Harlow, James H. “Transformers”
The Electric Power Engineering Handbook
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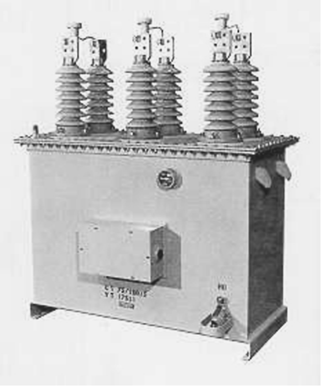
Combination Metering Units

The last major assembly is the metering unit, which consists of VT and CT elements in single phase or three phase arrangements. Metering units can be single molded elements mounted on a structure that is bolted to a utility pole, or in a pad-mount compartment. The elements can be in any combination needed to provide accurate energy measurement.

Metering units are also available in three-phase tanks with the elements submerged in oil. In high voltage systems, a single- phase combination CT/VT unit is available that looks much like a high voltage CT. The VT element is L-G and is common to the H1 terminal. The elements are independent of each other. The CT element is mounted on top and can house several cores, which can be used for metering and relaying applications. The VT element is located in the bottom.

When measuring energy usage for the purposes of revenue billing, and knowing the RCF and phase angle readings of each element, you can correct the watts or watthours by multiplying the reading by the product of $[\mathrm{TCF}_{CT}][\mathrm{TCF}_{VT}]$.



3-Phase metering unit. (Courtesy of Kuhlman Electric Corp.)

New Horizons

With de-regulation of the utility industry, buying and selling of power, leasing power lines, etc., the need for monitoring power at the transmission and distribution level will increase. There will be a need to add more metering points within existing systems starting at the generator. The utilities will want to add this feature at the most economical cost. The use of window-type slipover CTs for revenue metering will drive the industry towards improved performance. The need for higher accuracies at all levels will be desired, and can be obtained easily with the use of low burden solid-state devices. Products will become more environmentally safe and smaller in size. To help the transformer industry fulfill these needs, steel producers will need to make improvements by lowering losses, increasing initial permeability, and developing new composites.

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3.9 Transformer Connections

Dan D. Perco

In deciding the transformer connections required in a particular application, there are so many considerations to be taken into account that the final solution must necessarily be a compromise. It is therefore necessary to study in detail the various features of the transformer connections together with the local requirements under which the transformer will be operated.

This section describes the common connections for Distribution, Power, HVDC Converter and Rectifier Transformers. Space does not permit a detailed discussion of each type of transformer connection or other uncommon connections. The information presented in this section is primarily directed at transformer users. Additional information can be obtained from the IEEE transformer standards. In particular, reference is made to IEEE Standards C57.12.70, “Terminal Markings and Connections for Distribution and Power Transformers”, C57.105, “ Application of Transformer Connections in Three-Phase Distribution Systems”, C57.129 “ General Requirements and Test Code for Oil-Immersed HVDC Converter Transformers”, and C57.18.10 “ Practices and Requirements for Semiconductor Power and Rectifier Transformers”.

Polarity of Single-Phase Transformers

Transformers can be either subtractive or additive polarity. Most of the standards require subtractive polarity. In either case, the polarity of the transformer is identified by the terminal markings as shown in Fig. 3.132. Subtractive polarity has correspondingly marked terminals for the primary and secondary windings opposite each other. For additive polarity, the terminal markings of the secondary winding are reversed.

Angular Displacement of Three-Phase Transformers

Connection of three-phase transformers or three single-phase transformers in a three-phase bank can create angular displacement between the primary and secondary terminals. The convention for the direction of rotation of the voltage phasors is taken as counterclockwise. The standard angular displacement for two winding transformers is shown in Fig. 3.133. The references for the angular displacement are shown as dashed lines. The angular displacement is the angle between the lines drawn from the neutral to H1 and from the neutral to X1 in a clockwise direction from H1 to X1. The angular displacement between the primary and secondary terminals can be changed from 0° to 330° in 30° steps simply by altering the three-phase connections of the transformer. Therefore, systems with difference angular displacements can be connected by selecting the appropriate three-phase transformer connections.

Figure 3.133 shows angular displacement for common, double wound three-phase transformers. Multiwinding and autotransformers are similarly connected.

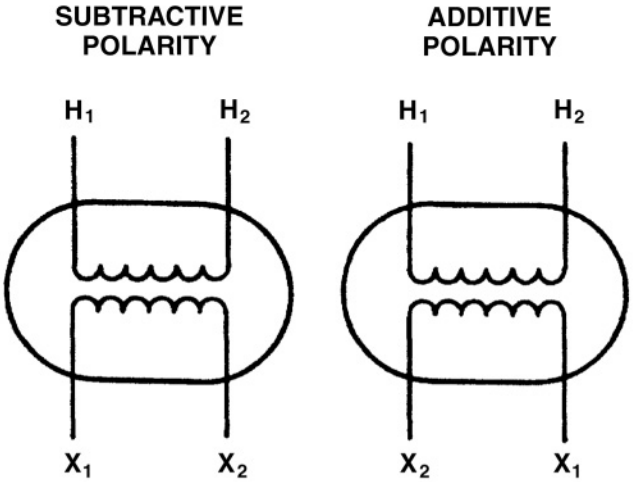


FIGURE 3.132 Single-phase transformer terminal markings.

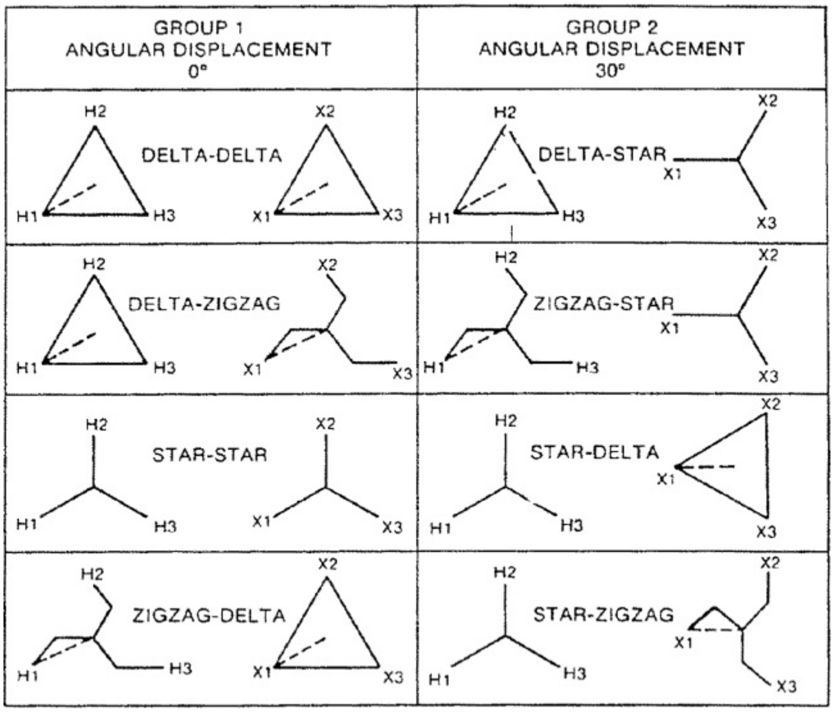


FIGURE 3.133 Standard angular displacement for three-phase transformers.

Three-Phase Transformer Connections

Three-phase transformer connections can be compared with each other with respect to:

1. Ratio of kVA output to the kVA rating of the bank
2. Degree of voltage symmetry with unbalanced phase loads
3. Voltage and current harmonics

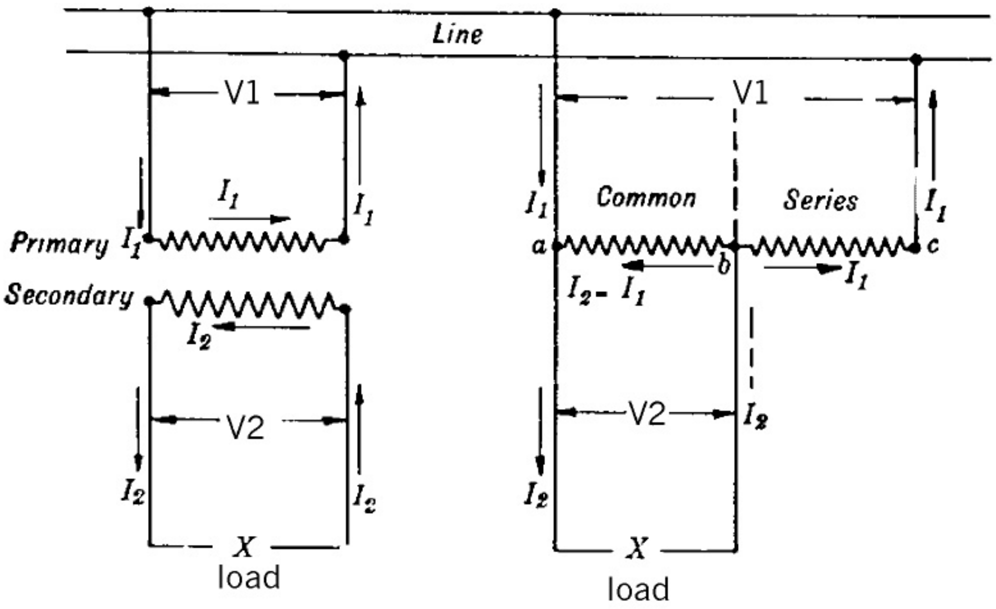


FIGURE 3.134 Current flow in double wound and autotransformers.

4. Transformer ground availability
5. System fault or transient voltages

and other operating characteristics to determine the most suitable connection for each application.

Double Wound Transformers

The majority of three-phase transformer connections are made by connecting single phase or the phases of a three-phase transformer, either between the power system lines, thus forming a delta connection, or one end of each phase together and the other ends to the lines thus forming a Y connection. For these connections, the internal winding rating is equal to the through load rating. This accounts for the popularity of these connections. For all other double wound transformer connections, the ratio is less than unity. For example, in the interconnected star or zigzag connection, the transformer is capable of delivering a load equal to only 86.6% of the internal winding rating. These types of three-phase connections are shown in Fig. 3.133.

Voltage and current symmetry, both with respect to the three lines and also lines to neutral are obtained only in the delta and zigzag connections. The Y connection is symmetrical as far as the lines are concerned, but introduce third-harmonic voltage and current dissymmetry between lines and neutral. If the transformer and generator neutrals are grounded, third harmonic current will flow that can create interference in telephone circuits. Third harmonic voltages are also created on the lines that can subject the power system to dangerous overvoltages due to resonance with the line capacitance. This is particularly true for shell type three-phase transformers, five-limb coreform and three-phase banks of single phase transformers. For any three-phase connection of three-limb coreform transformers, the impedance to third harmonic flux is relatively high on account of the magnet coupling between the three phases, resulting in a more stabilized neutral voltage. A delta tertiary winding can be added on Y–Y transformers to provide a path for third harmonic and zero sequence currents and stabilize the neutral voltage.

Delta-connected transformers do not introduce third harmonics or their multiples into the power lines. However, this type of three-phase transformer connection will have higher ground voltages during system fault or transient voltages. Supplying an artificial neutral to the system with a grounding transformer can control these voltages. The delta connection is also more costly to manufacture for high voltages and is generally limited to 345-kV systems and below.

In the Y-delta or delta-Y connections, complete voltage and current symmetry is maintained by the presence of the delta. These connections are more free from objectionable features than any other connections.

Multiwinding Transformers

Transformers having more than two windings are frequently used in power and distribution systems. The arrangement of windings can be varied to change the value of leakage reactance between winding pairs. In this way, the voltage regulation and the short circuit requirements are optimized. The application of multiwinding transformers permits:

1. Interconnection of several power systems operating at different voltages.
2. Use of a delta-connected stabilizing winding, which can also be used to supply external loads.
3. Regulation and control of reactive power compensation.

A disadvantage of multiwinding transformers is that all the windings are magnetically coupled and are affected by the loading of the other windings. It is therefore essential to understand the leakage impedance behavior of this type of transformer to be able to calculate the voltage regulation of each winding. As an example, for three winding transformers, the leakage reactance between each pair of windings must be converted into a star equivalent circuit. After the loading of each winding is determined, the regulation can be calculated for each impedance branch.

Autotransformers Connections

Autotransformers will deliver more than the internal winding ratings, depending on the voltage ratios of the primary and secondary voltages as shown in Fig. 3.134 and the following formula:

$$\text{Output/Internal rating} = V1/(V1 - V2)$$

where V1 = the voltage of the highest voltage winding
V2 = the voltage of the lower voltage winding

Consequently, the internal rating, size, cost, and efficiency of an autotransformer is better than a double wound transformer. This also shows that the greatest benefit of the autotransformer is achieved when the system voltages are close to each other.

A disadvantage of the autotransformer is that the short circuit current and forces are increased because of the reduced leakage reactance. In addition, most three-phase autotransformers are Y-Y connected. This form of connection has the same limitations as for the Y-Y double wound transformers.

Often this type of transformer has a delta-connected tertiary winding to reduce third harmonic voltages, permit the transformation of unbalanced three-phase loads, and supply station auxiliary load or power factor improvement equipment. The tertiary winding must be designed to accept all these external loads as well as the severe short circuit currents and forces associated with three-phase faults on its own terminals or single line-to-ground faults on any other terminal. If no external loading is required, the tertiary winding terminals should not be brought out except for one terminal to ground the delta during service operation.

The problem of transformer insulation stresses and system transient protection is more complicated for autotransformers, particularly when tapping windings are also required. Transients can also be more easily transferred between the power systems with the autotransformer connection.

Interconnected Star and Grounding Transformers

The star/interconnected star connections have the advantages of the star/delta connections with the additional advantage of the neutral. The interconnected star or zigzag connection allows unbalanced phase load currents without creating severe neutral voltages. This connection also provides a path for third harmonic currents created by the non-linearity of the magnetic core material. As a result, interconnected

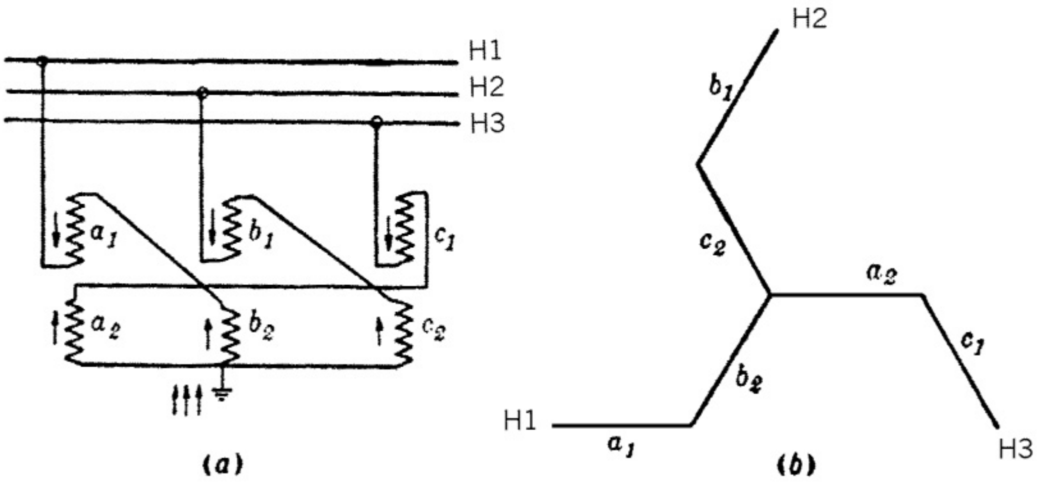


FIGURE 3.135 Interconnected star grounding transformer. (a) Current distribution in the coils for a line-to-ground fault. (b) Normal operating voltages in the coils.

star neutral voltages are essentially eliminated. However, the zero sequence impedance of interconnected star windings is often so low that high third harmonic and zero sequence currents will result when the neutral is directly grounded. These can be limited to an acceptable level by connecting a reactor between the neutral and ground.

The stable neutral inherent in the interconnected star or zigzag connection has made its use possible as a grounding transformer for otherwise isolated systems. This is shown in Fig. 3.135. The connections to the second set of windings can also be reversed to produce the winding angular displacements shown in Fig. 3.133.

For a line-to-neutral load or a line-to-ground fault on the system, the current is limited by the leakage reactance between the two coils on each phase of the grounding transformer.

Three-Phase to Six-Phase Connections

For six-pulse rectifier systems, the three-phase connections discussed above are commonly used. However, for 12-pulse rectifier systems, three-phase to six-phase transformations are required. For low voltage DC applications, there are numerous practical connection arrangements possible to achieve this. However, for high voltage DC applications, there are few practical arrangements. The most commonly used connections are either a delta or Y primary with two secondaries, one Y and one Delta connected.

Paralleling of Transformers

Transformers having terminals marked in the manner shown in the section entitled “Polarity of Single-Phase Transformers” may be operated in parallel by connecting similarly marked terminals together, provided their ratios, voltages, angular displacement, resistances, reactances, and ground connections are such as to permit parallel operation.

The difference in the no load terminal voltages of the transformers will cause a circulating current to flow between the transformers when paralleled. This current will flow at any load. The impedance of the circuit, which is usually the sum of the impedances of the transformers paralleled, limits the circulating current. The circulating current adds vectorially to the load current to establish the total current in the transformer. As a result, the capacity of the transformer to carry load current is reduced by the circulating current when the transformers are paralleled.

The load currents in the paralleled transformers will divide inversely to the impedances of the transformers paralleled. Generally, the difference in resistance has an insignificant effect on the circulating current because the leakage reactance of the transformers involved is much larger than the resistance. Transformers having different impedance values can be made to divide their load in proportion to their load ratings by placing a reactor in series with one transformer so that the resultant impedance of the two branches will create the required load sharing.

When delta–delta connected transformer banks are paralleled, the voltages are completely determined by the external circuit, but the division of current among the phases depends upon internal characteristics of the transformers. Considerable care must be taken in the selection of transformers, particularly single-phase transformers in three-phase banks, if the full capacity of the banks is to be used when the ratios of transformation on all phases are not alike. In the delta-Y connection, the division of current is indifferent to the differences in the characteristics of individual transformers.

3.10 LTC Control and Transformer Paralleling

James H. Harlow

Tap changing under load (TCUL), be it with load tap changing power transformers or step-voltage regulators, is the primary means of dynamically regulating the voltage on utility power systems. Switched shunt capacitors may also be used for this purpose, but in the context of this discussion, shunt capacitors are presumed to be applied with the objective of improving the system power factor.

The control of a tap changer is much more involved than simply responding to a voltage excursion at the transformer secondary. Modern digital versions of LTC control include so many ancillary functions and calculated parameters that it is often used to serve as the means for system condition monitoring.

The control of the tap changer in a transformer or step-voltage regulator is essentially the same. Unless stated otherwise, the use of the term "transformer" in this section applies equally to step-voltage regulators. It should be recognized that either type of product may be constructed as a single-phase or three-phase apparatus, but that transformers are most often three-phase while step-voltage regulators are most commonly single-phase.

System Perspective, Single Transformer

This discussion is patterned to a typical utility distribution system, the substation and the feeder, although much of the material is also applicable to transmission applications. This first discussion of the control considers that the control operates only one LTC in isolation; that is, there is no opportunity for routine operation of transformers in parallel.

The system may be configured in any of several ways, according to the preference of the user. Figure 3.136 depicts two common implementations. In the illustrations of Fig. 3.136, the dashed line box depicts a substation enclosing a transformer or step-voltage regulators. The implementations illustrated accomplish bus voltage regulation on a three-phase or single-phase basis. Another common application is to use voltage regulators on the distribution feeders. A principal argument for the use of single-phase regulators is that the voltages of the three phases are controlled independently, whereas a three-phase transformer or regulator will control the voltage of all phases based on knowledge of the voltage of only one phase. For the figure:

S = source, the utility network at transmission or sub-transmission voltage, usually 69 kV or greater.
Z = impedance of the source as "seen" looking back from the substation.
L = loads, distributed on the feeders, most often at 15 to 34.5 kV.

The dominance of load tap changing apparatus involves either 33 voltage steps of 5/8% voltage change per step, or 17 voltage steps of 1¼% voltage change per step. In either case, the range of voltage regulation is ±10%.

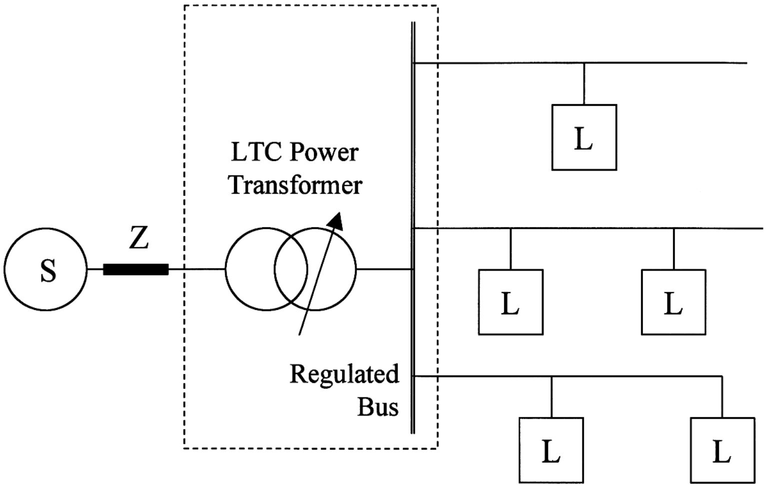


FIGURE 3.136(a) Three-phase bus regulation, three-phase LTC transformer.

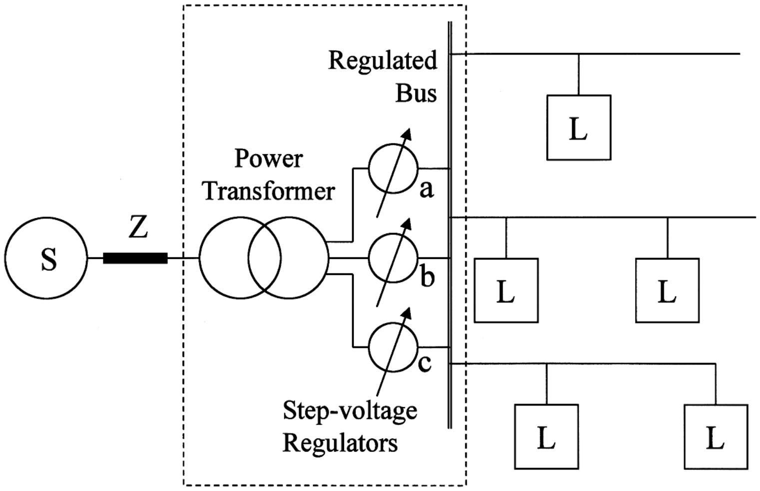


FIGURE 3.136(b) Independent phase bus regulation, three single-phase step-voltage regulators.

Control Inputs

Voltage Input

The voltage class of the primary system is unimportant to the LTC control. The system will always include a voltage transformer (VT) or other means to drop the system voltage to a nominal 120 V for use by the control. Because of this, the control is calibrated in terms of 120 V and it is common to speak of the voltage as being, say, "118 V", or "124 V", it being understood that the true system voltage is the value stated times the VT ratio. Presuming a single tap step change represents 5/8% voltage, it is easily seen that a single tap step change will result in 0.00625 pu × 120 V = 0.75 V change at the control.

The control will receive only a single 120-V signal from the voltage transformer, with it tracking the line-ground voltage of one phase, or a line-line voltage of two phases. For the case of three-phase apparatus, the user must exhibit great care, as later described, in selecting the phase(s) for connecting the VT.

Current Input

The current transformer(s) (CT) is provided by the transformer manufacturer so as to deliver control current of "…not less than 0.15 A and not more than 0.20 A … when the transformer is operating at the maximum continuous current for which it is designed…" (This is per ANSI/IEEE standards where the nominal current is 0.2 A. Other systems may be based on a different nominal current, such as 5.0 A.) As with the voltage, the control will receive only one current signal, but it may be that of one phase or the cross-connection (the paralleling of two CTs) of two phases.

Phasing of Voltage and Current Inputs

In order for the control to perform all of its functions properly, it is essential that the voltage and current input signals be in-phase for a unity power factor load, or, if not, that appropriate recognition and corrective action be made for the expected phasing error.

Figure 3.137(a,b,c) depicts the three possible CT and VT orientations for three-phase apparatus. Note that for each of the schemes the instrument transformers could be consistently shifted to different phases from that illustrated without changing the objective. The first scheme, involving only a line to ground rated VT and a single CT, is clearly the simplest and least expensive; however, it causes all control action to be taken solely on the basis of knowledge of conditions of one phase. Some may prefer the second scheme as it gives reference to all three phases, one for voltage and the two not used for voltage to current. The third scheme is often found with a delta connected transformer secondary. Note that the current signal derived in this case is √3 times the magnitude of the individual CT secondary currents. This must be scaled before the signal is delivered to the control.

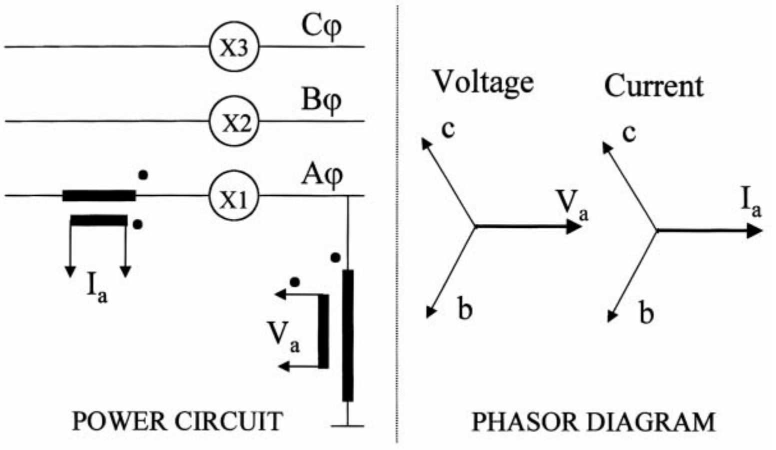
The Need for Voltage Regulation

Referring to the circuits of Fig. 3.136, it will be recognized that system conditions will change over time with the result that the voltage at the substation bus, and as delivered to the load, will change. From Fig. 3.136, the source voltage, the source impedance, and the load conditions will be expected to change with time. The most notable of these, the load, must be recognized to consist of two factors: (1) the magnitude and the power factor, or what is the same point, the real (watt) and (2) reactive (var) components.

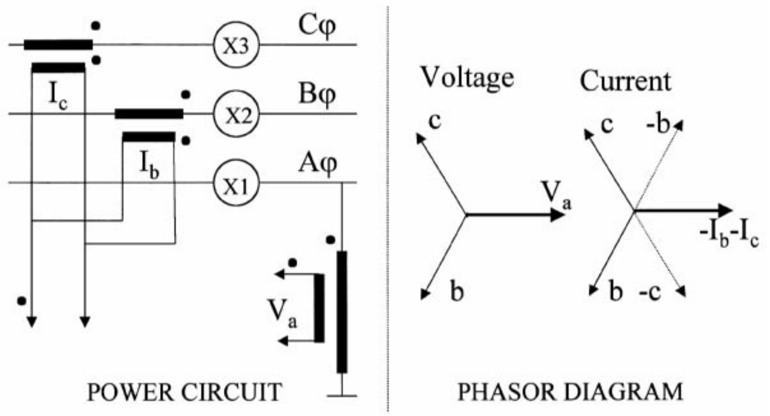
Regulation of the Voltage at the Bus

Many times the object of the LTC is to simply hold the substation bus voltage at the desired level. If this is the sole objective, it is sufficient to bring only a VT signal that is representative of the bus voltage into the control. The secondary of the VT is usually 120 V at the nominal bus voltage, but other VT secondary voltages, especially 125 V, 115 V, and 110V, are used. Figure 3.138 shows the circuit. The figure shows a motor (M) on the LTC which is driven in either the Raise or Lower direction by the appropriate output (M_R or M_L) of the control. This first control, Fig. 3.138, is provided with only three settings, these being those required for the objective of regulating the substation secondary bus voltage:

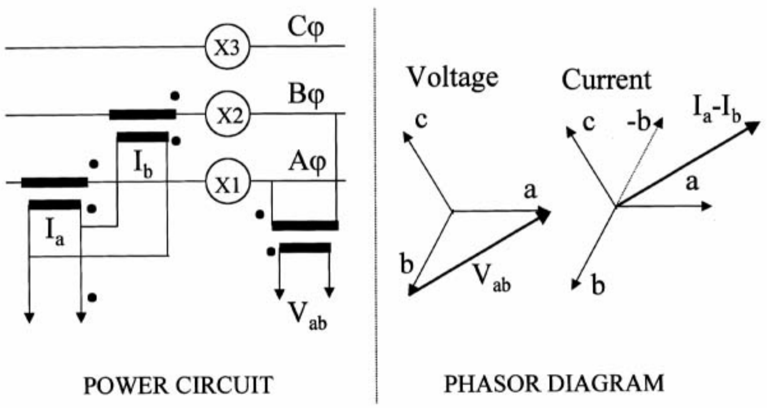
- **Voltage Set Point.** This, on the control voltage base, as 120 V, is the voltage desired to be held *at the load.* (The load location for this first case is the substation secondary bus because line drop compensation is not yet considered and is therefore zero). This characteristic is also commonly spoken of as "Voltage Band Center", this being illustrative of the point that there is a band of acceptable voltage, and this is the midpoint of that band. If line drop compensation (LDC, as detailed later) is not used, the set point will often be somewhat higher than 120 V, perhaps 123 V to 125 V; with use of LDC the setting will be lower, perhaps 118 V.
- **Bandwidth.** The bandwidth describes the voltage range, or band, which is considered acceptable, i.e., in which there is no need for any LTC corrective action. The bandwidth is defined in the ANSI/IEEE standard as a voltage, with one-half of the value above and one-half below the voltage set point. Some other controls adjust the bandwidth as a percentage of the voltage set point and the value represents the band on each side of the bandcenter. The bandwidth voltage selected is



VT (L-G), 1 CT on same phase

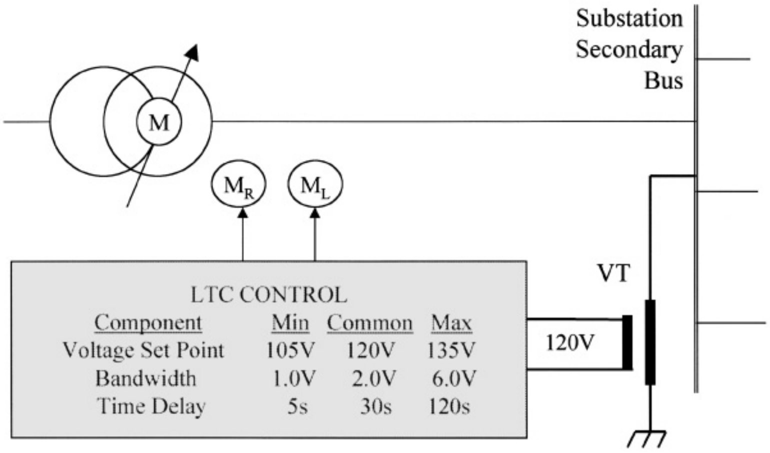


VT (L-G), 2 CTs on other phases



VT (L-L), 2 CTs on same phases

FIGURE 3.137(a,b,c) Phasing of voltage and current inputs.



Component	Min	Common	Max
Voltage Set Point	105V	120V	135V
Bandwidth	1.0V	2.0V	6.0V
Time Delay	5s	30s	120s

FIGURE 3.138 Control for voltage regulation of the bus.

basically determined by the LTC voltage change per step. Consider a transformer where the voltage change per step is nominally 0.75 V (5/8% of 120 V). Often this is only the average; the actual voltage change per step may differ appreciably at different steps. Clearly, the bandwidth must be somewhat greater than the maximum step change voltage as if the bandwidth were less than the voltage change per step, the voltage could pass fully across the band with a single step, causing a severe hunting condition. The minimum suggested bandwidth setting is twice the nominal step change voltage, plus 0.5 V, for a 2.0-V minimum setting for the most common 5/8% systems. Many users use somewhat higher bandwidths when the voltage is not critical and there is a desire to reduce the number of daily tap changes.

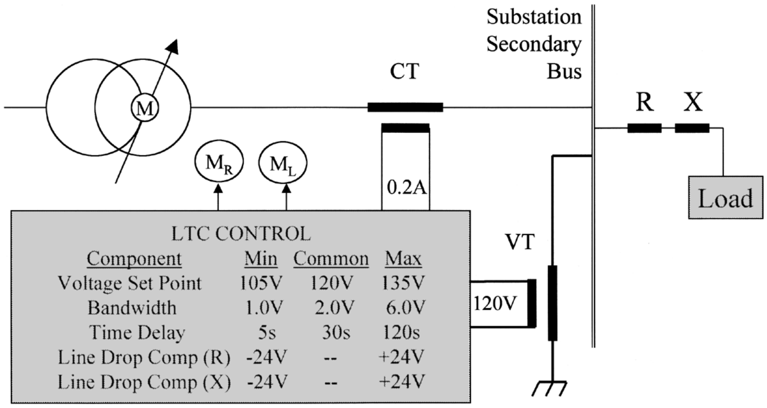
- **Time Delay.** All LTC controls incorporate an intentional time delay from the time the voltage is "out-of-band" until a command is given for tap changer action. Were it not for the control delay, the LTC would respond to short-lived system voltage sags and swells causing many unwanted and unnecessary tap changes. Most applications use a linear time delay characteristic, usually set in the range of 30 to 60 sec, although controls with inverse time delay characteristics are also available, where the delay is related inversely to the voltage digression from the set point.

Regulation of the Voltage at the Load

It is recognized that if it were easy to do so, the preferred objective would be to regulate the voltage at the load, rather than at the substation bus. The difficulty is that the voltage at the load is not commonly measured and communicated to the control; therefore, it must be calculated in the control using system parameters calculated by the user. Basically, the calculation involves determining the line impedance $(R + jX_L)$ between the substation and the load, the location of which is itself usually very nebulous.

The procedure used is that of Line Drop Compensation (LDC), that is the boosting of the voltage at the substation in order to compensate for the voltage drop on the line. The validity of the method is subject to much debate because of (1) the uncertainty of where to consider the load to be when it is in fact distributed, and (2) the inaccuracies encountered in determining the feeder line resistance and reactance.

The principle upon which LDC is based is that there is one concentrated load located a sufficient distance from the LTC transformer for the voltage drop in the line to be meaningful. Consider Fig. 3.139 which is similar to Fig. 3.138 with the addition of a load located remote from the substation and a current signal input to the control. The distance from the substation to the load must be defined in terms of the electrical distance, the resistance (R) and inductive reactance (X) of the feeder. The means of determining the line R and X values is available in the literature of most producers of the control equipment.



LTC CONTROL

Component	Min	Common	Max
Voltage Set Point	105V	120V	135V
Bandwidth	1.0V	2.0V	6.0V
Time Delay	5s	30s	120s
Line Drop Comp (R)	-24V	--	+24V
Line Drop Comp (X)	-24V	--	+24V

FIGURE 3.139 Control for voltage regulation at the load.

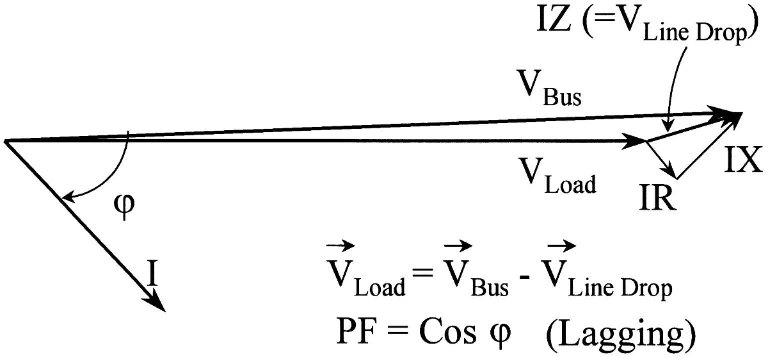


FIGURE 3.140(a) Load phasor diagram, normal load, lagging power factor.

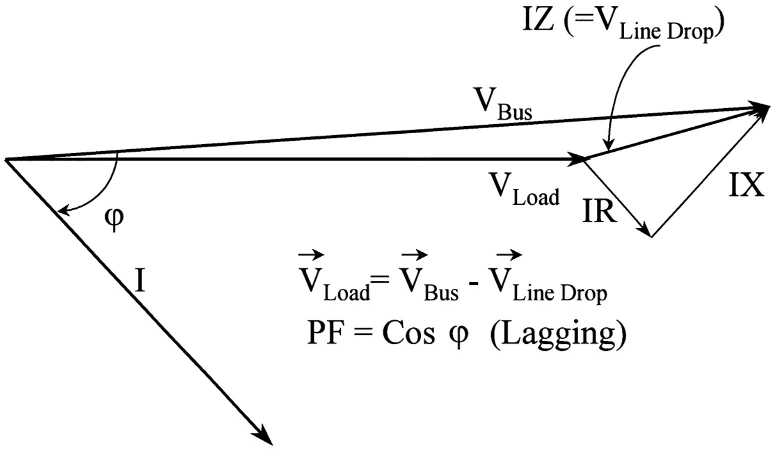
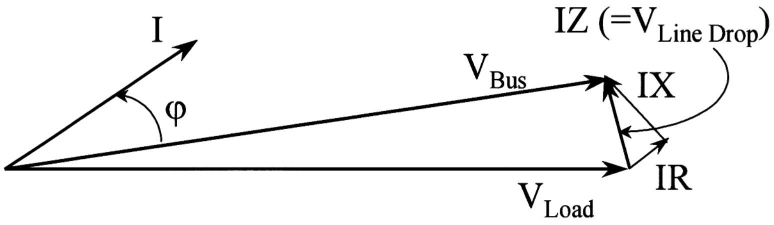


FIGURE 3.140(b) Load phasor diagram, heavy load, lagging power factor.

The LDC resistance and reactance settings are expressed as a value of volts on the 120-V base. These voltage values are the voltage drop on the line (R = in-phase component; X = quadrature component) when the line current magnitude is the CT primary rated current.



$$\vec{V}_{Load} = \vec{V}_{Bus} - \vec{V}_{Line\ Drop}$$

$$PF = \text{Cos}\ \varphi\ \text{(Leading)}$$

FIGURE 3.140(c) Load phasor diagram, normal load, leading power factor.

The manner in which the control accounts for the line voltage drop is illustrated with phasor diagrams. Figure 3.140 presents three illustrations showing the applicable phasor diagram as it changes by virtue of the load magnitude and power factor. In the illustrations, the voltage desired at the load, V_{Load}, is the reference phasor; its magnitude does not change. All of the other phasors will change when the load current changes in magnitude or phase angle. For all of the diagrams:

IR = voltage drop on the line due to line resistance; in-phase with the current.
IX = voltage drop on the line due to line inductive reactance; leads the current by 90°.
IZ = total line voltage drop, the phasor sum of IR and IX.

In the first illustration, the power factor angle, φ, is about 45°, lagging, for an illustration of an exaggerated power factor of about 0.7. It is seen that the voltage at the bus will need to be boosted to the value V_{Bus} in order to overcome the IR and IX voltage drops on the line. The second illustration simply shows that if the line current doubles, with no change of phase angle, the IR and IX phasors also double and a commensurately greater boost of V_{Bus} is required to hold the V_{Load} constant. The third illustration considers that the line current magnitude is the same as the first case, but the angle is now leading. The IZ phasor simply pivots to reflect the new phase angle. It is interesting to note that in this case, the V_{Load} magnitude *exceeds* V_{Bus}. This is modeling the real system: too much shunt capacitance on the feeder (excessive leading power factor) will result in a voltage rise along the feeder. The message for the user is that LDC accurately models the line drop, both in magnitude and phase.

No "typical" set point values for LDC can be given, unless it is zero, as the values are so specific to the application. Perhaps due to the difficulty in calculating reasonable values, line drop compensation is not used in many applications. An alternative to line drop compensation, Z-compensation is sometimes preferred for its simplicity and essential duplication of LDC. To use Z-comp, the control is programmed to simply raise the output voltage as a linear function of the load current, to some maximum voltage boost. This method is not concerned with the location of the load, but also does not accurately compensate for changes in the power factor of the load.

LTC Control with Power Factor Correction Capacitors

Many utility distribution systems include shunt capacitors to improve the load power factor as seen from the substation, and reduce the overall losses by minimizing the need for volt-amperes reactive (vars) from the utility source. This practice is often implemented both with capacitors that are fixed and others that are switched in response to some user selected criteria. Further, the capacitors may be located at the substation, at the load, or at any intermediate point.

The capacitors, located at the load and source, are illustrated in Fig. 3.141. The position of the capacitors is important to the LTC control when LDC is used.

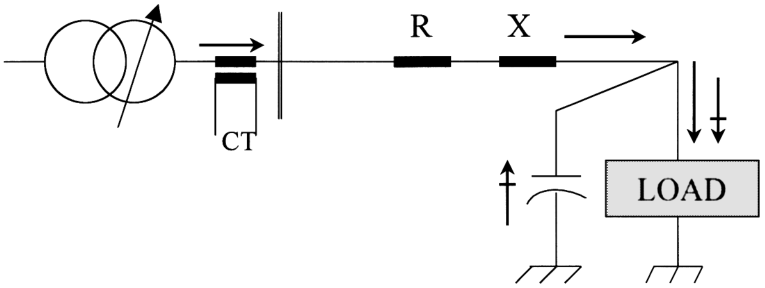


FIGURE 3.141(a) Feeder with power factor correction capacitors, capacitors at the load.

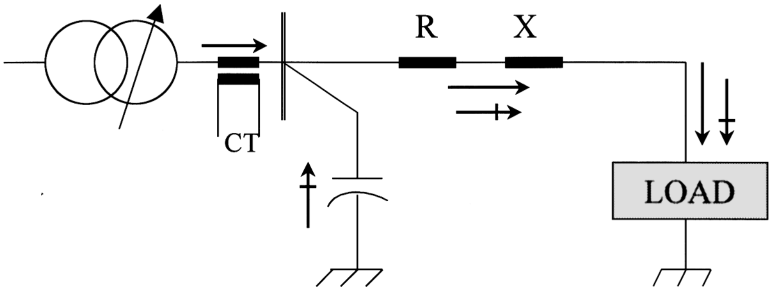


FIGURE 3.141(b) Feeder with power factor correction capacitors, capacitors at the source bus.

With the capacitors located at the load, Fig. 3.141a, the transformer CT current is exactly the current of the line. Here LDC is correctly calculated in the control because the control LDC circuit accurately represents the current causing the line voltage drop.

In the second illustration, Fig. 3.141b, the capacitor is at the substation bus. There is a voltage drop in the line due to the reactive current in the line. This reactive current is not measured by the LDC CT. In this case, the line drop voltage is not correctly calculated by the control. To be accurate for this case, it is necessary to determine the voltage drop on the feeder due to the capacitor produced portion of the load current, and add that voltage to the control set point voltage to account for the drop not recognized by the LDC circuit.

The matter is further confused when the capacitor bank is switched. With the capacitor bank in the substation it is possible devise a control change based on the presence of the bank. No realistic procedure is recognized for the case where the bank is not in close physical proximity to the control, keeping in mind that the need is lessened to zero as the capacitor location approaches the load location.

Extended Control of LTC Transformers and Step-Voltage Regulators

An LTC control often includes much more functionality than is afforded by the five basic set points. Much of the additional functionality can be provided for analog controls with supplemental hardware packages, or is provided as standard equipment with the newer digital controls. Some functionality, most notably serial communications, is available only with digital controls.

Voltage Limit Control

Perhaps the most requested supplemental LTC control function is voltage limit control, also commonly known as "first house (or first customer) protection". This feature may be important with the use of line drop compensation, where excessive line current could result in the voltage at the substation bus becoming excessive. System realities are such that this means that the voltage at the "first house", or the load immediately outside of the substation, is also exposed to this high voltage condition.

Review again Fig. 3.139 where LDC is used and it is desired to hold 118 V at the load. The voltage at the source (the secondary substation bus) is boosted as the load increases in order to hold the load at 118 V. If the load continues to grow, the voltage at the source will rise accordingly. At some point the load could increase to the point where the first customer is receiving power at excessive voltage. Recognize that the control is performing properly; it is because of the unanticipated excessive load on the system that the bus voltage is too high.

The Voltage Limit Control functions only in response to the actual local bus voltage, opening the Raise circuit to the drive motor at a user selected voltage, thereby defeating the basic control Raise signal when the bus voltage becomes excessive. In this way, the LTC action will not be responsible for first customer overvoltage.

These controls provide additional control if the bus voltage should further exceed the selected voltage set point cutoff voltage, as may be due to a sudden loss of load or other system condition unrelated to the LTC. If the voltage exceeds a second value, usually about 2 V higher than the selected voltage set point cutoff voltage, the voltage limit control will, of itself, command LTC Lower action.

Most of these controls provide a third capability, that of undervoltage LTC blocking so that the LTC will not run Lower if the voltage is already below a set point value. This function mirrors the Raise block function described above.

The voltage limit control functionality described is built into all of the digital controls. This is good in that it is conveniently available to the user, but caution needs to be made regarding its expected benefit. The function cannot be called a backup control unless it is provided as a physically separate control. Consider that the bus voltage is rising, not correctly because of LDC action, but because of a failure of the LTC control. The failure mode of the control may cause the LTC to run high and the bus voltage to rise accordingly. This high voltage will not be stopped if the Voltage Limit Control function used is that which is integral to the defective digital control. Only a supplemental device will stop this, and thereby qualify as a backup control.

Voltage Reduction Control

Numerous studies have reported that, for the short term, a load reduction essentially proportional to a voltage reduction can be a useful tool to reduce load and conserve generation during critical periods of supply shortage. It is very logical that this can be implemented using the LTC control. Many utilities prepare for this with the voltage reduction capability of the control.

With analog controls, voltage reduction is usually implemented using a "fooler" transformer at the sensing voltage input of the control. This transformer could be switched into the circuit using SCADA to boost the voltage at the control input by a given percentage, or often up to three different percentages using different taps on the fooler transformer. Having the sensed voltage boosted by, say, 5% without changing the voltage set point of the control will cause the control to run the tap position down by 5% voltage, accomplishing the desired voltage reduction. The percentage of three reduction steps, most commonly 2.5, 5.0, and 7.5%, is pre-established by the design of the fooler transformer.

Digital controls do the same function much more conveniently, more accurately, and more quickly. The voltage reduction applicable to steps 1, 2, and 3 are individually programmed, and upon implementation effectively lower the voltage set point. Control based on the new set point is implemented without intentional time delay, reverting to panel time delay after the voltage reduction has been implemented. Most often controls provide for three steps of voltage reduction, with each step individually programmed up to 10.0%.

Reverse Power Flow

Voltage regulators as used on distribution feeders are sometimes subjected to reverse power flow due to system switching, a situation treated in the step-voltage regulator section of this chapter.

The apparatus and procedures defined for step-voltage regulators are not correct for most transformer applications where reverse power flow can occur. The basic difference is that the feeder regulator application remains a radial system after the line switching is complete. Reverse power in transformers is more likely to occur on a system where the reverse power is due to a remote generator, which is operating continuously in parallel with the utility. The proper operation of the LTC in this case must be evaluated for the system. Perhaps the preferred operation would be to control the LTC so as to minimize the var exchange between the systems. Some systems are simply operated with the LTC control turned off of automatic operation during RPF so that the LTC stays fixed on position until FPF resumes.

Introduction to Control for Parallel Operation of LTC Transformers and Step-Voltage Regulators

For a variety of reasons, it may be desirable to operate LTC transformers or regulators in parallel with each other. This may be done simply to add additional load handling capability to an existing overloaded transformer, or it may be by initial design to afford additional system reliability anticipating that there may be a failure of one transformer.

Most common paralleling schemes have the end objective of having the load tap changers operate on the same, or on nearly the same, tap position at all times. For more complex schemes this may not be the objective. A knowledge of the system is required in order to assess the merits of the various techniques.

The Need for Special Control Considerations

To understand why special control consideration needs to be given to paralleling, consider two LTC transformers operating in parallel, i.e., the primary and secondary of the transformers are bussed together as in Fig. 3.142. If the transformers are identical, they will evenly divide the load between them at all times while they are operating on the same tap position. Consider that the voltage at the secondary bus goes out-of-band. Even if the controls are set the same, they are not *identical* and one will command tap change operation before the other. Later, when the voltage again changes so as to require a second voltage correction, the same control which operated more quickly the first time will be expected to do so again. This can continue indefinitely with one LTC doing all of the operation. As the tap positions of the LTC transformers digress, the current that circulates in the substation increases. This current simply circulates around the loop formed by the busses and the two transformers doing no useful work, but causing an increase in losses and perhaps causing one or both of the transformers to overheat. To put the matter in perspective, consider the case of a distribution substation where there are two 5/8% steps, 15 MVA LTC transformers of 8.7% impedance in parallel. The secondary voltage is 12.47 kV. For a tap difference of only 1 step, a circulating current of 25 A flows in the substation LV bus. This current magnitude increases linearly with tap position difference.

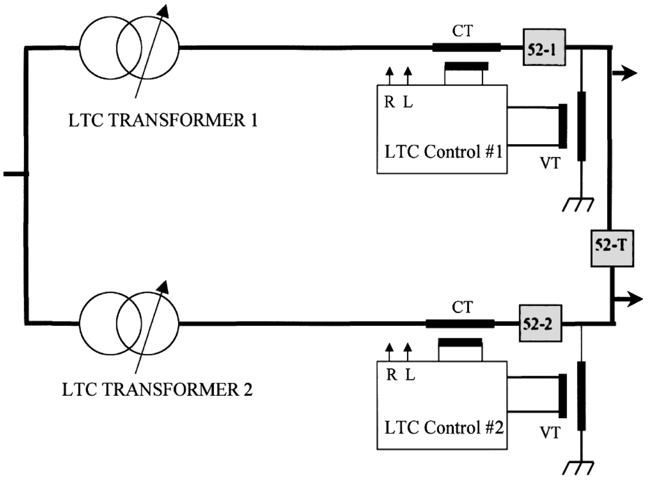


FIGURE 3.142 LTC transformers in parallel with no interconnections.

In the illustration above for LTC transformers, the circulating current was limited by the impedances of the transformers. It is very important to recognize that the same procedure cannot be done with step-voltage regulators as the impedance of a regulator is very low at even the extreme tap positions, and may be essentially zero at the Neutral tap position. In this case, if one regulator is on Neutral and the other moves to position 1R, the circulating current will be expected to be sufficient to cause catastrophic failure of the regulators. *Step-voltage regulators can only be operated in parallel when there is adequate supplemental impedance included in the current loop.* This is most often the impedance of the transformers which are in series with each regulator bank, or may be a series current limiting reactor.

Instrument Transformer Considerations

Refer again to Fig. 3.137. Most techniques for paralleling use the voltage and current signals derived for line drop compensation; it is essential that the transformers which will be paralleled deliver voltage and current signals that are in phase with each other, when the system has no circulating current. This means that the instrument transformers must deliver signals from equivalent phases. Further, the ratios of the instrument transformers must be the same, except as very special conditions will require otherwise.

Defined Paralleling Procedures

Numerous procedures have been identified over the years to accomplish LTC transformer paralleling using electronic control. These are listed with some limited description, with alternative names sometimes heard:

1. Negative Reactance (Reverse Reactance): Seldom used today except in some network applications, this is one of the oldest procedures accomplished by other than mechanical means. This means of paralleling is the reason LTC controls are required by the standard to provide negative X capability on the line drop compensation.
   Advantages: Simplicity of installation. The system requires no apparatus other than the basic control, with LDC X set as a negative value. There is no control interconnection wiring so transformers may be distant from each other.
   Disadvantages: Operation is with a usually high –X LDC set point, meaning that the bus voltage will be *lowered* as the load increases. Attempts to compensate with +R LDC settings are only marginally successful.
2. Cross-connected Current Transformers: Unknown in practice today. The system operates on precepts similar to the Negative Reactance method. The LDC circuits of two controls are fed from the line CT of the opposite transformer.
   Advantages: System requires no apparatus other than the basic control, but does require CT circuits to pass between the transformers.
   Disadvantages: Operation may need to be with a value of +X LDC much higher than desired for LDC purposes, thereby boosting the voltage too much. The system may be used on two transformers only.
3. Circulating Current (Current Balance): The most common method in use in the U.S. today; about 90% of new installations use this procedure. It has been implemented with technical variations by several sources.
   Advantages: Generally reliable operation for any reasonable number of paralleled transformers. Uses the same CT as that provided for LDC, but operates independently of the line drop compensation.
   Disadvantages: Control circuits can be confusing, and must be accurate as to instrument transformer polarities, etc. Proper operation is predicated on the system being such that any significant difference in CT currents must be due only to circulating current. Matched transformers will, at times, operate unbalanced under normal conditions.

4. Master/Follower (Master/Slave, Electrical Interlock, Lock-in-step): Used by the 10% of new installations in the U.S. which do not use circulating current. It is much more commonly used worldwide than in the U.S.
   Advantages: Matched transformers will always be balanced, resulting in minimum system losses.
   Disadvantages: As usually implemented, involves numerous auxiliary relays which may fail, locking out the system.
5. Reactive Current Balance (Delta VAR): Generally used only when special system circumstances require it. Operates so as to balance the reactive current in the transformers.
   Advantages: Can be made to parallel transformers in many more complex systems where other methods do not work.
   Disadvantages: May be more expensive than more common means.

The two most common paralleling procedures are Master/Follower and Circulating Current Minimization.

Master/Follower

The Master/Follower method operates on the simple premise: Designate one control as the Master, any other units are Followers. Only the Master needs to know the voltage and need for a tap change. Upon recognition of such a need, the Master so commands a tap change of the LTC on the first transformer. Tap changer action of #1 activates contacts and relays, which make the circuit for LTC following action in all of the Followers, and temporarily lock out further action by the Master. The LTC action of the Followers in turn activates additional contacts and relays which free the Master to make a subsequent tap change when required.

Circulating Current Method

All of the common analog implementations of the circulating current method provide an electronic means (a “paralleling balancer”) of extracting (1) the load current and (2) the circulating current from the total transformer current. These currents are then used for their own purposes, the load current to be the basis for line drop compensation and the circulating current to bias the control to favor the next LTC action which will tend to keep the circulating current to a minimum.

Consider Fig. 3.143. The balancers receive the scaled transformer current and divide it into the components of load current and circulating current. The load current portion of the transformer current is that required for line drop compensation. The circulating current portion is essentially totally reactive

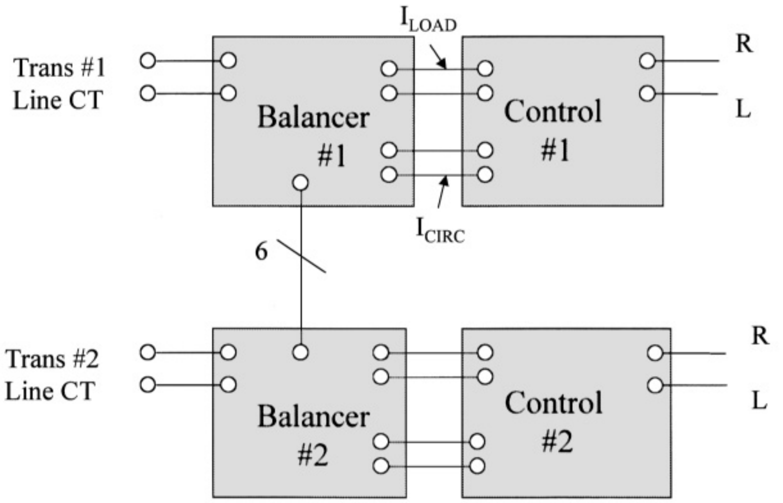


FIGURE 3.143 Control block diagram, paralleling by usual circulating current method.

and is the same in magnitude in the two controls, but of opposite polarity. Presuming a lagging power factor load, the control monitoring the transformer on the higher tap position will "see" a more lagging current; that on the lower tap position a less lagging, or perhaps leading, current. This circulating current is injected into the controls. The polarity difference serves to bias them differently. The LTC which next operates is that which will correct the voltage, while tending to reduce the circulating current, i.e., bring the tap positions into closer relation to each other.

Characteristics Important for LTC Transformer Paralleling

There are many transformer characteristics which must be known and evaluated when it is planned to parallel LTC transformers. Some of the more notable follow:

1. Impedance and MVA. "Impedance" as a criteria for paralleling is more correctly stated as the percent impedance referred to as a common MVA base. Two transformers of 10% impedance but one of 10 MVA and the other of 15 MVA are not the same. Two other transformers, one 10% impedance and 10 MVA and another of 15% impedance and 15 MVA are suitably matched per this criteria. There is no definitive difference in the impedances which will be the limit of acceptability, but a difference of no greater than 7.5% is realistic.
2. Voltage rating and turns ratio. It may not be essential that the voltage ratings and turns ratios be identical. If one transformer is 69-13.8 kV and the other 69-12.47 kV, the difference may be tolerated by recognizing and accepting a fixed step tap discrepancy, or it may be that the ratios may be made more nearly the same using the de-energized tap changers.
3. Winding configuration. The winding configuration, as delta–wye, wye–wye, etc., is critical, yet transformers of different configurations may be paralleled if care is taken to assure that the phase shift through the transformers is the same.
4. Instrument transformers. The transformers must have VTs and CTs which produce in-phase signals of the correct ratio to the control, and must be measuring the same phase in the different transformers.

Paralleling Transformers with Mismatched Impedance

Very often it is desired to use two existing transformers in parallel where it is recognized that the impedance mismatch is greater than that recommended for proper operation. This can usually be accomplished, although some capacity of one transformer will be sacrificed.

If the impedances of the transformers in parallel are not equal, the current will divide inversely as the impedances in order for the same voltage to appear across both impedances.

The impedances are effectively the transformer impedance as read from the nameplate, which may be taken to be wholly reactive. The problem when dealing with mismatched transformers in parallel is that the current will divide per the impedances, but the control, if operating using the conventional circulating current method, is attempting to match the currents.

Realize that the LTC control and the associated paralleling equipment really has no knowledge of the actual line current; it knows only a current on its scaled base which could represent anything, say 100 A to 3000 A. The objective of the special considerations to permit the mismatched impedance transformers to be paralleled is to supply equal current signals to the controls when the transformers are carrying load current in inverse proportion to their impedances.

To illustrate, consider the paralleling of two 20 MVA transformers of 9% and 11% impedance, which is much more than the 7.5% difference criteria stated earlier. We establish that $Z_1 = k \times Z_2$, so:

$$k = Z_1/Z_2 = 9/11 = 0.818.$$

And since $I_1 = I_2/k$:

$$I_1 = I_2/k = 1.222\ I_2.$$

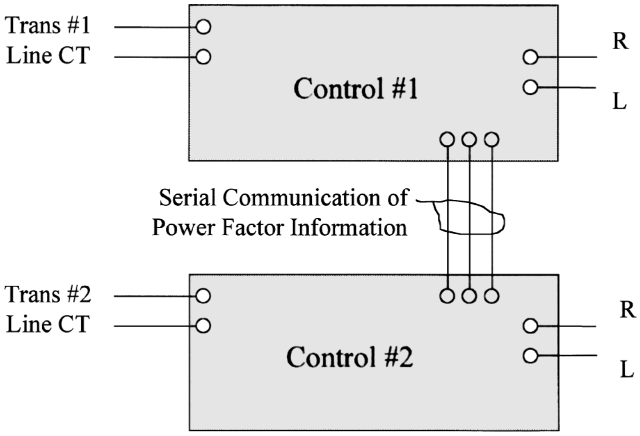


FIGURE 3.144 Control block diagram, paralleling by equal power factor, circulating current method.

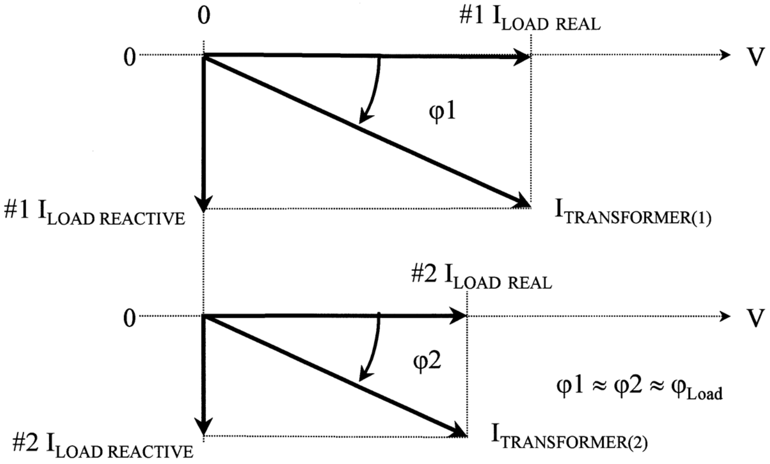


FIGURE 3.145 Phasor diagram — mismatched transformers in parallel by equal power factor method.

Transformer T1 will carry 22.2% more load than transformer T2, even though they are of the same MVA rating. A resolution is to fool the controls to act as though the current is balanced when, in fact, it is mismatched by 22%.

A solution is found by placing a special ratio auxiliary CT in the control current path of T2, which boosts that current by 22%. This will cause both controls to see the same current when, in fact, T1 is carrying 22% more current.

In this way the controls are fooled into thinking that the load is balanced when it is actually unbalanced due to the impedance mismatch. Transformer T2 has effectively been derated by 22% in order to have the percent impedances match.

The circulating current paralleling described above is that commonly used in the U.S. Another basis for implementing circulating current paralleling is now available. The new scheme does not require the breakout of the circulating current and the load current from the total transformer current. Rather, the procedure is to recognize the apparent power factors as seen by the transformers and act so as to make the power factors be equal. The control configuration used is as shown in Fig. 3.144, where the phasor diagram, Fig. 3.145, shows typical loading for mismatched transformers. The fundamental difference in this manner of circulating current paralleling is that the principle involves the equalization of the apparent power factors as seen by the transformers, i.e., the control acts to make $\varphi 1 \approx \varphi 2$. The benefit of this subtle difference is that it is more amenable to use where the transformers exhibit mismatched impedance.

3.11 Loading Power Transformers

Robert F. Tillman, Jr.

Design Criteria

ANSI Standards Collection C57.12.99-1993 sets forth the general requirements for the design of power transformers. With respect to loading, the requirements of concern are those that define the transformer's thermal characteristics. The average ambient temperature of the air in contact with the cooling equipment for a 24-h period shall not exceed 30°C (86°F) and the maximum shall not exceed 40°C (104°F) (IEEE, 1994). For example, a day with a high temperature of 96°F and a low of 76°F has an approximate average ambient temperature of 86°F.

The average winding temperature rise above ambient shall not exceed 65°C for a specified continuous load current (IEEE, 1994). The industry uses this criteria because manufacturers can obtain it by measuring the resistance of the windings during temperature rise tests. The manufacturer must guarantee to meet this requirement.

The hottest conductor temperature rise (hot spot) in the winding shall not exceed 80°C under these same conditions (IEEE, 1994). This 80°C limit is no assurance that the hot spot rise is 15°C higher than the average winding temperature rise. In the past, using the 15°C adder to determine the hot spot rise produced very conservative test results. The greatest level of thermal degradation occurs at this location. The hot spot location is near the top of the high or low voltage winding. The most common reason for hot spots to occur is that these regions have higher localized eddy losses because the leakage flux fringes radially at the winding ends.

ANSI Standards Collection C57.12.99-1993 paragraph 4.1.6 specifies requirements for operation above rated voltage. At no load, the voltage shall not exceed 110% (IEEE, 1994). At full load, the voltage shall not exceed 105% (IEEE, 1994). Modern transformers are usually capable of excitation beyond these limits without causing saturation of the core. However, this causes the core to contribute greater than predicted heating. Consequently, all temperature rises will increase. While not critical at rated load, this becomes important when loading transformers past their rating criteria.

Nameplate Ratings

The transformer nameplate provides the voltage (excitation) rating for all taps. If a transformer has a 4-step de-energized high voltage tap changer and a 32-step LTC, then it has 5 primary voltage ratings and 33 secondary voltage ratings. The excitation limits apply to all ratings.

The cooling class affects the design of the cooling package. Different cooling classes have different thermal profiles. Therefore, gauge readings can be different for equivalently rated transformers under the same loading conditions. Consequently, the operator must understand the cooling classes and their thermal profiles in order to confirm that a given transformer is responding thermally as it should.

OA cooling uses natural air flow through the radiators to dissipate heat. FA cooling uses fans to force air through radiators in order to substantially increase the rate of cooling. There is natural convective flow of the oil in the radiators from top to bottom with both OA and FA cooling. FOA non-directed flow (NDF) cooling uses fans, as with FA, along with pumps to draw the hot oil out of the top of the transformer and force it through the radiators into the bottom of the tank. The most common modern transformer found in service with this cooling class is General Electric medium power transformers (12 MVA and larger) manufactured in Rome, Georgia. FOA directed flow also uses fans and pumps. However, this design incorporates a cooling duct that directs the oil from the radiator outlet directly through the winding from bottom to top (Pierce, 1993).

Medium power transformers, 12 MVA and larger, have three stages of cooling, OA/FA/FA or OA/FOA/FOA. Most are OA/FA/FA. Large power transformers are usually OA/FOA/FOA directed flow cooling. Some large power transformers, especially GSU transformers, are FOA only. They have no rating unless the auxiliary cooling equipment is operating.

The nameplate kVA (or MVA) rating is the continuous load at rated voltage that produces an average winding temperature rise within the 65°C limit and hot spot temperature rise within the 80°C limit (IEEE, 1994). The rating of each cooling stage is given. The transformer design must meet temperature rise guarantees for each cooling stage. Operators and planners generally express loading capability as a percent (or per unit) of the maximum MVA rating.

The windings contribute most of the heat that produces the temperature rises. The winding heat results from the "I squared r" loss in the conductor. When users express loading as a percent on an MVA basis, they are assuming that the transformer is operating at rated voltage, both primary and secondary. Operators should express the load for thermal calculations as a percent (or per unit) of the full load current for a given set of primary and secondary tap positions (Tillman, 1998).

Other Thermal Characteristics

Other thermal characteristics are dependent on the design, loss optimization, and cooling class. Top oil temperature is the temperature of the bulk oil in the top of the tank. Users can directly measure this with a gauge mounted on the transformer tank. The temperature of the oil exiting the oil duct in the top of the winding is actually the important characteristic (Chew, 1978; Pierce, 1993). Users normally do not have a direct measurement of this in practice. Manufacturers can measure this during heat run tests but normally they do not.

Bottom oil rise is the temperature rise above ambient of the oil entering the bottom of the core and coil assembly. In all cooling classes, the bottom oil temperature is approximately equal to the temperature of the oil exiting the radiators (Chew, 1978; Pierce, 1993). Manufacturers can easily measure it during heat run tests and provide the information on certified test reports. Users should require manufacturers to provide this information. In service, users can measure the bottom oil temperature with an infrared camera.

Average oil rise is the key oil thermal characteristic needed to calculate the winding gradient (Chew, 1978). It is approximately equal to the average of the temperature rise of oil entering the bottom of the core and coil assembly and the oil exiting the top. The location of the average oil is approximately equal to the location of the average winding.

The winding gradient is the difference between the average winding and average oil temperature rises (Chew, 1978). Designers assume that this gradient is the same from the bottom to the top of the winding except at the ends where the hot spot exists. The hot spot gradient is somewhat higher than the winding gradient. Designers calculate this gradient by determining the effects of localized eddy losses at the end of the winding. Computers allow designers to calculate this very accurately. An engineer can obtain an estimate of the hot spot gradient by multiplying the winding gradient by 1.1 (Chew, 1978).

Thermal Profiles

Thermal profiles show the relationships between different temperatures inside a transformer. Operators must understand these thermal profiles for given cooling classes in order to understand a transformer's thermal response to a given load. A plot of winding temperature vs. its axial position in the tank is a thermal profile.

For FA cooling, the oil temperature outside the winding is approximately equal to the oil temperature inside the winding from bottom to top (Chew, 1978). This is due to the oil movement by natural convection both inside and outside the core and coil assembly. The oil temperature exiting the bottom of the radiators approximately equals that entering the bottom of the core and coil assembly (Chew, 1978; Pierce, 1993). The top bulk oil temperature approximately equals the oil temperature at the top of the winding (IEEE, 1995). It is relatively easy for engineers to determine the gradients for this cooling class. They can verify that a transformer is responding properly to a given load by obtaining load information, reading the top oil temperature gauge, measuring the bottom oil temperature by use of an infrared camera, and comparing with calculations and data from the manufacturer's test reports.

For FOA NDF cooling, the oil pumps force oil into the bulk oil at the bottom of the tank. The higher rate of flow produces a small bottom to top temperature differential in the coolers. The oil flow in the winding is by natural convection. The pumps circulate cool oil throughout the tank and around the core and coil assembly while only a small portion passes through the windings. Therefore, the temperature profile of the oil internal to the windings does not match that of the external profile. The top winding duct oil, the key temperature, is much hotter than the top bulk oil (Pierce, 1992; 1993).

For FOA directed flow cooling, the oil pumps force oil through a sealed oil duct directly into the bottom of the core and coil assembly. The oil flows within the winding and exits the top of the winding into the bulk oil. The temperature profile of the oil external to the winding approximately equals that of the oil internal to the winding. The bottom to top oil temperature rise is very small. Top oil temperature rises for this design are lower than equivalent FA designs. The hot spot temperature is not lower because the hot spot gradient is much larger (Pierce, 1992; 1993).

Temperature Measurements

The user specifies the gauges and monitors installed by the manufacturer. The top oil temperature gauge directly measures the temperature of the top bulk oil. Most oil gauges in service are mechanical and provide instantaneous and maximum temperature readings. They also have contacts for controlling cooling and providing alarms. Some of these gauges are electronic and provide analog outputs for SCADA. This gauge reading is approximately equal to the temperature of the top winding duct oil for FA and FOA directed flow cooling and is much lower for FOA non-directed flow cooling (IEEE, 1995; Chew, 1978; Pierce, 1992; 1993).

The winding temperature gauge is actually an assembly that simulates the hot spot winding temperature. This hot spot temperature simulator measures top bulk oil and adds to it another temperature increment (hot spot gradient) proportional to the square of the load current. This incremental temperature is actually a simulation of the hot spot gradient. An oil probe inserted in a resistive well and a current obtained from a BTCT in the main winding is a method used for simulating the hot spot temperature. Designers calibrate the resistor and the current to the hot spot gradient. For FA and FOA directed flow cooling, this simulation is valid because the measured top oil temperature is approximately equal to the top winding duct oil temperature (IEEE, 1995; Chew, 1978). However, this simulation is not valid for FOA non-directed flow cooling because the measured top oil temperature is less than the top winding duct oil temperature (Pierce, 1992). It is more difficult to predict and verify the thermal response of a transformer with FOA non-directed flow cooling.

The hot spot simulator is accurate only for steady state constant loads because there is a thermal lag between the top oil and hot spot winding temperatures. A given load takes several hours to heat up the bulk oil to its ultimate temperature. On the other hand, the same load takes only a few minutes to heat up the winding conductors to their ultimate temperature. Consequently, a transformer must have an applied constant load for many hours for the hot spot simulator to indicate an accurate measurement. For transient loading, the instantaneous indication is meaningless to an operator. The actual hot spot temperature is greater for increasing loads than the simulator indicates and lower for decreasing loads (IEEE, 1995).

Users also specify electronic gauges. These have many features built into one box. They include many adjustable alarm and control contacts, both top oil and simulated hot spot temperatures, and analog outputs for SCADA. This monitor creates the hot spot simulation by routing the current directly to the monitor. Designers calibrate a microprocessor in the monitor to calculate the hot spot gradient. This provides a more reliable indication than mechanical gauges but is still a simulation with the same drawbacks discussed above.

Direct measurements of the hot spot temperature are possible through application of fiber optics. A sensor inserted in the oil duct between two winding discs replaces a key-spacer. Design engineers determine the locations to install the sensors. Fiber optic probes transmit the temperature from the sensors to a storage device (PC). These applications are relatively unreliable. Designers typically call for many probes in order to have a few that work properly. The application of fiber optics also produces additional risk of internal dielectric failure in the transformer. While fiber optics is a good research tool and appropriate for special applications, its general application is usually not worth the added risk and cost (Pierce, 1993).

Predicting Thermal Response

The IEEE Standards C57.91-1995 Guide for Loading Mineral-Oil-Immersed Transformers gives detailed formulas for calculating oil and winding temperatures. It gives formulas for constant steady state and transient loading. Users apply the transient loading equations in computer programs. Computer simulations are good for gaining understanding but are not necessary for most situations.

Users must calculate oil temperatures in order to predict a transformer's thermal response. The total losses in a transformer cause the oil temperature to rise for a given load (IEEE, 1995). Total losses include core, load, stray, and eddy losses. The oil temperatures vary directly with the ratio of the total losses raised to an exponent. The industry designation for the oil rise exponent is "n" (IEEE, 1995; Chew, 1978; Pierce, 1993).

$$TO_2 = TO_1(TL_2/TL_1)^n \tag{3.64}$$

where:

TO_2 = ultimate top oil rise
TO_1 = initial or known top oil rise
TL_2 = total losses at ultimate load
TL_1 = total losses at known load

Users can calculate a conservative approximation by neglecting the core, stray, and eddy losses and considering only the "i^2r" load losses:

$$TO_2 = TO_1(i_2^2r/i_1^2r)^n = TO_1(i_2^2/i_1^2)^n$$

$$TO_2 = TO_1(i_2/i_1)^{2n} \tag{3.65}$$

The value of "n" varies between transformer designs. The industry generally accepts an approximate value of 0.9 for FA class transformers (IEEE, 1995; Chew, 1978; Pierce, 1993). This is a conservative value.

$$TO_2 = TO_1(i_2/i_1)^{1.8} \tag{3.66}$$

If i_1 is the full load current rating, then i_2/i_1 is the per unit current loading. As an example, consider a transformer with FA cooling that has a top oil temperature rise of 55°C at full load current. Calculate the ultimate steady state top oil temperature rise due to a constant 120% load:

$$TO_2 = 55(1.2)^{1.8} = 76°C$$

If the maximum ambient temperature is 95°F (35°C), then the ultimate top oil temperature is 111°C. The user can find detailed transient equations in IEEE C57.91-1995. They appear complex but are only expanded forms of the above equations. The same basic principles apply. However, their use requires many incremental calculations summed over given time periods. There are computer programs available that apply these equations.

Transient analysis has the most value when actual temperature profiles are available. Except for special applications, this is often not the case. Usually, the temperature available is the maximum for a given time period. Furthermore, engineers do not always have time available to analyze and compare computer outputs vs. field data. The key issue is that the engineer must have the ability to predict a transformer's thermal response to a given load (steady state or transient) in order to ensure that the transformer is responding properly. They can use the above simplified steady state equations to calculate maximum temperatures reached for a given load cycle. Using a load equal to 90% of a peak cyclical load in the steady state equations yields a good approximation of the peak temperature for an operator to expect. In the above example, the resultant expected top oil temperature for a cyclical 120% load is 98°C.

The relationships for winding temperature equations are similar to the oil temperature equations. The key element is the hot spot gradient. Once an engineer calculates this gradient, he/she adds it to the calculated top oil temperature to obtain the hot spot temperature. Similar to Eq. (3.65), the hot spot gradient varies directly with the ratio of the current squared raised to an exponent "m" (IEEE, 1995; Chew, 1978; Pierce, 1993).

$$\mathrm{HSG}_2 = \mathrm{HSG}_1(i_2/i_1)^{2m} \tag{3.67}$$

where:

HSG_2 = ultimate hot spot gradient
HSG_1 = initial or known hot spot gradient
i_2 = current at the ultimate load
i_1 = current at the known or initial load

As with "n", the values of "m" vary between transformers. However, the variance for "m" is much greater. It is very dependent on the current density and loss optimization used to design a particular transformer. High losses and current densities produce large values of "m". Low losses and current densities produce small values for "m". For example, a high loss transformer design may have a lower hot spot temperature at rated load than a similar low loss transformer design. However, the low loss transformer is likely more suitable for loading past its nameplate criteria. The industry generally accepts an approximate value of 0.8 for FA class transformers (IEEE, 1995; Chew, 1978; Pierce, 1993). Again, this is a conservative value:

$$\mathrm{HSG}_2 = \mathrm{HSG}_1(i_2/i_1)^{1.6} \tag{3.68}$$

Engineers can calculate the "m" and "n" constants by requiring manufacturers to perform overload temperature tests (i.e., 125%). This, along with temperature data from standard temperature tests, provides two points for calculating these values.

There are limiting elements in a transformer other than the active part. These include bushings, leads, tap changers, and BTCTs. Sometimes it is difficult to determine the bushing rating in older transformers. Infrared scanning can help determine if a bushing is heating excessively. In modern transformers, manufacturers choose bushings with ample margin for overloading the transformer. Insulated leads are also subject to overheating, especially if the manufacturer applies too much insulation. LTC contact life can accelerate. For arcing-under-oil tap changers, oil contamination increases. It is also important to know if a transformer has a series (booster) winding. The user will probably not know the ratio of the series transformer for older transformers.

Load Cyclicality

Past practices called for loading power transformers to a percentage of their nameplate kVA or MVA rating. A typical loading criteria was 100%. The measured load used to determine the percent loading was the annual peak 15-min integrated output demand in kVA or MVA. Few users considered the cyclicality of the load or the ambient temperature. These thermal cycles allow operators to load transformers beyond their nameplate rating criteria for temporary peak loads with little or no increased loss of life or probability of failure.

To completely define the load profile, the user must know the current for thermal calculations and the power factor for voltage regulation calculations as a function of time, usually in hourly increments. Cyclical loads generally vary with temperature due to air conditioning and heating. However, summer and winter profiles are very different. Summer peak loads occur when peak temperatures occur. The reverse occurs in winter. In fall and spring, not only is the ambient temperature mild but there is little or no air conditioning or heating load. The thermal stress on a transformer with a cyclical load during fall and spring is negligible. It is also usually negligible during winter peak loading.

If ambient conditions differ from the nameplate criteria, then the user must adjust the transformer capability accordingly. IEEE C57.91-1995 provides tables and equations for making these adjustments. A good approximation is an adjustment of 1% of the maximum nameplate rating for every degree C above or below the nameplate rating (IEEE, 1995). If the transformer operates in 40°C (104°F) average ambient, then the user must de-rate the nameplate kVA by 10% in order to meet the nameplate thermal rating criteria. Conversely, operating in a 0°C (32°F) average ambient environment allows the user to up-rate the transformer by approximately 30%.

Twenty-four hour summer load cycles resemble a sine wave. The load peak occurs approximately when the temperature peak occurs, 3 to 5 PM. The load peak lasts less than 1 h. The load valley occurs during predawn hours when ambient temperature minimums occur, 4 to 6 AM. The magnitude of the valley load is 50 to 60% of the peak load. The user can calculate the top oil temperature at the valley in the same manner as at the peak. The value of making these calculations is to verify that a particular loaded transformer response is correct. If the transformer responds properly, then it meets one of the criteria for recommending overload capability.

Science of Transformer Loading

The thermal rating of a power transformer differs from the thermal rating of other current carrying elements in a substation. Examples of other elements are conductor, bus-work, connectors, disconnects, circuit breakers, etc. The insulation system for these elements is air and solid support insulators. The cooling system is passive (ambient air). The thermal limits depend on the properties of the conductor itself. These elements are maximum rated devices. In a power transformer, the cooling system is active. The thermal limits depend on the dielectric and mechanical properties of the cellulose and oil insulation system. As a maximum rated device, the transformer capability is 200% of the maximum nameplate rating (IEEE, 1995).

With overly conservative loading practices, cellulose insulation life due to thermal stress is practically limitless, theoretically more than 1000 years. In practice, deterioration of accessories and non-active parts limits the practical life of the transformer. These elements include the tank, gauges, valves, fans, radiators, bushings, LTC, etc. The average, practical life of a transformer is probably 30 to 50 years. Many fail beyond economical repair before 30 years. Therefore, it is reasonable and responsible to allow some thermal aging of the cellulose insulation system. The key is to identify the risk. Loss of insulation life is seldom the real risk. Most of the time, risks other than loss of insulation life are the limiting characteristics.

Paper insulation must have mechanical and dielectric strength. The mechanical strength allows it to withstand forces caused by through faults. When through faults occur, the winding conductors try to move. If the paper has sufficient mechanical strength, the coil assemblies will also have sufficient strength to withstand these forces. When aged paper loses its mechanical strength, through faults will cause excessive winding movement. Physical damage due to excessive winding movement during through fault conditions reduces the dielectric withstand of the paper insulation. At this point, the risk of dielectric failure is relatively high.

Arrhenius reaction equation is the basic principle for thermal aging calculations (Kelly et al., 1988a; Dakin, 1948):

$$L = Ae^{(B/T)} \tag{3.69}$$

"L" is the calculated insulation life in hours. "A" and "B" are constants that depend on the aging rate and end-of-life definition. They also depend on the condition of the insulation system. "T" is the absolute temperature in degrees Kelvin (degrees C + 273) (Kelly et al., 1988a). There is a limited amount of functional life test data available. Most available data is over 20 years old. Past calculations of life expectancy used extremely conservative numbers for the "A" and "B" constants (Kelly et al., 1988a).

Normal life of cellulose insulation is the time in years for a transformer operated with a constant 110°C hot spot winding temperature to reach its defined end of life criteria. DP (degree of polymerization) and tensile strength are properties that quantify aging of cellulose paper insulation (Kelly et al., 1988b). In the past, the industry accepted approximately 7½ years for normal life. This is a misleadingly low value. Actual practice and more recent studies show that normal life under these conditions is somewhere between 20 years and infinity (IEEE, 1995). It is not important for users to master these relationships and equations. However, the user should understand the following realities:

1. The relationship between life expectancy and temperature is logarithmic (McNut, 1995). As the hottest spot conductor temperature moves below 110°C, the life expectancy increases rapidly and vice versa. An accepted rule of thumb is the life doubles for every 8°C decrease in operating temperature. It halves for every 8°C increase in operating temperature (Kelly et al., 1988a).
2. Users seldom operate transformers such that the hot spot winding temperature is above, at, or anywhere near 110°C. Even when peak loads cause 140°C hot spot winding temperatures, the cumulative time that it operates above 110°C is relatively short; it is probably less than 200 to 400 h per year.
3. Cellulose aging is a chemical reaction. As in all reactions, heat, water, and oxygen act as a catalyst. In the Arrhenius equation, the "A" and "B" constants are highly dependent on the presence of moisture and oxygen in the system (Kelly et al., 1988b). The expected life of the paper halves when the water content doubles (Bassetto et al., 1997; Kelly et al., 1988b). Also, tests indicate that the aging rate increases by a factor of 2.5 when oxygen content is high (Bassetto et al., 1997; Kelly et al., 1988b).

Water in Transformers Under Load

The action of water in the insulation system of power transformers poses one of the major risks in loading transformers past their nameplate rating criteria. The insulation system inside a transformer consists of cellulose paper and oil working together. Water always exists in this system. The paper must have some moisture content in order to maintain its tensile strength (Kelly et al., 1988b). However, the distribution of the water in this system is uneven. The paper attracts much more water than the oil (Kelly et al., 1988c). As the transformer cycles thermally throughout its life, the water redistributes itself. The water will collect in the coldest part of the winding (bottom disks) and in the area of highest electrical intensity (Kelly et al., 1988c). This redistribution of moisture is very unpredictable.

When a transformer is hot due to a heavy load, water moves from the paper to the oil. The heat in the conductor pushes the water out of the paper insulation while the solubility of water in oil increases with temperature (Kelly et al., 1988b). When the transformer cools, water moves back to the paper. However, the water goes back into the paper much more slowly than it is driven out (Kelly et al., 1988b). As the oil cools, the water in the oil can approach saturation.

As long as changes take place gradually and temperatures do not reach extreme levels, the insulation system can tolerate the existence of a significant amount of water (Kelly et al., 1988b). However, loading transformers to a higher level causes higher temperatures and greater changes during the thermal cycling. Emergency loading causes greater temperature swings than normal loading. The key is to understand what is an excessive temperature and when it will occur. That is the point at which elevated temperatures introduce the risk of failure. That temperature level depends on the moisture content in the insulation system. There are two basic risks associated with the relationship between loading and water in the insulation system; they are reduction in dielectric strength due to saturation of moisture in oil, and bubble evolution.

Dielectric Effects of Moisture in Oil

The dielectric strength of oil is a function of the average oil temperature and percent saturation of water in the oil (Moore, 1997). As long as the oil is hot, the water solubility is high (Kelly et al., 1988b). Therefore, a given amount of water in the oil produces a lower percent saturation at high temperature than at low temperature. As an example, consider a transformer with 1.5% water in the paper. A 100% load on a hot summer day produces a 70°C average oil temperature. The water content of the oil reaches 20 ppm as the moisture is driven from the paper into the oil (Kelly et al., 1988c). The water saturation at this point is 220 ppm, resulting in less than 10% saturation (Kelly et al., 1988b). The dielectric breakdown of the oil as measured by ASTM D1816 method is quite high, approximately 50 kV (Moore, 1997). In the evening, the load and temperature decrease, producing an average oil temperature of 50°C. The saturation level of water in the oil reduces to approximately 120 ppm (Kelly et al., 1988b). Since the oil goes back into the paper slowly, the water in oil is still 20 ppm resulting in almost 20% saturation, which is still quite low. The dielectric breakdown is somewhat lower, approximately 45 kV (Moore, 1997). This is still quite high and poses no real problem.

Now consider the same example where the peak load increases to 120%. The resultant peak average oil temperature is 90°C causing the moisture content of the oil to reach 60 ppm (Kelly et al., 1988c). The percent saturation at peak temperature is still less than 10% (Kelly et al., 1988b). However, during the evening the average oil temperature is 55°C. The water saturation level is 140 ppm, greater than 40% saturation (Kelly et al., 1988b). The dielectric breakdown reduces significantly to approximately 35 kV (Moore, 1997).

The conditions in this example should not cause problems, especially if the transformer in question is relatively new. However, the insulation systems in service aged transformers have properties that magnify the risk illustrated in this example (Oommen et al., 1995). Severe emergency loading can produce higher risk levels, especially if they occur in winter. At 0°C, oil saturates at approximately 20 ppm (Kelly et al., 1988b). There is a point where the probability of failure increases to an unacceptable level.

Bubble Evolution

Bubble evolution is a function of conductor temperature, water content by dry weight of the paper insulation, and gas content of the oil (Oommen et al., 1995). Gas bubbles in a transformer insulation system are of concern because the dielectric strength of the gases is significantly lower than that of the cellulose insulation and oil. When bubbles evolve, they replace the liquid insulation. At this point, the dielectric strength decreases and the risk of dielectric failure of the major and minor insulation systems increases.

Bubbles result from a sudden thermal change in the insulation at the hottest conductor. In a paper insulation system, there is an equilibrium state between the partial pressures of the dissolved gases in the paper. As temperature increases, the vapor pressure increases exponentially. When the equilibrium balance tips, the water vapor pressure causes the cellulose insulation to suddenly release the water vapor as bubbles (Oommen et al., 1995).

According to past studies, moisture content is the most important factor influencing bubble evolution. The temperature at which bubbles evolve decreases exponentially as the moisture content in the cellulose insulation increases. Increasing content of other gases also significantly influences bubble evolution when high moisture content exists. Increasing content of other gases does not significantly influence bubble evolution at low moisture content (McNut, 1995). Data show that in a dry transformer (less than 0.5% moisture by dry weight) bubble evolution from overload may not occur below 200°C. A service aged transformer with 2.0% moisture may evolve bubbles at 140°C or less (Oommen et al., 1995).

Voltage Regulation

Voltage regulation is the voltage drop through a transformer's impedance. It determines the output voltage at the load side terminals of a power transformer. If output voltage is too low, then regulating equipment cannot provide adequate voltage control to the system it serves. Voltage regulation also affects the thermal response of a transformer (Tillman, 1998).

A transformer load flowing through its impedance produces voltage drop. In order to calculate this drop, an engineer must know the load current and power factor in addition to the impedance of the transformer. The impedance is "r + jx" (usually expressed in percent at OA rating and rated voltage). The load is "$I\angle-\theta$" where "I" is the magnitude of the load current and "θ" is the inverse cosine of the power factor (p). Voltage regulation is the magnitude of the input voltage (V_{in}) minus the magnitude of the output voltage (V_{out}) divided by the magnitude of the output voltage (Bean et al., 1959):

$$\text{Regulation} = \left\{\left|V_{in}\right| - \left|V_{out}\right|\right\}\Big/\left|V_{out}\right| \tag{3.70}$$

To calculate the voltage drop, one must solve the following equation (Bean et al., 1959):

$$V_{in} = \left\{I\angle-\theta\right\}\left\{r + jx\right\} + V_{out} \tag{3.71}$$

Letting V_{out} equal $1\angle 0$, solving Eq. (3.71) for V_{in}, and plugging into Eq. (3.70), one derives the following regulation equation in per unit values:

$$\text{Regulation} = \text{SQRT}\left[I^2\left(r^2 + x^2\right) + 2I\left(pr + qx\right) + 1\right] - 1 \tag{3.72}$$

where

I = load current in per unit of the OA load current
p = load power factor in per unit
q = load reactive factor in per unit; positive for lagging and negative for leading
r = load loss resistance in per unit at the OA rating
x = leakage reactance in per unit at the OA rating

For illustration, consider an example where the load is 120% of the maximum nameplate rating (2 per unit of the OA rating), power factor is .90 lagging (p = .90 and q = .45), and impedance is .005 + j.105 per unit. The calculated voltage drop through the transformer is approximately 12%. Tap changing equipment will have to operate at or near maximum raise in order to compensate for this large voltage drop. Further loading in this example is impossible unless users improve the power factor by providing Varr support.

Planners use measured output MVA and a transformer's maximum nameplate MVA rating in order to calculate the percent (or per unit) loading. However, the loading used in Eq. (3.72) is current. The per unit MVA load only equals the per unit current load when the actual output voltage equals the rated output voltage (Tillman, 1998). This almost never happens. In the previous example, consider an input voltage equal to 100% (or 1.00 per unit) of the transformer HV rating. The calculated output voltage due to the 12% voltage drop is .88 per unit of the output voltage rating. In order to deliver nameplate MVA at .88 per unit voltage, the actual current has to be the rated voltage divided by the actual voltage times the rated current:

$$I_{actual} = I_{rated}(1/0.88) = 1.136(I_{rated})$$

In the previous example, the 120%, of MVA, load used to calculate voltage drop was actually a 136% (120% × 1.136), of current, load. The actual voltage drop is approximately 13½% by recalculating Eq. (3.68) using per unit current rather than per unit MVA. Also, Eq. (3.66) calls for per unit current to calculate the top oil temperature rise. The calculated top oil temperature rise is 7 to 10°C higher using current instead of MVA (Tillman, 1998).

Loading Recommendations

The IEEE loading guide and many published papers give guidelines and equations for calculating transformer loading. In theory, operators can load modern transformers temporarily up to 200% of nameplate rating or 180°C hottest conductor temperature. These guidelines provide a tool to help a user understand the relationship between loading and the design limitations of a power transformer. However, understanding the relationship between loading and the general condition of and moisture in the insulation system along with voltage regulation is also important. Unless conditions are ideal, these factors will limit a transformer's loading capability before quantified loss of life considerations.

The following loading recommendations assume the load is summer and winter peaking, the fall and spring peak is approximately 60% of summer peak, average ambient temperature on a normal summer day is 30°C, the daily load profile is similar to the cyclical load profile described earlier, the winter peak is less than 120% of the summer peak, and the non-cyclical load is constant except for downtime:

Type of Load	FA Max Top Oil Temp (°C)	NDFOA Max Top Oil Temp (°C)	Max Winding Temp (°C)	Max % Load
Normal summer load	105	95	135	130
Normal winter load	80	70	115	140
Emergency summer load	115	105	150	140
Emergency winter load	90	80	130	150
Non-cyclical load	95	85	115	110

Alarm Settings	FA 65°C Rise	NDFOA 65°C Rise
Top Oil	105°C	95°C
Hot Spot	135°C	135°C
Load Amps	130%	130%

1. The normal summer loading accounts for periods when temperatures are abnormally high. These might occur every three to five years. For every degree C that the normal ambient temperature during the hottest month of the year exceeds 30°C, de-rate the transformer 1% (i.e., 129% loading for 31°C average ambient).
2. The percent load is given on the basis of the current rating. For MVA loading, multiply by the per unit output voltage. If the output voltage is .92 per unit, the recommended normal summer MVA loading is 120%.
3. Exercise caution if the load power factor is less than 0.95 lagging. If the power factor is less than 0.92 lagging, then lower the recommended loading by 10% (i.e., 130% to 120%).
4. Verify that cooling fans and pumps are in good working order and oil levels are correct.
5. Verify that the oil condition is good: moisture is less than 1.5% (1.0% preferred) by dry weight, oxygen is less than 2.0%, acidity is less than 0.5, and CO gas increases after heavy load seasons are not excessive.
6. Verify that the gauges are reading correctly when transformer loads are heavy. If correct field measurements differ from manufacturer's test report data, then investigate further before loading past nameplate criteria.
7. Verify with infrared camera or RTD during heavy load periods that the LTC top oil temperature relative to the main tank top oil temperature is correct. For normal LTC operation, the LTC top oil is cooler than the main tank top oil. A significant deviation from this indicates LTC abnormalities.
8. If the load current exceeds the bushing rating, do not exceed 110°C top oil temperature (IEEE, 1995). If bushing size is not known, perform an infrared scan of the bushing terminal during heavy load periods. Investigate further if the temperature of the top terminal cap is excessive.

9. Use winding power factor tests as a measure to confirm the integrity of a transformer's insulation system. This gives an indication of moisture and other contaminants in the system. High BIL transformers require low winding power factors (<0.5%), while low BIL transformers can tolerate higher winding power factors (<1.5%).
10. If the transformer is extremely dry (less than 0.5% by dry weight) and the load power factor is extremely good (0.99 lag to 0.99 lead), then add 10% to the above recommendations.

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3.12 Causes and Effects of Transformer Sound Levels

Jeewan Puri

In modern communities, there is an increasing prevalence of local ordinances specifying sound levels at commercial and residential property lines. Consequently, the sound energy radiated from transformers has become a factor of increasing importance to the neighboring residential areas. It is therefore appropriate that a good understanding of sound power radiation and its measurement principles be developed for appropriately specifying sound levels in transformers. A good understanding of these principles can be helpful in minimizing community complaints regarding the present and future installations of transformers.

Transformer Sound Levels

In order to evaluate a sound source, we must understand the following basic principles used for the quantification of sound energy.

Sound Pressure Level

The main quantity used to describe a sound is the size or amplitude of the pressure fluctuations at a human ear. The weakest sound a healthy human ear can detect has an amplitude of 20 millionths of a Pascal (20 µPa). A pressure change of 20 µPa is so small that it causes the eardrum to deflect a distance less than the diameter of a single hydrogen molecule. Amazingly, the ear can tolerate sound pressures more than one million times higher. Thus, if we measured sound in Pa, we would end up with some quite large, unmanageable numbers. To avoid this, another scale is used — the decibel or dB scale.

The decibel is not an absolute unit of measurement. It is a ratio between a measured quantity and an agreed reference level. The dB scale is logarithmic and uses the hearing threshold of 20 µPa as the reference level. This is defined as 0 dB. A sound pressure level L_p may therefore be defined as:

$$L_p \text{ dB} = 10 \log (P/P_o)^2$$

where P_o = reference level = 20 µPa

One useful aspect of the decibel scale is that it gives a much better approximation of the human perception of relative loudness than the Pascal scale.

Perceived Loudness

We have already defined sound as a pressure variation, which can be heard by a human ear. A healthy human ear of a young person can hear frequencies ranging from 20 Hz to 20 kHz. In terms of sound pressure level, audible sounds range from the threshold of hearing at 0 dB to the threshold of pain which can be over 130 dB.

Although an increase of 6 dB represents a doubling of the sound pressure, in actuality an increase of about 10 dB is required before the sound subjectively appears to be twice as loud. The smallest change in sound level we can perceive is about 3 dB.

The subjective or perceived loudness of a sound is determined by several complex factors. One such factor is that the human ear is not equally sensitive at all frequencies. It is most sensitive to sounds between 2 and 5 kHz and less sensitive at higher and lower frequencies.

Sound Power

A source sound radiates energy and this results in a sound pressure. Sound energy is the cause. Sound pressure is the effect. Sound power is the rate at which energy is radiated (energy per unit time). The sound pressure that we hear or measure with a microphone is dependent on the distance from the source and the acoustic environment (or sound field) in which sound waves are present. This in turn depends on the size of the room and the sound absorption characteristics of its wall surfaces. Therefore by measuring sound pressure, we cannot necessarily quantify how much noise a machine makes. We have to find the sound power because this quantity is more or less independent of the environment and is the unique descriptor of the noisiness of a sound source.

Sound Intensity Level

Sound intensity describes the rate of energy flow through a unit area. The units for sound intensity are watts per square meter (W/m^2).

Sound intensity also gives a measure of direction, as there will be energy flow in some directions but not in others. Therefore, sound intensity is a vector quantity as it has both magnitude and direction. On the other hand, pressure is a scalar quantity as it has magnitude only. Usually we measure the intensity in a direction normal (at 90°) to a specified unit area through which the sound energy is flowing.

Sound intensity is measured as the time-averaged rate of energy flow per unit area. At some points of measurements, energy may be traveling back and forth. If there is no net energy flow in the direction of measurement, there will be no net recorded intensity.

Like sound pressure, sound intensity level L_I is also quantified using a dB scale where the measured intensity I in W/m^2 is expressed as ratio to a reference intensity level I_o as follows:

$$L_I\ dB = 10 \log (I/I_o)$$

where I_o = reference level = 10^{-12} W/m^2

Sound Intensity and Sound Pressure Level Relationship

For any free progressive wave there is a unique relation between the mean-square sound pressure and the intensity. This relation at a particular point and in the direction of the wave propagation is described as follows:

$$I = P^2_{rms}/\rho c\ W/m^2$$

where

I = intensity, W/m^2
P^2_{rms} = mean-square sound pressure, $(N/m^2)^2$, measured at that particular point where I is desired in the free progressive wave
ρc = characteristic resistance, mks rayls

Note that for air, at T = 20°C and atmospheric pressure = 0.751 m of Hg, ρc = 406 mks rayls.

As described earlier, sound intensity level in decibels is:

$$L_I = 10 \log (I/I_o)\ dB$$

where I = sound intensity (power passing in a specified direction through a unit area), W/m^2

Combining the above equations, the sound intensity level may be expressed as:

$$L_1 = 10 \log((P^2{}_{rms}/\rho c)/I_{o)}$$

$$= 10 \log(P_{rms}/P_o)^2 + 10 \log ((P^2_o/\rho c)/I_o)$$

From this expression, L_1 may be defined as follows:

$$L_1 = L_p - 10 \log K$$

where K = constant = $I_o * \rho c/P^2{}_o$, which is dependent upon ambient pressure and temperature.

By definition,

$$P^2{}_o/I_o = (20*10^{-6})^2/10^{-12} = 400 \text{ mks rayls}$$

Note that the quantity 10 log K will equal zero, when K = 1 or when ρc equals 400.

As described earlier, under commonly encountered temperature and atmospheric conditions, pc is ~400.

Therefore, in free field measurements $L_p \approx L_I$.

That is, noise pressure and noise intensity measurement in free space yield the same numerical value.

Sound Energy Measurement Techniques

Sound level of a source may be measured by directly measuring sound pressure or sound intensity at a known distance. Both of these measurement techniques are quite equivalent and acceptable. In most of the industry worldwide, sound pressure measurements have been used for quantifying sound levels in transformers. As a result of the recent work completed by CIGRE, sound intensity measurements are now being incorporated as an alternative in the IEC Standard 60076-10.

Sound Pressure Level Measurement

A sound level meter is an instrument designed to respond to sound in approximately the same way as the human ear and to give objective, reproducible measurements of sound pressure level. There are many different sound measuring systems available. Although different in detail, each system consists of a microphone, a processing section, and a read-out unit.

The microphone converts the sound signal to an equivalent electrical signal. The most suitable type of microphone for sound level meters is the condenser microphone, which combines precision with stability and reliability. The electrical signal produced by the microphone is quite small. It is therefore amplified by a preamplifier before being processed.

Several different types of processing may be performed on the signal. The signal may pass through a weighting network of filters. It is relatively simple to build an electronic circuit whose sensitivity varies with frequency in the same way as the human ear, thus simulating the equal loudness contours. This has resulted in three different internationally standardized characteristics termed the “A”, “B”, and “C” weightings.

Nowadays the “A” weighting network is the most widely used since the “B” and “C” weightings do not correlate well with subjective tests.

Sound Intensity Measurements

Until recently, we could only measure sound pressure that was dependent on the sound field. Sound power can be related to sound pressure only under carefully controlled conditions where special assumptions are made about the sound field. Therefore, a noise source had to be placed in specially constructed rooms such as anechoic or reverberant chambers to measure sound power levels with the desired accuracy.

Sound intensity, however, can be measured in any sound field. This property allows all the measurements to be done directly in situations where a plurality of sound sources are present. Measurements on any sound source can be made even when all the others are radiating noise simultaneously. It should be noted that steady background noise makes no contribution to the sound power of the source determined with sound intensity measurements.

Sound intensity is the time-averaged product of the pressure and particle velocity. A single microphone can measure pressure. However, measuring particle velocity is not as simple. With Euler’s linearized equation, the particle velocity can be related to the *pressure gradient* (i.e., the rate at which the instantaneous pressure changes with distance).

Euler’s equation is essentially Newton’s second law applied to a fluid. Newton’s Second Law relates the acceleration given to a mass to the force acting on it. If we know the force and the mass, we can find the acceleration and then integrate it with respect to time to find the velocity.

With Euler’s equation, it is the pressure gradient that accelerates a fluid of density ρ.

With the knowledge of pressure gradient and density of the fluid, the particle acceleration (or deceleration) can be calculated as follows:

$$a = -1/\rho \ \partial P/\partial r$$

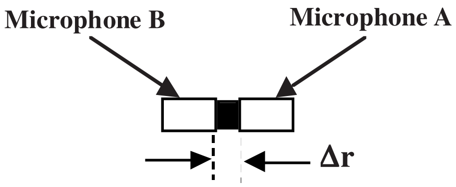
where a = particle deceleration due to a pressure change ∂P in a fluid of density ρ across a distance ∂r.

Integrating the above gives the particle velocity ‘u’ as follows:

$$u = -\int 1/\rho \ \partial P/\partial r \ dt$$

It is possible to measure the pressure gradient with two closely spaced microphones facing each other and relate it to the particle velocity using the above equation.

With two closely spaced microphones 'A' and 'B' separated by a distance Δr, it is possible to obtain a straight line approximation to the pressure gradient by taking the difference in their measured pressures P_A and P_B and dividing it by the distance Δr between them. This is called a finite difference approximation.



The pressure gradient signal must now be integrated to give the particle velocity 'u' as follows:

$$u = -1/\rho \int((P_A - P_B)/\Delta r)dt$$

Since intensity I is the time averaged product of pressure P and particle velocity u

$$I = -P/\rho \int((P_A - P_B)/\Delta r)dt$$

where $P = (P_A + P_B)/2$

This is the basic principle of signal processing in sound intensity measuring equipment.

Sources of Sound in Transformers

Unlike cooling fan or pump noise, the sound radiated from a transformer is tonal in nature, consisting of even harmonics of the power frequency. It is generally recognized that the predominant source of transformer noise is the core. The low frequency, tonal nature of this noise makes it harder to mitigate than the broad band higher frequency noise that comes from the other sources. This is because low frequencies propagate farther with less attenuation. Also, tonal noise can be perceived more acutely than broad band levels, even with high background noise levels. This combination of low attenuation and high perception makes tonal noise the dominant problem in the neighboring communities around transformers. To address this problem, most noise ordinances impose penalties or stricter requirements for tonal noise.

Even though the core is the principal noise source in transformers, the load noise, which is principally caused by the electromagnetic forces in the windings, can also be a significant influence in low sound level transformers. The cooling equipment (fans and pumps) noise typically dominates the very low and very high frequency ends of the sound spectrum, whereas the core noise dominates in the intermediate range of frequencies between 100 and 600 Hz.

These sound producing mechanisms may be further characterized as follows:

Core Noise — When a strip of iron is magnetized, it undergoes a very small change in its dimensions (usually only a few parts in a million). This phenomenon is called magnetostriction. This change in dimension is independent of the direction of magnetic flux; therefore, it occurs at twice the line frequency. Because the magnetostriction curve is nonlinear, even higher harmonics also appear in the resulting core vibration at higher induction levels (above 1.4 T).

Flux density, core material, core geometry, and the waveform of excitation voltage are the factors that influence the magnitude and frequency components of the transformer core sound levels. The mechanical resonance in transformer mounting structure, core, and tank walls can also have a significant influence on the magnitude of transformer vibrations and consequently on the acoustic noise generated.

Load Noise — Load noise is caused by vibrations in tank walls, magnetic shields, and transformer windings due to the electromagnetic forces resulting from leakage fields produced by load currents. These electromagnetic forces are proportional to the square of the load currents.

The load noise is predominantly produced by axial and radial vibration of transformer windings. However, marginally designed magnetic shielding can also be a significant source of sound in transformers. A rigid design for laminated magnetic shields with firm anchoring to the tank walls can greatly reduce their influence on the overall load sound levels. The frequency of load noise is usually twice the power frequency. An appropriate mechanical design for laminated magnetic shields can be helpful in avoiding resonance in the tank walls. The design of the magnetic shields should take into account the effects of overloads to avoid saturation, which would cause higher sound levels during such operating conditions.

Studies have shown that except in very large coils, radial vibrations do not make any significant contribution to the winding noise. The compressive electromagnetic forces produce axial vibrations and thus can be a major source of sound in poorly supported windings. In some cases, the natural mechanical frequency of winding clamping systems may tend to resonate with electromagnetic forces, thereby severely intensifying the load noise. In such cases, damping of the winding system may be required to minimize this effect.

The presence of harmonics in load current and voltage (e.g., in rectifier transformers) can produce vibrations at twice the harmonic frequencies and thus a sizeable increase in the overall sound level of a transformer.

Through several decades the contribution of the load noise to the total transformer noise has remained moderate. However, in transformers designed with low induction levels and improved core designs for complying with low sound level specifications, the load-dependent winding noise of electromagnetic origin can become a significant contributor to the overall sound level of the transformer. In many such cases, the sound power of the winding noise is only a few dB below that of the core noise.

Fan and Pump Sound — Power transformers generate considerable heat because of the losses in the core, coils, and other metallic structural components of the transformer. This heat is removed by fans which blow air over radiators or coolers. Noise produced by the cooling fans is usually broad band in nature. Cooling fans usually contribute more to the total noise for transformers of smaller rating and for low-induction transformers. Factors that affect the total fan noise output include tip speed, blade design, number of fans, and the arrangement of the radiators.

Sound Level and Measurement Standards for Transformers

NEMA Publication TR-1, Tables 02 thorough 04, lists standard sound levels for liquid filled power, liquid filled distribution, and dry type transformers. These sound level requirements must be met unless special lower sound levels are specified by the customer.

The present sound level measurement procedures as described in IEEE Standards C57.12.90 and C57.12.91 specify that the sound level measurements on a transformer shall be made under no load conditions. Sound pressure measurements shall be made to quantify the total sound energy radiated by a transformer. Sound intensity measurements have already been incorporated into IEC Sound Level Measurement Standard 60076-10 as an acceptable alternative. It is anticipated that this method will be adopted in the IEEE standards in the near future. The following is a brief description of the procedures used for this determination.

Transformer Connections During Test

This test is performed by exciting one of the transformer windings at rated voltage of sinusoidal wave shape at rated frequency while all the other windings are open circuited. The tap-changer (if any) is at the rated voltage tap position. In some cases (e.g., transformers equipped with reactor type on-load-tap-changers), a tap position other than the rated may be used if the transformer produces maximum sound levels at this position.

Principal Radiating Surface for Measurements

This is the surface from which the sound energy is emanating toward the receiver locations. The location of the radiating surface is determined based on the proximity of the cooling equipment to the transformer.

For transformers with no cooling equipment or with cooling equipment mounted less than 3 m from the transformer tank or dry type transformers with enclosures provided with cooling equipment (if any) inside the enclosure, the principal radiating surface is obtained by taking the vertical projection of a string contour surrounding the transformer and its cooling equipment (if any) as shown in Fig. 3.146 (taken from IEC 60076-10) . The vertical projection begins at the tank cover and terminates at the base of the transformer.

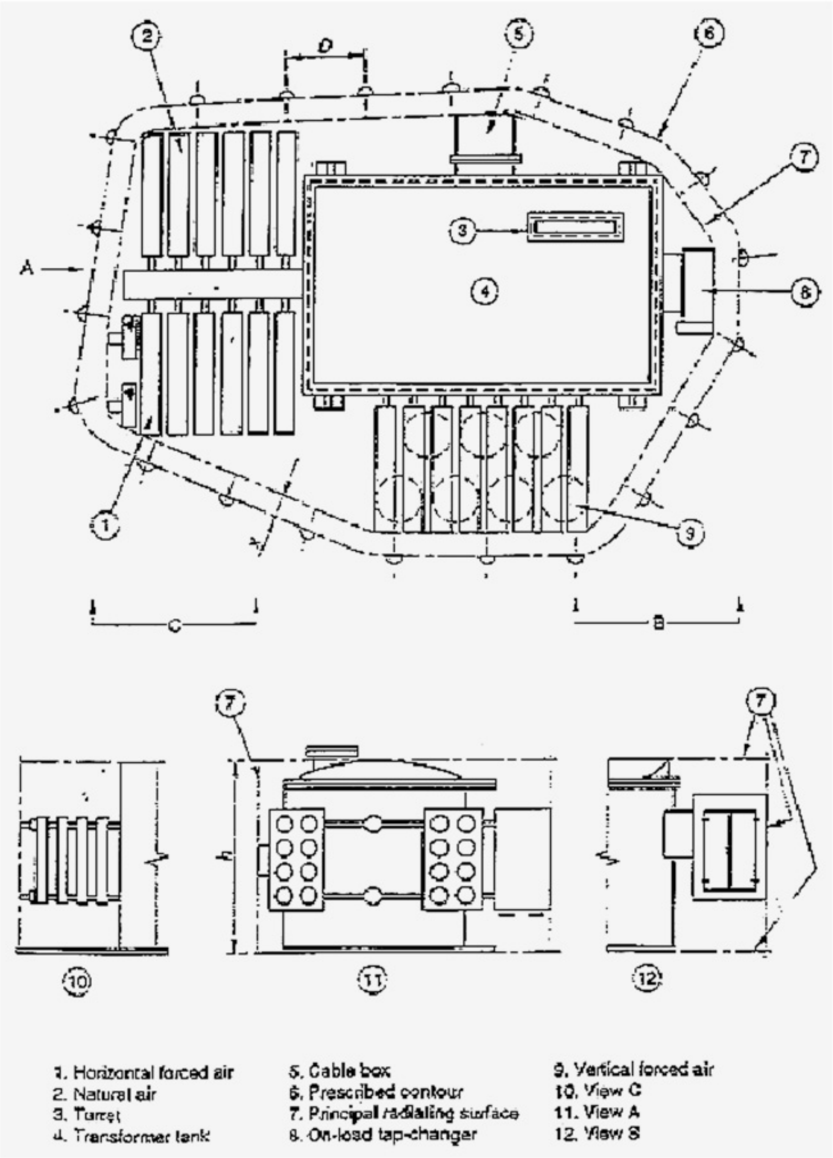


FIGURE 3.146 Typical microphone positions for sound measurement on transformers having cooling auxiliaries mounted either directly on the tank or on a separate structure spaced <3 m away from the principal radiating surface of the main tank.

Separate radiating surfaces for the transformer and its cooling equipment are determined if the cooling equipment is mounted more than 3 m from the transformer tank. The principal radiating surface for the cooling equipment is determined by taking the vertical projection of the string perimeter surrounding the cooling equipment as shown in Fig. 3.147 (taken from IEC 60076-10). The vertical projection begins at the top of the cooling structure and terminates at its base.

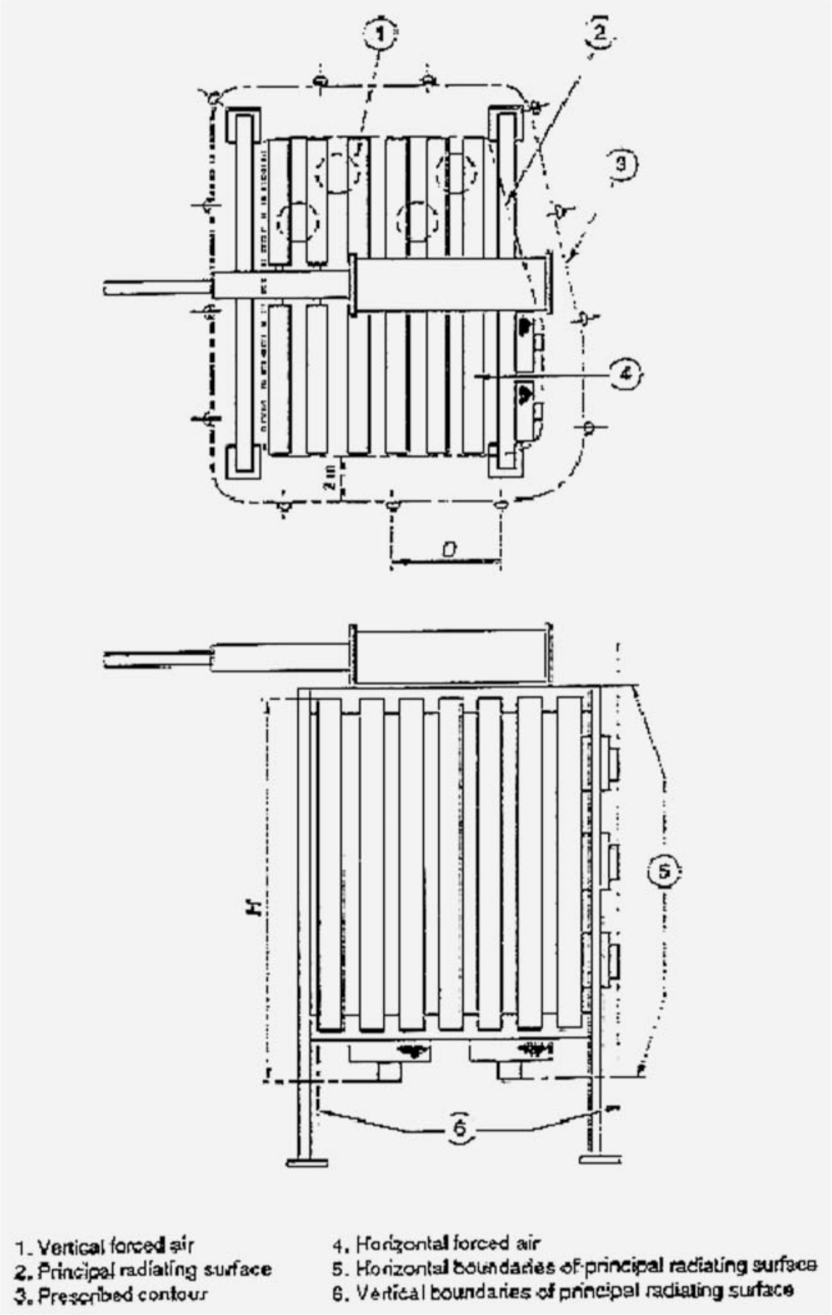


FIGURE 3.147 Typical microphone positions for sound measurement on cooling auxiliaries mounted on a separate structure spaced ≥3 m away from the principal radiating surface of the transformer.

Prescribed Contour Location for Measurements

All sound level measurements are made on a prescribed contour located 0.3 m away from the radiating surface. The location of this contour will depend on the radiating surface as determined by the proximity of the cooling equipment to the transformer as shown in Figs. 3.146 and 3.147.

The location of the prescribed contours above the base of the transformer shall be at half the tank height for transformer tanks < 2.5 m high or at one-third and two-thirds the tank height for transformer tanks <2.5 m high.

Measuring Positions on Prescribed Contour

The first microphone position is located on the prescribed contour opposite the main tank drain valve. Proceeding in a clockwise direction (as viewed from the top of the transformer), additional measuring positions on the prescribed contour are located no more than 1 m apart.

The minimum number of measurements as stipulated in IEEE C57.12.90 or IEEE C57.12.91 for North American practices is taken on each prescribed contour. These standards specify that sound level measurements shall be made with and without the cooling equipment in operation. IEC 60076-10 standard should be consulted for European practices, which are slightly different.

Sound Pressure Level Measurements

A-weighted sound pressure level measurements are the most commonly used method for determining sound levels in transformers.

Sound pressure measurements are quite sensitive to the ambient sound levels on the test floor. Therefore, appropriate corrections for the ambient sound level and reflected sound from the surrounding surfaces must also be quantified for determining the true sound level of the transformer.

It is recommended that acceptable ambient sound level conditions should be met for obtaining reliable measurements on transformers. For this reason, industry standards specify that A-weighted ambient sound pressure levels must be measured immediately before and after the measurements on the transformer. The ambient noise level readings are taken at each microphone position on the prescribed contours with the transformer and cooling equipment (if any) de-energized. These measurements are used for correcting the measurements made on the transformer. The magnitude of this correction depends upon the difference between the ambient and the transformer sound levels. This difference should not be less than 5 dB for a valid measurement. No correction is necessary if the ambient sound level is more than 10 dB lower than the transformer sound level.

From the measured sound pressure levels, L_{pAi}, at each microphone position on the prescribed contour, an A-weighted average sound pressure level, L_{pA}, may be calculated using the following equation:

$$L_{pA} = 10 \log \left[1/N \sum_{i=1}^{N} 10^{0.1 L_{pAi}} \right] - K \text{ dB}$$

where

L_{pA} = A-weighted average sound pressure level, in decibels — Reference: 20 μPa
L_{pAi} = A-weighted sound pressure level measured at the *i*th position and corrected for the ambient noise level, in decibels — Reference: 20 μPa
N = total number of measuring positions on the prescribed contour
K = environmental correction for the influence of reflected sound and ambient sound level, in decibels. IEEE and IEC standards should be consulted for details.

Sound Intensity Measurements

The equipment for these measurements has only recently emerged in the industry. By definition, the A-weighted sound intensity measurements provide a measure of sound power radiated in watts through a unit area per unit time. This type of measurement yields a vector quantity that represents the sound energy radiated in a direction normal to the principal radiating surface of the transformer.

The noise intensity measuring probes use two matched microphones that respond to sound pressure so that the readings taken by them does not differ by more than 1.5 dB at any location.

From the measured sound intensity levels, L_{IAi}, at each position of the prescribed contour, an A-weighted average sound intensity level in decibels, L_{IA}, may be calculated using the following equation:

$$L_{IA} = 10 \log \left[1/N \sum_{i=1}^{N} 10^{0.1 L_{ia}} \right] \text{dB}$$

where

L_{IA} = A-weighted average sound intensity level, in decibels — Reference: 10^{-12} W/m^2
L_{ia} = A-weighted sound intensity level measured at the *i*th position for the ambient noise level — Reference: 10^{-12} W/m^2
N = total number of measuring positions on the prescribed contour

Unlike sound pressure, the noise intensity measurements are not influenced by the ambient noise level provided the ambient noise remains constant as the measurements are taken around the prescribed contour. Under such conditions, noise intensity measurements can be made in ambient sound level even higher than the sound level of the transformer. For this reason, these types of measurements are especially suitable for transformers designed for very low noise levels.

It should be recognized that at this time the transformer industry experience in sound intensity measurement is rather limited. Actual measurements published in CIGRE publications have demonstrated that the reliability of the sound intensity measurements depends upon the difference ΔL between the average sound intensity and pressure measurements made by the same probes. This work suggests that for optimum results, ΔL should not be more than 8 dB.

Calculation of Sound Power Level

For demonstrating compliance with the local ordinances, it becomes necessary to calculate sound pressure levels at property lines located away from the transformer.

Sound power level provides a measure of the total sound energy radiated by a transformer. With this quantity, the sound pressure levels at any desired distance (outside the prescribed contour) from the transformer may be calculated.

Since sound pressure or sound intensity measurements yield the same numerical result, the following equations may be used for calculating sound power levels in decibels from the measured sound pressure or sound intensity levels.

$$L_{WA} = L_{IA} + 10 \log (S) \text{ dB}$$

or

$$L_{WA} = L_{pA} + 10 \log (S) \text{ dB}$$

where

S = the area of the radiating surface in square meters
L_{WA} = 10 log(W/W_0) dB = A-weighted sound power level in decibels, ($W_0 = 10^{-12}$ W)
L_{pA} = A-weighted average sound pressure level, in decibels — Reference: 20 µPa
L_{IA} = A-weighted average sound intensity level, in decibels — Reference: 10^{-12} W/m^2

The calculation of effective radiating surface area S is also a function of the distance at which the sound measurements were made. IEEE or IEC standards may be consulted for details.

Sound Pressure Level Calculations at Far Field Receiver Locations

Sound level requirements at a specific receiver location in the far field play a major role in specifying sound levels for transformers.

The following basic method may be considered for estimating transformer sound pressure levels for simple installations. These calculations provide an accurate estimate of transformer noise emissions at distances roughly greater than twice the largest dimension of the transformer.

Given the sound pressure level requirement of L_{pD} dB at a distance D from the transformer, the maximum allowable sound power L_W for the transformer may be estimated as follows:

$$L_W = L_{pD} + 10 \text{ Log } (2 \prod D^2) \text{ W}$$

Therefore, the maximum allowable sound pressure L_{pT} level at the measurement surface near the transformer will be:

$$L_{pT} = L_W - 10 \text{ Log (Measurement Surface Area)}$$

$$\text{Measurement Surface Areas} = (1.25 * \text{Transformer tank height in meters} * \text{Measurement contour length in meters})$$

Factors Affecting Sound Levels in Field Installations

In order to assure repeatability, the factory measurements are made under controlled conditions specified by sound measurement standards. Every effort is made to maintain core excitation voltage constant and sinusoidal for assuring known core induction while making sound level evaluations in transformers.

The effects of ambient sound levels and reflections must be subtracted from the overall sound level measurements in order to determine the true sound power of a transformer. It is therefore assured that the ambient sound levels are constant and are measured accurately. Many times it becomes necessary to make these measurements in a sound chamber where ambient sound level is very low and the effects of reflecting surfaces can also be eliminated.

The sound level measurements at the transformer site can be drastically different depending upon its operating conditions. The effects of the following factors should therefore be considered while defining the sound level requirements for transformers.

Load Power Factor

In the factory, core and winding sound levels are measured separately at rated voltage and full load current, respectively. These sound levels are produced by core and winding vibrations of twice the power frequency and its even harmonics. It is assumed that these vibrations are in phase with each other and therefore their power levels are added to predict the overall sound level of the transformer. However, this assumption applies only when the transformer is carrying purely resistive load.

Under actual operating conditions, depending upon the power factor of the load, the phase angle between voltage and load current may induce a change in the factory predicted transformer sound level.

Internal Regulation

The magnitude and the phase angle of the load currents also change the internal voltage drop in the transformer windings. The transformer loading conditions therefore can change the core induction level and significantly influence the core sound levels.

Load Current and Voltage Harmonics

During factory tests, only sinusoidal load current is simulated for measuring winding noise. This noise is produced by magnetic forces that are proportional to the square of the load current. However, harmonic content in the load current has a larger impact on the sound level than might be expected from the amplitude of the harmonic currents since they interact with the power frequency load current. In such cases, the magnetic force is proportional to the cross product between the power frequency current and the harmonic current in addition to the force that is proportional to the square of load current and the square of the harmonic current. Thus, the highest contribution to the sound level due to the harmonic current occurs when the product of the load current and the harmonic current reaches the maximum. The resulting audible tones are made up of frequencies of the harmonic current ± the fundamental power frequency.

Current harmonics are a major source of increase in sound levels in HVDC and rectifier transformers.

Non-linear loads cause harmonics in the excitation voltage, resulting in an increase in core sound levels. This influence must be considered while specifying sound level for a transformer.

DC Magnetization

Even a moderate DC magnetization of a transformer core will result in a significant increase in the transformer audible sound level. In addition to increasing the power level of the normal harmonics in the transformer vibrations (i.e., even harmonics of the power frequencies), DC magnetization will add odd harmonic tones to the overall sound level of the transformer.

Modern cores have high remnant flux density. Upon energization, the core sound levels may be as much as 20 dB higher than the factory test value. It is therefore recommended that a transformer should be energized for approximately 6 h before evaluating its sound levels.

Traditionally, circuits like DC feeders to the transportation systems have been a source of DC fields in transformers. However, with the increased use of power electronic equipment in power transmission systems and in the industry, the number of possible sources for DC magnetization is increasing. Geomagnetic storms may also cause severe DC magnetization in transformers connected to long transmission lines.

Acoustical Resonance

Dry type transformers are most frequently applied inside buildings. In a room with walls of low sound absorption coefficient, the sound from the transformer will reflect back and forth between walls, resulting in a build-up of sound level in the room.

The number of dBs by which the sound level at the transformer will increase may be approximated as follows:

$$\text{dB build-up} = 10 \log \left(1 + 4\left(1 - a\right) A_T \middle/ \left(a\ A_U\right)\right)$$

where

A_T = surface area of the transformer
A_U = area of the reflecting surface
a = average absorption coefficient of the surfaces

In a room with concrete walls (with an absorption coefficient of 0.01) and with sound reflecting surface area four times that of the transformer ($A_U/A_T = 4$), the increase in sound level at the transformer can be 20 dB. However, covering the reflecting surfaces of this room with sound absorbing material with absorption coefficient of 0.3 will reduce this build-up to 5.5 dB.

Sound propagation is affected by many factors such as atmospheric absorption, interceding barriers, and reflective surfaces. An explanation of these factors is beyond the scope of this text; however, they are mentioned to make the reader aware of their potential influence. If the site conditions that will influence the sound propagation exist, the reader is advised to use reference textbooks dealing with the subject of acoustic propagation or consult an expert in conducting more accurate sound propagation calculations.

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3.13 Electrical Bushings

Loren B. Wagenaar

ANSI/IEEE Std. C57.19.00 (1997) defines an electrical bushing as "an insulating structure, including a through conductor or providing a central passage for such a conductor, with provision for mounting a barrier, conducting or otherwise, for the purpose of insulating the conductor from the barrier and conducting current from one side of the barrier to the other." As a less formal explanation, the purpose of an electrical bushing is simply to transmit electrical power in or out of enclosures, i.e., barriers, of an electrical apparatus such as transformers, circuit breakers, shunt reactors, and power capacitors. The bushing conductor may take the form of a conductor built directly as a part of the bushing, or alternately, as a separate conductor which is drawn through, usually through the center of, the bushing.

Since electrical power is the product of voltage and current, insulation in a bushing must be capable of withstanding the voltage at which it is applied, and its current carrying conductor must be capable of carrying rated current without overheating the adjacent insulation. For practical reasons, bushings are not rated by the power transmitted through them; rather, they are rated by the maximum voltage and current for which they are designed.

Types of Bushings

There are many methods to classify the types of bushings. These classifications are based on practical reasons, which will become apparent in the following.

According to Insulating Media on Ends

One method is to designate the types of insulating media at the ends of the bushing. This classification depends primarily on the final application of the bushing.

An air-to-oil bushing has air insulation at one end of the bushing and oil insulation at the other. Since oil is more than twice as strong dielectrically as air at atmospheric pressure, the oil end is approximately half as long or less than the air end. This type of bushing is quite common for usage between atmospheric air and any oil-filled apparatus.

An air-to-air bushing has air insulation on both ends and is normally used in building applications where one end is exposed to outdoor atmospheric conditions, and the other end is exposed to indoor

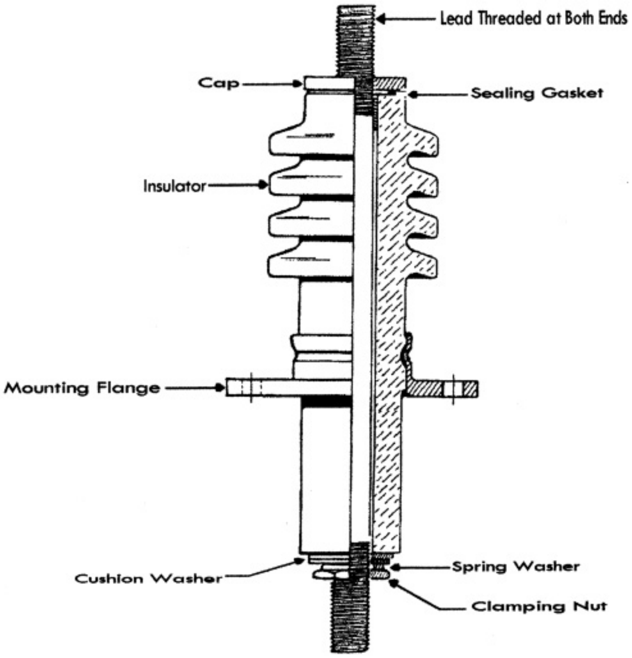

FIGURE 3.148 Solid type bushing.

conditions. The outer end may have higher creep distances in order to withstand higher pollution environments and possibly higher strike distances in order to withstand transient voltages during adverse weather conditions such as rainstorms.

Special application bushings have limited usage and include: air-to-SF_6 bushings, usually used in SF_6 insulated circuit breakers; SF_6-to-oil bushings, used as transitions between SF_6 bus ducts and oil filled apparatus; and oil-to-oil bushing, used between oil bus ducts and oil filled apparatus.

According to Construction

There are basically two types of construction, the solid or bulk type, and the capacitance-graded or condenser type.

Solid Bushing

The solid type bushing, depicted in Fig. 3.148, is typically made with a central conductor and porcelain or epoxy insulators at either end, and is primarily used at the lower voltages through 25 kV. This construction is generally relatively simple compared to the capacitance-graded type, which was used for the original bushings, and its present usage is quite versatile with respect to size. It is commonly used for applications ranging from small distribution transformers and circuit switchers to large generator step-up transformers and hydrogen cooled power generators.

At the lower end of the applicable voltage range, the central conductor may be a small diameter lead connected directly to the transformer winding, and such a lead typically passes through an arbitrarily shaped bore of an outer and inner porcelain or epoxy insulator(s). Between the two insulators is typically located a mounting flange for mounting the bushing to the transformer or other apparatus. In one rather unique design, only one porcelain insulator was used, and the flange was assembled onto the porcelain after the porcelain had been fired. At higher voltages, particularly at 25 kV, more care is taken to make certain that the lead and bore of the insulator(s) are circular and concentric, so that the electric stresses in the gap between these two items are more predictable and uniform. For higher current bushings, typically up to 20 kA, large diameter circular copper leads or several copper bars arranged in a circle and brazed to copper end plates may be used.

The space between the lead and insulator may consist of only air on lower voltage solid type bushings, or this space may be filled with electric grade mineral oil or some other special compound on higher voltage bushings. The oil may be self-contained within the bushing, or it may be oil from the apparatus in which the bushing is installed. Special compounds are typically self-contained. Oil and compounds are used for three reasons. First, they enable better cooling of the conductor than air does. Second, they have higher dielectric constants (about 2.2 for oil) than air, and therefore, when used with materials with higher dielectric constants, such as porcelain or epoxy, they endure a smaller share of the voltage than an equally sized gap occupied by air. The result is that oil and compounds withstand higher voltages than air does. Third, oil and other compounds display higher breakdown strengths than air.

The primary limitation of the solid bushing is its ability to withstand 60-Hz voltages above 90 kV. Hence, its applications are limited to 25-kV equipment ratings, which have test voltages of 70 kV. Recent applications require low partial discharge limits on the 25-kV terminals during transformer test and have caused further restrictions on the use of this type of bushing. In these cases, either a specially designed solid bushing, with unique grading shielding that enables low inherent partial discharge levels, or a more expensive capacitance-graded bushing must be used.

Capacitance-Graded Bushings

Technical literature dating back to the early twentieth century describes the principles of the capacitance-graded bushing (Easly and Stockum, 1984). R. Nagel of Siemens published a German paper (Nagel, 1906) in 1906 describing an analysis and general principles of condenser bushings, and Reynders of Westinghouse published a U.S. paper (Reynders, 1909) which described the principles of the capacitance-graded bushing and compared the characteristics of these bushings with those of solid type construction. Thereafter, several additional papers were published, including those by individuals from Micafil of Switzerland and ASEA of Sweden.

The value of the capacitance-graded bushing was quickly demonstrated, and this bushing type was produced extensively by those companies possessing the required patents. Currently, this construction is used for virtually all voltage ratings above 25 kV system voltage and has been used for bushings through 1500 kV system voltage. This construction uses conducting layers at predetermined radial intervals within oil-impregnated paper or some other insulation material which is located in the space between the central conductor and the insulator. Different manufacturers have used a variety of materials and methods for making capacitance-graded bushings. Early methods were to insert concentric porcelain cylinders with metallized surfaces or laminated pressboard tubes with embedded conductive layers. Later designs used conductive foils, typically aluminum or copper, in oil-impregnated kraft paper. An alternative method is to print semi-conductive ink (different manufacturers have used different conductivities) on all or some of the oil-impregnated kraft paper wraps.

Figure 3.149 shows the general construction of an oil-filled, capacitance-graded bushing. The principal elements are the central circular conductor, onto which the capacitance-graded core is wound, the top and lower insulators, the mounting flange, the oil and an oil expansion cap, and the top and bottom terminals. Figure 3.150 is a representation of the equipotential lines in a simplified capacitance-graded bushing in which neither the expansion cap nor the sheds on either insulator are shown. The bold lines within the capacitance-graded core depict the voltage grading elements. The contours of the equipotential lines show the influence of the grading elements, both radially within the core and axially along the length of the insulators.

The mathematical equation for the radial voltage distribution as a function of diameter between two concentric conducting cylinders is:

$$V(d) = V\left(\ln\left(D_2/d\right)\Big/\ln\left(D_2/D_1\right)\right) \tag{3.73}$$

where V is the voltage between the two cylinders

D_1 and D_2 are the diameters of the inner and outer cylinders, respectively.

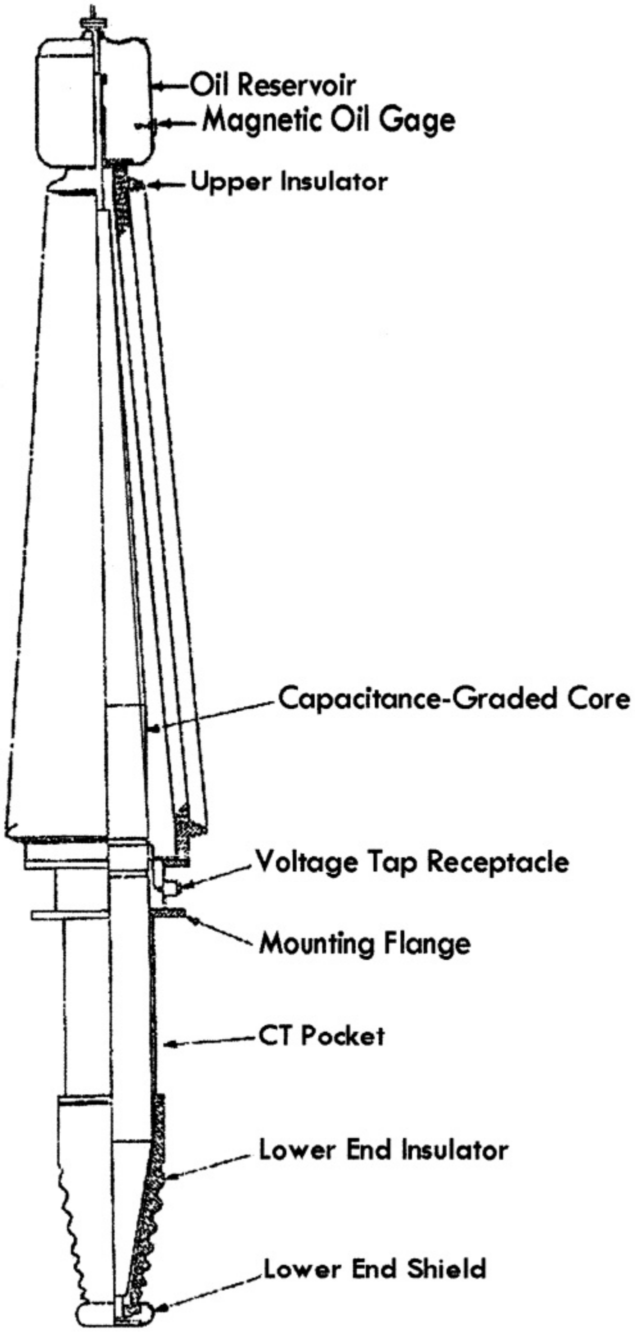

FIGURE 3.149 Capacitance-graded bushing.

Since this is a logarithmic function, the voltage is non-linear, concentrating around the central conductor and decreasing near the outer cylinder. Likewise, the associated radial electric stress, calculated by

$$E(d) = 2V/\left(d\ln\left(D_2/D_1\right)\right) \tag{3.74}$$

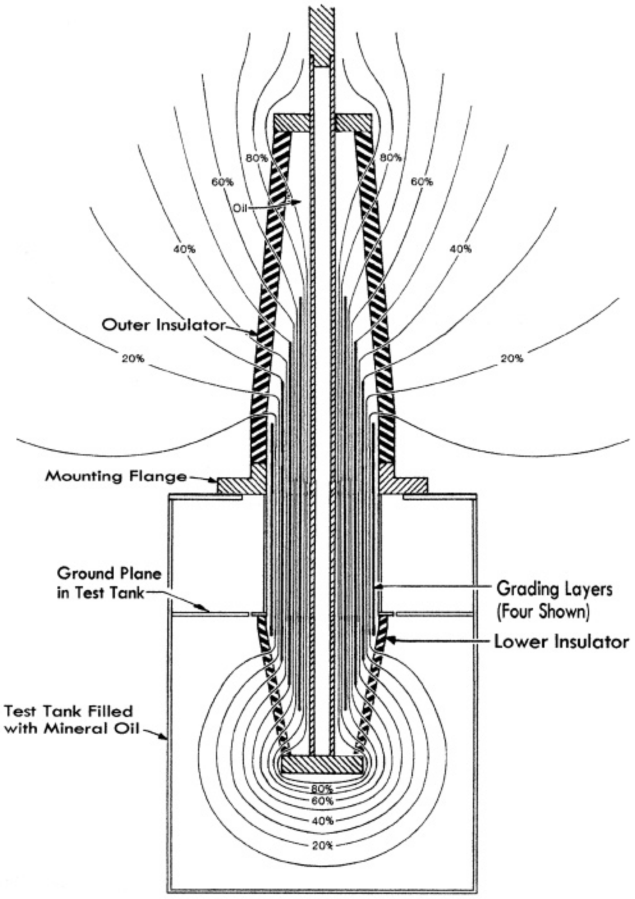

FIGURE 3.150 Equipotential plot of capacitance graded bushing.

will be the greatest at $d = D_1$. The lengths of grading elements and the diameters at which they are positioned are such as to create a more uniform radial voltage distribution than found in a solid type bushing.

As seen from Fig. 3.150, the axial voltage distribution along the inner and outer insulators is almost linear when the proper capacitance grading is employed. Therefore, both insulators on capacitance-graded bushings can be shorter than their solid bushing counterparts.

Capacitance-graded bushings involve many more technical and manufacturing details than solid bushings and are therefore more expensive. These details include the insulation/conducting layer system, equipment to wind the capacitor core, and the oil to impregnate the paper insulation. However, it should be noted that the radial dimension required for the capacitance-graded bushing is much less than the solid construction, and this saves on material within the bushing as well as in the apparatus in which the bushing is used. Also, from a practical standpoint, higher voltage bushings could not possibly be manufactured with a solid construction.

According to Insulation Inside Bushing

Still another classification relates to the insulating material used inside the bushing. In general, these materials can be used in either the solid or capacitance-graded construction, and more than one of these insulating materials can be used in conjunction. The following text gives a brief description of these types:

1. **Air-insulated bushings** generally are used only with air-insulated apparatus and of the solid construction that employs air at atmospheric pressure between the conductor and the insulators.
2. **Oil-insulated or oil-filled bushings** have electrical grade, mineral oil between the conductor and the insulators in solid type bushings. This oil may be contained within the bushing or may be shared with the apparatus in which the bushing is used. Capacitance-graded bushings also use mineral oil, usually contained within the bushing, between the insulating material and the insulators for the purposes of impregnating the kraft paper and transferring heat from the conducting lead.
3. **Oil-impregnated paper insulated bushings** use the dielectric synergy of mineral oil and electric grades of kraft paper to produce a composite material with superior dielectric withstand characteristics. This material has been extensively used as the insulating material in capacitance-graded cores for approximately the last 50 years.
4. **Resin-bonded paper insulated bushings** use a resin-coated kraft paper to fabricate the capacitance-graded core, whereas **resin-impregnated paper insulated bushings** use paper impregnated with resin which is then used to fabricate the capacitance-graded core. The latter type of bushings has superior dielectric characteristics, comparable with oil-impregnated paper insulated bushings.
5. **Cast insulation bushings** are constructed of a solid cast material with or without an inorganic filler. These bushings may be either of the solid or capacitance-graded types, although the former type is more representative of present technology.
6. **Gas-insulated bushings** (Spindle) use pressurized gas, such as SF_6 gas, to insulate between the central conductor and the flange. The bushing shown in Fig. 3.151 is one of the simpler designs and is typically used with circuit breakers. It uses the same pressurized gas as the circuit breaker, has no capacitance grading and uses the dimensions and placement of the ground shield to control the electric fields. Other designs use a lower insulator to enclose the bushing, which permits the gas pressure to be different than the circuit breaker. Still other designs use capacitance-graded cores made of plastic film material that is compatible with SF_6 gas.

Bushing Standards

Several bushing standards exist in the various countries around the world. The major standards have been established by the Transformers Committee within the IEEE Power Engineering Society and by IEC Committee 37. Five important standards established by these committees include the following:

1. ANSI/IEEE Std. C57.19.00, Standard Performance Characteristics and Test Procedure for Outdoor Power Apparatus Bushings (1997). This general standard is widely used by countries in the western hemisphere and contains definitions, service conditions, ratings, general electrical and mechanical requirements, and detailed descriptions of routine and design test procedures for outdoor power apparatus bushings.
2. IEEE Std. C57.19.01, Standard General Requirements and Test Procedure for Outdoor Power Apparatus Bushings (IEEE, 1997a). This standard lists the electrical insulation and test voltage requirements for power apparatus bushings rated from 15 kV through 800 kV maximum system voltages. It also lists dimensions for standard dimensioned bushings, cantilever test requirements for bushings rated through 345 kV system voltage and partial discharge limits, as well as limits for power factor and capacitance change from before to after the standard electrical tests.
3. IEEE Std. C57.19.03, Standard Requirements, Terminology and Test Procedures for Bushings for DC Applications (IEEE, 1996). This standard gives the same type of information as ANSI/IEEE Std. C57.19.00 for bushings for direct current equipment, including oil-filled converter transformers and smoothing reactors. It also covers air-to-air DC bushings.
4. IEEE Std. C57.19.100, Guide for Application of Power Apparatus Bushings (IEEE, 1997b). This guide recommends practices to be used for thermal loading above nameplate rating for bushings applied on power transformers and circuit breakers, and for bushings connected to isolated-phase

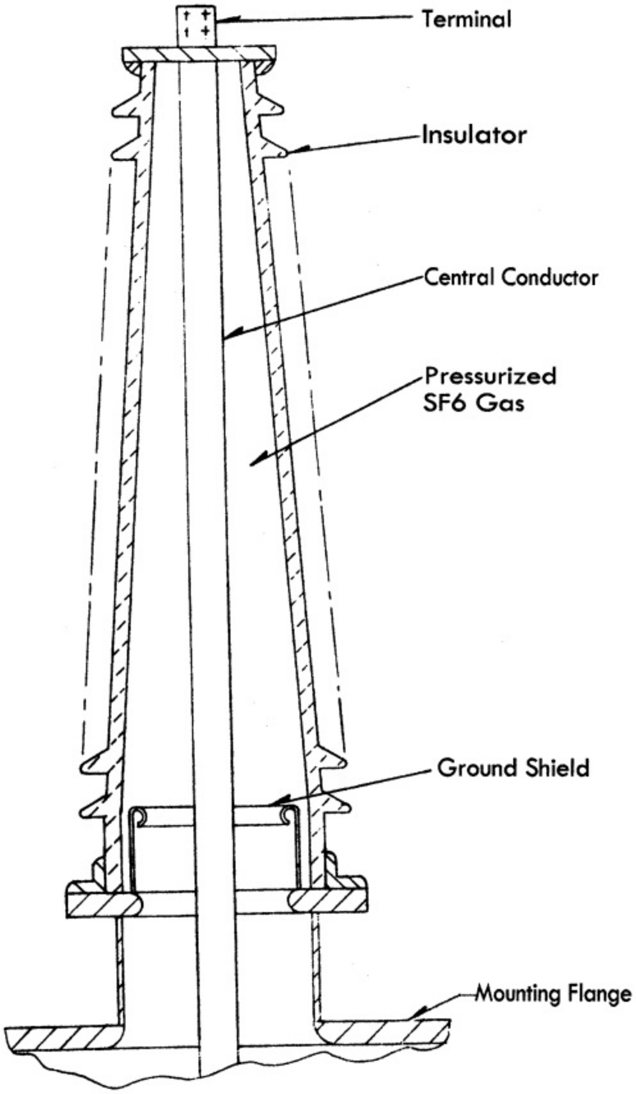

FIGURE 3.151 Pressurized SF_6 gas bushing.

bus. It also recommends practices for allowable cantilever loading caused by the pull of the line connected to the bushing, applications for contaminated environments and high altitudes, and maintenance practices.

5. IEC Publication 137, Bushings for Alternating Voltages above 1000 V. This standard is the IEC equivalent to the first standard listed above and is used widely in European and Asian countries.

Important Design Parameters

Conductor Size and Material

The conductor diameter is determined primarily by the current rating. There are two factors at work here. First, the skin depth of copper material at 60 Hz is about 1.3 cm and that of aluminum is about 1.6 cm. This means that most of the current will flow in the region from the outer portion of the conductor and radially inward to a depth of the skin depth δ. Second, the losses generated within a conductor will be:

$$P_{loss} = I^2R = I^2\rho L \big/ A = 4I^2\rho L \big/ \pi\left(D_1^2 - D_0^2\right) \tag{3.75}$$

where I = rated current
ρ = resistivity of the conductor material, ohm m
L = length of conductor, m
A = cross-section of conductor = $\pi(D_1^2 - D_0^2)/4$
D_1 = outside diameter of conductor, m
$D_0 = D_1 - \delta$, m

It can be seen from Eq. (3.75) that P_{loss} decreases as D_1 increases. Hence, design practice is to increase the outside diameter of the conductor for higher current ratings and to limit the wall thickness to near the skin depth. There are other technical advantages to increasing the outside conductor diameter. First, from Eq. (3.74), observe that electric field stress reduces as $d = D_1$ increases. Therefore, a larger diameter conductor will have higher partial discharge inception and withstand voltages. Second, the mechanical strength of the conductor is dependent on the total cross-sectional area of the conductor, so that a larger diameter is sometimes used to achieve higher withstand forces in the conductor.

Insulators

Insulators must have sufficient length to withstand the steady state and transient voltages that the bushing will experience. Adequate lengths depend on the insulating media in which the insulator is used and on whether the bushing is capacitively graded. In cases where there are two different insulating media on either side of an insulator, the medium with the inferior dielectric characteristics determines the length of the insulator.

Air Insulators

Primary factors that determine the required length of insulators used in air at atmospheric pressure are lightning impulse voltage under dry conditions and power frequency and switching impulse voltages under wet conditions. Standard dry conditions are based on 760 mm Hg atmospheric pressure and 20°C, and wet conditions are discussed in the section entitled "Low Frequency Tests".

Bushings are normally designed to be adequate for altitudes up to 1000 m (3300 ft). Beyond 1000 m, longer insulators must be used in order to accommodate the lower reduced air density present at the higher altitudes.

Insulators exposed to pollution must have adequate creep distance, measured along the external contour of the insulator, for purposes of withstanding detrimental insulating effects of contamination on the insulator surface. Figure 3.149 shows the undulations on the weather sheds, and additional creep distance is obtained by adding undulations or increasing their depth. Recommendations (IEEE, 1997b) for creep distance are shown in Table 3.18, according to four different classifications of contamination.

For example, a 345-kV bushing has a maximum line to ground voltage of 220 kV, so that the minimum creep is 220 × 28 = 6160 mm for a light contamination level and 220 × 44 = 9680 mm for a heavy contamination level.

The term ESDD (Equivalent Salt Density Deposit) used in Table 3.18 is the conductivity of the water-soluble deposits on the insulator surface. It is expressed in terms of the density of sodium chloride

TABLE 3.18 Recommended Creep Distances for Four Contamination Levels

Contamination Level	(ESDD) (mg/cm^2)	Recommended Minimum Creep Distance (mm/kV)
Light	0.03–0.08	28
Medium	0.08–0.25	35
Heavy	0.25–0.6	44
Extra heavy	Above 0.6	54

deposited on the insulator surface that will produce the same conductivity. Following are typical environments for the four contamination levels listed (IEEE, 1997b):

Light contamination areas include areas without industry and with low density emission producing residential heating systems, and areas with some industrial areas or residential density but with frequent winds and/or precipitation. These areas are not exposed to sea winds or located near the sea.

Medium contamination areas include areas with industries not producing highly polluted smoke and/or with average density of emission producing residential heating systems, areas with high industrial and/or residential density but subject to frequent winds and/or precipitation, and areas exposed to sea winds but not located near the sea coast.

Heavy contamination areas include those areas with high industrial density and large city suburbs with a high density emission producing residential heating systems, and areas close to the sea or exposed to strong sea winds.

Extra heavy contamination areas include those areas subject to industrial smoke producing thick conductive deposits and small coastal areas exposed to very strong and polluting sea winds.

Oil Insulators

Since mineral oil is dielectrically stronger than air, the length of insulators immersed in oil is typically 30 to 40% the length of air insulators. In equipment having oil with low contamination levels, no sheds are required on oil-immersed insulators. In situations where some contamination exists in the oil, such as carbon particles in oil insulated circuit breakers, small ripples are generally cast on the outer insulator surface exposed to the oil.

Pressurized SF_6 Gas Insulators

Since various pressures may be used for this application, the length of the insulator may be equal or less than an insulator immersed in oil. Since particles are harmful to the dielectric strength of any pressurized gas, precautions are generally taken to keep the SF_6 gas free of particles, and therefore, in such cases no sheds are required on the insulators.

Flange

The flange has two purposes: First, to mount the bushing to the apparatus on which it is utilized; second, to contain the gaskets located on the extreme ends of the flange, as described in the section entitled "Clamping System". Flange material may be cast aluminum for high activity bushings where the casting mold can be economically justified. In cases where production activities are not so high, flanges may be fabricated from steel or aluminum plate material. A further consideration for high current bushings is that aluminum or some other non-magnetic material is used in order to eliminate magnetic losses caused by currents induced in the flange by the central conductor.

Oil Reservoir

An oil reservoir, often called the expansion cap, is required on larger bushings with self-contained oil for at least one and often two related reasons. First, mineral oil expands and contracts with temperature, and the oil reservoir is required to contain the oil expansion at high oil temperatures. Second, oil-impregnated insulating paper must be totally submerged in oil in order to keep its insulating qualities. Hence, the reservoir must have sufficient oil in it to maintain oil over the insulating paper at the lowest anticipated temperatures. Since oil is an incompressible fluid, the reservoir must also contain a sufficient volume of gas, such as nitrogen, so that excessive pressures are not created within the bushing at highest temperatures. Excessive pressures within a bushing may cause oil leakage.

On bushings for mounting at angles up to about 30° from vertical, the reservoir is mounted on the top end of the bushing. On smaller, lower voltage bushings, the reservoir may be within the top end of the upper insulator. Oil-filled bushings that are horizontally mounted usually have an oil reservoir mounted on the flange, but some have bellows, either inside or outside the bushing, which expand and contract with the temperature of the oil.

For the purpose of checking the oil level in the bushing, an oil level gage is often incorporated into the reservoir. There are two basic types of oil gages, the clear glass type and the magnetic type. The former type is cast from colored or clear glass such that the oil level can be seen from any angle of rotation around the bushing. The second type is two-piece gage; the part inside the reservoir being a float attached to a magnet that rotates on an axis perpendicular to the reservoir wall. The part outside the reservoir is then a gage dial attached to a magnet that follows the rotation of the magnet mounted inside the reservoir. This type of gage suffers the disadvantage of only being able to viewed at an angle of approximately 120° around the bushing. For this reason, bushings with this type of gage are normally rotated on the apparatus such that the gage can be seen from ground level.

Clamping System

Two types of clamping systems are generally used on bushings. The first uses an external flange on the end of each insulator, and bolts are used to fasten them to mating parts, i.e., the mounting flange and the top and bottom terminals. A grading ring is often placed over this area so as to shield the bolts from electric fields. The pressurized gas bushing shown in Fig. 3.151 uses this type of clamping system.

The second system is to place a compression type spring assembly in the reservoir located at the top of the bushing, thereby placing the central conductor in tension when the spring assembly is released. This action simultaneously places the insulators, flange, and gaskets between these members, and the terminals at the extreme ends of the insulators in compression, thereby sealing the gaskets.

Whatever method is used for the clamping system, the clamping force must be adequate to withstand the cantilever forces that will be exerted on the ends of a bushing during its service life. The major mechanical force to which the top end of an outdoor bushing is subjected during service is the cantilever force applied to the top terminal by the line pull of the connecting lead. This force is comprised of the static force exerted during normal conditions plus those forces exerted due to wind loading and/or icing on the connecting lead. In addition, bushings mounted at an angle from vertical exert a force equivalent to a static cantilever force at the top of the bushing, and this force must be accounted for in the design.

In addition to the static forces, bushings must also withstand short-time dynamic forces created by short-circuit currents and seismic shocks. In particular, the lower end of bushings mounted in circuit breakers must also withstand the forces created by the interruption devices within the breaker.

In order to give the user some guidance for allowable line pull, standards (IEEE, 1997b) recommend permissible loading levels: the static line loading should not exceed 50% of the test loading, as defined later in the section entitled “Mechanical Tests”, and the short-time, dynamic loading should not exceed 85% of the same test loading.

Other Features on Bushings

Voltage Taps

It is possible within capacitance-graded bushings to create a capacitance divider arrangement wherein a small voltage, on the order of 5 kV, appears at the “voltage tap” when the bushing is operated at normal voltage. The voltage tap is created by attaching to one of the grading elements just to the inside of the grounded element. This tap, shown in Fig. 3.149, can be used during the testing operation of the bushing and the apparatus into which it is installed, as well as during field operation. In the former application, it is used to measure partial discharge within the bushing tested by itself or within the transformer. It is used during field operation to provide voltage to relays, which monitor phase voltages and instruct the circuit breakers to operate under certain conditions.

Bushing Current Transformer Pockets

The bushing flange creates a very convenient site to locate bushing current transformers (BCTs). The flange is extended on its inner end, and the BCTs, having 500 to 5000 turns in the windings, are placed around the flange. This location is called the BCT pocket and is shown in Fig. 3.149. In this case, the bushing central conductor forms the single turn primary of the BCT, and the turns in the windings form the secondary.

Lower End Shield

It can be seen from Fig. 3.150 that all regions of the lower end of air-to-oil bushings experience high dielectric stresses. In particular, the areas near the corners of the lower terminal are very highly stressed. Therefore, electrostatic shields with large radii, such as the one shown on Fig. 3.149, are attached to the lower end of these bushings in order to reduce the electric fields that appear in this area. Such shields also serve the purpose of shielding the bolted connections used to connect the lead to the bushing. Since shields with a thin dielectric barrier are somewhat stronger dielectrically, crepe paper is wrapped or molded pressboard is placed on the outer surfaces of the shield.

Tests on Bushings

Categories of Tests

Standards (ANSI/IEEE, 1997) designate three types of tests to be applied to bushings, as follows:

Design Tests

Design, or type, tests are only made on prototype bushings, i.e., the first of a design. The purpose of design tests is to ascertain that the bushing design is adequate to meet its assigned ratings, to ensure that the bushing can operate satisfactorily under usual or special service conditions, and to demonstrate compliance with industry standards. These tests need not be repeated unless the customer deems it necessary to have them performed on a routine basis.

Test levels at which bushings are tested during design tests are higher than the levels encountered during normal service so as to establish margins that take into account dielectric aging of insulation as well as material and manufacturing variations in successive bushings. Bushings must withstand these tests without evidence of partial or full failure, and incipient damage which initiates during the dielectric tests is usually detected by comparing values of power factor, capacitance, and partial discharge before and after the testing program.

Standards (ANSI/IEEE, 1997) prescribe the following design tests:

a. Low-frequency wet withstand voltage on bushings rated 242 kV maximum system voltage and less
b. Full-wave lightning impulse withstand voltage
c. Chopped-wave lightning impulse withstand voltage
d. Wet switching impulse withstand voltage on bushings rated 345 kV maximum system voltage and greater
e. Draw-lead bushing cap pressure test
f. Cantilever withstand test
g. Temperature test at rated current

Routine Tests

Routine, or production, tests are made on every bushing produced, and their purpose is to check the quality of the workmanship and the materials used in the manufacture. Standards (ANSI/IEEE, 1997) prescribe the following routine tests:

a. Capacitance and power factor measurements at 10 kV
b. Low-frequency dry withstand test with partial discharge measurements
c. Tap withstand voltage test
d. Internal hydraulic pressure test

Special Tests

Special tests are for establishing the characteristics of a design practice and are not part of routine or design tests. The only special test currently included in standards (ANSI/IEEE, 1997) is the thermal stability test, only applicable to EHV bushings, but other tests could be added in the future. These include short time, short-circuit withstand, and seismic capabilities.

Dielectric Tests

Low Frequency Tests

There are two low frequency tests: The **low-frequency wet-withstand voltage test** is applied on bushings rated 242 kV and below while a waterfall at a particular precipitation rate and conductivity is applied. The values of precipitation rate, water resistivity, and the time of application vary in different countries. American standard practice is a precipitation rate of 5 mm/min, a resistivity of 178 ohm-m, and a test duration of 10 sec, whereas European practice is 3 mm/min, 100 ohm-m, and 60 sec, respectively (IEEE, 1995). If the bushing flashes over externally during the test, it is allowed to apply the test one additional time. If this attempt also flashes over, then the test fails and something must be done to modify the bushing design or test set up so that the capability can be established.

The **low frequency dry withstand test** was until recently made for a 1-min duration without the aid of partial discharge measurements to detect incipient failures, but standards (ANSI/IEEE, 1997) currently specify a 1-h duration for the design test, in addition to partial discharge measurements. The present test procedure is:

1. Partial discharge (either radio influence voltage or apparent charge) shall be measured at 1.5 times the maximum line-ground voltage. Maximum limits for partial discharge vary for different bushing constructions and range from 10 to 100 μV or pC.
2. A 1-min test at the dry withstand level, approximately 1.7 times the maximum line-ground voltage, is applied. If an external flashover occurs, it is allowed to make another attempt; but if this one also flashes over, the bushing fails the test. No partial discharge tests are required for this test.
3. Partial discharge measurements are repeated every 5 min during the 1-h test duration at 1.5 maximum line-ground voltage required for the design test. Routine tests specify only a measurement of partial discharge at 1.5 maximum line-ground voltage, after which the test is considered complete.

Bushing standards were changed in the early 1990s to align with the transformer practice, which started to use the 1-h test with partial discharge measurements in the late 1970s. Experience with this new approach has been good in that incipient failures were uncovered in the factory test laboratory, rather than in service, and it was decided to add this procedure to the bushing test procedure. Also, from a more practical standpoint, bushings are applied to every transformer, and transformer manufacturers require that these tests be applied to the bushings prior to application so as to reduce the number of bushing failures during the transformer tests.

Wet Switching Impulse Withstand Voltage

This test is required on bushings rated 345 kV systems and above. The test waveshape is 250 μs time to crest and 2500 μs time to half value with tolerance of ±30% on the time to crest and ±20% on the time to half value. This is the standard waveshape for testing insulation systems without magnetic core steel present in the test object and is different than the waveshape for transformers.

Three different standard test procedures are commonly used for establishing the wet switching impulse withstand voltage of the external insulation:

1. Fifteen impulses of each polarity are applied with no more than two flashovers.
2. Three impulses of each polarity are applied. If a flashover occurs, then it is permitted to apply three additional impulses. If no flashovers occur at either polarity, then the bushing passes the test. Otherwise, the bushing fails the test.
3. The 90% (1.3 σ) level is established from the 50% flashover tests.

Lightning Impulse Tests

The same waveshapes are used for establishing the lightning impulse capability of bushings and transformers. The waveshape for the full wave is 1.2 μs for the wavefront and 50 μs for the time to half value, and the chopped wave flashes over at a minimum of 3.0 μs. One of the same procedures as described above for the wet switching impulse tests is followed to establish the full wave capability for both polarities. The chopped wave capability is established by applying a minimum of three chopped impulses at each polarity.

Mechanical Tests

IEEE Std. C57.19.01 (IEEE, 1997a) specifies the static cantilever withstand forces to be applied separately to the top and bottom ends of outdoor apparatus bushings. The forces applied to the top end range from 150 lb for the smaller, lower voltage bushings to 1200 lb for the larger, higher voltage or current bushings, and the forces applied to the lower end are generally about twice the top end forces.

The test procedure is to apply the specified forces perpendicular to the bushing axis, first at one end and then at the other, each application of force lasting 1 min. Permanent deflection, measured at the bottom end, shall not exceed 0.76 mm, and there shall be no oil leakage at either end at any time during the test or within 10 min after removing the force.

Thermal Tests

There are two thermal tests. The first is the thermal test at rated current, and it is applied to all bushing designs. The second test is the thermal stability test and it is applied for only EHV bushings:

Thermal Test at Rated Current

This test demonstrates a bottom-connected bushing's ability to carry rated current. The bushing is first equipped with a sufficient number of thermocouples, usually placed inside the inner diameter of the hollow tube conductor, to measure the hottest spot temperature of the conductor. The bushing is then placed in an oil-filled tank, the oil is heated to a temperature rise above ambient air of 55°C for transformers and 40°C for circuit breakers, and rated current is passed through the central conductor until thermal equilibrium is reached. The bushing passes the test if the hottest spot temperature rise above ambient air does not exceed 65°C.

Thermal Stability Test (Wagenaar, 1994)

Capacitive leakage currents in the insulating material within bushings cause dielectric losses. Dielectric losses within a bushing can be calculated by the following equation using data directly from the nameplate or test report:

$$P_d = 2\,\pi\,f\,C\,V^2 \tan\delta \tag{3.76}$$

where P_d = dielectric losses, W
f = applied frequency, Hz
C = capacitance of bushing (C_1), Farads
V = operating voltage, rms V
$\tan\delta$ = dissipation factor, p.u.

A bushing operating at rated voltage and current generates both ohmic and dielectric losses within the conductor and insulation, respectively. Since these losses, which both appear in the form of heat, are generated at different locations within the bushing, they are not directly additive. However, heat generated in the conductor influences the quantity of heat which escapes from within the core. A significant amount of heat generated in the conductor will raise the conductor temperature and prevent losses from escaping from the inner surface of the core. This causes the dielectric losses to escape from only the outer surface of the core, and consequently raises the hottest spot temperature within the core. Most insulating materials display an increasing dissipation factor, tan δ, with higher temperatures, such that as the temperature rises, tan δ also raises, which in turn, raises the temperature even more. If this cycle does not stabilize, then tan δ increases rapidly and total failure of the insulation system ensues.

Bushing failures due to thermal stability have occurred both on the test floor and in service. One of the classic symptoms of a thermal stability failure is the high internal pressure caused by the gases generated from the deteriorating insulation. These high pressures cause an insulator, usually the outer one because of its larger size, either to lift off the flange or to explode. If the latter event occurs with a porcelain insulator, shards of porcelain saturated with oil become flaming projectiles that may endanger the lives of personnel and cause damage to nearby substation equipment.

Note from Eq. (3.76) that the operating voltage, V, particularly influences the losses generated within the insulating material. It has been found from testing experience that thermal stability only becomes a factor at operating voltages 500 kV and above.

The test procedure given in (ANSI/IEEE, 1997) is to first immerse the lower end of the bushing in oil at a temperature of 95°C tan δ and then pass rated current through the bushing. When the bushing comes to thermal equilibrium, a test voltage equal to 1.2 times the maximum line-ground voltage is applied, and tan δ is measured at regular, normally hourly, intervals. These conditions are maintained until tan δ rises no more than 0.02% over a period of 5 h. The bushing is considered to have passed the test if it has reached thermal stability at this time and it withstands all of the routine dielectric tests without significant change from the previous results.

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3.14 Load Tap Changers (LTCs)

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For many decades power transformers equipped with LTCs have been the main components of electrical networks and industry. The LTC allows voltage regulation and/or phase shifting by varying the transformer ratio under load without interruption.

From the beginning of LTC development, two switching principles have been used for the load transfer operation, the high-speed resistance-type and the reactance-type. Over the decades both principles have been developed into reliable transformer components available in a broad range of current and voltage applications to cover the needs of today's network and industrial process transformers as well as ensuring optimum system and process control (Goosen, 1996).

This section refers to LTCs immersed in transformer mineral oil. The use of other insulating fluids or gas insulation requires the approval of the LTC's manufacturer and may lead to a different LTC design.