4

Transformers

Ac transformers are one of the keys to allowing widespread distribution of electric power as we see it today. Transformers efficiently convert electricity to higher voltage for long distance transmission and back down to low voltages suitable for customer usage. The distribution transformer normally serves as the final transition to the customer and often provides a local grounding reference. Most distribution circuits have hundreds of distribution transformers. Distribution feeders may also have other transformers: voltage regulators, feeder step banks to interface circuits of different voltages, and grounding banks.

4.1 Basics

A transformer efficiently converts electric power from one voltage level to another. A transformer is two sets of coils coupled together through a magnetic field. The magnetic field transfers all of the energy (except in an autotransformer). In an ideal transformer, the voltages on the input and the output are related by the turns ratio of the transformer:

$$V_1 = \frac{N_1}{N_2} V_2$$

where N_1 and N_2 are the number of turns and V_1 and V_2 are the voltage on windings 1 and 2.

In a real transformer, not all of the flux couples between windings. This *leakage* flux creates a voltage drop between windings, so the voltage is more accurately described by

$$V_1 = \frac{N_1}{N_2} V_2 - X_L I_1$$

where X_L is the leakage reactance in ohms as seen from winding 1, and I_1 is the current out of winding 1.

The current also transforms by the turns ratio, opposite of the voltage as

$$I_1 = \frac{N_2}{N_1} I_2 \quad \text{or} \quad N_1 I_1 = N_2 I_2$$

The "ampere-turns" stay constant at $N_1 I_1 = N_2 I_2$; this fundamental relationship holds well for power and distribution transformers.

A transformer has a magnetic core that can carry large magnetic fields. The cold-rolled, grain-oriented steels used in cores have permeabilities of over 1000 times that of air. The steel provides a very low-reluctance path for magnetic fields created by current through the windings.

Consider voltage applied to the *primary* side (source side, high-voltage side) with no load on the *secondary* side (load side, low-voltage side). The winding draws *exciting* current from the system that sets up a sinusoidal magnetic field in the core. The flux in turn creates a back emf in the coil that limits the current drawn into the transformer. A transformer with no load on the secondary draws very little current, just the exciting current, which is normally less than 0.5% of the transformer's full-load current. On the unloaded secondary, the sinusoidal flux creates an open-circuit voltage equal to the primary-side voltage times the turns ratio.

When we add load to the secondary of the transformer, the load pulls current through the secondary winding. The magnetic coupling of the secondary current pulls current through the primary winding, keeping constant ampere-turns. Normally in an inductive circuit, higher current creates more flux, but not in a transformer (except for the leakage flux). The increasing force from current in one winding is countered by the decreasing force from current through the other winding (see Figure 4.1). The flux in the core on a loaded transformer is the same as that on an unloaded transformer, even though the current is much higher.

The voltage on the primary winding determines the flux in the transformer (the flux is proportional to the time integral of voltage). The flux in the core determines the voltage on the output-side of the transformer (the voltage is proportional to the time derivative of the flux).

Figure 4.2 shows models with the significant impedances in a transformer. The detailed model shows the series impedances, the resistances and the reactances. The series resistance is mainly the resistance of the wires in each winding. The series reactance is the leakage impedance. The shunt branch is the magnetizing branch, current that flows to magnetize the core. Most of the magnetizing current is reactive power, but it includes a real power component. Power is lost in the core through:

- *Hysteresis* — As the magnetic dipoles change direction, the core heats up from the friction of the molecules.

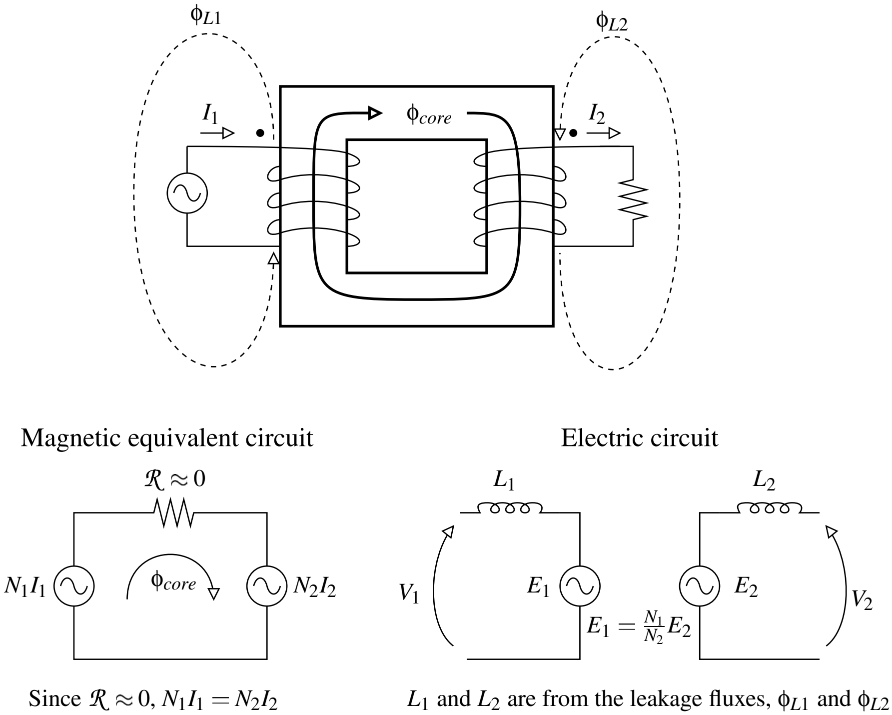


FIGURE 4.1
Transformer basic function.

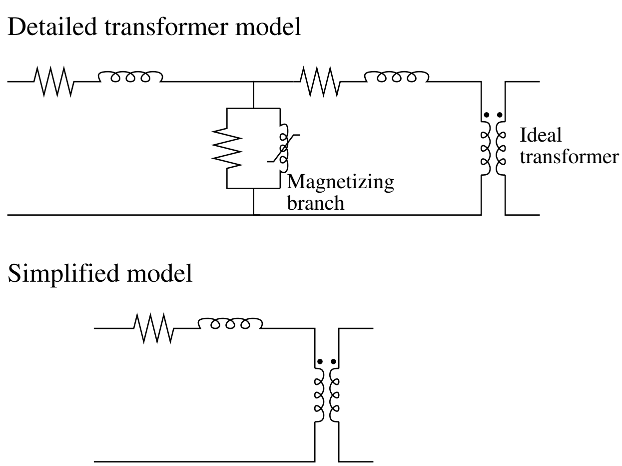


FIGURE 4.2
Transformer models.

TABLE 4.1

Common Scaling Ratios in Transformers

Quantity	Relative to kVA	Relative to a Reference Dimension, l
Rating	kVA	l^4
Weight	K kVA$^{3/4}$	K l^3
Cost	K KVA$^{3/4}$	K (% Total Loss)$^{-3}$
Length	K kVA$^{1/4}$	K l
Width	K kVA$^{1/4}$	K l
Height	K kVA$^{1/4}$	K l
Total losses	K kVA$^{3/4}$	K l^3
No-load losses	K kVA$^{3/4}$	K l^3
Exciting current	K kVA$^{3/4}$	K l^3
% Total loss	K kVA$^{-1/4}$	K l^{-1}
% No-load loss	K kVA$^{-1/4}$	K l^{-1}
% Exciting current	K kVA$^{-1/4}$	K l^{-1}
% R	K kVA$^{-1/4}$	K l^{-1}
% X	K kVA$^{1/4}$	K l
Volts/turn	K kVA$^{1/2}$	K l^2

Source: Arthur D. Little, "Distribution Transformer Rulemaking Engineering Analysis Update," Report to U.S. Department of Energy Office of Building Technology, State, and Community Programs. Draft. December 17, 2001.

- *Eddy currents* — Eddy currents in the core material cause resistive losses. The core flux induces the eddy currents tending to oppose the change in flux density.

The magnetizing branch impedance is normally above 5,000% on a transformer's base, so we can neglect it in many cases. The core losses are often referred to as iron losses or no-load losses. The load losses are frequently called the wire losses or copper losses. The various parameters of transformers scale with size differently as summarized in Table 4.1.

The simplified transformer model in Figure 4.2 with series resistance and reactance is sufficient for most calculations including load flows, short-circuit calculations, motor starting, or unbalance. Small distribution transformers have low leakage reactances, some less than 1% on the transformer rating, and X/R ratios of 0.5 to 5. Larger power transformers used in distribution substations have higher impedances, usually on the order of 7 to 10% with X/R ratios between 10 and 40.

The leakage reactance causes voltage drop on a loaded transformer. The voltage is from flux that doesn't couple from the primary to the secondary winding. Blume et al. (1951) describes leakage reactance well. In a real transformer, the windings are wound around a core; the high- and low-voltage windings are adjacent to each other. Figure 4.3 shows a configuration; each winding contains a number of turns of wire. The sum of the current in each wire of the high-voltage winding equals the sum of the currents in the

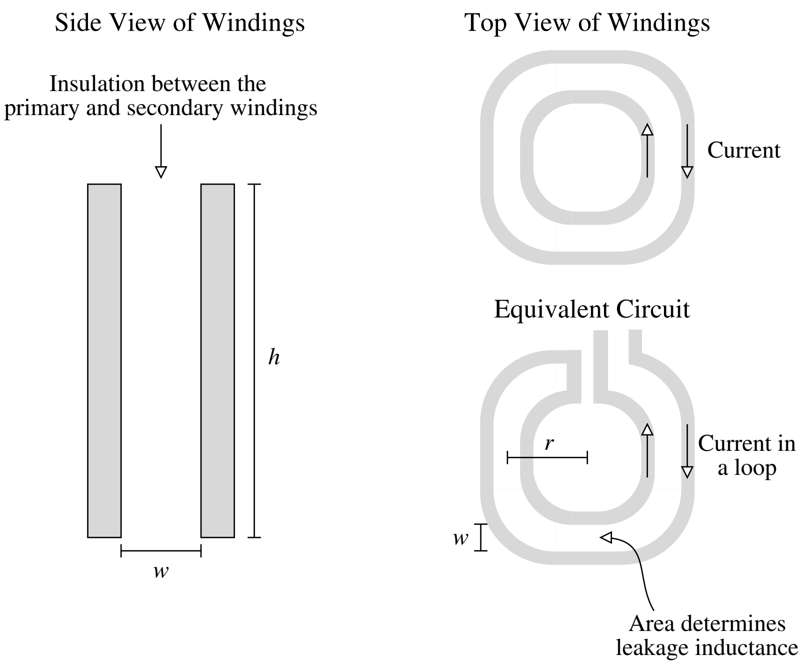


FIGURE 4.3
Leakage reactance.

low-voltage winding ($N_1I_1 = N_2I_2$), so each winding is equivalent to a busbar. Each busbar carries equal current, but in opposite directions. The opposing currents create flux in the gap between the windings (this is called *leakage flux*). Now, looking at the two windings from the top, we see that the windings are equivalent to current flowing in a loop encompassing a given area. This area determines the leakage inductance.

The leakage reactance in percent is based on the coil parameters and separations (Blume et al., 1951) as follows:

$$X_{\%} = \frac{126 f (NI)^2 rw}{10^{11} h S_{kVA}}$$

where

f = system frequency, Hz
N = number of turns on one winding
I = full load current on the winding, A
r = radius to the windings, in.
w = width between windings, in.
h = height of the windings, in.
S_{kVA} = transformer rating, kVA

In general, leakage impedance increases with:

- Higher primary voltage (thicker insulation between windings)
- kVA rating
- Larger core (larger diameter leads to more area enclosed)

Leakage impedances are under control of the designer, and companies will make transformers for utilities with customized impedances. Large distribution substation transformers often need high leakage impedance to control fault currents, some as high as 30% on the base rating.

Mineral oil fills most distribution and substation transformers. The oil provides two critical functions: conducting heat and insulation. Because the oil is a good heat conductor, an oil-filled transformer has more load-carrying capability than a dry-type transformer. Since it provides good electrical insulation, clearances in an oil-filled transformer are smaller than a dry-type transformer. The oil conducts heat away from the coils into the larger thermal mass of the surrounding oil and to the transformer tank to be dissipated into the surrounding environment. Oil can operate continuously at high temperatures, with a normal operating temperature of 105°C. It is flammable; the flash point is 150°C, and the fire point is 180°C. Oil has high dielectric strength, 220 kV/in. (86.6 kV/cm), and evens out voltage stresses since the dielectric constant of oil is about 2.2, which is close to that of the insulation. The oil also coats and protects the coils and cores and other metal surfaces from corrosion.

4.2 Distribution Transformers

From a few kVA to a few MVA, distribution transformers convert primary-voltage to low voltage that customers can use. In North America, 40 million distribution transformers are in service, and another one million are installed each year (Alexander Publications, 2001). The transformer connection determines the customer's voltages and grounding configuration.

Distribution transformers are available in several standardized sizes as shown in Table 4.2. Most installations are single phase. The most common

TABLE 4.2

Standard Distribution Transformer Sizes

	Distribution Transformer Standard Ratings, kVA
Single phase	5, 10, 15, 25, 37.5, 50, 75, 100, 167, 250, 333, 500
Three phase	30, 45, 75, 112.5, 150, 225, 300, 500

TABLE 4.3

Insulation Levels for Distribution Transformers

Low-Frequency Test Level, kV rms	Basic Lightning Impulse Insulation Level, kV Crest	Chopped-Wave Impulse Levels	
		Minimum Voltage, kV Crest	Minimum Time to Flashover, μs
10	30	36	1.0
15	45	54	1.5
19	60	69	1.5
26	75	88	1.6
34	95	110	1.8
40	125	145	2.25
50	150	175	3.0
70	200	230	3.0
95	250	290	3.0
140	350	400	3.0

Source: IEEE Std. C57.12.00-2000. Copyright 2000 IEEE. All rights reserved.

overhead transformer is the 25-kVA unit; padmounted transformers tend to be slightly larger where the 50-kVA unit is the most common.

Distribution transformer impedances are rather low. Units under 50 kVA have impedances less than 2%. Three-phase underground transformers in the range of 750 to 2500 kVA normally have a 5.75% impedance as specified in (ANSI/IEEE C57.12.24-1988). Lower impedance transformers provide better voltage regulation and less voltage flicker for motor starting or other fluctuating loads. But lower impedance transformers increase fault currents on the secondary, and secondary faults impact the primary side more (deeper voltage sags and more fault current on the primary).

Standards specify the insulation capabilities of distribution transformer windings (see Table 4.3). The low-frequency test is a power-frequency (60 Hz) test applied for one minute. The basic lightning impulse insulation level (BIL) is a fast impulse transient. The front-of-wave impulse levels are even shorter-duration impulses.

The through-fault capability of distribution transformers is also given in IEEE C57.12.00-2000 (see Table 4.4). The duration in seconds of the short-circuit capability is:

$$t = \frac{1250}{I^2}$$

where I is the symmetrical current in multiples of the normal base current from Table 4.4.

Overhead and padmounted transformer tanks are normally made of mild carbon steel. Corrosion is one of the main concerns, especially for anything on the ground or in the ground. Padmounted transformers tend to corrode

TABLE 4.4

Through-Fault Capability of Distribution Transformers

Single-Phase Rating, kVA	Three-Phase Rating, kVA	Withstand Capability in per Unit of Base Current (Symmetrical)
5–25	15–75	40
37.5–110	112.5–300	35
167–500	500	25

Source: IEEE Std. C57.12.00-2000, *IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers.*

near the base (where moisture and dirt and other debris may collect). Submersible units, being highly susceptible to corrosion, are often stainless steel.

Distribution transformers are "self cooled"; they do not have extra cooling capability like power transformers. They only have one kVA rating. Because they are small and because customer peak loadings are relatively short duration, overhead and padmounted distribution transformers have significant overload capability. Utilities regularly size them to have peak loads exceeding 150% of the nameplate rating.

Transformers in underground vaults are often used in cities, especially for network transformers (feeding secondary grid networks). In this application, heat can be effectively dissipated (but not as well as with an overhead or padmounted transformer).

Subsurface transformers are installed in an enclosure just big enough to house the transformer with a grate covering the top. A "submersible" transformer is normally used, one which can be submerged in water for an extended period (ANSI/IEEE C57.12.80-1978). Heat is dissipated through the grate at the top. Dirt and debris in the enclosure can accelerate corrosion. Debris blocking the grates or vents can overheat the transformer.

Direct-buried transformers have been attempted over the years. The main problems have been overheating and corrosion. In soils with high electrical and thermal resistivity, overheating is the main concern. In soils with low electrical and thermal resistivity, overheating is not as much of a concern, but corrosion becomes a problem. Thermal conductivity in a direct-buried transformer depends on the thermal conductivity of the soil. The buried transformer generates enough heat to dry out the surrounding soil; the dried soil shrinks and creates air gaps. These air gaps act as insulating layers that further trap heat in the transformer.

4.3 Single-Phase Transformers

Single-phase transformers supply single-phase service; we can use two or three single-phase units in a variety of configurations to supply three-phase

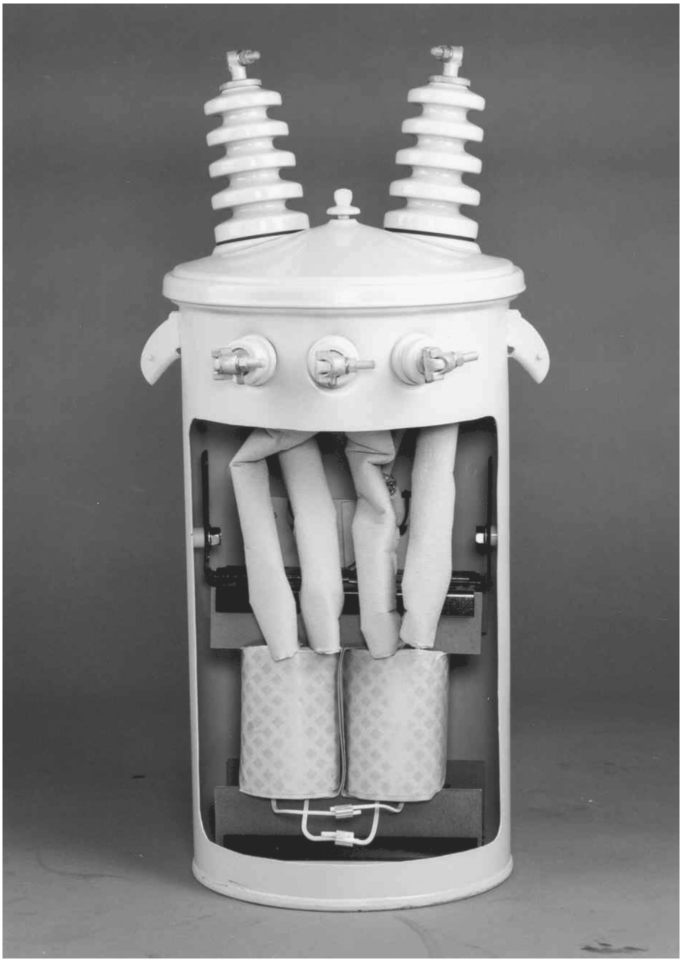


FIGURE 4.4
Single-phase distribution transformer. (Photo courtesy of ABB, Inc. With permission.)

service. A transformer's nameplate gives the kVA ratings, the voltage ratings, percent impedance, polarity, weight, connection diagram, and cooling class. Figure 4.4 shows a cutaway view of a single-phase transformer.

For a single-phase transformer supplying single-phase service, the load-full current in amperes is

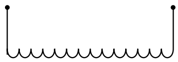
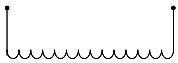
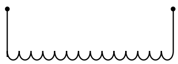
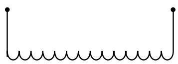
$$I = \frac{S_{kVA}}{V_{kV}}$$

where

S_{kVA} = Transformer kVA rating
V_{kV} = Line-to-ground voltage rating in kV

TABLE 4.5

Winding Designations for Single-Phase Primary and Secondary Transformer Windings with One Winding

Nomenclature	Examples	Description
E	13800 	E shall indicate a winding of E volts that is suitable for Δ connection on an E volt system.
E/E_1Y	2400/4160Y 	E/E_1Y shall indicate a winding of E volts that is suitable for Δ connection on an E volt system or for Y connection on an E_1 volt system.
E/E_1GrdY	7200/12470GrdY 	E/E_1GrdY shall indicate a winding of E volts having reduced insulation that is suitable for Δ connection on an E volt system or Y connection on an E_1 volt system, transformer, neutral effectively grounded.
E_1GrdY/E	12470GrdY/7200 480GrdY/277 	E_1GrdY/E shall indicate a winding of E volts with reduced insulation at the neutral end. The neutral end may be connected directly to the tank for Y or for single-phase operation on an E_1 volt system, provided the neutral end of the winding is effectively grounded.
$E_1 = \sqrt{3}\ E$		

Note: E is line-to-neutral voltage of a Y winding, or line-to-line voltage of a Δ winding.

Source: IEEE Std. C57.12.00-2000.

So, a single-phase 50-kVA transformer with a high-voltage winding of 12470GrdY/7200 V has a full-load current of 6.94 A on the primary. On a 240/120-V secondary, the full-load current across the 240-V winding is 208.3 A.

Table 4.5 and Table 4.6 show the standard single-phase winding connections for primary and secondary windings. High-voltage bushings are labeled H*, starting with H1 and then H2 and so forth. Similarly, the low-voltage bushings are labeled X1, X2, X3, and so on.

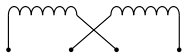
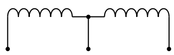
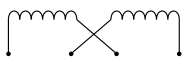
The standard North American single-phase transformer connection is shown in Figure 4.5. The standard secondary load service is a 120/240-V three-wire service. This configuration has two secondary windings in series with the midpoint grounded. The secondary terminals are labeled X1, X2, and X3 where the voltage X1-X2 and X2-X3 are each 120 V. X1-X3 is 240 V.

Power and distribution transformers are assigned polarity dots according to the terminal markings. Current entering H1 results in current leaving X1. The voltage from H1 to H2 is in phase with the voltage from X1 to X3.

On overhead distribution transformers, the high-voltage terminal H1 is always on the left (when looking into the low-voltage terminals; the terminals are not marked). On the low-voltage side, the terminal locations are different, depending on size. If X1 is on the right, it is referred to as *additive polarity* (if X3 is on the right, it is *subtractive polarity*). Polarity is additive if the voltages add when the two windings are connected in series around the transformer (see Figure 4.6). Industry standards specify the polarity of a

TABLE 4.6

Two-Winding Transformer Designations for Single-Phase Primaries and Secondaries

Nomenclature	Examples	Description
E/2E	120/240 240/280  X4 X3 X2 X1	E/2E shall indicate a winding, the sections of which can be connected in parallel for operation at E volts, or which can be connected in series for operation at 2E volts, or connected in series with a center terminal for three-wire operation at 2E volts between the extreme terminals and E volts between the center terminal and each of the extreme terminals.
2E/E	240/120  X3 X2 X1	2E/E shall indicate a winding for 2E volts, two-wire full kilovoltamperes between extreme terminals, or for 2E/E volts three-wire service with 1/2 kVA available only, from midpoint to each extreme terminal.
E × 2E	240 × 480  X4 X3 X2 X1	E × 2E shall indicate a winding for parallel or series operation only but not suitable for three-wire service.

Source: IEEE Std. C57.12.00-2000.

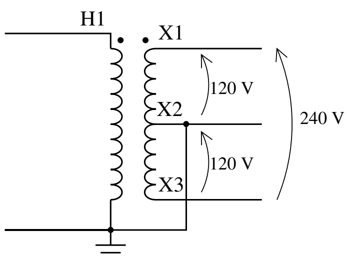
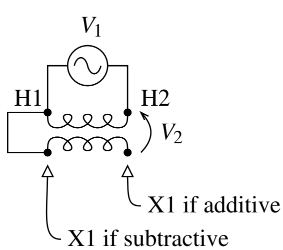


FIGURE 4.5
Single-phase distribution transformer diagram.



Additive:
$V_1 > V_2$

Subtractive:
(>200kVA or >8660V)
$V_2 > V_1$

FIGURE 4.6
Additive and subtractive polarity.

transformer, which depends on the size and the high-voltage winding. Single-phase transformers have additive polarity if (IEEE C57.12.00-2000):

$$\text{kVA} \leq 200 \text{ and } V \leq 8660$$

All other distribution transformers have subtractive polarity. The reason for the division is that originally all distribution transformers had additive polarity and all power transformers had subtractive polarity. Increasing sizes of distribution transformers caused overlap between "distribution" and "power" transformers, so larger distribution transformers were made with subtractive polarity for consistency. Polarity is important when connecting single-phase units in three-phase banks and for paralleling units.

Manufacturers make single-phase transformers as either shell form or core form (see Figure 4.7). Core-form designs prevailed prior to the 1960s; now, both shell- and core-form designs are available. Single-phase core-form transformers must have *interlaced* secondary windings (the low-high-low design). Every secondary leg has two coils, one wrapped around each leg of the core. The balanced configuration of the interlaced design allows unbalanced loadings on each secondary leg. Without interlacing, unbalanced secondary loads excessively heat the tank. An unbalanced secondary load creates an unbalanced flux in the iron core. The core-form construction does not have a return path for the unbalanced flux, so the flux returns outside of the iron core (in contrast, the shell-form construction has a return path for such flux). Some of the stray flux loops through the transformer tank and heats the tank.

The shell-form design does not need to have interlaced windings, so the *noninterlaced* configuration is normally used on shell-form transformers since it is simpler. The noninterlaced secondary has two to four times the reactance: the secondary windings are separated by the high-voltage winding and the insulation between them. Interlacing reduces the reactance since the low-voltage windings are right next to each other.

Using a transformer's impedance magnitude and load losses, we can find the real and reactive impedance in percent as

$$R = \frac{W_{CU}}{10S_{kVA}}$$

$$X = \sqrt{Z^2 - R^2}$$

where

S_{kVA} = transformer rating, kVA
$W_{CU} = W_{TOT} - W_{NL}$ = load loss at rated load, W
W_{TOT} = total losses at rated load, W
W_{NL} = no-load losses, W
Z = nameplate impedance magnitude, %

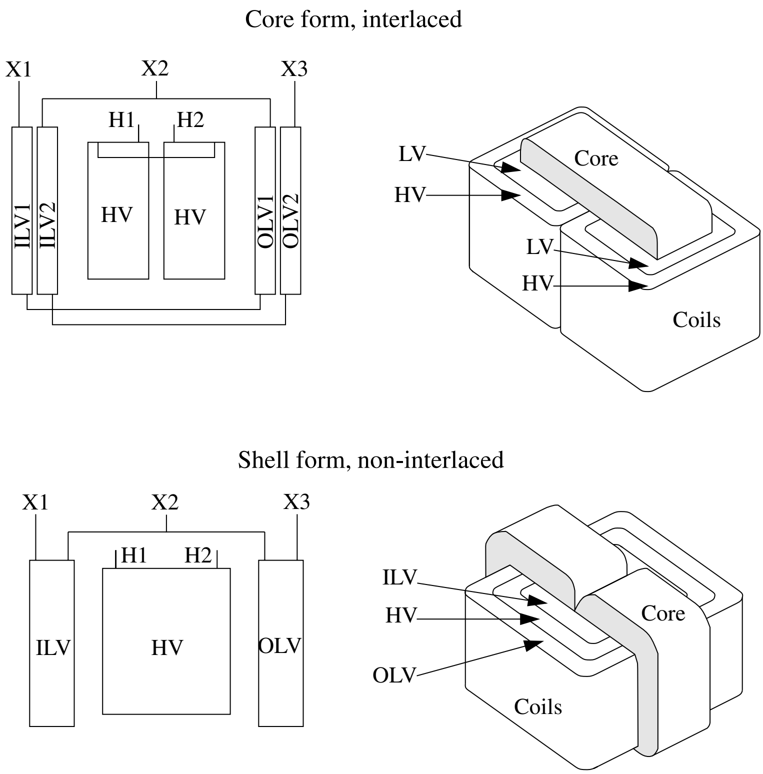
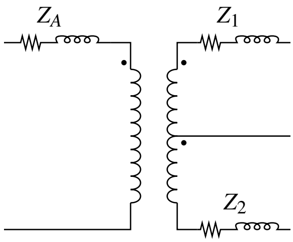


FIGURE 4.7
Core-form and shell-form single-phase distribution transformers. (From IEEE Task Force Report, "Secondary (Low-Side) Surges in Distribution Transformers," *IEEE Trans. Power Delivery*, 7(2), 746–756, April 1992. With permission. ©1992 IEEE.)

The nameplate impedance of a single-phase transformer is the *full-winding* impedance, the impedance seen from the primary when the full secondary winding is shorted from X1 to X3. Other impedances are also important; we need the two *half-winding* impedances for secondary short-circuit calculations and for unbalance calculations on the secondary. One impedance is the impedance seen from the primary for a short circuit from X1 to X2. Another is from X2 to X3. The half-winding impedances are not provided on the nameplate; we can measure them or use the following approximations. Figure 4.8 shows a model of a secondary winding for use in calculations.

The half-winding impedance of a transformer depends on the construction. In the model in Figure 4.8, one of the half-winding impedances in percent equals $Z_A + Z_1$; the other equals $Z_A + Z_2$. A core- or shell-form transformer with an interlaced secondary winding has an impedance in percent of approximately:

$$Z_{\mathrm{HX1-2}} = Z_{\mathrm{HX2-3}} = 1.5\,R + \mathrm{j}\,1.2\,X$$



Full-winding impedance = $R + jX$

Interlaced secondary winding

$Z_A = 0.5R + j0.8X$

$Z_1 = Z_2 = R + j0.4X$

Noninterlaced secondary winding

$Z_A = 0.25R - j0.6X$

$Z_1 = 1.5R + j3.3X$

$Z_2 = 1.5R + j3.1X$ (inner winding)

FIGURE 4.8
Model of a 120/240-V secondary winding with all impedances in percent. (Impedance data from [Hopkinson, 1976].)

where R and X are the real and reactive components of the full-winding impedance (H1 to H2 and X1 to X3) in percent. A noninterlaced shell-form transformer has an impedance in percent of approximately:

$$Z_{\mathrm{HX1-2}} = Z_{\mathrm{HX2-3}} = 1.75\,R + \mathrm{j}\,2.5\,X$$

In a noninterlaced transformer, the two half-winding impedances are not identical; the impedance to the inner low-voltage winding is less than the impedance to the outer winding (the radius to the gap between the outer secondary winding and the primary winding is larger, so the gap between windings has more area).

A secondary fault across one 120-V winding at the terminals of a noninterlaced transformer has current about equal to the current for a fault across the 240-V winding. On an interlaced transformer, the lower relative impedance causes higher currents for the 120-V fault.

Consider a 50-kVA transformer with Z = 2%, 655 W of total losses, no-load losses of 106 W, and a noninterlaced 120/240-V secondary winding. This translates into a full-winding percent impedance of 1.1 + j1.67. For a fault across the 240-V winding, the current is found as

$$Z_{\Omega,240\mathrm{V}} = (R + jX)\frac{10(0.24\mathrm{kV})^2}{S_{kVA}} = (1.1 + j1.67)\frac{10(0.24\mathrm{kV})^2}{50\mathrm{kVA}} = 0.013 + j0.019\Omega$$

$$I_{240\mathrm{V}} = \left|\frac{0.24\mathrm{kV}}{Z_{\Omega,240\mathrm{V}}}\right| = 10.4\mathrm{kA}$$

For a fault across the 120-V winding on this noninterlaced transformer, the current is found as

$$Z_{\Omega,120\text{V}} = (1.75R + j2.5X)\frac{10(0.12\text{kV})^2}{S_{kVA}} = (1.93 + j4.18)\frac{10(0.12\text{kV})^2}{50\text{kVA}}$$

$$= 0.0055 + j0.0120\Omega$$

$$I_{120\text{V}} = \left|\frac{0.12\text{kV}}{Z_{\Omega,120\text{V}}}\right| = 9.06\text{kA}$$

Consider the same transformer characteristics on a transformer with an interlaced secondary and Z = 1.4%. The 240-V and 120-V short-circuit currents are found as

$$Z_{\Omega,240\text{V}} = (R + jX)\frac{10(0.24\text{kV})^2}{S_{kVA}} = (1.1 + j0.87)\frac{10(0.24\text{kV})^2}{50\text{kVA}} = 0.013 + j0.01\Omega$$

$$I_{240\text{V}} = \left|\frac{0.24\text{kV}}{Z_{\Omega,240\text{V}}}\right| = 14.9\text{kA}$$

$$Z_{\Omega,120\text{V}} = (1.5R + j1.2X)\frac{10(0.12\text{kV})^2}{S_{kVA}} = (1.65 + j1.04)\frac{10(0.12\text{kV})^2}{50\text{kVA}}$$

$$= 0.0048 + j0.003\Omega$$

$$I_{120\text{V}} = \left|\frac{0.12\text{kV}}{Z_{\Omega,120\text{V}}}\right| = 21.4\text{kA}$$

The fault current for a 120-V fault is significantly higher than the 240-V current.

Completely self-protected transformers (CSPs) are a widely used single-phase distribution transformer with several built-in features (see Figure 4.9):

- Tank-mounted arrester
- Internal “weak-link” fuse
- Secondary breaker

CSPs do not need a primary-side cutout with a fuse. The internal primary fuse protects against an internal failure in the transformer. The weak link has less fault-clearing capability than a fuse in a cutout, so they need external current-limiting fuses where fault currents are high.

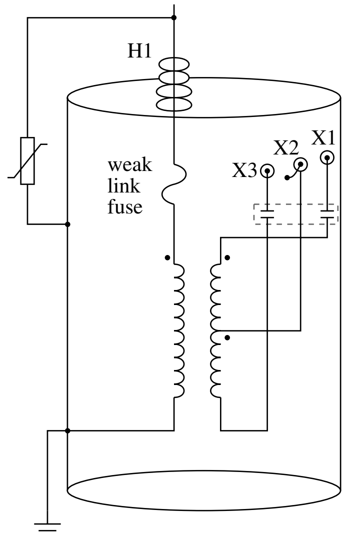


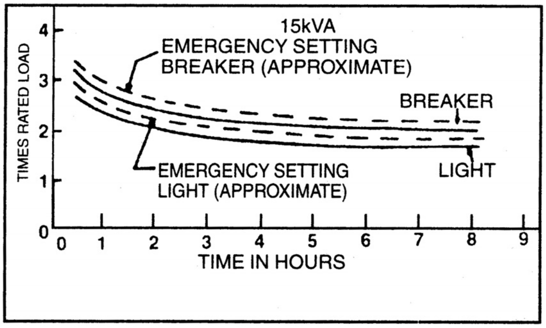
FIGURE 4.9
Completely self-protected transformer.

Secondary breakers provide protection against overloads and secondary faults. The breaker responds to current and oil temperature. Tripping is controlled by deflection of bimetallic elements in series. The oil temperature and current through the bimetallic strips heat the bimetal. Past a critical temperature, the bimetallic strips deflect enough to operate the breaker. Figure 4.10 shows trip characteristics for secondary breakers inside two size transformers. The secondary breaker has an emergency position to allow extra overload without tripping (to allow crews time to replace the unit). Crews can also use the breaker to drop the secondary load.

Some CSPs have overload-indicating lights that signal an overload. The indicator light doesn't go off until line crews reset the breaker. The indicator lights are not ordered as often (and crews often disable them in the field) because they generate a fair number of nuisance phone calls from curious/helpful customers.

4.4 Three-Phase Transformers

Three-phase overhead transformer services are normally constructed from three single-phase units. Three-phase transformers for underground service (either padmounted, direct buried, or in a vault or building or manhole) are normally single units, usually on a three- or five-legged core. Three-phase distribution transformers are usually core construction (see Figure 4.11), with



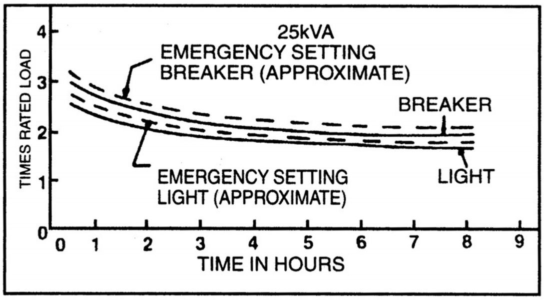


FIGURE 4.10
Clearing characteristics of a secondary breaker. (From ERMCO, Inc. With permission.)

either a three-, four-, or five-legged core construction (shell-type construction is rarely used). The five-legged wound core transformer is very common. Another option is *triplex* construction, where the three transformer legs are made from single individual core/coil assemblies (just like having three separate transformers).

The kVA rating for a three-phase bank is the total of all three phases. The full-load current in amps in each phase of a three-phase unit or bank is

$$I = \frac{S_{kVA}}{3V_{LG,kV}} = \frac{S_{kVA}}{\sqrt{3}V_{LL,kV}}$$

where

S_{kVA} = Transformer three-phase kVA rating
$V_{LG,kV}$ = Line-to-ground voltage rating, kV
$V_{LL,kV}$ = Line-to-line voltage rating, kV

A three-phase, 150-kVA transformer with a high-voltage winding of 12470GrdY/7200 V has a full-load current of 6.94 A on the primary (the same current as one 50-kVA single-phase transformer).

There are many types of three-phase connections used to serve three-phase load on distribution systems (ANSI/IEEE C57.105-1978; Long, 1984; Rusch

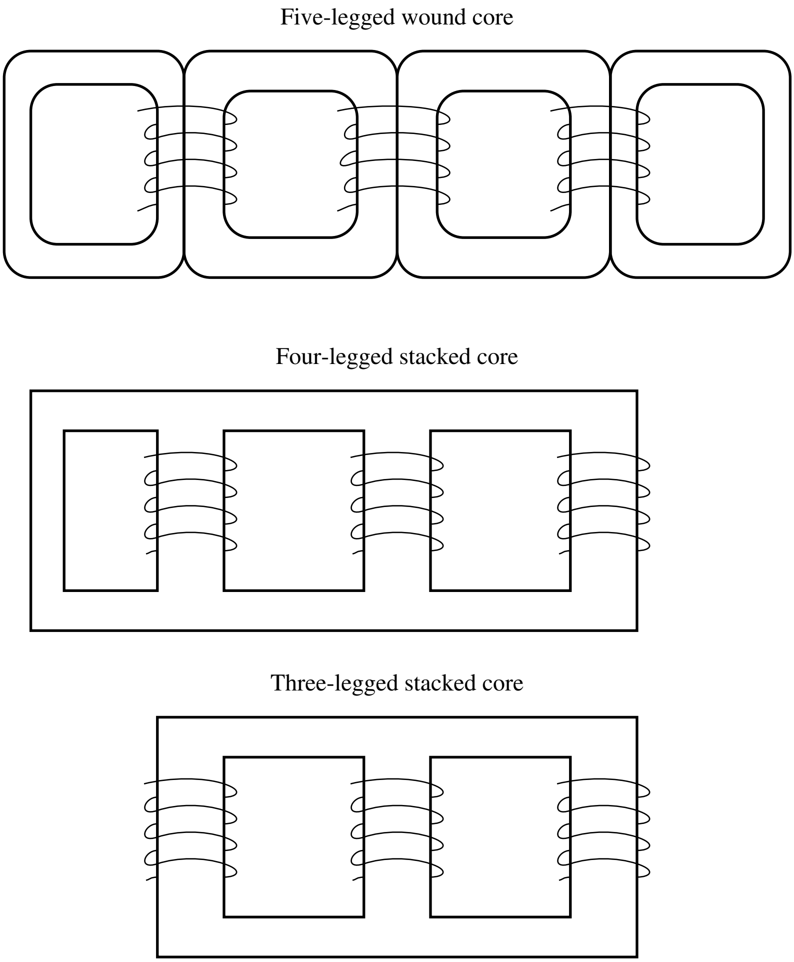


FIGURE 4.11
Three-phase core constructions.

and Good, 1989). Both the primary and secondary windings may be connected in different ways: delta, floating wye, or grounded wye. This notation describes the connection of the transformer windings, not the configuration of the supply system. A "wye" primary winding may be applied on a "delta" distribution system. On the primary side of three-phase distribution transformers, utilities have a choice between grounded and ungrounded winding connections. The tradeoffs are:

- *Ungrounded primary* — The delta and floating-wye primary connections are suitable for ungrounded and grounded distribution systems. Ferroresonance is more likely with ungrounded primary connections. Ungrounded primary connections do not supply ground fault current to the primary distribution system.

- *Grounded primary* — The grounded-wye primary connection is only suitable on four-wire grounded systems (either multigrounded or unigrounded). It is not for use on ungrounded systems. Grounded-wye primaries may provide an unwanted source for ground fault current.

Customer needs play a role in the selection of the secondary configuration. The delta configuration and the grounded-wye configuration are the two most common secondary configurations. Each has advantages and disadvantages:

- *Grounded-wye secondary* — Figure 4.12 shows the most commonly used transformers with a grounded-wye secondary winding: grounded wye – grounded wye and the delta – grounded wye. The

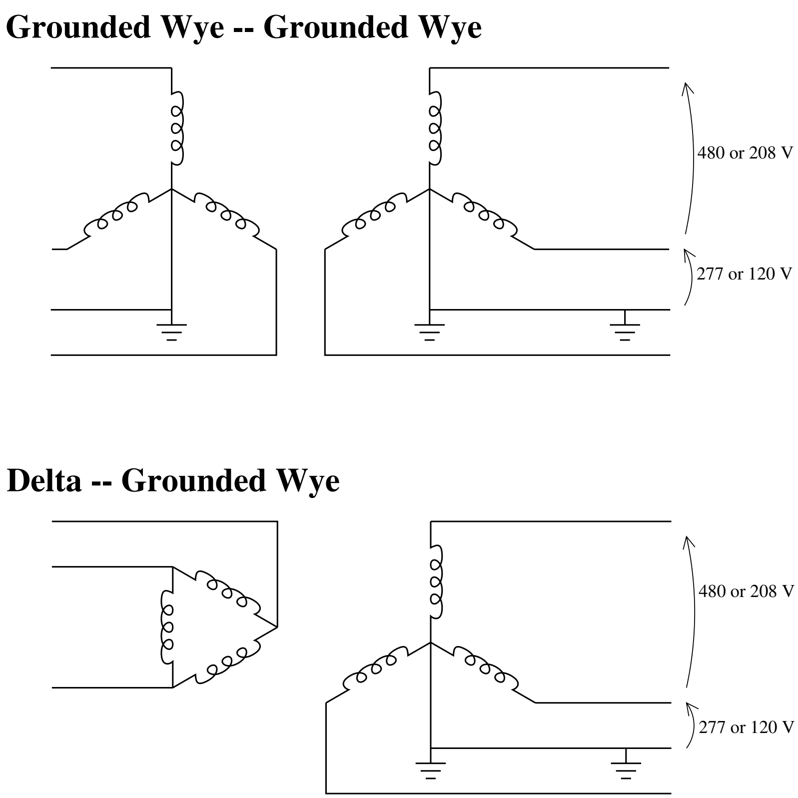


FIGURE 4.12
Three-phase distribution transformer connections with a grounded-wye secondary.

standard secondary voltages are 480Y/277 V and 208Y/120 V. The 480Y/277-V connection is suitable for driving larger motors; lighting and other 120-V loads are normally supplied by dry-type transformers. A grounded-wye secondary adeptly handles single-phase loads on any of the three phases with less concerns about unbalances.

- *Delta secondary* — An ungrounded secondary system like the delta can supply three-wire ungrounded service. Some industrial facilities prefer an ungrounded system, so they can continue to operate with line-to-ground faults. With one leg of the delta grounded at the midpoint of the winding, the utility can supply 240/120-V service. End-users can use more standard 230-V motors (without worrying about reduced performance when run at 208 V) and still run lighting and other single-phase loads. This tapped leg is often called the *lighting* leg (the other two legs are the *power* legs). Figure 4.13 shows the most commonly used connections with a delta secondary windings. This is commonly supplied with overhead transformers.

Many utilities offer a variety of three-phase service options and, of course, most have a variety of existing transformer connections. Some utilities restrict choices in an effort to increase consistency and reduce inventory. A restrictive utility may only offer three choices: 480Y/277-V and 208Y/120-V four-wire, three-phase services, and 120/240-V three-wire single-phase service.

For supplying customers requiring an ungrounded secondary voltage, either a three-wire service or a four-wire service with 120 and 240 V, the following provides the best connection:

- Floating wye – delta

For customers with a four-wire service, either of the following are normally used:

- Grounded wye – grounded wye
- Delta – grounded wye

Choice of preferred connection is often based on past practices and equipment availability.

A wye – delta transformer connection shifts the phase-to-phase voltages by 30° with the direction dependent on how the connection is wired. The phase angle difference between the high-side and low-side voltage on delta – wye and wye – delta transformers is 30°; by industry definition, the low voltage lags the high voltage (IEEE C57.12.00-2000). Figure 4.14 shows wiring diagrams to ensure proper phase connections of popular three-phase connections.

Table 4.7 shows the standard winding designations shown on the nameplate of three-phase units.

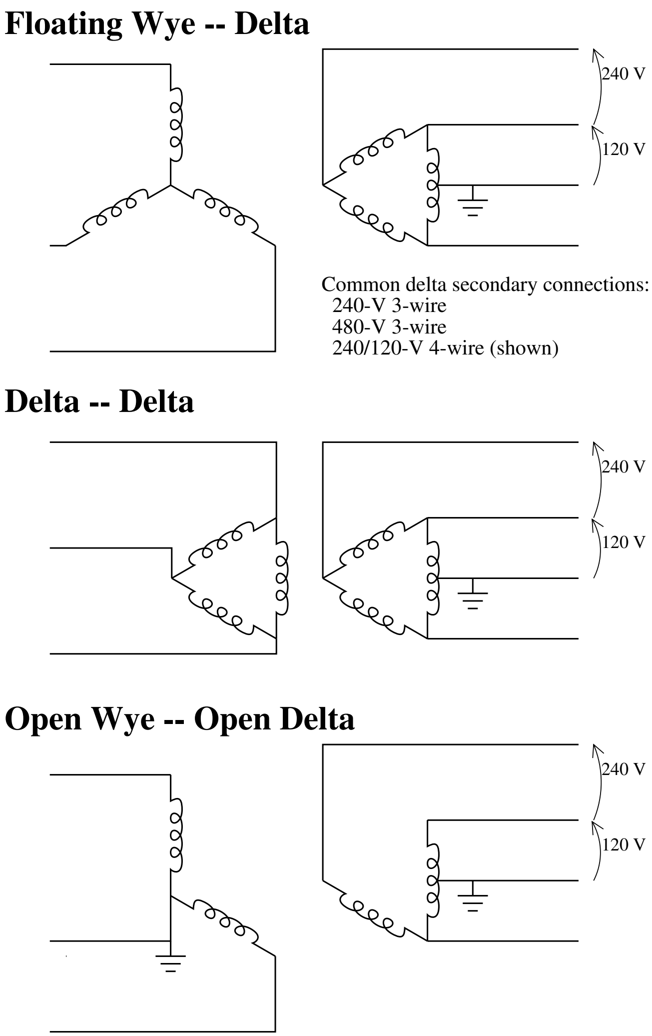


FIGURE 4.13
Common three-phase distribution transformer connections with a delta-connected secondary.

4.4.1 Grounded Wye – Grounded Wye

The most common three-phase transformer supply connection is the grounded wye – grounded wye connection. Its main characteristics are:

- *Supply* — Must be a grounded 4-wire system
- *Service*
  - Supplies grounded-wye service, normally either 480Y/277 V or 208Y/120 V.

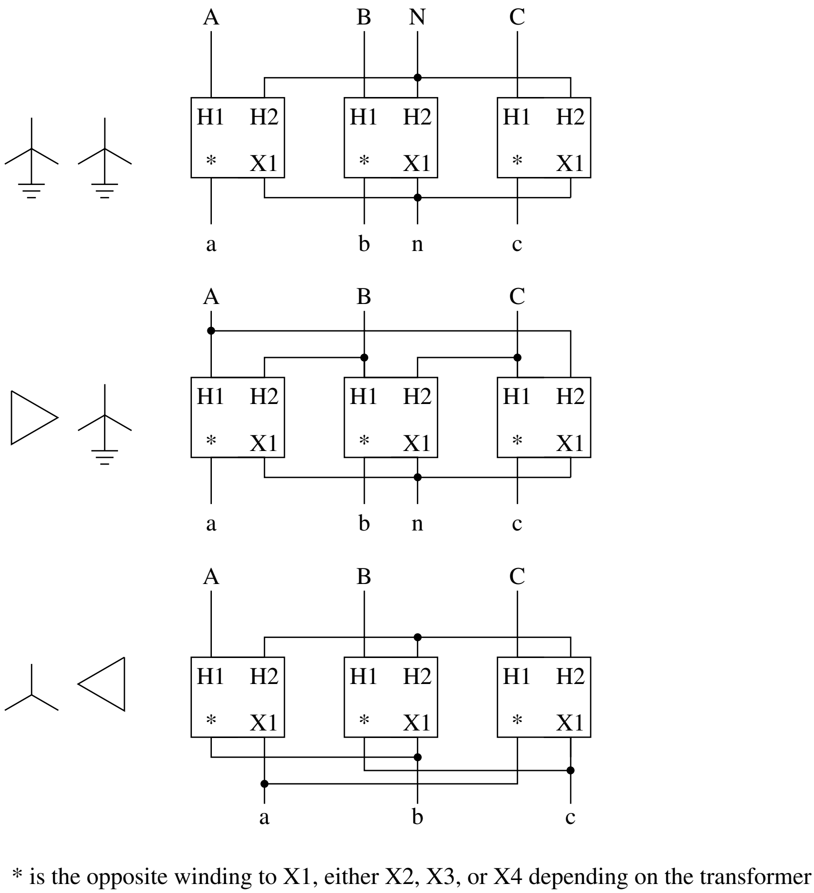


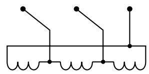
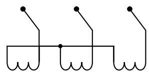
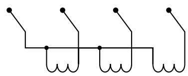
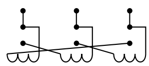
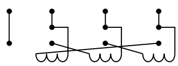
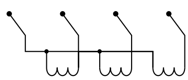
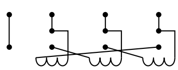
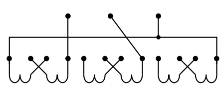
FIGURE 4.14
Wiring diagrams for common transformer connections with additive units. Subtractive units have the same secondary connections, but the physical positions of X1 and * are reversed on the transformer.

  - Cannot supply 120 and 240 V.
  - Does not supply ungrounded service. (But a grounded wye – floating wye connection can.)

- *Tank heating* — Probable with three-legged core construction; less likely, but possible under severe unbalance with five-legged core construction. Impossible if made from three single-phase units.
- *Zero sequence* — All zero-sequence currents — harmonics, unbalance, and ground faults — transfer to the primary. It also acts as a high-impedance ground source to the primary.
- *Ferroresonance* — No chance of ferroresonance with a bank of single-phase units or triplex construction; some chance with a four- or five-legged core construction.

TABLE 4.7

Three-Phase Transformer Designations

Nomenclature	Examples	Description
E	2400 	E shall indicate a winding that is permanently Δ connected for operation on an E volt system.
E_1Y	4160Y 	E_1Y shall indicate a winding that is permanently Y connected without a neutral brought out (isolated) for operation on an E_1 volt system.
E_1Y/E	4160Y/2400 	E_1Y/E shall indicate a winding that is permanently Y connected with a fully insulated neutral brought out for operation on an E_1 volt system, with E volts available from line to neutral.
E/E_1Y	2400/4160Y 	E/E_1Y shall indicate a winding that may be Δ connected for operation on an E volt system, or may be Y connected without a neutral brought out (isolated) for operation on an E_1 volt system.
$E/E_1Y/E$	2400/4160Y/2400 	$E/E_1Y/E$ shall indicate a winding that may be Δ connected for operation on an E volt system or may be Y connected with a fully insulated neutral brought out for operation on an E_1 volt system with E volts available from line to neutral.
E_1GrdY/E	12470GrdY/7200 	E_1GrdY/E shall indicate a winding with reduced insulation and permanently Y connected, with a neutral brought out and effectively grounded for operation on an E_1 volt system with E volts available from line to neutral.
$E/E_1GrdY/E$	7200/12470GrdY/7200 	$E/E_1GrdY/E$ shall indicate a winding, having reduced insulation, which may be Δ connected for operation on an E volt system or may be connected Y with a neutral brought out and effectively grounded for operation on an E_1 volt system with E volts available from line to neutral.
$V \times V_1$	7200 × 14400 	$V \times V_1$ shall indicate a winding, the sections of which may be connected in parallel to obtain one of the voltage ratings (as defined in a–g) of V, or may be connected in series to obtain one of the voltage ratings (as defined in a–g) of V_1. Winding are permanently Δ or Y connected.

Source: IEEE Std. C57.12.00-2000. Copyright 2000 IEEE. All rights reserved.

- *Coordination* — Because ground faults pass through to the primary, larger transformer services and local protective devices should be coordinated with utility ground relays.

The grounded wye – grounded wye connection has become the most common three-phase transformer connection. Reduced ferroresonance is the main reason for the shift from the delta – grounded wye to the grounded wye – grounded wye.

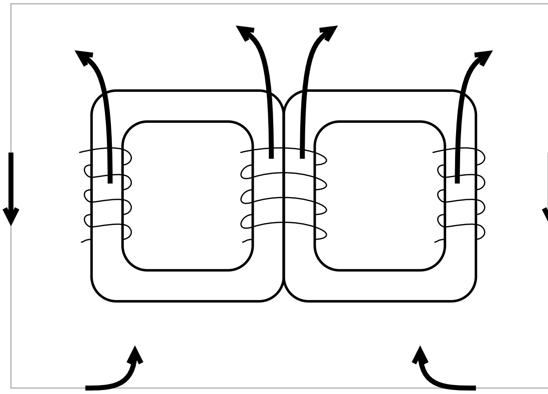


FIGURE 4.15
Zero-sequence flux caused by unbalanced voltages or unbalanced loads.

A grounded wye – grounded wye transformer with three-legged core construction is not suitable for supplying four-wire service. Unbalanced secondary loading and voltage unbalance on the primary system, these unbalances heat the transformer tank. In a three-legged core design, zero-sequence flux has no iron-core return path, so it must return via a high-reluctance path through the air gap and partially through the transformer tank (see Figure 4.15). The zero-sequence flux induces eddy currents in the tank that heat the tank.

A four- or five-legged core transformer greatly reduces the problem of tank heating with a grounded wye – grounded wye connection. The extra leg(s) provide an iron path for zero-sequence flux, so none travels into the tank. Although much less of a problem, tank heating can occur on four and five-legged core transformers under certain conditions; very large voltage unbalances may heat the tank. The outer leg cores normally do not have full capacity for zero-sequence flux (they are smaller than the inner leg cores), so under very high voltage unbalance, the outer legs may saturate. Once the legs saturate, some of the zero-sequence flux flows in the tank causing heating. The outer legs may saturate for a zero-sequence voltage of about 50 to 60% of the rated voltage. If a fuse or single-phase recloser or single-pole switch opens upstream of the transformer, the unbalance may be high enough to heat the tank, depending on the loading on the transformer and whether faults still exist. The worst conditions are when a single-phase interrupter clears a line-to-line or line-to-line-to-line fault (but not to ground) and the transformer is energized through one or two phases.

To completely eliminate the chance of tank heating, do not use a core-form transformer. Use a bank made of three single-phase transformers, or use triplex construction.

A wye – wye transformer with the primary and secondary neutrals tied together internally causes high line-to-ground secondary voltages if the neutral is not grounded. This connection cannot supply three-wire ungrounded service. Three-phase padmounted transformers with an H0X0 bushing have the neutrals bonded internally. If the H0X0 bushing is floated, high voltages can occur from phase to ground on the secondary.

To supply ungrounded secondary service with a grounded-wye primary, use a grounded wye – floating wye connection: the secondary should be floating wye with no connection between the primary and secondary neutral points.

4.4.2 Delta – Grounded Wye

The delta – grounded wye connection has several interesting features, many related to its delta winding, which establishes a local grounding reference and blocks zero-sequence currents from entering the primary.

- *Supply* — 3-wire or 4-wire system.
- *Service*
  - Supplies grounded-wye service, normally either 480Y/277 V or 208Y/120 V.
  - Cannot supply both 120 and 240 V.
  - Does not supply ungrounded service.
- *Ground faults* — This connection blocks zero sequence, so upstream ground relays are isolated from line-to-ground faults on the secondary of the customer transformer.
- *Harmonics* — The delta winding isolates the primary from zero-sequence harmonics created on the secondary. Third harmonics and other zero-sequence harmonics cannot get through to the primary (they circulate in the delta winding).
- *No primary ground source* — For line-to-ground faults on the primary, the delta – grounded wye connection cannot act as a grounding source.
- *Secondary ground source* — Provides a grounding source for the secondary, independent of the primary-side grounding configuration.
- *No tank heating* — The delta connection ensures that zero-sequence flux will not flow in the transformer's core. We can safely use a three-legged core transformer.
- *Ferroresonance* — Highly susceptible.

4.4.3 Floating Wye – Delta

The floating-wye – delta connection is popular for supplying ungrounded service and 120/240-V service. This type of connection may be used from either a grounded or ungrounded distribution primary. The main characteristics of this supply are:

- *Supply* — 3-wire or 4-wire system.
- *Service*
  - Can supply ungrounded service.
  - Can supply four-wire service with 240/120-V on one leg with a midtapped ground.
  - Cannot supply grounded-wye four-wire service.
- *Unit failure* — Can continue to operate if one unit fails if it is rewired as an open wye – open delta.
- *Voltage unbalance* — Secondary-side unbalances are more likely than with a wye secondary connection.
- *Ferroresonance* — Highly susceptible.

Do not use single-phase transformers with secondary breakers (CSPs) in this connection. If one secondary breaker opens, it breaks the delta on the secondary. Now, the primary neutral can shift wildly. The transformer may be severely overloaded by load unbalance or single phasing on the primary.

Facilities should ensure that single-phase loads only connect to the lighting leg; any miswired loads have overvoltages. The phase-to-neutral connection from the neutral to the opposite phase (where both power legs come together) is 208 V on a 240/120-V system.

The floating wye – delta is best used when supplying mainly three-phase load with a smaller amount of single-phase load. If the single-phase load is large, the three transformers making up the connection are not used as efficiently, and voltage unbalances can be high on the secondary.

In a conservative loading guideline, size the lighting transformer to supply all of the single-phase load plus 1/3 of the three-phase load (ANSI/IEEE C57.105-1978). Size each power leg to carry 1/3 of the three-phase load plus 1/3 of the single-phase load. ABB (1995) describes more accurate loading equations:

Lighting leg loading in kVA:

$$kVA_{bc} = \frac{1}{3}\sqrt{k_3^2 + 4k_1^2 + 4k_3k_1\cos\alpha}$$

Lagging power leg loading in kVA:

$$kVA_{ca} = \frac{1}{3}\sqrt{k_3^2 + k_1^2 - 2k_3k_1\cos(120° + \alpha)}$$

Leading power leg loading in kVA:

$$kVA_{ab} = \frac{1}{3}\sqrt{k_3^2 + k_1^2 - 2k_3k_1\cos(120° - \alpha)}$$

where
k_1 = single-phase load, kVA
k_3 = balanced three-phase load, kVA
$\alpha = \theta_3 - \theta_1$
θ_3 = phase angle in degrees for the three-phase load
θ_1 = phase angle in degrees for the single-phase load

For wye – delta connections, the wye on the primary is normally intentionally ungrounded. If it is grounded, it creates a grounding bank. This is normally undesirable because it may disrupt the feeder protection schemes and cause excessive circulating current in the delta winding. Utilities sometimes use this connection as a grounding source or for other unusual reasons.

Delta secondary windings are more prone to voltage unbalance problems than a wye secondary winding (Smith et al., 1988). A balanced three-phase load can cause voltage unbalance if the impedances of each leg are different. With the normal practice of using a larger lighting leg, the lighting leg has a lower impedance. Voltage unbalance is worse with longer secondaries and higher impedance transformers. High levels of single-phase load also aggravate unbalances.

4.4.4 Other Common Connections

4.4.4.1 Delta – Delta

The main features and drawbacks of the delta – delta supply are:

- *Supply* — 3-wire or 4-wire system.
- *Service*
    - Can supply ungrounded service.
    - Can supply four-wire service with 240/120-V on one leg with a midtapped ground.
    - Cannot supply grounded-wye four-wire service.
- *Ferroresonance* — Highly susceptible.
- *Unit failure* — Can continue to operate if one unit fails (as an open delta – open delta).
- *Circulating current* — Has high circulating current if the turns ratios of each unit are not equal.

A delta – delta transformer may have high circulating current if any of the three legs has unbalance in the voltage ratio. A delta winding forms a series loop. Two windings are enough to fix the three phase-to-phase voltage vectors. If the third winding does not have the same voltage as that created by the series sum of the other two windings, large circulating currents flow to offset the voltage imbalance. ANSI/IEEE C57.105-1978 provides an example where the three phase-to-phase voltages summed to 1.5% of nominal as measured at the open corner of the delta winding (this voltage should be zero for no circulating current). With a 5% transformer impedance, a current equal to 10% of the transformer rating circulates in the delta when the open corner is connected. The voltage sees an impedance equal to the three winding impedances in series, resulting in a circulating current of 100% × 1.5% / (3×5%) = 10%. This circulating current directly adds to one of the three windings, possibly overloading the transformer.

Single-phase units with secondary breakers (CSPs) should not be used for the lighting leg. If the secondary breaker on the lighting leg opens, the load loses its neutral reference, but the phase-to-phase voltages are maintained by the other two legs (like an open delta – open delta connection). As with the loss of the neutral connection to a single-phase 120/240-V customer, unbalanced single-phase loads shift the neutral and create low voltages on one leg and high voltages on the lightly loaded leg.

4.4.4.2 Open Wye – Open Delta

The main advantage of the open wye – open delta transformer configuration is that it can supply three-phase load from a two-phase supply (but the supply must have a neutral).

The main features and drawbacks of the open wye – delta supply are:

- *Supply* — 2 phases and the neutral of a 4-wire grounded system.
- *Service*
  - Can supply ungrounded service.
  - Can supply four-wire service with 240/120-V on one leg with a midtapped ground.
  - Cannot supply grounded-wye four-wire service.
- *Ferroresonance* — Immune.
- *Voltage unbalance* — May have high secondary voltage unbalance.
- *Primary ground current* — Creates high primary-side current unbalance. Even with balanced loading, high currents are forced into the primary neutral.

Open wye – open delta connections are most efficiently applied when the load is predominantly single phase with some three-phase load, using one large lighting-leg transformer and another smaller unit. This connection is easily upgraded if the customer's three-phase load grows by adding a second power-leg transformer.

For sizing each bank, size the power leg for $1/\sqrt{3} = 0.577$ times the balanced three-phase load, and size the lighting leg for all of the single-phase load plus 0.577 times the three-phase load (ANSI/IEEE C57.105-1978). The following equations more accurately describe the split in loading on the two transformers (ABB, 1995). The load on the lighting leg in kVA is

$$kVA_L = \frac{k_3^2}{3} + k_1{}^2 + \frac{2k_3k_1}{\sqrt{3}}\cos(\alpha + 30°) \text{ for a leading lighting leg}$$

$$kVA_L = \frac{k_3^2}{3} + k_1^2 + \frac{2k_3k_1}{\sqrt{3}}\cos(\alpha - 30°) \text{ for a lagging lighting leg}$$

The power leg loading in kVA is:

$$kVA_L = \frac{k_3}{\sqrt{3}}$$

where

k_1 = single-phase load, kVA
k_3 = balanced three-phase load, kVA
$\alpha = \theta_3 - \theta_1$
θ_3 = phase angle in degrees for the three-phase load
θ_1 = phase angle in degrees for the single-phase load

The lighting leg may be on the leading or lagging leg. In the open wye – open delta connection shown in Figure 4.13, the single-phase load is on the leading leg. For a lagging connection, switch the lighting and the power leg. Having the lighting connection on the leading leg reduces the loading on the lighting leg. Normally, the power factor of the three-phase load is less than that of the single-phase load, so α is positive, which reduces the loading on the lighting leg.

On the primary side, it is important that the two high-voltage primary connections are not made to the same primary phase. If this is accidentally done, the phase-to-phase voltage across the open secondary is two times the normal phase-to-phase voltage.

The open wye – open delta connection injects significant current into the neutral on the four-wire primary. Even with a balanced three-phase load, significant current is forced into the ground as shown in Figure 4.16. The extra unbalanced current can cause primary-side voltage unbalance and may trigger ground relays.

Open-delta secondary windings are very prone to voltage unbalance, which can cause excessive heating in end-use motors (Smith et al., 1988). Even balanced three-phase loads significantly unbalance the voltages. Voltage unbalance is less with lower-impedance transformers. Voltage unbalance

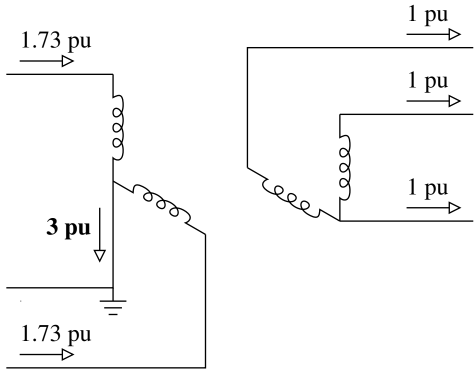


FIGURE 4.16
Current flow in an open wye – open delta transformer with balanced three-phase load.

reduces significantly if the connection is upgraded to a floating wye – closed delta connection. In addition, the component of the negative-sequence voltage on the primary (which is what really causes motor heating) can add to that caused by the transformer configuration to sometimes cause a negative-sequence voltage above 5% (which is a level that significantly increases heating in a three-phase induction motor).

While an unusual connection, it is possible to supply a balanced, grounded four-wire service from an open-wye primary. This connection (open wye – partial zig-zag) can be used to supply 208Y/120-V service from a two-phase line. One of the 120/240-V transformers must have four bushings; X2 and X3 are not tied together but connected as shown in Figure 4.17. Each of the transformers must be sized to supply 2/3 of the balanced three-phase load. If four-bushing transformers are not available, this connection can be made with three single-phase transformers. Instead of the four-bushing transformer, two single-phase transformers are placed in parallel on the primary, and the secondary terminals of each are configured to give the arrangement in Figure 4.17.

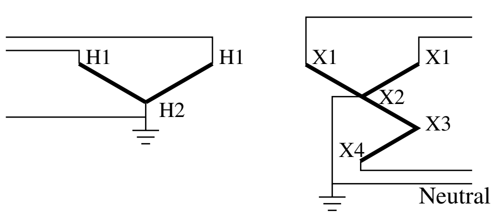


FIGURE 4.17
Quasiphasor diagram of an open-wye primary connection supplying a wye four-wire neutral service such as 208Y/120 V. (From ANSI/IEEE Std. C57.105-1978. Copyright 1978 IEEE. All rights reserved.)

4.4.4.3 Other Suitable Connections

While not as common, several other three-phase connections are used at times:

- *Open delta – Open delta* — Can supply a three-wire ungrounded service or a four-wire 120/240-V service with a midtapped ground on one leg of the transformer. The ungrounded high-side connection is susceptible to ferroresonance. Only two transformers are needed, but it requires all three primary phases. This connection is less efficient for supplying balanced three-phase loads; the two units must total 115% of the connected load. This connection is most efficiently applied when the load is predominantly single phase with some three-phase load, using one large lighting-leg transformer and another smaller unit.
- *Delta – Floating wye* — Suitable for supplying a three-wire ungrounded service. The ungrounded high-side connection is susceptible to ferroresonance.
- *Grounded wye – Floating wye* — Suitable for supplying a three-wire ungrounded service from a multigrounded primary system. The grounded primary-side connection reduces the possibility of ferroresonance.

4.4.5 Neutral Stability with a Floating Wye

Some connections with a floating-wye winding have an unstable neutral, which we should avoid. Unbalanced single-phase loads on the secondary, unequal magnetizing currents, and suppression of third harmonics — all can shift the neutral.

Consider a *floating wye – grounded wye* connection. In a wye – wye transformer, the primary and secondary voltages have the same vector relationships. The problem is that the neutral point does not have a grounding source; it is free to float. Unbalanced loads or magnetizing currents can shift the neutral and create high neutral-to-earth voltages and overvoltages on the phases with less loading. The reverse connection with a grounded wye – floating wye works because the primary-side neutral is connected to the system neutral, which has a grounding source. The grounding source fixes the neutral voltage.

In a floating wye, current in one branch is dependent on the currents in the other two branches. What flows in one branch must flow out the other two branches. This creates conditions that shift the neutral (Blume et al., 1951):

- *Unbalanced loads* — Unequal single-phase loads shift the neutral point. Zero-sequence current has no path to flow (again, the ground source is missing). Loading one phase drops the voltage on that phase and raises the voltage on the other two phases. Even a small unbalance significantly shifts the neutral.

- *Unequal magnetizing currents* — Just like unequal loads, differences in the amount of magnetizing current each leg needs can shift the floating neutral. In a four- or five-legged core, the asymmetry of the core causes unequal magnetizing requirements on each phase.
- *Suppression of third harmonics* — Magnetizing currents contain significant third harmonics that are zero sequence. But, the floating wye connection has no ground source to absorb the zero-sequence currents, so they are suppressed. The suppression of the zero-sequence currents generates a significant third-harmonic voltage in each winding, about 50% of the phase voltage on each leg according to Blume et al. (1951). With the neutral grounded in the floating wye – grounded wye, a significant third-harmonic voltage adds to each phase-to-ground load. If the neutral is floating (on the wye–wye transformer with the neutrals tied together), the third-harmonic voltage appears between the neutral and ground.

In addition to the floating wye – grounded wye, avoid these problem connections that have an unstable neutral:

- *Grounded wye – grounded wye on a three-wire system* — The grounded-wye on the primary does not have an effective grounding source, so it acts the same as a floating-wye – grounded-wye.
- *A wye – wye transformer with the primary and secondary neutrals tied together internally (the H0X0 bushing) but with the neutral left floating* — Again, the neutral point can float. Unbalanced loading is not a problem, but magnetizing currents and suppression of third harmonics are. These can generate large voltages between the neutral point and ground (and between the phase wires and ground). If the secondary neutral is isolated from the primary neutral, each neutral settles to a different value. But when the secondary neutral is locked into the primary neutral, the secondary neutral follows the neutral shift of the primary and shifts the secondary phases relative to ground.

Another poor connection is the floating wye – floating wye. Although not as bad as the floating-wye – grounded-wye connection, the neutral can shift if the connection is made of three units of different magnetizing characteristics. The neutral shift can lead to an overvoltage across one of the windings. Also, high harmonic voltage appears on the primary-side neutral (which is okay if the neutral is properly insulated from the tank).

Three-legged core transformers avoid some of the problems with a floating wye. The phantom tertiary acts as a mini ground source, stabilizes the neutral, and even allows some unbalance of single-phase loads. But as it stabilizes the neutral, the unbalances heat the tank. Given that, it is best to avoid these transformer connections. They provide no features or advantages over other transformer connections.

4.4.6 Sequence Connections of Three-Phase Transformers

The connection determines the effect on zero sequence, which impacts unbalances and response to line-to-ground faults and zero-sequence harmonics. Figure 4.18 shows how to derive sequence connections along with common examples. In general, three-phase transformers may affect the zero-sequence circuit as follows:

- *Isolation* — A floating wye – delta connection isolates the primary from the secondary in the zero sequence.
- *Pass through* — The grounding of the grounded wye – grounded wye connection is determined by the grounding upstream of the transformer.
- *Ground source* — A delta – grounded wye connection provides a ground source on the secondary. (And, the delta – grounded wye connection also isolates the primary from the secondary.)

4.5 Loadings

Distribution transformers are *output rated*; they can deliver their rated kVA without exceeding temperature rise limits when the following conditions apply:

- The secondary voltage and the voltage/frequency do not exceed 105% of rating. So, a transformer is a constant kVA device for a voltage from 100 to 105% (the standards are unclear below that, so treat them as constant current devices).
- The load power factor ≥ 80%.
- Frequency ≥ 95% of rating.

The transformer loading and sizing guidelines of many utilities are based on ANSI/IEEE C57.91-1981.

Modern distribution transformers are 65°C rise units, meaning they have normal life expectancy when operated with an average winding temperature rise above ambient of not more than 65°C and a hottest spot winding temperature rise of not more than 80°C. Some older units are 55°C rise units, which have less overloading capability.

At an ambient temperature of 30°C, the 80°C hottest-spot rise for 65°C rise units gives a hottest-spot winding temperature of 110°C. The hot-spot tem-

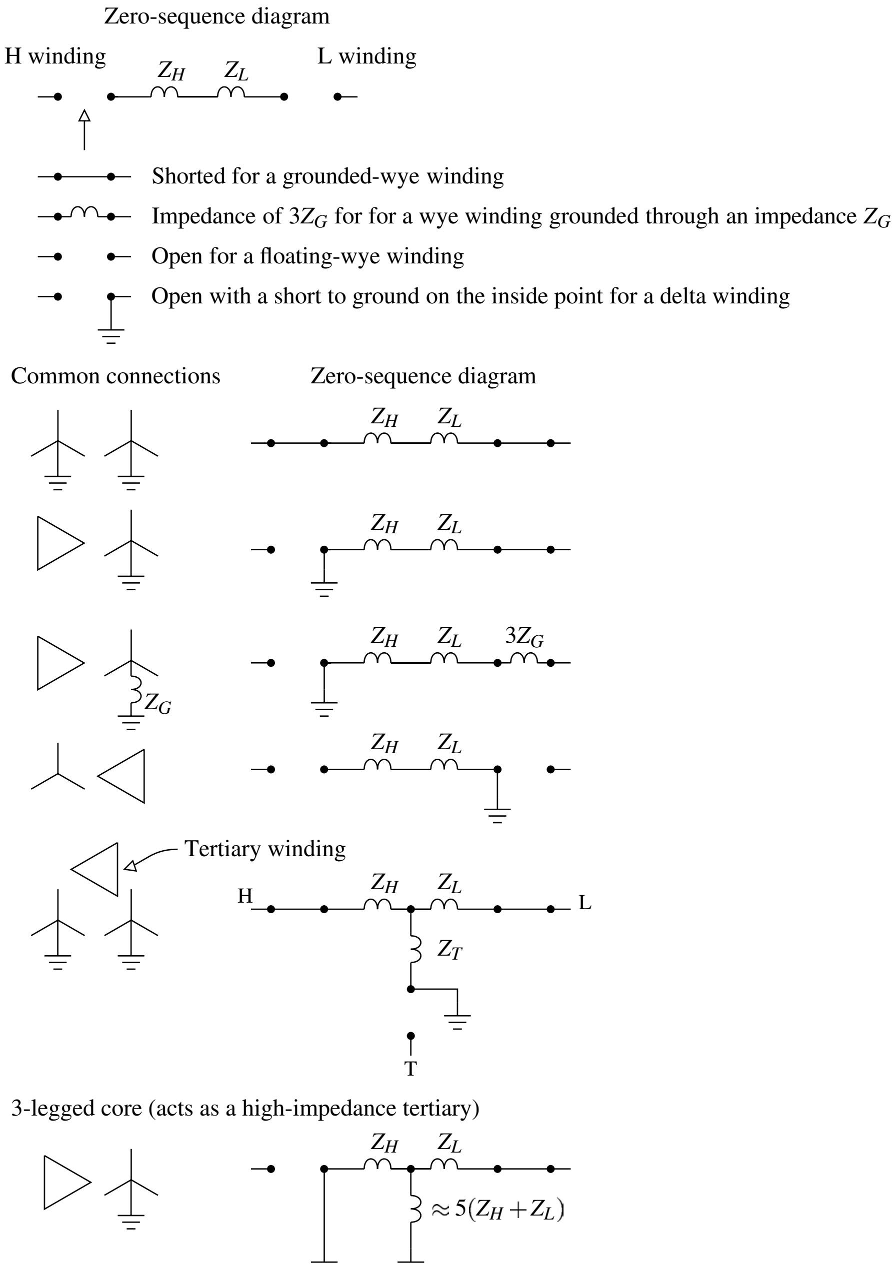


FIGURE 4.18
Zero-sequence connections of various three-phase transformer connections.

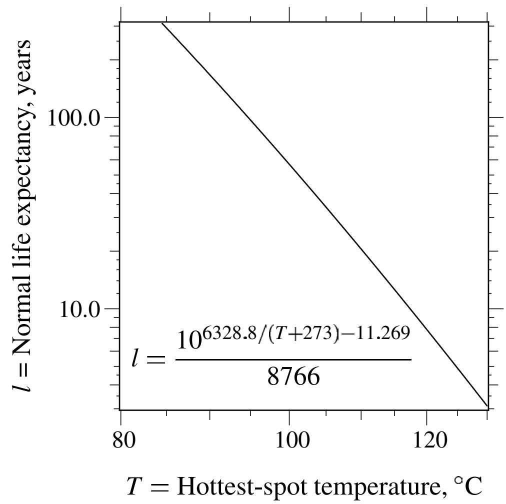


FIGURE 4.19
Transformer life as a function of the hottest-spot winding temperature.

perature on the winding is critical; that's where insulation degrades. The insulation's life exponentially relates to hot-spot winding temperature as shown in Figure 4.19. At 110°C, the normal life expectancy is 20 years. Because of daily and seasonal load cycles, most of the time temperatures are nowhere near these values. Most of the time, temperatures are low enough not to do any significant insulation degradation. We can even run at temperatures above 110°C for short periods. For the most economic operation of distribution transformers, they are normally sized to operate at significant overloads for short periods of the year.

We can load distribution transformers much more heavily when it is cold. Locations with winter-peaking loads can have smaller transformers for a given loading level. The transformer's kVA rating is based on an ambient temperature of 30°C. For other temperatures, ANSI/IEEE C57.91-1981 suggests the following adjustments to loading capability:

- > 30°C: decrease loading capability by 1.5% of rated kVA for each °C above 30°C.
- < 30°C: increase loading capability by 1% of rated kVA for each °C above 30°C.

Ambient temperature estimates for a given region can be found using historical weather data. For loads with normal life expectancy, ANSI/IEEE C57.91-1981 recommends the following estimate of ambient temperature:

- *Average daily temperature for the month involved* — As an approximation, the average can be approximated as the average of the daily highs and the daily lows.

For short-time loads where we are designing for a moderate sacrifice of life, use:

- *Maximum daily temperature*

In either case, the values should be averaged over several years for the month involved. C57.91-1981 also suggests adding 5°C to be conservative. These values are for outdoor overhead or padmounted units. Transformers installed in vaults or other cases with limited air flow may require some adjustments.

Transformers should also be derated for altitudes above 3300 ft (1000 m). At higher altitudes, the decreased air density reduces the heat conducted away from the transformer. ANSI/IEEE C57.91-1981 recommends derating by 0.4% for each 330 ft (100 m) that the altitude is above 3300 ft (1000 m).

Load cycles play an important role in determining loading. ANSI/IEEE C57.91-1981 derives an equivalent load cycle with two levels: the peak load and the initial load. The equivalent two-step load cycle may be derived from a more detailed load cycle. The guide finds a continuous load and a short-duration peak load. Both are found using the equivalent load value from a more complicated load cycle:

$$L = \sqrt{\frac{L_1^2 t_1 + L_2^2 t_2 + L_3^2 t_3 + \cdots + L_n^2 t_n}{t_1 + t_2 + t_3 + \cdots + t_n}}$$

where

L = equivalent load in percent, per unit, or actual kVA
$L_1, L_2, \ldots,$ = The load steps in percent, per unit, or actual kVA
$t_1, t_2, \ldots,$ = The corresponding load durations

The continuous load is the equivalent load found using the equation above for 12 h preceding and 12 h following the peak and choosing the higher of these two values. The guide suggests using 1-h time blocks. The peak is the equivalent load from the equation above where the irregular peak exists.

The C57.91 guide has loading guidelines based on the peak duration and continuous load prior to the peak. Table 4.8 shows that significant overloads are allowed depending on the preload and the duration of the peak.

Because a region's temperature and loading patterns vary significantly, there is no universal transformer application guideline. Coming up with standardized tables for initial loading is based on a prediction of peak load, which for residential service normally factors in the number of houses, average size (square footage), central air conditioner size, and whether electric heat is used. Once the peak load is estimated, it is common to pick a transformer with a kVA rating equal to or greater than the peak load kVA estimate. With this arrangement, some transformers may operate significantly above their ratings for short periods of the year. Load growth can push the peak

TABLE 4.8

Transformer Loading Guidelines

Peak Load Duration, Hours	Extra Loss of Life[a], %	Equivalent Peak Loading in Per Unit of Rated kVA with the Percent Preload and Ambient Temperatures Given Below										
		50% Preload				75% Preload				90% Preload		
		Ambient Temp., °C				Ambient Temp., °C				Ambient Temp., °C		
		20	30	40	50	20	30	40	50	20	30	40
1	Normal	2.26	2.12	1.96	1.79	2.12	1.96	1.77	1.49	2.02	1.82	1.43
	0.05	2.51	2.38	2.25	2.11	2.40	2.27	2.12	1.95	2.31	2.16	1.97
	0.10	2.61	2.49	2.36	2.23	2.50	2.37	2.22	2.07	2.41	2.27	2.11
	0.50	2.88	2.76	2.64	2.51	2.77	2.65	2.52	2.39	2.70	2.57	2.43
2	Normal	1.91	1.79	1.65	1.50	1.82	1.68	1.52	1.26	1.74	1.57	1.26
	0.05	2.13	2.02	1.89	1.77	2.05	1.93	1.80	1.65	1.98	1.85	1.70
	0.10	2.22	2.10	1.99	1.87	2.14	2.02	1.90	1.75	2.07	1.95	1.81
	0.50	2.44	2.34	2.23	—	2.37	2.26	2.15	—	2.31	2.20	2.08
4	Normal	1.61	2.50	1.38	1.25	1.56	1.44	1.30	1.09	1.50	1.36	1.13
	0.05	1.80	1.70	1.60	1.48	1.76	1.65	1.54	1.40	1.71	1.60	1.47
	0.10	1.87	1.77	1.67	—	1.83	1.72	1.62	1.50	1.79	1.68	1.56
	0.50	2.06	1.97	—	—	2.02	1.93	—	—	1.99	1.89	—
8	Normal	1.39	1.28	1.18	1.05	1.36	1.25	1.13	0.96	1.33	1.21	1.02
	0.05	1.55	1.46	1.36	1.25	1.53	1.43	1.33	1.21	1.51	1.41	1.29
	0.10	1.61	1.53	1.43	1.33	1.59	1.50	1.41	1.30	1.57	1.47	1.38
	0.50	1.78	1.69	1.61	—	1.76	1.67	1.58	—	1.74	1.65	1.56
24	Normal	1.18	1.08	0.97	0.86	1.17	1.07	0.97	0.84	1.16	1.07	0.95
	0.05	1.33	1.24	1.15	1.04	1.33	1.24	1.13	1.04	1.32	1.23	1.13
	0.10	1.39	1.30	1.21	1.11	1.38	1.29	1.20	1.10	1.38	1.29	1.20
	0.50	1.54	1.45	1.37	1.28	1.53	1.45	1.37	1.28	1.53	1.45	1.36

[a] Extra loss of life in addition to 0.0137% per day loss of life for normal life expectancy.

Source: ANSI/IEEE C57.91-1981, *IEEE Guide for Loading Mineral-Oil-Immersed Overhead and Pad-Mounted Distribution Transformers Rated 500 kVA and Less with 65 Degrees C or 55 Degrees C Average Winding Rise.*

load above the peak kVA estimate, and inaccuracy of the load prediction will mean that some units are going to be loaded more than expected. The load factor (the ratio of average demand to peak demand) for most distribution transformers is 40 to 60%. Most distribution transformers are relatively lightly loaded most of the time, but some have peak loads well above their rating. In analysis of data from three utilities, the Oak Ridge National Laboratory found that distribution transformers have an average load of 15 to 40% of their rating, with 30% being most typical (ORNL-6925, 1997).

The heat input into the transformer is from no-load losses and from load losses. The economics of transformer application and purchasing involve consideration of the thermal limitations as well as the operating costs of the losses. Transformer stocking considerations also play a role. For residential customers, a utility may limit inventory to 15, 25, and 50-kVA units (5, 10, 15, 25, 37.5, 50-kVA units are standard sizes).

Some utilities use transformer load management programs to more precisely load transformers to get the most economic use of each transformer's

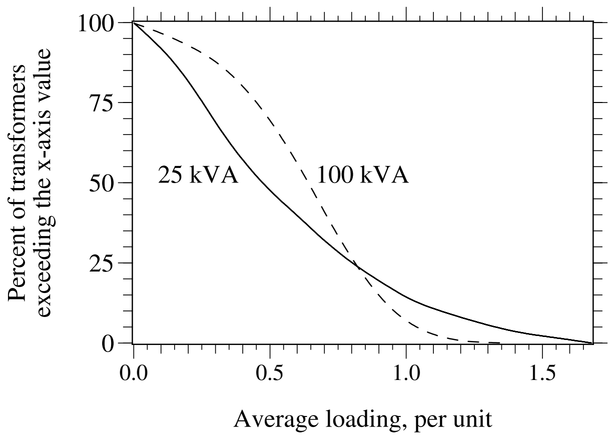


FIGURE 4.20
Distributions of average loadings of two transformer sizes at one utility. (From [ORNL-6927, 1998])

life. These programs take billing data for the loads from each transformer to estimate that transformer's loading. These programs allow the utility to more aggressively load transformers because those needing changeout can be targeted more precisely. Load management programs require data setup and maintenance. Most important, each meter must be tied to a given transformer (many utilities have this information infrastructure, but some do not).

Transformer loadings vary considerably. Figure 4.20 shows the distribution of average loadings on two sizes of transformers at one typical utility. Most transformers are not heavily loaded: in this case, 85% of units have average loadings less than the nameplate. Many units are very lightly loaded, and 10% are quite heavily loaded. Smaller units have more spread in their loading.

Seevers (1995) demonstrates a simple approach to determining transformer loading. Their customers (in the southern U.S.) had 1 kW of demand for every 400 kWh's, regardless of whether the loads peaked in the winter or summer. Seevers derived the ratio by comparing substation demand with kWh totals for all customers fed from the substation (after removing primary-metered customers and other large loads). To estimate the load on a given transformer, sum the kWh for the month of highest usage for all customers connected to the transformer and convert to peak demand, in this case by dividing by 400 kWh per kW-demand. While simple, this method identifies grossly undersized or oversized transformers. Table 4.9 shows guidelines for replacement of underloaded transformers.

Transformers with an internal secondary breaker (CSPs) are a poor-man's form of transformer load management. If the breaker trips from overload, replace the transformer (unless there are extraordinary weather and loading conditions that are unlikely to be repeated).

TABLE 4.9

One Approach to a Transformer Replacement Program

Existing Transformer kVA	Loading Estimate in kVA	Recommended Size in kVA
25	10 or less	10
37.5	15 or less	10
50	20 or less	15
75	37.5 or less	37.5
100	50 or less	50
167	100 or less	100
	75 or less	75 or 50

Source: Seevers, O. C., *Management of Transmission and Distribution Systems*, Penn Well Publishing Company, Tulsa, OK, 1995.

Especially in high-lightning areas, consider the implications of reduction of insulation capability. At hottest-spot temperatures above 140°C, the solid insulation and the oil may release gasses. While not permanently reducing insulation, the short-term loss of insulation strength can make the transformer susceptible to damage from lightning-caused voltage surges. The thermal time constant of the winding is very short, 5 to 15 min. On this time scale, loads on distribution transformers are quite erratic with large, short-duration overloads (well above the 20- or 30-min demand loadings). These loads can push the winding hottest-spot temperature above 140°C.

Padmounted transformers have a special concern related to loading: case temperatures. Under heavy loading on a hot day, case temperatures can become hot. ABB measured absolute case temperatures of 185 to 200°F (85 to 95°C) and case temperature rises above ambient of 50 to 60°C on 25 and 37.5-kVA transformers at 180% loadings and on a 50-kVA transformer at 150% continuous load (NRECA RER Project 90-8, 1993). The hottest temperatures were on the sides of the case where the oil was in contact with the case (the top of the case was significantly cooler). While these temperatures sound quite high, a person's pain-withdrawal reflexes will normally protect against burns for normal loadings that would be encountered. Reflexes will protect against blistering and burning for case temperatures below 300°F (149°C). Skin contacts must be quite long before blistering occurs. For a case temperature of 239°F (115°C), NRECA reported that the skin-contact time to blister is 6.5 sec (which is more than enough time to pull away). At 190°F (88°C), the contact time to blister is 19 sec.

4.6 Losses

Transformer losses are an important purchase criteria and make up an appreciable portion of a utility's overall losses. The Oak Ridge National Laboratory estimates that distribution transformers account for 26% of transmission and distribution losses and 41% of distribution and subtransmission losses (ORNL-6804/R1, 1995). At one utility, Grainger and Kendrew (1989) estimated that distribution transformers were 55% of distribution losses and 2.14% of electricity sales; of the two main contributors to losses, 86% were no-load losses, and 14% were load losses.

Load losses are also called copper or wire or winding losses. Load losses are from current through the transformer's windings generating heat through the winding resistance as I^2R.

No-load losses are the continuous losses of a transformer, regardless of load. No-load losses for modern silicon-steel-core transformers average about 0.2% of the transformer rating (a typical 50-kVA transformer has no-load losses of 100 W), but designs vary from 0.15 to 0.4% depending on the needs of the utility. No-load losses are also called iron or core losses because they are mainly a function of the core materials. The two main components of no-load losses are eddy currents and hysteresis. Hysteresis describes the memory of a magnetic material. More force is necessary to demagnetize magnetic material than it takes to magnetize it; the magnetic domains in the material resist realignment. Eddy current losses are small circulating currents in the core material. The steel core is a conductor that carries an alternating magnetic field, which induces circulating currents in the core. These currents through the resistive conductor generate heat and losses. Cores are typically made from cold-rolled, grain-oriented silicon steel laminations. Manufacturers limit eddy currents by laminating the steel core in 9- to 14-mil thick layers, each insulated from the other. Core losses increase with steady-state voltage.

Hysteresis losses are a function of the volume of the core, the frequency, and the maximum flux density (Sankaran, 2000):

$$P_h \propto V_e f B^{1.6}$$

where
V_e = volume of the core
f = frequency
B = maximum flux density

The eddy-current losses are a function of core volume, frequency, flux density, lamination thicknesses, and resistivity of the core material (Sankaran, 2000):

$$P_e \propto V_e B^2 f^2 t^2 / r$$

where
t = thickness of the laminations
r = resistivity of the core material

TABLE 4.10

Loss Reduction Alternatives

	No-Load Losses	Load Losses	Cost
To Decrease No-Load Losses			
Use lower-loss core materials	Lower	No change[a]	Higher
Decrease flux density by:			
(1) increasing core CSA[b]	Lower	Higher	Higher
(2) decreasing volts/turn	Lower	Higher	Higher
Decrease flux path length by decreasing conductor CSA	Lower	Higher	Lower
To Decrease Load Losses			
Use lower-loss conductor materials	No change	Lower	Higher
Decrease current density by increasing conductor CSA	Higher	Lower	Higher
Decrease current path length by:			
(1) decreasing core CSA	Higher	Lower	Lower
(2) increasing volts/turn	Higher	Lower	Higher

[a] Amorphous core materials would result in higher load losses.
[b] CSA=cross-sectional area

Source: ORNL-6847, *Determination Analysis of Energy Conservation Standards for Distribution Transformers*, Oak Ridge National Laboratory, U.S. Department of Energy, 1996.

Amorphous core metals significantly reduce core losses — as low as one quarter of the losses of silicon-steel cores — on the order of 0.005 to 0.01% of the transformer rating. Amorphous cores do not have a crystalline structure like silicon-steel cores; their iron atoms are randomly distributed. Amorphous materials are made by rapidly cooling a molten alloy, so crystals do not have a chance to form. Such core materials have low hysteresis loss. Eddy current-losses are very low because of the high resistivity of the material and very thin laminations (1-mil thick). Amorphous-core transformers are larger for the same kVA rating and have higher initial costs.

Load losses, no-load losses, and purchase price are all interrelated. Approaches to reduce load losses tend to increase no-load losses and vice versa. For example, a larger core cross-sectional area decreases no-load losses (the flux density core is less), but this requires longer winding conductors and more I^2R load losses. Table 4.10 shows some of the main tradeoffs.

Information from transformer load management programs can help with transformer loss analysis. Table 4.11 shows typical transformer loading data from one utility. The average load on most transformers is relatively low (25 to 30% of transformer rating), which highlights the importance of no-load losses. The total equivalent losses on a transformer are

$$L_{total} = P^2 F_{ls} L_{load} + L_{no-load}$$

where

L_{total} = average losses, kW (multiply this by 8760 to find the annual kilowatt-hours)
P = peak transformer load, per unit
F_{ls} = loss factor, per unit
$L_{no\text{-}load}$ = rated no-load losses, kW
L_{load} = rated load losses, kW

Many utilities evaluate the total life-cycle cost of distribution transformers, accounting for the initial purchase price and the cost of losses over the life of the transformer (the total owning cost or TOC). The classic work done by Gangel and Propst (1965) on transformer loads and loss evaluation provides the foundation for much of the later work. Many utilities follow the Edison Electric Association's economic evaluation guidelines (EEI, 1981). To evaluate the total owning cost, the utility's cost of losses are evaluated using transformer loading assumptions, including load factor, coincident factor, and responsibility factor. Utilities typically assign an equivalent present value for the costs of no-load losses and another for the cost of load losses. Loss values typically range from \$2 to \$4/W of no-load losses and \$0.50 to \$1.50/W of load losses (ORNL-6847, 1996). Utilities that evaluate the life costs of transformers purchase lower-loss transformers. For example, a 50-

TABLE 4.11

Summary of the Loading of One Utility's Single-Phase Pole-Mounted Distribution Transformers

Size (kVA)	No. of Installed Transformers	MWh/ Transformer	Annual PU Avg. Load	Annual PU Load Factor	Calculated Loss Factor
10	59,793	21	0.267	0.405	0.200
15	106,476	34	0.292	0.430	0.221
25	118,584	60	0.309	0.444	0.234
37	77,076	96	0.329	0.445	0.235
50	50,580	121	0.308	0.430	0.222
75	24,682	166	0.281	0.434	0.225
100	8,457	220	0.280	0.463	0.252
167	3,820	372	0.283	0.516	0.304
250	592	631	0.320	0.568	0.360
333	284	869	0.331	0.609	0.407
500	231	1,200	0.304	0.598	0.394
667	9	1,666	0.317	0.476	0.264
833	51	2,187	0.333	0.629	0.431

Note: PU = per unit

Source: ORNL-6925, *Supplement to the "Determination Analysis" (ORNL-6847) and Analysis of the NEMA Efficiency Standard for Distribution Transformers*, Oak Ridge National Laboratory, U.S. Department of Energy, 1997.

kVA single-phase, non-loss-evaluated transformer would have approximately 150 W of no-load losses and 675 W of load losses; the same loss-evaluated transformer would have approximately 100 W of no-load losses and 540 W of load losses (ORNL-6925, 1997). Nickel (1981) describes an economic approach in detail and compares it to the EEI method. The IEEE has developed a more recent guide (C57.12.33).

4.7 Network Transformers

Network transformers, the distribution transformers that serve grid and spot networks, are large three-phase units. Network units are normally vault-types or subway types, which are defined as (ANSI C57.12.40-1982):

- *Vault-type transformers* — Suitable for occasional submerged operation
- *Subway-type transformers* — Suitable for frequent or continuous submerged operation

Network transformers are often housed in vaults. Vaults are underground rooms accessed through manholes that house transformers and other equipment. Vaults may have sump pumps to remove water, air venting systems, and even forced-air circulation systems. Network transformers are also used in buildings, usually in the basement. In these, vault-type transformers may be used (as long as the room is properly built and secured for such use). Utilities may also use dry-type units and units with less flammable insulating oils.

A network transformer has a three-phase, primary-side switch that can open, close, or short the primary-side connection to ground. The standard secondary voltages are 216Y/125 V and 480Y/277 V. Table 4.12 shows standard sizes. Transformers up to 1000 kVA have a 5% impedance; above 1000 kVA, 7% is standard. *X/R* ratios are generally between 3 and 12. Lower impedance transformers (say 4%) have lower voltage drop and higher secondary fault currents. (Higher secondary fault currents help on a network to burn clear faults.) Lower impedance has a price though — higher circulating currents and less load balance between transformers. Network trans-

TABLE 4.12

Standard Network Transformer Sizes

Standard Ratings, kVA	
216Y/125 V	300, 500, 750, 1000
480Y/277 V	500, 750, 1000, 1500, 2000, 2500

formers may also be made out of standard single-phase distribution transformers, but caution is warranted if the units have very low leakage impedances (which could cause very high circulating currents and secondary fault levels higher than network protector ratings).

Most network transformers are connected delta – grounded wye. By blocking zero sequence, this connection keeps ground currents low on the primary cables. Then, we can use a very sensitive ground-fault relay on the substation breaker. Blocking zero sequence also reduces the current on cable neutrals and cable sheaths, including zero-sequence harmonics, mainly the third harmonic. One disadvantage of this connection is with combination feeders — those that feed network loads as well as radial loads. For a primary line-to-ground fault, the feeder breaker opens, but the network transformers will continue to backfeed the fault until all of the network protectors operate (and some may stick). Now, the network transformers backfeed the primary feeder as an ungrounded circuit. An ungrounded circuit with a single line-to-ground fault on one phase causes a neutral shift that raises the line-to-neutral voltage on the unfaulted phases to line-to-line voltage. The non-network load connected phase-to-neutral is subjected to this overvoltage.

Some networks use grounded wye – grounded wye connections. This connection fits better for combination feeders. For a primary line-to-ground fault, the feeder breaker opens. Backfeeds to the primary through the network still have a grounding reference with the wye – wye connection, so chances of overvoltages are limited. The grounded wye – grounded wye connection also reduces the change of ferroresonance in cases where a transformer has single-pole switching.

Most network transformers are core type, either a three- or five-legged core. The three-legged core, either with a stacked or wound core, is suitable for a delta – grounded wye connection (but not a grounded wye – grounded wye connection because of tank heating). A five-legged core transformer is suitable for either connection type.

4.8 Substation Transformers

In a distribution substation, power-class transformers provide the conversion from subtransmission circuits to the distribution primary. Most are connected delta – grounded wye to provide a ground source for the distribution neutral and to isolate the distribution ground system from the subtransmission system.

Station transformers can range from 5 MVA in smaller rural substations to over 80 MVA at urban stations (base ratings). Stations with two banks, each about 20 MVA, are common. Such a station can serve about six to eight feeders.

Power transformers have multiple ratings, depending on cooling methods. The base rating is the self-cooled rating, just due to the natural flow to the surrounding air through radiators. The transformer can supply more load with extra cooling turned on. Normally, fans blow air across the radiators and/or oil circulating pumps. Station transformers are commonly supplied with OA/FA/FOA ratings. The OA is open air, FA is forced air cooling, and FOA is forced air cooling plus oil circulating pumps.

The ANSI ratings were revised in the year 2000 to make them more consistent with IEC designations. This system has a four-letter code that indicates the cooling (IEEE C57.12.00-2000):

- *First letter* — Internal cooling medium in contact with the windings:
  - **O** mineral oil or synthetic insulating liquid with fire point = 300˚C
  - **K** insulating liquid with fire point > 300˚C
  - **L** insulating liquid with no measurable fire point
- *Second letter* — Circulation mechanism for internal cooling medium:
  - **N** natural convection flow through cooling equipment and in windings
  - **F** forced circulation through cooling equipment (i.e., coolant pumps); natural convection flow in windings (also called nondirected flow)
  - **D** forced circulation through cooling equipment, directed from the cooling equipment into at least the main windings
- *Third letter* — External cooling medium:
  - **A** air
  - **W** water
- *Fourth letter* — Circulation mechanism for external cooling medium:
  - **N** natural convection
  - **F** forced circulation: fans (air cooling), pumps (water cooling)

So, OA/FA/FOA is equivalent to ONAN/ONAF/OFAF. Each cooling level typically provides an extra one-third capability: 21/28/35 MVA. Table 4.13 shows equivalent cooling classes in the old and new naming schemes.

Utilities do not overload substation transformers as much as distribution transformers, but they do run them hot at times. As with distribution transformers, the tradeoff is loss of life versus the immediate replacement cost of the transformer. Ambient conditions also affect loading. Summer peaks are much worse than winter peaks. IEEE Std. C57.91-1995 provides detailed loading guidelines and also suggests an approximate adjustment of 1% of the maximum nameplate rating for every degree C above or below 30°C. The hottest spot conductor temperature is the critical point where insulation degrades. Above a hot-spot conductor temperature of 110°C, life expectancy decreases exponentially. The life halves for every 8°C increase in operating temperature. Most of the time, the hottest temperatures are nowhere near

TABLE 4.13

Equivalent Cooling Classes

Year 2000 Designations	Designations Prior to Year 2000
ONAN	OA
ONAF	FA
ONAN/ONAF/ONAF	OA/FA/FA
ONAN/ONAF/OFAF	OA/FA/FOA
OFAF	FOA
OFWF	FOW

Source: IEEE Std. C57.12.00-2000. Copyright 2000 IEEE. All rights reserved.

this. Tillman (2001) provides the loading guide for station transformers shown in Table 4.14.

The impedance of station transformers is normally about 7 to 10%. This is the impedance on the base rating, the self-cooled rating (OA or ONAN). The impedance is normally higher for voltages on the high-side of the transformer that are higher (like 230 kV). Transformer impedance can be specified when ordering. Large stations with 50 plus MVA transformers are normally provided with extra impedance to control fault currents, some as high as 30% on the transformer's base rating.

The positive and zero-sequence impedances are the same for a shell-type transformer, so the bolted fault currents on the secondary of the transformer are the same for a three-phase fault and for a line-to-ground fault (provided that both are fed from an infinite bus). In a three-legged core type transformer, the zero-sequence impedance is lower than the positive-sequence impedance (typically $Z_0 = 0.85Z_1$), so ground faults can cause higher currents. With a three-legged core transformer design, there is no path for zero-sequence flux. Therefore, zero-sequence current will meet a lower-impedance branch. This makes the core-type transformer act as if it had a delta-connected tertiary winding. This is the magnetizing branch (from line to ground), and this effectively reduces the zero-sequence impedance. In a shell-type transformer, there is a path through the iron for flux to flow, so the excitation impedance to zero sequence is high.

Because most distribution circuits are radial, the substation transformer is a critical component. Power transformers normally have a failure rate between 1 to 2% annually (CEA 485 T 1049, 1996; CIGRE working group 12.05, 1983; IEEE Std. 493-1997). Many distribution stations are originally designed with two transformers, where each is able to serve all of the substation's feeders if one of the transformers fails. Load growth in some areas has severely reduced the ability of one transformer to supply the whole station. To ensure transformer reliability, use good lightning protection and thermal management. Do not use reduced-BIL designs (BIL is the basic lightning impulse insulation level). Also, reclosing and relaying practices should ensure that excessive through faults do not damage transformers.

TABLE 4.14

Example Substation Transformer Loading Guide

Type of Load	FA (ONAF) Max Top Oil Temp (°C)	NDFOA (OFAF) Max Top Oil Temp (°C)	NDFOA (OFAF) 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%

Notes: (1) The normal summer loading accounts for periods when temperatures are abnormally high. These might occur every 3 to 5 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 % 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 0.92 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 soil condition is good: moisture is less than 1.5% (1.0% preferred) by dry weight, oxygen is less than 2%, 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.

Source: Tillman, R. F., Jr, "Loading Power Transformers," in *The Electric Power Engineering Handbook*, L. L. Grigsby, Ed.: CRC Press, Boca Raton, FL, 2001.

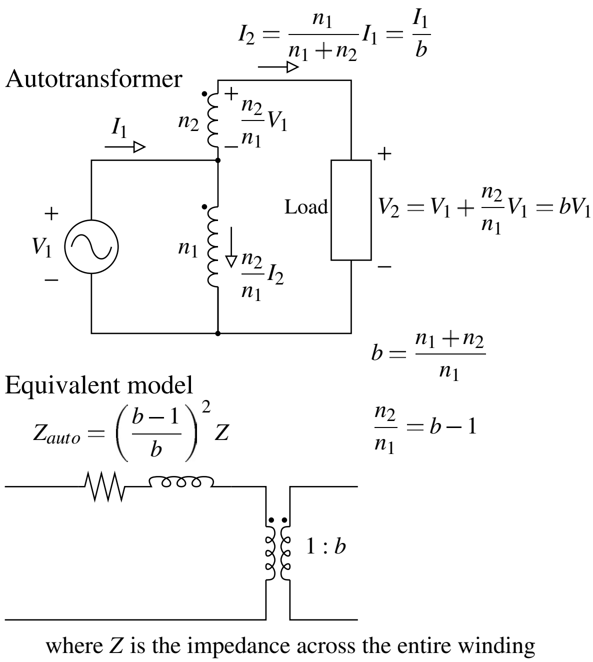


FIGURE 4.21
Autotransformer with an equivalent circuit.

4.9 Special Transformers

4.9.1 Autotransformers

An autotransformer is a winding on a core with a tap off the winding that provides voltage boost or buck. This is equivalent to a transformer with one winding in series with another (see Figure 4.21).

For small voltage changes, autotransformers are smaller and less costly than standard transformers. An autotransformer transfers much of the power directly through a wire connection. Most of the current passes through the lower-voltage series winding at the top, and considerably less current flows through the shunt winding.

Autotransformers have two main applications on distribution systems:

- *Voltage regulators* — A regulator is an autotransformer with adjustable taps that is normally capable of adjusting the voltage by ±10%.
- *Step banks* — Autotransformers are often used instead of traditional transformers on step banks and even substation transformers where

the relative voltage change is moderate. This is normally voltage changes of less than a factor of three such as a 24.94Y/14.4 kV–12.47Y/7.2 kV bank.

The required rating of an autotransformer depends on the voltage change between the primary and secondary. The rating of each winding as a percentage of the load is

$$S = \frac{b-1}{b}$$

where
b = voltage change ratio, per unit

To obtain a 10% voltage change (b = 1.1), an autotransformer only has to be rated at 9% of the load kVA. For a 2:1 voltage change (b = 2), an autotransformer has to be rated at 50% of the load kVA. By comparison, a standard transformer must have a kVA rating equal to the load kVA.

The series impedance of autotransformers is less than an equivalent standard transformer. The equivalent series impedance of the autotransformer is

$$Z_{auto} = \left(\frac{b-1}{b}\right)^2 Z$$

where Z is the impedance across the entire winding. A 5%, 100-kVA conventional transformer has an impedance of 25.9 Ω at 7.2 kV line to ground. A 2:1 autotransformer (b = 2) with a load-carrying capability of 100 kVA and a winding rating of 50 kVA and also a 5% winding impedance has an impedance of 6.5 Ω, one-fourth that of a conventional transformer.

For three-phase applications on grounded systems, autotransformers are often connected in a grounded wye. Other possibilities are delta (each winding is phase to phase), open delta (same as a delta, but without one leg), and open wye. Because of the direct connection, it is not possible to provide ground isolation between the high- and low-voltage windings.

4.9.2 Grounding Transformers

Grounding transformers are sometimes used on distribution systems. A grounding transformer provides a source for zero-sequence current. Grounding transformers are sometimes used to convert a three-wire, ungrounded circuit into a four-wire, grounded circuit. Figure 4.22 shows the two most common grounding transformers. The zig-zag connection is the most widely used grounding transformer. Figure 4.23 shows how a grounding bank supplies current to a ground fault. Grounding transformers

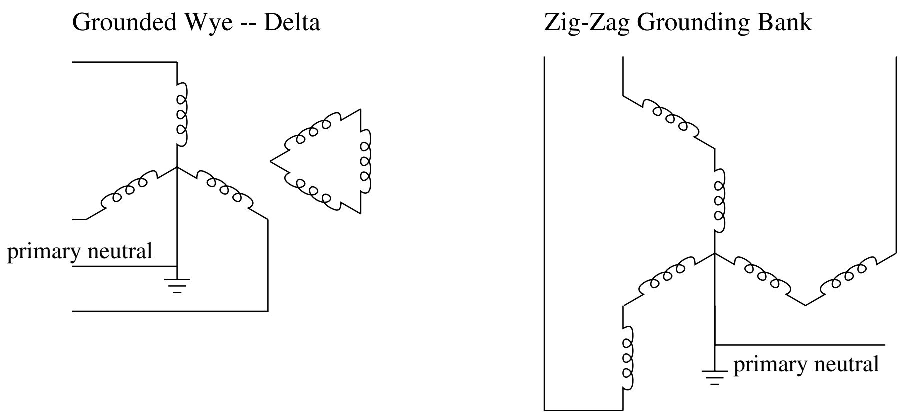


FIGURE 4.22
Grounding transformer connections.

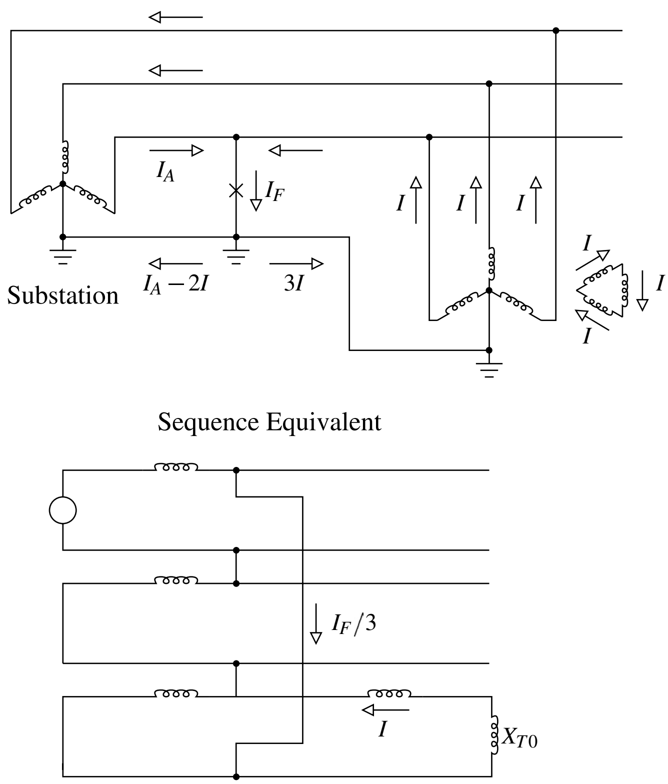


FIGURE 4.23
A grounding transformer feeding a ground fault.

used as the only ground source to a distribution circuit should be in service whenever the three-phase power source is in service. If the grounding transformer is lost, a line-to-ground causes high phase-to-neutral voltages on the unfaulted phases, and load unbalances can also cause neutral shifts and overvoltages.

A grounding transformer must handle the unbalanced load on the circuit as well as the duty during line-to-ground faults. If the circuit has minimal unbalance, then we can drastically reduce the rating of the transformer. It only has to be rated to carry short-duration (but high-magnitude) faults, normally a 10-sec or 1-min rating is used. We can also select the impedance of the grounding transformer to limit ground-fault currents.

Each leg of a grounding transformer carries one-third of the neutral current and has line-to-neutral voltage. So in a grounded wye – delta transformer, the total power rating including all three phases is the neutral current times the line-to-ground voltage:

$$S = V_{LG} I_N$$

A zig-zag transformer is more efficient than a grounded wye – delta transformer. In a zig-zag, each winding has less than the line-to-ground voltage, by a factor of $\sqrt{3}$, so the bank may be rated lower:

$$S = V_{LG} I_N / \sqrt{3}$$

ANSI/IEEE Std. 32-1972 requires a continuous rating of 3% for a 10-sec rated unit (which means the short-time rating is 33 times the continuous rating). A 1-min rated bank has a continuous current rating of 7%. On a 12.47-kV system supplying a ground-fault current of 6000 A, a zig-zag would need a 24.9-MVA rating. We will size the bank to handle the 24.9 MVA for 10 sec, which is equivalent to a 0.75-MVA continuous rating, so this bank could handle 180 A of neutral current continuously.

For both the zig-zag and the grounded wye – delta, the zero-sequence impedance equals the impedance between one transformer primary and its secondary.

Another application of grounding transformers is in cases of telephone interference due to current flow in the neutral/ground. By placing a grounding bank closer to the source of the neutral current, the grounding bank shifts some of the current from the neutral to the phase conductors to lower the neutral current that interferes with the telecommunication wires.

Grounding transformers are also used where utilities need a ground source during abnormal conditions. One such application is for a combination feeder that feeds secondary network loads and other non-network line-to-ground connected loads. If the network transformers are delta – grounded wye connected, the network will backfeed the circuit during a line-to-ground fault. If that happens while the main feeder breaker is open, the single-phase load on the unfaulted phases will see an overvoltage because the circuit is being back fed through the network loads as an ungrounded system. A grounding bank installed on the feeder prevents the overvoltage during backfeed conditions. Another similar application is found when applying distributed generators. A grounded wye – delta transformer is often specified as the interconnection transformer to prevent overvoltages if the generator drives an island that is separated from the utility source.

Even if a grounding bank is not the only ground source, it must be sized to carry the voltage unbalance. The zero-sequence current drawn by a bank is the zero-sequence voltage divided by the zero-sequence impedance:

$$I_0 = V_0/Z_0$$

Severe voltage unbalance can result when one phase voltage is opened upstream (usually from a blown fuse or a tripped single-phase recloser). In this case, the zero-sequence voltage equals the line-to-neutral voltage. The grounding bank will try to hold up the voltage on the opened phase and supply all of the load on that phase, which could severely overload the transformer.

4.10 Special Problems

4.10.1 Paralleling

Occasionally, crews must install distribution transformers, either at a changeover or for extra capacity. If a larger bank is being installed to replace an existing unit, paralleling the banks during the changeover eliminates the customer interruption. In order to parallel transformer banks, several criteria should be met:

- *Phasing* — The high and low-voltage connections must have the same phasing relationship. On three-phase units, banks of different connection types can be paralleled as long as they have compatible outputs: a delta – grounded wye may be paralleled with a grounded wye – grounded wye.
- *Polarity* — If the units have different polarity, they should be wired accordingly. (Flip one of the secondary connections.)
- *Voltage* — The phase-to-phase and phase-to-ground voltages on the outputs should be equal. Differences in turns ratios between the transformers will cause circulating current to flow through the transformers (continuously, even with zero load).

Before connecting the second transformer, crews should ensure that the secondary voltages are all zero or very close to zero (phase A to phase A, B to B, C to C, and the neutral to neutral).

If the percent impedances of the transformers are unequal, the load will not split in the same proportion between the two units. Note that this is the percent impedance, not the impedance in ohms. The unit with the lower percent impedance takes more of the current relative to its rating. For unequal impedances, the total bank must be derated (ABB, 1995) as

$$d = \frac{\frac{Z_2}{Z_1} K_1 + K_2}{K_1 + K_2}$$

where

K_1 = Capacity of the unit or bank with the *larger* percent impedance
K_2 = Capacity of the unit or bank with the *smaller* percent impedance
Z_1 = Percent impedance of unit or bank 1
Z_2 = Percent impedance of unit or bank 2

4.10.2 Ferroresonance

Ferroresonance is a special form of series resonance between the magnetizing reactance of a transformer and the system capacitance. A common form of ferroresonance occurs during single phasing of three-phase distribution transformers (Hopkinson, 1967). This most commonly happens on cable-fed transformers because of the high capacitance of the cables. The transformer connection is also critical for ferroresonance. An ungrounded primary connection (see Figure 4.24) leads to the highest magnitude ferroresonance. During single phasing (usually when line crews energize or deenergize the transformer with single-phase cutouts at the cable riser pole) a ferroresonant circuit between the cable capacitance and the transformer's magnetizing

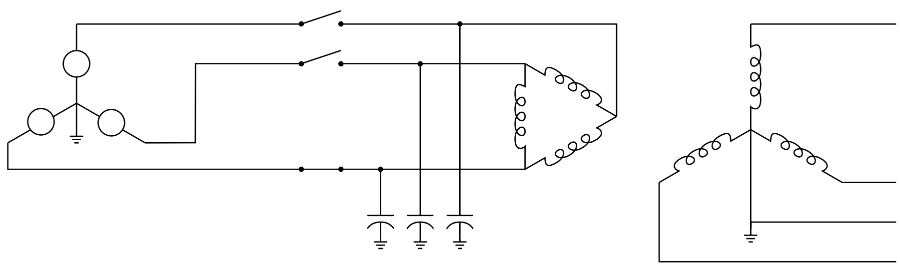


FIGURE 4.24
Ferroresonant circuit with a cable-fed transformer with an ungrounded high-side connection.

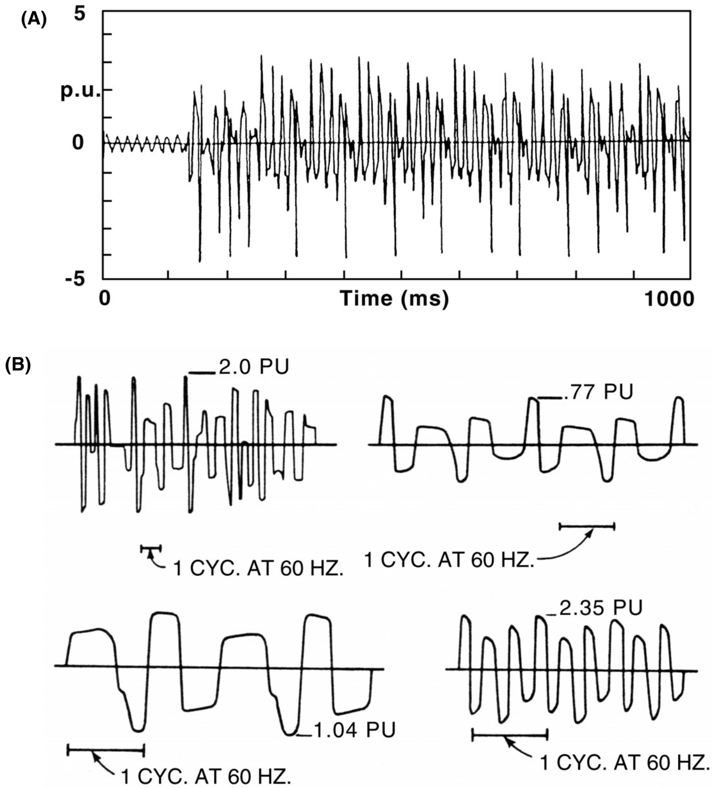


FIGURE 4.25
Examples of ferroresonance. (A) From Walling, R. A., Hartana, R. K., and Ros, W. J., "Self-Generated Overvoltages Due to Open-Phasing of Ungrounded-Wye Delta Transformer Banks," *IEEE Trans. Power Delivery,* 10(1), 526-533, January 1995. With permission. ©1995 IEEE. (B) Smith, D. R., Swanson, S. R., and Borst, J. D., "Overvoltages with Remotely-Switched Cable-Fed Grounded Wye-Wye Transformers," *IEEE Trans. Power Apparatus Sys.*, PAS-94(5), 1843-1853, 1975. With permission. ©1975 IEEE.

reactance drives voltages to as high as five per unit on the open legs of the transformer. The voltage waveform is normally distorted and often chaotic (see Figure 4.25).

Ferroresonance drove utilities to use three-phase transformer connections with a grounded-wye primary, especially on underground systems.

The chance of ferroresonance is determined by the capacitance (cable length) and by the core losses and other resistive load on the transformer (Walling et al., 1993). The core losses are an important part of the ferroresonant circuit.

Walling (1994) breaks down ferroresonance in a way that highlights several important aspects of this complicated phenomenon. Consider the simplified ferroresonant circuit in Figure 4.26. The transformer magnetizing branch has the core-loss resistance in parallel with a switched inductor. When the trans-

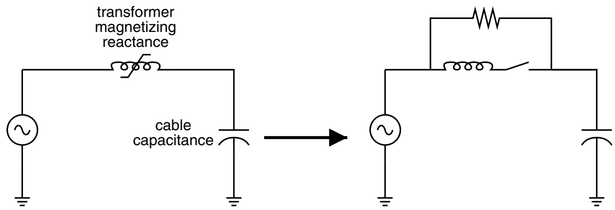


FIGURE 4.26
Simplified equivalent circuit of ferroresonance on a transformer with an ungrounded high-side connection.

former is unsaturated, the switched inductance is open, and the only connection between the capacitance and the system is through the core-loss resistance. When the core saturates, the capacitive charge dumps into the system (the switch in Figure 4.26 closes). The voltage overshoots and, as the core comes out of saturation, charge is again trapped on the capacitor (but of opposite polarity). This happens every half cycle (see Figure 4.27 for waveforms). If the core loss is large enough (or the resistive load on the transformer is large enough), the charge on the capacitor drains off before the next half cycle, and ferroresonance does not occur. The transformer core does not stay saturated long during each half cycle, just long enough to

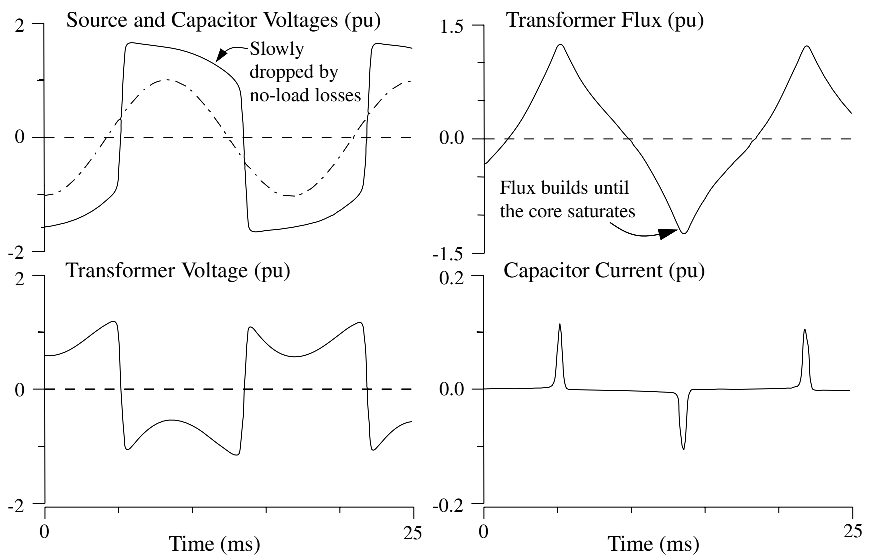


FIGURE 4.27
Voltages, currents and transformer flux during ferroresonance. (Adapted from Walling, R. A., "Ferroresonant Overvoltages in Today's Loss-Evaluated Distribution Transformers," IEEE/PES Transmission and Distribution Conference, 1994. With permission of the General Electric Company.)

TABLE 4.15

Transformer Primary Connections Susceptible to Ferroresonance

Susceptible Connections	Not Susceptible
Floating wye Delta Grounded wye with 3, 4, or 5-legged core construction Line-to-line connected single-phase units	Grounded wye made of three individual units or units of triplex construction Open wye – open delta Line-to-ground connected single-phase units

release the trapped charge on the capacitor. If the cable susceptance or even just the transformer susceptance is greater than the transformer core loss conductance, then ferroresonant overvoltages may occur.

In modern silicon-steel distribution transformers, the flux density at rated voltage is typically between 1.3 and 1.6 T. These operating flux densities slightly saturate the core (magnetic steel fully saturates at about 2 T). Because the core is operated near saturation, a small transient (such as switching) is enough to saturate the core. Once started, the ferroresonance self-sustains. The resonance repeatedly saturates the transformer every half cycle.

Table 4.15 shows what types of transformer connections are susceptible to ferroresonance. To avoid ferroresonance on floating wye – delta transformers, some utilities temporarily ground the wye on the primary side of floating wye – delta connections during switching operations.

Ferroresonance can occur on transformers with a grounded primary connection if the windings are on a common core such as the five-legged core transformer [the magnetic coupling between phases completes the ferroresonant circuit (Smith et al., 1975)]. The five-legged core transformer connected as a grounded wye – grounded wye is the most common underground transformer configuration. Ferroresonant overvoltages involving five-legged core transformers normally do not exceed two per unit.

Ferroresonance is a function of the cable capacitance and the transformer no-load losses. The lower the losses relative to the capacitance, the higher the ferroresonant overvoltage can be. For transformer configurations that are susceptible to ferroresonance, ferroresonance can occur approximately when

$$B_C \geq P_{NL}$$

where

B_C = capacitive reactive power per phase, vars
P_{NL} = core loss per phase, W

The capacitive reactive power on one phase in vars depends on the voltage and the capacitance as

$$B_C = \frac{V_{kV}^2}{3} 2\pi f C$$

where

V_{kV} = rated line-to-line voltage, kV

f = frequency, Hz

C = capacitance from one phase to ground, μF

Normally, ferroresonance occurs without equipment failure if the crew finishes the switching operation in a timely manner. The loud banging, rumbling, and rattling of the transformer during ferroresonance may alarm line crews. Occasionally, ferroresonance is severe enough to fail a transformer. The overvoltage stresses the transformer insulation, and the repeated saturation may cause tank heating as flux leaves the core (although many modes of ferroresonance barely saturate the transformer and do not cause significant tank heating). Surge arresters are the most likely equipment casualty. In attempting to limit the ferroresonant overvoltage, an arrester may absorb more current than it can handle and thermally run away. Gapped silicon-carbide arresters were particularly prone to failure, as the gap could not reseal the repeated sparkovers from a long-duration overvoltage. Gapless metal-oxide arresters are much more resistant to failure from ferroresonance and help hold down the overvoltages. Ferroresonant overvoltages may also fail customer's equipment from high secondary voltages. Small end-use arresters are particularly susceptible to damage.

Ferroresonance is more likely with

- *Unloaded transformers* — Ferroresonance disappears with load as little as a few percent of the transformer rating.
- *Higher primary voltages* — Shorter cable lengths are required for ferroresonance. Resonance is more likely even without cables, just due to the internal capacitance of the transformer. With higher voltages, the capacitances do not change significantly (cable capacitance increases just slightly because of thicker insulation), but vars are much higher for the same capacitance.
- *Smaller transformers* — Smaller no-load losses.
- *Low-loss transformers* — Smaller no-load losses.

Severe ferroresonance with voltages reaching peaks of 4 or 5 per unit occurs on three-phase transformers with an ungrounded high-voltage winding during single-pole switching. If the transformer is fed by underground cables and crews switch the transformer remotely, ferroresonance is likely.

On overhead circuits, ferroresonance is common with ungrounded primary connections on 25- and 35-kV distribution systems. At these voltages, the internal capacitance of most transformers is enough to ferroresonate. The use of low-loss transformers has caused ferroresonance to appear on overhead 15-kV distribution systems as well. Amorphous core and low-loss silicon-steel core transformers have much lower core losses than previous designs. With less core losses, ferroresonance happens with lower amounts of capacitance. Tests by the Southern California Edison Company on three-phase transformers with ungrounded primary connections found that ferroresonance occurred when the capacitive power per phase exceeded the transformer's no-load losses per phase by the following relationship (Jufer, 1994):

$$B_C \geq 1.27 P_{NL}$$

The phase-to-ground capacitance of overhead transformers is primarily due to the capacitance between the primary and secondary windings (the secondary windings are almost at zero potential). A typical 25-kVA transformer has a phase-to-ground capacitance of about 2 nF (Walling et al., 1995). For a 7.2-kV line-to-ground voltage, 0.002 μF is 39 vars. So, if the no-load losses are less than 39 vars/1.27 = 30.7 W per phase, the transformer may ferroresonate under single-pole switching.

Normally, ferroresonance occurs on three-phase transformers, but ferroresonance can occur on single-phase transformers if they are connected phase to phase, and one of the phases is opened either remotely or at the transformer. Jufer (1994) found that small single-phase padmounted transformers connected phase to phase ferroresonate when remotely switched with relatively short cable lengths. Their tests of silicon-steel core transformers found that a 25-kVA transformer resonated with 50 ft (15 m) of 1/0 XLPE cable at 12 kV. A 50-kVA transformer resonated with 100 ft of cable, and a 75-kVA unit resonated with 150 ft of the cable. Peak primary voltages reached 3 to 4 per unit. Secondary-side peaks were all under 2 per unit. Longer cables produced slightly higher voltages during ferroresonance. Jufer found that ferroresonance didn't occur if the resistive load in watts per phase (including the transformer's no-load losses and the resistive load on the secondary) exceeded 1.15 times the capacitive vars per phase ($P_{NL} + P_L > 1.15B_C$). Bohmann et al. (1991) describes a feeder where single-phase loads were switched to a phase-to-phase configuration, and the reconfiguration caused a higher-than-normal arrester failure rate that was attributed to ferroresonant conditions on the circuit.

It is widely believed that a grounded-wye primary connection eliminates ferroresonance. This is not true if the three-phase transformer has windings on a common core. The most common underground three-phase distribution transformer has a five-legged wound core. The common core couples the phases. With the center phase energized and the outer phases open, the coupling induces 50% voltage in the outer phases. Any load on the outer two phases is effectively in series with the voltage induced on the center phase. Because the coupling is indirect and the open phase capacitance is in parallel with a transformer winding to ground, this type of ferroresonance is not as severe as ferroresonance on configurations with an ungrounded primary winding. Overvoltages rarely exceed 2.5 per unit.

Five-legged core ferroresonance also depends on the core losses of the transformer and the phase-to-ground capacitance. If the capacitive vars exceed the resistive load in watts, ferroresonance may occur. Higher capac-

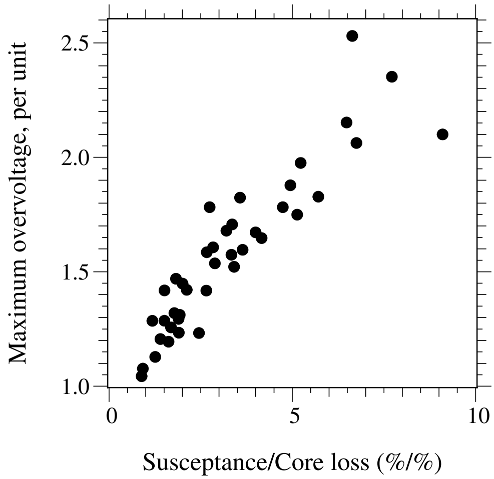


FIGURE 4.28
Five-legged core ferroresonance as a function of no-load losses and line-to-ground capacitance. (Adapted from Walling, R. A., Barker, K. D., Compton, T. M., and Zimmerman, L. E., "Ferroresonant Overvoltages in Grounded Wye-Wye Padmount Transformers with Low-Loss Silicon Steel Cores," *IEEE Trans. Power Delivery*, 8(3), 1647-60, July 1993. With permission. ©1993 IEEE.)

itances — longer cable lengths — generally cause higher voltages (see Figure 4.28). To limit peak voltages to below 1.25 per unit, the capacitive power must be limited such that [equivalent to that proposed by Walling (1992)]:

$$B_C \leq 1.86 P_{NL}$$

with B_C in vars and P_{NL} in watts; both are per phase.

Ferroresonance can occur with five-legged core transformers, even when switching at the transformer terminals, due to the transformer's internal line-to-ground capacitance. On 34.5-kV systems, transformers smaller than 500 kVA may ferroresonate if single-pole switched right at the transformer terminals. Even on 15-kV class systems where crews can safely switch all but the smallest 5-legged core transformers at the terminals, we should include the transformer's capacitance in any cable length calculation; the transformer's capacitance is equivalent to several feet (meters) of cable. The capacitance from line-to-ground is mainly due to the capacitance between the small paper-filled layers of the high-voltage winding. This capacitance is very difficult to measure since it is in parallel with the coil. Walling (1992) derived an empirical equation to estimate the line-to-ground transformer capacitance per phase in μF:

$$C = \frac{0.000469 S_{kVA}^{0.4}}{V_{kV}^{0.25}}$$

where

S_{kVA} = transformer three-phase kVA rating

V_{kV} = rated line-to-line voltage in kV

In vars, this is

$$B_C = 0.000982 f V_{kV}^{1.75} S_{kVA}^{0.4}$$

where f is the system frequency, Hz.

To determine whether the transformer no-load losses exceed the capacitive power, the transformer's datasheet data is most accurate. For coming up with generalized guidelines, using such data is not realistic since so many different transformer makes and models are ordered. Walling (1992) offered the following approximation between the three-phase transformer rating and the no-load losses in watts per phase:

$$P_{NL} = S_{kVA}\left(4.54 - 1.13\log_{10}\left(S_{kVA}\right)\right)/3$$

Walling (1992) used his approximations of transformer no-load losses and transformer capacitance to find cable length criteria for remote single-pole switching. Consider a 75-kVA 3-phase 5-legged core transformer at 12.47 kV. Using these approximations, the no-load losses are 60.5 W per phase, and the transformer's capacitance is 27.4 vars per phase. To keep the voltage under 1.25 per unit, the total vars allowed per phase is 1.86(60.5W) = 111.9 vars. So, the cable can add another 84.5 vars before we exceed the limit. At 12.47 kV, a 4/0 175-mil XLPE cable has a capacitance of 0.412 μF/mi, which is 1.52 vars per foot. For this cable, 56 ft is the maximum length that we should switch remotely. Beyond that, we may have ferroresonance above 1.25 per unit. Table 4.16 shows similar criteria for several three-phase transformers and voltages. The table shows critical lengths for 4/0 cables; smaller cables have less capacitance, so somewhat longer lengths are permissible. At 34.5 kV, crews should only remotely switch larger banks.

Another situation that can cause ferroresonance is when a secondary has ungrounded power factor correction capacitors. Resonance can even occur on a grounded wye – grounded wye connection with three separate transformers. With one phase open on the utility side, the ungrounded capacitor bank forms a series resonance with the magnetizing reactance of the open leg of the grounded-wye transformer.

Ferroresonance most commonly happens when switching an unloaded transformer. It also usually happens with manual switching; ferroresonance can occur because a fault clears a single-phase protective device, but this is much less common. The main reason that ferroresonance is unlikely for most situations using a single-phase protective device is that either the fault or the existing load on the transformer prevents ferroresonance.

TABLE 4.16

Cable Length Limits in Feet for Remote Single-Pole Switching to Limit Ferroresonant Overvoltages to Less than 1.25 per Unit

	Critical Cable Lengths, ft		
Transformer Rating kVA	12.47 kV 4/0 XLPE 175 mil 0.412 μF/mi 1.52 vars/ft	24.94 kV 4/0 XLPE 260 mil 0.261 μF/mi 4.52 vars/ft	34.5 kV 4/0 XLPE 345 mil 0.261 μF/mi 7.08 vars/ft
75	56	5	0
112.5	81	10	0
150	103	16	0
225	144	26	1
300	181	36	6
500	265	59	16
750	349	82	27
1000	417	100	36
1500	520	128	49
2000	592	146	56

If the fuse is a tap fuse and several customers are on a section, the transformers will have somewhat different characteristics, which lowers the probability of ferroresonance (and ferroresonance is less likely with larger transformers).

Solutions to ferroresonance include

- Using a higher-loss transformer
- Using a three-phase switching device instead of a single-phase device
- Switching right at the transformer rather than at the riser pole
- Using a transformer connection not susceptible to ferroresonance
- Limiting remote switching of transformers to cases where the capacitive vars of the cable are less than the transformer's no load losses

Arrester application on transformer connections susceptible to ferroresonance brings up several interesting points. Ferroresonance can slowly heat arresters until failure. Ferroresonance is a weak source; even though the per-unit magnitudes are high, the voltage collapses when the arrester starts to conduct (we cannot use the arresters time-overvoltage curve [TOV] to predict failure). Normally, extended ferroresonance of several minutes can occur before arresters are heated enough to enter thermal runaway. The most vulnerable arresters are those that are tightly applied relative to the voltage rating. Tests by the DSTAR group for ferroresonance on 5-legged core transformers in a grounded wye – grounded wye connection (Lunsford, 1994; Walling et al., 1994) found

- Arrester currents were always less than 2 A.
- Under-oil arresters, which have superior thermal characteristics, reached thermal stability and did not fail.
- Porcelain-housed arresters showed slow heating — sometimes enough to fail, sometimes not, depending on the transformer type, cable lengths, and arrester type. Elbow arresters showed slow heating — slower than the riser-pole arresters. Failure times for either type were typically longer than 30 min.

With normal switching times of less than one minute, arresters do not have enough time to heat and fail. Crews should be able to safely switch transformers under most circumstances. Load — even 5% of the transformer rating — prevents ferroresonance in most cases. The most danger is with unloaded transformers. If an arrester fails, the failure may not operate the disconnect, which can lead to a dangerous scenario. When a line worker recloses the switch, the stiff power-frequency source will fail the arrester. The disconnect should operate and draw an arc. On occasion, the arrester may violently shatter.

One option to limit the exposure of the arresters is to put the arresters upstream of the switch. At a cable riser pole this is very difficult to do without seriously compromising the lead length of the arrester.

4.10.3 Switching Floating Wye – Delta Banks

Floating wye – delta banks present special concerns. As well as being prone to ferroresonance, single-pole switching can cause overvoltages due to a neutral shift. On a floating wye – delta, the secondary delta connection fixes the transformer's primary neutral close to ground potential. After one phase of the primary wye is opened, the neutral can float far from ground. This causes overvoltages, both on the secondary side and the primary side. The severity depends on the balance of the load.

When crews open one of the power-leg phases, if there is no three-phase load and only the single-phase load on the lighting leg of the transformer, the open primary voltage V_{open} reaches 2.65 times normal as shown in Figure 4.29. The voltage across the open switch also sees high voltage. The voltage from B to B′ in Figure 4.29 can reach over 2.75 per unit. Secondary line-to-line voltages on the power legs can reach 1.73 per unit. The secondary delta forces the sum of the three primary line-to-neutral voltages to be equal. With single-phase load on phase C and no other load, the neutral shifts to the C-phase voltage. The delta winding forces $V_{B'N}$ to be equal to $-V_{AN}$, significantly shifting the potential of point B′.

The line-to-ground voltage on the primary-side of the transformer on the open phase is a function of the load unbalance on the secondary. Given the ratio of the single-phase load to the three-phase load, this voltage is [assuming

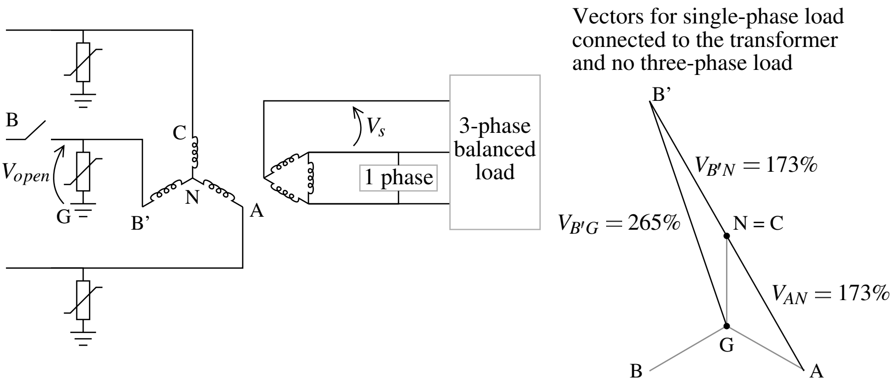


FIGURE 4.29
Neutral-shift overvoltages on a floating wye – delta transformer during single-pole switching.

passive loads and that the power factor of the three-phase load equals that of the single-phase load (Walling et al., 1995)]

$$V_{open} = \frac{\sqrt{7K^2 + K + 1}}{K + 2}$$

where

$$K = \frac{\text{Single-phase load}}{\text{Balanced three-phase load}}$$

On the secondary side, the worst of the two line-to-line voltages across the power legs have the following overvoltages depending on loading balance (PTI, 1999):

$$V_s = \sqrt{3}\,\frac{K + 1}{K + 2}$$

Figure 4.30 shows these voltages as a function of the ratio *K*.

Contrary to a widespread belief, transformer saturation does not significantly reduce the overvoltage. Walling et al.'s (1995) EMTP simulations showed that saturation did not significantly reduce the peak voltage magnitude. Saturation does distort the waveforms significantly and reduces the energy into a primary arrester.

Some ways to avoid these problems are

- *Use another connection* — The best way to avoid problems with this connection is to use some other connection. Some utilities do not

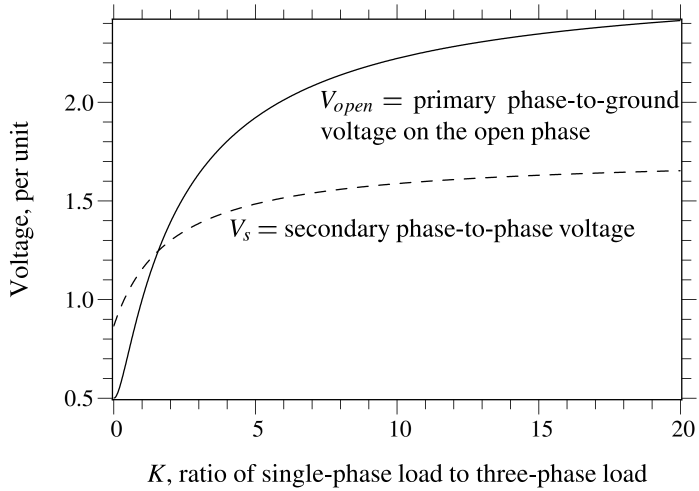


FIGURE 4.30
Neutral-shift overvoltages as a function of the load unbalance.

offer an open wye – delta connection and instead move customers to grounded-wye connections.

- *Neutral grounding* — Ground the primary-wye neutral during switching operations, either with a temporary grounding jumper or install a cutout. This prevents the neutral-shift and ferroresonant overvoltage. The ground-source effects during the short-time switching are not a problem. The line crew must remove the neutral jumper after switching. Extended operation as a grounding bank can overheat the transformer and interfere with a circuit's ground-fault protection schemes.
- *Switching order* — Neutral shifts (but not ferroresonance) are eliminated by always switching in the lighting leg last and taking it out first.

Arrester placement is a sticky situation. If the arrester is upstream of the switch, it does not see the neutral-shift/ferroresonant overvoltage. But the transformer is not protected against the overvoltages. Arresters downstream of the switch protect the transformer but may fail. One would rather have an arrester failure than a transformer failure, unless the failure is near a line crew (since an arrester is smaller, it is more likely than a transformer to explode violently — especially porcelain-housed arresters). Another concern was reported by Walling (2000): during switching operations, 10-per-unit overvoltage bursts for 1/4 cycle ringing at about 2 kHz when closing in the second phase. These were found in measurements during full-scale tests and also in simulations. This transient repeats every cycle with a declining peak magnitude for more than one second. If arresters are downstream from the switches, they can easily control the overvoltage. But if they are upstream of the switches, this high voltage stresses the transformer insulation.

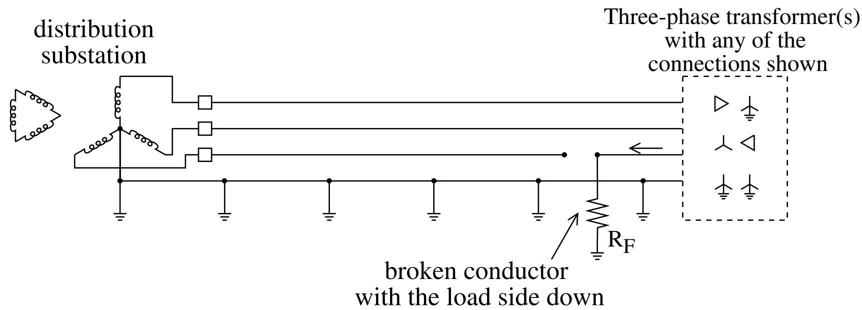


FIGURE 4.31
Backfeed to a downed conductor.

Overall, grounding the transformer's primary neutral is the safest approach.

4.10.4 Backfeeds

During a line-to-ground fault where a single-phase device opens, current may backfeed through a three-phase load (see Figure 4.31). It is a common misconception that this type of backfeed can only happen with an ungrounded transformer connection. Backfeed can also occur with a grounded three-phase connection. This creates hazards to the public in downed wire situations. Even though it is a weak source, the backfed voltage is just as dangerous. Lineworkers also have to be careful. A few have been killed after touching wires downstream of open cutouts that they thought were deenergized.

The general equations for the backfeed voltage and current based on the sequence impedances of the load (Smith, 1994) are

$$I_F = \frac{\left(A - 3Z_0Z_2\right)V}{3Z_0Z_1Z_2 + R_FA}$$

$$V_F = R_FI_F$$

where

$A = Z_0Z_1 + Z_1Z_2 + Z_0Z_2$
Z_1 = positive-sequence impedance of the load, Ω
Z_2 = negative-sequence impedance of the load, Ω
Z_0 = zero-sequence impedance of the load, Ω
R_F = fault resistance, Ω
V = line-to-neutral voltage, V

The line and source impedances are left out of the equations because they are small relative to the load impedances. Under an open circuit with no fault ($R_F = \infty$), the backfeed voltage is

$$V_F = \frac{\left(A - 3Z_0Z_2\right)V}{A}$$

For an ungrounded transformer connection ($Z_0 = \infty$), the backfeed current is

$$I_F = \frac{\left(Z_1 - 2Z_2\right)V}{3Z_1Z_2 + R_F\left(Z_1 + Z_2\right)}$$

The backfeed differs depending on the transformer connection and the load:

- Grounded wye – grounded wye transformer connection
  - Will not backfeed the fault when the transformer is unloaded or has balanced line-to-ground loads (no motors). It will backfeed the fault with line-to-line connected load (especially motors).
- Ungrounded primary transformer
  - Will backfeed the fault under no load. It may not be able to provide much current with no load, but there can be significant voltage on the conductor. Motor load will increase the backfeed current available.

Whether it is a grounded or ungrounded transformer, the available backfeed current depends primarily on the connected motor load. Motors dominate since they have much lower negative-sequence impedance; typically it is equal to the locked-rotor impedance or about 15 to 20%. With no fault impedance ($R_F = 0$), the backfeed current is approximately:

$$I_F = \frac{M_{kVA}}{9V_{LG,kV} \cdot Z_{2,pu}}$$

where M_{kVA} is the three-phase motor power rating in kVA (and we can make the common assumption that 1 hp = 1 kVA), $V_{LG,kV}$ is the line-to-ground voltage in kV, and $Z_{2,pu}$ is the per-unit negative-sequence (or locked-rotor) impedance of the motor(s). Figure 4.32 shows the variation in backfeed current versus motor kVA on the transformer for a 12.47-kV system (assuming $Z_{2,pu} = 0.15$).

The voltage on the open phases depends on the type of transformer connection and the portion of the load that is motors. Figure 4.33 shows the backfeed voltage for an open circuit and for a typical high-impedance fault ($R_F = 200\ \Omega$).

As discussed in Chapter 7, the maximum sustainable arc length in inches is roughly $l = \sqrt{I} \cdot V$ where I is the rms current in amperes, and V is the

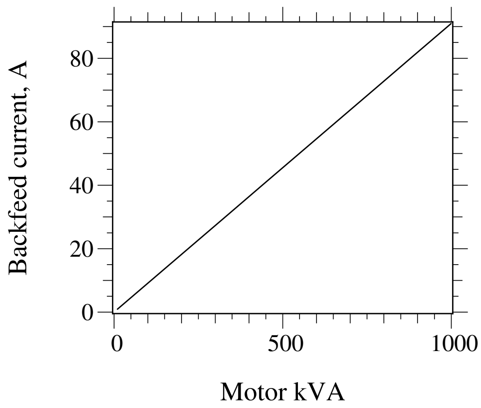


FIGURE 4.32
Available backfeed current on a 12.47-kV circuit (grounded wye – grounded wye or an ungrounded connection, $R_F = 0$).

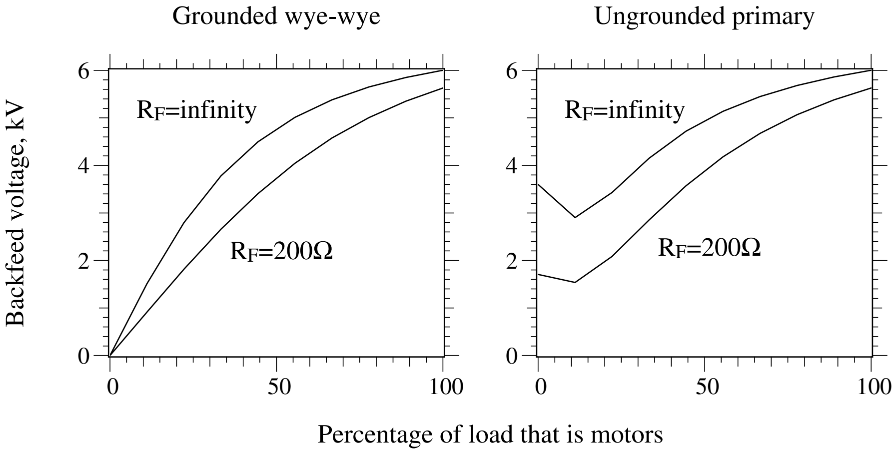


FIGURE 4.33
Available backfeed voltage on a 12.47-kV circuit.

voltage in kV. For a line-to-ground fault on a 12.47-kV circuit, if the backfeed voltage is 4 kV with 50 A available (typical values from Figure 4.32 and Figure 4.33), the maximum arc length is 28 in. (0.7 m). Even though the backfeed source is weak relative to a traditional fault source, it is still strong enough to maintain a significant arc during backfeeds.

In summary, the backfeed voltage is enough to be a safety hazard to workers or the public (e.g., in a wire down situation). The available backfeed is a stiff enough source to maintain an arc of significant length. The arc can continue to cause damage at the fault location during a backfeed condition. It may also spark and sputter at a low level. Options to reduce the chances of backfeed problems include:

- Make sure crews follow safety procedures (if it is not grounded, it is not dead).
- Follow standard practices regarding downed conductors including proper line designs and maintenance, public education, and worker training.

Another option is to avoid single-pole protective devices (switches, fuses, or single-phase reclosers) upstream of three-phase transformer banks. Most utilities have found that backfeeding problems are not severe enough to warrant not using single-pole protective devices.

To analyze more complicated arrangements, use a steady-state circuit analysis program (EMTP has this capability). Most distribution fault analysis programs cannot handle this type of complex arrangement.

4.10.5 Inrush

When a transformer is first energized or reenergized after a short interruption, the transformer may draw *inrush* current from the system due to the core magnetization being out of sync with the voltage. The inrush current may approach short-circuit levels, as much as 40 times the transformer's full-load current. Inrush may cause fuses, reclosers, or relays to falsely operate. It may also falsely operate faulted-circuit indicators or cause sectionalizers to misoperate.

When the transformer is switched in, if the system voltage and the transformer core magnetization are not in sync, a magnetic transient occurs. The transient drives the core into saturation and draws a large amount of current into the transformer.

The worst inrush occurs with residual flux left on the transformer core. Consider Figure 4.34 and Figure 4.35, which shows the worst-case scenario. A transformer is deenergized near the peak core flux density (B_{max}), when the voltage is near zero. The flux decays to about 70% of the maximum and holds there (the residual flux, B_r). Some time later, the transformer is reenergized at a point in time when the flux would have been at its negative peak; the system voltage is crossing through zero and rising positively. The positive voltage creates positive flux that adds to the residual flux already on the transformer core (remember, flux is the time integral of the voltage). This quickly saturates the core; the effective magnetizing branch drops to the air-core impedance of the transformer.

The air core impedance is roughly the same magnitude as the transformer's leakage impedance. Flux controls the effective impedance, so when the core saturates, the small impedance pulls high-magnitude current from the system. The core saturates in one direction, so the transformer draws pulses of inrush every other half cycle with a heavy dc component. The dc offset introduced by the switching decays away relatively quickly.

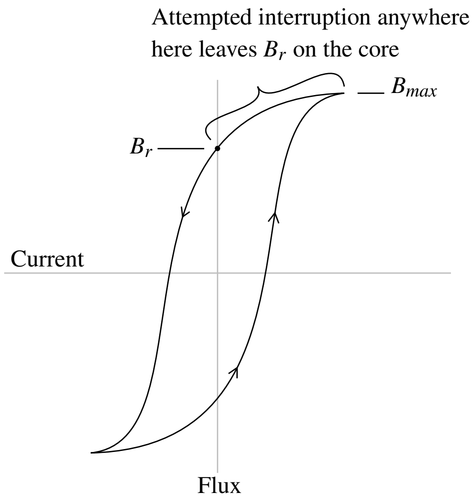


FIGURE 4.34
Hysteresis curve showing the residual flux during a circuit interruption.

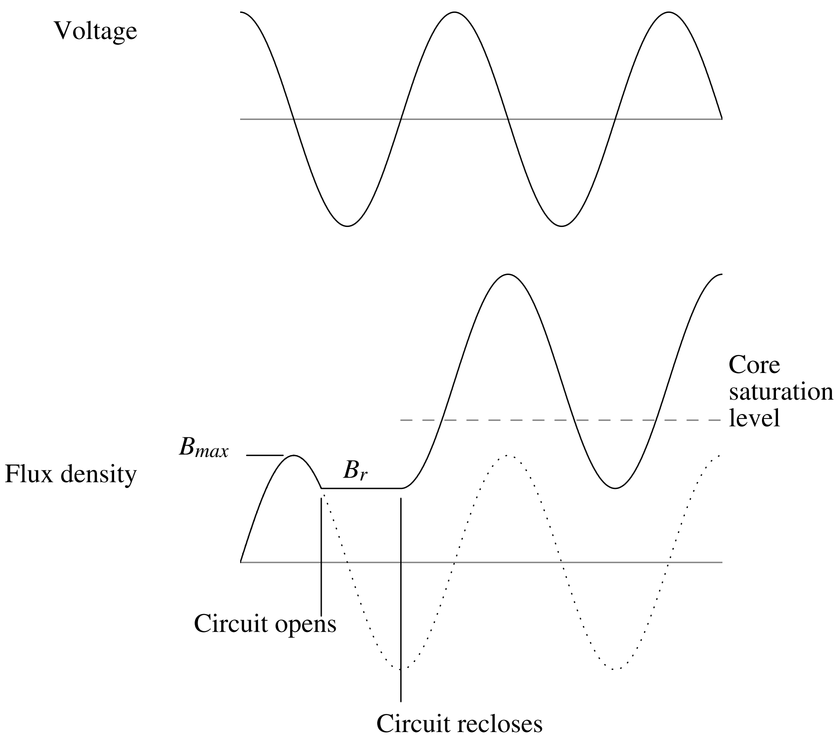


FIGURE 4.35
Voltage and flux during worst-case inrush.

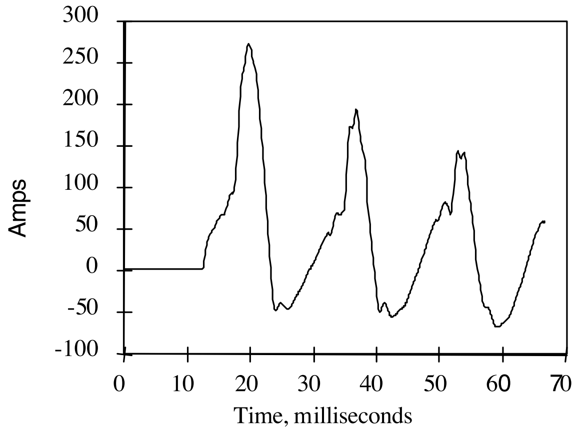


FIGURE 4.36
Example inrush current measured at a substation (many distribution transformers together). (Copyright © 1996. Electric Power Research Institute. TR-106294-V3. *An Assessment of Distribution System Power Quality: Volume 3: Library of Distribution System Power Quality Monitoring Case Studies.* Reprinted with permission.)

Figure 4.36 shows an example of inrush following a reclose operation measured at the distribution substation breaker.

Several factors significantly impact inrush:

- *Closing point* — The point where the circuit closes back in determines how close the core flux can get to its theoretical maximum. The worst case is when the flux is near its peak. Fortunately, this is also when the voltage is near zero, and switches tend to engage closer to a voltage peak (an arc tends to jump the gap).
- *Design flux* — A transformer that is designed to operate lower on the saturation curve draws less inrush. Because there is more margin between the saturation point and the normal operating region, the extra flux during switching is less likely to push the core into saturation.
- *Transformer size* — Larger transformers draw more inrush. Their saturated impedances are smaller. But, on a per-unit basis relative to their full-load capability, smaller transformers draw more inrush. The inrush into smaller transformers dies out more quickly.
- *Source impedance* — Higher source impedance relative to the transformer size limits the current that the transformer can pull from the system. The peak inrush with significant source impedance (Westinghouse Electric Corporation, 1950) is

$$i_{peak} = \frac{i_0}{1 + i_0 X}$$

where

i_0 = peak inrush without source impedance in per unit of the transformer rated current

X = source impedance in per unit on the transformer kVA base

Other factors have less significance. The load on the transformer does not significantly change the inrush. For most typical loading conditions, the current into the transformer will interrupt at points that still leave about 70% of the peak flux on the core.

While interruptions generally cause the most severe inrush, other voltage disturbances may cause inrush into a transformer. Voltage transients and especially voltage with a dc component can saturate the transformer and cause inrush. Some examples are:

- *Voltage sags* — Upon recovery from a voltage sag from a nearby fault, the sudden rise in voltage can drive a transformer into saturation.
- *Sympathetic inrush* — Energizing a transformer can cause a nearby transformer to also draw inrush. The inrush into the switched transformer has a significant dc component that causes a dc voltage drop. The dc voltage can push the other transformer into saturation and draw inrush.
- *Lightning* — A flash to the line near the transformer can push the transformer into saturation.

References

ABB, *Distribution Transformer Guide*, 1995.

Alexander Publications, *Distribution Transformer Handbook*, 2001.

ANSI C57.12.40-1982, *American National Standard Requirements for Secondary Network Transformers, Subway and Vault Types (Liquid Immersed).*

ANSI/IEEE C57.12.24-1988, *American National Standard Underground-type Three-Phase Distribution Transformers, 2500 kVA and Smaller; High Voltage 34 500 GrdY/19 200 V and Below; Low Voltage 480 V and Below — Requirements.*

ANSI/IEEE C57.12.80-1978, *IEEE Standard Terminology for Power and Distribution Transformers.*

ANSI/IEEE C57.91-1981, *IEEE Guide for Loading Mineral-Oil-Immersed Overhead and Pad-Mounted Distribution Transformers Rated 500 kVA and Less with 65 Degrees C Or 55 Degrees C Average Winding Rise.*

ANSI/IEEE C57.105-1978, *IEEE Guide for Application of Transformer Connections in Three-Phase Distribution Systems.*

ANSI/IEEE Std. 32-1972, *IEEE Standard Requirements, Terminology, and Test Procedure for Neutral Grounding Devices.*

Blume, L. F., Boyajian, A., Camilli, G., Lennox, T. C., Minneci, S., and Montsinger, V. M., *Transformer Engineering*, Wiley, New York, 1951.

Bohmann, L. J., McDaniel, J., and Stanek, E. K., "Lightning Arrester Failures and Ferroresonance on a Distribution System," IEEE Rural Electric Power Conference, 1991.

CEA 485 T 1049, *On-line Condition Monitoring of Substation Power Equipment Utility Needs*, Canadian Electrical Association, 1996.

CIGRE working group 12.05, "An International Survey on Failure in Large Power Transformer Service," *Electra*, no. 88, pp. 21–48, 1983.

EEI, "A Method for Economic Evaluation of Distribution Transformers," March, 28–31, 1981.

EPRI TR-106294-V3, *An Assessment of Distribution System Power Quality: Volume 3: Library of Distribution System Power Quality Monitoring Case Studies*, Electric Power Research Institute, Palo Alto, CA, 1996.

Gangel, M. W. and Propst, R. F., "Distribution Transformer Load Characteristics," *IEEE Transactions on Power Apparatus and Systems*, vol. 84, pp. 671–84, August 1965.

Grainger, J. J. and Kendrew, T. J., "Evaluation of Technical Losses on Electric Distribution Systems," CIRED, 1989.

Hopkinson, F. H., "Approximate Distribution Transformer Impedances," General Electric Internal Memorandum, 1976. As cited by Kersting, W. H. and Phillips, W. H., "Modeling and Analysis of Unsymmetrical Transformer Banks Serving Unbalanced Loads," Rural Electric Power Conference, 1995.

Hopkinson, R. H., "Ferroresonant Overvoltage Control Based on TNA Tests on Three-Phase Delta-Wye Transformer Banks," *IEEE Transactions on Power Apparatus and Systems*, vol. 86, pp. 1258–65, October 1967.

IEEE C57.12.00-2000, *IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers*.

IEEE Std. 493-1997, *IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (Gold Book)*.

IEEE Std. C57.91-1995, *IEEE Guide for Loading Mineral-Oil-Immersed Transformers*.

IEEE Task Force Report, "Secondary (Low-Side) Surges in Distribution Transformers," *IEEE Transactions on Power Delivery*, vol. 7, no. 2, pp. 746–56, April 1992.

Jufer, N. W., "Southern California Edison Co. Ferroresonance Testing of Distribution Transformers," IEEE/PES Transmission and Distribution Conference, 1994.

Long, L. W., "Transformer Connections in Three-Phase Distribution Systems," in Power Transformer Considerations of Current Interest to the Utility Engineer, 1984. IEEE Tutorial Course, 84 EHO 209-7-PWR.

Lunsford, J., "MOV Arrester Performance During the Presence of Ferroresonant Voltages," IEEE/PES Transmission and Distribution Conference, 1994.

Nickel, D. L., "Distribution Transformer Loss Evaluation. I. Proposed Techniques," *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-100, no. 2, pp. 788–97, February 1981.

NRECA RER Project 90-8, *Underground Distribution System Design and Installation Guide*, National Rural Electric Cooperative Association, 1993.

ORNL-6804/R1, *The Feasibility of Replacing or Upgrading Utility Distribution Transformers During Routine Maintenance*, Oak Ridge National Laboratory, U.S. Department of Energy, 1995.

ORNL-6847, *Determination Analysis of Energy Conservation Standards for Distribution Transformers*, Oak Ridge National Laboratory, U.S. Department of Energy, 1996.

ORNL-6925, *Supplement to the "Determination Analysis" (ORNL-6847) and Analysis of the NEMA Efficiency Standard for Distribution Transformers*, Oak Ridge National Laboratory, U.S. Department of Energy, 1997.

ORNL-6927, *Economic Analysis of Efficient Distribution Transformer Trends*, Oak Ridge National Laboratory, U.S. Department of Energy, 1998.

PTI, "Distribution Transformer Application Course Notes," Power Technologies, Inc., Schenectady, NY, 1999.

Rusch, R. J. and Good, M. L., "Wyes and Wye Nots of Three-Phase Distribution Transformer Connections," IEEE Rural Electric Power Conference, 1989.

Sankaran, C., "Transformers," in *The Electrical Engineering Handbook*, R. C. Dorf, Ed.: CRC Press, Boca Raton, FL, 2000.

Seevers, O. C., *Management of Transmission & Distribution Systems*, PennWell Publishing Company, Tulsa, OK, 1995.

Smith, D. R., "Impact of Distribution Transformer Connections on Feeder Protection Issues," Texas A&M Annual Conference for Protective Relay Engineers, March 1994.

Smith, D. R., Braunstein, H. R., and Borst, J. D., "Voltage Unbalance in 3- and 4-Wire Delta Secondary Systems," *IEEE Transactions on Power Delivery*, vol. 3, no. 2, pp. 733–41, April 1988.

Smith, D. R., Swanson, S. R., and Borst, J. D., "Overvoltages with Remotely-Switched Cable-Fed Grounded Wye-Wye Transformers," *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-94, no. 5, pp. 1843–53, 1975.

Tillman, R. F., Jr, "Loading Power Transformers," in *The Electric Power Engineering Handbook*, L. L. Grigsby, Ed.: CRC Press, Boca Raton, FL, 2001.

Walling, R. A., "Ferroresonance Guidelines for Modern Transformer Applications," in Final Report to the Distribution Systems Testing, Application, and Research (DSTAR) Consortium: General Electric, Industrial and Power Systems, Power Systems Engineering Department, 1992. As cited in NRECA RER Project 90-8, 1993.

Walling, R. A., "Ferroresonant Overvoltages in Today's Loss-Evaluated Distribution Transformers," IEEE/PES Transmission and Distribution Conference, 1994.

Walling, R. A., 2000. Verbal report at the fall IEEE Surge Protective Devices Committee Meeting.

Walling, R. A., Barker, K. D., Compton, T. M., and Zimmerman, L. E., "Ferroresonant Overvoltages in Grounded Wye-Wye Padmount Transformers with Low-Loss Silicon Steel Cores," *IEEE Transactions on Power Delivery*, vol. 8, no. 3, pp. 1647–60, July 1993.

Walling, R. A., Hartana, R. K., Reckard, R. M., Sampat, M. P., and Balgie, T. R., "Performance of Metal-Oxide Arresters Exposed to Ferroresonance in Padmount Transformers," *IEEE Transactions on Power Delivery*, vol. 9, no. 2, pp. 788–95, April 1994.

Walling, R. A., Hartana, R. K., and Ros, W. J., "Self-Generated Overvoltages Due to Open-Phasing of Ungrounded-Wye Delta Transformer Banks," *IEEE Transactions on Power Delivery*, vol. 10, no. 1, pp. 526–33, January 1995.

Westinghouse Electric Corporation, *Electrical Transmission and Distribution Reference Book*, 1950.

All hell broke loose, we had a ball of fire that went phase to phase shooting fire out the xfmer vents like a flame thrower showering slag on the linemen and sent the monster galloping down the line doing the Jacobs ladder effect for 2 spans before it broke …

The next time you're closing in on that new shiny xfmer out of the shop, think about the night we got a lemon.

anonymous poster
www.powerlineman.com