

Unit-V Protective Devices & Co-ordination

Objectives of distribution system protection

The main objectives of distribution system protection are (1) to minimize the duration of a fault and (2) to minimize the number of consumers affected by the fault.

The secondary objectives of distribution system protection are (1) to eliminate safety hazards as fast as possible, (2) to limit service outages to the smallest possible segment of the system, (3) to protect the consumers' apparatus, (4) to protect the system from unnecessary service interruptions and disturbances, and (5) to disconnect faulted lines, transformers, or other apparatus.

Overhead distribution systems are subject to two types of electrical faults, namely, transient (or temporary) faults and permanent faults.

Depending on the nature of the system involved, approximately 75 to 90 percent of the total number of faults are temporary in nature [2]. Usually, *transient faults* occur when phase conductors electrically contact other phase conductors or ground momentarily due to trees, birds or other animals, high winds, lightning, flashovers, etc. Transient faults are cleared by a service interruption of sufficient length of time to extinguish the power arc. Here, the fault duration is minimized and unnecessary fuse blowing is prevented by using instantaneous or high-speed tripping and automatic reclosing of a relay-controlled power circuit breaker or the automatic tripping and reclosing of a circuit recloser. The breaker speed, relay settings, and recloser characteristics are selected in a manner to interrupt the fault current before a series fuse (i.e., the nearest source-side fuse) is blown, which would cause the transient fault to become permanent.

Permanent faults are those which require repairs by a repair crew in terms of (1) replacing burned-down conductors, blown fuses, or any other damaged apparatus, (2) removing tree limbs from the line, and (3) manually reclosing a circuit breaker or recloser to restore service. Here, the number of customers affected by a fault is minimized by properly selecting and locating the protective apparatus on the feeder main, at the tap point of each branch, and at critical locations on branch circuits. Permanent faults on overhead distribution systems are usually sectionalized by means of fuses. For example, permanent faults are cleared by fuse cutouts installed at submain and lateral tap points. This practice limits the number of customers affected by a permanent fault and helps locate the fault point by reducing the area involved. In general, the only part of the distribution circuit not protected by fuses is the main feeder and feeder tie line. The substation is protected from faults on feeder and tie lines by circuit breakers and/or reclosers located inside the substation.

On the other hand, most of the faults are permanent on an underground distribution system, thereby requiring a different protection approach. Even though the number of faults occurring on an underground system is relatively much less than that on the overhead systems, they are usually permanent and can affect a larger number of customers. Faults occurring in the URD systems are cleared by the blowing of the nearest sectionalizing fuse or fuses. Faults occurring on the feeder are cleared by tripping and lockout of the feeder breaker.

Figure 10-18 shows a protection scheme of a distribution feeder circuit. As shown in the figure, each distribution transformer has a fuse which is located either externally, i.e., in a fuse cutout next to the transformer, or internally, i.e., inside the transformer tank as is the case for a completely self-protected (CSP) transformer.

As shown in Fig. 10-18, it is a common practice to install a fuse at the head of each lateral (or branch). The fuse must carry the expected load, and it must coordinate with load-side transformer fuses or other devices. It is customary to select the rating of each lateral fuse adequately large so that it is protected from damage by the transformer fuses on the lateral. Furthermore, the lateral fuse is

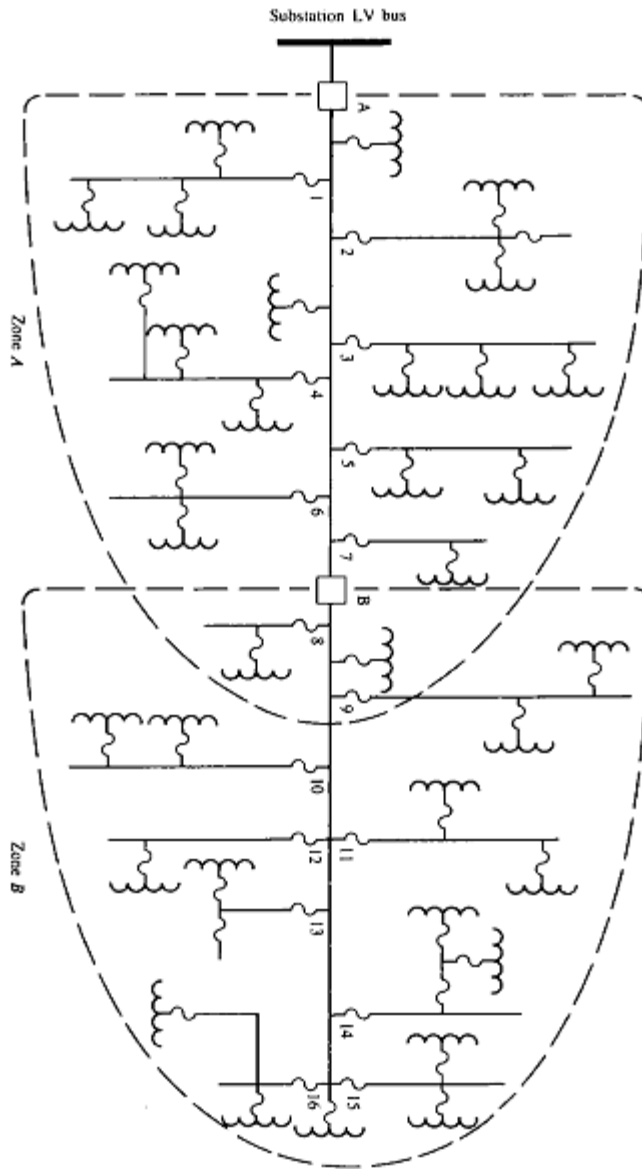


Figure 10-18 A distribution feeder protection scheme.

usually expected to clear faults occurring at the ends of the lateral. If the fuse does not clear the faults, then one or more additional fuses may be installed on the lateral.

As shown in the figure, a recloser, or circuit breaker *A* with reclosing relays, is located at the substation to provide a backup protection. It clears the temporary faults in its protective zone. At the limit of the protective zone, the minimum available fault current, determined by calculation, is equal to the smallest value of current (called *minimum pickup current*) which will trigger the recloser, or circuit breaker, to operate. However, a fault beyond the limit of this protection zone may not trigger the recloser, or circuit breaker, to operate. Therefore this situation may require that a second recloser, with a lower pickup current rating be installed at location *B*, as shown in the figure. The major factors which play a role in making a decision to choose a recloser over a circuit breaker are (1) the costs of equipment and installation and (2) the reliability. Usually, a comparable recloser can be installed for approximately one-third less than a relay-controlled oil circuit breaker. Even though a circuit breaker provides a greater interrupting capability, this excess capacity is not always required. Also, some distribution engineers prefer reclosers because of their flexibility, due to the many extras that are available with reclosers but not with circuit breakers.

OBJECTIVES OF DISTRIBUTION SYSTEM PROTECTION

- Minimize the fault duration
- Minimize the number of consumer effected by the fault
- Eliminates the safety hazards as fast as possible
- minimize the service failure to the smallest possible branch in the distribution system
- To discriminate between over loading, short circuit and very temporary fauly.

PROTECTION SETTINGS: INTRODUCTION

- A power system is composed of a number of sections (equipment) such as generator, transformer, bus bar and transmission line.
- These sections are protected by protective relaying systems comprising of instrument transformers (ITs), protective relays, circuit breakers (CBs) and communication equipment.
- In case of a fault occurring on a section, its associated protective relays should detect the fault and issue trip signals to open their associated CBs to isolate the faulted section from the rest of the power system, in order to avoid further damage to the power system.

COORDINATION OF PROTECTIVE DEVICES

The process of selecting overcurrent protection devices with certain time–current settings and their appropriate arrangement in series along a distribution circuit in order to clear faults from the lines and apparatus according to a preset sequence of operation is known as *coordination*. When two protective apparatus installed in series have characteristics which provide a specified operating sequence, they are said to be *coordinated* or *selective*. Here, the device which is set to operate first to isolate the fault (or interrupt the fault current) is defined as the *protecting device*. It is usually the apparatus closer to the fault. The apparatus which furnishes backup protection but operates only when the protecting device fails to operate to clear the fault is defined as the *protected device*. Properly coordinated protective devices help (1) to eliminate service interruptions due to temporary faults, (2) to minimize the extent of faults in order to reduce the number of customers affected, and (3) to locate the fault, thereby minimizing the duration of service outages.

Since coordination is primarily the selection of protective devices and their settings to develop zones that provide temporary fault protection and limit an outage area to the minimum size possible if a fault is permanent, to coordinate protective devices, in general, the distribution engineer must assemble the following data:

1. Scaled feeder-circuit configuration diagram (map).
2. Locations of the existing protective devices
3. Time-current characteristics (TCC) curves of protective devices
4. Load currents (under normal and emergency conditions)
5. Fault currents or megavoltamperes (under minimum and maximum generation conditions) at every point where a protective apparatus might be located

Usually, these data are not readily available and therefore must be brought together from numerous sources. For example, the TCCs of protective devices are gathered from the manufacturers, the values of the load currents and fault currents are usually taken from computer runs called the *load flow studies* and *fault studies*, respectively.

In general, manual techniques for coordination are still employed by most utilities, especially where distribution systems are relatively small or simple and therefore only a small number of protective devices are used in series. However, some utilities have established standard procedures, tables, or other means to aid the distribution engineer and field personnel in coordination studies. Some utilities employ semiautomated, computerized coordination programs developed either by the protective device manufacturers or by the company's own staff.

A general coordination procedure, regardless of whether it is manual or computerized, can be summarized as [3, 4]:

1. Gather the required and aforementioned data.
2. Select initial locations on the given distribution circuit for protective (i.e., sectionalizing) devices.
3. Determine the maximum and minimum values of fault currents (specifically for three-phase, line-to-line, and line-to-ground faults) at each of the selected locations and at the end of the feeder main, branches, and laterals.
4. Pick out the necessary protective devices located at the distribution substation in order to protect the substation transformer properly from any fault that might occur in the distribution circuit.
5. Coordinate the protective devices from the substation outward or from the end of the distribution circuit back to the substation.
6. Reconsider and change, if necessary, the initial locations of the protective devices.
7. Reexamine the chosen protective devices for current-carrying capacity, interrupting capacity, and minimum pickup rating.
8. Draw a composite TCC curve showing the coordination of all protective devices employed, with curves drawn for a common base voltage (this step is optional).
9. Draw a circuit diagram which shows the circuit configuration, the maximum and minimum values of the fault currents, and the ratings of the protective devices employed, etc.

There are also some additional factors that need to be considered in the coordination of protective devices (i.e., fuses, reclosers, and relays) such as (1) the differences in the TCCs and related manufacturing tolerances, (2) preloading conditions of the apparatus, (3) ambient temperature, and (4) effect of reclosing cycles. These factors affect the adequate margin for selectivity under adverse conditions.

Types of common faults

* overhead distribution systems are subject to two types of electrical faults, namely, transient (or temporary) faults and permanent faults. depending on the nature of the system involved, approximately 75-90% of the total number of faults are temporary in nature. permanent faults are those which require repair by a repair crew in terms of replacing or removing the apparatus or wires.

* most of the faults are permanent on an underground distribution system, thereby requiring a different protection approach. Although the number of faults occurring on an underground system is relatively small comparatively overhead systems.

Procedure for fault calculations

Fault current calculations

There are four possible fault types that might occur in a given distribution system:

1. Three-phase grounded or ungrounded fault (3 ϕ).
2. Phase-to-phase (or line-to-line) ungrounded fault (L-L).
3. Phase-to-phase (or double line-to-ground) grounded fault (2LG).
4. Phase-to-ground (or single line-to-ground) fault (SLG).

The first type of fault can take place only on three-phase circuits, and the second and third on three-phase or two-phase (i.e., vee or open-delta) circuits. However, even on these circuits usually only SLG faults will take place due to the multigrounded construction. The relative numbers of the occurrences of different fault types depend upon various factors, e.g., circuit configuration, the height of ground wires, voltage class, method of grounding, relative insulation levels to ground and between phases, speed of fault clearing, number of stormy days per year, and atmospheric conditions. Based on Ref. 6, the probabilities of prevalence of the various types of faults are ‡

SLG faults =	0.70
L-L faults =	0.15
2LG faults =	0.10
3 ϕ faults =	0.05
—	
Total =	1.00

The actual fault current is usually less than the bolted three-phase value. (Here, the term *bolted* means that there is no fault impedance (or fault resistance) resulting from fault arc, that is, $Z_f = 0$.) However, the SLG fault often produces a greater fault current than the 3 ϕ fault especially (1) where the associated generators

have solidly grounded neutrals or low-impedance neutral impedances, and (2) on the wye-grounded side of delta-wye grounded transformer banks [7]. Therefore, for a given system, each fault at each fault location must be calculated based on actual circuit conditions. When this is done, according to Anderson [8], it is usually the case that the SLG fault is the most severe, with the 3 ϕ , 2LG, and L-L following in that order. In general, since the 2LG fault value is always somewhere in between the maximum and minimum, it is usually neglected in the distribution system fault calculations [3].

In general, the maximum and minimum fault currents are both calculated for a given distribution system. The maximum fault current is calculated based on the following assumptions:

1. All generators are connected, i.e., in service.
2. The fault is a bolted one; i.e., the fault impedance is zero.
3. The load is maximum, i.e., on-peak load.

whereas the minimum current is calculated based on the following assumptions:

1. The number of generators connected is minimum.
2. The fault is not a bolted one, i.e., the fault impedance is not zero but has a value somewhere between 30 and 40 Ω .
3. The load is minimum, i.e., off-peak load.

On 4-kV systems, the value of the minimum fault current available may be taken as 60 to 70 percent of the calculated maximum line-to-ground fault current.

In general, these fault currents are calculated for each sectionalizing point, including the substation, and for the ends of the longest sections. The calculated maximum fault-current values are used in determining the required interrupting capacities (i.e., ratings) of the fuses, circuit breakers, or other fault-clearing apparatus; the calculated minimum fault-current values are used in coordinating the operations of fuses, reclosers, and relays.

To calculate the fault currents one has to determine the zero-, positive-, and negative-sequence Thevenin impedances of the system† at the high-voltage side of the distribution substation transformer looking into the system. These impedances are usually readily available from transmission system fault studies. Therefore, for any given fault on a radial distribution circuit, one can simply add the appropriate impedances to the Thevenin impedances as the fault is moved away from the substation along the circuit. The most common types of distribution substation transformer connections are (1) delta-wye solidly grounded and (2) delta-delta.

10-11-1 Three-Phase Faults

Since this fault type is completely balanced, there are no zero- or negative-sequence currents. Therefore, when there is no fault impedance,

$$\begin{aligned} I_{f,3\phi} &= I_{f,a} = I_{f,b} = I_{f,c} \\ &= \left| \frac{\bar{V}_{L-N}}{\bar{Z}_1} \right| \quad \text{A} \end{aligned} \quad (10-4)$$

and when there is a fault impedance,

$$I_{f,3\phi} = \left| \frac{\bar{V}_{L-N}}{\bar{Z}_1 + \bar{Z}_f} \right| \quad \text{A} \quad (10-5)$$

where $I_{f,3\phi}$ = three-phase fault current, A
 \bar{V}_{L-N} = line-to-neutral distribution voltage, V
 \bar{Z}_1 = total positive-sequence impedance, Ω
 \bar{Z}_f = fault impedance, Ω

$I_{f,a}, I_{f,b}, I_{f,c}$ = fault currents in $a, b,$ and c phases

Since the total positive-sequence impedance can be expressed as

$$\bar{Z}_1 = \bar{Z}_{1,\text{sys}} + \bar{Z}_{1,T} + \bar{Z}_{1,\text{ckt}} \quad (10-6)$$

where $\bar{Z}_{1,\text{sys}}$ = positive-sequence Thevenin-equivalent impedance of the system (or source) referred to distribution voltage, Ω

$\bar{Z}_{1,T}$ = positive-sequence transformer impedance referred to distribution voltage, Ω

$\bar{Z}_{1,\text{ckt}}$ = positive-sequence impedance of faulted segment of distribution circuit, Ω

Substituting Eq. (10-6) into Eqs. (10-4) and (10-5), the three-phase fault current can be expressed as

$$I_{f,3\phi} = \left| \frac{\bar{V}_{L-N}}{\bar{Z}_{1,\text{sys}} + \bar{Z}_{1,T} + \bar{Z}_{1,\text{ckt}}} \right| \quad \text{A} \quad (10-7)$$

and

$$I_{f,3\phi} = \left| \frac{\bar{V}_{L-N}}{\bar{Z}_{1,\text{sys}} + \bar{Z}_{1,T} + \bar{Z}_{1,\text{ckt}} + \bar{Z}_f} \right| \quad \text{A} \quad (10-8)$$

Equations (10-7) and (10-8) are applicable whether the source connection is wye-grounded or delta. At times, it might be necessary to reflect a three-phase

fault on the distribution system as a three-phase fault on the subtransmission system. This can be accomplished by using

$$I_{F,3\phi} = \frac{V_{L-L}}{V_{ST,L-L}} \times I_{f,3\phi} \quad \text{A} \quad (10-9)$$

where $I_{F,3\phi}$ = three-phase fault current referred to subtransmission voltage, A
 $I_{f,3\phi}$ = three-phase fault current based on distribution voltage, A
 V_{L-L} = line-to-line distribution voltage, V
 $V_{ST,L-L}$ = line-to-line subtransmission voltage, V

10-11-2 Line-to-Line Faults

Assume that a line-to-line fault exists between phases b and c . Therefore, if there is no fault impedance,

$$\begin{aligned} I_{f,a} &= 0 \\ I_{f,L-L} &= I_{f,c} = -I_{f,b} \\ &= \left| \frac{j\sqrt{3} \times \bar{V}_{L-N}}{\bar{Z}_1 + \bar{Z}_2} \right| \quad \text{A} \end{aligned} \quad (10-10)$$

where $I_{f,L-L}$ = line-to-line fault current, A
 \bar{Z}_2 = total negative-sequence impedance, Ω

However,

$$\bar{Z}_1 = \bar{Z}_2$$

thus

$$I_{f,L-L} = \left| \frac{j\sqrt{3} \times \bar{V}_{L-N}}{2\bar{Z}_1} \right| \quad \text{A} \quad (10-11)$$

or substituting Eq. (10-6) into Eq. (10-11),

$$I_{f,L-L} = \left| \frac{j\sqrt{3} \times \bar{V}_{L-N}}{2(\bar{Z}_{1,\text{sys}} + \bar{Z}_{1,T} + \bar{Z}_{1,\text{ckt}})} \right| \quad \text{A} \quad (10-12)$$

However, if there is a fault impedance,

$$I_{f,L-L} = \left| \frac{j\sqrt{3} \times V_{L-N}}{2(\bar{Z}_{1,\text{sys}} + \bar{Z}_{1,T} + \bar{Z}_{1,\text{ckt}}) + \bar{Z}_f} \right| \quad \text{A} \quad (10-13)$$

By comparing Eq. (10-11) with Eq. (10-4), one can determine a relationship between the three-phase fault and line-to-line fault currents as

$$\begin{aligned} I_{f,L-L} &= \frac{\sqrt{3}}{2} \times I_{f,3\phi} \\ &= 0.866 \times I_{f,3\phi} \end{aligned} \quad (10-14)$$

which is applicable to any point on the distribution system. The equations derived in this section are applicable whether the source connection is wye-grounded or delta.

10-11-3 Single Line-to-Ground Faults

Assume that a single line-to-ground fault exists on phase a . If there is no fault impedance,

$$I_{f,L-G} = \left| \frac{\bar{V}_{L-N}}{\bar{Z}_G} \right| \quad \text{A} \quad (10-15)$$

where $I_{f,L-G}$ = line-to-ground fault current, A

\bar{Z}_G = impedance to ground, Ω

\bar{V}_{L-N} = line-to-neutral distribution voltage, V

However,

$$\bar{Z}_G = \frac{\bar{Z}_1 + \bar{Z}_2 + \bar{Z}_0}{3} \quad (10-16)$$

or

$$\bar{Z}_G = \frac{2\bar{Z}_1 + \bar{Z}_0}{3} \quad (10-17)$$

since

$$\bar{Z}_1 = \bar{Z}_2$$

Therefore, by substituting Eq. (10-17) into Eq. (10-15),

$$I_{f,L-G} = \left| \frac{\bar{V}_{L-N}}{\frac{1}{3}[2\bar{Z}_1 + \bar{Z}_0]} \right| \quad \text{A} \quad (10-18)$$

However, if there is a fault impedance,

$$I_{f,L-G} = \left| \frac{\bar{V}_{L-N}}{\frac{1}{3}[2\bar{Z}_1 + \bar{Z}_0] + \bar{Z}_f} \right| \quad \text{A} \quad (10-19)$$

where \bar{Z}_0 = total zero-sequence impedance, Ω .

Equations (10-18) and (10-19) are only applicable if the source connection is wye-grounded. If the source connection is delta, they are not applicable since the fault current would be equal to zero due to the zero-sequence impedance being infinite.

If the primary distribution feeders are supplied by a delta-wye solidly grounded substation transformer, a single line-to-ground fault on the distribution system is reflected as a line-to-line fault on the subtransmission system. Therefore, the low-voltage-side fault current may be referred to the high-voltage side by using the equation

$$I_{F,L-L} = \frac{V_{L-L}}{\sqrt{3} \times V_{ST,L-L}} \times I_{f,L-G} \quad \text{A} \quad (10-20)$$

where $I_{f,L-G}$ = single line-to-ground fault current based on distribution voltage, A
 $I_{F,L-L}$ = single line-to-ground fault current reflected as a line-to-line fault current on the subtransmission system, A
 V_{L-L} = line-to-line distribution voltage, V
 $V_{ST,L-L}$ = line-to-line subtransmission voltage, V

In general, the zero-sequence impedance Z_0 of a distribution circuit with multigrounded neutral is very hard to determine precisely, but it is usually larger than its positive-sequence impedance Z_1 . However, some empirical approaches are possible. For example, Anderson [3] gives the following relationship between the zero- and positive-sequence impedances of a distribution circuit with multigrounded neutral:

$$\bar{Z}_0 = K_0 \cdot \bar{Z}_1 \quad (10-21)$$

where Z_0 = zero-sequence impedance of distribution circuit, Ω
 Z_1 = positive-sequence impedance of distribution circuit, Ω
 K_0 = a constant

Table 10-6 gives various possible values for the constant K_0 . If the earth has a very bad conducting characteristic, the constant K_0 is totally established by the neutral-wire impedance. Anderson [3] suggests using an average value of 4 where exact conditions are not known.

Table 10-6 Estimated values of the K_0 constant for various conditions*

Condition	K_0
Perfectly conducting earth (e.g., a system with multiple water-pipe grounds)	1.0
Ground wire same size as phase wire	4.0
Ground wire one size smaller	4.6
Ground wire two sizes smaller	4.9
Finite earth impedance	3.8–4.2

10-11-4 Components of the Associated Impedance to the Fault

Impedance of the source If the associated fault duty S given in megavoltamperes at the substation bus is available from transmission system fault studies, the system impedance, i.e., “backup” impedance, can be calculated as

$$\begin{aligned} Z_{1, \text{sys}} &= \frac{V_{L-N}}{I_L} \\ &= \frac{V_{L-L}}{\sqrt{3} \times I_L} \end{aligned} \quad (10-22)$$

$$I_L = \frac{S}{\sqrt{3} \times V_{L-L}} \quad (10-23)$$

therefore

$$Z_{1, \text{sys}} = \frac{V_{L-L}^2}{S} \quad (10-24)$$

If the system impedance is given at the transmission substation bus rather than at the distribution substation bus, then the subtransmission line impedance has to be involved in the calculations so that the total impedance (i.e., the sum of the system impedance and the subtransmission line impedance) represents the impedance up to the high side of the distribution substation transformer.

If the maximum three-phase fault current on the high-voltage side of the distribution substation transformer is known, then

$$Z_{1, \text{sys}} + Z_{1, \text{ST}} = \frac{V_{\text{ST}, L-L}}{\sqrt{3}(I_{F, 3\phi})_{\text{max}}} \quad (10-25)$$

where $Z_{1, \text{sys}}$ = positive-sequence impedance of system, Ω

$Z_{1, \text{ST}}$ = positive-sequence impedance of subtransmission line, Ω

$V_{\text{ST}, L-L}$ = line-to-line subtransmission voltage, V

$(I_{F, 3\phi})_{\text{max}}$ = maximum three-phase fault current referred to subtransmission voltage, A

Note that the impedances found from Eq. (10-24) and (10-25) can be referred to the base voltage by using Eq. (10-9).

Impedance of the substation transformer If the percent impedance of the substation transformer is known, the transformer impedance† can be expressed as

$$Z_{1,T} = \frac{(\% Z_T)(V_{L-L}^2)10}{S_{T,3\phi}} \quad (10-26)$$

where $\% Z_T$ = percent transformer impedance

V_{L-L} = line-to-line base voltage, kV

$S_{T,3\phi}$ = three-phase transformer rating, kVA

Impedance of the distribution circuits The impedance values for the distribution circuits depend on the pole-top conductor configurations and can be calculated by means of symmetrical components. For example, Fig. 10-25 shows a typical pole-top overhead distribution circuit configuration. The equivalent spacing (i.e., mutual geometric mean distance) of phase wires and the equivalent spacing between phase wires and neutral wire can be determined from

$$dp = D_{eq} = D_m \triangleq (D_{ab} \cdot D_{bc} \cdot D_{ca})^{1/3} \quad (10-27)$$

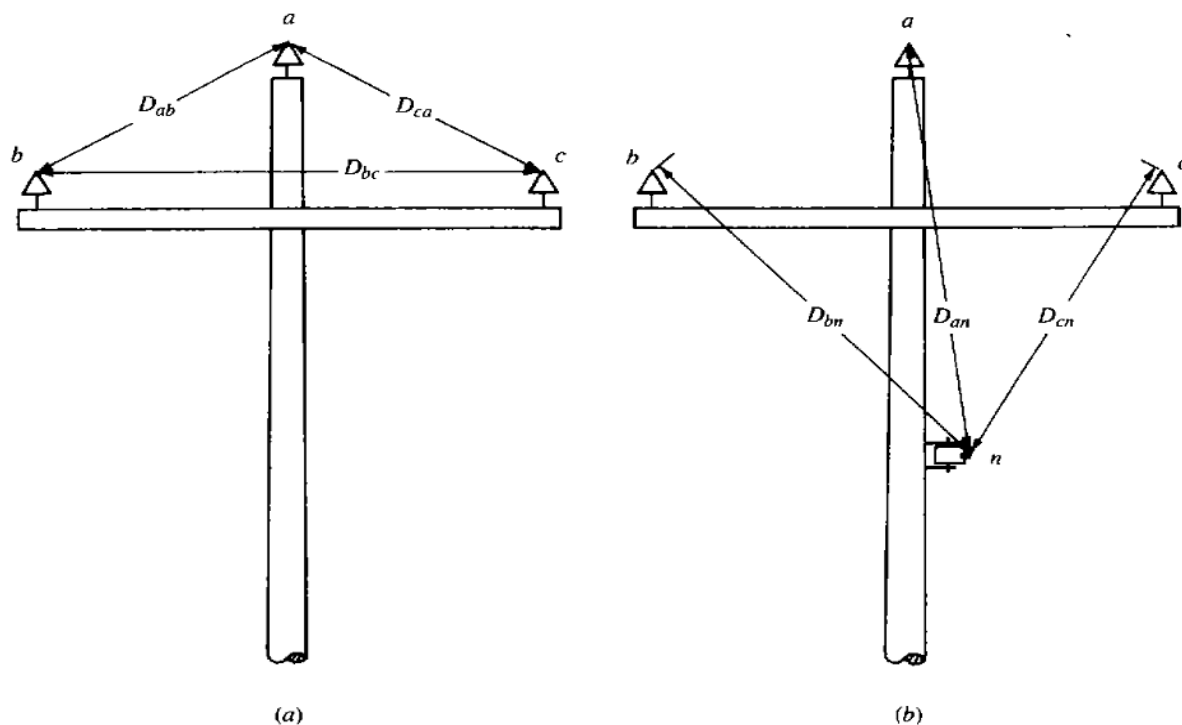


Figure 10-25 Typical pole-top overhead distribution circuit configuration.

and

$$dn \triangleq (D_{an} \cdot D_{bn} \cdot D_{cn})^{1/3} \quad (10-28)$$

Similarly, the mutual reactances (spacing factors) for phase wires, and between phase wires and neutral wire (due to equivalent spacings), can be determined as

$$x_{dp} = 0.05292 \log_{10} dp \quad \Omega/1000 \text{ ft} \quad (10-29)$$

and

$$x_{dn} = 0.05292 \log_{10} dn \quad \Omega/1000 \text{ ft} \quad (10-30)$$

1. If the distribution circuit is a three-phase circuit, the positive- and negative-sequence impedances are

$$\bar{z}_1 = \bar{z}_2 = r_{ap} + j(x_{ap} + x_{dp}) \quad \Omega/1000 \text{ ft} \quad (10-31)$$

and the zero-sequence impedance is

$$\bar{z}_0 = \bar{z}_{0,a} - \frac{\bar{z}_{0,ag}^2}{\bar{z}_{0,g}} \quad \Omega/1000 \text{ ft} \quad (10-32)$$

with

$$\bar{z}_{0,a} = r_{ap} + r_e + j(x_{ap} + x_e - 2x_{dp}) \quad \Omega/1000 \text{ ft} \quad (10-33)$$

$$\bar{z}_{0,ag} = r_e + j(x_e - 3x_{dn}) \quad \Omega/1000 \text{ ft} \quad (10-34)$$

$$\bar{z}_{0,g} = 3r_{an} + r_e + j(3x_{an} + x_e) \quad \Omega/1000 \text{ ft} \quad (10-35)$$

where r_e = resistance of earth = $0.0542 \Omega/1000 \text{ ft}$

x_e = reactance of earth = $0.4676 \Omega/1000 \text{ ft}$

x_{dn} = spacing factor between phase wires and neutral wire, $\Omega/1000 \text{ ft}$

x_{dp} = spacing factor for phase wires, $\Omega/1000 \text{ ft}$

r_{ap} = resistance of phase wires, $\Omega/1000 \text{ ft}$

r_{an} = resistance of neutral wires, $\Omega/1000 \text{ ft}$

x_{ap} = reactance of phase wire with 1-ft spacing, $\Omega/1000 \text{ ft}$

x_{an} = reactance of neutral wire with 1-ft spacing, $\Omega/1000 \text{ ft}$

$z_{0,a}$ = zero-sequence self-impedance of phase circuit, $\Omega/1000 \text{ ft}$

$z_{0,g}$ = zero-sequence self-impedance of one ground wire, $\Omega/1000 \text{ ft}$

$z_{0,ag}$ = zero-sequence mutual impedance between the phase circuit as one group of conductors and the ground wire as other conductor group, $\Omega/1000 \text{ ft}$

2. If the distribution circuit is an open-wye and single-phase delta circuit, the positive- and negative-sequence impedances are

$$\bar{z}_1 = \bar{z}_2 = r_{ap} + j(x_{ap} + x_{dp}) \quad \Omega/1000 \text{ ft} \quad (10-36)$$

and the zero-sequence impedance is

$$\bar{z}_0 = \bar{z}_{0,a} - \frac{\bar{z}_{0,ag}^2}{\bar{z}_{0,g}} \quad \Omega/1000 \text{ ft} \quad (10-37)$$

where

$$\bar{z}_{0,a} = r_{ap} + \frac{2r_e}{3} + j\left(x_{ap} + \frac{2x_e}{3} - x_{dp}\right) \quad \Omega/1000 \text{ ft} \quad (10-38)$$

$$\bar{z}_{0,ag} = \frac{2r_e}{3} + j\left(\frac{2x_e}{3} - 2x_{dn}\right) \quad \Omega/1000 \text{ ft} \quad (10-39)$$

$$\bar{z}_{0,g} = 2r_{an} + \frac{2r_e}{3} + j\left(2x_{an} + \frac{2x_e}{3}\right) \quad \Omega/1000 \text{ ft} \quad (10-40)$$

3. If the distribution circuit is a single-phase multigrounded circuit, its impedance is

$$\bar{z}_{1\phi} = \bar{z}_{0,a} - \frac{\bar{z}_{0,ag}^2}{\bar{z}_{0,g}} \quad \Omega/1000 \text{ ft} \quad (10-41)$$

where

$$\bar{z}_{0,a} = \bar{z}_{0,g} = r_{ap} + \frac{r_e}{3} + j\left(x_{ap} + \frac{x_e}{3}\right) \quad \Omega/1000 \text{ ft} \quad (10-42)$$

$$\bar{z}_{0,ag} = \frac{r_e}{3} + j\left(\frac{x_e}{3} - x_{dn}\right) \quad \Omega/1000 \text{ ft} \quad (10-43)$$

10-11-5 Sequence-Impedance Tables for the Application of Symmetrical Components

The zero-sequence impedance equation (given as Eq. (10-32), (10-37), or (10-41) in Sec. 10-11-4), that is,

$$\bar{z}_0 = \bar{z}_{0,a} - \frac{\bar{z}_{0,ag}^2}{\bar{z}_{0,g}} \quad \Omega/1000 \text{ ft}$$

can be expressed as

$$\bar{z}_0 = \bar{z}_{0,a} + \bar{z}'_0 \quad \Omega/1000 \text{ ft} \quad (10-44)$$

or

$$\bar{z}_0 = \bar{z}_{0,a} + \bar{z}''_0 \quad \Omega/1000 \text{ ft} \quad (10-45)$$

where $z_{0,a}$ = zero-sequence self-impedance of phase circuit, $\Omega/1000 \text{ ft}$

z'_0 = equivalent zero-sequence impedance due to combined effects of zero-sequence self-impedance of one ground wire, and zero-sequence mutual impedance between the phase circuit as one group of conductors and the ground wire as another conductor group, assuming a specific vertical distance between the ground wire and phase wires, for example, 38 in

z''_0 = Same as z'_0 , except the vertical distance is a different one, for example, 62 in

Therefore it is possible to develop precalculated sequence-impedance tables for the application of symmetrical components. For example, Figs. 10-26 to 10-30 show various overhead pole-top conductor configurations with and without ground wire. The corresponding sequence-impedance values at 60 Hz and 50°C are given in Tables 10-7 to 10-11.

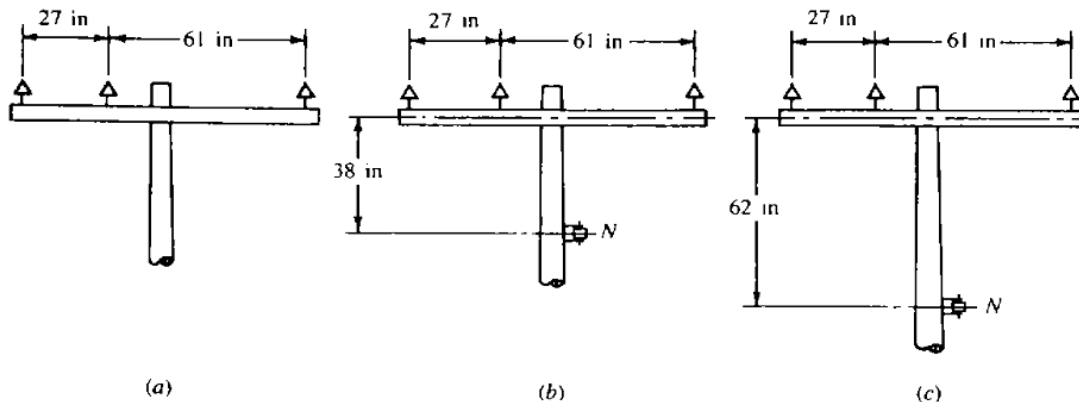


Figure 10-26 Various overhead pole-top conductor configurations: (a) without ground wire, $z_0 = z_{0,a}$; (b) with ground wire, $z_0 = z_{0,a} + z'_0$; (c) with ground wire, $z_0 = z_{0,a} + z''_0$.

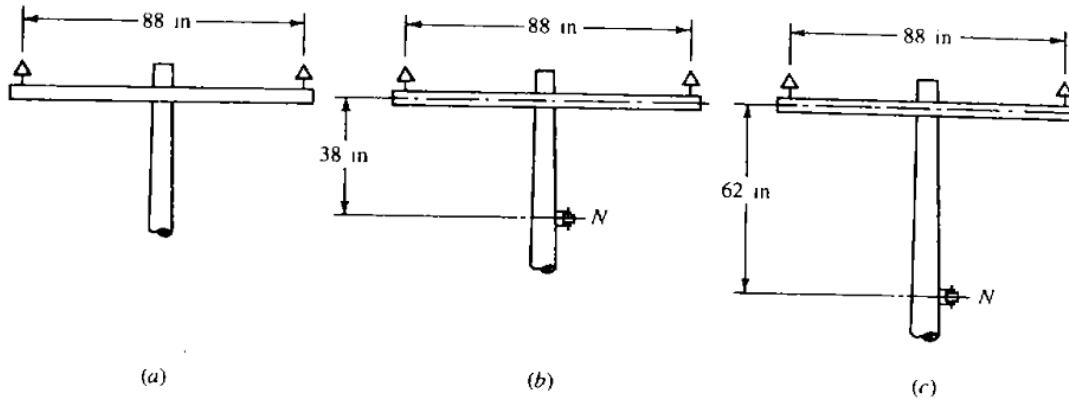


Figure 10-27 Various overhead pole-top conductor configurations: (a) without ground wire, $z_0 = z_{0(a)}$; (b) with ground wire, $z_0 = z_{0,a} + z'_0$; (c) with ground wire, $z_0 = z_{0,a} + z''_0$.

Protective Devices

Over current Protective Devices

The overcurrent protective devices applied to distribution systems include relay-controlled circuit breakers, automatic circuit reclosers, fuses, and automatic line sectionalizers.

Fuses

A fuse is an overcurrent device with a circuit-opening fusible member (i.e., fuse link) directly heated and destroyed by the passage of overcurrent through it in the event of an overload or short-circuit condition. Therefore the purpose of a fuse is to clear a permanent fault by removing the defective segment of a line or equipment from the system. A fuse is designed to blow within a specified time for a given value of fault current. The time-current characteristics of a fuse are represented by two curves: (1) the minimum-melt curve and (2) the total-clearing curve. The minimum-melt curve of a fuse is a plot of the minimum time vs. current required to melt the fuse link. The total-clearing curve is a plot of the maximum time vs. current required to melt the fuse link and extinguish the arc.

Fuses designed to be used above 600 V are categorized as *distribution cutouts* (also known as *fuse cutouts*) or *power fuses*. Figure 10-1 gives detailed classification for high-voltage fuses.

The liquid-filled (oil-filled) cutouts are mainly used in underground installations and contain the fusible elements in an oil-filled and sealed tank. The expulsion-type distribution cutouts are by far the most common type of protective device applied to overhead primary distribution systems. In these cutouts, the melting of the fuse link causes heating of the fiber fuse tube which, in turn, produces deionizing gases to extinguish the arc. Expulsion-type cutouts are classified according to their external appearance and operation methods as (1) enclosed-fuse cutouts, (2) open-fuse cutouts, and (3) open-link-fuse cutouts.

The ratings of the distribution fuse cutouts are based on continuous current-carrying capacity, nominal and maximum design voltages, and interrupting capacity. In general, the fuse cutouts are selected based upon the following data:

1. The type of system for which they are selected, e.g., overhead or underground, delta or grounded-wye system
2. The system voltage for which they are selected
3. The maximum available fault current at the point of application
4. The X/R ratio at the point of application
5. Other factors, e.g., safety, load growth, and changing duty requirements

The use of symmetrical ratings simplified the selection of cutouts as a simple comparison of the calculated system requirements with the available fuse cutout ratings. In spite of that, fuse cutouts still have to be able to interrupt asymmetrical currents which are, in turn, subject to the X/R ratios of the circuit. Therefore symmetrical cutout rating tables are prepared on the basis of assumed maximum

X/R ratios. Table 10-1 gives the interrupting ratings of open-fuse cutouts. Figure 10-2 shows a typical open-fuse cutout in pole-top style for 7.2/14.4-kV overhead distribution. Figure 10-3 shows a typical application of open-fuse cutouts in 7.2/14.4-kV overhead distribution.

In 1951, a joint study by the EEI and NEMA established standards specifying *preferred* and *nonpreferred* current ratings for fuse links of distribution fuse cutouts and their associated time-current characteristics in order to provide interchangeability for fuse links. The reason for stating certain ratings to be preferred or nonpreferred is based on the fact that the ordering sequence of the current ratings is set up such that a preferred-size fuse link will protect the next higher preferred size. This is also true for the nonpreferred sizes. The current ratings of fuse links for preferred sizes are given as 6, 10, 15, 25, 40, 65, 100, 140, and 200 A, and for nonpreferred sizes as 8, 12, 20, 30, 50, and 80 A.

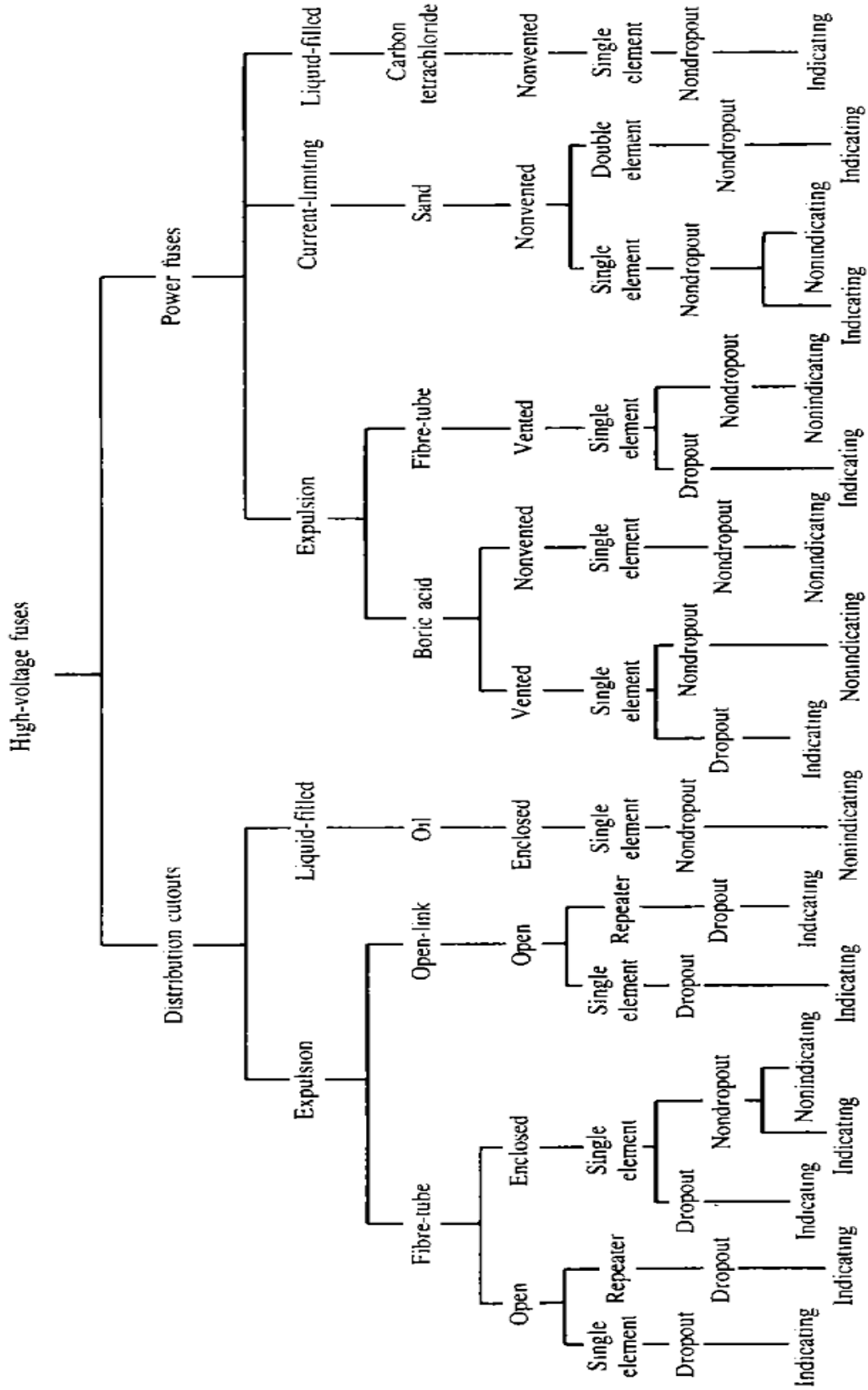


Figure 10-1 Classification of high-voltage fuses [1].

Table 10-1 Interrupting ratings of open-fuse cutouts*

Rating of cutout			Interrupting rating in rms amperes at				Interrupting rating nomenclature
Continuous current, A	Nominal voltage, kV	Maximum design voltage, kV	5.2 kV	7.8 kV	15 kV	27 kV	
100	5.0	5.2	3000				Normal duty Heavy duty Extra heavy duty
100	5.0	5.2	5000				
100	5.0	5.2	10000				
200	5.0	5.2	4000				Normal duty Heavy duty
200	5.0	5.2	12000				
100	7.5	7.8		3000			Normal duty Heavy duty Extra heavy duty
100	7.5	7.8		5000			
100	7.5	7.8		10000			
200	7.5	7.8		4000			Normal duty Heavy duty
200	7.5	7.8		12000			
100	15	15			2000		Normal duty Heavy duty Extra heavy duty
100	15	15			4000		
100	15	15			8000		
200	15	15			4000		Normal duty Heavy duty
200	15	15			10000		
100	25	27				1200	Normal duty

Furthermore, the standards also classify the fuse links as (1) type K (fast) and (2) type T (slow). The difference between these two fuse links is in the relative melting time which is defined by the speed ratio as

$$\text{Speed ratio} = \frac{\text{melting current at 0.1 s}}{\text{melting current at 300 or 600 s}}$$

Here, the 0.1 and 300 s are for fuse links rated 6 to 100 A, and the 0.1 and 600 s are for fuse links rated 140 to 200 A. Therefore the speed ratios for type K and type T fuse links are between 6 and 8, and 10 and 13, respectively.

Power fuses are employed where the system voltage is 34.5 kV or higher and/or the interrupting requirements are greater than the available fuse cutout ratings. They are different from fuse cutouts in terms of (1) higher interrupting ratings, (2) larger range of continuous current ratings, (3) applicable not only for distribution but also for subtransmission and transmission systems, and (4) designed and built usually for substation mounting rather than pole and crossarm mounting. A power fuse is made of a fuse mounting and a fuse holder. Its fuse link

is called the *refill unit*. In general, they are designed and built as (1) expulsion (boric acid or other solid material [SM]) type, (2) current-limiting (silver-sand) type, or (3) liquid-filled type. Power fuses are identified by the letter "E" (for example, 200E or 300E) to specify that their time-current characteristics comply

with the interchangeability requirements of the standard.

Circuit breakers

* circuit breakers are automatic interrupting devices which are capable of breaking & reclosing a circuit under all conditions, that is, faulted or normal operating conditions. The primary task of a circuit breaker is to extinguish the arc that develops due to separation of its contacts in an arc-extinguishing medium, for example, in air, as is the case for air circuit breakers, in oil, as is the case for oil circuit breakers (OCB's), in SF₆ (sulfur hexafluoride), or in vacuum. In some types, the arc is extinguished by a blast of compressed air, as is the case for magnetic blow-out circuit breakers. The circuit breakers used at distribution system voltages are of the air circuit breaker or oil circuit breaker type. For low-voltage applications molded-case circuit breakers are available.

- the air circuit breaker or oil circuit breaker type. In voltage applications molded-case circuit breakers are available.
- * oil circuit breakers controlled by protective relays are usually installed at the source substations to provide protection against faults on distribution feeders.
 - * currently, circuit breakers are rated on the basis of RMS symmetrical current. Usually circuit breakers used in the distribution systems have minimum operating times of five cycles. In general, relay-controlled circuit breakers are preferred to reclosers due to their greater flexibility, accuracy, design margins and esthetics. However, they are much more expensive than reclosers.
 - * The relay, or fault-sensing device, that opens the circuit breaker is generally an overcurrent induction type with inverse, very inverse or extremely inverse TCC, for example, the overcurrent relays of the inverse overcurrent relays.