- The absolute temperature of the area of the equipment being inspected
- The temperature differential between the area of the equipment being inspected and the surrounding ambient air temperature

Theoretically, the temperature of any item connected to a conductor, such as a cable lug at the terminal of a disconnect switch or a bushing, should be the same as that of the conductor. For

the ideal connection, there should not be any temperature rise above the conductor. This ideal connection is seldom realized in actual installations. The temperature of an object depends upon the resistance in the connection. The higher resistances cause higher I^2R losses, which increase the temperature of the device or connection. This increased resistance can occur due to improper construction and usage of the material when it was initially built or to oxidation of the material during its service life. Resistance due to oxidation will increase over time. If there is an increase in current flow through a switch, a connection with an already high resistance will experience an increase in deterioration. This deterioration will manifest itself as a higher temperature rise above the temperature of the conductor. Therefore, even a minor hot spot could lead to a future failure.

To effectively utilize thermography as a condition assessment tool, the data collected during each thermographic inspection should be stored, thereby permitting easy development of a database of trend information so that incipient problems can be quantified and tracked.

Thermography is considered by many to be the easiest and most productive method of finding potential problems before they become failures (predictive maintenance).



Key Technical Point

Thermography is considered by many to be the easiest and most productive method of finding potential problems before they become failures.

6.9 Monitoring and Mitigation of Geomagnetically Induced Currents (GICs)

About every 11 years, major disturbances occur on the surface of the sun. These disturbances cause tremendous amounts of charged particles to be catapulted into interplanetary space. Some of these charged particles may collide with the earth's magnetosphere and, through complex interactions, cause the ionospheric current systems that are sometimes visible as the aurora. The fluctuating ionospheric current systems induces a flow of quasi-direct current on the surface of the earth and into man-made structures such as transmission lines, communications cable, pipelines, and railway tracks.

6.9.1 Mitigation Techniques

Since GICs were discovered to have detrimental effects on power systems in the 1960s, there have been and still are ongoing attempts to mitigate these harmful effects.

6.9.1.1 GIC Monitoring Program

Some utilities are monitoring GICs to determine how they affect their power systems and to decide if any mitigation is necessary. The three main methods being used are:

- Measure the perturbations to the earth's magnetic field.
- Measure the GIC in the transmission lines or transformer neutrals.
- Measure the power system total harmonic distortion and abnormal reactive power flow.

6.9.1.2 GIC Blocking Devices

Devices to block the flow of GIC have been developed and are in limited use in a small number of utilities. These are capacitive devices that can be inserted in the transformer neutrals or in series with long transmission lines. They are complicated and hundreds would be required to completely protect a typical power system.

6.9.1.3 GIC System Operating Guidelines

Many utilities have opted instead to set up operating guidelines to cope with GIC. Many of the operating guidelines used by utilities apply to transmission system operation. The ones that can apply to power plant transformer operation are:

- Restore out-of-service transmission lines and transformers and discontinue planned maintenance work
- Adjust system voltage set points to more optimum positions
- Reduce the loading on key transformers
- Re-dispatch generation to optimize vars, system voltage, loading, and operating reserves
- Reduce the number of switching operations on the system
- If possible, remove critical transformers from service. Such critical equipment is site specific, and is usually identified as vulnerable by past experience with a GIC event.

6.10 Observations

Transformers are exposed to lightning voltages, switching surges, and other abnormal conditions that impress higher voltage on the transformer terminals or windings. The impressed voltage from surge voltages is not uniform across the windings and usually tends to be much greater on a few turns next to the terminal. Subsequent voltage oscillations within the winding might develop and raise the voltage higher than that impressed on the terminal.

Transformers are designed to withstand abnormal conditions and the purpose of factory tests is to test the material and workmanship of the insulation structure. By successfully passing tests as described in the IEEE Std. C57.12.90-1999, the equipment demonstrates that it is capable of meeting abnormal conditions. Transformers are designed to withstand specified impulse tests.

It is important for utilities to determine their vulnerability to GIC effects and then determine the appropriate mitigation techniques for their system. A GIC monitoring program, along with a procedural approach, is suggested as the easiest technique for a utility to develop their mitigation strategy.

Monitoring transformers through certain on-line and off-line tests can provide insight to conditions, but will affect transformer operation and life. Collecting and trending data will allow users to make informed decisions based on transformer condition.

7

MAINTENANCE

7.1 Introduction

Transformers in service are continuously being subjected to electrical and mechanical stresses. Extreme weather conditions coupled with high loads add more stresses. Large power transformers are designed and built with uniform temperature gradients to avoid hot spots. The oil preservation system keeps virtually all moisture and oxygen away from the transformer interior. However, after several years of service, moisture, oxygen, and temperature are the key factors that create chemical activity, which degrades the condition of the cellulose insulation material.

The generator step-up unit and reserve/system auxiliary transformers must be constantly available for the generator output to be connected to the transmission network. Demand for continuous availability necessitates quality maintenance practices resulting in high equipment reliability.

While these transformers are in service and over many years of operation, they can be subjected to various electrical and mechanical stresses. These stresses can affect the core and windings, bushings, bus ducts, and transformer accessories. Transients from switching operations, lightning discharges, load rejections, and various other causes can impact the condition of the equipment. Although the design of the transformers took into consideration these phenomena and their protection has been improved, these events may happen and electrical and/or mechanical stresses are in some cases unavoidable. Therefore, proper operations, inspections, and maintenance are essential to these transformers.

Periodic inspection and maintenance of transformers and their accessories can identify potential problems to avoid further complications. Proper maintenance is the key factor for a long life of a transformer and its accessories.

The recommendations summarized below for predictive and preventive maintenance ensure that transformers are maintained and operated with fewer or no in-service interruptions. These recommendations are divided into two categories:

- Condition assessment tests that determine the need for maintenance or repair
- Routine maintenance and inspections

7.2 Condition Assessment Tests

There are several test methods currently employed to determine or assess degradation occurring in a transformer. Degradation is often determined or inferred by checking the condition of cooling liquid, taking electrical measurements of insulation condition, or monitoring temperature by infrared or other devices.

7.2.1 Oil Testing

Preventive maintenance requires the transformer liquid insulation be tested at least annually or semiannually to ensure that it is free from moisture, heat, oxidation, and combustible gases. The American Society for Testing and Materials (ASTM) lists several tests in its publication D117, “Standard Methods of Testing Electrical Insulating Oils” [31]. In addition to the tests listed in Section 6.5.1.2, Table 7-1 lists additional tests used for insulating oil condition assessment.

Table 7-1
Oil Condition Assessment Tests

Test Number	Title
ASTM D913	Standard Practices for Sampling Electrical Insulating Liquids
ASTM D924	Standard Test Method for Dissipation Factor (or Power Factor)
ASTM D923	Standard Practices for Sampling Electrical Insulating Liquids
ASTM D1698	Standard Test Method for Sediments and Soluble Sludge
ASTM D1524	Standard Test Method for Visual Examination of Used Electrical Insulating Oils
ASTM D1298	Standard Test Method for Relative Density (Specific Gravity) Density
ASTM D971	Standard Test Method for Interfacial Tension of Oil Against Water
ASTM D1500	Standard Test Method for ASTM Color of Petroleum Products
ASTM D3613	Standard Test Method for Sampling Insulating Liquids for Gas Analysis and Determination of Water Content
ASTM D5837	Standard Test Method for Furanic Compounds in Electrical Insulating Liquids by High-Performance Liquid Chromatography (HPLC)
ASTM D974	Standard Test Method for Acid and Base Number by Color-Indicator

Highly refined mineral oil is the most common insulating liquid used in power transformers. It provides dielectric strength to the transformer insulation system and efficient cooling and heat transfer. Transformer mineral oil and insulating material can undergo chemical changes during the transformer’s operation after long periods of time due to moisture, oxygen, and heat.

Procedures for oil sampling should be written according to ASTM standards and in particular ASTM D923 and D3613 to include sampling apparatus, containers, and proper handling.

Sufficient quantity of oil sample must be taken to cover the test requirements. When samples are taken, the temperature of the oil should be equal or greater than the temperature of the ambient air to minimize moisture intrusion into the sample. Also, the oil and ambient air temperature as well as the relative humidity should be recorded. If relative humidity exceeds 50% under conditions of rain or snow, the tests should be rescheduled.

7.2.1.1 Types of Oil Tests

Various tests are commonly performed on insulating oil that can help detect problems before they become serious:

- **Dielectric Strength.** The dielectric strength of the fluid is a good overall measure of its insulation property. Low values are usually the result of moisture and/or particulates. Values in the 30 kV–40 kV range are typical. Values below 26 kV require immediate attention upon verification of the low value. Refer to Section 6.5.1.2 for additional information about dielectric testing of insulating oil.
- **Moisture.** Direct moisture measurements of the oil are also possible. However, the temperature of the unit at the time of sampling is important in the evaluation of the results since equilibrium moisture levels are dependent on the unit's temperature. Typically, values for moisture run between 10 ppm–20 ppm. Values in excess of 20 ppm for 345 kV transformers should require corrective action upon verification of a high result. Refer to Section 6.5.1.2 for additional information about moisture testing of insulating oil.
- **Interfacial Tension and Acidity.** The interfacial surface tension test measures the surface tension of the oil compared to water. Typically, it will remain in the 30 dyne/cm–40 dyne/cm range unless polar contaminants have been added to the oil. Polar contaminants can contribute to static electrification or can lead to sludge formation as their levels increase. The acidity of the oil is another test to measure the aging of the oil and its tendency to sludge. Both of these tests are not required as frequently as dielectric strength and moisture. (See Section 6.5.1.4 for more details.)
- **Dissolved Gas-in-Oil.** Dissolved gas-in-oil analysis (known as DGA) is an excellent predictive maintenance tool for evaluation of the condition of a transformer. The ideal sample is collected while the unit is operating. Therefore, the technique is non-intrusive in nature. It is very sensitive, detecting gas in the parts per million range in the oil, long before problems become serious. These gases are generated from the affect of various faults occurring in the oil and/or paper insulation. Each type of fault has its own “fingerprint” of gases and gas ratios that help to identify the fault present. (See Section 6.5.1 for more details).

By trending of the various gas results, one not only can identify the type of fault but can also assign a level of seriousness based upon the rate of rise in gas levels. With the use of this data, one can better predict problems and plan outages in advance. Although DGA cannot detect all failures (for example, rapid faults or mechanical problems), many types of internal transformer problems have been detected with this method.

**Key O&M Cost Point**

By trending of the various gas results, one not only can identify the type of fault but can also assign a level of seriousness based upon the rate of rise in gas levels. With the use of this data, one can better predict problems and plan outages in advance.

Various on-line analyzers are now available for monitoring of dissolved gases in the oil. The primary advantage for field monitoring is that continuous data can be obtained. Unlike periodic samples, on-line equipment is more likely to detect rapidly developing faults. Some have attempted to transfer the involved laboratory technique into a field unit. These units tend to be difficult to operate by less experienced personnel. Another unit that has gained a wide acceptance at some utilities monitors only the dissolved hydrogen in the oil. During arcing conditions large quantities of hydrogen are generated along with acetylene. Hence, this detector can rapidly pick up an arcing condition that is likely to fail the unit. Its design is simple and has been in field use since the mid-1980s. An on-line monitor has been developed that can monitor up to eight of the key dissolved gases. This unit is capable of reporting these gas levels every four hours.

7.2.1.2 Transformer Gassing

All transformers generate some gases from the oil and paper at normal temperatures. But occasionally, a gas-generating abnormality occurs within an operating transformer such as local or general overheating or dielectric problem. These abnormalities are called “faults” and are classified as thermal or electrical faults. These faults will cause higher than normal levels of gases to be produced from oil and insulation material. Interpretation of the results of gas-in-oil testing is covered in Section 6.5.1.

7.2.2 Insulation Condition Monitoring

The insulation condition assessment test is an important maintenance test used to verify the state of dryness and to determine the condition of transformer insulation. The test determines the insulation strength of the individual windings to ground and between windings. Trending provides the best interpretation tool for insulation power factor testing. An upward trend indicates that a change has occurred in the transformer insulation system. Section 6.5.5 has more details on this subject.

The current trend is to perform power factor tests when the oil tests and the moisture in insulation calculations indicate possible problems, such as high moisture content or contamination in the insulation. However, power factor tests at intervals of five to seven years are recommended by some utilities, even if the oil tests are normal, to detect incipient problems that might not have been indicated by the oil or other tests.

Power factor tests should be performed more frequently on bushings that have a history of problems in service or that have an upward trend in the power factor.

Off-line power factor tests on bushings might not always detect a defective bushing before it fails because the problem could evolve between measurement periods. On-line power factor monitoring systems are available for continuous monitoring.

7.2.2.1 Insulation Resistance

Insulation resistance (megger) tests are used most often to detect moisture in coil insulation. Since insulation resistance tests apply a dc voltage between the windings and ground, it is most important to properly ground windings except the one being tested. It is also important to ground all terminals for several minutes after each winding is tested in order to remove any stored charge. A typical rule of thumb for acceptable winding resistance is $2 \text{ M}\Omega/1000 \text{ V}$ of rated nameplate voltage.

7.2.2.2 Power Factor

Power factor test of a complete winding may indicate the presence of moisture in solid insulation. Doble testing's version of insulation power factor (also called tip up test) is usually done by applying 10,000 Vac from one winding to another and ground. The value that is often used is 0.5% to 1.0% for good power factor reading. The transformer manufacturer and/or the test equipment vendor may have more specific guidance on test data and conduct of a power factor test.

There are several other tests that provide similar information as the power factor tests and the tests are capacitance and $\tan\delta$ (dissipation factor). All of these tests can be used to reveal some information about the insulation condition of a transformer.

7.2.2.3 Electrical Power Discharge

Partial discharges occur in insulation when there are any voids in the insulation. These voids act as tiny capacitors as the voltage changes in the winding. These tiny capacitors will tend to discharge into the tiny void space and overtime cause the insulation in that area to be degraded and if the partial discharges are high enough, then the whole cycle become self-perpetuating.

This test measures the level of activity of high frequency discharges that occur in an insulation system. The discharges may be internal to the insulation, that is between the conductor and the groundwall insulation or the discharges may occur on the coil surface.

7.2.2.4 Acoustic Partial Discharge

Acoustic detection of partial discharges uses a mechanical device to detect and/or measure the results of electrical discharges. The acoustic monitor will detect partial discharges as they are transmitted through the transformer oil. This method has been widely used in factories under controlled conditions but in the field, it is very difficult to isolate all sources of interference; however, some in the field has used this method.

Maintenance

There are ultrasonic methods that are in use to detect partial discharges, arcing, and other discharge activities in electrical equipment. Several probes are on the market that can be used to detect ultrasonic emissions from equipment.

7.2.3 Infrared Thermography

Other techniques have also been employed to help detect problems before they become serious. Infrared thermography can be used on bushings and other connections. Pumps and load tap changers running hot can also be detected. Thermography is less effective on the overall transformer tank due to the volume of oil and thickness of the steel. However, some hot spots near the tank wall have been detected using this technique.

Thermography can be used on the following components:

- Control cabinet internals and terminal blocks
- Tank
- Bushings and connections
- Surge Arresters
- Load tap changers
- Coolers, pumps, and motors
- Instrument transformers (PT and CT)
- Cooling System (including radiators, motors for pumps and fans)

Section 6.8 provides more detailed information on infrared thermography.

7.3 Routine Maintenance and Inspections

A good transformer maintenance program must have an early warning feature. This program should contain thorough routine inspections and effective preventive maintenance. These inspections are many times in addition to shift activities such as checking temperature and oil levels. Although quite a bit of data can be collected by data acquisition systems, it is still important to have inspections done by knowledgeable plant personnel.

7.3.1 External Inspections

A physical inspection should be performed since it is a good method for revealing potential problems in the early stage. External inspection and evaluation of the equipment will give an indication of the equipment condition and what maintenance may need to be done.

During operator rounds or maintenance surveillance, personnel should be checking for abnormal external conditions such as:

- Tank oil spills
- Any evidence of hot spots/metal discoloration
- Damage to bushing, lightning/surge arresters, cooling equipment
- Verify correct main tank and bushing oil levels
- Desiccant visual condition
- Proper temperature meter indication
- Positive gas pressure if transformer is nitrogen blanketed
- Gas in the gas detector relay, if applicable
- Verify the alarm, control and trip settings
- Verify that the cooling fans and/or pumps operate correctly
- Report any unusual noises

Some inspections might require visual assistance such as field glasses (binoculars) to properly inspect some components.

Corona (air ionization) could be visible at tops of bushings at twilight or night, especially during periods of rain, mist, fog, or high humidity. Corona normally occurs at the top of a bushing; however, as a bushing becomes more and more contaminated, corona will creep lower and lower. If corona seems to be lower than normal on a bushing, inspect and clean the bushing, and then perform a power factor test as soon as possible. A corona scope can be used to view and photograph low levels of corona at twilight or night.



Key Technical Point

As a bushing becomes more and more contaminated, corona will creep lower and lower. If corona seems to be lower than normal on a bushing, inspect and clean the bushing, and then perform a power factor test as soon as possible.

7.3.2 Bushing Maintenance

High voltage bushings must be maintained free of any external contamination and should be examined on a regular basis. The porcelain insulation should be examined for chips, cracks, and oil leakage. The main objective is to prevent flashover that could lead to catastrophic failure.

External contamination builds continuously and might become severe enough to cause electrical breakdown after two to three years on non-coated bushings depending on conditions. It should be noted that bushing faults of various kinds are relatively common failure causes of oil filled transformers. This inspection will be required more often in atmospheres where salts and dust deposits collect on bushings.

Maintenance

Because the severity of contamination depends strongly on local conditions, it is not possible to state a generic interval for this task (for example, the interval could be anywhere in the range from 2 to 10 years) but this decision should be based on visual inspections and local environmental conditions.

Bushing cleaning is usually done with hot wash methods to remove contamination build up on a bushing. Powder blasting with dry air will safely remove metallic oxides, chemicals, salt deposits, and almost any hard contaminate. Other materials, such as potters clay, walnut or pecan shells, ground up corn cobs, or crushed coconut shells can be used to remove contaminates. Carbon dioxide (CO₂) pellet blasting is more expensive but virtually eliminates cleanup because it evaporates. Whatever cleaning method is used, the cleaner should avoid removing the original glazing placed on the porcelain at manufacture. There are companies that specialize in cleaning bushings on line. Cleaning can be done on or off line depending on plant needs. Bushings should be cleaned before power factor tested in order to provide trendable data from test to test.



Key Technical Point

Bushings should be cleaned before power factor testing in order to provide trendable data from test to test.

There are various coatings that can be used to limit the collection of contaminants on bushings and other porcelain-type insulators. A light application of silicone-type grease will help reduce risk of external flashover. The downside of this treatment is that a grease buildup may occur. In high humidity and wet areas, a better choice may be a high quality silicone wax applied to the porcelain, which will reduce the risk of flashover. Wax will cause water to form beads rather than a continuous sheet, which reduces flashover risk. There are companies that will retreat porcelain insulators with an elastomeric coating that will cause water to roll off and make cleaning easier.

7.3.3 Heat Exchanger Maintenance

Oil temperature rise is associated with the heat exchanger operation. The core and coils in the transformer dissipate heat energy into the oil, which raises the oil temperature. Thus, the temperature differential between the oil and the external air depends on the efficiency of the heat exchangers. Decreases in the thermal performance of heat exchangers are caused by contamination on the cooling surfaces, such as oil combined with dust or dirt. It is recommended that heat exchangers be inspected, especially if there is a thermal problem. Thermography can locate a radiator that is at a higher temperature than others on a transformer. Heat exchangers/radiators should be cleaned on a routine basis. Radiators may need to be cleaned in areas where deposits appear on pipes and headers. Dirt and deposits hamper heat transfer. Finned radiators are typically cleaned with compressed air when they become dirty. Some companies use water, water and solvent, high pressure water, or low pressure steam to clean radiators. Before using any cleaning method, be sure to review vendor recommendations to ensure that cleaning methods do not damage and/or promote radiator corrosion.

**Key Technical Point**

Before using any cleaning method, be sure to review vendor recommendations to ensure that cleaning methods do not damage and/or promote radiator corrosion.

A common cause for motor thermal tripping or even burnout on forced oil-to-air coolers is clogged fins, particularly on the horizontal plate fin tube bundles. This clogging increases the load on the motor. Cleaning of the tube bundles will normally solve the problem.

Recirculation of the hot air from the coolers caused by obstructions, and so on, results in high ambient temperature, which could cause motor trips, and, in extreme cases, motor failures. One solution is to add deflectors that direct the hot air upward so that it does not recirculate the air around the coolers.

Repair of heat exchanger leaks is difficult to accomplish. Temporary repairs of small leaks in steel fabricated fin radiators can sometimes be made by cleaning the area with a solvent and applying a quick-setting epoxy resin. This repair should only be done by qualified personnel and as a temporary repair. For more extreme leaks, a transformer may have to be taken out of service and the radiator removed for more thorough repair. Some repair services will weld radiators while in place and full of oil; however, this is a very risky undertaking.

**Key O&M Cost Point**

For more extreme leaks, a transformer may have to be taken out of service and the radiator removed for more thorough repair. Some repair services will weld radiators while in place and full of oil; however, this is a very risky undertaking.

7.3.4 Tank and Oil Preservation System Maintenance

Tank integrity is of the utmost importance to the proper operation and life of a transformer. The tank protects the windings, contains the oil, and provides a path for removing excess heat from a transformer. Checks should be made for excessive corrosion and oil leaks. During inspections, pay special attention to flanges and gaskets (bushings, valves, and radiators) and the lower section of the main tank. Report oil leaks to maintenance, and specific attention should be given to the oil level indicator if leaks are found. Severely corroded spots should be cleaned and painted with a rust inhibitor.

7.3.4.1 Sealed Tank System

At installation, a transformer will be pressurized with dry air or nitrogen. The bleeder valve is designed to hold pressure inside to approximately plus or minus 5 psi (0.34 bar). Air or nitrogen is exhausted to the outside atmosphere when a positive pressure more than 5 psi (0.34 bar) occurs inside the tank. This process does not add moisture and oxygen to the tank. However, when cooling, the oil contracts and if pressure falls 5 psi below the outside atmosphere, the valve allows outside air into the tank, which pulls in moisture and oxygen.

Maintenance

Periodically, check the pressure gage against the weekly data sheets; if the pressure never varies with seasonal temperature changes, the gage is defective. Add nitrogen if the pressure falls below 1 psi (0.069 bar) to keep moisture laden air from being pulled in. Add enough nitrogen to bring the pressure to 2 psi (0.137 bar) or 3 psi (0.207 bar). Sealed tank systems can be backfitted with a desiccant-type dryer on the bleeder valve in order to prevent the introduction of moisture and oxygen into the transformer tank.

**Key Technical Point**

Sealed tank systems can be backfitted with a desiccant-type dryer on the bleeder valve in order to prevent the introduction of moisture and oxygen into the transformer tank.

**Key Technical Point**

Caution: When replacing nitrogen cylinders, do not use a typical nitrogen cylinder from the local welding supplier. Transformers require nitrogen that meets ASTM D1933 Type III, which has a -59°C dew point as specified by paragraph 6.6.6.3 of IEEE C57.12-1993.

7.3.4.2 Inert-Gas Pressure System

This system keeps space above the oil pressurized with a dry inert gas, normally nitrogen. This design prevents air and moisture from coming into contact with insulating oil. Typically, a nitrogen gas bottle is used to maintain pressure between 0.5 psi (0.034 bar) and 5 psi (0.34 bar). Pressure gages are provided in the nitrogen cabinet for both high and low pressures. A pressure/vacuum gage is normally connected to read low gas pressure inside the tank. This gage may be located on the transformer and normally has high and low pressure alarm contacts.

**Key Human Performance Point**

Caution: When replacing nitrogen cylinders, do not use a typical nitrogen cylinder from the local welding supplier. Transformers require nitrogen that meets ASTM D1933 Type III, which has a -59°C dew point as specified by paragraph 6.6.6.3 of IEEE C57.12-1993.

Inert-gas pressure systems are usually equipped with an adjustable, three-element pressure control system, which maintains a pressure range of 0.5 psi (0.034 bar) to 5 psi (0.34 bar) in the transformer tank. There is also a bleeder valve that exhausts gas to atmosphere when pressure exceeds relief pressure of the valve [normally greater than 5 psi (0.34 bar) to 8 psi (0.55 bar)].

7.3.4.3 Conservator Bladder System

The conservator bladder system consists of a bladder within the conservator vessel and an air dryer in the airflow path from the conservator bladder to atmosphere. The inside of the bladder or top of the diaphragm is open to atmospheric pressure—as oil expands and contracts and as atmospheric pressure changes, the bladder or diaphragm “breathes” air in and out. This keeps air

and transformer oil essentially at atmospheric pressure. The bladder is not totally impermeable and air will migrate through the bladder membrane into the transformer oil. In addition if a perforation occurs in the bladder, air will directly migrate into the oil. These conditions produce air and moisture contamination within the transformer oil and require prevention to insure optimal transformer life.

Every three to five years, the conservator inspection flange should be opened, and the internal of the conservator should be inspected. If the bladder has been perforated, oil will be present on the top of the bladder, and it should be replaced. Instructions for the specific transformer should be followed for replacement and commissioning of a new bladder.



Key Technical Point

Every three to five years, the conservator inspection flange should be opened, and the internal of the conservator should be inspected. If the bladder has been perforated, oil will be present on the top of the bladder, and it should be replaced.

Air dryers are used to remove moisture from the air entering the conservator and is usually a desiccant-type dryer. The desiccant should be checked on a routine basis to be sure that it is still in an acceptable condition and providing its intended function. The dryer canister has a view port on the side to inspect the appearance of the desiccant. There are several types of desiccant in use and each starts with a different color indication when new and transitions to a different color when absorbing moisture. The transformer manufacturer should be consulted as to the desiccant used and its transition color when reaching a spent condition. One of the manufacturers is using a desiccant, which is sandstone in color and turns lighter yellow brown when spent. A second manufacturer is using purple or blue desiccant when new that transitions to a faded pink or white when spent. Each provides a different indication and the spent color should be noted for inspection evaluations.

7.3.5 Calibrate Gauges and Relays

Gauges and relays should be calibrated periodically. Some gauges may require replacement if they cannot be calibrated or if they drift greatly between calibrations. This would include the sudden pressure relay, gas volume relays, oil level gauges and alarms, and temperature and pressure gauges. Gaskets should be replaced when the devices are serviced.

Temperature indicators (especially winding temperature indicators) may not be accurate and they are often difficult to calibrate. Caution should be taken when these devices read consistently low. Since these are pressure-filled systems, the indicator will typically read low if it is out of calibration. Field testing has shown some gages will read 15°C to 20°C lower than actual winding temperature. This is hazardous for transformers because it will allow them to continuously run hotter than intended, due to delayed alarms and cooling activation. If thermometers are not tested and error adjustments made, transformer service life may be shortened or premature failure may occur.

7.3.6 Load Tap Changer (LTC)

Load tap changers are susceptible to various thermal and mechanical problems. The oil should be drained and the entire tap changer inspected for signs of overheating and loose, broken or missing components.

Each of the contacts should be checked, and worn contacts or contacts that are pitted or thermally damaged may need to be replaced. Vacuum bottles, if used, should be checked for vacuum integrity. Because the load tap changer is a mechanical device, various components may become loose or become out of adjustment, causing contact misalignment.

Arcing in oil during current interruption will result in carbon deposits on various surfaces of the load tap changer. The deposits should be wiped-down and the oil either filtered or replaced.

Coking deposits on the load tap changer (LTC) reversing switches may occur when the tap changer does not go through neutral for long periods of time and the contacts are not wiped. The contacts then coke, which may permanently damage the contacts and even cause failure of the tap changer. The tap setting should be chosen so that the load tap changer passes through the neutral position on a frequent basis. If this is not the case, the load tap changer should be operated manually through the neutral position several times at least every sixty days. Frequency of load tap changer manual operation is dependent on the size of the unit. Some companies have found that installing on-line filtering of load tap changer oil or replacing the original style reversing switch contacts with improved thermal capability contacts is effective in mitigating potential contact coking problems.

7.3.7 Instrument Transformers

Oil in CT should be tested periodically. Oil power factor tests should be done to determine oil condition. Some company operators monitor CTs continuously and remove them from service before they fail.

PTs are less problematic than CTs but they still require care. Typically, oil tests are advisable at 3-year intervals for PTs.

7.3.8 Lightning/Surge Arrester

Visual inspection is typically done for lightning/surge arresters. The following items should be checked during this inspection:

- Corroded and/or loose grounding wire
- Broken or cracked porcelain insulators
- Actuated pressure relief device
- Overheated seals around the base and/or the top of the arrester
- Signs of flashover

7.3.9 Functional Tests

Proper operation of various auxiliary devices can be confirmed by performing these functional tests:

- Verify that the appropriate groups and/or banks of cooler pumps and fans operate at the appropriate set points.
- Verify that all alarms operate at appropriate set points.
- Verify that remote locations receive alarms, if applicable.
- Cycle the load tap changer both manually and electrically.

Some utilities prefer not to include no-load (de-energized) tap changer in their regular maintenance list because once the tap setting is chosen and set, there is no movement of the tap changer contacts while the transformer remains in operation. The decision not to cycle the tap changer was reinforced in some cases. Where the tap changer was cycled, contacts were not completely made, and the transformer failed when it was energized.

Other utilities prefer to cycle the no-load tap changer to ensure its electrical and mechanical integrity. After cycling the tap changer, a transformer turns ratio test (TTR) is performed to verify the contacts are made up and that there is no open circuit.

7.4 Recommended Maintenance Tests, Routine Maintenance, Inspections, and Frequency for Performing Them

The recommended types of maintenance tests (condition assessment) performed and the frequency for performing them should not be less than the requirements stated in the applicable vendor instruction manual. The recommended frequencies for performing maintenance contained in this report must be used in conjunction with recommendations provided in the applicable vendor instruction manuals. The maintenance frequencies shown in Table 7-2 are recommended minimum intervals and should be optimized based on the results of condition assessment testing and actual experience with specific types of transformers. On-line monitoring can also be effective in reducing the amount of maintenance performed at fixed intervals. In addition, insurance requirements may dictate more frequent oil testing.

Table 7-2
Recommended Maintenance Tests, Routine Maintenance, Inspections, and Frequency for Performing Them

Maintenance Task	Recommended Minimum Maintenance Frequency
Condition Assessment Tests:	
Oil dielectric strength and moisture content	6 months–1 year
Oil interfacial tension and acidity	2 years
Dissolved gasses in oil	6 months–1 year
Winding insulation and bushing power factor	5 to 7 years
Infrared thermography	6 months to 1 year
Routine Maintenance and Inspections:	
Formal external inspection	3 months
Bushing cleaning	2–4 years or as needed. Determined by visual inspection
Heat exchanger maintenance	1 to 2 years or as need
Calibrate gauges and relays	5 years
Functional tests	5 years
Tap changer	2 to 4 years

7.5 Surveillance Program and Predictive Maintenance

Predictive maintenance is a continuous or periodic monitoring and diagnosis of equipment and components, using the tests described in the previous section, to forecast equipment failures. Condition monitoring results are used to monitor and trend equipment performance so that planned maintenance can be performed or the equipment replaced before it fails.



Key O&M Cost Point

Condition monitoring results are used to monitor and trend equipment performance so that planned maintenance can be performed or the equipment replaced before it fails.

The development of a surveillance or routine inspection program is essential to the long-term viability of the equipment. The surveillance program should examine key parameters of the transformer on a frequent basis to identify potential issues before they degrade to a critical condition. The following are elements that should be incorporated into a routine surveillance program.

Transformer (general):

- General appearance of the transformer and its associated systems (preservation, cleaning, and debris)
- Signs of hot spots on the surface of the tank or bus
- Signs of metal cracks or weak metal structures or weld leaks on the main tank or around the reinforcing brackets
- Loose objects in the area which could become transients causing faults/shorts
- Evidence of oil leakage through the CT box and conduits to control cabinet

Transformer Control Cabinet:

- Proper closure and latching of the cabinet door
- Cabinet door gaskets free from cracks, tears, breaks, and so on, and securely fastened
- Cabinet general exterior and interior appearance (preservation, cleanliness)
- Interior lighting operating properly
- Proper sealing of all incoming cables and conduits
- Evidence of water leaks (corrosion, stains, and so on)
- Frayed or missing insulation, loose or disconnected wires
- Evidence of overheating and discoloration at any terminal point
- Proper labeling of cooler breakers, throw-over aux power, and so on

Transformer Cooling System:

- Radiators
 - Thermography to indicate proper cooling
 - Air passage free from dirt and foreign material
 - Proper air flow when fans are in operation
 - Evidence of an oil film on the radiator piping
 - Oil leakage from radiator upper bank-header vent or drain valve
- Cooling Fans
 - Proper connection and sealing of fan cables and conduits
 - Loud or unusual noises from the fan bearings
 - Proper direction of rotation
 - Evidence of fan blade cracking, chipping, looseness or missing bolts

Maintenance

- Oil pumps
 - Signs of oil leakage from pump flanges or pump valve seals
 - Loud or unusual noises from the oil pump bearings
 - Proper connection and sealing of oil pump cables and conduits
 - Evidence of pump/fan cord and plug seal deterioration
- Oil System
 - Oil condition
 - Conservator level

Bushings, Insulators, and Lightning/Surge Arresters:

- Evidence of porcelain chipping, cracking, arcing, uncleanliness, or other physical damage
- Evidence of oil leakage
- Proper oil level
- Evidence of corrosion or discoloration due to heating
- Blown pressure relief device on surge arrester
- Amount of leakage current
- Surge arrester cycle counter
- Sparkover gap test (SF6)
- Evidence of sooted seals around surge arrester base or top

Neutral Resistor:

- Proper closure and bolting of the enclosure cover
- Cover general exterior and interior appearance
- Evidence of resistor cracking, arcing, flaking, or other physical damage
- Evidence of water leaks (corrosion, stains, flaking, or other physical damage)

Gas Blanketing System:

- Enclosure general exterior and interior appearance (preservation, cleanliness)
- Proper closure and latching of the cabinet door
- Proper sealing of all valves, regulators and tubing
- Evidence of nitrogen leaks (gage pressure)
- Review log sheet or tracking sheet for periodicity of cylinder change and nitrogen consumption

Fire Protection System:

- Evidence of corrosion or mechanical damage to the fire protection pipe line supports
- Evidence of corrosion, water leakage or mechanical damage to the spray nozzles
- Evidence of deluge spray nozzle blockage
- Proper mounting of the transformer heat sensors

Field tests of the transformer are discussed in Section 6.5 and should be performed to identify the source of any abnormal tests and determine if further maintenance is required.

Tests performed under energized condition include:

- Gas-in-oil (see Section 6.5.1)

Tests under de-energized condition include:

- Winding resistance (see Section 6.5.2)
- Turns ratio (see Section 6.5.3)
- Low voltage exciting current (see Section 6.5.4)
- Insulation power factor and resistance (see Section 6.5.5)

Within the routine surveillance program, operating parameters should be recorded, reviewed, and examined for trends or abnormal operating conditions. The following are typical operating parameters that should be evaluated and results trended (see Tables 7-3 and 7-4):

- Oil temperature
- Voltage
- Load (MW, MVARs)
- Oil level
- Combustible gas monitor condition
- Transformer pressure
- Winding temperature

A detailed visual examination of the transformer components should also be conducted during an equipment outage. This would primarily consist of a “close in” inspection of the components that are not accessible when the transformer is energized. This typically includes those items on the routine inspection and the top surfaces of the unit adjacent to normally energized equipment.

Maintenance

An extensive examination of the transformer might be required if the condition assessment testing indicates an abnormal condition. The transformer field tests, oil testing, insulation power factor, or infrared thermography tests may require the transformer be further inspected. The following parameters should be examined as indicated by prior testing:

Transformer Interior

- Indication of corrosion or moisture contamination
- Stress fracture or indication of hot spots on the internal tank supports or structure
- Loose objects in the internals of the transformer
- Indication of leakage

Transformer Controls

- Load or no-load tap changer condition
- Transformer instrument connections (internals)

Radiator

- Sludge buildup in tank or radiator
- Blockages in oil paths

Bushings and Insulators

- Internal Connection parts
- Stressing or cracks of internal components

Conservator System

- Bladder integrity
- Contamination in conservator
- Internal indication for level or pressure

Core

- Indication of overheating or structural damage
- Supports damage
- Loose bands

Windings

- Instrumentation visual integrity
- Support integrity
- Indication of overheating or damage

Table 7-3
Routine Inspection

Item #	Equipment/Component	Notes
1	Transformer temperature and load	Record oil temperature, voltage, load (MW, Mvars)
2	Oil level	Record oil level gauges (main tank, conservator)
3	Bushing	Check oil level, oil leaks, corona location
4	Cooling equipment	Check for oil leaks, abnormal sound or vibration (fans, pumps, etc.)
5	Main tank and protective components	Check for oil leakage (main tank, valves, pressure relief device, sudden pressure relay, and so on)
6	Dehydrating breather	Check discoloration of the absorbent (follow vendors instructions)
7	Control cabinet	Check for proper door latching, rust, abnormal condition

Table 7-4
Periodic Inspection and Maintenance

Item #	Equipment/Component	Inspection	Comments
1	Main tank	• Check for oil leaks • Check for hot spots, paint discoloration	The source of oil leaks can be traced to gasket joints, cemented parts, welded parts and other sources
2	Insulating oil	• Gas analysis • Oil dielectric strength • Water content	Comparison must be made with values obtained by periodical samples and tests
3	Oil preservation	• Oil level. Compare with oil temperature • Oil leaks • Check valve to main tank open	Refer to Vendor manual for specific instructions

Maintenance

Table 7-4 (cont.)
Periodic Inspection and Maintenance

Item #	Equipment/ Component	Inspection	Comments
4	Bushings/ surge arresters/ other insulators	• Check for oil level • Check bushing connection terminal (loose connection or change in color) • Check for porcelain contamination, damage, and oil leaks. Clean porcelain. • Measure insulation resistance	Insulation resistance values to be compared with previous test results Visual check for corona level on insulators
5	Cooling equipment	• Clean heat exchangers • Check for oil leaks • Check oil pumps and fan motors for vibration and unusual noise • Check for bearing wear.	Refer to vendor manual for additional maintenance information Depending on the transformer location periodic inspection and cleaning may be required to prevent corroding or rusting of metal parts and to ensure proper air flow
6	Auxiliary control cabinet	• Check for proper closure, seal, gaskets, moisture intrusion • Check lighting, heaters • Check molded case circuit breakers, contactors for loose connection or discoloration.	
7	Sudden pressure relay, pressure relief device, Buchholz relay, gas detector relay	• Check for oil leaks and gasket condition • Check control circuit • Operational tests or check Vendor manual for specific instructions and periodicity	Gas accumulation is a sign of internal defect

7.6 Manufacturer's Maintenance Recommendations

Implementation of manufacturer's recommendations into the maintenance program is the first step for equipment warranty and equipment life preservation. Manufacturer's instructions contain material for receiving, storage, installation, operation and maintenance of each shipped transformer, major components and accessories. When the transformer manufacturers issue

updates to manuals, the changes should be evaluated in accordance with the station vendor manual control program and the manual should be updated.

Manufacturer's instruction books typically cover, in addition to the transformer itself, installation and maintenance instructions for the following:

- Insulating oil
- Radiators and pump valves
- Cooling controls for FOA/FOA transformers
- Oil flow, level, and temperature indicators
- Bushings
- Rapid pressure rise relay
- Pressure relief device
- Desiccant air dryer
- Instrument transformers

While a transformer is under warranty, it is essential that, at a minimum, the user should adhere to the manufacturer's instructions.



Key O&M Cost Point

While a transformer is under warranty, it is essential that, at a minimum, the user should adhere to the manufacturer's instructions.

7.7 Storage of Spare Transformers

A spare transformer should be set up in a permanent location on a concrete pad. Such large power transformers should never be stored on rollers, blocks, or jacks. It should be assembled, fitted with all accessories including primary and secondary bushings. The transformer should be filled with oil. If it is a nitrogen-blanketed type, a complete nitrogen tank system should be provided to maintain a positive pressure.



Key Technical Point

A spare transformer should be set up in a permanent location on a concrete pad. Such large power transformers should never be stored on rollers, blocks, or jacks.

The spare transformer should be grounded as though the installation is permanent. Bushings should be shorted with wire and grounded to prevent any charge buildup in the windings. Auxiliary power should be connected to the control cabinet and to the heaters to prevent condensation. In many cases, when heaters were not energized or were not available, components in the control cabinets became rusted and damaged.

Maintenance

Inspection of a spare transformer should be performed as though the transformer is in service. Oil samples for dielectric strength and moisture content should be taken once a year and analyses should be performed. Fans and pumps should be energized at frequent intervals to circulate the oil and to ensure equipment is in good working condition.

The manufacturer's instructions should always be used for additional information regarding the storage of spare transformers.

7.8 Supplemental Maintenance Information

The Sandia report SAND93-7068-UC-523, "Aging Management Guidelines," provides important information on maintenance and surveillance of power transformers [13]. For an effective maintenance program utility procedures have been evaluated and as a result a list of common activities was performed during operation and surveillance of power transformers. The common activities provide additional detail and supplement the information provided in Section 6.3.

The Sandia report is an excellent tool that provides the necessary information to investigate each transformer component. It provides signs to look for during inspection and analysis/interpretation of monitoring results. Visual inspection can be performed during routine walkdowns or during scheduled maintenance.

Table 7-5, reproduced from the Sandia report, SAND93-7068-UC-523, provides information on aging mechanisms and maintenance/surveillance techniques that are related to each major transformer component.

Table 7-5
Common Maintenance Issues and Surveillance Techniques

Component	Aging Mechanisms	Maintenance and Surveillance Techniques
Metal Enclosure (Tank) and Cover(s)	Material degradation from corrosion.	Visual inspection of enclosure components and hardware; cleaning of exterior and interior enclosure surfaces (where accessible); painting of rusted or corroded portions of structure.
	Deterioration of seals and gaskets	Visual inspection for embrittlement, cracking, or signs of fluid leakage; replacement as necessary.
	Loss of fastening components	Visual inspection for missing screws, nuts, washers, and other fastening components; replacement as necessary.
Primary and Secondary Windings	Degradation of organic supports and spacers	Visual inspection of spacers, supports, and other insulating materials; insulation resistance testing; power factor testing; gas and oil evaluation.

Table 7-5 (cont.)
Common Maintenance Issues and Surveillance Techniques

Component	Aging Mechanisms	Maintenance and Surveillance Techniques
	Formation of localized high temperature areas (hot spots)	Monitoring of hot spot, top oil, and other temperature indications; sampling and analysis of transformer insulating fluid for indication of decomposition byproducts and gases.
	Loosening of winding mounting systems	Visual inspection of winding mounting system for loose or damaged components; measurement of critical winding tolerances.
Magnetic Core	Winding (conductor) failure	Visual inspection for overheating or breaks in insulation/conductor; resistance and continuity testing.
	Loosening of core mounting system	Visual inspection of core mounting; core-to-ground test; measurement of critical core/winding tolerances.
Insulation System	Dielectric breakdown of insulating fluid	Sampling and analysis for dielectric strength, power factor, water/impurity content, and combustible/non-combustible gases, as well as other analyses as applicable.
	Particulate and/or moisture contamination	Visual inspection of insulating fluid for signs of impurities or water; dielectric strength and power factor testing; laboratory analysis for water content.
	High acidity	Sampling and laboratory analysis (neutralization number)
	Oxidation and sludge formation	Visual inspection of insulating fluid; laboratory analysis for sludge and inhibitor content; maintenance of seals and airtight integrity of tank and oil preservation system components.
Bushings	Degradation of organic materials	Power factor and capacitance testing.
	Contamination or deterioration of porcelain exterior surfaces	Visual inspection for dust, salt, contamination, cracking, streaking, discoloration, or chipping of porcelain insulator; cleaning, coating, or replacement as necessary.
	Deterioration and leakage of oil/inert gas	Visual inspection for indications of leakage; verification of bushing oil level; replacement of gaskets/seals as required.
	Electrical connection damage or loosening	Verification of connection tightness and check for excessive strain.
Cooling System	Wear/fatigue of the pump and fan motor bearings, shaft, and impeller	Visual inspection of fan motor, housing, and rotating assembly for loose/missing parts or other damage; inspection of pump impeller for cracking, pitting or erosion; verification of normal fan or pump operation (no vibration, abnormal noise, overheating, etc.); periodic lubrication; bearing or component replacement as required.

Table 7-5 (cont.)
Common Maintenance Issues and Surveillance Techniques

Component	Aging Mechanisms	Maintenance and Surveillance Techniques
	Degradation of motor winding and lead insulation	Winding insulation resistance testing; replacement of motor and/or leads as required.
	Electrical auxiliary component degradation	Visual inspection and cleaning of contactor mechanisms, contact surfaces, wiring and terminations, and other minor electrical components; functionality testing; replacement as necessary.
Fluid Preservation and Sampling System	Fouling of heat transfer surfaces	Visual inspection and cleaning of radiator fins, tubes, and other heat transfer surfaces; verification of adequate air or cooling water flow.
	Deterioration of organic and inorganic materials	Visual inspection of piping, valves, coolers, and welded seams for cracking, rust, corrosion, or other deterioration; cleaning and painting; functionality testing; replacement as required.
	Wear of mechanical components	Inspection for component looseness or loss of adjustment; measurement and adjustment of component tolerances; lubrication; replacement as required.
	Loss of component adjustment	Verification of proper pressure regulating valve setpoints and operation; cleaning and adjustment as required.
	Deterioration of desiccant	Visual inspection and replacement of desiccant within the air dryer.
Tap Changers (Load Tap Changer: liquid only)	Wear of mechanical components	Verification of component tolerances and adjustment.
	Deterioration or failure of electrical components	Visual inspection and cleaning of tap changer electrical components and contact surfaces; electrical and functionality testing; replacement as necessary.
	Degradation of organic insulating materials	Visual inspection of components for cracking or other loss of mechanical properties; insulation resistance testing.
	Loss of adjustment of braking systems	Visual inspection of brake linings for wear; verification of proper braking system adjustment and torque; replacement of brake linings when required.
	Wear of main contact surfaces	Visual inspection of moving and stationary contact surfaces for wear or contamination; cleaning, reconditioning, or replacement as necessary.
	Tap changer compartment leakage	Visual inspection for leakage or deteriorated gaskets; verification of proper oil level.

Table 7-5 (cont.)
Common Maintenance Issues and Surveillance Techniques

Component	Aging Mechanisms	Maintenance and Surveillance Techniques
Fault Pressure Relay (liquid only)	Degradation of organic seals and gaskets	Visual inspection for signs of leakage, cracking, or other gasket/seal degradation; functional testing.
Bushing Current Transformers	Degradation of organic insulating materials	Insulation inspection; insulation resistance testing.
Pressure Relief Devices	Degradation of seals	Periodic testing for functionality; visual inspection for seal degradation.
Temperature Indicators	Failure of hot spot heating oil element	Periodic verification of temperature sensor functionality and accuracy.

7.9 Observations

The GSUs and auxiliary transformers are key equipment in a power plant. Reliability and continuous operation of these transformers is of paramount importance. To assure continuous service, a program of periodic inspection and maintenance should be in place. Periodic maintenance and inspection of the transformer and its accessories contribute to a trouble-free operation. The frequency of inspection and maintenance may vary somewhat from one plant to another, but procedures should be in place to cover daily, weekly, and quarterly rounds. In addition, scheduled outage-related maintenance work and procedures should cover larger ticket items.

Equipment monitoring and predictive maintenance provide the diagnostic information of the equipment to be automatically collected and forewarn the transformer personnel of any pending problems. More advanced diagnostic systems are continually being developed by the industry. Technological advancement provides the opportunity to reduce extended outages due to equipment failures and in many cases to prevent catastrophic failures.

The overall transformer, along with its major components such as windings, tank, insulation and bushings, should be inspected on regular time intervals and maintained according to manufacturer's recommendations and industry standards.

The life expectancy of a transformer depends mainly on the condition of the insulation system. Moisture- and oxygen-free insulation and efficient cooling are the keys to maintaining a healthy transformer.



Key O&M Cost Point

The life expectancy of a transformer depends mainly on the condition of its insulation system. Moisture- and oxygen-free insulation along with efficient cooling are the keys to maintaining a healthy transformer.

Maintenance

The maintenance program objective is:

- To achieve the maximum equipment operating efficiency
- To obtain optimum life
- To minimize unexpected failures and outages

8

VACUUM AND OIL FILLING PROCESS

8.1 Introduction

The purpose of this section is to provide generic information regarding vacuum processing and oil filling. Manufacturer's instructions should be followed in all cases. Specific guidelines, equipment, and parameters may be required during the process of vacuuming and oil filling. All gasses must be removed from the internal space of a transformer by a vacuum process before it is oil filled.

Atmospheric pressure—14.7 psia (lbs/sq. inch absolute) or 29.9" Hg Abs (inches mercury absolute) or 1 bar

Torr—1 mm Hg Abs or 1000 microns Hg Abs

The vacuuming process is the method used to remove moisture and/or any trapped gas pockets from the core and insulation, as well as the moisture and gas from the insulating oil. Generally, the vacuuming process is required even if the core was only partially exposed to atmosphere. However, because vacuum filling requirements by different manufacturers may vary, the manufacturer's instruction book should be followed in all cases. The insulation system of power transformers is extremely sensitive to moisture contamination. The oil used to fill power transformers is highly refined mineral oil; however, during the operation of the transformer, the oil becomes contaminated with decay by-products from thermal degradation of the paper (cellulose) insulation. The vacuum oil filling process is performed on transformers that have been shipped by the manufacturer with dry air or nitrogen, or on transformers in which the windings or leads have been partially or completely exposed to the atmosphere.

Preparations to vacuum and oil fill a transformer require certain steps and precautions, such as knowing the expected weather conditions, and the time coordinating activities to keep transformer open time to a minimum. Precautions should be taken not to enter the transformer until the gas in the tank is replaced by dry air and the oxygen content is at least 19.5%. For new transformers, follow the vendor's instructions on how to oil fill the transformer on site to comply with warranty requirements. To ensure that proper vacuuming procedures are followed, review the manufacturer's instructions and atmospheric conditions before starting the process.



Key Technical Point

Precautions should be taken not to enter the transformer until the gas in the tank is replaced by dry air and the oxygen content is at least 19.5%.

Vacuum and Oil Filling Process

Vacuum should never be pulled on any transformer with any amount of oil in the tank because gas bubbles could be created which may become trapped in the insulation. The transformer should be dressed, that is, all accessories, bushings, radiators, pumps should be installed. The process for vacuum oil filling is described below.

8.1.1 Safety Precautions**Key Human Performance Point**

Transformers, transformer terminals, vacuum equipment, oil tankers, and so on must be grounded.

**Key Human Performance Point**

Bushings must be shorted to prevent static discharges that would injure personnel and/or damage the transformer.

**Key Human Performance Point**

Check internal pressure prior to removal of any covers, and bleed off any positive pressure.

**Key Human Performance Point**

Check internal atmosphere for oxygen content prior to entering the tank. Be aware of the danger of nitrogen gas pockets inside the tank. Breathable air should be available while personnel are inside the transformer tank.

**Key Human Performance Point**

Never walk or climb on top of the tank under vacuum.

8.1.2 Preparing the Transformer

In addition to safety precautions and grounding, review manufacturer's procedures for additional information and requirements. Normally such information is available with the vendor manual.

If the transformer has a conservator or expansion tank, the pipe to the main tank must be removed and the valve plugged if the tank is not designed to withstand full vacuum.



Key Human Performance Point

If the transformer has a conservator or expansion tank, the pipe to the main tank must be removed and the valve plugged if the tank is not designed to withstand full vacuum.

8.2 Evacuating the Transformer

Once it has been confirmed that all the oil has been drained, several steps are taken before a vacuum is drawn and a vacuum pump reading is taken. Vacuum is pumped until a reading of 2 mm or less is obtained.

8.3 Performing a Leak Test

After 2 mm of vacuum is reached, a leak test is conducted. Wait for approximately 5 minutes and start monitoring the pressure. If the pressure rise is more than the typical values shown in Table 8-1, leaks are probably present and should be repaired. Generally, the sources of leaks are:

- Gaskets
- Valves
- Connections to the hoses and vacuum pump

Table 8-1
Leak Rates

Main Tank Oil Volume (Gallons)	(Liters)	Allowable Leak Rate (mm Rise in 10 Minutes)
Less than 5,000	Less than 18,925	0.80
5,001–7,500	18,926–28,390	0.53
7,501–10,000	28,391–37,850	0.40
10,501–12,500	37,851–47,315	0.32
12,501–15,000	47,316–56,775	0.27
15,001–17,500	56,776–66,240	0.23
17,501–20,000	66,241–75,700	0.20
20,001–22,500	75,701–85,165	0.17

It should be noted that surface water on the insulation could cause the vacuum to increase. If there are no leaks, the pressure increase is probably due to the vaporization of surface water on the insulation. In such cases, continue the vacuum to flash-off this moisture. Table 8-2 can be used as a guide for removing surface moisture.

Table 8-2
Guide for Removal of Surface Moisture

Vacuum (mm)	Temperature (°C)	Time (Hours)
2	50	24
1	40	24
0.5	20	24
0.5	15	24

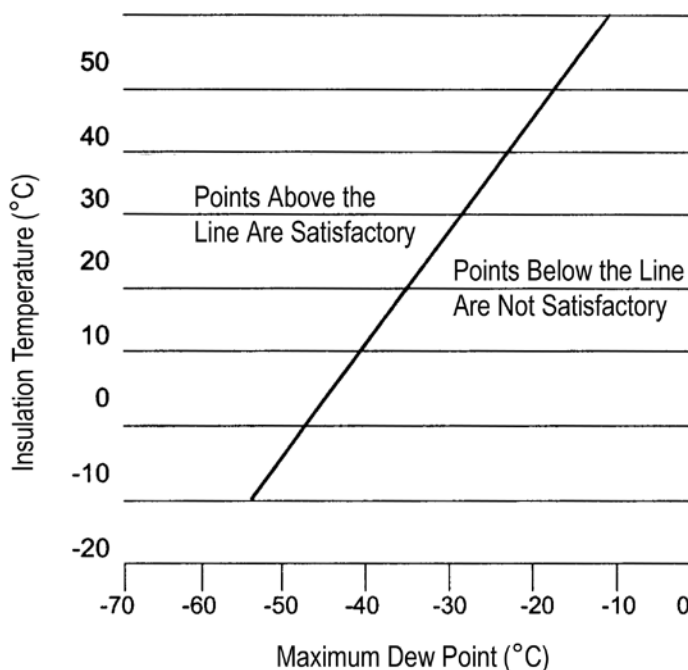
If the leak test is successful, vacuum is pumped and held for four to six hours.

8.4 Taking a Dew Point Measurement of the Main Tank

After the leak test is complete and at the end of vacuum hold time of four to six hours, the next steps should be followed:

- Break the vacuum with dry air or nitrogen and apply a positive pressure of two to three pounds. The dry air or nitrogen should have a dew point of -50°C (-70°F) or lower.
- Allow the transformer to sit idle for 24 hours in order to allow the gas and the surface moisture of the insulation to approach equilibrium.
- Measure the dew point after a 24-hour hold time. Determine if the dew point measurement is acceptable. The graph in Figure 8-1 may be used as a guide.

In order to use the graph that follows, the insulation temperature must be estimated. The best estimate would be to use the temperature of the oil from the oil temperature gauge. The reading should be made when the oil temperature is steady and should be taken early in the day before the sun has had an effect on the oil and tank temperatures.



- Enter Chart at Insulation Temperature
- Read Over to Dew Point Value
- Acceptance Values Are Above the Dew Point Line
- Chart Applies to Pressures in the Range of 1-3 psi (7-21 kPa)

Figure 8-1
Dew Point Readings

If the dew point is found acceptable, the transformer can be vacuum oil filled. If the dew point reading is found unacceptable, a dry-out procedure must be followed before proceeding with oil filling.

8.5 Vacuum Oil Filling

After an acceptable leak test and dew point reading, the transformer is ready for vacuum oil filling (that is, filling the transformer with oil under vacuum). The transformer should not be left under vacuum except during the filling process with the vacuum pump operating. If there are any leaks in the transformer or the connecting external pipes from the oil processing equipment, moisture could enter the tank. Figure 8-2 shows the typical equipment and connections for the vacuum oil filling process.



Key Technical Point

The transformer should not be left under vacuum except during the filling process with the vacuum pump operating. If there are any leaks in the transformer or the connecting external pipes from the oil processing equipment, moisture could enter the tank.



Key Human Performance Point

The transformer should not be left under vacuum except during the filling process with the vacuum pump operating. If there are any leaks in the transformer or the connecting external pipes from the oil processing equipment, moisture could enter the tank.

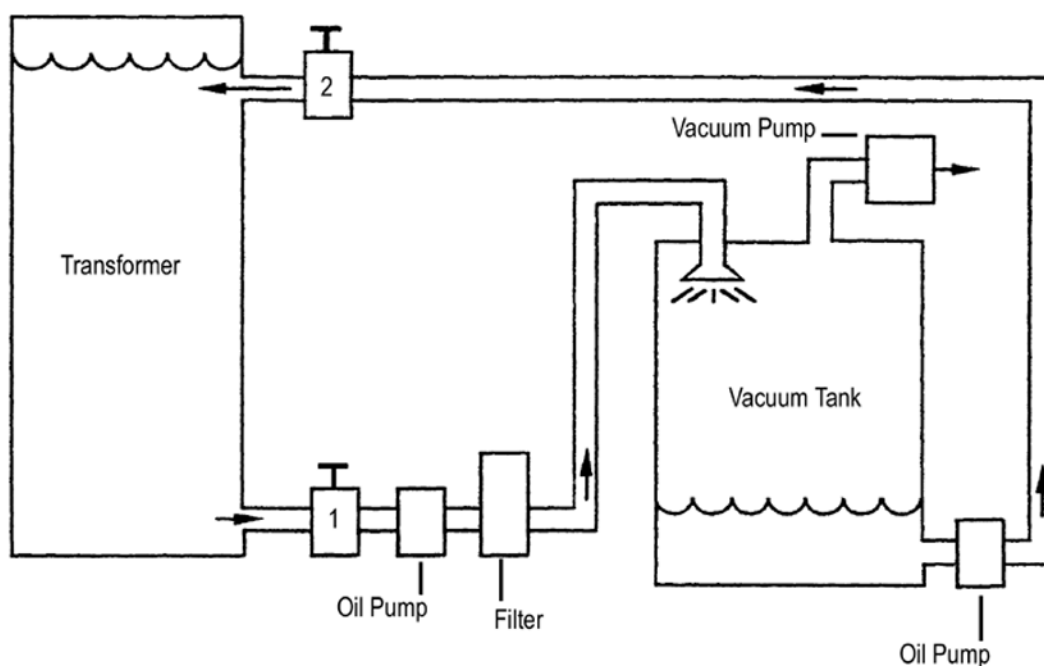


Figure 8-2
Typical Equipment and Connections for Vacuum Oil Filling Process

Prior to and during refilling with oil under vacuum, the following table shows the recommended vacuum levels, times, rate of filling, and oil temperature as well as the set time after filling.

Table 8-3
Vacuum Levels and Times

	230 kV and Below	345 kV	525 kV	800 kV
Vacuum—mm Hg	2	1	1	1
Time—hours	8	8	10	12
Vacuum during filling—mm Hg	3	2	2	1
Rate of filling—gpm (L/m)	40–50 (150–190)	40–50 (150–190)	40–50 (150–190)	40 (150)
Minimum temperature of oil during filling—°C	10	20	20	20
Set time after filling—hours	24	50	100	120

Note: Special procedures are required for filling transformers equipped with expansion tanks and rubber bags. Since different manufacturers require different procedures, they are not outlined in this guideline. Refer to the manufacturer's instructions.

8.6 Eliminating Trapped Air

Various manufacturers specify different procedures after the transformer is filled with oil. Most of them specify that the pumps be run before energizing to remove any air that could have been trapped in the pumps, piping, or heat exchangers. If the transformer has pumps and the manufacturer has not specified a procedure for running them prior to energizing, the following guideline can be used. Use the manufacturer's specification if available. Running of all oil pumps at ambient temperatures is not recommended, since there is a possibility of generating damaging static electrification discharges.

General guideline to eliminating trapped air:

- Run one half of the pumps for 1 hour.
- Run the remaining pumps for 1 hour.
- The transformer should set for a minimum of 4 hours with no pumps in operation prior to energizing.

8.7 Field Dry Out Procedure

On certain occasions, there might be a transformer that cannot be dried by using dry vacuum alone. High moisture levels require that a hot oil dry-out procedure must be followed to drive the moisture from the insulation. The following is a general guideline to adhere to:

Vacuum and Oil Filling Process

- Drain all oil and pull a vacuum of 2 mm or less for 4 hours to flash off some of the surface water.
- Fill the transformer under vacuum with oil from an oil processor at temperatures up to 75°C until the coils and insulation are covered. Use a plastic hose, such as Tygon, connected to the bottom drain valve and to a valve at the top of the transformer to determine the oil level.
- If the operation is performed in cool weather, the tank should be blanketed with insulation blankets or rolls of insulation to conserve the heat.
- Circulate the oil from the bottom of the transformer through the oil processor where it is dehumidified and heated, and back into the top of the transformer. Maintain the temperature of the incoming oil as high as possible but not greater than 90°C. Continue circulating until the oil leaving the transformer is within 10% of the oil temperature entering the transformer.
- Drain the oil down until there is between 24 inches and 36 inches (0.6 meters and 0.9 meters) in the bottom of the tank.
- Spray hot oil in at the cover under vacuum using nozzles that break the stream into small drops, take it out the bottom, circulate it through the oil processor, and back in at the cover. This method keeps the insulation hot during the drying process and makes it more efficient.
- Install the spray nozzles at the start of the process and use them to input oil into the cover. The nozzles should be located near the centerline of the tank. One or more nozzles should be installed so that the entire top end of the transformer is exposed to the oil spray. The nozzles should provide a mist over the top end. The highest practical flow rate through each set of nozzles should be used. Some manufacturers use high flow rates, such as 150 gpm (9.45 L/s) for each phase, but this is difficult to obtain in service.
- Continue to spray oil in at the cover under vacuum. The vacuum should be below 1 mm at the end of the spray part of the cycle. Monitor the amount of water coming out of the insulation with the cold trap. When the amount of water is stable and has reached a level of 1 oz/h (30 mL/h), stop the spraying and drain the remaining oil.
- Perform the final high vacuum operation and oil fill.

8.8 Observations

Power transformers operate at high voltage levels and their internal insulation and the oil is their protection to withstand high voltages. The insulation system is extremely sensitive to moisture contamination. Transformer oil is highly refined mineral oil, but after years of service it becomes contaminated with decay by-products from thermal degradation of the paper insulation. The vacuuming process is used to remove moisture from the insulating oil or from the core and winding insulation.

Transformer oil, core and winding, and all parts in the transformer tank must be vacuumed or purified when the transformer core has been exposed to dry air, nitrogen, or the atmosphere. The vacuum and drying out process is used to remove moisture and trapped gas pockets from a transformer. The process involves expensive equipment and requires careful work and supervision to prevent damage to the equipment and the core and winding insulation.

Before the drying process starts, custom made procedures must be in-place for the specific location and equipment. Also, specific method(s) must be chosen. If transformer instructions do not include the required information, the manufacturer should be consulted to assist in the preparation of procedures and appropriate drying methods.

9

METAL-ENCLOSED BUSES

9.1 Introduction

In power plants, the generator, the generator step-up transformer, and the unit auxiliary transformer are interconnected with an isophase bus duct. The unit auxiliary power transformer is tapped off the isophase bus duct and its secondaries are connected either to a non-segregated or to a segregated phase bus duct. The reserve or system auxiliary power transformer secondaries are also connected to the non-segregated or to segregated bus duct. The auxiliary power transformers provide the power to the station auxiliary systems through the segregated or non-segregated bus ducts.

9.2 Definitions

The following bus duct definitions are taken from ANSI/IEEE C37.23-1987 [32]:

Metal-Enclosed Bus

An assembly of conductors with associated connections, joints, and insulating supports within a grounded metal enclosure. The conductors may be rigid or flexible.

Non-Segregated-Phase

One in which all phase conductors are in a common metal enclosure without barriers between the phases. When associated with metal-clad switchgear, the primary bus and connections are covered with insulating material equivalent to the switchgear insulation system.

Segregated-Phase

One in which all phase conductors are in a common metal enclosure but are segregated by metal barriers between phases.

Isolated-Phase

One in which each phase conductor is enclosed by an individual metal housing separated from adjacent conduct or housing by an air space.

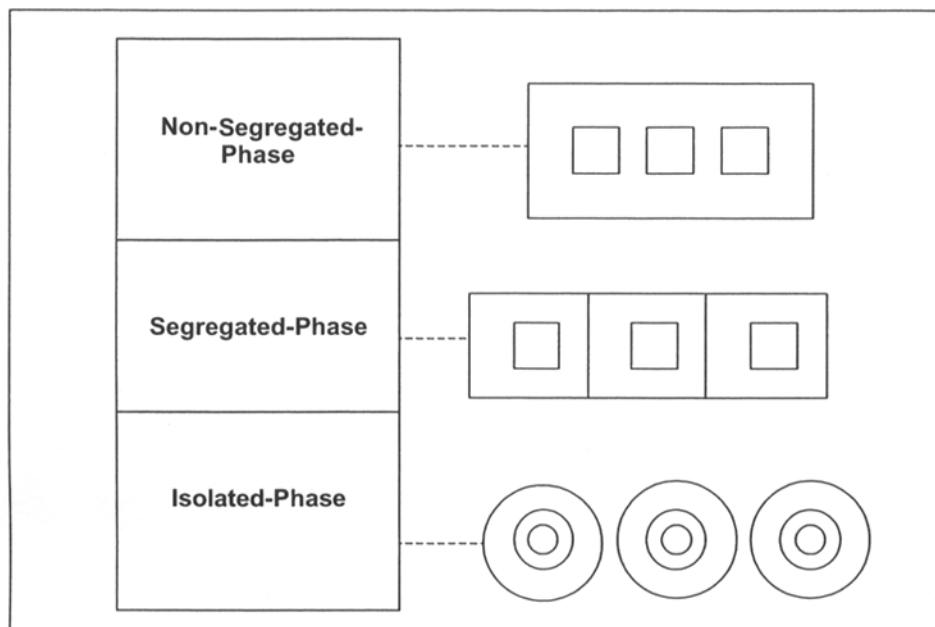


Figure 9-1
Types of Bus Assemblies

9.3 Basic Bus Duct Overview

Bus work or buses are used to carry current from a transformer to its attached loads. Bus work can take on various forms depending on the level of current that is being supplied. The typical bus work used to connect transformers to their associated loads and their typical configurations will be discussed in more detail in this section.

9.3.1 Isophase

In an isophase or isolated phase bus each phase conductor is enclosed by an individual metal housing and is separated from the adjacent conductor housings by an air space. Conventional isophase bus designs use bare conductors supported on porcelain insulators. In smaller power plant units, the use of cables is possible instead of the conventional isophase system with enclosures. The bus duct also connects to surge protection and potential devices.

With the isolated enclosed design, the enclosure is air and moisture tight. The tightness of the enclosure reduces the amount of dust, dirt, and condensation that could accumulate within the enclosure and on the supporting porcelain insulators. The only source of dirt is through the filters from the makeup air on units with air cooling system.

9.3.2 Segregated/Non-Segregated

The non-segregated or segregated bus ducts are indoor and/or, outdoor weather proof with no air ventilation. Conductors are either copper or aluminum according to ASTM Standards B187 and B236 [33 and 34]. Contact surfaces of bolted copper joints are normally electro-silver plated and contact surfaces of aluminum joints are electro-tin plated.

Bus conductors may be bare or insulated. Insulation is usually an epoxy. Conductor supports are molded glass polyester, porcelain or phenolic insulation. Split joints are insulated with removable boots. A continuous ground is provided that has the same short circuit rating as the main conductors.

9.4 Isophase Bus Duct Type of Enclosure

In large power plants, the isophase bus ducts carry heavy alternating currents through their conductors. The flowing current through the conductors produces a strong magnetic flux that induces voltages in the adjacent enclosure tending to cause current flow in the enclosure in a direction opposite to the current in the conductor. The current flow and distribution in the enclosure depends on the manner the enclosures are connected to each other with or without interconnected metal plates. According to ANSI/IEEE Standard C37.23-1987 there are two principal type of enclosures: bonded/continuous (no-flux) and insulated enclosure/non-continuous.

9.4.1 Bonded/Continuous or No-Flux Enclosure

In bonded, continuous or no-flux type the enclosures of the bus are electrically continuous along the entire length between the shorting plates located physically near each termination point (that is, the generator, the generator step-up transformer, and the unit auxiliary power transformer). The enclosures are grounded by direct bolting to structural steel or directly to the system ground (see Figure 9-2). In this design the external electromagnetic field is weak and multiple grounding causes no problem. The circulating currents in the enclosures flow along the enclosure path, through the shorting plates at each end, and then to the ground. Because of the insulation near the transformers and generator, a cable ground should be connected to the system ground.

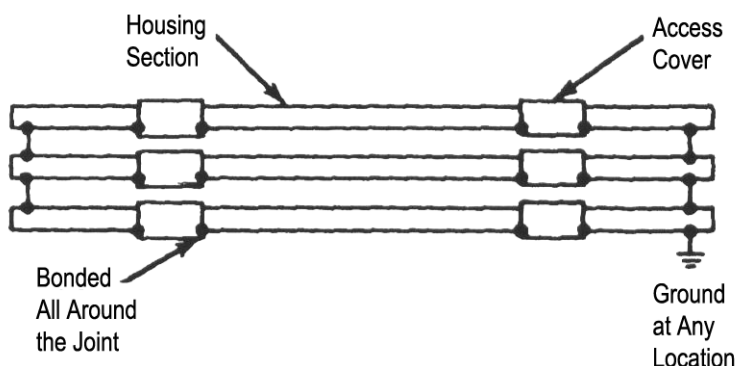


Figure 9-2
Bonded/Continuous or No-Flux Enclosure

9.4.2 Insulated Enclosure/Non-Continuous

A non-continuous isolated phase bus enclosure is one that the consecutive enclosure sections surrounding the same phase conductor are electrically insulated from each other so as to prevent longitudinal current flow across the enclosure joints. Each enclosure section is connected to a ground bus at one point only. If a second ground were placed on a section, it would create a loop that could provide a return path for the induced currents. The circulating currents through the second ground will cause severe heating and burning. Diaphragm expansion joints provide for expansion and contraction of the enclosures due to temperature changes.

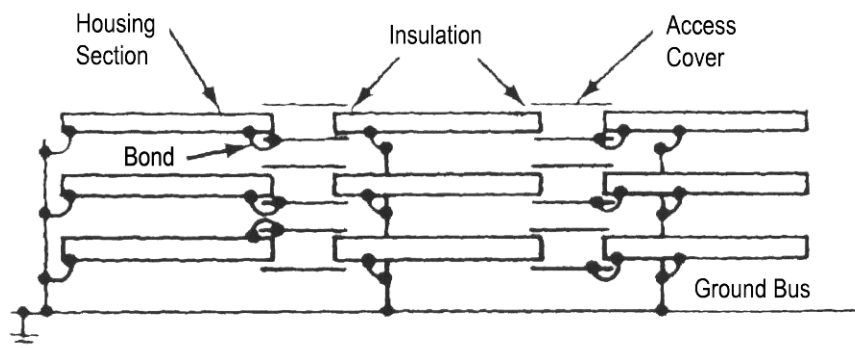


Figure 9-3
Non-Continuous Isolated Phase Bus Enclosure

To prevent circulating currents from entering the generator frame or transformer tank, insulated and gasketed split covers are used to join the bus enclosures at the ends where the generator and transformer are connected. On top of the transformer there is an enclosure for the transformer bushings and bus conductors where connections are made through flex connectors. The flex connectors are used to protect the equipment from vibration, stress from electrical or mechanical fault, and to allow easy isolation of transformer and bus duct when equipment are taken out of service for maintenance and tests.

Most large current buses are designed as continuous enclosure type. Generator termination sections and tap-off sections may use the non-continuous type in this specific area of the bus duct run. The continuous enclosure eliminates the need of gasket and insulation materials that are required for the non-continuous type.

Comparison of the two types of isolated phase bus is shown in Table 9-1, taken from the *Electric Light and Power* magazine dated March 1963 [35].

Table 9-1
Comparison of the Two Types of Isolated Phase Bus

	Open-Circuited Housings	Bonded Housings
Size	Size of conductors and enclosures are the same for either type of construction	
Covers	Gasketed	Field-welded
Expansion Bellows	Not required	Required
Ground Bus	Longitudinal run required, connected to system ground at one point. Ground bus is required for each cover section.	A system ground is required. No insulation or other ground bus is required since all housings are bonded together.
Magnetic Shielding Requirements	Supporting steel and building steel may need protection.	No protection required for supporting or building steel.
Losses	Highest in center phase. Lower in outside phases.	Approximately same in all three phases.
Cover Temperatures	Higher in center phase. Lower in outside phases.	Approximately same in all three phases.
Installation Costs	Lowest	Highest because of field welding.

9.4.3 Construction Details

The isophase bus duct is constructed with emphasis on thermal expansion and contraction effects, continuous and short circuit forces and operation and impulse voltage stresses. Laminated and flexible connectors are used to allow expansion stress on the conductors and enclosures as internal or external joints (see Figure 9-4).

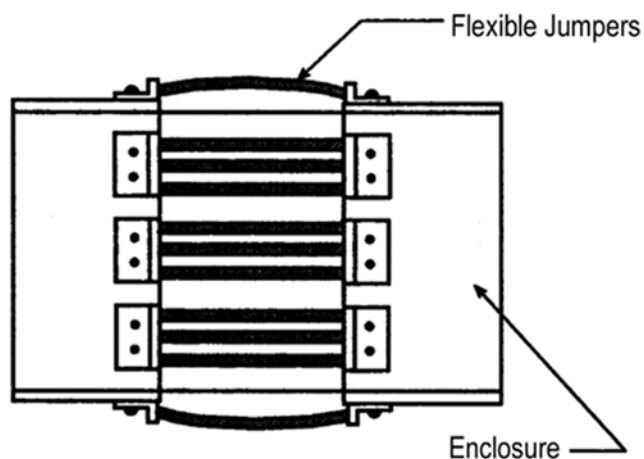


Figure 9-4
External Expansion Joint, Bolted Type

Metal-Enclosed Buses

In most isophase bus ducts, enclosures are fitted with a rubber expansion joint between the end shorting plate and transformer bushing (see Figure 9-5). Expansion joints or bellows are used on the enclosures to absorb vibration effects and to eliminate stray currents in the non-shielded bus.

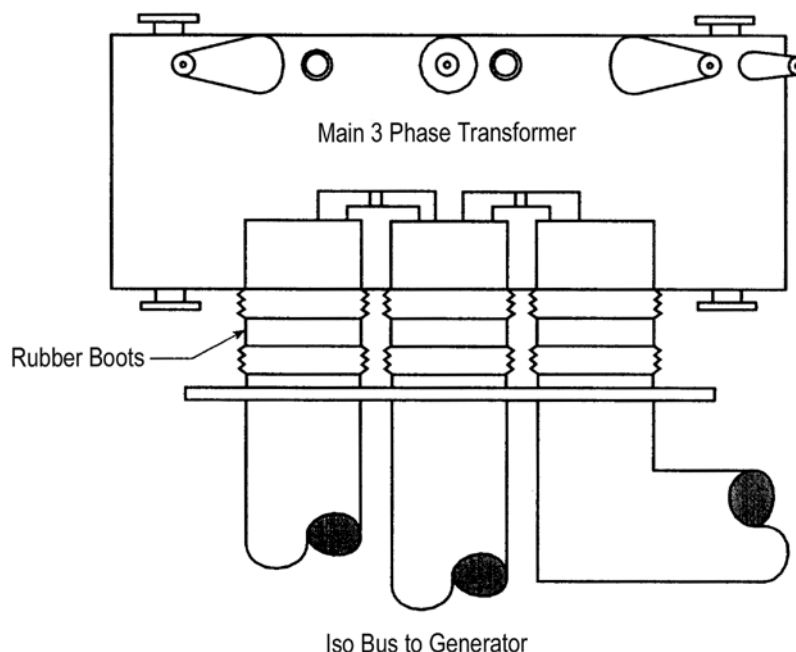


Figure 9-5
Typical Location of Enclosure Boots

The conductors are mounted and bolted on porcelain post type insulators. Mounting on the insulators allows for expansion and contraction of the conductor. The porcelain insulators used to support the conductors have skirts to increase creepage path length from conductor to ground.

Usually, the outside enclosure is painted gray to improve the heat transfer characteristics to outside ambient.

9.4.4 Isophase Bus Duct Cooling Systems

Small size ampere rating bus ducts can be self-cooled, but for large size bus ducts forced air is required. Forced air-cooled cooling units are the re-circulatory and the non-circulatory type.

9.4.4.1 Re-Circulatory Cooling Units

The re-circulatory cooling unit is a forced air-cooling system that consists of a motor-driven fan and a heat exchanger (generally air-to-water). It utilizes the heat exchanger to cool the return air. In some systems, cooled air is introduced into the two outside phases and the return air passes through the center phase to return to the heat exchangers. The motor driven fan is used to re-circulate the cooler air through the bus.

Make-up air is provided through a filter to replenish air lost due to leakage in the system. There are also enclosed bus ducts that utilize gas or liquid. There are others that are self-cooled.

9.4.4.2 Non-Recirculatory Cooling Units

This type of cooling system consists of a motor-driven fan and air filtering system. The filtered air is circulated in the bus duct and exhausted into the atmosphere. Ambient air is drawn through the filter to continue the cooling cycle.

A typical isophase bus duct forced air flow cooling system is shown in Figure 9-6.

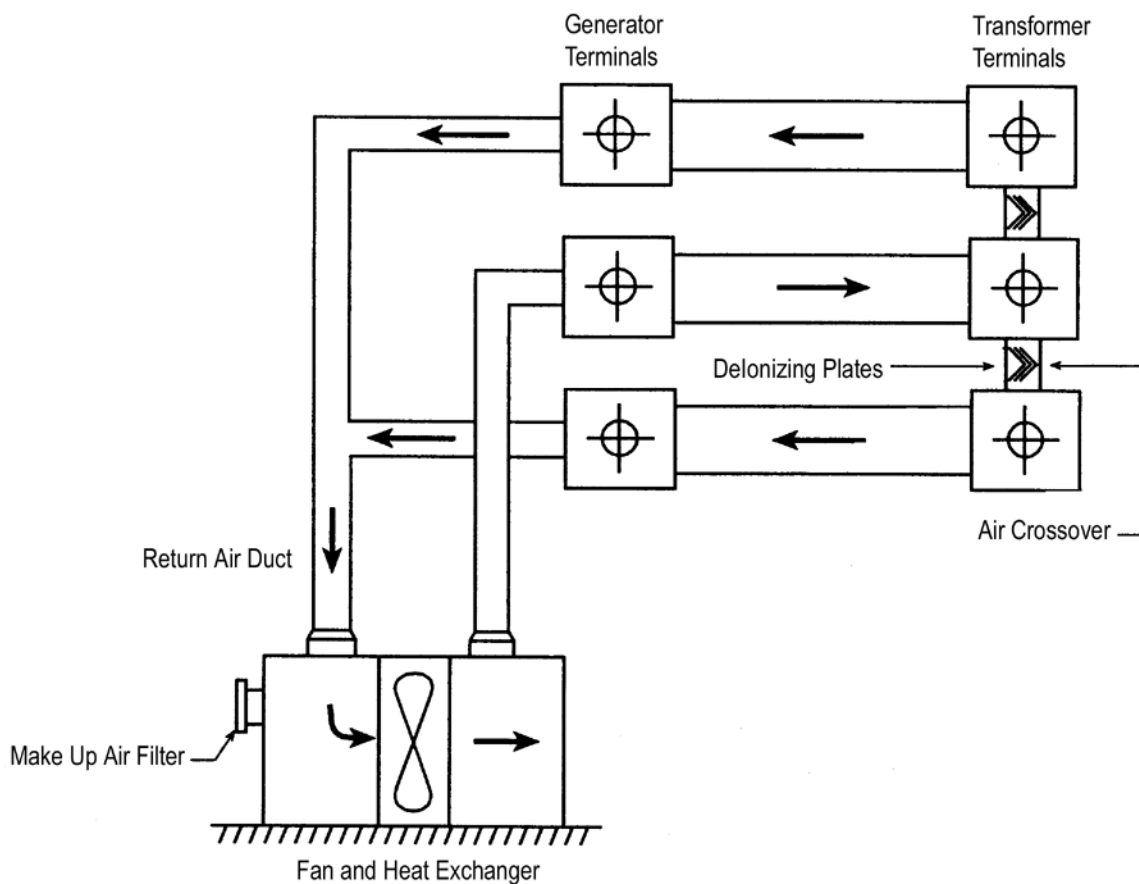


Figure 9-6
Typical Isophase Bus Forced Air Flow Cooling System

9.5 Ratings

The rating of a bus structure includes the following:

- Rated voltage
- Maximum design voltage
- Rated frequency
- Rated continuous current
- Rated momentary current
- Withstand test voltage
- Insulation (BIL) level
- Temperature rise of conductor and enclosure

Bus structures are normally designed for ambient temperature not to exceed 40°C.

According to ANSI guidelines, the temperature rise and maximum limits are as follows:

Table 9-2
Isolated Phase Bus Enclosure Temperature Limits

	Rise	Maximum
Accessible Parts	40°C	80°C
Non-Accessible Parts	70°C	110°C

Accessible parts are the section of the bus enclosure inside the plant and non-accessible parts is the section outside the plant. Outside the plant, direct sunlight can add several degrees to enclosure temperatures.

Table 9-3
Isolated Phase Bus Conductor Temperature Limits

	Rise	Maximum
Aluminum-to-Aluminum Joints, Plain	30°C	70°C
Aluminum-to-Aluminum Joints, Plated	65°C	105°C

9.6 Testing

Tests are usually classified as design, production, and field tests.

9.6.1 Design and Production Testing

The design and production test are defined and performed on the bus ducts in accordance with ANSI/IEEE Standard C37.23-1987 [32] and IEEE Standard C37.20.2-1999 [36], the National Electric Code (NEC), and National Electric Manufacturers Association (NEMA). Some of the tests are:

- Temperature rise
- Insulation withstand
- Impulse
- Momentary short circuit
- Insulation flame
- Wet and dry withstand test
- Weatherproof

9.6.2 Field Tests

Bus duct manufacturers can recommend periodic maintenance tests that are required after the initial installation. In addition, IEEE Std. C37.23-1987, “Guide for Metal-Enclosed Bus and Calculating Losses in Isolated Phase Bus,” contains field tests (see Section 6.5), which can be used on a periodic basis for maintenance of the bus duct and its auxiliary equipment [32].

9.7 Stressors

The bus enclosures are exposed to potential stressors, such as temperature (ambient and internal), solar radiation, and weather.

The isolated-phase bus ducts, the segregated or non-segregated bus ducts have no moving parts and consist of solid conductors, porcelain insulators and housings. However, very large currents due to operating loads go through the enclosed bus duct conductors and produce heat losses (I^2R). Large currents produce high temperatures that lead to temperature stressors. The effect from high temperatures could lead to insulation thermal and age related degradation.

Bus ducts are mostly outdoors and as a result they are subjected to extreme weather conditions, such as extreme high temperature or sub-zero temperatures. These extreme environmental factors can cause gradual deterioration on gaskets, rubber boots and neoprene materials.

The effect of temperature cycling is not a major factor in base load units because the continual energization of the bus duct provides a fairly constant source of heat from the inherent resistive losses of the phase conductors.

Radiation is not a major factor because bus ducts are physically located outside the radiation area; but weather related exposure and ultra-violet rays are significant for the outside portion of the metal enclosure and gasket material.

The isophase bus ducts are designed and built with features to absorb vibration. The segregated and non-segregated bus ducts are normally connected to the transformers with flexible connectors and solidly connected to the switchgear.

Vibration and excessive temperature variations could result in loose bolted connections in the conductors and enclosures. Loose connections lead to overheated bus joints and outside air infiltration through the enclosures. These conditions can result in the presence of condensation and dirt on insulating surfaces, which lead to insulator flashover and corrosion of the enclosure.

9.8 Maintenance

Of the available bus systems, the isolated phase bus duct provides an excellent, reliable system. The main mechanical feature of this system is the enclosure of each conductor in its own grounded metal enclosure. Proper tightness of the enclosure reduces the amount of dust and condensation that could accumulate within the enclosure and on the insulating surfaces and, therefore, reduces the possibility of a component failure.

Bus ducts require less inspection and maintenance. It is important to follow the vendor's recommendations regarding the type of maintenance and periodicity.

Inspection of the isophase, segregated and non-segregated bus ducts includes visual inspection and thermographic inspection. Visual inspection from the ground is somewhat limited but it should be performed during regular rounds to check for the first signs of unusual condition, such as signs of corrosion, deformation, buckling, discoloration or any physical damage.

Thermographic inspection is one of the most important tools in preventive maintenance. Inspection on a periodic basis is a quick and cost-effective means to detect common problems that result in an abnormal temperature. Typical problems that can be detected include poor connections, loose or poor moving or braided conductors, and so on.



Key O&M Cost Point

Thermographic inspection on a periodic basis is a quick and cost-effective means to detect common problems that result in an abnormal temperature.

Inspection hatches are provided at certain lengths to allow inspection of the interior and bus supporting insulators during a scheduled maintenance when the unit is in an outage.

Prerequisites:

- Bus ducts should be checked with thermography prior to shutdown to identify any localized hot spots or hot spot connections.



Key Technical Point

Bus ducts should be checked with thermography prior to shutdown to identify any localized hot spots or hot spot connections.

- Bus duct cooler blowers of the isophase bus ducts must be run with cooling water OFF for several hours prior to performing insulation resistance testing. This allows drying time for isophase bus duct insulators.

**Key Technical Point**

Bus duct cooler blowers for the isophase bus ducts must be run with cooling water OFF for several hours prior to performing insulation resistance testing. This allows drying time for isophase bus duct insulators.

Precautions:

- Static charge could be present on any section of a conductor. Appropriate grounding/discharge is necessary prior to any work or testing.

**Key Human Performance Point**

Static charge may be present on any section of a conductor. Appropriate grounding/discharge is necessary prior to any work or testing.

- After meggering a bus, a sufficient amount of time must be allowed for the charge to dissipate before removing megger leads; otherwise, personnel injury might result.

**Key Human Performance Point**

After meggering a bus, a sufficient amount of time must be allowed for the charge to dissipate before removing megger leads; otherwise, personnel injury might result.

- The isophase bus duct enclosure is a confined space. Confined space entries must comply with approved procedures.

**Key Human Performance Point**

The isophase bus duct enclosure is a confined space. Confined space entries must comply with approved procedures.

- Potential transformer fuses should be pulled prior to starting maintenance work.

**Key Human Performance Point**

Potential transformer fuses should be pulled prior to starting maintenance work.

Limitations:

- Bus ducts should not remain OPEN for extended periods of time to prevent dust and moisture intrusion. All openings must be covered when personnel are not performing work.

Metal-Enclosed Buses

Inspection and maintenance procedures should include a list of equipment and material required for the task such as:

- Silicone grease
- Lint-free cleaning rags
- Approved cleaner such as mineral spirits
- Digital low resistance ohmmeter (DLRO)
- Calibrated 2500 V megger
- Torque wrench

The inspection checklist shown in Table 9-4 provides a good beginning for routine and regular maintenance outage work. Maintenance personnel can use or modify according to their specific equipment installation.

Table 9-4
Metal-Enclosed Bus Duct Inspection and Maintenance Recommendations

Equipment	Visual Inspection	Inspection Frequencies	Tests
Bus Duct (General)	1. General posting of the non-segregated bus duct for high voltage.	Weekly or monthly, depending on the environment and operating conditions. (See Note 1.)	
	2. General appearance of the non-segregated bus duct and its associated systems (preservation, cleaning, debris).		
	3. Proper clearance from all adjacent structures and equipment (permanent and temporary).		
	4. Proper connection between the bus duct enclosure and ground contact assembly and ground.		
	5. Proper bracing, suspension alignment and evidence of damage to any of the bus duct structural supports.		
Bus Enclosure	1. Exterior general cleanliness and wildlife intrusion and/or nesting.	Weekly or monthly, depending on the environment and operating conditions. (See Note 1.)	
	2. Interior cleanliness (free from moisture, dust or foreign materials).		
	3. Proper mounting of the bus enclosure inspection covers including fastener/fastener sealing washer arrangement and tightness.		
	4. Evidence of moisture/water coming from the inspection cover gasket area or standing water.		
	5. Degradation of the inspection cover gaskets		
	6. Proper mounting of all duct flange bolting assemblies including fastener, gasket, and fastener tightness		
	7. Bus duct drain connections properly installed and aligned		
	8. Proper posting of the requirements to access the bus duct through each inspection cover.		
	9. Cracking of the enclosure walls.		
	10. Damaged and/or missing nut retainers.		

Metal-Enclosed Buses

Table 9-4 (cont.)

Metal-Enclosed Bus Duct Inspection and Maintenance Recommendations

Equipment	Visual Inspection	Inspection Frequencies	Tests
Stand-Off Insulators	1. Evidence of porcelain chipping, cracking, arcing, flaking, missing hardware, cleanliness, or other physical damage.	During major maintenance outage or every 7 to 10 years.	Perform thermographic inspection every 6 months when buses run at a full load, thermography test frequency may be applied as required.
	2. Evidence of corrosion or discoloration due to heating		Perform insulation resistance (megger) tests during major maintenance outage or every 7 to 10 years. Perform tests before returning equipment to service.
	3. Proper tightness of stand-off insulator electrical connections		Hi-potential tests may be necessary when repair or replacement of parts/components have been performed. Consult vendor manuals or vendor for hi-potential test values. Hi-potential values after initial installation and during maintenance test should be lower in kV values.
	4. Proper tightness of stand-off insulator mounting hardware		
	5. Proper stand-off insulator washer compression		
	6. Record the serial numbers of all stand-off insulators inspected		
Bus Conductor	1. Evidence of blistering and separating of silver plating on rigid and flexible connections.	During major maintenance outage or every 7 to 10 years.	
	2. Evidence of corrosion or discoloration due to heating at each of the following: • Bus work-to-bus work connections • Bus work-to-transformer bushing connections • Bus work-to-disconnect link connections • Bus work-to-metering and relaying connections • Bus work-to-stand-off insulator connections		
	3. Proper alignment at all bus connections.		

Table 9-4 (cont.)

Metal-Enclosed Bus Duct Inspection and Maintenance Recommendations

Equipment	Visual Inspection	Inspection Frequencies	Tests
	4. Proper tightness of bus work electrical connections including washer compression at each of the following: • Bus work-to-bus work connections • Bus work-to-transformer connections • Bus work-to-disconnect link connections • Bus work-to-metering and relaying connections 5. Proper clearance between the bus work and the bus enclosure. 6. Main power transformer low voltage busing compartment crossover duct mounting bolts exhibiting discoloration due to overheating from carrying magnetic shielding currents. 7. Proper installation of bus section flash band taping		
Auxiliary Power Transformer Secondary Bushing Enclosure	Inspect secondary bushing connections to segregated or non-segregated bus duct for evidence of oil leakage from gasket deteriorating or excessive transformer vibration.	During major maintenance outage or every 7 to 10 years. Replace bushing gaskets as required.	
Boots	Inspect for material condition: • dryness • cracks	During major maintenance outage or every 7 to 10 years. Replace every 15 years.	
Expansion Joints	Inspect for material condition; cracking of flexible metal sheets.	During major maintenance outage or every 7 to 10 years.	Thermography every 6 months or as required.

*Metal-Enclosed Buses***Table 9-4 (cont.)****Metal-Enclosed Bus Duct Inspection and Maintenance Recommendations**

Equipment	Visual Inspection	Inspection Frequencies	Tests
Cooling System	Inspect cooling equipment for the following: • Water leaks from cooling coils • Standing water • Corrosion or other deterioration • Fan/motor impeller for proper operation and material condition • Damper condition and alignment	Monthly inspections. Detailed inspection and major maintenance during unit planned outage. Review vendor recommendations for cooling coil maintenance.	
Fire/Vapor Barriers and Wall/Floor	1. Proper installation, sealing and materials in the fire/vapor barriers.	Inspect during major maintenance outage or in accordance with fire protection requirements.	
	2. Proper installation and sealing of the building wall/floor penetrations.		
	3. Indication of separation between the fire/vapor barrier materials and the bus works.		
	4. Indication of corrosion/missing hardware at the junction between the wall penetration frame and building wall.		
	5. Indication of corrosion/missing hardware at the junction between the floor penetration frame and the building floor.		
	6. Indication of wildlife roosting/nesting.		

Note 1:

In areas of industrial contamination or coastal areas where ocean vapors are prevalent, inspections might be required at intervals of two weeks and two months. Less frequent inspections may be required in areas of relatively clean atmosphere.

9.9 Observations

The isophase and the segregated or non-segregated bus ducts like the subject transformers are vital equipment in a power plant. Without bus ducts the generator, the generator step-up and unit and reserve/system auxiliary power transformers cannot perform their function.

Bus ducts, depending on the service conditions, can be exposed to abnormal operating service conditions such as thermal expansion and contraction effects, continuous and short circuit forces, and operating and impulse voltage stresses.

An effective maintenance program should consider the stressors and degrading mechanisms that deteriorate the component and the overall bus.

10

TROUBLESHOOTING

Routine inspection, regular maintenance, and analysis of trending data could provide the corrective actions needed when a transformer in-service shows signs of deterioration or imminent fault.

The external condition of a transformer is the starting point to look for abnormal conditions such as:

- Oil spills
- Overheating or hot spots
- Damaged bushings, arresters
- Abnormal temperature indications
- High or low oil levels
- Other signs of abnormal conditions

The second step is to review all available diagnostic tests and monitoring devices such as:

- Gas-in-oil-analysis
- Oil condition and dielectric strength
- Insulation resistance and power factor
- Turns ratio
- Other monitoring and tests results
- Original factory test report
- Winding resistance

Troubleshooting

In many cases, while the transformer is in-service, oil tests will provide the first clues of the internal condition of the transformer. Listed below are just a few examples of indications from monitoring and test results:

- High concentration of carbon monoxide—thermal damage to cellulose
- High acetylene—internal arcing
- Carbon particles in the oil—probable internal electrical breakdown
- Low oil dielectric strength—moisture or particle contamination
- Low insulation resistance—moisture contamination or damaged insulation
- Abnormal turns ratio—short turns in the windings

10.1 Scenarios

Troubleshooting can be aided with the use of scenarios and/or flow charts. A few flow charts are provided to aid in the troubleshooting process. It is suggested that the user develop a set of these charts with symptom pages and plans of action to help in decision making and to capture lessons learned.



Key Human Performance Point

Troubleshooting can be aided with the use of scenarios and/or flow charts. A few flow charts are provided to aid in the troubleshooting process. It is suggested that the user develop a set of these charts with symptom pages and plans of action to help in decision making and to capture lessons learned.

Scenario 1: Gas pressure relay alarm operates (see Figure 10-1).

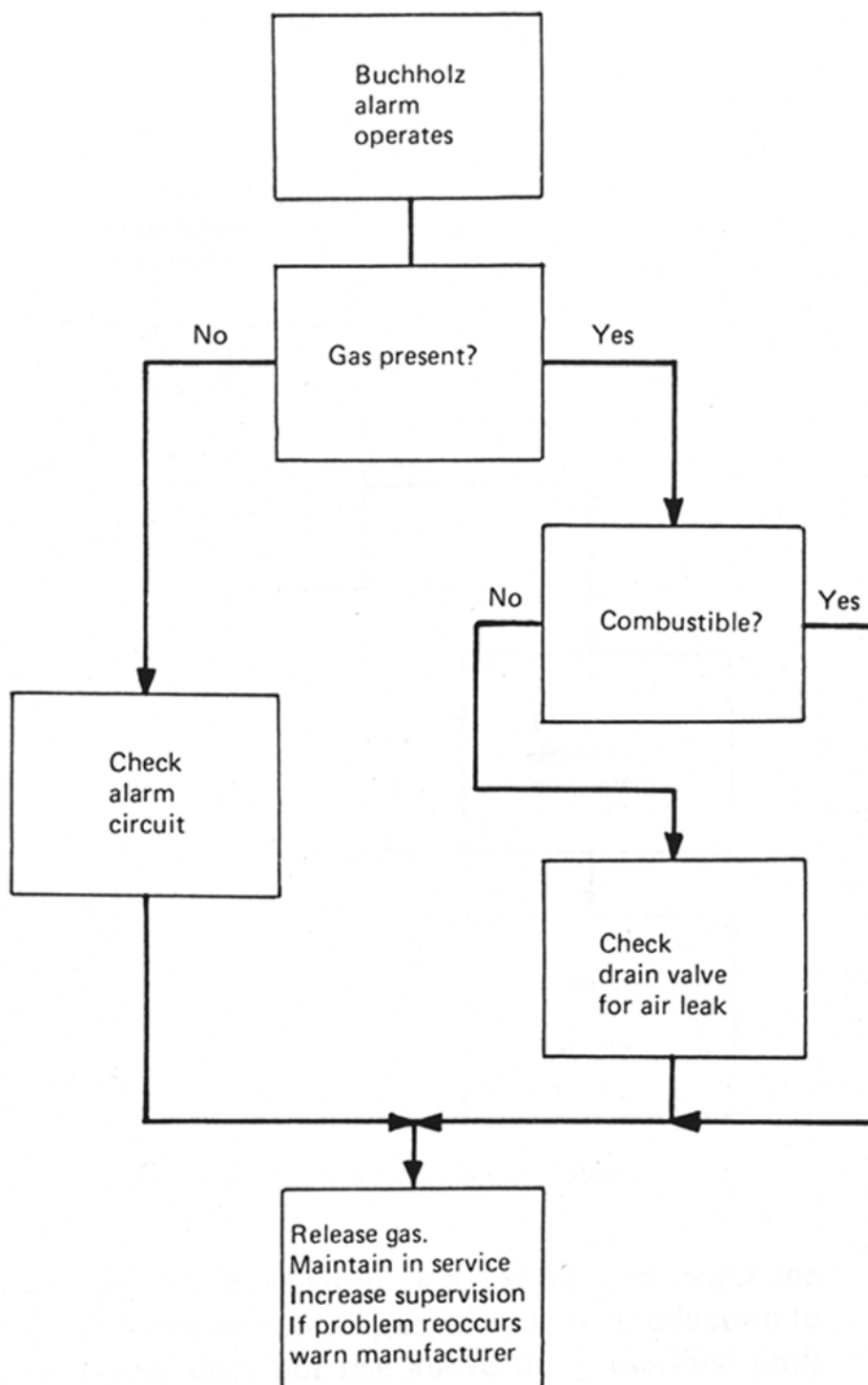


Figure 10-1
Instructions if Buchholz Alarm Operates

Troubleshooting

Scenario 2: Gas pressure relay trip operates (see Figure 10-2).

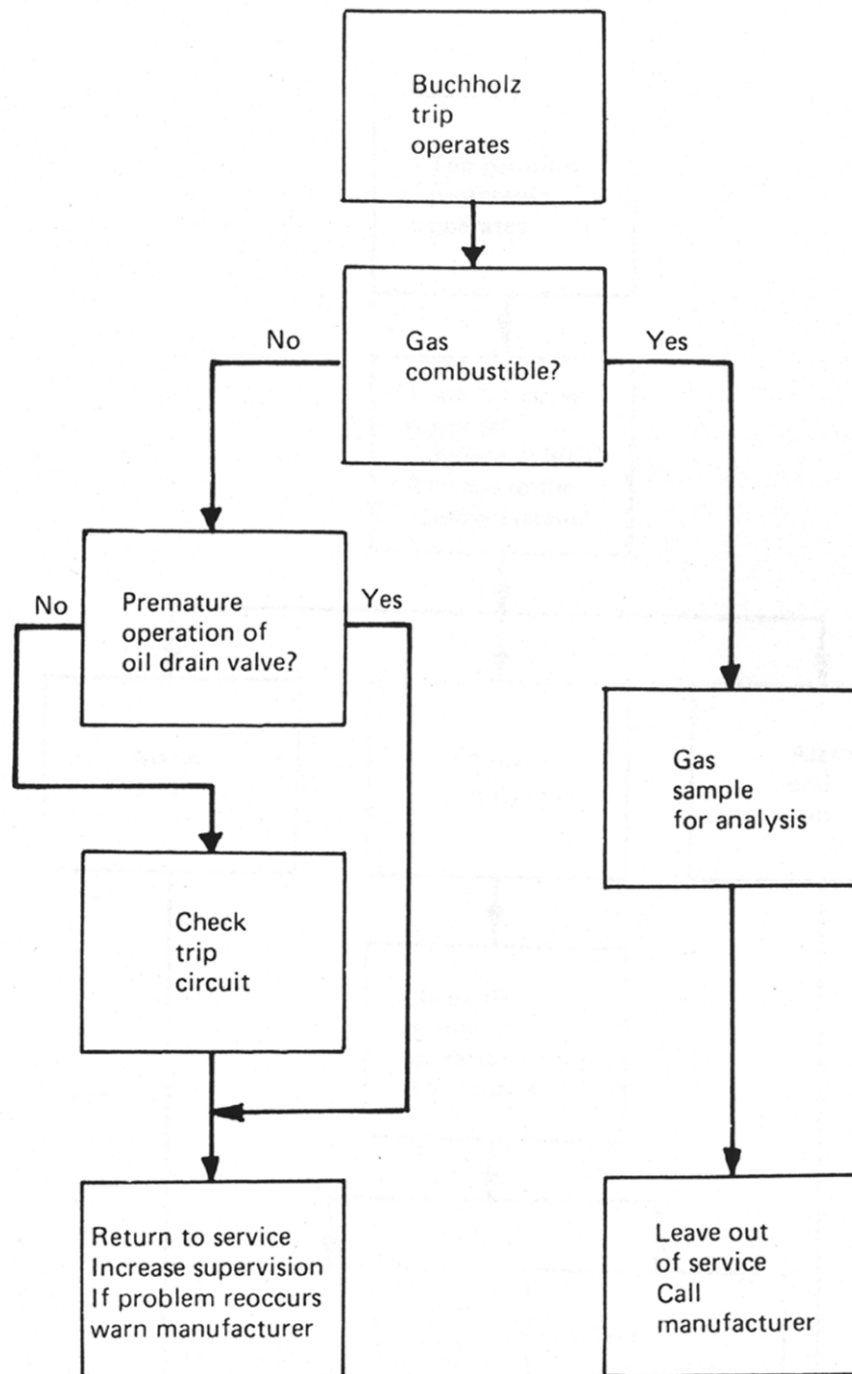


Figure 10-2
Instructions if Buchholz Trip Operates

Scenario 3: Ground leakage protection operates (see Figure 10-3).

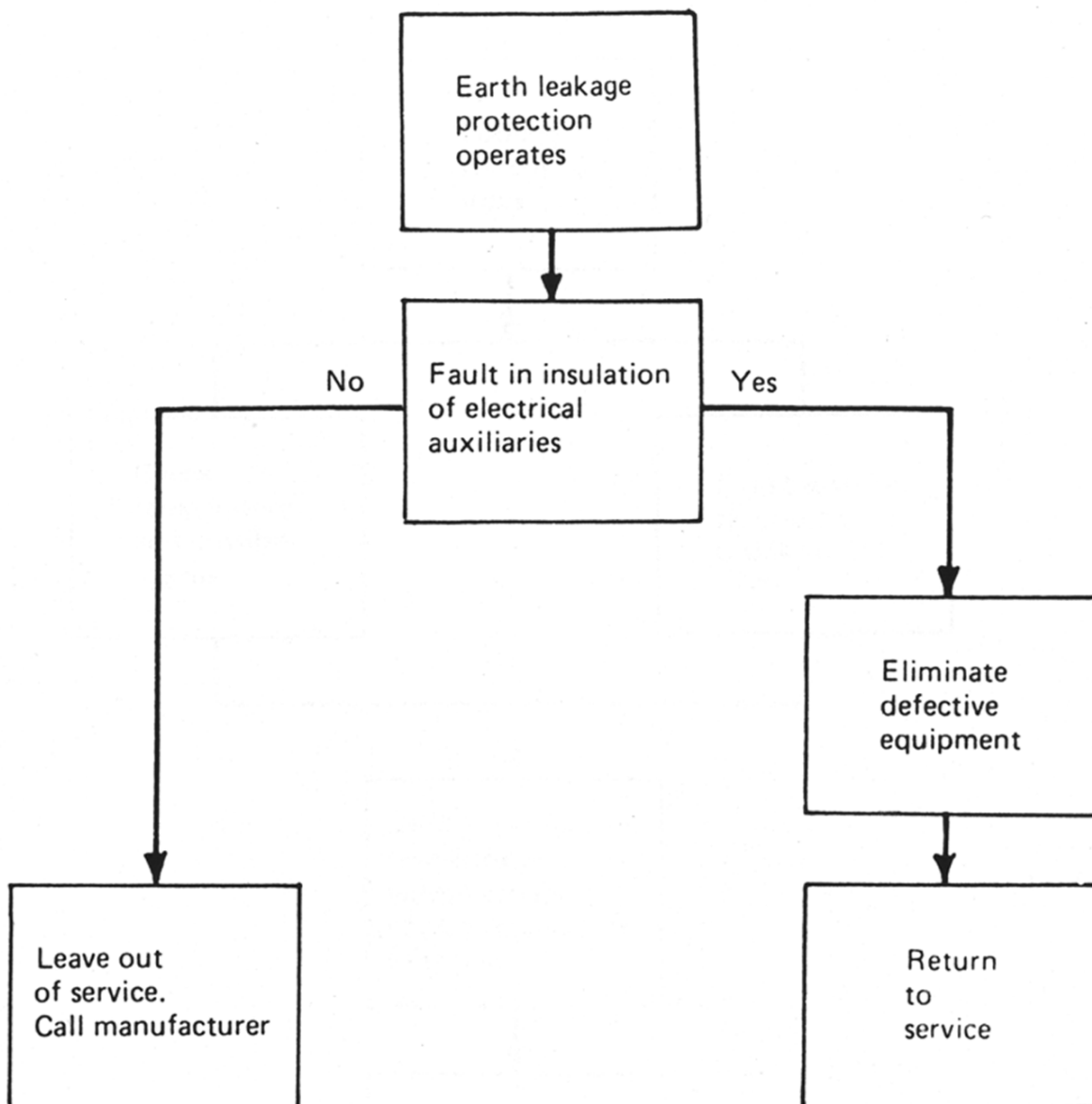


Figure 10-3
Instructions if Earth-Leakage Protection Operates

Troubleshooting

Scenario 4: Temperature protection operates (see Figure 10-4).

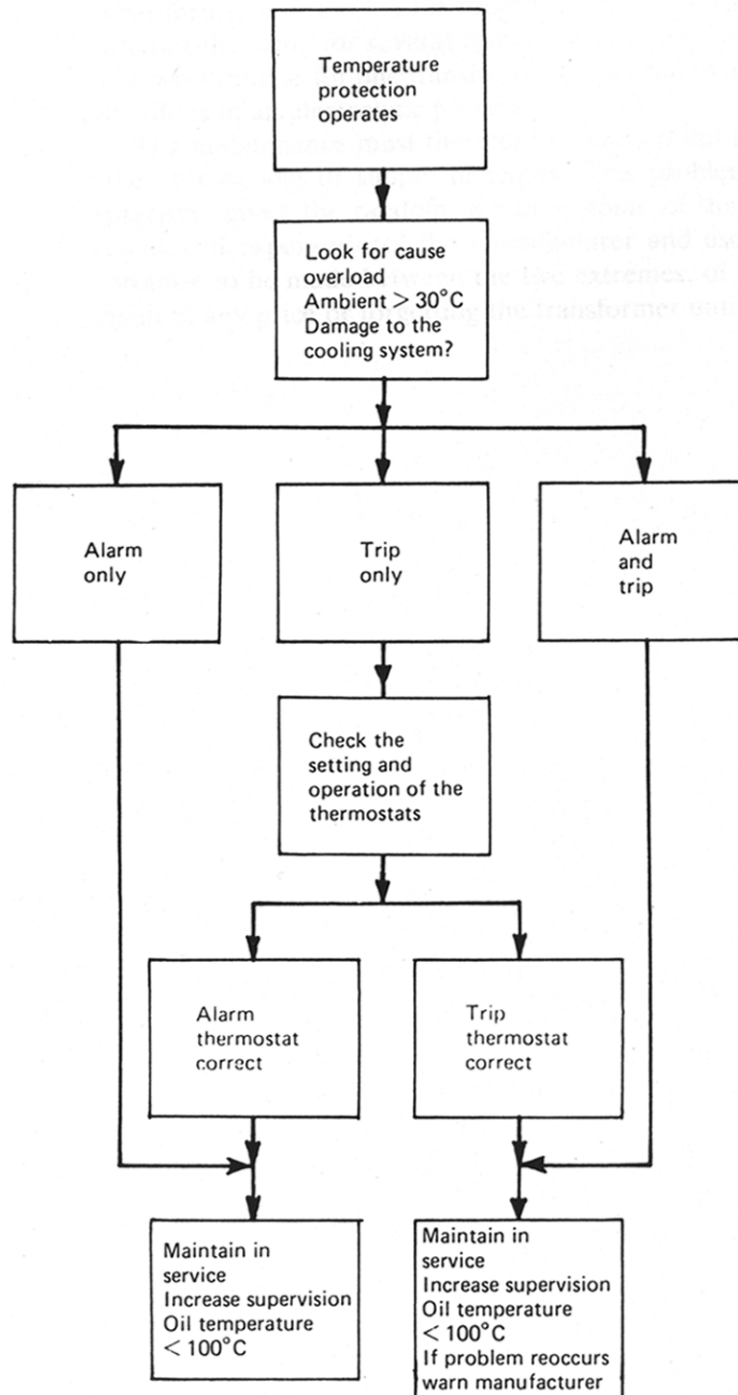


Figure 10-4
Instructions if Temperature Protection Operates

Scenario 5: Cooling system stops (see Figure 10-5).

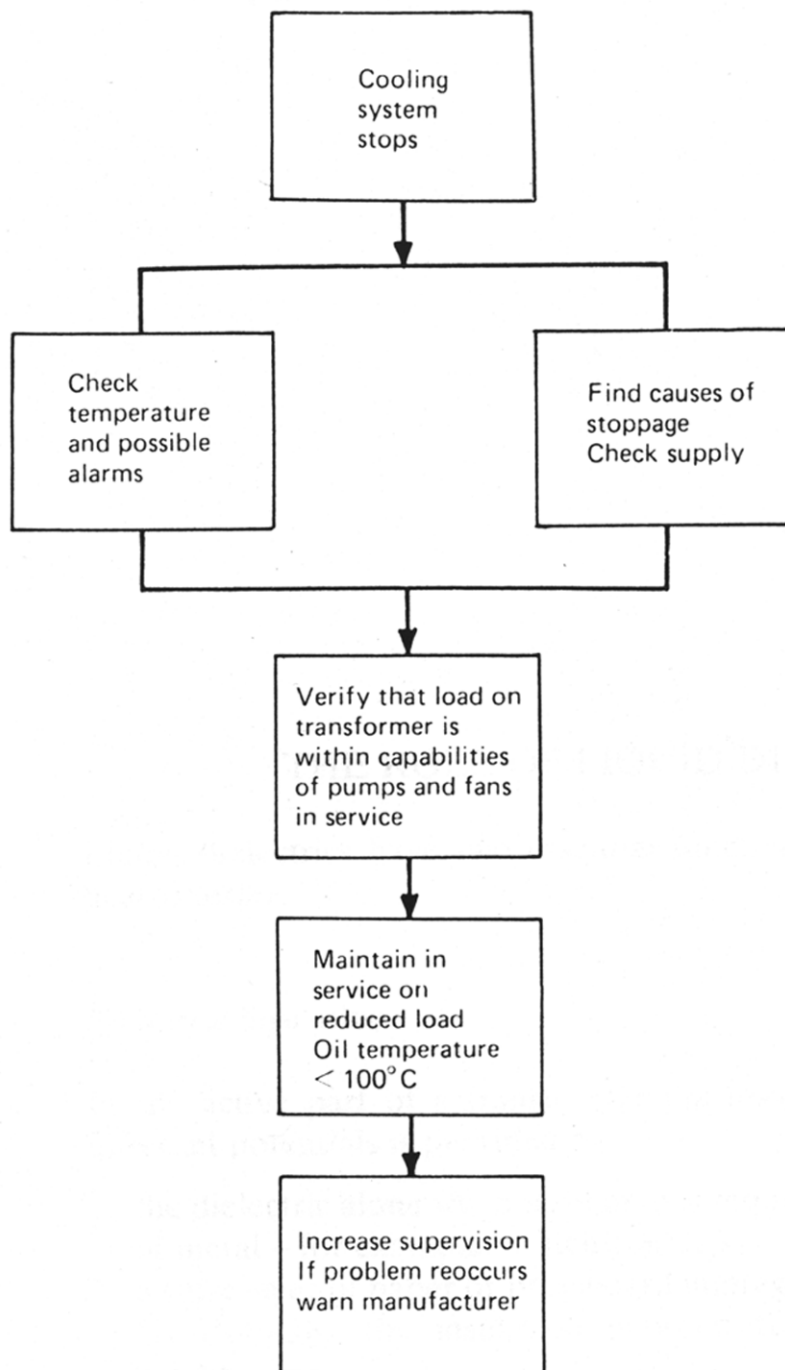


Figure 10-5
Instructions if Cooling Stops

10.2 Options

After an analysis of the condition, the decision to de-energize the transformer has to be made to avoid further damage. If such a step is to be taken, other equipment will be needed, such as oil tankers, vacuum and oil pumps, grounding equipment, etc. The transformer manufacturer should be notified at an early stage of possible transformer problems. If necessary, a decision to arrange for repairs/schedule at the factory, for transportation, for heavy hauling equipment, and transportation routes should be made.

In some instances little or no warning is given and the transformer may break down, causing service interruption and extensive damage. In cases where a transformer failure occurs, an assessment should be made which include the following:

- What is the information that can be obtained from the protective scheme and for oscillograph records?
- How extensive is the damage?
- What field tests can be performed before internal inspection?
- Perform an internal inspection to assess damage.
- Decision for local repair or transport to manufacturer's facilities.

An investigation flowchart from IEEE Std. C57.125-1991 [37] provides the steps to be taken if routine tests show a possible transformer problem, or steps to be taken after transformer tripped.

The guide recommends analysis of all data to investigate the problem. After analysis of the data, a decision can be made to return to service or perform additional tests. If the damage is obvious, a decision can be made to repair or scrap the failed transformer. In the case of additional tests, upon completion of the test and their analysis the decision for a site repair or factory repair is the next step. In the case of a factory repair, a teardown investigation prior to repair is possible.

The standard has detailed information on internal inspection of the main tank, and the tap changer compartment, and analysis of electrical and mechanical failures, including:

- Preparation items
- A checklist of general observations
- Electrical and diagnostic tests
- Field test interpretation
- Internal inspection

A checklist for an internal transformer inspection could include some of the following questions:

- What is the condition of cable/cooper terminals?
- What is the condition of outside windings?
- What is the condition of oil? Odor, burnt insulation?

- Is there any contamination and/or debris from failure?
- Is there any obvious failure path?
- Is there any visible damage to the core?
- What is the condition of the tap changer?

Tear-Down Inspection

Internal inspection either at the site or at the factory can provide the corrective actions to prevent a recurrence. Internal inspection of the transformer, either for maintenance or for trouble investigation, requires certain precautionary measures.



Key Human Performance Point

Before opening a transformer or removing an inspection cover, the transformer internal pressure has to be lowered to atmospheric pressure. Failure to do so may cause the cover to become a missile.



Key Human Performance Point

Do not enter the transformer tank until the gas in the tank is replaced by dry air. The oxygen content inside must be at least 19.5% before entering for inspection. While inside, oxygen content must always be checked. Oxygen less than 19.5% may cause drowsiness and/or injury or death.

Table 10-1 provides typical troubleshooting guidelines for transformer components. Listed below are a series of typical questions to assist in the evaluation of the internal condition of the transformer.

- Is there any mechanical distortion of the turns?
- Is there any damage to winding insulation?
- Is there any fault between turns or windings?
- Is there any tracking on the barrier insulation or to the core?
- Is there any mechanical distortion of core laminations or structural parts?
- What is the condition of the core ground?

Troubleshooting

Table 10-1
Troubleshooting Guidelines

Component	Problem	Probable Causes	Recommendation
Bushing	Capacitance increase	Shorted condenser foils	Replace the bushing if the capacitance is equal to 110% or greater than original measurement
	Power factor increase	Moisture ingress	Replace the bushing if the power factor is double the original measurement.
	Low oil level	Overheated gaskets	Check connections at the top of the bushing. Replace the gaskets if overheating is not severe. Otherwise, replace the bushing
	Abnormal tap voltage	Shorted condenser foils	Replace the bushing
	Tracking on external surface or corona level	Surface contamination	Perform cleaning of external surface
Control cabinet	Rust or water accumulation	Inoperative heater	Check condition and setting of heater
	Oil accumulation at bottom	Gasket leaks at tank penetrations for control cables	Replace gaskets and cables, depending on condition
Core	Low resistance to ground	Inadvertent core grounds	Internally inspect to locate and remove the inadvertent grounds
De-energized tap changer	High winding resistance	Poor contact, coking	Internally inspect to confirm the problem. Clean or replace the contact. High resistance could also be caused by bad cable joints or connections.
Heat exchanger (Forced air coolers)	Oil temperature alarm, no oil flow alarm or fan motor tripping	Clogged heat exchanger tubes	Clean the tubes with high pressure water
		Temperature switch malfunction	Repair/calibrate
		No oil flow because of failed oil pump motor	Replace the motor
		No oil flow because shut-off valves inadvertently closed	Check the proper position of the valves
	Heat exchangers not all at same temperature	Clogged heat exchanger tubes or shut-off valves inadvertently closed	Clean the tubes with high pressure water. Check the proper position of the shut-off valves

Table 10-1 (cont.)
Troubleshooting Guidelines

Component	Problem	Probable Causes	Recommendation
Load tap changer	Increasing trend of differential between LTC oil temperature and main tank oil temperature	Contact overheating/coking	Internally inspect the LTC to identify and replace the overheated contacts. Reversing switch should be operated at least every 60 days.
	Oil flowing out of the breather	Deteriorated seals between LTC compartment and main tank	The tap changer must be removed from its compartment and the tap board and/or the seals replaced.
	Abnormal number of operations (high or low) or abnormal voltage	Defective drive system components	Replace any worn, broken or sheared mechanical components.
		Defective control system	Replace control system or components
Oil	Audible snapping or cracking noises	Static electrification	Change the cooling configuration. <u>The condition must be addressed immediately.</u>
	High oxygen content	Deteriorated gaskets	Replace gaskets
	High hydrogen content	Internal partial discharges	Perform acoustic partial discharge testing to locate the source of the discharges.
	High carbon monoxide content	Inefficient cooling	Clean the heat exchanger, check operation of pumps and fans
		High oxygen content in the oil	De-gas the oil to remove the gasses
	High quantities of methane, ethane and ethylene	Circulating current in core caused by multiple grounds	Internally inspect to locate and remove the grounds. If unable to locate, consider inserting a resistor in series with the intentional ground to limit circulating current.
		Overexcitation of core	Reduce the excitation
		Overheated de-energized tap changer contact	Clean or replace the overheated contact
	Low levels of acetylene	Capacitive discharges	Internally inspect for loose bolted connections inside the main tank.
		Short in oil pump motor	Check motor operation or motor winding resistance
	Low dielectric strength	Contamination from particles or moisture	Perform particle count and moisture tests to determine contamination cause.

Troubleshooting

Table 10-1 (cont.)
Troubleshooting Guidelines

Component	Problem	Probable Causes	Recommendation
	High moisture content	Gasket leaks, inadequate nitrogen supply Perforated conservator bladder Spent desiccant	Replace deteriorated gaskets. Nitrogen bottle may need replacement Replace conservator bladder Replace desiccant
	Low oil level, leaks	Gasket leaks	Replace deteriorated gaskets. Consider use of high temperature material gaskets.
	High particle count	Oil pump impeller or bearing wear	Replace defective pumps. Depending on the degree of contamination, may need to filter the oil and clean the inside of the transformer.
	Oil discharge from pressure relief device	Excessive oil temperature or overfilling of oil	Heat exchanger tubes may need cleaning. Remove some oil if overfilled.
Oil (LTC)	Acetylene detected (vacuum LTC)	Vacuum bottle failure	Test all the bottles and replace faulty ones
		By-pass switch arcing	Re-adjust drive mechanism and vacuum bottle alignment. May need to replace support structure.
	Low dielectric strength	Desiccant saturated with water	Replace the desiccant when its color changes
Oil preservation system	Frequent replacement of nitrogen bottles or nitrogen pressure alarm	Gasket leaks	Replace deteriorated gaskets
	Low oil level for sealed conservator system	Bladder leak	Replace bladder
Radiators	High oil temperature alarm or radiators not all same temperature	Shut-off valves inadvertently closed	Check the proper position of the valves
Winding	High carbon monoxide in oil indicating insulation degradation	Overloading	Reduce the load or increase the cooling
		Clogged heat exchanger tubes	Clean the tubes
	High power factor or low insulation resistance	Moisture in the oil and insulation	Remove the moisture from the oil and dry-out the insulation
	Unequal turns ratio among the three phases	De-energized tap changer setting not all on same tap	Check mechanical linkage of tap changer mechanism to determine source of problem.

11

TRAINING

The intent of this guide is to provide information for engineers responsible for transformer operation and maintenance in power plants. Several transformer books, articles, and/or guides have been written on this subject that can be used as reference material, along with this guide to assist those that have transformer operations and maintenance responsibilities.

The generator step-up, unit auxiliary and reserve auxiliary power transformers, isophase and segregated/non-segregated bus ducts are the backbone of a generating plant. A plant's power delivery capability depends on the continuous operation of this equipment. Continuous operation requires that experienced personnel put an adequate inspection and maintenance program in place, along with the necessary monitoring and trending of equipment data, in order to avoid transformer failures. Also, it requires good communications between various departments or individuals to obtain, share, and maintain important information.

There should be a program in place that covers various aspects of transformers and their effect on plant operations. For instance, a basic training area that covers the description of power transformers for those that will be performing routine and detail visual inspections should be available. For those that will be doing more specific testing and monitoring, such as oil sampling, oil analysis, and electrical tests, there should be training that at least describes these tests, their programs, and the suggested periodicity. Also, operation procedures should be reviewed to limit the potential for inadvertent abuse of power transformers. These procedures should provide loading and expected operating temperature for transformers.

Listed below are some recommendations for those handling transformer and bus duct work to assist with task responsibilities:

- Review vendor manuals and incorporate instructions into the inspection, operations and maintenance program.
- Read transformer handbooks or manuals to become familiar with transformer and auxiliary equipment.
- Participate in continuous training such as seminars and industry meetings.
- Form peer groups and establish periodic meetings to share and exchange knowledge and information.
- In many cases, there are experts within a company or other industry experts who can provide excellent information and training on various pieces of equipment.
- Review of applicable IEEE and other industry standards on transformers and accessories.
- Knowledgeable transformer system engineers can provide fundamental training to electrical maintenance personnel and those who perform work on transformers and bus ducts.

12

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B

GLOSSARY OF TERMS

B.1 Abbreviations

ABB—Asea Brown Boveri

ANSI—American National Standards Institute

BIL—Basic Impulse Level

ASTM—American Society for Testing and Materials

CT—Current Transformer

CSA—Canadian Standards Association

DGA—Dissolved Gas-in-Oil Analysis

EMI—Electromagnetic Interference

EMP—Electromagnetic Impulse

GE—General Electric

GIC—Geomagnetically Induced Currents

GSU—Generator Step-Up Transformer

IEC—International Electrotechnical Commission

IEEE—Institute of Electrical and Electronic Engineers

MVA—Mega Volt Ampere

MVAR—Mega Volt Ampere Reactive

MW—Mega Watt

NEMA—National Electrical Manufacturers Association

Glossary of Terms

NETA—International Electrical Testing Association

O&M—Operating and Maintenance

PT—Potential Transformer

RFI—Radio-Frequency Interference

SAT—Station Auxiliary Transformer

TTR—Transformer Turns Ratio

UL—Underwriters Laboratories

UAT—Unit Auxiliary Transformer

B.2 Definitions

Basic Impulse Insulation Level (BIL): A reference impulse insulation strength expressed in terms of the crest value of the withstand voltage of a standard full impulse voltage wave.

Bus: An electrical conductor that serves as a common connection for two or more electrical circuits.

Capacitance: The property of a system of conductors and dielectrics that permits the storage of electrically separated charges when potential differences exist between the conductors.

Chopped Wave: A voltage impulse that is terminated intentionally by spark-over of a gap.

Corrective Maintenance: The maintenance carried out after a failure has occurred and intended to restore an item to a state in which it can perform its required function. Actions performed to restore a failed or degraded equipment. It includes fault isolation, repair or replacement of defective units, alignment and checkout.

Core-Form Transformer: A transformer in which the core has the form of legs with two common yokes and the core legs pass through the windings or the windings surround the core legs.

Core Loss: The power dissipated in a magnetic core subjected to a time-varying magnetizing force. Note: Core loss includes hysteresis and eddy-current losses of the core. The power dissipated in a magnetic core subjected to a time-varying magnetizing force. Core loss includes hysteresis and eddy-current losses of the core.

Core-Type Transformer: See Core-Form Transformer

Corona: A luminous discharge due to ionization of the air surrounding a conductor caused by a voltage gradient exceeding a certain critical value. A type of localized discharge resulting from transient gaseous ionization in an insulation system when the voltage stress exceeds a critical value. The ionization is usually localized over a portion of the distance between the electrodes of the system.

Critical Impulse Flashover Voltage: The crest value of the impulse wave that, under specified conditions, causes flashover through the surrounding medium on 50% of the applications.

Decibel (dB): One-tenth of a bel. The number of decibels denoting the ratio of the two amounts of power being 10 times the logarithm to the base 10 of this ratio: $n = 10 \log(10) I_1/I_2$ decibel; $n = 20 \log(10) V_1/V_2$ decibel.

Dissipation factor: The reciprocal of the ratio between the insulating materials capacitive reactance to its resistance at a specified frequency.

Eddy-current: Current that circulates in a metallic material as a result of electromotive forces induced by a variation of magnetic flux. The currents that are induced in the body of a conducting mass by the time variation of magnetic flux.

Generator Step-Up (GSU): This is a transformer or bank of transformers used to connect the generator to the grid (high voltage distribution system).

Ground: A conducting connection, whether intentional or accidental, by which an electric circuit or equipment is connected to the earth, or to some conducting body, of a relatively large extent, that serves in place of the earth.

Harmonic: A sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency.

Hottest Spot Temperature: The highest temperature attained in any part of the insulation of electric equipment. The highest temperature inside the transformer winding. It is greater than the measured average temperature (using the resistance change method) of the coil conductors.

Hysteresis Loss: The energy loss in magnetic material that results from an alternating magnetic field as the elementary magnets within the material seek to align themselves with the reversing magnetic field.

Impulse Flashover Voltage: The crest voltage of an impulse causing a complete disruptive discharge through the air between electrodes of a test specimen.

Impulse (Surge Arresters): A surge of unidirectional wave of current or voltage of very short duration containing no appreciable oscillatory components.

Impulse Withstand Voltage: The crest value of an applied impulse voltage which does not cause a flashover, puncture, or disruptive discharge on the test specimen.

Glossary of Terms

Induction: The process of generating time-varying voltages and/or currents in conductive objects or electric circuits by the influence of the time-varying electric, magnetic, or electromagnetic fields. The process of generating time-varying voltages and/or currents in otherwise un-energized conductive objects or electric circuits by the influence of the time-varying electric and/or magnetic fields.

Insulation Level (Surge Arresters): A combination of voltage values (both power-frequency and impulse) that characterize the insulation of equipment with regard to its capability of withstanding dielectric stresses.

Isokeraunic Level (Lightning): The average annual number of thunderstorm days.

Joule: The unit of work and energy in the International System of Units (SI). The joule is the work done by a force of 1 newton acting through a distance of 1 meter.

Induced Current (General): Current in a conductor due to the application of a time-varying electromagnetic field. (Lightning Strokes) The voltage induced on a network or electric installation by an indirect stroke.

Induced Voltage (General): A voltage produced around a closed path or circuit by a change in magnetic flux linking that path. (Lightning Strokes) The voltage induced on a network or electric installation by an indirect stroke.

Inductance: The property of an electric circuit by virtue of which a varying current induces an electromotive force in that circuit or in a neighboring circuit.

Leakage Current (Insulation): The current that flows through or across the surface of insulation and defines the insulation resistance at the specified direct-current potential.

Mutual Inductance: The common property of two electric circuits whereby an electromotive force is induced in one circuit by a change of current in the other circuit. The coefficient of mutual inductance M between two windings is given by the following equation: $\text{emf} = M \, di/dt$, where $M = \text{constant}$.

Power Factor: The cosine of the voltage-current phase angle (cosine of the resistance-impedance phase angle). The unit of real power (kW) to apparent power (kVA) for any given period of time. Power Factor is defined as the cosine of the voltage-current phase angle (cosine of the resistance-impedance phase angle).

Preventive Maintenance: Tests, measurement, replacements, adjustments, repairs, and similar activities carried out with the intention of preventing faults or malfunctions from occurring during subsequent operation. Preventive maintenance is designed to keep equipment and programs in proper operating condition and is performed on a scheduled basis. The maintenance carried out at predetermined intervals or corresponding to prescribed criteria, and intended to reduce the probability of failure or the performance degradation of an item.

RAT (Reserve Auxiliary Transformer): See Station Auxiliary Transformer

Rated Continuous Current: The current expressed in amperes, root mean square, that the device can carry continuously under specified service conditions without exceeding the allowable temperature rise.

Rated Voltage: The RTS voltage, at rated frequency, which may be impressed between the terminals of the device under standard operating conditions for rated time without exceeding the limitations established by these standards.

Residual Voltage (Arrester): The voltage that appears between the line and ground terminals of an arrester during the passage of discharge current.

Saturation Curve: A characteristic curve that expresses the degree of magnetic saturation as a function of some property of the magnetic excitation.

Self-Inductance: The property of an electric circuit whereby an electromotive force is induced in that circuit by a change of current in the circuit. The coefficient of self-inductance L of a winding is given by the following expression: $e = L \, di/dt$, where $L = \text{constant}$.

Shell-Form Transformer: A transformer in which has a single stack of coils where the core passes through the coils and is split into at least two return circuits. The core basically surrounds the windings.

Spike (Pulse Term): A distortion in the form of a pulse wave form of relatively short duration superimposed on an otherwise regular or desired pulse wave form.

Station Auxiliary Transformer (SAT): A power system supply transformer that takes power from the offsite high voltage system to supply power plant system during refueling and startup periods.

Surge: A short, sudden rush or excess of electric current in a circuit.

Surge Arrester: A protective device for limiting surge voltages on equipment by discharging or bypassing surge current; it presents continued flow of follow current to ground, and is capable of repeating these functions as specified.

Surge Impedance: The ratio between voltage and current of a wave that travels on a line of infinite length and of the same characteristics as the relevant line.

Tan δ : See dissipation factor

Tap: A connection brought out of a winding at some point between its limits to allow changing the voltage or current ratio.

Tap Changer: A selector switch device used to change transformer tap settings. These selector switches can either be load tap changers and no-load (de-energized) tap depending on design.

Glossary of Terms

Transient: The peak voltage during the transient conditions resulting from the operation of a switching device.

Unit Auxiliary Transformer (UAT): A power system supply transformer that takes a portion of the generated power and supplies power to the station loads.

Watt: The unit of power in the International System of Units (SI). The watt is the power required to do work at the rate of one joule per second.

Withstand Current (Surge): The crest value attained by a surge of a given wave shape and polarity that does not cause disruptive discharge on the test specimen.

Withstand Voltage: The specified voltage that, under specified conditions, can be applied to insulation without causing flashover or puncture.

C

TRANSFORMER-RELATED TECHNICAL REPORTS, TECHNICAL PAPERS, INDUSTRY STANDARDS

C.1 Summary of Transformer-Related EPRI Technical Reports

C.1.1 TR-104994—Power Transformer Tank Rupture

Severe internal arcing fault can cause destructive internal pressures inside oil filled power transformer tank or compartment.

Internal transient pressures are the result of voltage and current surges, overloading, electrical arcing, loose connections, and through faults that cause core and/or coil movement. In a number of cases, internal gas pressures may start slowly because of insulation deterioration. The gas generation and pressure built up may continue if it not detected and eventually corrected.

Internal combustible and non-combustible gases such as carbon monoxide, carbon dioxide, hydrogen, ethane, methane, ethylene, and acetylene are indicative of abnormal internal conditions or incipient transformer failure.

Gas pressure detecting devices and fault gas monitors are used to monitor and detect the presence and concentration of gases.

The fault pressure device is a mechanical device that s used to mitigate the effects of large pressure changes within the tank. The tank is designed and built to withstand approximately 10 psig and the fault pressure device is designed to operate in lower pressure ranges.

A fault pressure relay is used to detect pressure transients. It measures the rate of change of pressure change in the oil. In severe cases, the relay will operate to protect the transformer form large pressure built up. In some cases, the operation of fault pressure relay may save the transformer from explosion but unfortunately this is not always the case.

Fault pressure relay, pressure relief device, fault gas monitor and gas detector must be installed and properly maintained.

C.1.2 EL/ER-6880—Static Electrification

According to EPRI's EL/ER-6880 June 1990 report, “static electrification continues to be a significant worldwide problem, jeopardizing the reliability of large forced-oil-cooled shell-form

and core-form transformers.” EPRI has published several studies and reports regarding the subject of static electrification. EPRI’s studies acknowledge that the contribution of static electrification to failures can be very difficult to diagnose.

Electrification characteristics have been documented as a function of flow, temperature, moisture and the duct type and structure. Factors that influence the charging tendency of transformer oil are temperature, moisture content, oxidation, and presence of certain contaminants.

The flow of insulating oil in large forced-oil-cooled power transformers produces static electrification. Static charge buildup is created when cooler oil is pushed by the pumps from the bottom of the transformer to the top as it moves through the insulation of the windings and heat exchangers. The ionization of the circulating oil builds up as a static charge which discharges through the cooling coil and creates a breakdown of the oil properties. Weakening of the oil dielectric strength could cause a flashover between the transformer windings, unable to maintain the required insulation.

Insulation paper wound coils and pressboard washers acquire a negative DC polarity while the oil that flows out becomes positively charged.

Negative charge accumulation is observed in the lower parts of the insulation structure. The upper tank where the oil exists builds up a positive charge.

Inspection of failed transformers has revealed that flashover usually occurs between a high voltage winding and a low voltage. Severe tracking has been observed in the lower parts of the insulation pieces. In all cases of catastrophic failures, the units were in the energized condition and the pumps were in operation.

Various studies and experiments have been performed since the static electrification was recognized as a cause of large power transformer failures and especially the Shell type. The following are some of the steps to mitigate the effects of static electrification:

C.1.3 TR-113381—Static Electrification Monitor for Large Power Transformers: The “Smart Manhole Cover”

The Static Electrification Monitor (“Smart Manhole Cover”) developed for EPRI is a platform at the top of the transformer with various transducers that monitor the condition of the charge in the transformer oil. It measures high frequency signals related to partial discharge within the transformer. A digital processor is used to collect and analyze the data.

Since electrification characteristics have been documented as a function of flow, temperature, and moisture, it is necessary to select a low charging oil and adjust the flow condition and flow paths for start-up and shutdown and backfeeding.

A special procedure must be in place to require that for nitrogen-blanketed transformers, the cooling system must run in stages and for a certain length of time. This process is not necessary for the conservator-type transformers.

C.1.4 TR-113741—Symposium Proceedings: Transformer Reliability: Management of Static Electrification in Power Transformers

The conclusion from the symposium is that static electrification failures of existing transformers are preventable. The technology and understanding exists to identify potentially high risk operating conditions; monitoring equipment is available or can be readily designed to detect incipient failures.

Design guidelines for new transformers can help minimize the risk of static electrification failures for future large forced-oil-cooled power transformers.

Acoustic partial discharge and leakage current measurements by utilizing discharge sensors, a leakage current meter, and temperature sensors, pump flow meters, a relative humidity meter and a set of video cameras looking into the transformer.

C.1.5 TR-113649—High Voltage Current Transformers & Bushings Failure Prediction and Prevention

Utility problems with degradation of high voltage oil/paper insulated current transformer (CTs). Normal aging due to thermal, electrical and environmental effects and premature failure not anticipated by periodic off-line tests. Potential conditions that can be monitored, such as: suitable discharge, gas-in-oil, power factor, and so on.

Bushing failures are attributed to several causes such as manufacturer's defects, airborne contaminants, loose connections, and so on.

Condition monitoring and failure prediction of high voltage current transformers and transformer bushings. High failure rates. In many cases CT and bushing failures are catastrophic that may result in losses and damages.

C.1.6 TR-11593—Power Transformer Oil Leak Mitigation—Technology Assessment

Transformer oil leaks become more and more likely as equipment ages and create serious and expensive technical problems. Evaluation of current and developing technologies for sealing leaking transformers.

C.1.7 EL-7333—Effects of Geomagnetic Disturbances on Electric Power Transmission Systems

Geomagnetic disturbances from solar storms resulting in the flow of low frequency electric currents in the winding of power transformers through the grounding system.

NRC Information Notice No. 90-42: Failure of Electrical Power Equipment Due to Solar Magnetic Disturbances

On March 13, 1989, an exceptionally strong geomagnetic storm caused major damage to electrical power equipment in Canada, Scandinavia, and the United States. The geomagnetic induced currents (GICs) can cause magnetic saturation of transformer cores. Depending on the size of the GICs and the core saturation, the transformer could overheat because of the reactive, eddy, and harmonic currents.

On September 19, 1989, at the Salem Unit 2 nuclear power plant, a second storm damaged the generator step-up transformer.

C.1.8 TR-112784—Isolated Phase Bus Maintenance

This document provides an overview of isolated phase bus systems, their design features and construction. The cooling systems for these bus systems are discussed, along with operating temperature limits and monitoring. Isolated phase bus maintenance is discussed, including periodic inspections and testing. Potential problems and repairs are also discussed.

C.2 Excerpts of Industry Standards

C.2.1 ASTM Standards

1. D664-01, “Standard Test Method for Acid Number of Petroleum Products by Potentiometric Titration.”

This test method covers procedures for the determination of acidic constituents in petroleum products and lubricants soluble or nearly soluble in mixtures of toluene and propan-2-ol (Note 1). It is applicable for the determination of acids whose dissociation constants in water are larger than 10^{-9} ; extremely weak acids whose dissociation constants are smaller than 10^{-9} do not interfere. Salts react if their hydrolysis constants are larger than 10^{-9} .

2. D923-97, “Standard Practices for Sampling Electrical Insulating Liquids.”

These practices cover sampling of new electrical insulating liquids including oils, askarels, silicones, and synthetic liquids as well as such liquids in service or subsequent to service in cables, transformers, circuit breakers, and other electrical apparatus. This test method shall apply to liquids having a viscosity of less than 3000 SUS (Saybolt Universal s) (647.3 cSt) and 100°F (37.8°C).

3. D974-01, “Standard Test Method for Acid and Base Number by Color-Indicator Titration.”

This test method covers the determination of acidic or basic constituents (Note 1) in petroleum products and lubricants soluble or nearly soluble in mixtures of toluene and isopropyl alcohol. It is applicable for the determination of acids or bases whose dissociation constants in water are larger than 10^{-9} ; extremely weak acids or bases whose dissociation constants are smaller than 10^{-9} do not interfere. Salts react if their hydrolysis constants are larger than 10^{-9} .

4. D2112-01a, “Standard Test Method for Oxidation Stability of Inhibited Mineral Insulating Oil by Pressure Vessel.”

This test method is intended as a rapid method for the evaluation of the oxidation stability of new mineral insulating oils containing a synthetic oxidation inhibitor. This test is considered of value in checking the oxidation stability of new mineral insulating oils containing 2,6-ditertiary-butyl para-cresol or 2,6-ditertiary-butyl phenol, or both, in order to control the continuity of this property from shipment to shipment. The applicability of this procedure for use with inhibited insulating oils of more than 12 cSt at 40°C (approximately 65 SUS at 100°F) has not been established.

5. D2440-99, “Standard Test Method for Oxidation Stability of Mineral Insulating Oil.”

This test method determines the resistance of mineral transformer oils to oxidation under prescribed accelerated aging conditions. Oxidation stability is measured by the propensity of oils to form sludge and acid products during oxidation. This test method is applicable to new oils, both uninhibited and inhibited, but is not well defined for used or reclaimed oils.

6. D3613-98, “Standard Practice for Sampling Insulating Liquids for Gas Analysis and Determination of Water Content.”

This practice covers sampling electrical insulating liquids having a viscosity less than 650 cSt at 40°C from apparatus for analysis of their gas content or for measurement of water content, or both. Guide D117, Test Methods D1533, and Test Methods D3612 provide detailed information regarding gas and water testing. Definitions of terms used in this practice may be found in Terminology D2864.

7. NEMA TR 1-1993 (R2000) “Transformers, Regulators, and Reactors.”

Provides a list of all ANSI C57 Standards that have been approved by NEMA. In addition, it includes certain NEMA standard test methods, test codes, and properties of liquid immersed transformers, regulators, and reactors that are not American National Standards.

C.2.2 IEEE

1. IEEE Standard No.: 637-1985, “IEEE Guide for the Reclamation of Insulating Oil and Criteria for Its Use.”

Detailed procedures are provided for reclaiming used mineral insulating oils (transformer oils) by chemical and mechanical means to make them suitable for reuse as insulating fluids. Reclamation procedures are described, as are the test methods used to evaluate the progress and end point of the reclamation process and the essential properties required for reuse in each class of equipment. Suitable criteria for the use of reclaimed oils are identified. The use of oil in new apparatus under warranty is not covered.

2. IEEE Standard No.: C37.20.2-1999, “IEEE Standard for Metal-Clad Switchgear.”

This IEEE Standards product is part of the C37 family on Switchgear, Substations and Protective Relays. Metal-enclosed medium voltage switchgear (ME), which can contain either drawout electrically operated circuit breakers or stationary electrically operated circuit breakers in individual three-pole grounded metal compartments, is covered. Further, metal-clad switchgear (MC) is compartmentalized to isolate all components such as instrumentation, main bus, and both incoming and outgoing connections with grounded metal barriers. Rated maximum voltage levels for metal-clad switchgear (MC) range from 5 kV through 38 kV with main bus continuous current ratings of 1200 A, 2000 A, and 3000 A. Rated maximum voltage levels for station-type cubicle switchgear (SC) range from 15.5 kV through 72.5 kV with main bus continuous current ratings of 2000 A, 3000 A, 4000 A, and 5000 A. ME switchgear also contains associated control, instruments, metering, relaying, protective, and regulating devices as necessary. Service conditions, ratings, temperature limitations, and classification of insulating materials, insulation (dielectric) withstand voltage requirements, test procedures, and application are discussed.

3. IEEE Standard No.: C37.23-1987, “IEEE Guide for Metal-Enclosed Bus and Calculating Losses in Isolated-Phase Bus.”

This IEEE Standards product is part of the C37 family on Switchgear, Substations and Protective Relays. Assemblies of metal-enclosed conductors and their associated interconnections, enclosures, supporting structures, switches, and disconnecting links are addressed. Ratings, tests, construction, miscellaneous accessories, and loss calculation for isolated-phase buses are covered. Specifically excluded are busways or bus assemblies for distribution of electric power less than 600 V, which consist of enclosed sectionalized prefabricated bus bars or associated structures and fittings, such as feeder busways (indoor or outdoor), plug-in busways (indoor only), and bus assemblies utilized at voltages in excess of 38.0 kV.

D

LIST OF NUCLEAR PLANT POWER TRANSFORMERS

List of Nuclear Plant Power Transformers

Plant	Equipment	Manf.	Voltage	Pwr Rating	Service	Form	Type of	Winding	Load Tap
	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Calvert Cliffs Nuclear									
	Generator Step-Up (GSU)	Wstghse	22/25	500	1975	Shell	FOA	3-phase	No
			500		1976				
	Unit Auxiliary (UAT)	GE	500	100	1975	Core	FOA	3-phase	No
			13.8		1975				
	Startup or Reserve Auxiliary (SAT/RAT)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Spare Transformer(s)	Wstghse	22/25	500	N/A	Shell	FOA	3-phase	No
			500						
D.C. Cook									
	Generator Step-Up (GSU)	U-1: Elin	25/345	1300	5/97	Core	FOA	3-phase	No
		U-2:Asea	25/765	1300	1978	Core	FOA	Single	No
	Unit Auxiliary (UAT)	Wstghse	26/4	18/24/30	1975		OA/FOA/FOA	3-phase	No
					1978				
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	34/4	18/24/30	1975		OA/FA/FA	3-phase	No
					1978				
	Spare Transformer(s)	1-U1 GSU,							
		1 Ph. U2 GSU							
		1 RAT, 1 UAT							

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	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Grand Gulf									
	Generator Step-Up (GSU)	Wstghse	20.9/500	450-55C	7/84	Core	FOA	Single	Yes (under
				510-65C					load No)
	Unit Auxiliary (UAT)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Startup or Reserve Auxiliary (SAT/RAT)	GE	500/34.4	90/120/150-55C	7/84	Core	OA/FA/FOA	3-phase	No
				101/135/168-65C					
	Spare Transformer(s)	Wstghse	20.9/500	450-55C	7/84	Core	FOA	Single	Yes (under
				510-65C					load No)
H.B. Robinson									
	Generator Step-Up (GSU)	Wstghse	H=248/242/236	260@55C Rise	1970	Shell	FOA	3-phase	No
		L=21.5	/230/224 Set on 230	291.2@65C Rise				Single	
	Unit Auxiliary (UAT)	Wstghse	H=21.95/21.42/20.9	44@55C	1970	Core	FOA	3-phase	No
		X,Y=4.16	/19.85 Set on 20.38	49.28@65C					
				X,Y=22@55C					
				24.64@65C					
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	H=120.75/117.875	44@55C	1970	Core	FOA	3-phase	No
			/115/112.125/109.25	49.28@65C					
		X,Y=4.368	Set on 115	X,Y=22@55C					
				24.64@65C					
	Spare Transformer(s)	Wstghse	H=248/242/236	260@55C Rise	1978*	Shell	FOA	Single	No
		L=21.5	/224 Set on 230	291.2@65C Rise					
		McGraw	H=120.75/117.875	44@55C	1970*	Core	FOA	3-phase	No

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	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
McGuire Nuclear									
	Generator Step-Up (GSU)	Unit 1- West	230/22.8	760	1973	Core	FOA	3-phase	No
		Unit 2 GE	525/22.8	750	1973	Core	FOA	Single	No
	Unit Auxiliary (UAT)		22.8/6.9/6.9	60/80/100	1973		OA/FOA/65C	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Spare Transformer(s)	AB		760		Core			No
Millstone 3									
	Generator Step-Up (GSU)	Wstghse	345/22.8	630	1/86	Shell	FOA	3-phase	No
		Wstghse	345/22.8	630	1/86	Shell	FOA	3-phase	No
	Unit Auxiliary (UAT)	McGraw	22.8/4.16	24/32/40KVA	1/86	Core	OA/FA/FA	3-phase	No
		McGraw	22.8/6.9	30/40/50KVA	1/86	Core	OA/FA/FA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	345/4.16	27/36/45KVA	1/86	Shell	OA/FOA/FOA	3-phase	No
		Wstghse	345/6.9	30/40/50KVA	1/86	Shell	OA/FOA/FOA	3-phase	No
Nine Mile Point 2									
	Generator Step-Up (GSU)	McGraw	202/24.3	457	1982	Shell	FOA	Single	No
	Station Service Transformer	GE	24.9/13.8/13.8	112	1982		FOA	3-phase	Yes
	Unit Auxiliary (UAT)	GE	13.8/4.16	11.9	1982		FOA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	GE	24.9/13.8/4.16	70	1982		OA/FA/FOA	3-phase	Yes
	Auxiliary Boiler Transformer	Wstghse	115/13.8/4.16	27.5	1982		OA/FA/FOA	3-phase	No
	Spare Transformer(s)	ABB	202/24.3	457	N/A		FOA	Single	No
								3-phase	

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	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Perry Nuclear									
	Generator Step-Up (GSU)	Wstghse	22/345	415/464.8	1985	Shell	FOA	Single	No
	Unit Auxiliary (UAT)	McGraw	22/13.8, 13.8	48/53.76	1985	Shell	OA/FA	3-phase	No
				64/71.68			OA/FOA		
	Startup or Reserve Auxiliary (SAT/RAT)	GE	345/13.8, 13.8	48/54	1980	Core	OA/FOA	3-phase	No
		GE(rewound)		80/89.6	1982				
	Spare Transformer(s)	Wstghse	22/345	415/464.8		Shell	FOA	Single	No
O.P.P.D — Ft. Calhoun									
	Generator Step-Up (GSU)	GE	345/22	579/648	1970	Core	FOA	3-phase	No
					9/73				
	Unit Auxiliary (UAT)	GE	22/4.16	16/17.9	1969	Core	OA/FA	3-phase	No
					9/73				
	Startup or Reserve Auxiliary (SAT/RAT)	GE	161/4.16	16/17.9	1969	Core	OA/FA	3-phase	No
					9/73				
	Spare Transformer(s)	VA Tech/Elin	345/22	651/730	2002	Core	FOA	Single	No
Salem/Hope Creek									
	Generator Step-Up (GSU)-Salem Unit 1	Wstghse	25/500	416.7/466.7	1984	Shell	FOA	Single	Yes
	Salem Unit 2	Wstghse/ABB	25/500	362.5/406	1989	Shell	FOA	Single	Yes
	GSU Hope Creek	Wstghse	24/500	362.5/406	1989	Shell	FOA	Single	Yes
	GSU Hope Creek	Wstghse	24/500	360/403.2	2000	Shell	FOA	Single	Yes
	Unit Auxiliary (UAT) Salem Unit 1 & 2	Wstghse	25/4.16	50/56	1977	Core	FOA	3-phase	Yes
					1981				
	Spare Transformer(s)	Wstghse	25/500	416.7/466.7	N/A	Shell	FOA	Single	Yes
		VA Tech Elin	24/500	416.7/466.7	N/A	Shell	FOA	Single	Yes

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	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Shearon Harris									
	Generator Step-Up (GSU)	ME	230	336	6/13/84	Shell	FOA	Single	No
	Unit Auxiliary (UAT)	GE	21.5	60/67.2	6/13/84	Core	FOA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	GE	230	48/60	1/6/83	Core	OA/FOA/FOA	3-phase	No
	Spare Transformer(s)	ME	230	336	N/A	Shell	FOA	Single	No
		GE	230	48/60	N/A	Core	OA/FOA/FOA	3-phase	No
South Texas Project									
	Generator Step-Up (GSU)	McGraw	362	700/784	1986	Shell	FOA	3-phase	No
	Unit Auxiliary (UAT)	Federal Pacific	25	112	1986	Core	OA/FOA	3-phase	Yes
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	362	87	1985	Core	OA/FOA	3-phase	No
	Spare Transformer(s)	McGraw	362	700/784	N/A	Shell	FOA	3-phase	No
Catawba Nuclear									
	Generator Step-Up (GSU)	Wstghse	230/20.9	750	1983	Shell	FOA	3-phase	Yes
	Unit Auxiliary (UAT)	Wstghse	20.9/6.9/6.9	70/35/35	1983	Core	OA/FOA/FOA	3-phase	Yes
		Wstghse	22.8/13.8	40	1983	Core	OA/FOA	3-phase	Yes

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	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Vogtle									
	Generator Step-Up (GSU) Unit 1	Wstghse	25/230	404	1986	Core	FOA	Single	Yes
	Unit 2	GE	25/500	404	1988	Core	FOA	Single	Yes
	Unit 2	Elin	25/500	404	1999	Core	FOA	Single	Yes
	Unit Auxiliary (UAT)	GE	25/13.8/4.16	36/21/15	1986	Core	FOA	3-phase	Yes
		(U-1&2)			1988				
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	23/13.8/4.16	56/36/21	1986	Core	FOA	3-phase	Yes
		(RAT, U-1&2)			1988				
		Kuhlman	13.8/4.16	12.5	1995		OA/FA	3-phase	Yes
		(SAT)							
	Spare Transformer(s)	GSU & RAT							
		for U-1&2							
Palisades									
	Generator Step-Up (GSU)	Wstghse	345/23	??	1986	Shell	FOA	3-phase	No
	Unit Auxiliary (UAT)	Wstghse	21/4.16	22.5/25.2	1971	Core	OA	3-phase	No
		Wstghse	21/2.4	8.00/8.96	1971	Core	OA	3-phase	No
		GE	345/4.16	22.5/25.2	1971	??	OA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	345/4.16	22.5/25.2	1971	Shell	OA	3-phase	No
		GE	345/2.4	9.5/10.64	1971	??	OA	3-phase	No
		Wstghse	345/4.16	22.5/25.2	1971	Shell	OA	3-phase	No
		McGraw	345/2.4		1989	Core	OA	3-phase	Yes
Beaver Valley Pwr									
	Generator Step-Up (GSU)	Wstghse	345/22	1050	11/87	Shell	FOA	3-phase	No
	Unit Auxiliary (UAT)	McGraw	22/4	32	6/76	Shell	FOA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	McGraw	138/4	32	6/81	Shell	FOA	3-phase	Yes
	Spare Transformer(s)	Wstghse	345	1050	Jan-70	Shell	FOA	3-phase	No

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	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Farley									
	Generator Step-Up (GSU)	GE	20.9-230	3@358.4 65C	8/77	Core	FOA	Single	No
		McGraw	20.9-500	3@352.8 65C	5/81	Shell	FOA	Single	No
	Unit Auxiliary (UAT)	Wstghse	22-4.16	37.333 65C	8/77	Core	OA/FA/FOA	3-phase	No
		Wstghse	22-4.16	37.333 65C	5/81	Core	OA/FA/FOA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	230-4.16	48.384 65C	8/77	Core	OA/FA/FOA	3-phase	No
		Wstghse	230-4.16	48.384 65C	5/81	Core	OA/FA/FOA	3-phase	No
	Spare Transformer(s)	GE	20.9-230	3@358.4 65C	N/A	Core	FOA	Single	No
		McGraw	20.9-500	352.8 65C	N/A	Shell	FOA	Single	No
		Wstghse	230-4.16	44.8 65C	N/A	Core	OA/FA/FOA	3-phase	No

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	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Dresden Station	(Unit 2)								
	Generator Step-Up (GSU)	GE	345/199-17.1	850@55	1970	Core	FOA	3-phase	No
				952@65					
	Unit Auxiliary (UAT)	GE	17.1-4.16/2.44	27.6 OA@55	Re-	Core	OA/FA/FOA	3-phase	No
			.16/2.4	36.8FA@55	blocked				
				46FOA@55	6/95				
				51.52FOA@65					
	Startup or Reserve Auxiliary (SAT/RAT)	Federal	138/79.6-4.16/2.4	27.6OA@55	1990	Core	OA/FA/FOA	3-phase	No
		Pacific	4.16/2.4	36.8FA@55					
				46FOA@55					
				51.52FOA@65					
	Spare Transformer(s)	GE	345/199-17.1	850@55	Repaired	Core	FOA	3-phase	No
				952@65	1999				
		GE	138/79.69-4.16/2.4	27.6 OA@55	Repaired	Core	OA/FA/FOA	3-phase	No
			4.16/2.4	36.8FA@55	Jun-05				
				46FOA@55					
				51.52FOA@65					
	(Unit 3)								
	Generator Step-Up (GSU)	ABB	345/199-17.1	850@55	1999	Shell	FOA	3-phase	No
				952@65					
	Unit Auxiliary (UAT)	GE	17.1-4.16/2.44	27.6 OA@55	Re-	Core	OA/FA/FOA	3-phase	No
			.16/2.4	36.8FA@55	blocked				
				46FOA@55	6/99				
				51.52FOA@65					
	Startup or Reserve Auxiliary (SAT/RAT)	GE	345/79.6-4.16/2.4	27.6OA@55	Re-	Core	OA/FA/FOA	3-phase	No
			4.16/2.4	36.8FA@55	blocked				
				46FOA@55	5/97				
				51.52FOA@65					
	Spare Transformer(s)	GE	345/79.6-4.16/2.4	27.6 OA@55	Re-	Core	FOA	3-phase	No
			4.16/2.4	36.8FA@55	blocked				
				46FOA@55	1999				
				51.52FOA@65					

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	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Diablo Canyon Pwr	(Unit 2)								
	Generator Step-Up (GSU)	Elin	25/525	440/492.8	10/99	Core	FOA	Single	No
	Unit Auxiliary (UAT)	UST	25/12	33.75/45/56.25	4/98	Core	OA/FA/FOA	3-phase	No
		FPE	25/4.16	24/32/40	1974	Core	OA/FA/FA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	ABB	230/122	40/60/75	4/97	Core	OA/FA/FA	3-phase	Yes
		FPE	12/4.16	24/32/40	1974	Core	OA/FA/FA	3-phase	No
	Spare Transformer(s)	Wstghse	25/12	33.75/45/56.25		Core	OA/FA/FA	3-phase	No
		FPE	12/4.16	24/32/40		Core	OA/FA/FA	3-phase	No
Diablo Canyon Pwr	(Unit 1)								
	Generator Step-Up (GSU)	GE	25/525	440/492.8	10/95	Core	FOA	Single	No
	Unit Auxiliary (UAT)	UST	25/12	33.75/45/56.25	2/96	Core	OA/FA/FOA	3-phase	No
		FPE	25/4.16	24/32/40	1974	Core	OA/FA/FA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	ABB	230/12	40/60/75	11/97	Core	OA/FA/FA	3-phase	Yes
		Wagner	12/4.16	24/32/40	1974	Core	OA/FA/FA	3-phase	No
	Spare Transformer(s)	GE	25/525	440/492.8		Core	FOA	3-phase	No
		FPE	25/4.16	24/32/40		Core	OA/FA/FA	3-phase	No
Songs									
	Generator Step-Up (GSU)	GE	230	1230/1378	1983		FOA	3-phase	No
					1984				
	Unit Auxiliary (UAT)	Wstghse	22	22.5/30	1983		OA/FOA	3-phase	Yes
				33.6@65C	1984				
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	230	30/40	1983		OA/FOA	3-phase	Yes
				44.8@65C	1984				
	Spare Transformer(s)	GE	230	1230/1378	1983		FOA	3-phase	No
		Wstghse	230	30/40	1983		OA/FOA	3-phase	Yes

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	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Indian Point 2									
	Generator Step-Up (GSU)	Wstghse	345/20.3	542/607	1973	Core	FOA	3-phase	No
	Unit Auxiliary (UAT)	Wstghse	22/6.9	43/48.1	1973	Core	FOA	3-phase	Yes
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	138/6.9	43/48.1	1973	Core	FOA	3-phase	Yes
	Spare Transformer(s)	Federal	138/6.9	43/48.1	N/A	Core	FOA	3-phase	Yes
		Pacific							
Millstone 2									
	Generator Step-Up (GSU)	ASEA	345/22.8	945	1973	Shell	FOA	3-phase	No
	Unit Auxiliary (UAT)	GE	22.8/6.9/4.16	24/32/45	1/86	Shell	OA/FA/FOA	3-phase	No
					1/86		OA/FA/FOA		
	Startup or Reserve Auxiliary (SAT/RAT)	GE	345/6.9/4.16	24/32/45	1/86	Shell	OA/FA/FOA	3-phase	No
					1/86				
	Spare Transformer(s)	ASEA	345/22.8	880	N/A/	Shell	FOA	3-phase	No
Point Beach NP									
	Generator Step-Up (GSU)	McGraw	19/345	181/203	1970		FOA	Single	No
		Wstghse	19/345	203	1986		FOA	Single	No
	Unit Auxiliary (UAT)	Wstghse	19/4.16	28/37.3/31.4/41.8	1970		OA/FA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	13.8/4.16	28/37.3/31.4/41.8	1970		OA/FA	3-phase	No
					1/86				
	Spare Transformer(s)	McGraw-GSU							
	SAT/RAT	Wstghse							

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	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
DAEC									
	Generator Step-Up (GSU)	Wstghse	161/22	660	1974	Shell	FOA	Single	No
	Unit Auxiliary (UAT)	Wstghse	22/4.16	39	1974	Core	FOA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	McGraw	161/4.16	41.67	1974	Core	FOA	3-phase	No
	Spare Transformer(s)	Spare Stepup	161/22	220	1974	Shell	FOA	Single	No
		phase							
Bruce Power A									
	Generator Step-Up (GSU)	Wstghse	525	275	1981	Core	OFAF	3x single	Off load
									525
	Unit Auxiliary (UAT)	Wstghse	22.8/13.8	70	1981	Core	OFAF	3-phase	On load
								2 sec	13.8
								windings	
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	5010/13.8	70	1981	Core	OFAF	3-phase	On load
								2 sec	13.8
								windings	
	Distribution Transformer(s)	Federal Pioneer	13.8/4.16	10	1981		ONAN	3-phase	Off load
									13.8
		Federal Pioneer	13.8/6.7	10	1981		ONAN	3-phase	No
							Silicon Oil		
		Federal Pioneer	13.8/0.600	10	1981		ONAN	3-phase	Off load
									13.8
	Spare Transformer(s)	Federal Pioneer	13.8/.600	10	1981		ONAN	3-phase	Off load
									13.8
		Federal Pioneer	13.8/4.16	10	1981		ONAN	3-phase	Off load
									13.8
		Federal Pioneer	13.8/6.7	10	1981		ONAN	3-phase	No
							Silicon Oil		
		Wstghse	525	275	1981	Core	OFAF	1x single	Off load

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	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
OPG-Darlington									
	Generator Step-Up (GSU)	Wstghse/ABB	525	330	1990-93	Core	OF/AF	Single	No
	Unit Auxiliary (UAT)	Wstghse/ABB	22	80	1990-93	Core	OF/AF	3-phase	Yes
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse/ABB	500	80	1990-93	Core	OF/AF	3-phase	Yes
	Spare Transformer(s)	ABB	500	330	Spare	Core	OF/AF	Single	No
E.I. Hatch									
	Generator Step-Up (GSU)	GE	230/24	900/1008	1/74		FOA	3-phase	No
		GE	500/24	297/332.6	1/74		FOA	Single	No
	Unit Auxiliary (UAT)- 1A & 2A	GE	24/4.16	18/24/30	1/74		OA/FA/FOA	3-phase	No
	1B & 2B	GE	24/4.16	15/20/25	1/74		OA/FA/FOA	3-phase	No
	(SAT/RAT)-1C & 2C	GE	230/4.16	15/20/25	1/74		OA/FA/FOA	3-phase	No
	1D & 2D	GE	230/4.16	18/24/30	1/74		OA/FA/FOA	3-phase	No
	Spare Transformer(s)-GSU Unit 2	GE	500/24	333			FOA	Single	No
	SAT	McGraw	230/13.8/4.16	40			OA/FOA	3-phase	No
	Unit 1 GSU		230/24	800			FOA	3-phase	No
Entergy—Pilgrim Sta.									
	Generator Step-Up (GSU)	ABB	345/22.8	880@55	1999	Shell	FOA	3-phase	No
	Unit Auxiliary (UAT)	Wstghse	23/4.16	33.3@55	1972	Core	OA/FA/FOA	3-phase	No
				37.3@65				Dual Sec.	
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	345/4.16	33.3@55	1972	Core	OA/FA/FOA	3-phase	No
				37.3@65				Dual Sec.	
	Shutdown Transformer (SDT)	Wstghse	23/4.16	5	1972	Core	OA	3-phase	No
	Spare Transformer(s)	Wstghse	345/22.8	880@65	Spare	Shell	FOA	3-phase	No

List of Nuclear Plant Power Transformers

Plant	Equipment	Manf.	Voltage	Pwr Rating	Service	Form	Type of	Winding	Load Tap
	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Browns Ferry NP									
	Generator Step-Up (GSU)	Ferranti	500	400	1970	Core	FOA	Single	No
	GSU	ASEA		448	1970	Core	FOA	Single	No
	Unit Auxiliary (UAT)	Ferranti	24	24/32/40	1970	Core	OA/FA/FOA	3-phase	No
	UAT	ASEA		24/32	1970	Core	OA/FA	3-phase	Yes
	Startup or Reserve Auxiliary (SAT/RAT)	GE	161	40.88	1970	Core	OA/FA/FOA	3-phase	Yes
		GE	161	40.88	1970	Core	OA/FA/FOA	3-phase	No
	Spare Transformer(s)	ASEA	500	448	1970	Core	FOA	Single	No
Point Lepreau									
	Generator Step-Up (GSU)	ASEA Brown	345/26	152-202-252	1995	Core	ONAF	3-phase	OFF
	Unit Auxiliary (UAT)	Feranti	26/13.8	-42-52-70	1981	Core	ONAF	3-phase	OFF
			13.8						
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	345/13.8	42-56-70	1978	Core	ONAF	3-phase	ON
				40.88					
	Spare Transformer(s)	Wstghse	345/13.8	152-202-252	Never	Core	ONAF	Single	OFF
	Spare Transformer(s)	Canadian GE	345/13.8	42-56-70	Never	Core	ONAF	3-phase	ON
Columbia Generating									
	Generator Step-Up (GSU)	ASEA	25/500	380/425	1983		FOA	Single	No
	Unit Auxiliary (UAT)	RTE-ASEA	25/4.16	40/44.8	1983		OA/FA	3-phase	No
		RTE-ASEA	25/6.9	31.25/35	1983		OA/FA	3-phase	No
	Startup Auxiliary (SAT)	ASEA	230/4.16/6.9	-/70	1983		OA/FA	3-phase	No
	Reserve Auxiliary (RAT)	RTE-ASEA	115/4.16	12.5/14	1983		OA/FA	3-phase	No

List of Nuclear Plant Power Transformers

Plant	Equipment	Manf.	Voltage	Pwr Rating	Service	Form	Type of	Winding	Load Tap
	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Arkansas Nuclear One									
	Generator Step-Up (GSU)	Wstghse	500/22	315@65C	1974	Shell	FOA	Single	No
	Unit Auxiliary (UAT)	GE	22/6.9/4.16	50@65C	1974	Core	OA/FA/FOA	3-phase	No
					1974	Core	OA/FA/FOA	3-phase	No
	Startup Auxiliary (SAT)	GE	22/6.9/4.16	45@65C	1974	Core	OA/FA/FOA	3-phase	No
	SAT shared	GE	161/6.9/4.16	45@65C	1974	Core	OA/FA/FOA	3-phase	No
	Spare Transformer(s)-SAT	GE	161/6.9/4.16	45@65C	1974	Core	OA/FA/FOA	3-phase	No
	Spare Main Phase	Wstghse	500/22	315@65C	1974	Shell	FOA	Single	No
	Spare Main Break	GE	500/22	465@65C	1979	Core	FOA	Single	No
Arkansas Nuclear One									
	Generator Step-Up (GSU)	GE	500/22	333@65C	1978	Core	FOA	Single	No
	Unit Auxiliary (UAT)	GE	22/6.9/4.16	58.5@65C	1974	Core	OA/FA/FOA	3-phase	No
	Startup Auxiliary (SAT)	GE	22/6.9/4.16	58.5@65C	1974	Core	OA/FA/FOA	3-phase	No
	SAT shared	GE	161/6.9/4.16	45@65C	1974	Core	OA/FA/FOA	3-phase	No
Oconee									
	Generator Step-Up (GSU)	Wstghse	18/230	1000	1972	Core	FOA	3-phase	No
	Unit Auxiliary (UAT)	GE	18/6.9/4.16	45/67.5	1972	Core	OA/FA	3-phase	No
			13.8						
	Startup or Reserve Auxiliary (SAT/RAT)	GE	230/6.9/4.16	45/67.5	1972	Core	OA/FA	3-phase	No
				40.88					
	Spare Transformer(s)	Wstghse	18/230	760	1985	Core	FOA	3-phase	No
	Spare Transformer(s)	GE	230/6.9/4.16	45/67.5	1990	Core	OA/FA	3-phase	No

List of Nuclear Plant Power Transformers

Plant	Equipment	Manf.	Voltage	Pwr Rating	Service	Form	Type of	Winding	Load Tap
	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
James A Fitzpatrick									
	Generator Step-Up (GSU)	GE	345/22.8	445/498.4	1974		OA/FOA	3-phase	No
	Unit Auxiliary (UAT)	GE	24/4	40/44.8	1974		OA/FOA	3-phase	Yes
			13.8						
	Startup or Reserve Auxiliary (SAT/RAT)	GE	115/4	20/22.4	1974		OA/FA	3-phase	No
	Spare Transformer(s)	Smit-Nymegen	115/4	20/22.4	N/A		OA	3-phase	No
			230/6.9/4.16						
VC Summer									
	Generator Step-Up (GSU)	Wstghse	22/230	940/1052.8	1994	Shell	OA/FOA	3-phase	Yes
	Unit Auxiliary (UAT)	Wstghse	22/7.2	64/71.68	1978	Core	OA/FA	3-phase	Yes
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	230/7.2	40/44.8	1978	Core	OA/FA/FOA	3-phase	Yes
	SAT/RAT	Wstghse	115/7.2	12.5/14	1978	Core	OA/FA	3-phase	Yes
	Spare Transformer(s)	Wstghse	22/230	940/1052.8	1978	Shell	OA/FOA	3-phase	Yes
River Bend									
	Generator Step-Up (GSU)	Wstghse	22/230	518	1985		FOA/FOA	3-phase	No
	Unit Auxiliary (UAT)	Wstghse	22/13.8	47.5	1985		FOA/FOA	3-phase	No
	UAT	Wstghse	22/4.16	16					
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	230/13.8	85	1989		OA/FOA/FOA	3-phase	Yes/No
	SAT/RAT	Wstghse	230/4.16	12.5	1985		OA/FA	3-phase	
	Spare Transformer(s)	Wstghse	230/4.16	12.5			OA/FOA	3-phase	No
	Spare Transformer(s)	Wstghse	230/13.8	60					

List of Nuclear Plant Power Transformers

Plant	Equipment	Manf.	Voltage	Pwr Rating	Service	Form	Type of	Winding	Load Tap
	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Watts Bar									
	Generator Step-Up (GSU)	GE	500	430/455	1975	Core	FOA	Single	No
	Unit Auxiliary (UAT)	Wagner	22.5	30/40	1975	Core	OA/FA	3-phase	No
				16					
	Startup or Reserve Auxiliary (SAT/RAT)	Wagner	161	51/76	1975	Core	OA/FA	3-phase	No
	SAT/RAT	ABB	161	33/55	1975	Core	FOA	3-phase	Yes
	Spare Transformer(s)	GE	500	430	1975	Core	FOA	Single	No
Seabrook Station									
	Generator Step-Up (GSU)	GE	345-24.5	410@55C 46@65C	1986	Core	FOA	Single	No
	Unit Auxiliary (UAT)	GE	24500-13800/4300	36@55C 40.3@65C	1986	Core	OA/FA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	345-13800/4300	36@55C 40@65C	1986	Core	OA/FA	3-phase	No
Pickering "B"									
	Generator Step-Up (GSU)	Wstghse	22.8/235	575@65C	1981	Core	ODWF	3-phase	No
	Unit Auxiliary (UAT)	GE	24/4.16	21.6/36@65C	1981	Core	ONAN/ONAF	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	GE	230/4.16	21.6-36@65C	1981	Core	ONAN/ONAF	3-phase	No
	Spare Transformer(s)	GE	22.8/235	575@65C	1981	Core	ODWF	3-phase	No

List of Nuclear Plant Power Transformers

Plant	Equipment	Manf.	Voltage	Pwr Rating	Service	Form	Type of	Winding	Load Tap
	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Sequoyah									
	Generator Step-Up (GSU)	ASEA	500/22.5	415/465@55C	1975	Core	OA/FA	Single	No
	GSU	ASEA	161/22.5	420/470@55C	1979	Core	OA/FA	Single	No
	Unit Auxiliary (UAT)	ASEA	22.5/6.9	21/28	1979	Core	OA/FA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	ABB	161/6.9/6.9	33/44/55	1991	Core	OA/FA/FOA	3-phase	Yes
	Spare Transformer(s)	ASEA	500/22.5	415/465@55C	1975	Core	OA/FA	Single	No
	Spare Transformer(s)	ASEA	161/22.5	420/470@55C	1979		OA/FA	Single	No
	Spare Transformer(s)	ABB	161/6.9/6.9	33/44/55	1991		OA/FA/FOA	3-phase	Yes
Three Mile Island									
	Generator Step-Up (GSU)	McGraw	230/18.05	485@55C	1974	Shell	FOA	3-phase	No
	Unit Auxiliary (UAT)								
	Startup or Reserve Auxiliary (SAT/RAT)	GE	230/6.9/4	33@55	1972	Core	OA/FA/FOA	3-phase	No
	Spare Transformer(s)	BBC	230/24-13.8	427	1979	Core	FOA	3-phase	No
North Anna									
	Generator Step-Up (GSU)	McGraw	22/500	288.7	1978	Shell	FOA	Single	No
	Unit Auxiliary (UAT)	Wstghse	22/4.16	22.4	1978	Core	OA/FA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	GE	34.5/4.16	33.6	1974	Core	OA/FA/FOA	3-phase	Yes

List of Nuclear Plant Power Transformers

Plant	Equipment	Manf.	Voltage	Pwr Rating	Service	Form	Type of	Winding	Load Tap
	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Cooper Nuclear									
	Generator Step-Up (GSU)	McGraw	21/345	300/330	1974	Core	FOA	Single	No
	Unit Auxiliary (UAT)	RTE-ASEA	21/4.16	10.8/14.4/18	1984	Core	OA/FA/FA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	Federal Pacific	161/4.16	10.8/14.4/18	1974	Core	OA/FA/FA	3-phase	No
	RAT	Federal Pacific	69/4.16	9/10/12.6	1974	Core	OA/FA/FA	3-phase	No
	Spare Transformer(s)	McGraw	21/345	300/330	N/A	Core	FOA	Single	No
Gentilly 2									
	Generator Step-Up (GSU)	ABB	230/24	775	1979	Core	OA/FA/FOA	3-phase	No
	Unit Auxiliary (UAT)	CGE	230/6.9/6.9	48/64	1979	Core	OA/FA	3-phase	Yes
	Startup or Reserve Auxiliary (SAT/RAT)	Ferranti Packard	230/6.9/6.9	48/64	1990	Core	OA/FA	3-phase	Yes
	Spare Transformer(s)	ABB	230/24	775	1995	Core	OA/FA/FOA	3-phase	No
Ginna Station									
	Generator Step-Up (GSU)	GE	120700/19000	550000/616000	1996	Core	FOA	3-phase	No
	Unit Auxiliary (UAT)	Wstghse	19000/4160	28000/37333	1969	Core	OA/FA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	34500/4160	28000/37333	1969	Core	OA/FA	3-phase	No
	Spare Transformer(s)	Wstghse	120700/19000	578000/647360	1969	Shell	FOA	3-phase	No

List of Nuclear Plant Power Transformers

Plant	Equipment	Manf.	Voltage	Pwr Rating	Service	Form	Type of	Winding	Load Tap
	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Oyster Creek									
	Generator Step-Up (GSU)	GE	24/240	325	1969	Core	FOA	3-phase	No
	GSU	GE	23/230	392	1989	Core	FOA	3-phase	No
	Unit Auxiliary (UAT)	GE	24/4.16	18/24/30	1969	Core	OA/FA/FOA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	GE	34.5/4.16	12/16/20	1969	Core	OA/FA/FOA	3-phase	No
	Spare Transformer(s)	GE	24/240	325	1969	Core	FOA	3-phase	No
St Lucie									
	Generator Step-Up (GSU)	ABB	235/21	475	1998	Shell	FOA	3-phase	No
	GSU	McGraw	235/21	475	1986	Shell	FOA	3-phase	No
	Unit Auxiliary (UAT)	GE	21/6.9/4.16	39/24/15	1976	Core	OA/FA/FOA	3-phase	No
	UAT	Wstghse	21/6.9/4.16	39/24/15	1983	Core	OA/FA/FOA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	GE	21/6.9/4.16	39/24/15	1976	Core	OA/FA/FOA	3-phase	No
	SAT	Wstghse	21/6.9/4.16	39/24/15	1983	Core	OA/FA/FOA	3-phase	No
	Spare Transformer(s)	ABB	235/21	475	N/A	Shell	FOA	3-phase	No
PPL Susquehanna									
	Generator Step-Up (GSU)	Unit 1-W	230	2-607	1983	Shell	FOA	3-phase	Manual
		Unit 2-ABB	500	3-420	1990s	Shell	FOA	Single	Manual
	Unit Auxiliary (UAT)	McGraw	23-13.8	55-61.6	1983	Core	OA/FA/FOA	3-phase	Manual
	Startup or Reserve Auxiliary (SAT/RAT)	Fed Pacific	230-13.8	75	1983	Shell	OA/FA/FOA	3-phase	Auto.
					1/86				
	Spare Transformer(s)	Wstghse w/ABB	230	850	N/A	Shell	FOA	3-phase	Manual
			500	420	N/A	Shell	FOA	Single	Manual

List of Nuclear Plant Power Transformers

Plant	Equipment	Manf.	Voltage	Pwr Rating	Service	Form	Type of	Winding	Load Tap
	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Comanche Peak									
	Generator Step-Up (GSU)	ABB	20.9/345	650	1993	Shell	FOA	3-phase	No
		Wstghse	20.9/345	650	1982	Shell	FOA	3-phase	No
		Wstghse	20.9/345	650	1987	Shell	FOA	3-phase	No
		Wstghse	20.9/345	650	1987	Shell	FOA	3-phase	No
	Unit Auxiliary (UAT)	GE	22/6.9	56	1983	Shell	OA/FA	3-phase	No
		GE	22/6.9	56	1988	Shell	OA/FA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	345/6.9	58.333	1988	Shell	OA/FOA	3-phase	No
		Wstghse	345/6.9	58.333	1988	Shell	OA/FOA	3-phase	No
		Wstghse	138/6.9	58.333	1978	Shell	FOA	3-phase	No
		Wstghse	345/6.9	58.333	1978	Shell	FOA	3-phase	No
	Spare Transformer(s)	Wstghse	20.9/345	650	1979	Shell	FOA	3-phase	No
		Wstghse	138/345/6.9	58.333		Shell	FOA	3-phase	No
Callaway									
	Generator Step-Up (GSU)	Wstghse	345	415	1984	Shell	FOA	Single	No
	Unit Auxiliary (UAT)	GE	25	100	1984	Core	OA/FA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	345	100	1984	Shell	FOA	3-phase	No
					1/86				
	Spare Transformer(s)	Wstghse	345	415	1984	Shell	FOA	Single	No
Crystal River									
	Generator Step-Up (GSU)	Wstghse	22/500	316.667	1979	Shell	FOA	Single	No
	Unit Auxiliary (UAT)	GE	22/4.16/6.9	33/44/55	1979	Core	OA/FA/FOA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	GE	22/4.16/6.9	33/44/55	1979	Core	OA/FA/FOA	3-phase	No
					1/86				
	Spare Transformer(s)	GE	230/4.16	12/16/20	1990	Core	OA/FA/FOA	3-phase	No
		GE	230/4.16	12/16/20	1991	Core	OA/FA/FOA	3-phase	No

List of Nuclear Plant Power Transformers

Plant	Equipment	Manf.	Voltage	Pwr Rating	Service	Form	Type of	Winding	Load Tap
	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Waterford 3									
	Generator Step-Up (GSU)	ABB	230	600	1985	Core	FOA	3-phase	No
	Unit Auxiliary (UAT)	Fed Pacific	25	39/52	1985	Core	OA/FOA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	Wstghse	230	33.6/44.8/56	1985	Core	OA/FA/FOA	3-phase	No
		ABB	230	33.6/44.8/56	1985	Core	OA/FA/FOA	3-phase	No
	Spare Transformer(s)								
Limerick Generating	Generator Step-Up (GSU)	Wstghse	230	387	1983	Shell	FOA	Single	No
		McGraw	500	422	1987	Shell	FOA	Single	No
	Unit Auxiliary (UAT)	Wstghse	22	31.5/42.0/52.5	1983	Shell	OA/FA/FOA	3-phase	No
		Wstghse	22	31.5/42.0/52.5	1987	Shell	OA/FA/FOA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	McGraw	230	37.0/49.3/61.6			OA/FA/FOA	3-phase	Yes
		Wstghse	13.2	35.0/46.7/58.3			OA/FA/FA	3-phase	Yes
	Spare Transformer(s)	Wstghse	230	387	N/A	Shell	FOA	Single	No
		McGraw	500	422	N/A	Shell	FOA	Single	No
Brunswick	Generator Step-Up (GSU)	GE	230/24	320	1972	Core	FOA	Single	No
	Unit Auxiliary (UAT)	Wstghse	24/4.16	27/36/45	1972	Core	FOA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	GE	230/4.16	27/36/45	1972	Core	FOA	3-phase	No
	Spare Transformer(s)								

List of Nuclear Plant Power Transformers

Plant	Equipment	Manf.	Voltage	Pwr Rating	Service	Form	Type of	Winding	Load Tap
	Description		Rating (kV)	MVA (55-65C)	Date		Cooling	Design	Changer
Wolf Creek	Generator Step-Up (GSU)	Wstghse	25/345	448	1985	Shell	FOA	Single	No
	Unit Auxiliary (UAT)	GE	25/13.8	100	1985	Shell	OA/FA	3-phase	No
	Startup or Reserve Auxiliary (SAT/RAT)	Wstgse	345/13.8	100	1985	Shell	FOA	3-phase	No
	Spare Transformer(s)	Wstghse	25/345	415		Shell	FOA	Single	No
Monticello	Generator Step-Up (GSU)	GE	345/22	650-728	1971	Core	FOA	3- phase	No
	Unit Auxiliary (UAT)	Wstghse	345/4.16	50-56	1986	Core	FOA	3-phase	Yes
	Spare Transformer(s)	Moloney	14/4.33	7.5	1971	Core	OA	3-phase	No
Coronado	Generator Step-Up (GSU)	GE	525/20.9	402/450			FOA/FOA		
		GE	525/20.9	402/450			FOA/FOA		
	Unit Auxiliary (UAT)	FPE	20.9/13.8/13.8	50.4/67.2/80.8			OA/FA/FA		
		GE	13.8/4.16/4.16	13.5/18/20.2			OA/FA		
		GE	13.8/4.16/4.16	13.5/18/20.2			OA/FA		
		GE	13.8/4.16	4/5/5.6			OA/FA		
		FPE	20.9/13.8/13.8	50.4/67.2/80.8			OA/FA/FA		
		GE	13.8/4.16/4.16	13.5/18/20.2			OA/FA		
		GE	13.8/4.16/4.16	13.5/18/20.2			OA/FA		
		McGraw	525/13.8/13.8	49.5/65.8/82.2			OA/FA/FA		
		GE	13.8/4.16	4/4.5			OA		
		GE	13.8/4.16	4/4.5			OA		
	Spare Transformer(s)	GE	525/20.9	402/450			FOA/FOA		
		McGraw	525/13.8/13.8	49.5/65.8/82.2			OA/FA/FA		
		GE	13.8/4.16/4.16	13.5/18/20.2			OA/FA		

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LIST OF NUCLEAR PLANT BUS DUCTS

Plant	Equipment Description	Manufacturer	In-Service Date	Voltage Rating (kV)	Current Rating
Calvert Cliffs Nuclear	Isolated Phase Bus Duct	Delta Uni-Bus	1975/1976	22/25	18kA
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
D.C. Cook	Isolated Phase Bus Duct	GE	1975 1978	35	30000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
Grand Gulf	Isolated Phase Bus Duct	Delta-Star	July 1984	25	42,500@65C Rise
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
H.B. Robinson	Isolated Phase Bus Duct	Wstghse (Delta Uni-Bus)	1970	25 (150kV B.I.L.)	12,000 (Amb. Air Cooled) 25,000 (Forced Air)
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	Wstghse	1970	5	4000 (Amb. Air Cooled)
McGuire Nuclear	Isolated Phase Bus Duct	GE	1973	24	4000FA/2000Self
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	West	1973	6.9kV&13.8kV	
Millstone 3	Isolated Phase Bus Duct	GE	1/86	24	34,4000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	Wstghse	1/86	6.9	2200
Nine Mile Point 2	Isolated Phase Bus Duct	H.K. Porter/ Delta-Unibus	1982	25	32,800
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	H.K. Porter/ Delta-Unibus	1982	4.16 13.8	3000/1200 3000/1200

List of Nuclear Plant Bus Ducts

Plant	Equipment Description	Manufacturer	In-Service Date	Voltage Rating (kV)	Current Rating
Perry Nuclear	Isolated Phase Bus Duct	H.K. Porter/	1985	22	40000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
O.P.P.D Ft. Calhoun	Isolated Phase Bus Duct	GE	9/73	22	16,280
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	GE	Sep-73	5	3000
Salem/Hope Creek	Isolated Phase Bus Duct	H.K. Porter (all three units)	1977 1981, 1986		
	Segregated Bus Duct	H.K. Porter (all three units)	1977 1981, 1986		
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
Shearon Harris	Isolated Phase Bus Duct				
	Segregated Bus Duct				
	Non-Segregated Bus Duct				
South Texas Project	Isolated Phase Bus Duct	GE	1986	25	31kA Forced Air
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	Wstghse	1986	15	2500
Vogtle	Isolated Phase Bus Duct	Delta Unibus	1986	25	32,818
			1986	25	
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
Palisades	Isolated Phase Bus Duct	Delta Unibus	1971	22	26400 Forced Cooled
		Delta Unibus	1971	22	900 Self Cooled
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	Powell	1989	2.4	3000
Beaver Valley Pwr	Isolated Phase Bus Duct	GE Canada	6/76	28	
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A

List of Nuclear Plant Bus Ducts

Plant	Equipment Description	Manufacturer	In-Service Date	Voltage Rating (kV)	Current Rating
Farley	Isolated Phase Bus Duct	GE	8/77	22, 110 BIL	
		Wstghse	5/81	22, 110 BIL	28,867
	Segregated Bus Duct				
	Non-Segregated Bus Duct				
Catawba Nuclear	Isolated Phase Bus Duct	Wstghse	1983	22	40000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
Dresden Station	Isolated Phase Bus Duct	GE	1970	18	33,000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	GE	1970	5	4000
Diablo Canyon Pwr (Unit 2)	Isolated Phase Bus Duct	HK Porter	1975	25	32000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	GE	1975	12	1200-3750
		GE	1975	4	1200-325
Diablo Canyon Pwr (Unit 1)	Isolated Phase Bus Duct	HK Porter	1974	25	32000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	GE	1974	12	1200-3750
		GE	1974	4	1200-3250
Songs	Isolated Phase Bus Duct	Wstghse	1983	22	36300 Forced Cool
			1984		
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
Indian Point 2	Isolated Phase Bus Duct	Wstghse/ Delta Unibus	1973	23	32000
	Segregated Bus Duct	Wstghse	1973	6.9	4000
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
PPL Susquehanna	Isolated Phase Bus Duct	GE-Canada Unit1	1983	24	32,500
		Unit 2	1984	24	
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	ITE	1983/1984	13.8	3000

List of Nuclear Plant Bus Ducts

Plant	Equipment Description	Manufacturer	In-Service Date	Voltage Rating (kV)	Current Rating
PBNP	Isolated Phase Bus Duct	Wstghse	1970	19	20000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	Wstghse	1970	13.8	
DAEC	Isolated Phase Bus Duct	GE	1974	22	18000
	Segregated Bus Duct				
	Non-Segregated Bus Duct	Calvert	1974	4.16	1200
Bruce Power A	Isolated Phase Bus Duct	GE	1981	24	270000
		(Mini-bus)			forced cooled
	Segregated Bus Duct				
	Non-Segregated Bus Duct	ITE	1981	15	2000
Millstone 2	Isolated Phase Bus Duct	H.K. Porter	1973	23	26000
		(Delta-Star)			
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
OPG-Darlington	Isolated Phase Bus Duct	Wstghse	1990-1993	22/24	28800 forced cooling
	Segregated Bus Duct				
	Non-Segregated Bus Duct				
E.I. Hatch	Isolated Phase Bus Duct				
	Segregated Bus Duct				
	Non-Segregated Bus Duct				
Entergy — Pilgrim Sta.	Isolated Phase Bus Duct	H.K Porter	1972	24	20000
		(Delta-Unibus)			
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
Browns Ferry NP	Isolated Phase Bus Duct	H.K Porter	1981		16500 Self cooled
		GE	1970	22	35270 Forced cooled
	Segregated Bus Duct				
	Non-Segregated Bus Duct	GE	1970	4	2000, 3000, & 4000
			1981		

List of Nuclear Plant Bus Ducts

Plant	Equipment Description	Manufacturer	In-Service Date	Voltage Rating (kV)	Current Rating
Point Lepreau	Isolated Phase Bus Duct	ITE Industries	1981	26.4	18000 Forced cooled
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
Columbia Generating	Isolated Phase Bus Duct	H.K. Porter	1983	25	30000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	HK. Porter	1983	5	2500
		HK. Porter	1983	5	4000
		HK. Porter	1983	5	5500
Arkansas Nuclear One	Isolated Phase Bus Duct	GE	1974	22	28000
		HK Porter(Delta-Star)	1978	22	29000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	Delta Star	1974	6.9,4.16	3000, 4000
		Delta Star	1978	6.9, 4.16	3000, 4000
Oconee	Isolated Phase Bus Duct	GE	1972	20	33000/16000 fa/self
	Segregated Bus Duct	ITE	1972	4.16/6.9	2000-4000 both
	Non-Segregated Bus Duct				
James A Fitzpatrick	Isolated Phase Bus Duct	GE	1974	24	24000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	GE	1974	5	2,000
VC Summer	Isolated Phase Bus Duct	GE	1982	22	30450
	Segregated Bus Duct	N/A	N/A	N/A	N/A
River Bend	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
	Isolated Phase Bus Duct	GE	1982	22	30000
Watts Bar	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	GE	1975	7.2	4000

List of Nuclear Plant Bus Ducts

Plant	Equipment Description	Manufacturer	In-Service Date	Voltage Rating (kV)	Current Rating
Seabrook Station	Isolated Phase Bus Duct	HK Porter	1986	25	35000
		(Delta-Unibus)			
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	ITE	1986	5/15	2000
Pickering "B"	Isolated Phase Bus Duct				
	Segregated Bus Duct				
	Non-Segregated Bus Duct				
Sequoyah	Isolated Phase Bus Duct	Wstghse	1975	24	34300
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	Delta-Unibus	1975	6.9	4000
Three Mile Island	Isolated Phase Bus Duct	Wstghse	1974	19	30000
	Segregated Bus Duct				
	Non-Segregated Bus Duct	Calvert	1972	7.2	3000
North Anna				5	4000
	Isolated Phase Bus Duct	GE	1978	22	30000
		GE	1980	22	30000
	Segregated Bus Duct				
Cooper Nuclear	Non-Segregated Bus Duct				
	Isolated Phase Bus Duct	ITE	1974	23	2800
				110	
	Segregated Bus Duct	N/A	N/A	N/A	N/A
Ginna Station					
	Non-Segregated Bus Duct	ITE	1974	4.76	3000
				60	2000
					1200
Gentilly 2	Isolated Phase Bus Duct	Wstghse	1969	19	12000
				110	
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	Unibus	1989	5	3000
		Westinghouse	1969	5	3000
	Isolated Phase Bus Duct	Wstghse	1983	24	2500
				110	
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	CGE	1983	13.8	4000
			1991		

List of Nuclear Plant Bus Ducts

Plant	Equipment Description	Manufacturer	In-Service Date	Voltage Rating (kV)	Current Rating
Oyster Creek	Isolated Phase Bus Duct	GE	1969	24	17500
	Segregated Bus Duct				
	Non-Segregated Bus Duct				
St Lucie	Isolated Phase Bus Duct	Wstghse		23	28000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	Wstghse		6.9/4.16	2000/3000
Waterford 3	Isolated Phase Bus Duct	Wstghse	1985	25	33000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	GE	1985	4.16	1200
Crystal River	Isolated Phase Bus Duct	Wstghse Delta Unibus	1979	22	27500/16000/2000
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	Calvert	1979	5 7.2	1200 1200/2000/3000/4000
Callaway	Isolated Phase Bus Duct	Delta Unibus	1984	25	33500
	Segregated Bus Duct				
	Non-Segregated Bus Duct				
Comanche Peak	Isolated Phase Bus Duct	H. K. Porter		23 23	37000 18000
	Segregated Bus Duct				
	Non-Segregated Bus Duct				
Limerick Generating	Isolated Phase Bus Duct	H. K. Porter H. K. Porter	1982 1987	22 22	20000 20000
	Segregated Bus Duct				
	Non-Segregated Bus Duct				
Brunswick	Isolated Phase Bus Duct	H. K. Porter	1972	24	25000
	Segregated Bus Duct				
	Non-Segregated Bus Duct	ITE	1972	4.16	2000/5000

List of Nuclear Plant Bus Ducts

Plant	Equipment Description	Manufacturer	In-Service Date	Voltage Rating (kV)	Current Rating
Wolf Creek	Isolated Phase Bus Duct	H. K. Porter	1985	26.5	33,500
		(Delta Unibus)			
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	N/A	N/A	N/A	N/A
Monticello	Isolated Phase Bus Duct	GE	1971	22	18,700 Forced
					10,500 Self
	Segregated Bus Duct	N/A	N/A	N/A	N/A
	Non-Segregated Bus Duct	Calvert Company	1986	5	3000
		GE	1971	5	2000
		GE	1971	5	3000

F

POP OUT SUMMARY

The following list provides the location of “Pop Out” information in this report.



Key O&M Cost Point

Emphasizes information that will result in reduced purchase, operating, or maintenance costs.

Location	Topic	Key O&M Cost Point
2.6.3 p. 2-17	Overexcitation	During an emergency situation, short-time overexcitation may be allowed without causing measurable damage to the transformer.
6.2.10 p. 6-6	Maintenance and Repair	Leak repair of large transformers can be extremely costly, especially if major gasket replacements become necessary.
6.5.5 p. 6-20	Power Factor Testing	The cost to conduct power factor tests is high because the transformer has to be taken off line. It should be noted that periodic power factor testing at prescribed intervals is done by most utilities. However, periodic power factor testing is recommended by most insurers even if the oil and other tests are satisfactory.
6.6 p. 6-23	On-line Monitoring	The emphasis on reduced maintenance costs and life extension makes it desirable to have on-line monitoring systems that will provide improved information for determining when maintenance should be performed and for life extension.
7.2.1.1 p. 7-4	Gas-in-Oil Oil Testing	By trending of the various gas results, one not only can identify the type of fault but can also assign a level of seriousness based upon the rate of rise in gas levels. With the use of this data, one can better predict problems and plan outages in advance.
7.3.3 p. 7-9	Maintenance and Repair	For more extreme leaks, a transformer may have to be taken out of service and the radiator removed for more thorough repair. Some repair services will weld radiators while in place and full of oil; however, this is a very risky undertaking.
7.5 p. 7-14	Monitoring	Condition monitoring results are used to monitor and trend equipment performance so that planned maintenance can be performed or the equipment replaced before it fails.

Pop Out Summary

Location	Topic	Key O&M Cost Point
7.6 p. 7-21	Maintenance	While a transformer is under warranty, it is essential that, at a minimum, the user should adhere to the manufacturer's instructions.
7.9 p. 7-25	Maintenance	The life expectancy of a transformer depends mainly on the condition of its insulation system. Moisture- and oxygen-free insulation along with efficient cooling are the keys to maintaining a healthy transformer.
9.8 p. 9-10	Infrared Thermography	Thermographic inspection on a periodic basis is a quick and cost-effective means to detect common problems that result in an abnormal temperature.

**Key Technical Point**

Targets information that will lead to improved equipment reliability.

Location	Topic	Key Technical Point
2.4 p. 2-10	Core	Core loss is a function of voltage; load loss is a function of current.
2.4.1.2 p. 2-13	Insulation	Stray losses are usually evident around the interior of the upper tank where bushings and secondary buses are located.
2.4.1.2 p. 2-13	Insulation	Accidental grounds to the shield will result in circulating currents and hot spots.
2.5 p. 2-14	Core	Overexciting the transformer can greatly increase core losses and core temperature and, in extreme cases, can permanently damage the core.
2.6.2 p. 2-16	Thermal Insulation	Severe overexcitation can cause a transformer failure within a short time; however, less extreme overexcitation can occur without the operator being aware of its existence or consequences. A failure might be separated from the initiating incident by months of normal service operation.
2.6.3 p. 2-18	Oil Testing	After a generator trip or load rejection, a GSU oil sample and analysis should be done
2.6.4 p. 2-18	Monitoring	In particular, separate volts per hertz detection should be installed on all unit-connected generator-transformer combinations to sense and control overexcitation.
3.5.1 p. 3-15	Insulation Testing	As paper ages, it becomes brittle. A measure of the brittleness can be determined by a test called degree of polymerization (DP).
4.3.1 p. 4-5	Insulation	Operation of transformers beyond their normal designed and operating rating causes loss of transformer life and should be avoided if at all possible.

Location	Topic	Key Technical Point
4.4.3 p. 4-6	Insulating Oil	Low oil level could endanger the transformer by exposing the core and coil.
5.2.5 p. 5-3	Maintenance	Blocking material might shrink over time, thus requiring core reclamping.
5.4.2 p. 5-6	Maintenance	Core looseness is not a commonly expected condition.
5.4.4 p. 5-8	Gas-in-Oil	Excess moisture in paper insulation that is released quickly by temperature excursions can produce bubbles of water vapor.
5.4.4 p. 5-8	Gas-in-Oil	A unit running at very high oil temperatures with a nitrogen supply set at high pressure will absorb high levels of nitrogen in the oil. If this oil is then rapidly cooled, nitrogen bubbles could form.
5.4.6 p. 5-9	Bushing Maintenance	Periodic cleaning and special coatings such as silicon grease, wax, or elastomers are used to limit the build up of contaminants on the surface of bushings.
6.2.10 p. 6-5	Maintenance	Oil leaks can originate from gas relay piping, valve packing, CT pockets, tap changers, radiators, and main tank covers. Covers are usually a major source of oil leaks if the installation is not done properly or materials are not compatible.
6.3 p. 6-6	Testing	Design tests are made by the manufacturer to determine the adequacy of a specific transformer design.
6.5.1.2 p. 6-12	Oil Testing Dielectric Strength	There are two test methods for determining the dielectric strength of oil. In the main tank, the ASTM D1816 method should be used. Generally, the ASTM D1816 method is more responsive to dissolved water and particles in the oil.
6.5.1.2 p. 6-12	LTC Testing	If the tap changer has sharp, uninsulated electrodes, the ASTM D877 method should be used. Otherwise, use the ASTM D1816 method, which is more suitable when insulated or well-rounded electrodes are used in the tap changer.
6.5.3 p. 6-16	Windings	The ratio in particular is checked during regular (for example, annual) inspections, and it is recommended that it be checked before returning the transformer to service if the unit has been subjected to a through-fault or if the setting of the de-energized tap changer has been changed.
6.5.5 p. 6-19	Insulation Testing	An insulation resistance test should be used to determine if the insulation is dry and clean before doing tests such as power factor, dissipation factor, or other tests.
6.5.5 p. 6-20	Insulation Testing	Power factor testing requires the transformer to be taken off line and test equipment and service personnel sent to the station.

Pop Out Summary

Location	Topic	Key O&M Cost Point
6.8 p. 6-38	Infrared Thermography	Thermography is considered by many to be the easiest and most productive method of finding potential problems before they become failures.
7.3.1 p. 7-7	Bushing Maintenance	As a bushing becomes more and more contaminated, corona will creep lower and lower. If corona seems to be lower than normal on a bushing, inspect and clean the bushing, and then perform a power factor test as soon as possible.
7.3.2 p. 7-8	Bushing Maintenance	Bushings should be cleaned before power factor testing in order to provide trendable data from test to test.
7.3.3 p. 7-9	Cooling	Before using any cleaning method, be sure to review vendor recommendations to ensure that cleaning methods do not damage and/or promote radiator corrosion.
7.3.4.1 p. 7-10	Maintenance	Sealed tank systems can be backfitted with a desiccant-type dryer on the bleeder valve in order to prevent the introduction of moisture and oxygen into the transformer tank.
7.3.4.1 p. 7-10	Maintenance	Caution: When replacing nitrogen cylinders, do not use a typical nitrogen cylinder from the local welding supplier. Transformers require nitrogen that meets ASTM D1933 Type III, which has a -59°C dew point as specified by paragraph 6.6.6.3 of IEEE C57.12-1993.
7.3.4.3 p. 7-11	Maintenance	Every three to five years, the conservator inspection flange should be opened, and the internal of the conservator should be inspected. If the bladder has been perforated, oil will be present on the top of the bladder, and it should be replaced.
7.7 p. 7-21	Spare Transformers	A spare transformer should be set up in a permanent location on a concrete pad. Such large power transformers should never be stored on rollers, blocks, or jacks.
8.1 p. 8-1	Maintenance	Precautions should be taken not to enter the transformer until the gas in the tank is replaced by dry air and the oxygen content is at least 19.5%.
8.5 p. 8-6	Vacuum & Oil Filling	The transformer should not be left under vacuum except during the filling process with the vacuum pump operating. If there are any leaks in the transformer or the connecting external pipes from the oil processing equipment, moisture could enter the tank.
9.8 p. 9-10	Bus Ducts	Bus ducts should be checked with thermography prior to shutdown to identify any localized hot spots or hot spot connections.
9.8 p. 9-11	Bus Ducts	Bus duct cooler blowers for the isophase bus ducts must be run with cooling water OFF for several hours prior to performing insulation resistance testing. This allows drying time for isophase bus duct insulators.



Key Human Performance Point

Denotes information that requires personnel action or consideration in order to prevent injury or damage or ease completion of the task.

Location	Topic	Key Human Performance Point
3.9.1 p. 3-26	No-Load Tap Changers	Prior to initial energization or after the taps have been changed, the transformer turns ratio (TTR) test should be performed to check that the contacts have seated properly and, therefore, that each winding has the same ratio.
3.12.1 p. 3-35	PT Secondary Fuses	Isolation of a PT by pulling primary fuses is important for safety reasons to prevent accidental backfeeding from the secondary fuses.
3.12.2 p. 3-38	Current Transformers	CT circuits should never be open while in service. Destructive arcing and a violent fireball will occur if the primary is energized.
3.12.2 p. 3-38	Current Transformers	Anyone working with CTs must always be sure that the secondary terminal points of the CT are in a closed circuit, and if not, they should be shorted together.
6.5.1 p. 6-9	Gas-in-Oil	When taking oil samples, it is extremely important that such samples be taken carefully to avoid the possibility of contaminating the sample. The procedures for taking oil samples described in ASTM D923 and/or D3613 should be followed.
6.5.1 p. 6-9	Gas-in-Oil	Never take an oil sample from a transformer under negative pressure. An air bubble could be drawn into the tank and cause a catastrophic transformer failure, possibly resulting in personal injury or death.
6.5.3 p. 6-17	Windings	Transformer winding ratios, polarity, and phase connections should be checked before energizing the transformer for the first time on site.
7.3.4.2 p. 7-10	Maintenance	Caution: When replacing nitrogen cylinders, do not use a typical nitrogen cylinder from the local welding supplier. Transformers require nitrogen that meets ASTM D1933 Type III, which has a -59°C dew point as specified by paragraph 6.6.6.3 of IEEE C57.12-1993.
8.1.1 p. 8-2	Vacuum & Oil Filling	Transformers, transformer terminals, vacuum equipment, oil tankers, and so on must be grounded.
8.1.1 p. 8-2	Vacuum & Oil Filling	Bushings must be shorted to prevent static discharges that would injure personnel and/or damage the transformer.
8.1.1 p. 8-2	Vacuum & Oil Filling	Check internal pressure prior to removal of any covers, and bleed off any positive pressure.
8.1.1 p. 8-2	Vacuum & Oil Filling	Check internal atmosphere for oxygen content prior to entering the tank. Be aware of the danger of nitrogen gas pockets inside the tank. Breathable air should be available while personnel are inside the transformer tank.

Pop Out Summary

Location	Topic	Key O&M Cost Point
8.1.1 p. 8-2	Vacuum & Oil Filling	Never walk or climb on top of the tank under vacuum.
8.1.2 p. 8-3	Vacuum & Oil Filling	If the transformer has a conservator or expansion tank, the pipe to the main tank must be removed and the valve plugged if the tank is not designed to withstand full vacuum.
8.5 p. 8-6	Vacuum & Oil Filling	The transformer should not be left under vacuum except during the filling process with the vacuum pump operating. If there are any leaks in the transformer or the connecting external pipes from the oil processing equipment, moisture could enter the tank.
9.8 p. 9-11	Maintenance	Static charge may be present on any section of a conductor. Appropriate grounding/discharge is necessary prior to any work or testing.
9.8 p. 9-11	Meggering	After meggering a bus, a sufficient amount of time must be allowed for the charge to dissipate before removing megger leads; otherwise, personnel injury might result.
9.8 p. 9-11	Isophase Bus Duct	The isophase bus duct enclosure is a confined space. Confined space entries must comply with approved procedures.
9.8 p. 9-11	Fuses	Potential transformer fuses should be pulled prior to starting maintenance work.
10.1 p. 10-2	Maintenance	Troubleshooting can be aided with the use of scenarios and/or flow charts. A few flow charts are provided to aid in the troubleshooting process. It is suggested that the user develop a set of these charts with symptom pages and plans of action to help in decision making and to capture lessons learned.
10.2 p. 10-9	Tear-Down Inspection	Before opening a transformer or removing an inspection cover, the transformer internal pressure has to be lowered to atmospheric pressure. Failure to do so may cause the cover to become a missile.
10.2 p. 10-9	Tear-Down Inspection	Do not enter the transformer tank until the gas in the tank is replaced by dry air. The oxygen content inside must be at least 19.5% before entering for inspection. While inside, oxygen content must always be checked. Oxygen less than 19.5% may cause drowsiness and/or injury or death.

G

SOERS

Twenty-three Significant Operating Experience Reports (SOERs) have been reviewed for events and failures on main and auxiliary power transformers that occurred since 1997. These SOERs cover significant events such as transformer and component failures, major equipment repair work, and/or plant shutdowns. The events were investigated to assess the applicability, significance, and probability for similar events elsewhere in the industry.

The majority of these events indicate that improper component/material selection, re-assembly, and installation are the main cause of failure. Design and fabrication is the second cause of failure, followed by inadequate maintenance.

The most frequent events involve the sudden pressure relays followed by bushing events, and then design or procedural issues. The sudden pressure relay events were attributed to fabrication deficiencies, and spurious operation. The bushing events were attributed to mainly improper re-assembly and improper material selection.

Significant Event Reports (SERs), Operating Experiences (OEs) and Licensee Event Reports (LERs) have also been reviewed, but no additional events or information was uncovered since the SOERs cover all related events. The LERs are issued by the plant to cover essentially the SOER event.

Table G-1 shows the same events, but lists the various causes of the component failure.

Table G-1
Main and Aux Power Transformer Failures

No.	Station/Unit	Component Type	Component Failure Mode	Cause No. 1	Cause No. 2	Cause No. 3	Cause No. 4
1	Diablo Canyon 1	Transformer bus links	Poor connection	Inadequate design	Contact corrosion/oxidation	Thermal failure of bolted bus	
2	Clinton 1	Breaker contactors	Spurious opening	Alignment tag-out not verified			
3	Callaway 1	Bushing	High temperature	Improper installation	Improper material used	Improper surface preparation	Under torqued
4	Beaver Valley 2	Relay	Spurious operation	Vibration	Not operated as designed		
5	Vermont Yankee 1	Tank access cover	External leakage	Fabrication deficiency			
6	St. Lucie 1	Relay	Loose wire contact	Design inadequacy	Fabrication deficiency	Inadequate preventive maintenance	
7	Diablo Canyon 2	No load tap changer	Failed to change state	Fabrication deficiency			
8	Clinton 1	Sudden pressure	Spurious operation	Fabrication deficiency			
9	Sequoyah 2	Bushing	Bushing failure	Improper reassembly of component			
10	Oconee 1	Control panel door	Human error	Improper reassembly of component			
11	Grand Gulf 1	Bushing connection	Improper connection (high thermoscan reading) no failure	Improper reassembly of component			
12	Brunswick 2	Cooling system	Loss of cooling	Beyond operating parameters	Omission of relevant information		
13	Three Mile Island 1	Sudden pressure relay	Sudden pressure relay failure	Mis-adjustment/misalignment			
14	Robinson 2	Sudden pressure relay	Sudden pressure relay failure	Defective relay			

Table G-1 (cont.)
Main and Aux Power Transformer Failures

No.	Station/Unit	Component Type	Component Failure Mode	Cause No. 1	Cause No. 2	Cause No. 3	Cause No. 4
15	Fort Calhoun 1	Deluge system	Transformer deluge valves internal leakage	Inadequate preventive maintenance	Particulate contamination		
16	Farley 1	Relay	Short of protection relays	Policy not adequately defined			
17	Sequoyah 2	Sudden pressure relay	Sudden pressure relay failure	Improper component selection	Quality control inadequate		
18	Davis-Besse 1	Deluge system	False deluge system actuation	Improper component selection			
19	Three Mile Island 1	Sudden pressure relay	Sudden pressure relay – spurious actuation	Improper installation	Inadequate assembly instructions	Omission of relevant information	
20	Peach Bottom 3	Transfer switch relay	Improper relay installation	Improper installation	Poor self-check		
21	Calvert Cliffs 1	Bushing	Bushing power reduction	Improper material selection	Expected aging		
22	Susquehanna 2	Bushing	Metal fatigue	Improper material selection			
23	Seabrook 1	Bus links	Bus links melted	No preventive maintenance performed			
24	Prairie Island 1 OE 13112	Non-segregated bus duct	Moisture intrusion				
25	Palo Verde OE 10893	SAT	Gas generation	Previous preventive maintenance testing failed to identify problem			
26	Pilgrim OE 9951	MPT bushing	Bushing arcing during testing	Incomplete work package			
27	Hope Creek SEN 215	“C” phase 500 kV transformer	Transformer failure	Spare transformer not ready for service	Moisture in the oil	Inadequate spare maintenance practices	

Target:
Nuclear Power

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