

For ground faults, arc resistance may be an important factor because of the longer arcs that can occur. Also, the relatively high tower footing resistance may appreciably limit the fault current.

Arc resistance is discussed in more detail in Chapter 12.

4.2.4 Distortion of Phases During Faults

The phasor diagrams in Figure 2-20 illustrate the effect of faults on the system voltages and currents. The diagrams shown are for effectively grounded systems. In all cases, the dotted or uncollapsed voltage triangle exists in the source (the generator) and the maximum collapse occurs at the fault location. The voltage at

other locations will be between these extremes, depending on the point of measurement.

5 SYMMETRICAL COMPONENTS

Relay application requires a knowledge of system conditions during faults, including the magnitude, direction, and distribution of fault currents, and often the voltages at the relay locations for various operating conditions. Among the operating conditions to be considered are maximum and minimum generation, selected lines out, line-end faults with the adjacent breaker open, and so forth. With this information, the relay engineer can select the proper relays and settings to protect all parts of the power system in a minimum amount of time. Three-phase fault data are used for the application and setting of phase relays and single-phase-to-ground fault data for ground relays.

The method of symmetrical components is the foundation for obtaining and understanding fault data on three-phase power systems. Formulated by Dr. C. L. Fortescue in a classic AIEE paper in 1918, the symmetrical components method was given its first practical application to system fault analysis by C. F. Wagner and R. D. Evans in the late 1920s and early 1930s. W. A. Lewis and E. L. Harder added measurably to its development in the 1930s.

Today, fault studies are commonly made with the digital computer and can be updated rapidly in response to system changes. Manual calculations are practical only for simple cases.

A knowledge of symmetrical components is important in both making a study and understanding the data obtained. It is also extremely valuable in analyzing faults and relay operations. A number of protective relays are based on symmetrical components, so the method must be understood in order to apply these relays successfully.

In short, the method of symmetrical components is one of the relay engineer's most powerful technical tools. Although the method and mathematics are quite simple, the practical value lies in the ability to think and visualize in symmetrical components. This skill requires practice and experience.

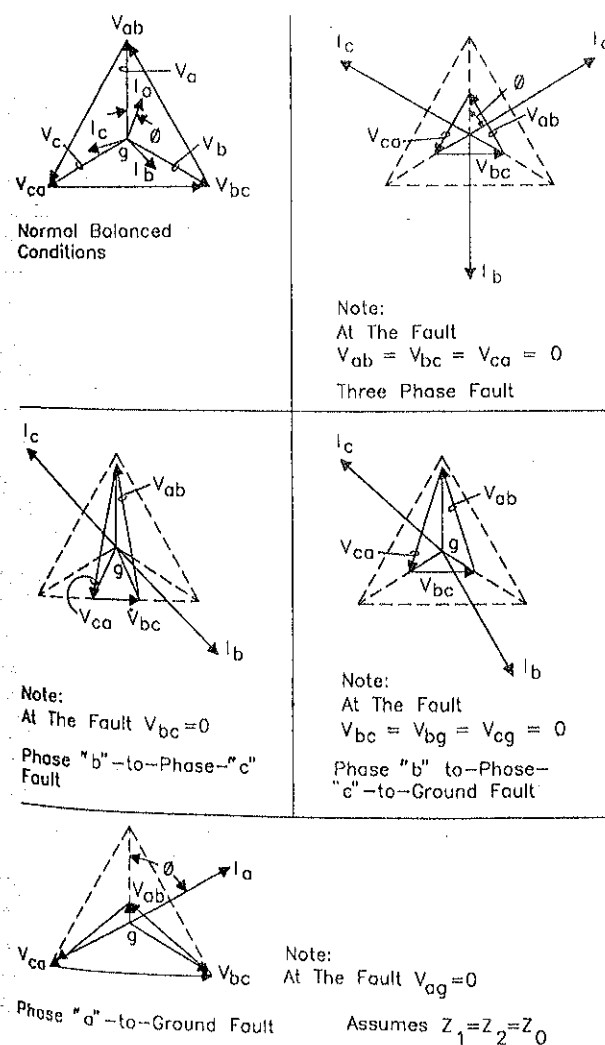


Figure 2-20 Phasor diagrams for the various types of faults occurring on a typical power system.

5.1 Basic Concepts

The method of symmetrical components consists of reducing any unbalanced three-phase system of phasors into three balanced or symmetrical systems:

the positive, negative, and zero sequence components. This reduction can be performed in terms of current, voltage, impedance, and so on.

The positive sequence components consist of three phasors equal in magnitude and 120° out of phase (Fig. 2-21a). The negative sequence components are three phasors equal in magnitude, displaced 120° with a phase sequence opposite to that of the positive sequence (Fig. 2-21b). The zero sequence components consist of three phasors equal in magnitude and in phase (Fig. 2-21c). *Note all phasors rotate in a counterclockwise direction.*

In the following discussion, the subscript 1 will identify the positive sequence component, the subscript 2 the negative sequence component, and the subscript 0 the zero sequence component. For example, V_{a1} is the positive sequence component of phase-a voltage, V_{b2} the negative sequence component of phase-b voltage, and V_{c0} the zero sequence component of phase-c voltage. *All components are phasor quantities, rotating counterclockwise.*

Since the three phasors in any set are always equal in magnitude, the three sets can be expressed in terms of one phasor. For convenience, the phase-a phasor is used as a reference. Thus,

Positive sequence	Negative sequence	Zero sequence	
$V_{a1} = V_{a1}$	$V_{a2} = V_{a2}$	$V_{a0} = V_{a0}$	(2-12)
$V_{b1} = a^2 V_{a1}$	$V_{b2} = a V_{a2}$	$V_{b0} = V_{a0}$	
$V_{c1} = a V_{a1}$	$V_{c2} = a^2 V_{a2}$	$V_{c0} = V_{a0}$	

The coefficients a and a^2 are operators that, when multiplied with a phasor, result in a counterclockwise angular shift of 120 and 240° , respectively, with no

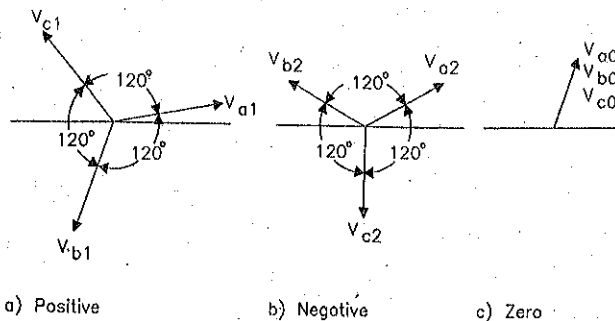


Figure 2-21 Sequence components of voltages.

change in magnitude:

$$a = 1 \angle 120^\circ = -0.5 + j0.866 \quad (2-1)$$

$$a^2 = 1 \angle 240^\circ = -0.5 - j0.866 \quad (2-2)$$

$$a^3 = 1 \angle 360^\circ = 1.0 + j0 \quad (2-3)$$

From these equations, useful combinations can be derived

$$1 + a + a^2 = 0$$

$$1 - a^2 = \sqrt{3} \angle 30^\circ \quad (2-4)$$

or

$$a^2 - 1 = \sqrt{3} \angle 210^\circ$$

$$a - 1 = \sqrt{3} \angle 150^\circ \quad (2-5)$$

or

$$1 - a = \sqrt{3} \angle -30^\circ$$

$$a^2 - a = \sqrt{3} \angle 270^\circ \quad (2-6)$$

or

$$a - a^2 = \sqrt{3} \angle 90^\circ \quad (2-7)$$

Any three-phase system of phasors will always have the sum of the three components:

$$V_a = V_{a1} + V_{a2} + V_{a0} \quad (2-8)$$

$$V_b = V_{b1} + V_{b2} + V_{b0} = a^2 V_{a1} + a V_{a2} + V_{a0} \quad (2-9)$$

$$V_c = V_{c1} + V_{c2} + V_{c0} = a V_{a1} + a^2 V_{a2} + V_{a0} \quad (2-10)$$

Since phase a has been chosen as a reference, the subscripts are often dropped for convenience. Thus,

$$V_a = V_1 + V_2 + V_0$$

and

$$I_a = I_1 + I_2 + I_0 \quad (2-11)$$

$$V_b = a^2 V_1 + a V_2 + V_0$$

and

$$I_b = a^2 I_1 + a I_2 + I_0 \quad (2-12)$$

$$V_c = a V_1 + a^2 V_2 + V_0$$

and

$$I_c = aI_1 + a^2I_2 + I_0 \quad (2-25)$$

Quantities V_1, V_2, V_0, I_1, I_2 , and I_0 , can always be assumed to be the phase-a components. Note that the b and c components always exist, as indicated by Eq. (2-12). Note that dropping the phase subscripts should be done with great care. Where any possibility of misunderstanding can occur, the additional effort of using the double subscripts will be rewarded.

Equations (2-20) to (2-22) can be solved to yield the sequence components for a general set of three-phase phasors:

$$V_{a1} = \frac{1}{3}(V_{ag} + aV_{bg} + a^2V_{cg})$$

and

$$I_{a1} = \frac{1}{3}(I_a + aI_b + a^2I_c)$$

$$V_{a2} = \frac{1}{3}(V_{ag} + a^2V_{bg} + aV_{cg}) \quad (2-26)$$

and

$$I_{a2} = \frac{1}{3}(I_a + a^2I_b + aI_c)$$

$$V_{a0} = \frac{1}{3}(V_{ag} + V_{bg} + V_{cg}) \quad (2-27)$$

and

$$I_0 = \frac{1}{3}(I_a + I_b + I_c) \quad (2-28)$$

A sequence component cannot exist in only one phase. If any sequence component exists by measurement or calculation in one phase, it exists in all three phases, as shown in Eq. (2-12) and Figure 2-21.

5.2 System Neutral

Figure 2-22 describes the definition of power-system neutral and contrasts it with ground. Neutral is established by connecting together the terminals of three equal resistances as shown with each of the other resistor terminals connected to one of the phases. We can thus write

$$\begin{aligned} V_{ag} &= V_{an} + V_{ng} \\ V_{bg} &= V_{bn} + V_{ng} \\ V_{cg} &= V_{cn} + V_{ng} \end{aligned} \quad (2-29)$$

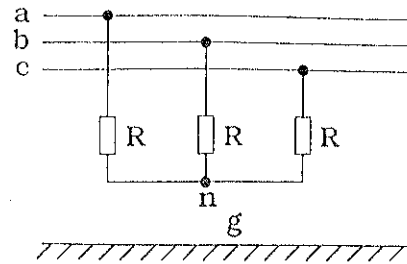


Figure 2-22 Power system neutral.

From Eq. (2-28),

$$V_0 = \frac{1}{3}(V_{ag} + V_{bg} + V_{cg})$$

Substituting Eq. (2-29), we obtain

$$V_0 = \frac{1}{3}(V_{an} + V_{ng} + V_{bn} + V_{ng} + V_{cn} + V_{ng})$$

Since $V_{an} + V_{bn} + V_{cn} = 0$,

$$V_0 = \frac{1}{3}(3V_{ng})$$

$$V_0 = V_{ng}$$

Neutral and ground are distinctly independent and differ in voltage by V_0 .

Grounding and its influence on relaying are discussed in Chapters 7 and 12.

5.3 Sequences in a Three-Phase Power System

Several important assumptions are made to greatly simplify the use of symmetrical components in practical circumstances. Interconnections of the three sequence networks allow any series or shunt discontinuity to be investigated. For the rest of the power-system network, it is assumed that the impedances in the individual phases are equal and the generator phase voltages are equal in magnitude and displaced 120° from one another.

Based on this premise, in the symmetrical part of the system, positive sequence current flow produces only positive sequence voltage drops, negative sequence current flow produces only negative sequence voltage drops, and zero sequence current flow produces only zero sequence voltage drops. For an unsymmetrical system, interaction occurs between components. For a particular series or shunt discontinuity being repre-

sented, the interconnection of the networks produces the required interaction.

Any circuit that is not continuously transposed will have impedances in the individual phases that differ. This fact is generally ignored in making calculations because of the immense simplification that results. From a practical viewpoint, ignoring this effect, in general, has no appreciable influence.

5.4 Sequence Impedances

Quantities Z_1 , Z_2 , and Z_0 are the system impedances to the flow of positive, negative, and zero sequence currents, respectively. Except in the area of a fault or general unbalance, each sequence impedance is considered to be the same in all three phases of the symmetrical system. A brief review of these quantities is given below for synchronous machinery, transformers, and transmission lines.

5.4.1 Synchronous Machinery

Three different positive sequence reactance values are specified. X_d'' indicates the subtransient reactance, X_d' the transient reactance, and X_d the synchronous reactance. These direct-axis values are necessary for calculating the short-circuit current value at different times after the short circuit occurs. Since the subtransient reactance values give the highest initial current value, they are generally used in system short-circuit calculations for high-speed relay application. The transient reactance value is used for stability consideration and slow-speed relay application.

The unsaturated synchronous reactance is used for sustained fault-current calculation since the voltage is reduced below saturation during faults near the unit. Since this generator reactance is invariably greater than 100%, the sustained fault current will be less than the machine rated load current unless the voltage regulator boosts the field substantially.

The negative sequence reactance of a turbine generator is generally equal to the subtransient X_d'' reactance. X_2 for a salient-pole generator is much higher. The flow of negative sequence current of opposite phase rotation through the machine stator winding produces a double frequency component in the rotor. As a result, the average of the subtransient direct-axis reactance and the subtransient quadrature-axis reactance gives a good approximation of negative sequence reactance.

The zero sequence reactance is much less than the others, producing a phase-to-ground fault current

magnitude $[3/(x_1 + x_2 + x_0)]$ greater than the three-phase fault current magnitude $(1/x_1)$. Since the machine is braced for only three-phase fault current magnitude, it is seldom possible or desirable to ground the neutral solidly.

The armature winding resistance is small enough to be neglected in calculating short-circuit currents. This resistance is, however, important in determining the de time constant of an asymmetrical short-circuit current.

Typical reactance values for synchronous machinery are available from the manufacturer or handbooks. However, actual design values should be used when available.

5.4.2 Transformers

The positive and negative sequence reactances of all transformers are identical. Values are available from the nameplate. The zero sequence reactance is either equal to the other two sequence reactances or infinite except for the three-phase, core-type transformers. In effect, the magnetic circuit design of the latter unit gives them the effect of an additional closed delta winding. The resistance of the windings is very small and neglected in short-circuit calculations.

The sequence circuits for a number of transformer banks are shown in Figure 2-23. The impedance indicated are the equivalent leakage impedance between the windings involved. For two-winding transformers, the total leakage impedance Z_{LH} measured from the L winding, with the H winding short-circuited. Z_{HL} is measured from the H winding with the L winding shorted. Except for a 1:1 transformer ratio, the impedances have different values in ohms. On a per unit basis, however, Z_{LH} equals Z_{HL} .

For three-winding and autotransformer bank there are three leakage impedances:

Impedance	Winding measured from	Shorted winding	Open winding
$Z_{HM}(Z_{HL})$	H	M(L)	L(T)
$Z_{HL}(Z_{HT})$	H	L(T)	M(L)
$Z_{ML}(Z_{LT})$	M(L)	L(T)	H

Both winding conventions shown above are common use. In the first convention, the windings are labeled H (high), L (low), M (medium); in the second H (high), L (low), and T (tertiary). Unfortunately, the L winding in the second convention

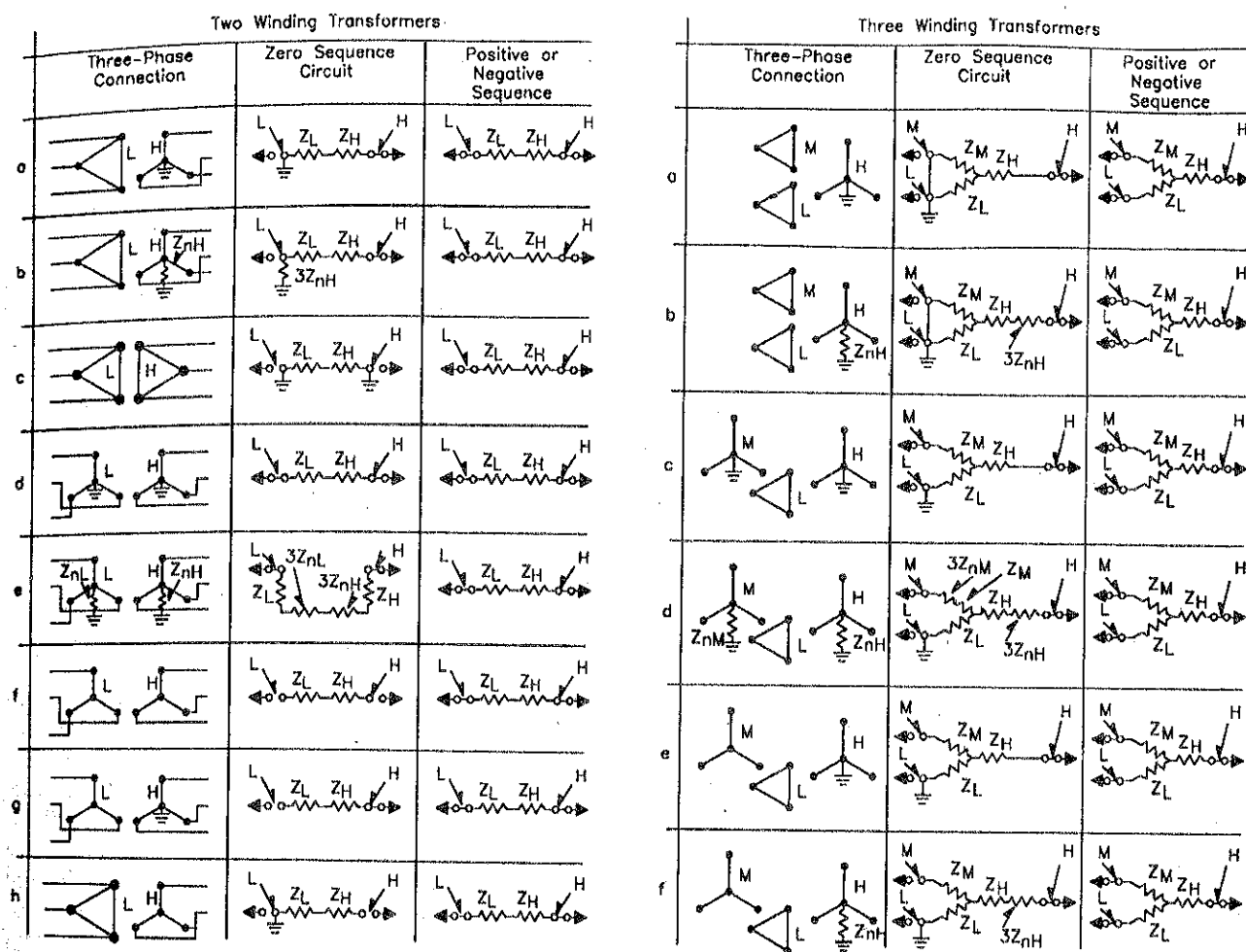


Figure 2-23 Equivalent positive, negative, and zero sequence circuits for some common and theoretical connections for two- and three-winding transformers.

equivalent to M in the first. The tertiary winding voltage is generally the lowest.

On a common kVA base, the equivalent wye leakage impedances are obtained from the following equations:

$$Z_H = \frac{1}{2}(Z_{HM} + Z_{HL} - Z_{ML})$$

or

$$Z_H = \frac{1}{2}(Z_{HL} + Z_{HT} - Z_{LT})$$

$$Z_M = \frac{1}{2}(Z_{HM} + Z_{ML} - Z_{HL})$$

or

$$Z_L = \frac{1}{2}(Z_{HL} + Z_{LT} - Z_{HT})$$

$$Z_L = \frac{1}{2}(Z_{HL} + Z_{ML} - Z_{HM})$$

or

$$Z_T = \frac{1}{2}(Z_{HT} + Z_{LT} - Z_{HL})$$

As a check, Z_H plus Z_M equals Z_{HM} , and so on. The wye is a mathematical equivalent valid for current and voltage calculations external to the transformer bank. The junction point of the wye has no physical significance. One equivalent branch, usually $Z_M(Z_L)$,

may be negative. On some autotransformers, Z_H is negative.

The equivalent diagrams shown in Figure 2-23 are satisfactory when calculations are to be made relative to one segment of a power system. However, a more complex representation is required when phase currents and voltages are to be determined at points in the system having an intervening transformer between them and the point of discontinuity being examined. For delta-wye transformers, a 30° phase shift must be accommodated. For ANSI standard transformers, the *high-voltage* phase-to-ground voltage *leads* the *low-voltage* phase-to-ground voltage by 30° , irrespective of which side the delta or wye is on. This phase shift may be included in the equivalent per unit diagram by showing a $1 \angle 30^\circ:1$ ratio for it.

The phase shift in the negative sequence network for the delta-wye transformer is the same amount, but in the opposite direction, to that in the positive sequence network. The phase shift then, for an ANSI standard transformer, would be $1 \angle -30^\circ:1$ in the negative sequence per unit diagram.

The phase shift must be used in all the combinations of Figure 2-23 where a wye and delta winding coexist. This effect is extremely important when consideration is being given to the behavior of devices on both sides of such a transformer.

5.4.3 Transmission Lines

For transmission lines, the positive and negative sequence reactances are the same. As a rule of thumb, the 60-Hz reactance is roughly $0.8 \Omega/\text{mi}$ for single conductor overhead lines and $0.6 \Omega/\text{mi}$ for bundled overhead lines.

The zero sequence impedance is always different from the positive and negative sequence impedances. It is a loop impedance (conductor plus earth and/or ground wire return), in contrast to the one-way

impedance for a positive and negative sequence. Zero sequence impedance can vary from 2 to 6 times X_1 ; a rough average for overhead lines is 3 to 3.5 times X_1 .

The resistance terms for the three sequences are usually neglected for overhead lines, except for lower-voltage lines and cables. In the latter cases, line angles of 30 to 60° may exist, and resistance can be significant. A good compromise is to use the impedance value rather than reactance and neglect the angular difference in fault calculations. This yields a lower current to assure that the relay will be set sensitively enough.

Zero sequence mutual impedance resulting from paralleled lines can be as high as 50 to 70% of the zero sequence self-impedance. This mutual impedance becomes an increasingly important factor as more lines are crowded into common rights of way.

5.5 Sequence Networks

With the system assumed to be balanced or symmetrical to the point of unbalance or fault, the three sequence components are independent and do not react with each other. Thus, three network diagrams are required to separate the three sequence components for individual consideration: one for positive, one for negative, and one for zero sequence. These sequence network diagrams consist of one phase to neutral of the power system, showing all the component parts relevant to the problem under consideration. Typical diagrams are illustrated in Figures 2-24 through 2-26.

The positive sequence network (Fig. 2-24) must show both the generator voltages and impedances of the generators, transformers, and lines. Balanced loads may be shown from any bus to the neutral bus. Generally, however, balanced loads are neglected. Compared to the system low-impedance high-angle quantities, they have a much higher impedance at a

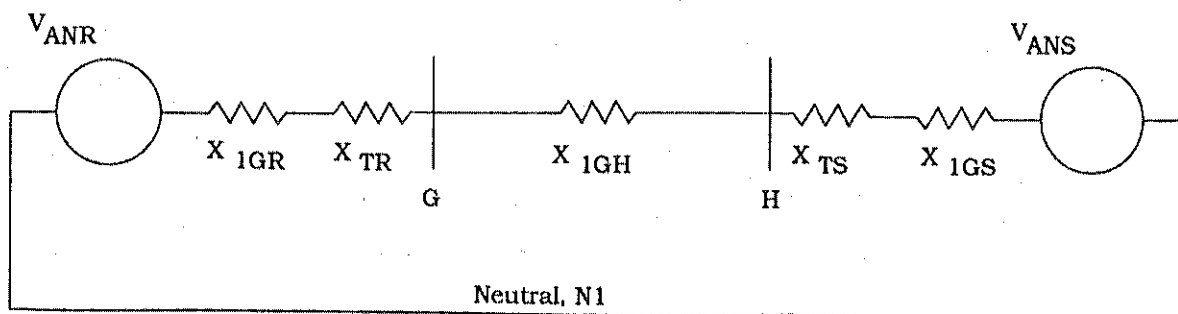


Figure 2-24 Example system and positive sequence network.

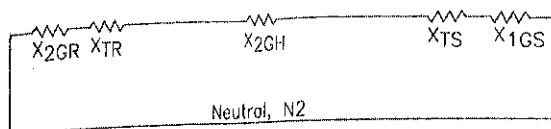


Figure 2-25 Negative sequence network for example system.

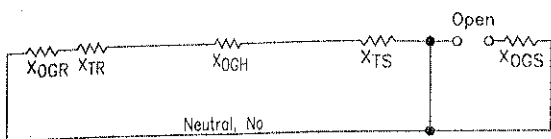


Figure 2-26 Zero sequence network for example system.

very low angle. In short, balanced loads complicate the calculations and generally do not affect the fault currents significantly.

With two exceptions, the negative sequence network (Fig. 2-25) will be a duplicate of the positive sequence network: (1) There will be no generator voltages, since synchronous machines generate a positive sequence only, and (2) the negative sequence reactance of synchronous machinery may be different from the positive, as previously described. For all practical calculations involving faults or discontinuities remote from the generating plant, however, X_1 is assumed to be equal to X_2 .

The zero sequence network (Fig. 2-26) is quite different from the other two. First of all, it has no voltage: Rotating machinery does not produce zero sequence voltage. Also, the transformer connections require special consideration and grounding impedances must be included. Figure 2-23 shows the zero sequence circuits for many transformers.

A three-line system diagram is usually not required to determine the zero sequence network, but if a question arises as to the flow of zero sequence currents, the three-line diagram can be useful. From this three-phase system diagram, the zero sequence network requirements can be resolved by determining whether or not equal and in-phase currents can exist in each of the three phases. If the zero sequence current component can flow, the zero sequence network must reflect its path.

For simplicity, Figure 2-27 shows the generators solidly grounded. In practice, however, solid grounding is used only in very special cases.

5.6 Sequence Network Connections and Voltages

The current flow direction and voltage connections illustrated in Figure 2-28 must be followed for Eqs. (2-29), (2-30), and (2-31) to apply. Current reference direction in any circuit element must be the same in all three networks to avoid confusion. Current flow in one or more of the networks may reverse for some types of unbalances, particularly if the networks are complex. Reverse flow should be treated as a negative current to ensure that it will be properly subtracted when determining the phase currents.

Each sequence network is, of course, a per unit diagram representing one of the three phases of the symmetrical power system. Therefore, a resistor (reactor, impedance) connected between the system neutral and ground, as shown in Figure 2-28, must be multiplied by 3 as indicated. In the system, $3I_0$ flows through R ; in the zero sequence network, however, I_0 flows through $3R$, producing an equivalent voltage drop.

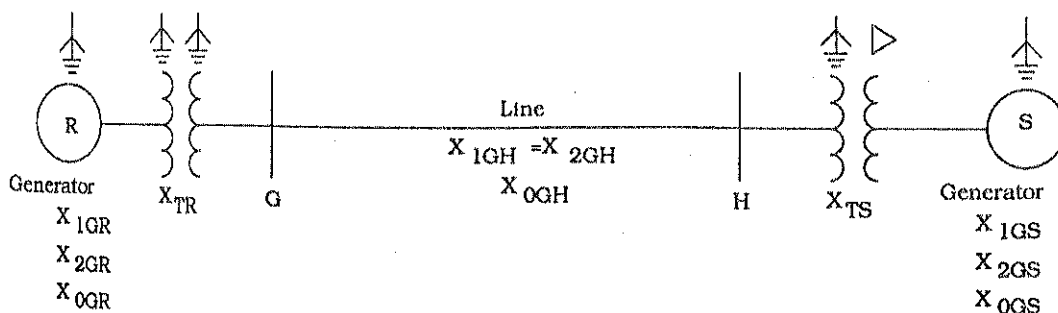
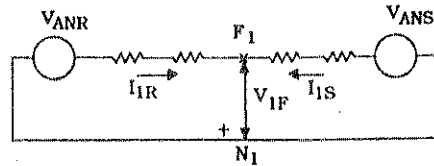


Figure 2-27 Example system (generators shown solidly grounded for simplification).

In the positive sequence network, the voltage drop at any point in the network is:

$$V_1 = V_{AN} - \sum I_1 Z_1$$

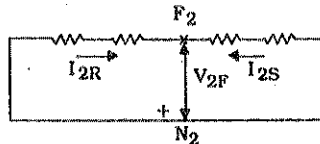
Where $\sum I_1 Z_1$ is the phasor sum of the $I_1 Z_1$ drops from the neutral or zero potential bus (N_1) to the point where the voltage is to be determined.



In the negative sequence network, the voltage drop at any point in the network is:

$$V_2 = 0 - \sum I_2 Z_2$$

Where $\sum I_2 Z_2$ is the phasor sum of the $I_2 Z_2$ drops from the neutral or zero potential bus (N_2) to the point where the voltage is to be determined.



In the zero sequence network, the voltage drop at any point in the network is:

$$V_0 = - \sum I_0 Z_0$$

Where $\sum I_0 Z_0$ is the phasor sum of the $I_0 Z_0$ drops from the zero potential bus (N_0) to the point where the voltage is to be determined.

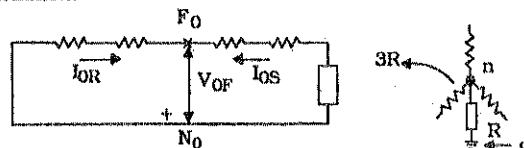


Figure 2-28 Sequence network connections and voltages.

5.7 Network Connections for Fault and General Unbalances

The sequence networks can be interconnected at a point of discontinuity, such as a fault. In such areas, negative and zero sequence voltages are generated, as previously described. Sequence network connections for various types of common faults are shown in Figures 2-29 through 2-32. From the three-phase diagrams of the fault area, the sequence network connections representing the fault can be derived. These diagrams do not show fault impedance, and fault studies do not include this effect except in very rare cases. The single-sequence impedance Z_1, Z_2, Z_0 (practically equivalent to X_1, X_2, X_0) shown in the

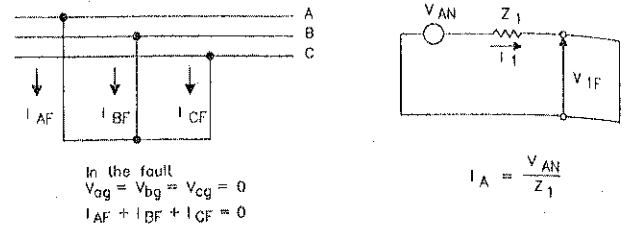


Figure 2-29 Three-phase fault and its network connection.

figures is the net impedance between the neutral bus and selected fault location. Based on zero load, all generated voltages (V_{AN}) are equal and in phase.

Since the three-phase fault is balanced, symmetrical components are not required for this calculation. However, since the positive sequence network represents the system, the network can be connected as shown in Figure 2-29 to represent the fault.

For a phase-a-to-ground fault, the three networks are connected in series (Fig. 2-30). Figure 2-31 illustrates a phase-b-c-to-ground fault and its sequence network interconnection. The phase-b-to-phase-c fault and its sequence connections are shown in Figure 2-32.

Fault studies normally include only three-phase faults and single-phase-to-ground faults. Three-phase faults are the most severe phase faults, whereas single-phase-to-ground faults are the most common. Studies of the latter faults provide useful information for ground relaying.

A fundamental study of both series and shunt unbalances was made by E. L. Harder in 1937. The shunt unbalances summarized in Figure 2-33 are taken from Harder's study. Note that all the faults shown in Figures 2-29 through 2-32 are also represented in Figure 2-33.

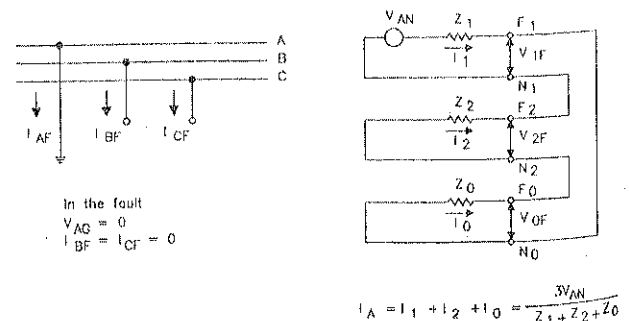


Figure 2-30 Phase-to-ground fault and its sequence network connections.

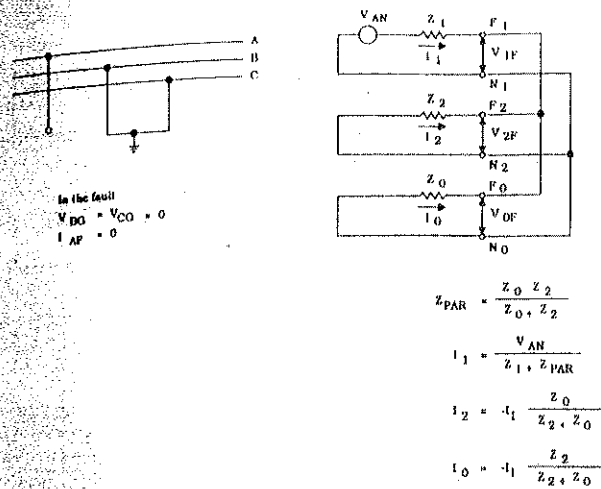


Figure 2-31 Double phase-to-ground fault and its sequence network connections.

In Figure 2-33, the entire symmetrical power system up to a point x of the shunt connection is represented by a rectangular box. Inside the topmost box for each shunt condition is a four-line representation of the shunt to be connected to the system at point x . The three lower boxes for each shunt condition are the positive, negative, and zero sequence representations of the shunt.

The sequence connections for the series unbalances, such as open phases and unbalanced series impedances, are shown in Figure 2-34. As before, these diagrams are taken from E. L. Harder's study. Here again, the diagrams inside the topmost box for each series condition represent the area under study, from point x on the diagrams left to point y on the right. The power system represented by the box is open between x and y to insert the circuits shown inside the box. Points x and y can be any distance apart, as long as there is no tap or other system connection between them. The

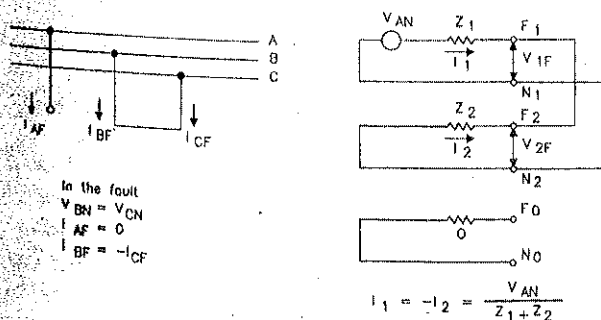


Figure 2-32 Phase-to-phase fault and its sequence network connections.

positive, negative, and zero sequence interconnections for the discontinuity shown in the top box are illustrated in the three boxes below it.

Simultaneous faults require two sets of interconnections from either Figures 2-33 or 2-34 or both. As shown in Figure 2-35, ideal or perfect transformers can be used to isolate the two restrictions. Perfect transformers are 100% efficient and have ratios of 1:1, 1:a, 1:a².

It is sometimes necessary to use two transformers as shown in Figure 2-35f. In this case, the first transformer (ratios 1: e^{-j30° , 1: e^{j30° , and 1:1) represents the wye-delta transformer, and the second transformer (ratios 1:a², 1:a, 1:1) represents the b-to-neutral fault. These can be replaced by an equivalent transformer with ratios 1: e^{-j150° , 1: e^{j150° , and 1:1.

Figure 2-35a, for example, represents an open phase-a conductor with a simultaneous fault to ground on the x side. The sequence networks are connected for the open conductor according to Figure 2-34j, with three 1:1 perfect transformers providing the restrictions required by Figure 2-33f. The manual calculations required, which involve the solution of simultaneous equations, may be quite tedious.

5.8 Sequence Network Reduction

When manual calculations are performed, the complete system networks are reduced to the single impedance values of Figures 2-29 through 2-32.

To simplify this reduction, with negligible effect on the results, the following basic assumptions are sometimes made:

- All generated voltages are equal and in phase.
- All resistance is neglected, or the reactance of machines and transformers is added directly with line impedances.
- All shunt reactances are neglected, including loads, charging, and magnetizing reactances.
- All mutual reactances are neglected, except on parallel lines.

By using these assumptions, the positive sequence network can be drawn with a single-source voltage V_{an} connected to the generator impedances by a bus.

If voltages are different, either the voltages must be retained in the network or Thevenin theorem and superposition must be used to reduce the network and calculate fault currents and voltages. Note that for the series unbalances of Figure 2-34, a difference in

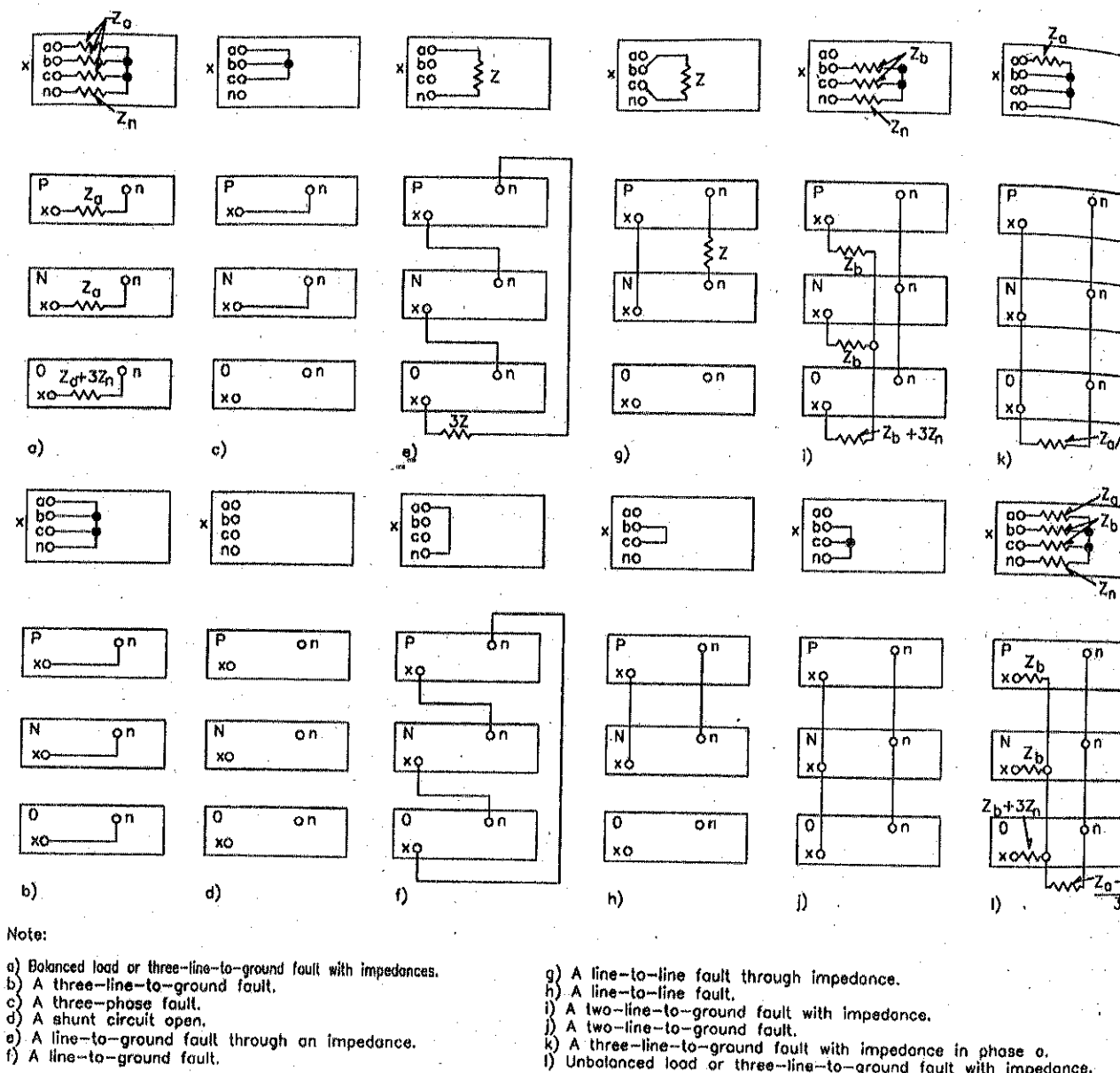


Figure 2-33 Sequence network interconnections for shunt balanced and unbalanced conditions.

voltage—either magnitude, phase angle, or both—is required for current to flow.

The single-sequence impedances Z_1 , Z_2 and Z_0 of Figures 2-29 through 2-32 will be different for each fault location because of the different network reductions. During the network reduction, the distribution of currents in the various branches should be calculated, both as a check and to determine the current flow through the relays involved in a fault. These distribution factors are calculated with the assumption that 1

per unit current flows in these single-sequence impedances at the fault or point of discontinuity.

Network reduction calculations for the system of Figure 2-24 are illustrated in Figures 2-36, 2-37, and 2-38. In these figures, X_1 , X_2 , and X_0 are the impedances between the neutral bus and the fault at bus G. I_{1R} , I_{1L} , I_{2R} , I_{2L} , I_{0R} , I_{0L} are the per unit distribution factors. I_1 , I_2 , and I_0 are all assumed to be equal to 1 per unit.

Analog or digital studies should be tailored to produce outputs that allow each branch current to

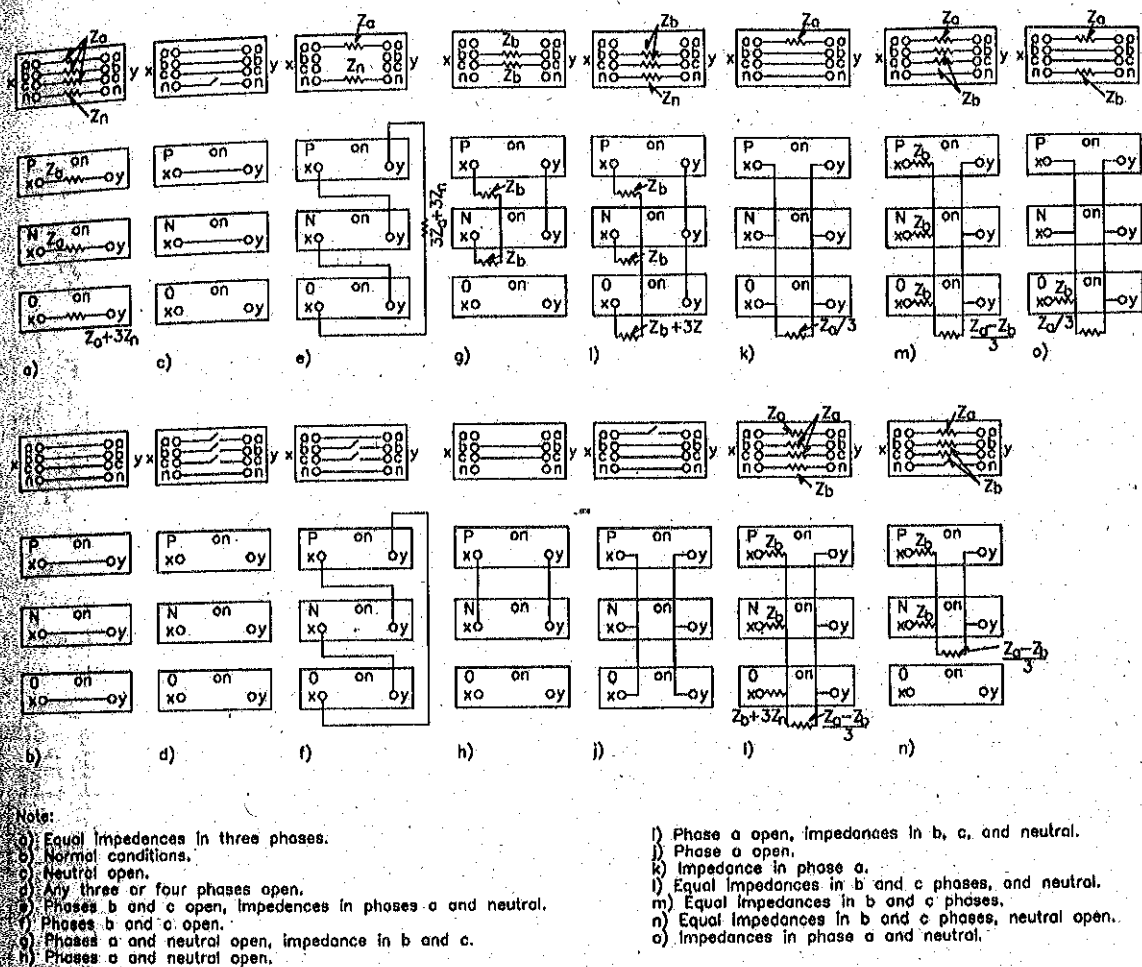


Figure 2-34 Sequence network interconnections for series balanced and unbalanced conditions.

each network to be identified. For single-phase-to-ground faults, $3I_0$ is required for relays.

When using the computer for sequence network reduction, the impedance data are input for the positive and zero sequence networks, along with bus and fault node points. The network is then solved for three-phase and single-phase-to-ground faults. Tabulated printed data are provided for phase-a fault current and three-phase fault voltages, along with the corresponding $3I_0$, $3V_0$ values for the phase-to-ground fault. I_2 and V_2 values should also be obtained for negative sequence relays.

These voltage and current values are needed for not only faults near the relay, but also those several buses or lines away. Among the operating conditions normally considered are maximum and minimum generation, selected lines out of service, and line-end faults where the adjacent breaker is open. This information allows the

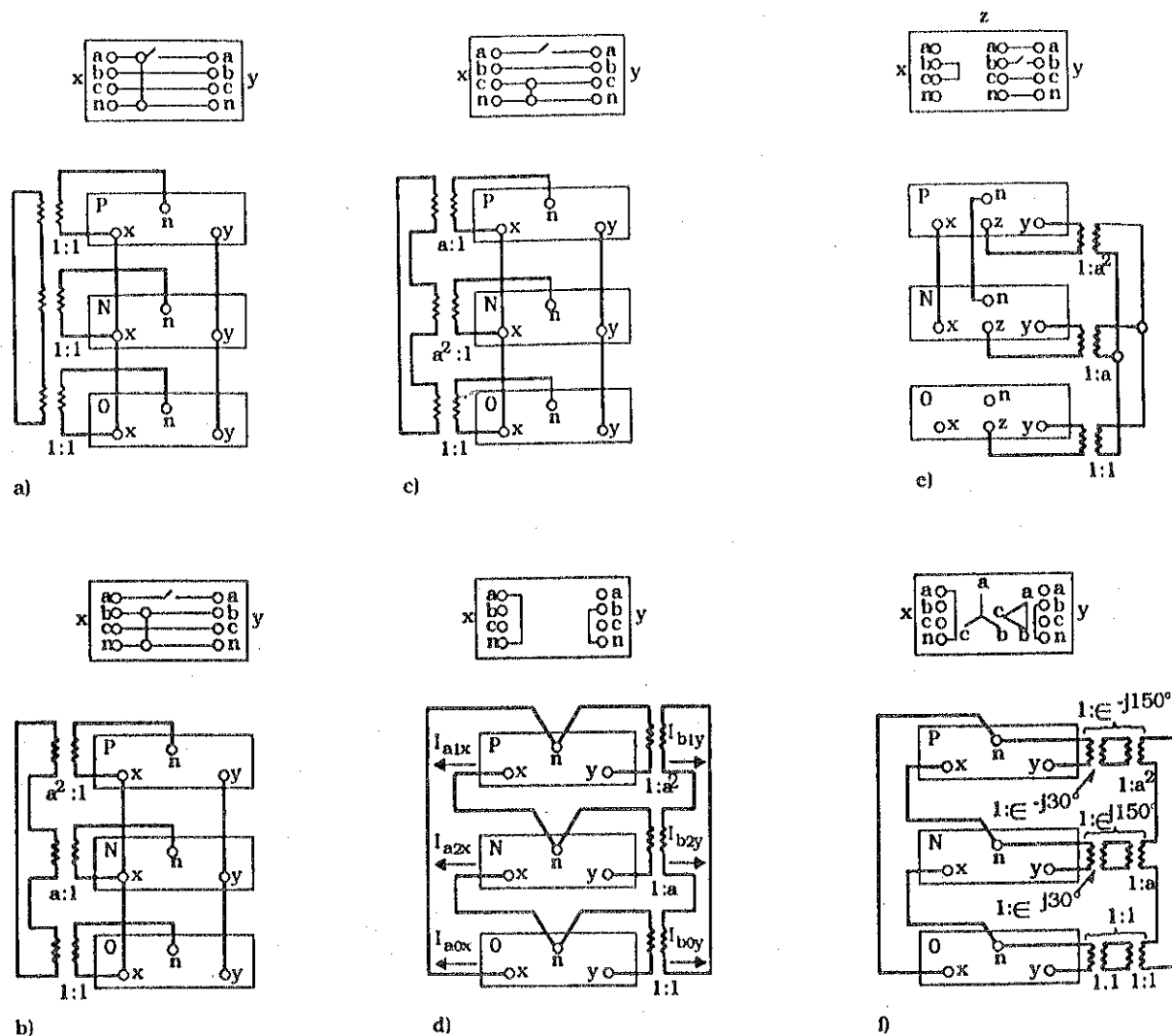
correct relay types and settings to be selected in a minimal amount of time for the entire power system.

The following steps must be performed for calculating fault currents and voltages:

Obtain a complete single-line diagram for the entire system, including generators, transformers, and transmission lines, along with the positive, negative, and zero sequence impedances for each component.

Prepare a single-line impedance diagram from the system diagram or establish the nodes in a digital study for the positive, negative, and zero sequence networks.

Reduce the impedance values of all network branches to a common base. Values may be expressed as per unit on a common kVA base or as ohms impedance on a common voltage base.



Note:

- a) One phase open and a fault to ground.
- b) Phase a open and b-phase-to-ground fault.
- c) Phase a open and c-phase-to-neutral fault.

- d) Phase a-to-ground fault at x and a b-phase-to-ground fault at y.
- e) A b-to-c fault at x, and b phase open z to y.
- f) Phase a-to-neutral fault at x, phase b-to-neutral fault on other side of star-delta transformer bank at y. x is taken as the reference point.

Figure 2-35 Representations for simultaneous unbalances.

Obtain, or have the computer obtain, the equivalent single impedance of each sequence network, current distribution factors, and equivalent source voltage for the positive-phase sequence network.

All quantities must be referred to the proper base. Interconnect the networks or utilize the computer program to represent the fault type involved, and calculate the total fault current at the fault.

Determine the current distribution and voltages as required in the system. Total fault current is

seldom of use as relays generally see a fraction of that current except for radial circuits.

5.9 Example of Fault Calculation on a Loop-Type Power System

For the typical loop system shown in Figure 2-39, the generator units at stations D, S, or E could each be combinations of several machines. Alternatively, they

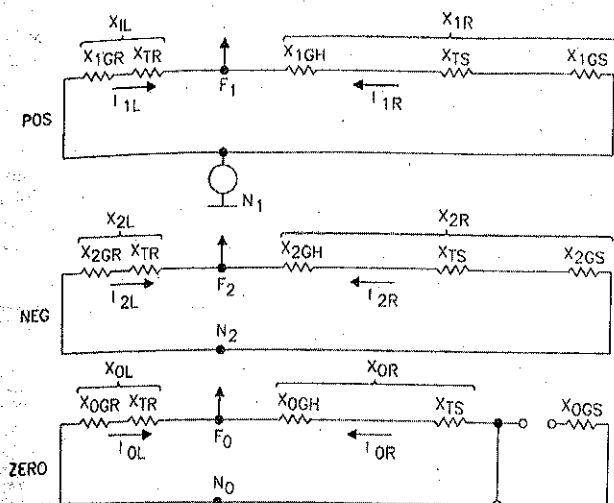


Figure 2-36 Network reduction for example system (Figure 2-24) fault at bus G.

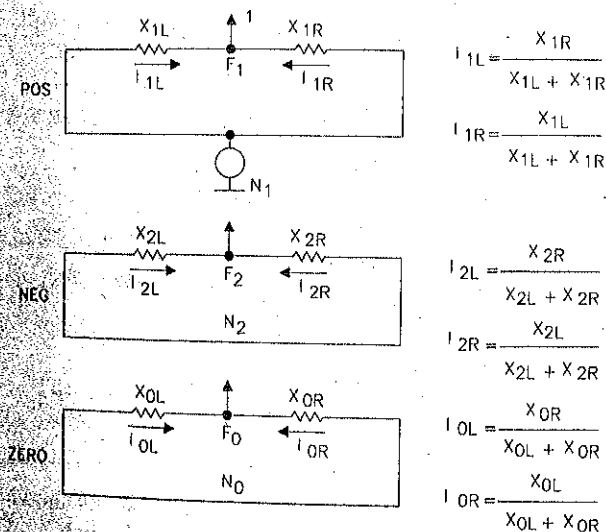


Figure 2-37 Network reduction and current distribution.

could represent the equivalent of a complex system up to the bus. All the impedances have been reduced to a common base, as indicated in the diagram. The positive sequence network for this system is shown in Figure 2-40, the zero sequence network in Figure 2-41. The negative sequence network is equal to Figure 2-40, except that V_{an} is not present.

To perform this sample calculation of a phase-to-ground fault on the bus at station D, the networks must be reduced to a single reactance value between the neutral bus and fault point. Of the several delta

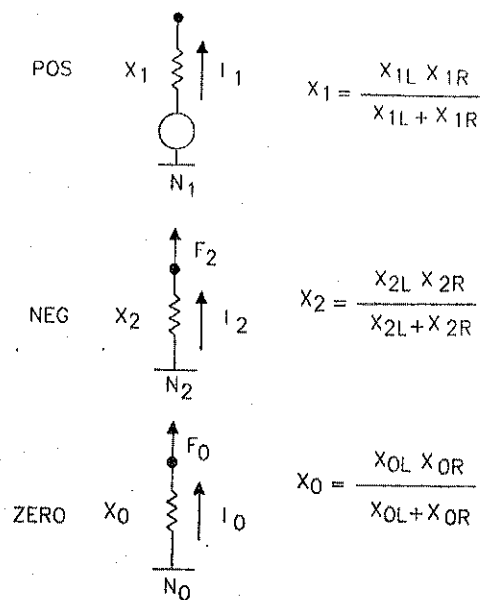


Figure 2-38 Final network reduction for fault at bus G in Figure 2-24.

loops, at least one must be converted to wye-equivalent in order to reduce the networks. After one loop is chosen (arbitrarily), the equivalent X , Y , Z branches for an equivalent wye are dotted in as shown in Figures 2-40 and 2-41.

The X , Y , Z conversion from delta to wye-equivalent is a simple process: The X branch of the wye-equivalent is the product of the two delta reactances on either side divided by the sum of the three delta impedances. The same relation applies to

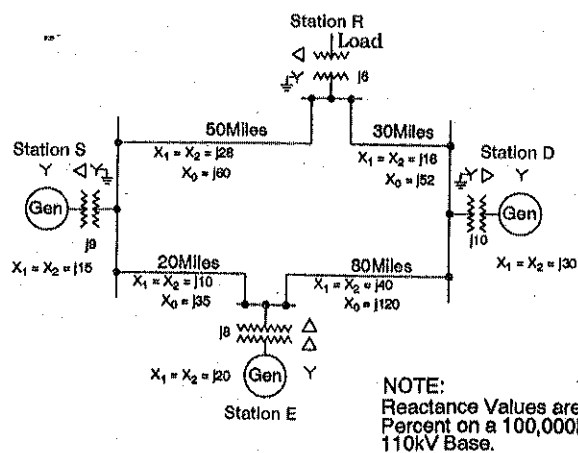


Figure 2-39 Single line diagram for a typical loop-type power system.

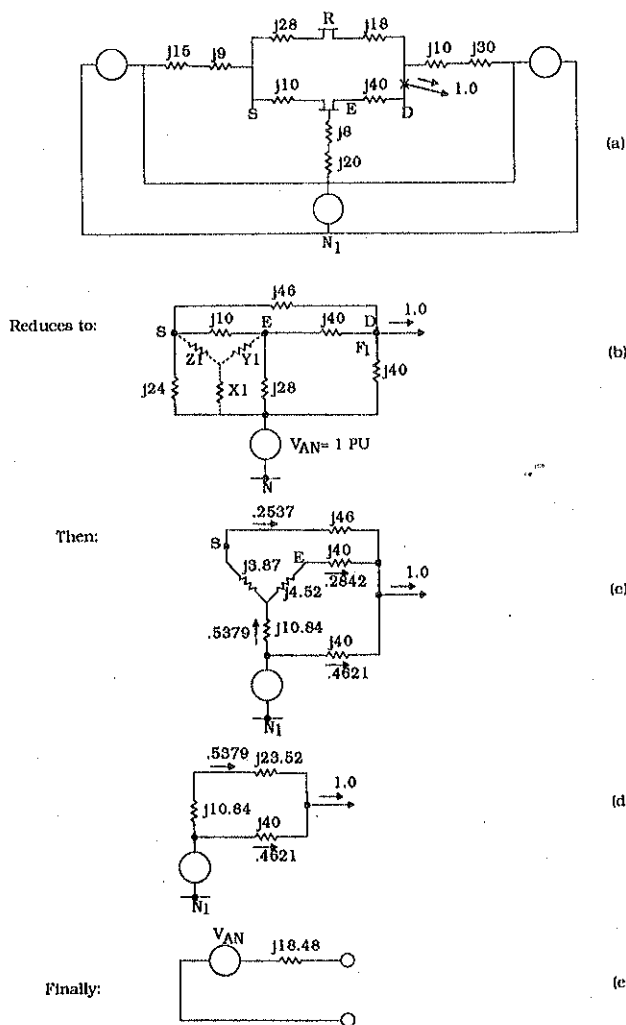


Figure 2-40 Positive sequence network reduction for the system of Figure 2-39.

the Y and Z branches. Thus, in Figures 2-40 and 2-41, the networks are reduced as follows:

Positive and negative sequence networks	Zero sequence network
$X_1 = \frac{24 \times 28}{62} = j10.84$	$X_0 = \frac{9 \times 6}{75} = j0.72$
$Y_1 = \frac{28 \times 10}{62} = j4.52$	$Y_0 = \frac{6 \times 60}{75} = j4.8$
$Z_1 = \frac{24 \times 10}{62} = j3.87$	$Z_0 = \frac{9 \times 60}{75} = j7.2$

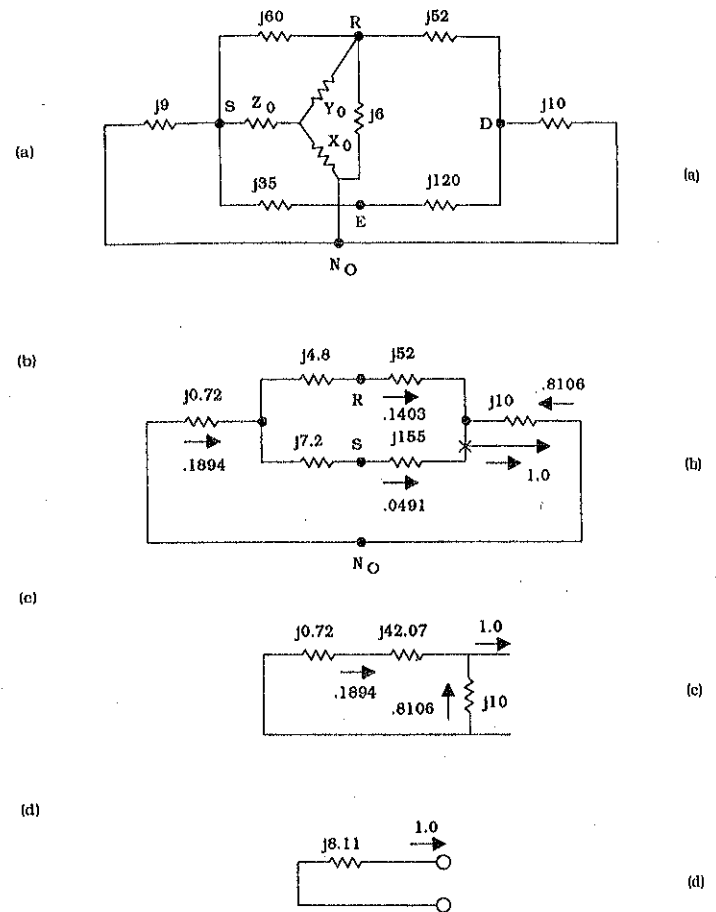


Figure 2-41 Zero sequence network reduction for the system of Figure 2-39.

The networks now reduce to the simpler forms shown in Figure 2-40c. Since the two upper branches of each network are in parallel, they can be reduced as follows:

Positive and negative sequence networks	Zero sequence network
0.4716 0.5284	0.2594 0.7406
$\frac{44.52 \times 49.87}{94.39}$	$\frac{56.8 \times 162.2}{219.0}$
= 23.52	= 42.07

These reductions are shown in Figures 2-40d and 2-41c. The remaining branches are in parallel and can also be reduced:

Positive and negative sequence networks	Zero sequence network
0.4621 0.5379	0.8106 0.1894
$X_1 = X_2 = \frac{34.36 \times 40}{74.36}$	$X_0 = \frac{42.79 \times 10}{52.79}$
$= j18.48\%$	$= j8.11\%$

The numbers written above the equations are the distribution factors for the parallel circuits. These factors are expressed as the ratio of each term in the numerator and denominator. Determining these factors provides a convenient check on the calculations, since the sum of the two fractions must be 1.

Distribution factors can be determined by working back through the reduction. The factors should be written on the diagrams as shown in Figure 2-42.

The distribution factors for the upper parallel branches of Figure 2-40c are determined as follows:

Positive sequence network

$$44.52\% \text{ branch: } 0.5284 \times 0.5379 = 0.2842$$

$$49.87\% \text{ branch: } 0.4716 \times 0.5379 = 0.2537$$

$$0.5379 \text{ (check)}$$

The distribution factors in the zero sequence network are

Zero sequence network

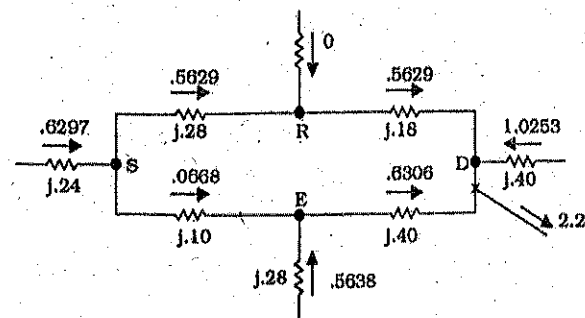
$$162.2\% \text{ branch: } 0.2594 \times 0.1894 = 0.0491$$

$$56.8\% \text{ branch: } 0.7406 \times 0.1895 = 0.1403$$

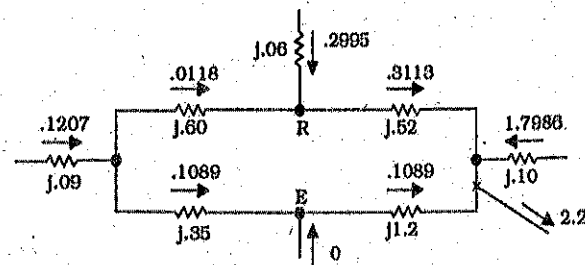
$$0.1894 \text{ (check)}$$

In turn, these distribution factors are added to the diagram, as shown in Figure 2-42b.

The delta current distribution factors are obtained from the X, Y, Z equivalents. The conversion technique is straightforward: The voltage drop across two of the wye branches is equivalent to the drop across the delta branch. Calculating from Figure 2-40c, we obtain



(a) Positive and Negative Sequence Current



(b) Zero Sequence Current

Figure 2-42 Per unit current distribution for AG fault at D.

Positive sequence network

$$\frac{0.5379 \times j10.84 + 0.2842 \times j4.52}{j28} = 0.2541$$

$$\frac{0.5379 \times j10.84 + 0.2537 \times j3.87}{j24} = 0.2838$$

$$\frac{-0.2537 + j3.87 + 0.2842 \times j4.52}{j10} = 0.0301$$

Zero sequence network

$$\frac{0.1894 \times j0.72 + 0.1403 \times j4.52}{j6} = 0.1350$$

$$\frac{0.1894 \times j0.72 + 0.0491 \times j7.20}{j24} = 0.0544$$

$$\frac{-0.0491 + j7.20 + 0.1403 \times j4.80}{j60} = 0.0053$$

Figure 2-42 shows the complete per unit distribution for the original network of Figure 2-39.

The three networks are connected in series for the phase-to-ground fault (Fig. 2-28). For convenience, the sequence currents are calculated in per unit values:

$$\begin{aligned}
 I_1 = I_2 = I_0 &= \frac{j1.0}{j0.1848 + j0.1848 + j0.0811} \\
 &= \frac{1.0}{0.4507} \\
 &= 2.22 \text{ p.u.}
 \end{aligned}$$

The 100% (1 p.u. base) current is

$$\begin{aligned}
 I_B &= \frac{\text{kVA base}}{\sqrt{3} \text{ kV}} \\
 &= \frac{100,000}{\sqrt{3} \times 110} \\
 &= 524.86 \text{ A at 110 kV} \\
 I_1 = I_2 = I_0 &= 2.22 \times 524.86 \\
 &= 1164.55 \text{ A at 110 kV}
 \end{aligned}$$

The current flowing in each branch of the networks can now be determined by multiplying the actual fault current by the distribution factor. These currents may be expressed in either per unit or ampere values. Currents in the fault are calculated for each phase as follows:

$$I_a = 3I_1 = 3I_2 = 3I_0 = 6.66 \text{ p.u.}$$

or

$$\begin{aligned}
 I_a &= 3493.66 \text{ A at 110 kV} \\
 I_b &= (a^2 I_1 + a I_2 + I_0) \\
 &= (-I_1 + I_0) = 0 \\
 I_c &= (a I_1 + a^2 I_2 + I_0) \\
 &= (-I_1 + I_0) = 0
 \end{aligned}$$

For each branch, the per unit positive, negative, and zero sequence currents can then be used to determine the individual phase currents by using Eqs. (2-23), (2-24), and (2-25). These are recorded in Figure 2-43.

Next, the sequence and phase voltages at each bus are determined as in Figure 2-28. It is convenient to calculate the voltages in per unit values. Note that the impedances listed in Figure 2-39 appear in percent, rather than ohms, and may be converted easily to per unit.

In the following calculations, the values in parentheses are volts, converted from the per unit values for the 110-kV system of Figure 2-39:

$$\begin{aligned}
 V_{\text{line-to-neutral}} &= 1.0 \text{ p.u.} \\
 &= \frac{110,000 \text{ V}}{\sqrt{3}} \\
 &= 63,508.53 \text{ V}
 \end{aligned}$$

From Figure 2-42, first the sequence and phase voltages are calculated at bus S:

$$\begin{aligned}
 V_1 &= j1.0 - 0.6297 \times j0.24 \\
 &= j1.0 - j0.1511 \\
 &= j0.8489 \text{ p.u. (53,912.39 V)} \\
 V_2 &= 0 - 0.6297 \times j0.24 \\
 &= -j0.1511 \text{ p.u. (9596.14 V)} \\
 V_0 &= 0 - 0.1207 \times j0.09 \\
 &= -j0.0109 \text{ p.u. (692.24 V)} \\
 V_{ag} &= V_1 + V_2 + V_0 \\
 &= j0.6869 \text{ p.u. (43,624.01 V)} \\
 V_{bg} &= a^2 V_1 + a V_2 + V_0 \\
 &= 0.8489 \angle -30^\circ + 0.1511 \angle +30^\circ - j0.0109 \\
 &= 0.7352 - j0.4245 + 0.1309 + j0.0756 - j0.0109 \\
 &= 0.8661 - j0.3598 \\
 &= 0.9379 \angle -22.56^\circ \text{ p.u. (59,594.65 V)} \\
 V_{cg} &= a V_1 + a^2 V_2 + V_0 \\
 &= 0.8489 \angle 210^\circ + 0.1511 \angle 150^\circ - j0.0109 \\
 &= -0.7352 - j0.4245 - 0.1309 + j0.0756 - j0.0109 \\
 &= -0.8661 - j0.3598 \\
 &= 0.9379 \angle 202.56^\circ \text{ p.u. (59,564.65 V)}
 \end{aligned}$$

Next, the sequence and phase voltages are calculated at bus D, the fault location:

$$\begin{aligned}
 V_1 &= j1.0 - 1.0253 \times j0.40 \\
 &= j1.0 - j0.4101 \\
 &= j0.5899 \text{ p.u. (37,463.68 V)} \\
 V_2 &= 0 - 1.0253 \times j0.40 \\
 &= -j0.4101 \text{ p.u. (26,044.85 V)} \\
 V_0 &= 0 - 1.7986 \times j0.1 \\
 &= -j0.1798 \text{ p.u. (11,418.83 V)} \\
 V_{ag} &= 0 \\
 V_{bg} &= 0.5899 \angle -30^\circ + 0.4101 \angle 30^\circ - j0.1798 \\
 &= 0.5109 - j0.2950 + 0.3552 + j0.2051 - j0.1798 \\
 &= 0.8661 - j0.2697 \\
 &= 0.9071 \angle -17.30^\circ \text{ p.u. (57,608.59 V)} \\
 V_{cg} &= 0.5899 \angle 210^\circ + 0.4101 \angle 150^\circ - j0.1798 \\
 &= 0.5109 - j0.2950 - 0.3552 + j0.2051 - j0.1798 \\
 &= -0.8661 - j0.2697 \\
 &= 0.9071 \angle 197.30^\circ \text{ p.u. (57,608.59 V)}
 \end{aligned}$$

Similarly, the sequence and phase voltages can be

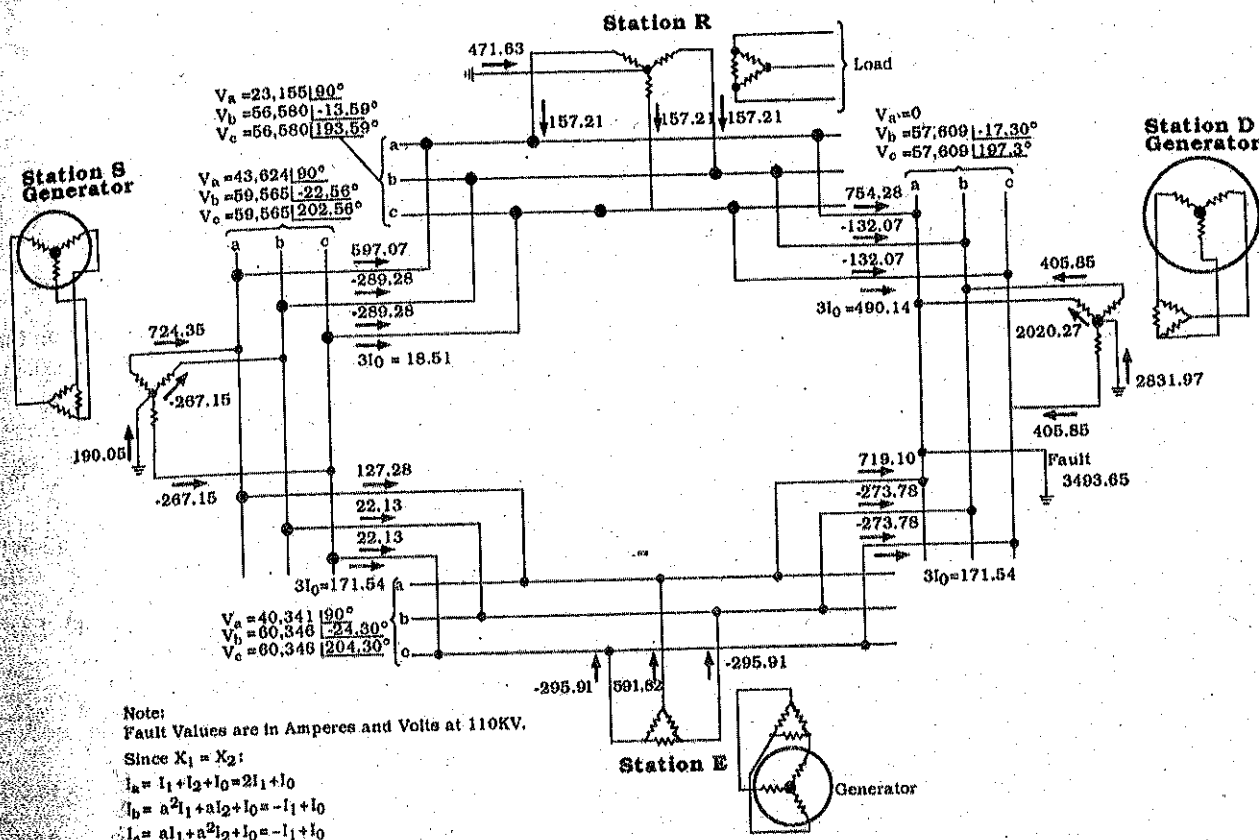


Figure 2-43 Current and voltage distribution for a single phase-to-ground fault at bus "D" of the system of Figure 2-37.

calculated at bus E:

$$V_{a0} = j0.6352 \text{ p.u. (40,340.62 V)}$$

$$V_{b0} = 0.9502 \angle -24.30^\circ \text{ p.u. (60,345.80 V)}$$

$$V_{c0} = 0.9502 \angle 204.30^\circ \text{ p.u. (60,345.80 V)}$$

Finally, the voltages are calculated at bus R:

$$V_{a0} = j0.3646 \text{ p.u. (23,155.21 V)}$$

$$V_{b0} = 0.8909 \angle 13.59^\circ \text{ p.u. (56,579.75 V)}$$

$$V_{c0} = 0.8909 \angle 193.59^\circ \text{ p.u. (56,579.75 V)}$$

The sequence voltages calculated above, as shown in Figure 2-43, complete the analysis of the single-phase-to-ground fault at bus D in the system of Figure 2-39. All the distributed current and voltage values for the system are displayed in Figure 2-43.

5.10 Phase Shifts Through Transformer Banks

In these fault calculations, the phase shifts through the wye-delta transformer banks were not considered. In this example, only a 110-kV system fault, with its currents and voltages, was involved. The effect of the phase shift through the transformer banks could not, however, have been neglected if currents and voltages were required for the opposite side of the power transformers.

If the transformer bank is wye-connected on the high-voltage side, as shown in Figure 2-44, the general equations for one phase are

$$I_A = n(I_a - I_c) \quad (2-30)$$

$$V_{an} = n(V_{An} - V_{Bn}) = nV_{AB} \quad (2-31)$$

The lowercase subscripts represent high-side quantities and the capital letter subscripts low-side quantities. In

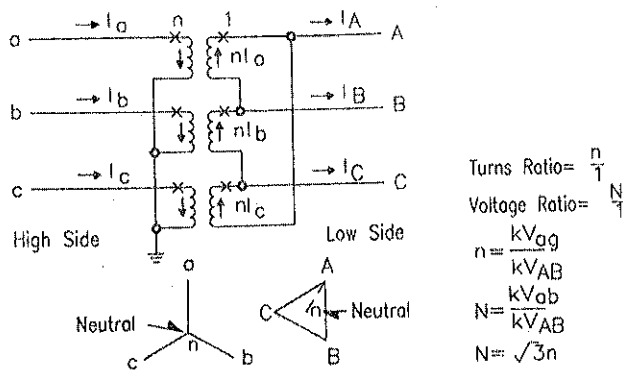


Figure 2-44 Connections and phasors for an ANSI standard power transformer bank with the wye connection on the high side (V_{ab} leads V_{AN} by 30°).

the balanced or symmetrical transformer bank, the sequences are independent.

Consequently, positive sequence only is first applied to Eqs. (2-30) and (2-31):

$$\begin{aligned} I_{A1} &= n(I_{a1} - I_{c1}) \\ &= n(I_{a1} - aI_{a1}) \\ &= n(1 - a)I_{a1} \\ &= n\sqrt{3}I_{a1} \angle -30^\circ \\ I_{A1} &= NI_{A1} \angle -30^\circ \end{aligned} \quad (2-32)$$

$$\begin{aligned} I_{a1} &= \frac{I_{A1}}{N} \angle 30^\circ \\ V_{a1} &= n(V_{A1} - V_{B1}) \\ &= n(V_{A1} - a^2V_{A1}) \\ &= n(1 - a^2)V_{A1} \end{aligned} \quad (2-33)$$

$$\begin{aligned} V_{a1} &= n\sqrt{3}V_{A1} \angle 30^\circ \\ V_{a1} &= NV_{A1} \angle 30^\circ \end{aligned} \quad (2-34)$$

$$V_{A1} = \frac{V_{a1}}{N} \angle -30^\circ \quad (2-35)$$

Next, only negative sequence quantities are applied to Eqs. (2-30) and (2-31):

$$\begin{aligned} I_{A2} &= n(I_{a2} - I_{c2}) \\ &= n(I_{a2} - a^2I_{a2}) \\ &= n(1 - a^2)I_{a2} \\ &= n\sqrt{3}I_{a2} \angle 30^\circ \\ I_{A2} &= NI_{A2} \angle 30^\circ \end{aligned} \quad (2-36)$$

$$I_{a2} = \frac{I_{A2}}{N} \angle -30^\circ \quad (2-37)$$

$$\begin{aligned} V_{a2} &= n(V_{A2} - V_{B2}) \\ &= n(V_{A2} - aV_{A2}) \\ &= n(1 - a)V_{A2} \\ &= n\sqrt{3}V_{A2} \angle -30^\circ \\ V_{a2} &= NV_{A2} \angle -30^\circ \\ V_{A2} &= \frac{V_{a2}}{N} \angle 30^\circ \end{aligned}$$

If a power transformer bank is connected *delta* on the *high-voltage* side, as shown in Figure 2-45, the general equations for one phase are

$$I_a = \frac{1}{n}(I_A - I_B) \quad (2-38)$$

$$V_A = \frac{1}{n}(V_a - V_c) \quad (2-39)$$

Applying only positive sequence quantities to Eqs. (2-38) and (2-39),

$$\begin{aligned} I_{a1} &= \frac{1}{n}(I_{A1} - I_{B1}) \\ &= \frac{1}{n}(I_{A1} - a^2I_{A1}) \\ &= \frac{1}{n}(1 - a^2)I_{A1} \\ &= \frac{\sqrt{3}I_{A1}}{n} \angle 30^\circ \\ I_{a1} &= \frac{I_{A1}}{N} \angle 30^\circ \end{aligned} \quad (2-40)$$

$$I_{A1} = NI_{a1} \angle -30^\circ \quad (2-41)$$

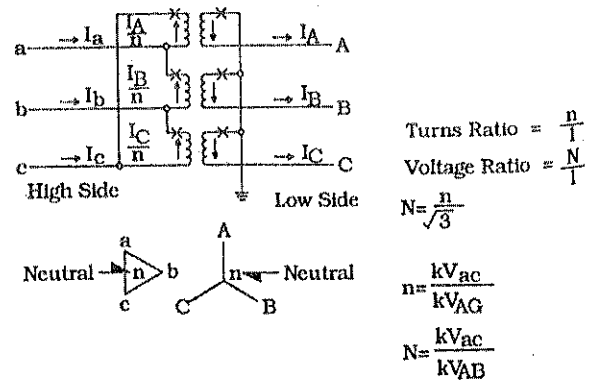


Figure 2-45 Connections and phasors for an ANSI standard power transformer bank with the delta connection on the high side (V_{ab} leads V_{AN} by 30°).

$$\begin{aligned}
 V_{A1} &= \frac{1}{n}(V_{a1} - V_{c1}) \\
 &= \frac{1}{n}(V_{a1} - aV_{a1}) \\
 &= \frac{1}{n}(1 - a)V_{a1} \\
 &= \frac{\sqrt{3}V_{a1}}{n} \angle -30^\circ \\
 V_{A1} &= \frac{V_{a1}}{N} \angle -30^\circ \quad (2-42) \\
 V_{a1} &= NV_{A1} \angle 30^\circ \quad (2-43)
 \end{aligned}$$

Then, applying only negative sequence quantities to Eqs. (2-38) and (2-39), we obtain

$$\begin{aligned}
 I_{a2} &= \frac{1}{n}(I_{A2} - I_{B2}) \\
 &= \frac{1}{n}(I_{A2} - aI_{A2}) \\
 &= \frac{1}{n}(1 - a)I_{A2} \\
 &= \frac{\sqrt{3}I_{A2}}{n} \angle -30^\circ \\
 I_{a2} &= \frac{I_{A2}}{N} \angle -30^\circ \quad (2-44)
 \end{aligned}$$

$$I_{A2} = NI_{a2} \angle 30^\circ \quad (2-45)$$

$$\begin{aligned}
 V_{A2} &= \frac{1}{n}(V_{a2} - V_{c2}) \\
 &= \frac{1}{n}(V_{a2} - a^2V_{a2}) \\
 &= \frac{1}{n}(1 - a^2)V_{a2} \\
 &= \frac{\sqrt{3}V_{a2}}{n} \angle 30^\circ \\
 V_{A2} &= \frac{V_{a2}}{N} \angle 30^\circ \quad (2-46) \\
 V_{a2} &= NV_{A2} \angle -30^\circ \quad (2-47)
 \end{aligned}$$

If the bank is connected according to ANSI standards, the formulas are the same and not dependent on whether the wye or the delta is on the high side. In either case, the positive sequence quantities are shifted 30° in one direction, while the negative sequence quantities are shifted 30° in the opposite direction. These relations for ANSI standard connections are summarized in Table 2-2. Zero sequence quantities are not affected by phase shift. These either pass directly through the bank or, more commonly, are blocked by the connections. Thus, in a wye-delta bank, zero sequence current and voltage on one side cannot pass through the bank to the other side.

Table 2-2 Phase Shift Relations for Power Transformer Banks

High side in terms of low side ^a	Low side in terms of high side ^a
$I_{a1} = \frac{I_{A1}}{N} \angle 30^\circ$	$I_{A1} = NI_{a1} \angle -30^\circ$
$V_{a1} = NV_{A1} \angle 30^\circ$	$V_{A1} = \frac{V_{a1}}{N} \angle -30^\circ$
$I_{a2} = \frac{I_{A2}}{N} \angle -30^\circ$	$I_{A2} = NI_{a2} \angle 30^\circ$
$V_{a2} = NV_{A2} \angle -30^\circ$	$V_{A2} = \frac{V_{a2}}{N} \angle 30^\circ$

^aThe lowercase subscripts represent high-side quantities, and the capital letter subscripts low-side quantities.

5.11 Fault Evaluations

The sample calculation of a phase-to-ground fault on a loop system (see Sec. 5.9) was made at no load; that is, before the fault all currents throughout the system were zero.

With a ground fault, current flows in not only the faulted phase "a," but also the unfaulted "b" and "c" phases. The positive and zero sequence distribution factors on any loop system will be different. Consequently, the positive, negative, and zero sequence currents will not add up to zero in the unfaulted phases. On a radial system (one with a source at one end only for both the positive and zero sequences), the three network distribution factors will all be equal to 1. For a phase-a-to-ground fault on these circuits, I_b equals I_c , which equals 0.

In practice, only $3I_0$ and related $3V_0$, V_2 , and I_2 values would be recorded for a phase-to-ground fault. The phase currents and voltages shown in Figure 2-43 were provided for academic purposes.

The reason for showing $3I_0$, rather than the faulted phase current, can be seen from Figure 2-43. In most circuits, there is a significant difference between the I_a and $3I_0$ currents in any loop network. In a radial system, however, I_a is equal to $3I_0$ and ground relays operate on $3I_0$.

On phase-to-ground faults, the phase relays will receive current and may start to operate. Coordination between ground and phase relays is usually not necessary. The principal reason there are so few coordination problems is that phase relays must be set above load (5 A secondary), whereas ground relays are conventionally set at 0.5 to 1.0 A secondary. Since the ground relays are more sensitive, they will generally

out the system. The same general conditions also apply to phase-to-ground faults, except that since V_a is zero, V_2 and V_0 are negative.

In summary, the positive sequence voltage is always highest at the generators or sources and lowest at a fault. In contrast, negative and zero sequence voltages are always highest at the fault and lowest at the "sources."

The phasor diagrams of Figure 2-20 illustrate the same phenomena, from a different viewpoint. In a three-phase fault, the voltages collapse symmetrically, except inside the generator. The three currents have a large symmetrical increase and lagging shift of angle.

Other phase faults shown in Figure 2-20 are characterized by the relative collapse of two of the phase-to-neutral voltages, compared to the relatively

normal third phase-to-neutral voltage. Two of the phase currents have a large lagging increase.

For a single-phase-to-ground fault, on the other hand, one phase-to-neutral voltage is collapsed relative to the other two phases. Similarly, one phase current has a large value and lags the line-to-ground voltage.

With wye-delta transformers between the fault and measurement point, the positive sequence quantities shift 30° in one direction, and the negative sequence quantities shift 30° in the opposite direction. As a result, a phase-to-ground fault on the wye side of a bank has the appearance of a phase-to-phase fault on the delta side.

Figures 2-47 and 2-48 offer a final look at sequence currents and voltages for faults. Note that the positive sequence currents and voltages, shown in the left-hand columns, have approximately the same phase relations

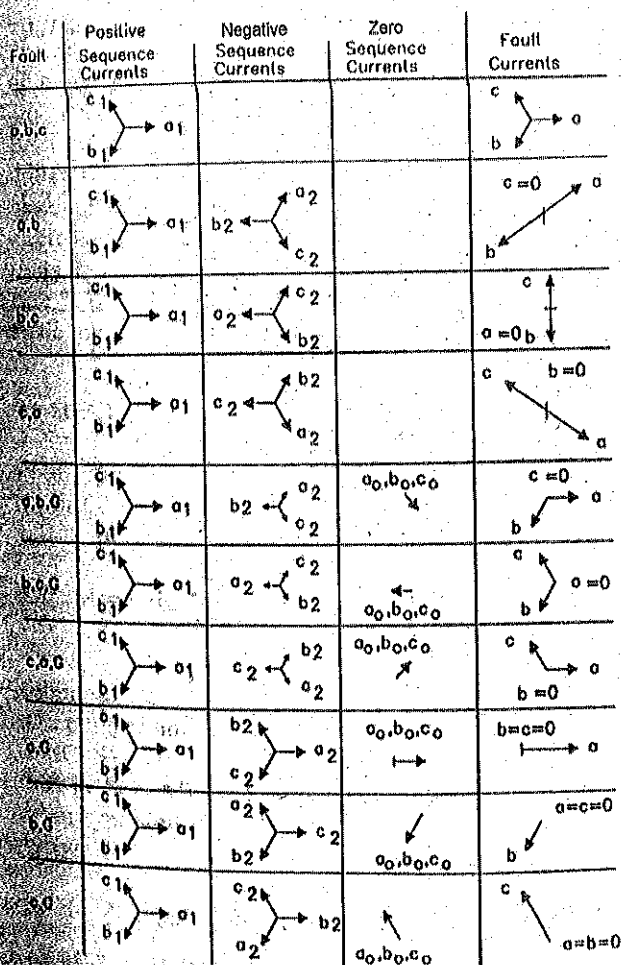


Figure 2-47 Sequence currents for various faults. Assumes $Z_1 = Z_2 = Z_0$.

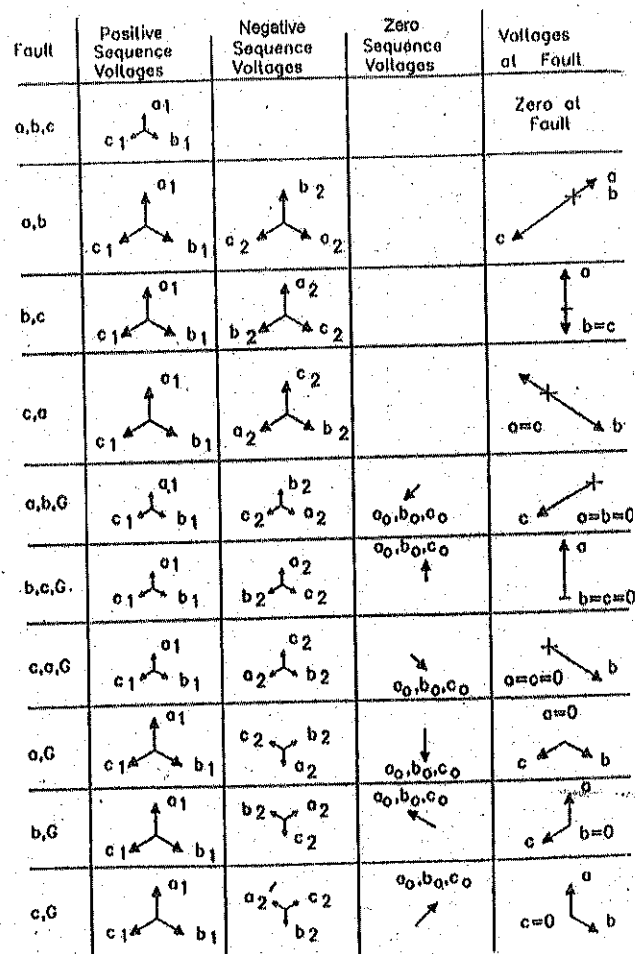


Figure 2-48 Sequence voltages for various faults. Assumes $Z_1 = Z_2 = Z_0$.

for all types of faults. At the fault are various nonsymmetrical currents and voltages, as shown in the far right-hand column. The negative and, sometimes, the zero sequence quantities provide the transition between the symmetrical left-hand column and nonsymmetrical right-hand column. These quantities rotate and change to produce the nonsymmetrical, or unbalanced, quantity when added to the positive sequence.

These phasors can be constructed easily by remembering which fault quantity should be minimum or maximum. In a phase c-a fault, for example, phase-b current will be small. Thus, I_{b2} will tend to be opposite I_{b1} . Since phase-b voltage will be relatively uncollapsed, V_{b1} and V_{b2} will tend to be in phase. After one sequence phasor is established, the others can be derived from Eq. (2-12) and Figure 2-21.

6 SYMMETRICAL COMPONENTS AND RELAYING

Since ground relays operate from zero sequence quantities, all ground relay types use symmetrical components. A number of other protective relays use combinations of the sequence quantities, as summarized in Table 2-3.

A zero sequence ($3I_0$) current filter is obtained by connecting three current transformers in parallel. A zero sequence ($3V_0$) voltage filter is provided by the wye-grounded-broken-delta connection for a voltage transformer or an auxiliary. Positive and negative sequence current and voltage filters are described in Chapter 3.

Table 2-3 Protective Relays Using Symmetrical Component Quantities for Their Operation

Device no.	Application	Sequence quantities used
50N, 51N	Ground overcurrent	I_0
59N	Ground voltage	V_0
67N	Ground directional overcurrent	I_0 with I_0 or $V_0 I_0$ or $V_2 I_2$
32N	Ground product overcurrent	I_0^2 or I_0, V_0
21N	Ground distance	I_0, V_0 $I_0, V_0, V_1 + V_2$
87	Phase and ground pilot	$K_1 I_1 + K_2 I_2 + K_0 I_0$
46	Phase unbalance voltage	V_2
46	Phase unbalance current	I_2
	Blown fuse detection	V_0 and not I_0