13 LINE PROTECTION WITH OVERCURRENT RELAYS

Lines are protected by overcurrent-, distance-, or pilot-relaying equipment, depending on the requirements. Overcurrent relaying is the simplest and cheapest, the most difficult to apply, and the quickest to need readjustment or even replacement as a system changes. It is generally used for phase- and ground-fault protection on station-service and distribution circuits in electric utility and in industrial systems, and on some subtransmission lines where the cost of distance relaying cannot be justified. It is used for primary ground-fault protection on most transmission lines where distance relays are used for phase faults, and for ground back-up protection on most lines having pilot relaying for primary protection. However, distance relaying for ground-fault primary and back-up protection of transmission lines is slowly replacing overcurrent relaying. Overcurrent relaying is used extensively also at power-transformer locations for externa-fault back-up protection, but here, also, there is a trend toward replacing overcurrent with distance relays.

It is generally the practice to use a set of two or three overcurrent relays for protection against interphase faults and a separate overcurrent relay for single-phase-to-ground faults. Separate ground relays are generally favored because they can be adjusted to provide faster and more sensitive protection for single-phase-to-ground faults than the phase relays can provide. However, the phase relays alone are sometimes relied on for protection against all types of faults. On the other hand, the phase relays must sometimes be made to be inoperative on the zero-phase-sequence component of ground-fault current. These subjects will be treated in more detail later.

Overcurrent relaying is well suited to distribution-system protection for several reasons. Not only is overcurrent relaying basically simple and inexpensive but also these advantages are realized in the greatest degree in many distribution circuits. Very often, the relays do not need to be directional, and then no a-c voltage source is required. Also, two phase relays and one ground relay are permissible. And finally, tripping reactor or capacitor tripping (described elsewhere) may be used.

In electric-utility distribution-circuit protection, the greatest advantage can be taken of the inverse-time characteristic because the fault-current magnitude depends mostly on the fault location and is practically unaffected by changes in generation or in the high-voltage transmission system. Not only may relays with extremely inverse curves be used for this reason but also such relays provide the best selectivity with fuses and reclosers. However, if ground-fault-current magnitude is severely limited by neutral-grounding impedance, as is often true in industrial circuits, there is little or no advantage to be gained from the inverse characteristic of a ground relay.

Inverse-time relaying is supplemented by instantaneous relaying wherever possible. Speed in clearing faults minimizes damage and thereby makes automatic reclosing more likely to be successful.

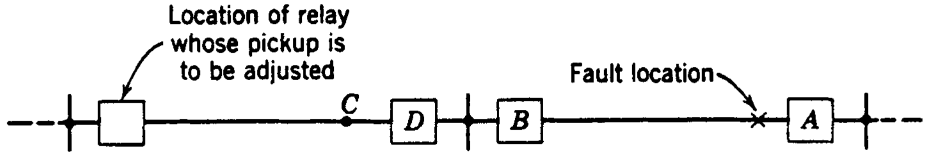

Fig. 1. The fault location for adjusting the pickup for back-up protection.

HOW TO SET INVERSE-TIME-OVERCURRENT RELAYS FOR COORDINATION

The first step is to choose the pickup of the relay so that it will (1) operate for all short circuits in its own line, and (2) provide back-up protection for short circuits in immediately adjoining system elements under certain circumstances. For example, if the adjoining element is a line section, the relay is set to pick up at a current somewhat less than it receives for a short circuit at the far end of this adjoining line section under minimum generating–or other–conditions that would cause the least current flow at the relay location. This is illustrated in Fig. 1.

For a phase relay, a phase-to-phase fault would be assumed since it causes less current to flow than does any other fault not involving ground. However, a phase relay must not be so sensitive that it will pick up under emergency conditions of maximum load over the line from which it receives its current. For a ground relay, a single-phase-to-ground fault would be assumed; load current is not a factor in the choice of a ground-relay's pickup except in a distribution system where there is ground current normally because of unbalanced loading. If there are two or more adjoining line sections, the fault should be assumed at the end of the section that causes the least current to flow at the location of the relay being adjusted.

Because of the effect of parallel circuits not shown, less current will flow at the relay location of Fig. 1 if breaker *A* is closed than if *A* is open. If satisfactory adjustment can be obtained with *A* closed, so much the better. However, the relay under consideration is being adjusted to operate if breaker *B* fails to open; it is not generally assumed that breaker *A* will also fail to open. There may be some occasions when one will wish to assume simultaneous equipment failures at different locations, but it is not the usual practice. Hence, it is permissible to assume that breaker *A* has opened, which is usually very helpful and may even be necessary.

Under certain circumstances, the relay will get less current for a phase-to-phase fault at *C* with breaker *D* closed and under minimum generating conditions than for the fault location shown in Fig. 1 with *A* open; the relay must be able to operate for this condition also.

In order to use the most inverse portion of the relay's time curves, the pickup in terms of primary current should be as high as possible and still be low enough so that the relay will operate reliably under the minimum fault-current condition. Under such conditions, the relay should operate at no less than about 1.5 times its pickup, but as near to that value as conveniently possible. The reason for this rule is that, closer to the pickup current, the torque is so low that a small increase in friction might prevent operation or it might increase the operating time too much. It may be that the CT ratio and the relay's range of adjustment do not permit adjusting for so low a multiple of pickup; in that event the only recourse, aside from changing the CT or the relay, is to use the highest possible pickup for which the relay can be adjusted.

To assure selectivity under all circumstances, the pickup of a given relay should be somewhat higher than that of other relays nearer to the fault and with which the given relay must be selective.

Because the impedance of generators increases from subtransient to synchronous as time progresses from the instant that a short circuit occurs, the question naturally arises as to which value of impedance to use in calculating the magnitude of short-circuit current for protective-relaying purposes where overcurrent relaying is involved. The answer to this question depends on the operating speed of the relay under consideration, on the amount by which generator impedance affects the magnitude of the short-circuit current, and on the particular relay setting involved. Usually, the impedance that limits the magnitude of the short-circuit current contains so much transformer and line impedance that the effect of changing generator impedance is negligible; one can always determine this effect in any given application. For relays near a large generating station that furnishes most of the short-circuit current, synchronous impedance would be best for determining the pickup of a relay for back-up purposes particularly if the operating time of the relay was to be as long as a second or two. On the other hand, the pickup of a high-speed relay near such a generating station would be determined by the use of transient—or possibly even subtransient—impedance. Ordinarily, however, transient impedance will be found most suitable for all purposes—particularly for subtransmission or distribution circuits where overcurrent relays are generally used; there is enough transformer and line impedance between such circuits and the generating stations so that the effect of changing generator impedance is negligible. In fact, for distribution circuits, it is frequently sufficiently accurate to assume a source impedance that limits the current to the source-breaker interrupting capacity on the high-voltage side of a power transformer feeding such a circuit; in other words, only slightly more total impedance than that of the transformer itself and of the circuit to be protected is assumed.

Whether to take into account the effect of arc and ground resistance depends on what one is interested in. Arc resistance may or may not exist. Occasionally, a metallic fault with no arcing may occur. When one is concerned about the maximum possible value of fault current, he should assume no arc resistance unless he is willing to chance the possibility of faulty relay operation should a fault occur without resistance. Thus, as will be seen later, for choosing the pickup of instantaneous overcurrent relays or the time-delay adjustment for inverse-time relays, it is more conservative to assume no arc resistance.

When one is choosing the pickup of inverse-time relays, the effect of arc resistance should be considered. This is done to a limited extent when one arbitrarily chooses a pickup current lower than the current at which pickup must surely occur, as recommended in the foregoing material; however, this pickup may not be low enough. In view of the fact that an arc may lengthen considerably in the wind, and thereby greatly increase its resistance, it is a question how far to go in this respect. At least, one should take into account the resistance of the arc, when it first occurs, whose length is the shortest distance between conductors or to ground. Beyond this, what one should do depends on the operating time of the relay under consideration and the wind velocity. The characteristics of an arc are considered later.

Ground resistance concerns us only for ground faults. It is in addition to arc resistance. This subject is considered later also, along with arc resistance.

For ground relays on lines between which there is mutual induction, this mutual induction should be taken into account in calculating the magnitude of current for single-phase-to-ground faults. In some studies, this will show that selectivity cannot be obtained when it would otherwise appear to be possible.

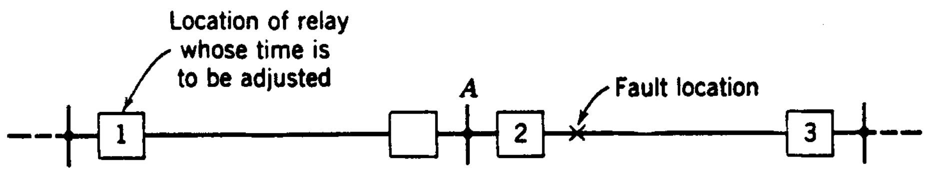

Fig. 2. The fault location for adjusting for selectivity.

The second step in the adjustment of inverse-time-overcurrent relays is to adjust the time delay for obtaining selectivity with the relays of the immediately adjoining system elements. This adjustment should be made for the condition for which the maximum current would flow at the relay location. This condition would exist for a short circuit just beyond the breaker in an adjoining system element. This is illustrated in Fig. 2. Under certain circumstances, more current will flow at the relay location if breaker 3 is open. For adjusting a phase relay, a three-phase fault would be assumed; and for a ground relay a single-phase-to-ground fault would be assumed. In either event, one would use the fault current for maximum generating conditions and for any likely switching condition that would make the current at 1 most nearly equal to the current at 2. For example, when there are other sources of ahort-circuit current connected to bus *A*, if it is considered a practical operating condition to assume them to be disconnected, they should be so assumed.

The adjustment for selectivity is made under maximum fault-current conditions because, if selectivity is obtained under such conditions, it is certain to be obtained for lower currents. This will be seen by examining the time-current curves of any inverse-time overcurrent relay, such as Fig. 3 of Chapter 3, and observing that the time spacing between any two curves increases as the multiple of pickup decreases. Hence, if there is sufficient time spread at any given multiple of pickup, the spread will be more than sufficient at a lower multiple. The foregoing assumes that relays having the same time-current characteristics are involved. Relays with different characteristics are to be avoided.

This brings us to the question of how much difference there must be between the operating times of two relays in order that selectivity will be assured. Let us examine the elements involved in the answer to this question by using the example of Fig. 2. For the fault as shown in Fig. 2, the relay located at breaker 2 must close its contacts, and breaker 2 must trip and interrupt the flow of short-circuit current before the relay at breaker 1 can close its contacts. Furthermore, since the relay at breaker 1 may "overtravel" a bit after the flow of short-circuit current ceases, provision should also be made for this overtravel.

We can express the required operating time of the relay at 1 in terms of the operating time of the relay at 2 by the following formula:

$$T_1 = T_2 + B_2 + O_1 + F$$

where T_1 = operating time of relay at 1.

T_2 = operating time of relay at 2.

B_2 = short-circuit interrupting time of breaker at 2.

O_1 = overtravel time of relay at 1.

F = factor-of-safety time.

The overtravel time will be different for different overcurrent relays and for different multiples of pickup, but, for the inverse-time types generally used, a value of about 0.1 second may be used. The factor-of-safety time is at the discretion of the user; this time should provide for normally expected variations in all the other times. A value of 0.2 to 0.3 second for overtravel plus the factor of safety will generally be sufficient; lower values may be used where accurate data are available.

We are now in a position to examine Fig. 3 where in time-versus-distance curves are shown for relays that have been adjusted as described in the foregoing. The time *S*, called the "selective-time interval," is the sum of the breaker, over travel, and factor-of-safety times. A vertical line drawn through any assumed fault location will intersect the operating-time

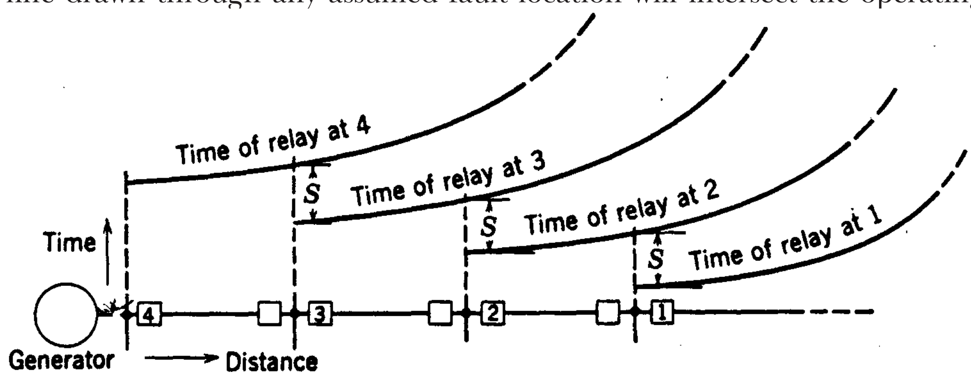

Fig. 3. Operating time of overcurrent relays with inverse-time characteristics.

curves of various relays and will thereby show the time at which each relay would operate if the short-circuit current continued to flow for that length of time.

The order in which the relays of Fig. 3 are adjusted is to start with the relay at breaker 1 and work back to the relay at breaker 4. This will become evident when one considers that the selectivity adjustment of each relay depends on the adjustment of the relay with which it must select. For cases like that shown in Fig. 3, we can generalize and say that one starts adjustment at the relay most distant electrically from the source of generation, and then works back toward the generating source.

ARC AND GROUND RESISTANCE

Although there is much difference of opinion on the interpretation of test data, the maximum value of rms volts per foot of arc length given by any of the data[1,2,3] for all arc currents greater than l000 rms amperes is about 550. For currents below l000 amperes, the formula $V = 8750/I^{0.4}$ gives the maximum reported value of rms volts per foot (V) for any rms value of arc current (I); from this formula, values considerably higher than 550 will be obtained at low currents. Actually, this formula gives a fairly good average of all the available data for any value of arc current, as will be seen by plotting superimposed the data of Fig. 1 of Reference 1, Fig. 5 of Reference 2, and the foregoing formula which is obtained from the formula given in Reference 3. However, because this average value is only about half of the maximum reported in Reference 1 for currents larger than 1000 amperes, it is more conservative not to use this average for such current values when one is interested in the maximum arc resistance.

To take into account the lengthening of the arc by wind, the approximate formula $L = 3vt + L_0$ may be used, where:

L = length of arc, in feet.

v = wind velocity, in miles per hour.

t = time, in seconds after the arc was first struck.

L_0 = initial arc length, i.e., the shortest distance between conductors or across insulator, in feet.

It will be evident that there are limits to which this formula may be applied because there are limits to the amount an arc may stretch without either restriking or being extinguished. Reference 2 gives several sets of data showing how the arc voltage increased during field tests.

Ground resistance is resistance in the earth. This resistance is in addition to that of an arc. When overhead ground wires are not used, or when they are insulated from the towers or poles, the ground resistance is the tower- or pole-footing resistance at the location where the ground fault has occurred plus the resistance of the earth back to the source. Electric utilities have measured data on such footing resistance. When overhead ground wires are connected to steel towers or to grounding connections on wood poles, the effect is somewhat as though all footing resistances were connected in parallel, which makes the resulting footing resistance negligible. Published zero-phase-sequence-impedance data do not include the effect of tower-footing resistance.

Occasionally, a conductor breaks and falls to the ground. The ground-contact resistance of such a fault may be much higher than tower-footing resistance where relatively low resistance is usually obtained with ground rods or counterpoises. The contact resistance depends on the geology of a given location, whether the ground is wet or dry, and, if dry, how high the voltage is; it takes a certain amount of voltage to break down the surface insulation.

Ground resistance can range over such wide limits that the only practical thing to do is to use measured values for any given locality. An example of extremely high ground resistance and the method of relaying is given in Reference 4.

In one system,[5] advantage was taken of ground resistance to decrease the rms magnitude of ground-fault current and to greatly shorten the time constant of its d-c component in order to reduce the interrupting stress on circuit breakers. However, such practice should be avoided in general.

Figure 3 best serves the purpose of illustrating how selectivity is provided with inverse-time-overcurrent relays. But, lest it mislead one by oversimplifying the problem, it is well to realize that, except for some parts of distribution systems, Fig. 3 does not truly represent most actual systems where loops are the rule and radial circuits are the exception. The principles involved and the general results obtained in the application and adjustment of overcurrent relays are correctly shown by reference to Fig. 3, but the difficulties in arriving at suitable adjustment in an actual system are minimized. This consideration is important because it is often the deciding factor that leads one to choose distance or pilot relaying in preference to overcurrent relaying.

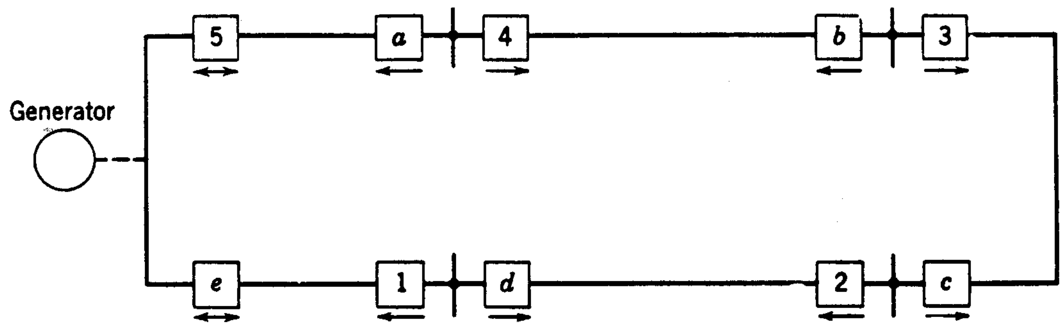

Fig. 4. The order for adjusting relays in a simple loop system.

When we studied the method of setting inverse-time-overcurrent relays, we saw that the relay most distant electrically from the generating source was adjusted first, and that one then worked back toward the generating source. The same procedure would be followed in the simple loop system illustrated in Fig. 4. The order in which the relays "looking" one way around the loop would be adjusted is 1-2-3-4-5, and looking the other way, *a-b-c-d-e*. Directional overcurrent relays would usually be employed as indicated by the single-ended arrows that point in the direction of fault-current flow for which the relays should trip. Only at locations *e* and 5 can fault current flow only in the same direction as that for which tripping is desired, and the relays there may be non-directional as indicated by the double-headed arrows. The first relay to be adjusted in each of the two groups can be made as sensitive and as fast as possible because the current flow at the relay location will decrease to zero as faults are moved from the relay location to the generator bus, and hence there is no problem of selectivity for those relays. The phase relay at 1, for example, must receive at least 1.5 times its pickup current for a phase-to-phase fault at the far end of its line with the breaker at *e* open, and with minimum generation. Of course, no phase overcurrent relay should be so sensitive that it will pick up on maximum load.

Occasionally, the short-circuit current that can flow in the non-tripping direction is so small in comparison with the current that can flow in the tripping direction that certain relays need not be directional, the system itself having a directional characteristic. But, if a relay can pick up on the magnitude of current that flows in the non-tripping direction, it is wise to make the relay directional or else the problem of obtaining selectivity under all possible conditions is needlessly complicated; and a future change in the system or its operation may demand directional relays anyway.

The first complication in adjusting overcurrent relays in loop circuits arises when generators are located at the various stations around the loop. The problem then is where to start. And, finally, when circuits of one loop form a part of other loops, the problem is most difficult. The trial-and-error method is the only way to proceed with such circuits. In fact, some such systems cannot be relayed selectively by inverse-time-overcurrent relays without operating the system with certain breakers normally open, and closing them only in emergencies. Supplementary instantaneous overcurrent relaying will sometimes give relief in such cases, as will be described later. Of course, such systems are not created in their entirety; they develop slowly, and the relaying problems arise each time that a change is made.

EFFECT OF SYSTEM ON CHOICE OF INVERSENESS OF RELAY CHARACTERISTIC

The less change there is in the magnitude of short-circuit current with changes in connected generating capacity, etc., for a fault at a given location, the more benefit can be obtained from greater inverseness. This is particularly true in distribution circuits where short-circuit-current magnitude is practically independent of normal changes in generating capacity. In such circuits one can use the very inverse–or extremely inverse overcurrent relays to advantage.

In systems, such as many industrial systems, where the magnitude of the ground-fault current is severely limited by neutral-grounding impedance, little or no advantage can be taken of the inverseness of a ground-relay's characteristic; the relays might just as well have definite-time characteristics. This would also be true even where no neutral impedance was used if the sum of the arc and ground resistance was high enough, no matter where the fault should happen to occur.

Later, under the heading "Restoration of Service to Distribution Feeders after Prolonged Outages," the need for the extremely inverse characteristic is described. This characteristic is also useful in areas of a distribution system adjacent to where fuses and reclosers begin to replace relays and circuit breakers, because the extremely inverse characteristic will coordinate with fuses and reclosers.

THE USE OF INSTANTANEOUS OVERCURRENT RELAYS

Instantaneous overcurrent relays are applicable if the fault-current magnitude under maximum generating conditions about triples as a fault is moved toward the relay location from the far end of the line. This will become evident by referring to Fig. 5 where the symmetrical fault-current magnitude is plotted as a function of fault location along a line for three-phase faults and for phase-to-phase faults, if we assume that the fault-current magnitude triples as the fault is moved from the far end of the line to the relay location. The pickup of the instantaneous relay is shown to be 25% higher than the magnitude of the current for a three-phase fault at the end of the line; the relay should not pick up at much less current or else it might overreach the end of the line when the fault-current wave is fully offset. In a distribution circuit, the relay could be adjusted to pick up at somewhat lower current because the tendency to overreach is less. For the condition of Fig. 5, it will be noted that the relay will operate for threephase faults out to 70% of the line length and for phase-to-phase faults out to 54%. If the ground-fault current is not limited by neutral impedance, or if the ground resistance is not too high, a similar set of characteristics for ground faults would probably show somewhat more than 70% of the line protected; this is because the ground-fault current usually increases at a higher rate as the fault is moved toward the relay. The technique of Fig. 5 may be used for any other conditions to determine the effectiveness of instantaneous overcurrent relaying, including the effect on fault-current magnitude because of changes in generation, etc.

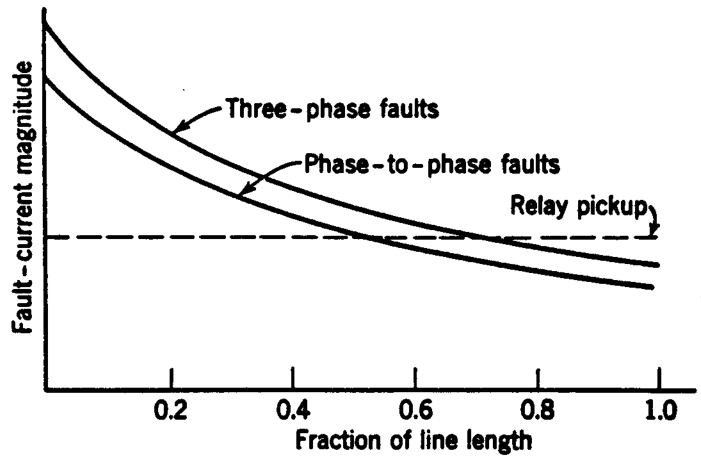

Fig. 5. Performance of instantaneous overcurrent relays.

The shaded area of Fig. 6 shows how much instantaneous overcurrent relaying reduces the over-all relaying time for most faults. Even if such reduction is obtained only under maximum generating conditions, and if instantaneous relays were not even operable under minimum generating conditions, the use of supplementary instantaneous relays is considered to be worth while because they are relatively so inexpensive.

With instantaneous overcurrent relaying at both ends of a line, simultaneous tripping of both ends is obtained under maximum generating conditions for faults in the middle portion of the line. For faults near the ends of the line, sequential instantaneous tripping will often occur, i.e., the end nearest the fault will trip instantly and then the magnitude of the current flowing to the fault from the other end will usually increase sufficiently to pick up the instantaneous overcurrent relays there.

When the magnitude of fault current depends only on the fault location, instantaneous overcurrent relaying is like distance relaying[6] except that the overcurrent relays cannot generally be as sensitive as distance relays.

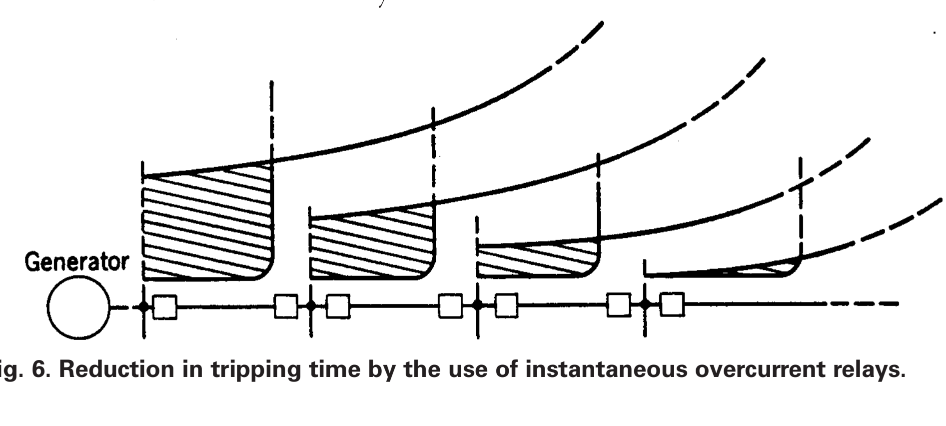

Fig. 6. Reduction in tripping time by the use of instantaneous overcurrent relays.

AN INCIDENTAL ADVANTAGE OF INSTANTANEOUS OVERCURRENT RELAYING

A useful advantage that can sometimes be taken of instantaneous overcurrent relaying is illustrated in Fig. 7. Without instantaneous overcurrent relaying at breaker 2, the inverse-time-overcurrent relays at 1 would have the dashed time curve so as to obtain the selective time interval *ab* with respect to the inverse-time relays at breaker 2. With instantaneous overcurrent relays at 2, the inverse-time relays at 1 need only be selective with the inverse-time relays at 2 for faults at and beyond the point where the instantaneous relays stop

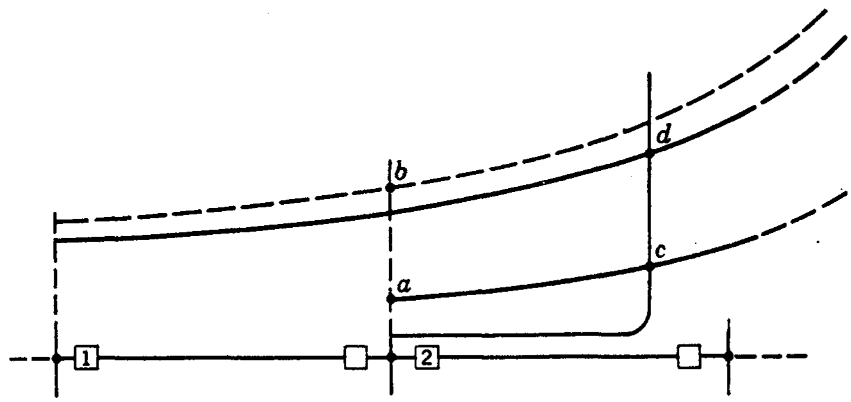

Fig. 7. Illustrating an additional advantage of instantaneous overcurrent relays.

operating, as shown by *cd*. This permits speeding up the relays at 1 from the dashed to the solid curve, which is sometimes very useful, or even necessary when complicated loop circuits are involved. Of course, under minimum generating conditions when the instantaneous relays may not operate, one must be sure that selectivity between the inverse-time relays is obtained. The fact that selectivity is not obtained between the inverse-time relays for faults just beyond the relay at 2 for maximum generating conditions is unimportant so long as selectivity is obtained down to the pickup current of the instantaneous relays.

"Overreach" is the tendency of a relay to pick up for faults farther away than one would expect if he neglected the effect of offset in the fault-current wave. Magnetic-attraction relays are more affected by offset waves than induction relays, and some induction relays are more affected than others. Certain induction relays can be designed to be unaffected by offset waves.

"Percent overreach" is a term that describes the degree to which the overreach tendency exists, and it has been defined as follows:

$$\text{Percent overreach} = 100\left(\frac{A - B}{A}\right)$$

where A = the relay's pickup current, in steady-state rms amperes.

B = the steady-state rms amperes which, when fully offset initially, will just pick up the relay.

In relays that have a tendency to overreach, the percent overreach increases as the ratio of reactance to resistance of the fault-current-limiting impedance increases, or, in other words, as the time constant of the d-c component of the fault current increases. The slower

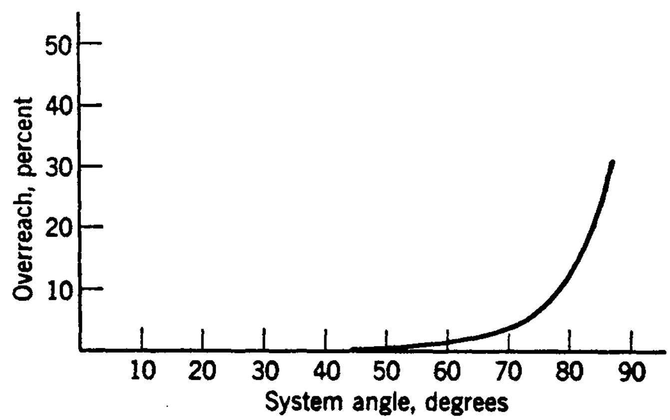

Fig. 8. Overreach characteristic of a certain instantaneous overcurrent relay.

the decay of the d-c component, the sooner will the integrated force acting on the relay cause it to pick up; and the sooner the relay tends to pick up, the lower may be the rms component of the fault current and still cause pickup. If the fault-current wave were continually fully offset, the rms component for pickup would be the smallest. It may be evident from the foregoing that, other things being equal, the faster a relay is, the greater will its percent overreach be. The maximum percent overreach would be 50% for a relay that was fast enough to respond to the instantaneous magnitude of current. Since the rms value of a fully offset sine wave is $\sqrt{3}$ times that if the wave were symmetrical, the maximum value of percent overreach is 42% for relays that are not fast enough to respond to the instantaneous magnitude of current. Figure 8 shows how the percent overreach of a certain relay increases as the system angle ($\tan^{-1} X/R$) increases. Because X/R in a distribution circuit is only about 1 or 2, the tendency to overreach is negligible.

To allow accurately for overreach when choosing the pickup of an instantaneous overcurrent relay, one must have a percent-overreach curve for the relay, like that of Fig. 8. Then, solving the foregoing equation for A, we obtain:

$$A = \frac{100B}{(100 - \text{Percent overreach})}$$

Thus, with an overcurrent relay that has a 15% overreach for a fault whose steady-state component of current is 10 amperes, if the relay is not to operate for that fault, A must exceed:

$$\frac{100 \times 10}{100 - 15} \text{ amperes} = 11.8 \text{ amperes}$$

When percent-overreach data are not available, it will usually be satisfactory to make the pickup about 25% higher than the maximum value of symmetrical fault current for which the relay must not operate. This will provide for overreach and also for some error in the data on which the setting is based.

The tendency of an instantaneous overcurrent relay to overreach on offset waves can be minimized by a so-called "transient shunt."[7] This device is described in Chapter 14 in connection with its use with distance relays for the same purpose.

THE DIRECTIONAL FEATURE

Overcurrent relaying is made directional to simplify the problem of obtaining selectivity when about the same magnitude of fault current can flow in either direction at the relay location. It would be impossible to obtain selectivity under such circumstances if overcurrent relays could trip their breakers for either direction of current flow. The directional feature is not needed for a radial circuit with a generating source at only one end. Nor is it required where short-circuit current can flow in either direction if the magnitude of current that can flow in the tripping direction is several times that in the other direction; here, the system has a sufficiently directional characteristic. However, it is best to install directional relays, even if the directional feature is not presently needed, because system changes are likely to make directional relays necessary.

All directional-overcurrent relays should have the directional-control feature, as described in Chapter 3, whereby the overcurrent unit cannot begin to operate until the directional unit operates for current flow in the direction for which the overcurrent unit should operate. Here, again, this feature is not always required, but need for it may develop in the near future.

Occasionally, voltage-restrained directional units are desirable for use with phase overcurrent relays. This need arises when the magnitude of fault current in the direction for which an overcurrent relay must trip its breaker can be about the same as–or even somewhat less than–the maximum load current that might flow in the same direction. Voltage-restrained directional units also minimize the likelihood of undesired tripping when severe power swings occur. Such directional units should also provide directional control.

The terms “directional-overcurrent” and “directional-ground,” as applied to ground relays with directional characteristics, are used by some people to denote two different types of relays. The term “directional-overcurrent” denotes a relay with separate directional and overcurrent units, and the term “directional-ground” denotes a directional unit with adjustable pickup and time-delay characteristics that combines the directional and overcurrent functions. The directional type is generally preferred because, although it imposes somewhat more burden on its CT’s and also takes up somewhat more panel space, it is much easier to adjust. This is because only the line-current magnitude affects its operation both as to sensitivity and time delay; its directional unit is so sensitive and fast that its effect may be ignored. The sensitivity and speed of the directional-ground type is a function of the product of the line current, the polarizing current or voltage, and the phase angle between them. The two types are not simply interchangeable, and it is best to standardize on one or the other and not to mix them in a system, or else selectivity may be jeopardized.

USE OF TWO VERSUS THREE RELAYS FOR PHASE-FAULT PROTECTION

The consideration of two versus three relays for phase-fault protection arises because of a desire to save the expense of one CT and one relay, or at least of one relay, in applications where only the bare minimum expense can be tolerated for the protection of a certain line. The considerations involved in such practices are as follows.

Non-Directional Relaying. Non-directional-overcurrent phase-fault relaying can be provided by two relays energized from CT’s in two of the three phases. However, protection will not necessarily be provided if the CT’s in all circuits are not located in the same phases, as illustrated in Fig. 9. The system shown in Fig. 9 is assumed to be ungrounded. Simultaneous ground faults on different phases of two different circuits will constitute a phase-to-phase fault on the system, and yet neither overcurrent relay will operate.

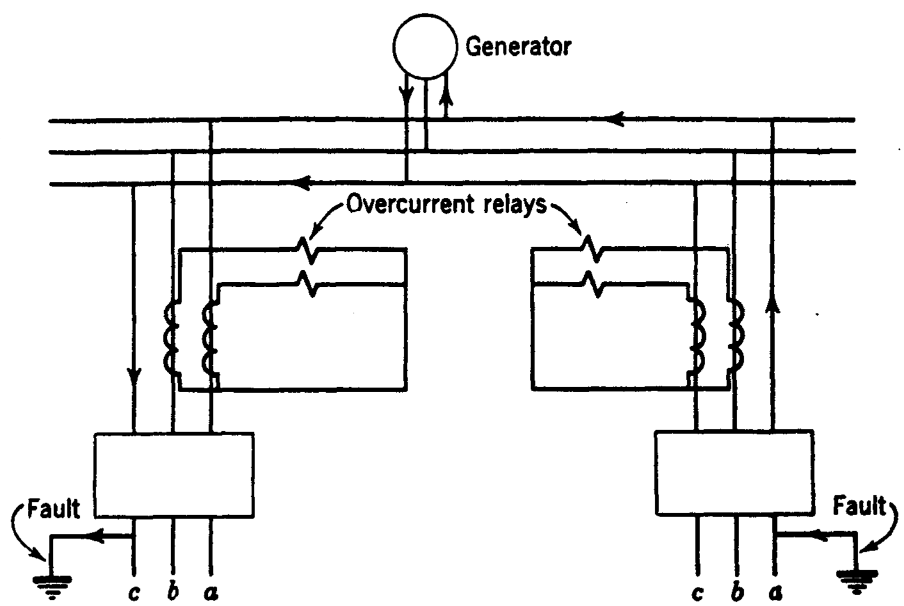

Fig. 9. A case of lack of protection with two overcurrent relays.

Whether the system neutral is grounded or not, complete protection against phase and ground faults, even in the situation of Fig. 9. is provided if three CT's are used with two phase relays and one ground relay as illustrated in Fig. 10.

If a wye-delta or a delta-wye power-transformer bank lies between the relays and a phase-to-phase fault, the magnitude of the current in one of the phases at the relay location will be twice as great as in either of the other two phases. If only two relays are used, neither relay will get this larger current for a fault between one pair of the three possible pairs of phases that may be faulted on the other side of the bank. This fact should be taken into account in choosing the pickup and time settings.

If the fault-current magnitude for a phase-to-phase fault is of the same order as the load current, the effect of load current adding to fault current in one phase and subtracting from it in another phase should be considered. This affects the pickup and time settings in a manner similar to that of an intervening power-transformer bank.

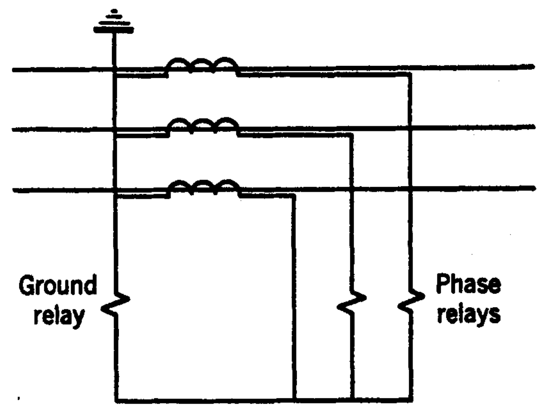

Fig. 10. Complete protection with two phase relays and one ground relay.

Three CT's and three phase relays are used wherever economically justifiable to avoid the foregoing difficulties because at least one relay will always operate for all interphase faults; and, except for the special conditions just described, two relays will operate, thereby giving double assurance of protection for much less than double the cost.

Directional Relaying. Directional-overcurrent phase-fault relaying is subject to the considerations described for non-directional-overcurrent relaying in so far as overcurrent units are concerned. In addition, there are the following considerations.

In a non-grounded system, two single-phase relays may generally be used if one is sure that the relays of all circuits are energized by currents from the same phases. Otherwise, grounds could occur on different phases of two different circuits, as in Fig. 9, thereby imposing a phase-to-phase fault on the system, and no protection would be provided. Directional-overcurrent relays for ground-fault protection are not usable on non-grounded systems, and, therefore, they could not alleviate this possible difficulty in the same way that non-directional ground-overcurrent relays do.

If directional phase relaying is to be used in two phases of a grounded-neutral system, ground relays must be provided for protection against ground faults. Then, the only question is if one or the other of the two phase relays will always operate for a phase-to-phase fault in the tripping direction.

If the magnitude of fault current for phase-to-phase faults is not several times the load-current magnitude, three single-phase directional-overcurrent relays should be used to assure tripping when desired. However, this problem involves more than just the number of relays required; the relays may operate to trip undesirably as well as to fail to trip when desired. Therefore, not only are three relays necessary but also voltage restraint on the directional units to keep them from operating undesirably. If three relays were not required for other reasons, they would be required as soon as voltage restraint is used. (This is why it is never the practice to use only two distance relays.)

With only two directional-overcurrent relays, the quadrature connection should be used. This is the best assurance that one of the two relays will always operate under the borderline conditions existing when faults occur close to the relay location.

SINGLE-PHASE VERSUS POLYPHASE DIRECTIONAL-OVERCURRENT RELAYS

Single-phase directional-overcurrent relays are generally preferred for protection against interphase faults. The main reason for this is that the very desirable feature of “directional control” is more simply and reliably obtained with single-phase directional-overcurrent relays than with a polyphase directional relay in combination with single-phase overcurrent relays. The directional-unit contact of a single-phase directional-overcurrent relay controls the operation of the overcurrent unit directly; an intermediate auxiliary relay is required when a polyphase directional unit is used.

Single-phase directional-overcurrent relays must be used when a-c tripping is involved, because separate contacts must be available for connection in each of the three CT secondary circuits. An auxiliary relay cannot be used with a polyphase directional relay to get the necessary contact separation, because there is no suitable voltage source to operate the auxiliary relay; the lack of such a voltage source is why a-c tripping is used.

A set of three single-phase directional-overcurrent relays can often be used to provide protection against single-phase-to-ground faults as well as against interphase faults. Polyphase directional relays may not be used for this purpose unless the minimum ground-fault current is more than 3 times the maximum load current.

Some users want to test the relays of each phase separately so that, if a fault occurs during testing, the relays of the other two phases can provide protection. This requires single-phase relays.

A minor advantage of single-phase relays is that they provide somewhat more flexibility in the layout of panels.

The advantage of a polyphase directional relay is that it is less subject to occasional misoperation than single-phase relays. For a certain fault condition, one of three single-phase relays may develop torque in the tripping direction when tripping would be undesirable; if the current in that one relay was high enough to operate the overcurrent unit, improper tripping would result. Since a polyphase directional relay operates on the net torque of its three elements, a reversed torque in one element can be overbalanced by the other two elements, and a correct net torque usually results. The subject of directional-relay misoperation is treated in the following section.

HOW TO PREVENT SINGLE-PHASE DIRECTIONAL OVERCURRENT-RELAY MISOPERATION DURING GROUND FAULTS

Under certain circumstances, single-phase directional-overcurrent relays for phase-fault protection may cause undesired tripping for ground faults in the non-tripping direction.

Such undesired tripping can be prevented if one only knows when special preventive measures are necessary.

The zero-phase-sequence components of ground-fault current produce the misoperating tendency. All these components are in phase, and, when wye-connected current transformers are used, these components always produce contact-closing torque in one of the three directional units no matter in which direction the current may be flowing. Generally, the other fault-current components are able to "swamp" the effect of the zero-phase-sequence components. But, when the fault current is largely composed of zero-phase-sequence component, misoperation is most likely.

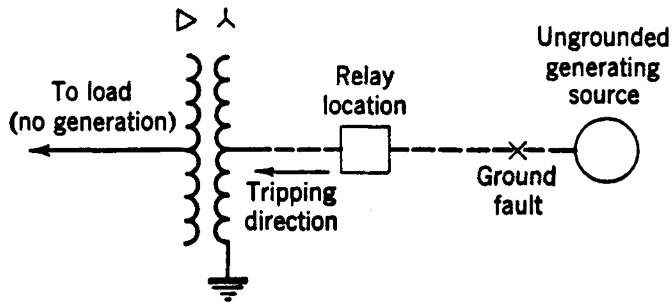

Fig. 11. A situation where single-phase directional-overcurrent relays may misoperate.

Figure 11 shows the basic type of application where undesired tripping is most apt to occur. Let us assume that the directional units of the relays are intended to permit tripping only for faults to the left of the relay location, as indicated by the arrow. However, a ground fault to the right, as shown, will cause at least one directional unit to close its contact and permit tripping by its overcurrent unit. Whether the overcurrent unit will actually trip its breaker will depend on its pickup and time settings, and on whether it gets enough current to operate before the fault is removed from the system by some other relay that is supposed to operate for this fault. Failure to trip when tripping is desired is not a problem.

Misoperation can occur also for conditions *approaching* those of Fig. 11.[8] In other words, misoperation may still occur if there is a small source of generation at the load end of Fig. 11. In general, one should examine the possibility of misoperation whenever the zero-phase-sequence impedances from the ground-fault location back to the sources of generation on either side of the fault are not approximately in the same complex ratio as the corresponding positive-phase-sequence impedances. Thus, in addition to the situation of Fig. 11, if one side of a system is grounded through resistance and the other side through reactance, misoperation is possible.

The likelihood of misoperation is greatest when the phase relays are used also for ground-fault protection, and particularly when the relays have to be more sensitive because the ground-fault current is limited by neutral impedance.

To prevent misoperation for the situation shown in Fig. 11, the phase relays should be prevented from responding to the zero-phase-sequence component of current. This can be done with a zero-phase-sequence shunt using three auxiliary current transformers, as shown in Fig. 12. It is emphasized that the neutral of the phase relays should not be connected to the CT neutral or else part of the effectiveness of the shunt will be lost. Delta-connecting the secondaries of the main current transformers would also remove the zero-phase-sequence component, but it introduces other misoperating tendencies, and it does not provide the required source of energization for ground relays. The 90-degree or quadrature connection of the phase relays should be used.

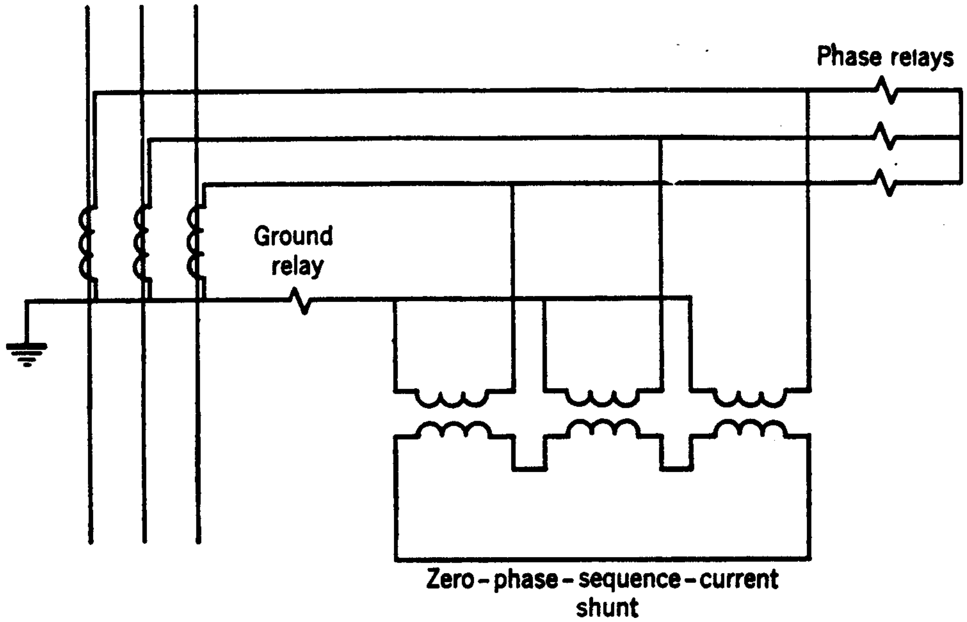

Fig. 12. Application of a zero-phase-sequence-current shunt.

The phase relays will still be able to respond to ground faults if the current magnitude is large enough, and if positive-phase-sequence components are present in the fault current. However, it is generally preferable to use separate directional-overcurrent ground relays for ground-fault protection because faster tripping can thereby be obtained. Where only zero-phase-sequence current can flow, as at the relay location of Fig. 11, separate ground relays must be used.

ADJUSTMENT OF GROUND VERSUS PHASE RELAYS

The satisfactory adjustment of ground overcurrent relays is generally easier to achieve than that of phase overcurrent relays in any system, including complicated loop systems. The principal reason for this is that the zero-phase-sequence impedance of lines (except single-phase cables) is approximately 2 to 5.5 times the positive-phase-sequence impedance, which provides two beneficial effects: (1) the magnitude of zero-phase-sequence current varies much more with fault location, and (2) the magnitude of the zero-phase-sequence current is not so much affected by changes in generating capacity.

These effects make it possible to take greater advantage of the inverse-time characteristic, and particularly of the very inverse characteristic; and also they aid the application of instantaneous overcurrent relays. Another simplification with ground relaying is that the pickup does not have to be higher than load current, because ground relays are not energized during normal load conditions, except in some distribution systems where ground current flows normally because of unbalanced phase-to-ground loading. (For other reasons to be discussed later there are limits as to how sensitive ground relays may be.) Finally, two-winding wye-delta or delta-wye power transformers are open circuits in the system so far as ground relays are concerned; in other words, except for the effect of CT errors, a ground-overcurrent relay cannot reach through such a transformer for any kind of fault on the other side. This minimizes the selectivity problem because it restricts the "reach" of the ground relays. The foregoing are the reasons why, when it is necessary to use distance relays for interphase faults, inverse-time and instantaneous overcurrent relaying are often satisfactory for ground faults.

An excellent coverage of the whole subject of ground-fault protection of transmission lines is in Reference 9.

EFFECT OF LIMITING THE MAGNITUDE OF GROUND-FAULT CURRENT

Current-limiting impedance in the grounded neutrals of generators or power transformers may be desirable from the standpoint of limiting the severity of a phase-to-ground short circuit. If carried too far, however, such practice tends to jeopardize the application of ground relaying where fast and selective operation is required.

Two problems must be considered. The first problem is that of obtaining sufficient sensitivity without danger of misoperation because of CT errors when large phase-fault currents flow. As explained later, an overcurrent relay in the neutral of wye-connected CT's will receive a current, even though a fault may not involve ground, if residual flux or d-c offset current in a CT of one phase causes it to have a different ratio error from a CT in another phase during a fault that involves large phase currents. The more sensitive the ground relay has to be in order to operate on the severely restricted phase-to-ground-fault currents, the more likely it is to operate on this CT error current.

The second problem when ground-fault current is limited by neutral impedance is to obtain prompt and selective tripping. The effect of limiting the ground-fault current by neutral impedance is to reduce the difference in magnitude of ground-fault current for faults at different locations. If there is little or no difference in the fault current for nearby or for distant faults, the inverse-time characteristic is of little use. The result is that selectivity must be obtained on the basis of time alone. Where several line sections are in series, the tripping time must be increased a fixed amount for each line section, the nearer a fault is to the source of fault current. As a consequence, faults adjacent to the source may not be cleared in less than several seconds, and during such a relatively long time the fault might involve other phases, thus causing a severe shock to the system.

It has been found from experience that a good rule of thumb is not to limit the ground-fault current of the generator or transformer to less than about its rated full-load current. Even this might be objectionable on some systems. The best procedure is to study the effect of limiting the current in each individual case.

Ground relays that are much more sensitive than phase relays may misoperate when simultaneous grounds exist at two different locations on different phases. Actually, this constitutes a phase-to-phase fault on the system, and the fault-current magnitude will be that for phase-to-phase faults. However, the ground relays of the circuits having these faults will operate as though a ground fault existed but at much higher speed than they would operate for ground faults because the current is 90 much higher. It is possible that these ground relays may operate faster than the phase relays that should operate, and the wrong breakers might be tripped because the ground relays might not be selective with each other at these higher currents[10]

TRANSIENT CT ERRORS

The principal problem introduced by transient CT errors is the effect on fast and sensitive overcurrent ground relays. The troublesome effect, often called "false residual current," is that large transient currents flow through the ground-relay coils in the CT neutral when there is no actual ground-fault current in the CT primaries. This happens because the CT's

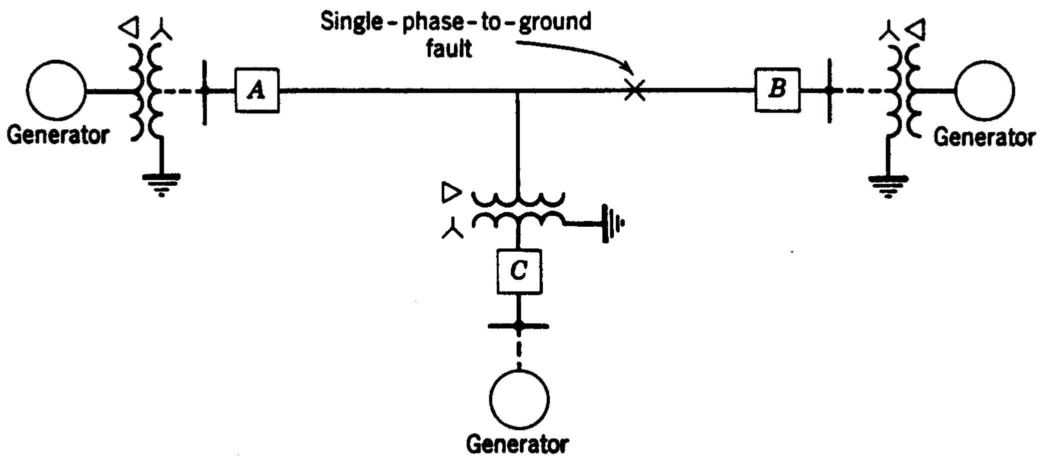

Fig. 13. Illustrating the possibility of ungrounded-neutral operation with a ground fault on the line.

have different errors because of unequal d-c offset in the primary currents or because of different amounts of residual magnetism. As a consequence, if ground-fault current is severely limited by neutral impedance and one needs to use very sensitive ground relays to detect ground faults reliably, the relays should have time delay or else they may operate undesirably on high-current interphase faults.

Such false residual current can be reduced appreciably by the addition of resistance to the CT neutral circuit if the relay burden is not already high enough to limit the current. The same mechanism applies as with current-differential relaying for bus protection, described in Chapter 12. The addition of such resistance tends to equalize the CT errors. However, the best solution is a CT whose magnetic circuit encircles all three phase conductors.[11]

Although not properly includable as consequences of transient CT errors, many other transient and steady-state conditions may cause ground-relay misoperation. Two of these–open phases and simultaneous ground faults at different locations–are described further in this chapter. The others are comprehensively treated in Reference 12. For these, as well as for transient CT errors, a solution that usually works is to make the ground relays less sensitive.

When none of the suggested solutions to false residual current can be used, it is possible to provide equipment that will permit a ground relay to close a circuit only if fault current is flowing in only one phase, such as, for example, by the relay described in Reference 13. However, this may be too heroic a solution for a distribution circuit.

The operation of other than distribution systems completely ungrounded is recognized as poor practice, and hence ground relaying in such systems is not usually a consideration. However, through circumstance, a portion of a system containing a source of generation may become disconnected from the rest of the system, and a condition of ungrounded operation may result. Consider the situation of Fig. 13 which is encountered quite frequently. Figure 13 shows a delta-wye power transformer tapped to a transmission line. A single-phase-to-ground fault on the line would cause the prompt tripping of breakers *A* and *B*.

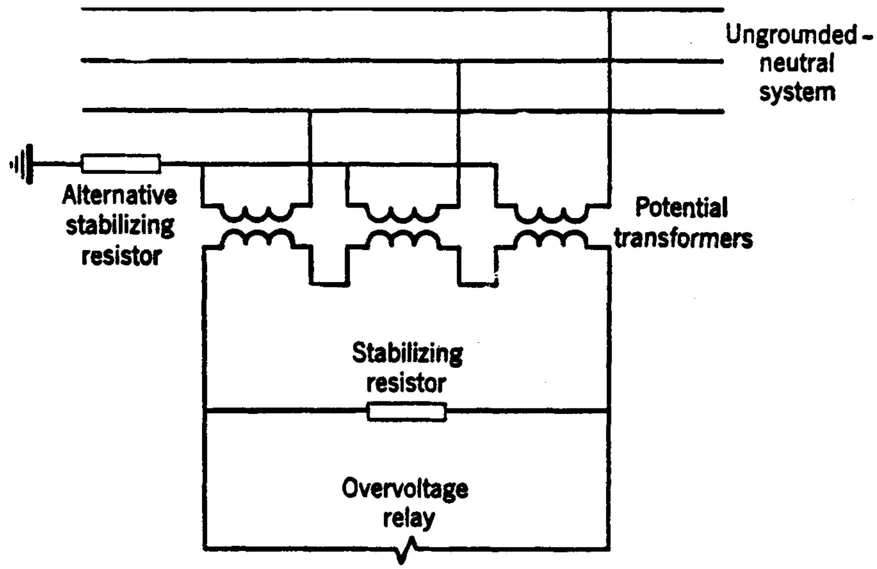

Fig. 14. A wye-broken-delta potential-transformer connection to detect a ground fault on an ungrounded-neutral system.

If we assume that breaker *C* did not trip by the operation of its phase relays before breakers *A* and *B* had tripped, the line section would still be left connected to the tapped station with no means for opening breaker *C*. So long as the fault remained single-phase-to-ground, there would be no current of short-circuit magnitude flowing at *C* after breakers *A* and *B* had opened; only charging currents would flow. But, if the fault was of a persistent nature, as, for example, if a conductor had fallen to the ground, it is highly desirable that breaker *C* open automatically.

The presence of a ground fault on an ungrounded-neutral system can be detected through the use of a wye-broken-delta potential transformer with an overvoltage relay connected across the opening in the delta, as illustrated in Fig. 14, or the wye windings of Fig. 14 may be connected to the system indirectly through the secondary of a wye-wye potential transformer, both of whose neutrals are grounded.

This potential-transformer connection will be recognized as being that described in Chapter 8 for obtaining a polarizing voltage for ground directional relays. When such a connection is used on an ungrounded system, the burden placed across the break in the delta should be greater than a certain minimum value, or else an unstable neutral condition (ferroresonance) may develop that would indicate the presence of a ground fault when no fault existed.[14] However, it has been found that occasionally the required burden is higher than that recommended in Reference 14, and is so high that it will quickly thermally overload the potential transformers. A promising solution in such cases appears to be a resistor in series with the grounded neutral of the wye windings, as shown in Fig. 14.

An alternative to Fig. 14 is one high-voltage potential transformer connected between one phase and ground, and one induction-type voltage relay with double-throw contacts. For this method to work, it is necessary that there be sufficient and well-enough-balanced capacitance to ground to establish the neutral of the three-phase system approximately at ground potential. The relay would be provided with a stiff enough control spring so that neither contact would be closed under normal-voltage conditions. Should a ground fault occur on the phase to which the potential transformer was connected, the voltage on the relay would drop and the relay would close its under voltage "*b*" contact. Should a ground fault occur on either of the other two phases, the relay voltage would rise and cause the overvoltage "*a*" contact to close. With such a relay arranged to trip a breaker on the closing of either contact, some provision must be made to permit reclosing the breaker if such reclosing is desired even though voltage has not been restored to the circuit to which the potential transformer is connected. Here, as in Fig. 14, sufficient stabilizing load should be connected to the potential-transformer secondary or inserted in series with the primary to prevent ferroresonance.[15] If a capacitance potential device were used, it would avoid this ferroresonance problem.

EFFECT OF GROUND-FAULT NEUTRALIZERS ON LINE RELAYING

Ground-fault neutralizers, or "Petersen coils," do not affect the choice of phase relays for line protection. When provision is made to short-circuit the neutralizer automatically after the expiration of a definite time if the ground fault is still present, ground relays are applied on the basis of solidly grounded-neutral operation.

Ordinarily, the ground relays will have no tendency to operate until after the neutralizer has been shorted, but rarely there may be a tendency to misoperate at certain locations before the neutralizer is shorted. Figure 15 shows a one-line diagram of a portion of a system, and the corresponding zero-phase-sequence diagram, to illustrate the cause of such a misoperating tendency. Although the total zero-phase current (I_0) may be zero or very small, the magnitudes of the currents flowing in certain branches of the zero-phase-sequence network can be large. The current through the neutralizer will be nearly equal to the normal phase-to-neutral voltage divided by the neutralizer's impedance. The total capacitance current is approximately equal in magnitude to the neutralizer current, but reversed in phase.

Ground-relay misoperation is possible in the branches where large capacitance current flows, such as at location *P* of Fig. 15. All the capacitance current in the network to the right of location *P* flows through this location. A ground directional relay at *P* is arranged not to operate when lagging current flows in the direction of the arrow. But capacitance, or leading, current flowing in the direction of the arrow will cause relay operation if the current is above the relay pickup. This tendency to misoperate can usually be corrected by increasing the relay's pickup slightly.

The more neutralizers there are at different points in the system, the less will be the charging current at any one location, and the tendency for ground relays to misoperate on charging current will be reduced.

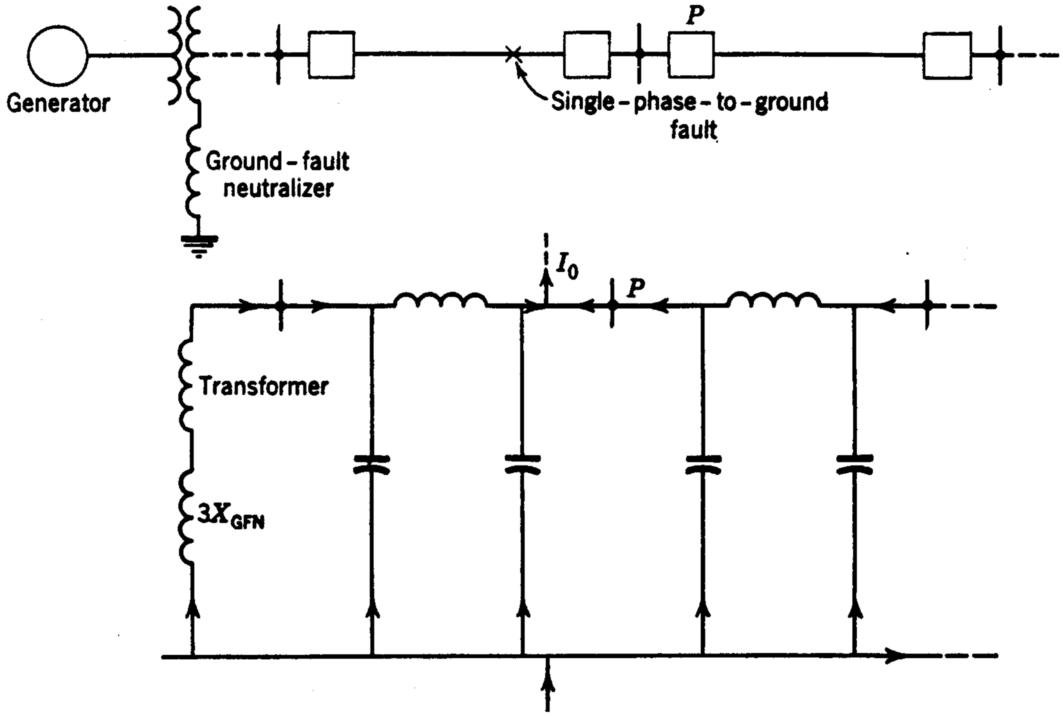

Fig. 15. System and zero-phase-sequence-network diagram illustrating tendency of ground relays to misoperate in the presence of a ground-fault neutralizer.

The practice of attempting to use very sensitive relays to obtain selective ground-relay operation without shorting neutralizers is to be discouraged in general. Such practice may be successful with radial lines, but in loop circuits it is not reliable.[16] If one objects to shorting neutralizers on the basis that destructive short-circuit currents may flow, one can always insert sufficient resistance in the neutralizer short circuit to limit the magnitude of the current and still permit enough to flow for reliable selective relay operation.

An application problem is frequently encountered when ground-fault neutralizers have been applied to a system where the line conductors are not sufficiently transposed. The consequence is that, owing to unbalanced phase-to-neutral capacitances, a net phase-to-neutral charging current returns through the earth and the neutralizer coil, and flows continuously. In the zero-phase-sequence circuit, this current path is essentially a series-resonant circuit, and large zero-phase voltages will exist continuously for relatively low currents in the series-resonant circuit. If these voltages are large enough, they will tend to cause overheating of relay voltage-polarizing coils. ((In the same system, but with solidly grounded neutrals, there is no series-resonant circuit, and the voltages are small enough to be negligible.)

Aside from not applying ground-fault neutralizers to such a system, the only solution is to be sure that the continuous ratings of ground-relay polarizing-coil circuits are high enough so that overheating will not occur, which may mean special relays or relays with decreased sensitivity. Incidentally, the ground-fault neutralizers must also be capable of withstanding the current that will flow through them continuously.

THE EFFECT OF OPEN PHASES NOT ACCOMPANIED BY A SHORT CIRCUIT

An open phase not accompanied by a short circuit may be caused by the blowing of a fuse, or by faulty contacts in a circuit breaker. Or an open-phase condition may exist for a short time because of non-simultaneous circuit-breaker-pole closing or opening, or because of single-phase switching.

This subject is too extensive to treat here in all its various aspects. In general, only ground relays are apt to operate undesirably, although sometimes the phase relays of balanced-current relaying may also operate undesirably. However, ground relays, being generally sensitive enough to operate on less than normal load current, are more apt to be the offenders. This subject is treated in more detail in Reference 12.

The operating tendencies of various types of relays can be determined from a study of the phase-sequence currents that flow during open-phase conditions. Consider the system diagram of Fig. 16. If one phase is open-circuited at the location shown in Fig. 16, the phase-sequence diagrams for the open phase are as shown in Fig. 17.

If two phases are open-circuited at the location shown in Fig. 16, the phase-sequence diagrams for the phase that is not open-circuited are shown in Fig. 18.

The arrows of Fig. 17 and 18 show the direction of current flow in the various phase-sequence networks. Note that all these currents are of load-current magnitude, their size depending on the magnitude of load current flowing before the open-phase condition occurred.

The operating tendency of current-polarized directional-ground relays can be analyzed quite simply from Figs. 17 and 18 by remembering that the relays can trip when zero-phase-sequence current flows out of the zero potential bus and into a line at a given location. A reversal of both of these directions also produces a tripping tendency. Based on this fact, Figs. 17 and 18 are labeled T (trip) and NT (not trip) at the ends of the lines to indicate the operating tendencies of the ground directional relays at those locations.

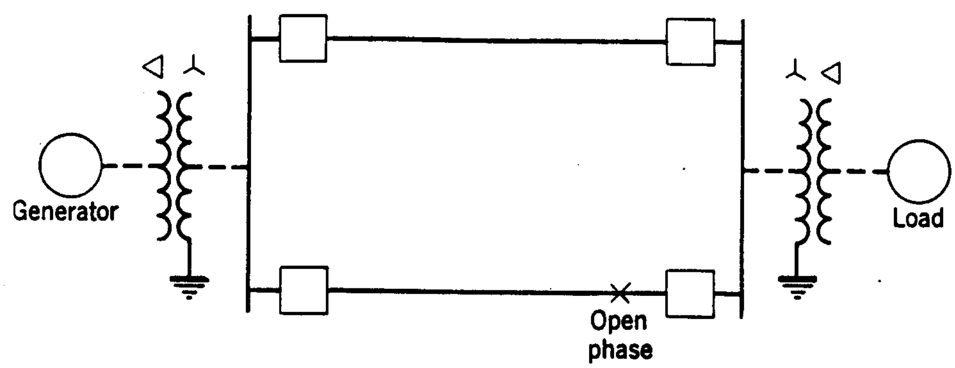

Fig. 16. Relay operation resulting from open phases.

The operation of voltage-polarized ground directional relays obtaining voltage from a bus source will be the same as for current-polarized relays. However, if voltage is obtained from the line side of the breakers, as with coupling-capacitor potential devices, an open circuit between a bus and the voltage source of a given relay will produce an operating tendency opposite to that shown on Figs. 17 and 18 for the relay at that location.

The effect that has been most troublesome, actually, is the transient effect on high-speed ground relays of non-simultaneous circuit-breaker-pole closing or opening. It has been necessary to employ induction types and sometimes to increase the pickup of the relays in order to avoid undesirable operation.

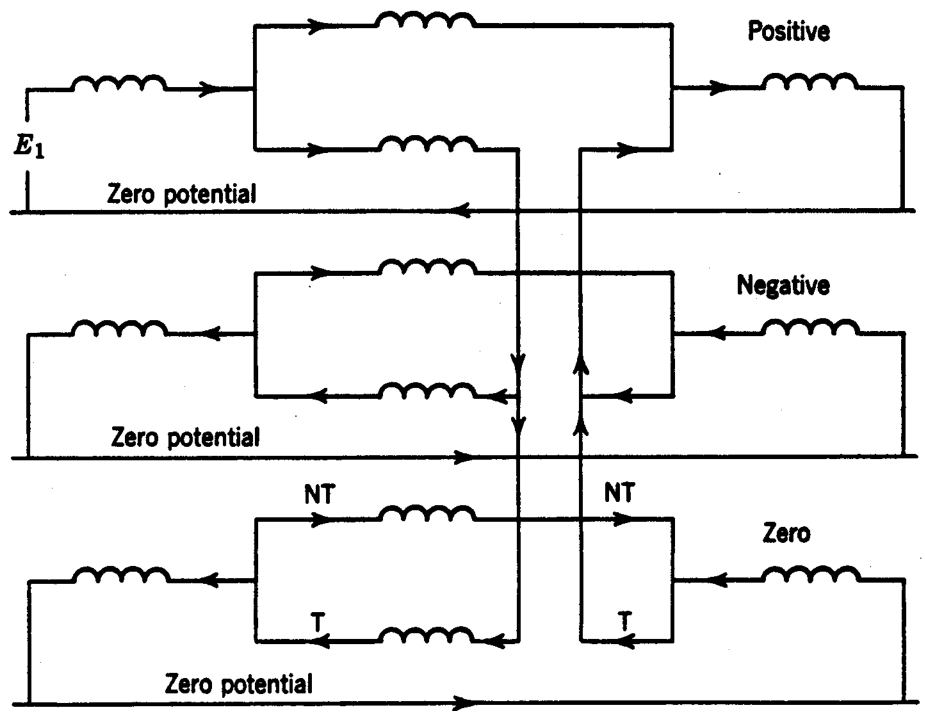

Fig. 17. Phase-sequence diagrams of the open phase when one phases is open.

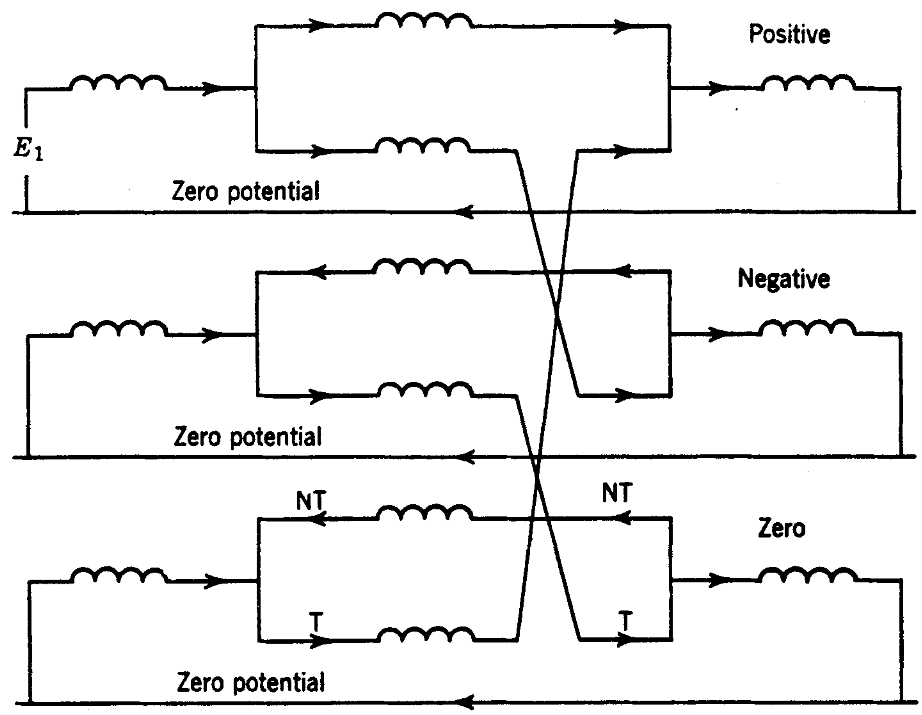

Fig. 18. Phase-sequence diagrams of the closed phase when two phases are open.

THE EFFECT OF OPEN PHASES ACCOMPANIED BY SHORT CIRCUITS

If a line conductor breaks, and one or both ends fall to the ground, we have simultaneous faults of two different types–an open-circuit and a phase-to-ground short circuit. Such faults can be analyzed by the method of symmetrical components.[17] However, it is rarely, if ever, that one has to make such an analysis because the presence of the short circuit takes command of the situation, and the proper protective relays operate to remove the short circuit from the system, the situation caused by the open circuit also being relieved.

POLARIZING THE DIRECTIONAL UNITS OF GROUND RELAYS

Directional units of ground relays may be polarized from certain zerophase-sequence-current or voltage sources, or from both simultaneously.[18] Chapter 8 describes voltage-polarization sources utilizing potential transformers or capacitance potential devices.

Figure 19 shows a method, not described in Chapter 8, for obtaining polarizing voltage from the low-voltage side of a delta-delta power-transformer bank, using only one high-voltage potential transformer to establish the neutral on the low-voltage side.[19] The same principle can be applied to a delta-wye transformer bank if the necessary auxiliary potential transformers are used to compensate for the 30° phase shift of voltages.

The voltage obtained by the method of Fig. 19 has an error caused by the voltage regulation in the transformer bank, owing to load current flowing from the high-voltage side to the low-voltage side, or caused by positive- and negative-phase-sequence currents flowing toward the fault if there is a source of generation connected to the low-voltage side. This error is not great enough to cause concern for large values of zero-phase-sequence

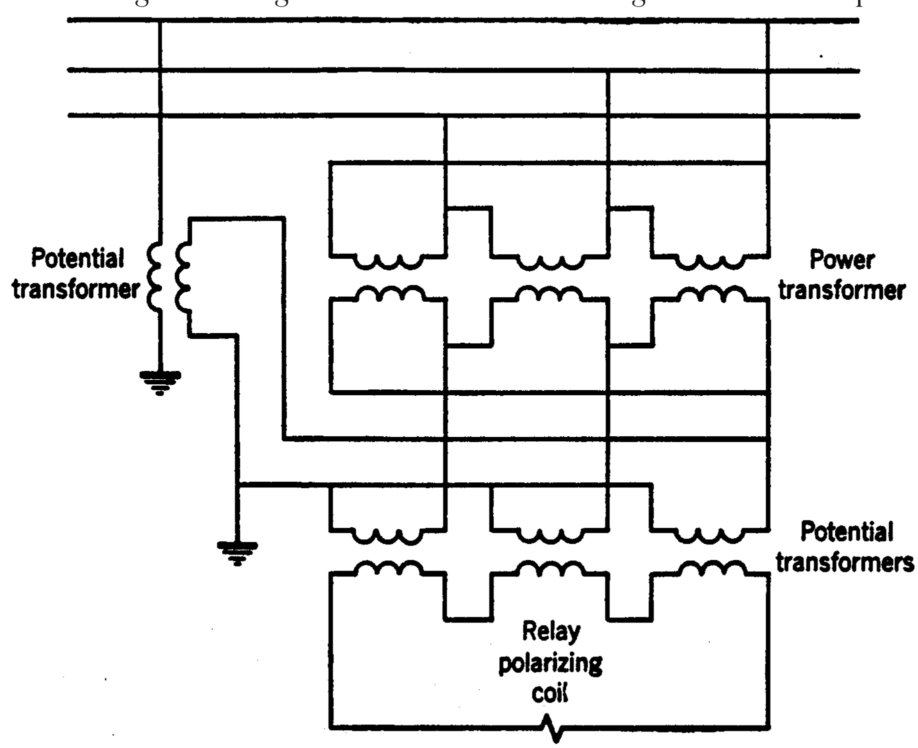

Fig. 19. Low-tension polarizing voltage for directional units of ground relays.

voltage, but for low values it might cause a directional relay to misoperate. Magnetizing-current inrush to the bank also could cause misoperation if the relay was a high-speed type. For these reasons, this kind of a polarizing source is not considered suitable for high-speed directional relays. It may be used with inverse-time directional-overcurrent relays.

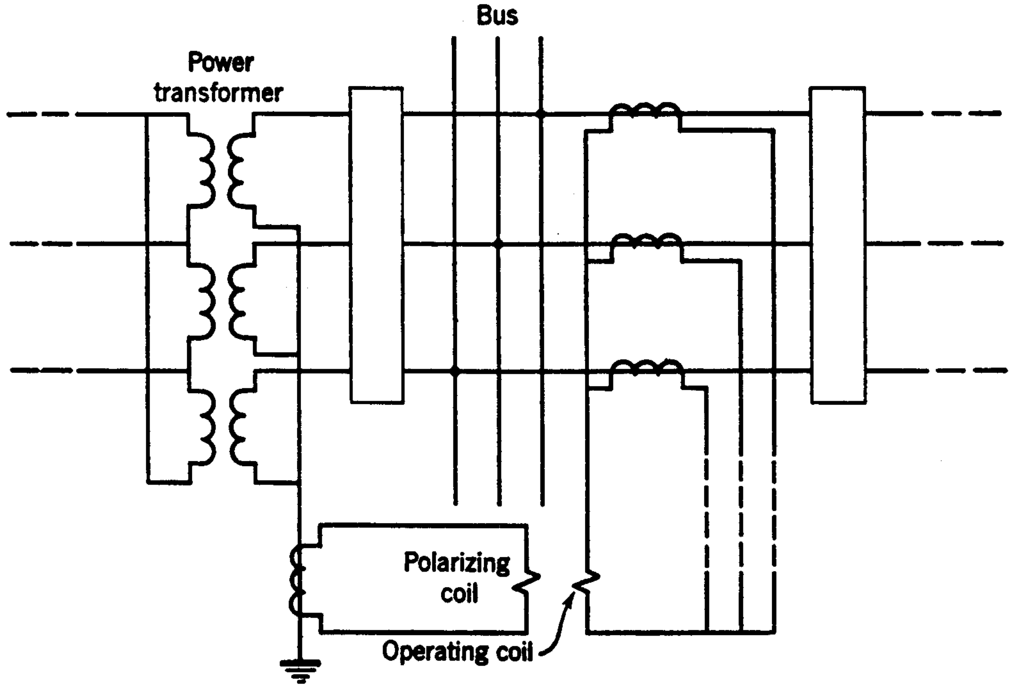

Fig. 20. Current polarization from power-transformer-neutral current.

Figure 20 shows how current polarization can be obtained from the grounded-neutral current of a three-phase power-transformer bank. As mentioned in Chapter 8 in connection with the use of voltage from the low-voltage side of a transformer bank, one should consider the reliability of a single transformer bank as a polarizing medium in view of the fact that it will be out of service occasionally for maintenance, or possibly for repair because of an internal fault. Polarizing current from paralleled CT's in the grounded neutrals of two or more transformer banks is considered sufficiently reliable if the banks have separate circuit breakers so that one bank will always be in service.

With a three-winding wye-delta-wye power-transformer bank, polarizing CT's should be put in the grounded neutrals of both wye windings and paralleled. The ratios of these two CT's should be inversely proportional to the voltage ratings of the wye windings.

As an alternative to the neutral CT's with either two- or three-winding transformers, a single CT in series with one of the delta windings may be used if these windings do not supply external load or are not connected to a generating source. If there are external connections to the delta, three CT's are required, one in each of the three windings. These CT's should be paralleled, as shown in Fig. 21, in such a way that their output is proportional to 3 times the zero-phase-sequence component of current circulating in the delta when a ground fault occurs.

As a second alternative to the neutral CT's, the neutral current of wye-connected CT's in series with the wye windings may be used, as in Fig. 22. In the three-winding power transformer, the ratios of these CT's should be inversely proportional to the voltage ratings

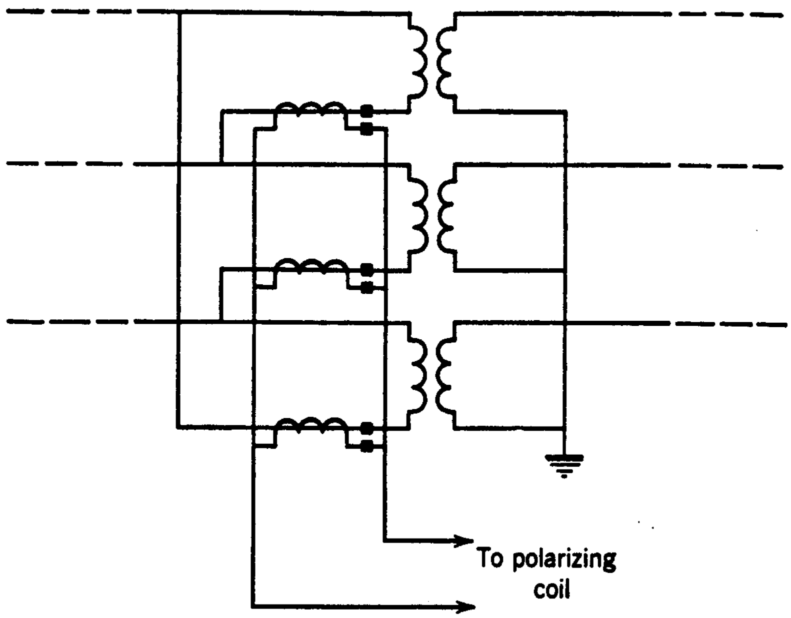

Fig. 21. Current polarization from a loaded power-transformer delta.

of the wye windings, as when neutral CT's are used. This alternative is not exactly equivalent to neutral CT's because of the possibility of false residual current, and, therefore, it should not be used with high-speed relays.

In an autotransformer bank with a delta tertiary, either of the two alternatives to the neutral CT's may be employed. It is generally not permissible to use a CT in the neutral because the neutral current for a low-voltage fault may be reversed from the neutral current for a high-voltage fault. Infrequently, the distribution of fault currents is such that a neutral CT may be used; however, one should realize that the conditions might change as system changes are made.

The primary-current rating of a neutral or delta-winding CT used for polarizing directional units of ground relays should be such that the polarizing and operating coils of a directional unit get about the same current magnitudes for any fault for which it must operate.

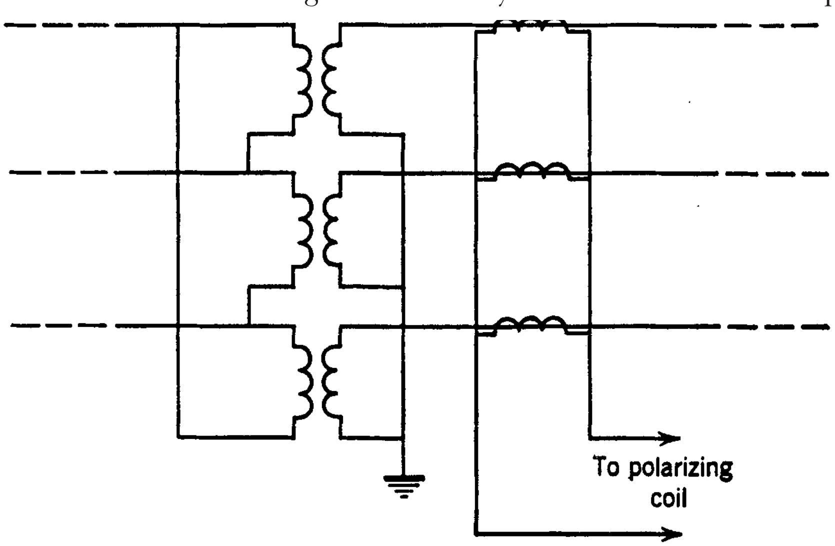

Fig. 22. Alternative to Fig. 20.

This is more important for the so-called "directional-ground" relays whose published characteristics hold only if one current does not differ too much from the other.

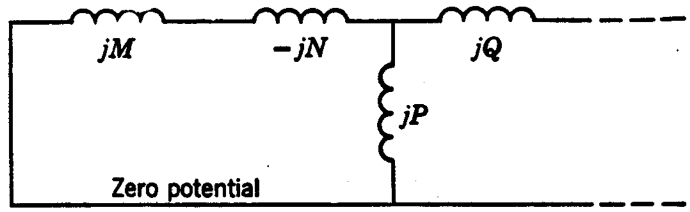

Fig. 23. Zero-phase-sequence diagram illustrating a case where polarization by the methods of Figs. 20 to 22 will cause misoperation.

In rare cases, such as that illustrated in Fig 23, none of the foregoing methods of current polarization may be used. Such circumstances may exist when one branch (N) of the equivalent circuit of a three-winding power transformer or autotransformer has negative reactance and when the zero-phase-sequence reactance of the system (M) connected to this negative branch is less than the reactance of the negative branch. In other words, on the side of this branch, the total zero-phase-sequence reactance including this branch of the transformer ($M + N$) is negative. Then, if this total negative reactance is smaller than the positive reactance of the branch representing the delta winding (P), all conditions are satisfied to make unsuitable any of the current-polarizing methods that have been described. When these circumstances exist, it becomes necessary either to use voltage polarization or, possibly, a special combination of currents.[20]

Directional relays are available that are arranged for polarization simultaneously by voltage and current.[18] Apart from simplifying the problem of stocking spare relays, "dual polarization," as it is called, has certain functional advantages. Sometimes, current or voltage alone is unsatisfactory because either source may sometime be disconnected from the system and thereby be rendered useless when it is still needed. With dual polarization, either source may be disconnected so long as the other is left in service. In other circumstances, either voltage or current polarization alone provides objectionably weak polarization but the two together assure strong polarization.

NEGATIVE-PHASE-SEQUENCE DIRECTIONAL UNITS FOR GROUND-FAULT RELAYING

When there is no zero-phase-sequence-current or voltage source for polarizing the directional unit of a ground relay, it is often possible to use a negative-phase-sequence directional unit if separate ground relaying is required. However, one must be sure that sufficient negative-phase-sequence current and voltage will be available to assure reliable operation of the directional unit for all conditions for which it must operate. In some systems that are grounded through impedance, the negative-phase-sequence quantities may be too small.

A negative-phase-sequence directional unit may be either a simple directional unit supplied with negative-phase-sequence current and voltage from filter circuits[21] or it may consist of two polyphase directional units with opposing torques, as described in Chap. 9.

Another advantage of negative-phase-sequence directional units is that they are not affected by mutual induction between paralleled circuits when ground faults occur.

Chapter 15 shows that directional relays with zero-phase-sequence polarization may operate undesirably under such circumstances.

In spite of any advantages the negative-phase-sequence relay may have, it is used only as a last resort, because the zero-phase-sequence relay is simpler and easier to test, and because it produces more reliable torque under all conditions where it is applicable.

CURRENT-BALANCE AND POWER-BALANCE RELAYING

Prior to the introduction of high-speed distance and pilot relaying, current-balance and power-balance relaying were used extensively for the protection of parallel lines. Aside from instantaneous overcurrent relaying, they were the only available forms of instantaneous. relaying for transmission lines. Their present-day usage for new installations is rare, but many old installations are still in service, and occasionally a new one is justified.

Current-balance relaying is illustrated in Fig. 24 for one phase of a pair of three-phase parallel lines. Two overcurrent-type current-balance units are shown schematically, having operating coils *O* and restraining coils *R*. One unit has contacts *A* that trip breaker *A*, and the other unit has contacts *B* for tripping breaker *B*. The trip circuits are not shown, but they are arranged so that tripping of either breaker can occur only when both breakers are closed. Furthermore, each phase-relay unit is restrained either by its control spring or by voltage (not shown) so that it will not operate with operating-coil current corresponding to maximum load and no restraining current (or, in other words, it will not operate when only one line is closed and carrying maximum load). This restraint is necessary with this type of relay to prevent immediate undesirable tripping when a line is being returned to

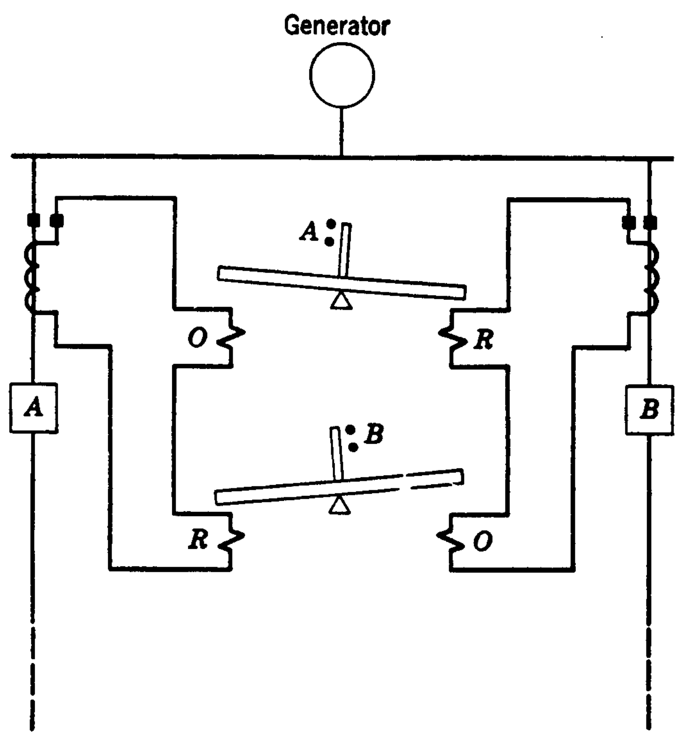

Fig. 24. Current balance relaying of parallel lines.

service and one end is closed while the other end is open. Such restraint is unnecessary on a current-balance ground relay obtaining current from the CT neutrals, because normally there is no neutral current.

Power-balance-relaying is illustrated in Fig. 25. As shown, the CT's of each corresponding phase of the two parallel lines are cross-connected, and the current coil of a directional relay is differentially connected across the CT interconnections. While the currents flowing into the two lines are equal vectorially, no current will flow in the directional-relay coil, the currents merely circulating between the two CT's. If the current in one line becomes larger than that of the other, current will flow in one direction through the relay coil. If the current of the other line is larger, the current will flow in the other direction. Thus, the relay will close one or the other of its doublethrow contacts to trip the breaker of the line having the larger current. Instead of the single relay shown in Fig. 25, two relays may be used, contact *A* being on one, and contact *B* on the other. As described for current-balance relaying, the trip circuits are arranged so that both breakers must be closed before either can be tripped. Supplementary overcurrent relays connected in series with the directional-relay current coils provide a sensitivity adjustment.

Power-balance relaying can be used at either end of parallel lines, as contrasted with current-balance relaying, which can be used only where there is a connection to a source of short-circuit current. If there is no such source at one end of a pair of parallel lines, the magnitudes of the currents in the two lines are equal at that end for a fault on one line, and hence a relay that compares only the magnitudes of the currents would not operate. The power-balance equipment compares not only magnitude but also the phase relation of the currents in the two lines, and, since the direction of current flow in one line is reversed from that in the other line at the load end, this equipment will operate to trip the faulty line. The only reason for ever using current-balance relaying is that it is somewhat

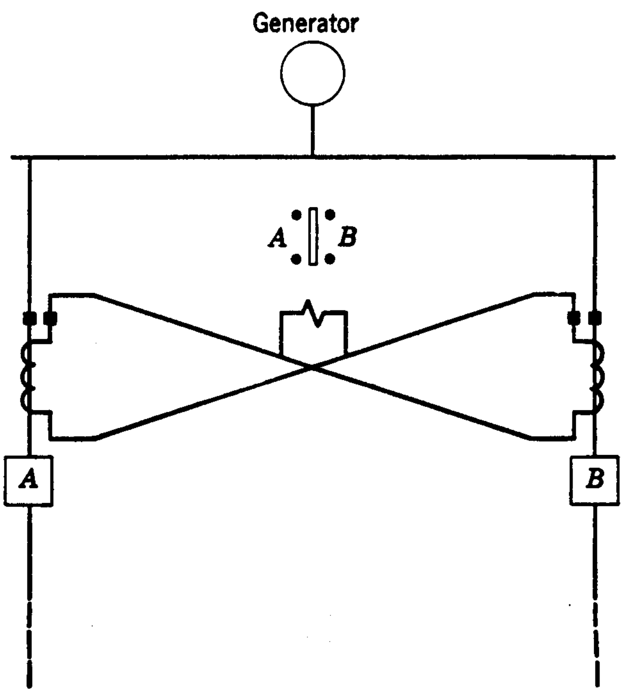

Fig. 25. Power-balance relaying of parallel lines.

simpler and less expensive, especially if no voltage restraint is involved and since supplementary overcurrent relays are not required to establish the sensitivity.

Both current-balance and power-balance relaying are effective only while both lines are in service. For single-line operation, supplementary relaying is required. This supplementary relaying is also required to provide back-up protection for faults in adjoining lines or other system elements, since the current- or power-balance relaying will not operate for faults outside the two parallel lines. Unless relaying comparable to that provided by distance relays is used for single-line operation, faults during single-line operation will not be cleared nearly so quickly as when both lines are in service; and, if fast clearing is required for single-line operation, current-balance or power-balance relaying cannot be justified. The only exception to this is for protection against single-phase-to-ground faults for which distance relaying may not be economically feasible; then, current-balance or power-balance relaying will minimize the likelihood of a single-phase-to-ground fault on one line developing into a fault involving the other line, when both lines are close together.

AUTOMATIC RECLOSING

Experience has shown that 70% to 95% of all high-voltage transmission-, subtransmission-, and distribution-line faults are non-persisting if the faulty circuit is quickly disconnected from the system. This is because most line faults are caused by lightning, and, if the ensuing arcing at the fault is not allowed to continue long enough to badly damage conductors or insulators, the line can be returned to service immediately.[22] Where the fault persists after the first trip and closure, experience has ah own it to be desirable to try as many as two or three more reclosures before keeping the line out of service until the trouble can be found and repaired.

Automatic reclosing is generally applied to all types of circuits. Subtransmission lines having overcurrent relaying usually have multi equipment, with supplementary "synchronism-check" equipment at one end if it is likely that the line may sometime be the only tie between certain generating stations. Synchronism-check equipment is relay equipment that permits a circuit breaker to be closed only if the parts to be connected by the breaker are in synchronism. On radial lines, there is no need for synchronism check.

In distribution systems in which selectivity with branch-circuit fuses is involved, multireclosure is also used.[23] Instantaneous and inverse-time overcurrent relays are arranged so that, when a fault occurs, the instantaneous relays operate to trip the breaker before a branch fuse can blow, and the breaker is then immediately reclosed. However, after the first tripout, the instantaneous relays are automatically cut out of service so that if the fault should persist the inverse-time relays would have to operate to trip the breaker. This gives time for the branch-circuit fuse of the faulty circuit to blow, if we assume that the fault is beyond this fuse. In this way, the cost of replacing blown branch-circuit fuses is minimized, and at the same time the branch-circuit outage is also minimized. If the breaker is not tripped within a certain time after reclosure, the instantaneous relays are automatically returned to service.

When industrial loads are to be fed from lines with automatic reclosing, certain problems exist that must be solved before automatic reclosing can be safely permitted. They have to do with the possible loss of synchronism between the utility and the industrial plant that makes it necessary to cut the plant loose from the utility before the utility's breakers reclose. At the same time, the industrial plant may have to resort to some "load shedding" of unessential loads so as to be able to supply its essential load from its own generating source. These problems, as well as other problems of industrial-plant protection, are discussed at length and solutions are given in the material under Reference 24.

RESTORATION OF SERVICE TO DISTRIBUTION FEEDERS AFTER PROLONGED OUTAGES

Large economies can be effected in the design and operation of distribution circuits and related equipment by taking advantage of the diversity between loads. Under normal operating conditions, the actual load on a distribution feeder will generally be considerably less than the total rating of the power-utilization equipment served by the feeder. When such a feeder is quickly reclosed after the clearing of a fault, the inrush current will not greatly exceed the normal load current, and the current will quickly return to normal. But after such a feeder has been out of service long enough so that the normal "off" period of all loads, such as electric furnaces, refrigerators, water heaters, pumps, air conditioners, etc., has been exceeded, all these loads will be thrown on together with no diversity between them. The total inrush current to all the electric motors involved, added to the current of other loads, may be several times the normal peak-load current, decaying to approximately 1.5 times the normal peak-load current after several seconds.[25] This subject has been called "cold-load restoration" or "cold-load pickup."

Protective relaying for such feeders is faced with the problem of selecting between such inrush currents and the current to a fault at or beyond the next automatic sectionalizing point. An induction-type extremely inverse-time-overcurrent relay, having a time-current curve closely matching that of a fuse down to an operating time of approximately 0.1 second, has given some relief for such an application. However, the best solution seems to be automatic sectionalizing on prolonged loss of voltage, and time-staggered automatic reclosing on the return of voltage.

COORDINATING WITH FUSES

When overcurrent relays must be selective with fuses, the relay that will provide such selectivity and still be the fastest for faults for which it must operate is the extremely inverse type just described for cold-load restoration. Occasionally it may be necessary to add a delay of a few cycles, in the form of an auxiliary relay, to maintain selectivity at very high fault currents.

A-C AND CAPACITOR TRIPPING

Some installations, particularly in distribution systems, cannot justify the expense and the maintenance of a storage battery and its charging equipment solely for use with protective-relaying equipment of one or two circuits. Then "a-c tripping" or "capacitor tripping" may be used if they are applicable.

In one type of a-c tripping equipment, a reactor, called a “tripping reactor,” is permanently connected in series with the coil of each overcurrent relay in the CT secondary circuit. The circuit breaker has a separate trip coil for each overcurrent relay. Each trip coil is connected across a tripping reactor through the contact of the corresponding overcurrent relay. Figure 26 shows the connections when three relays are involved. This method of tripping is applicable when the rms voltage drop through a reactor is sufficiently high during a short circuit to actuate the reactor’s corresponding trip-coil mechanism should its overcurrent relay close its contact. Reactors of various ratings are available for producing the required voltage whenever the current is high enough to close the relay contacts. However, owing to limitations in the ability of CT’s to produce sufficient rms voltage at low primary currents, this method of tripping is effective only for short-circuit currents of the order of rated load current or higher. Saturation of the tripping reactor limits the rms voltage to a safe value at high fault currents, and a shunt resistor, not shown in Fig. 26, holds down the crest value of voltage.

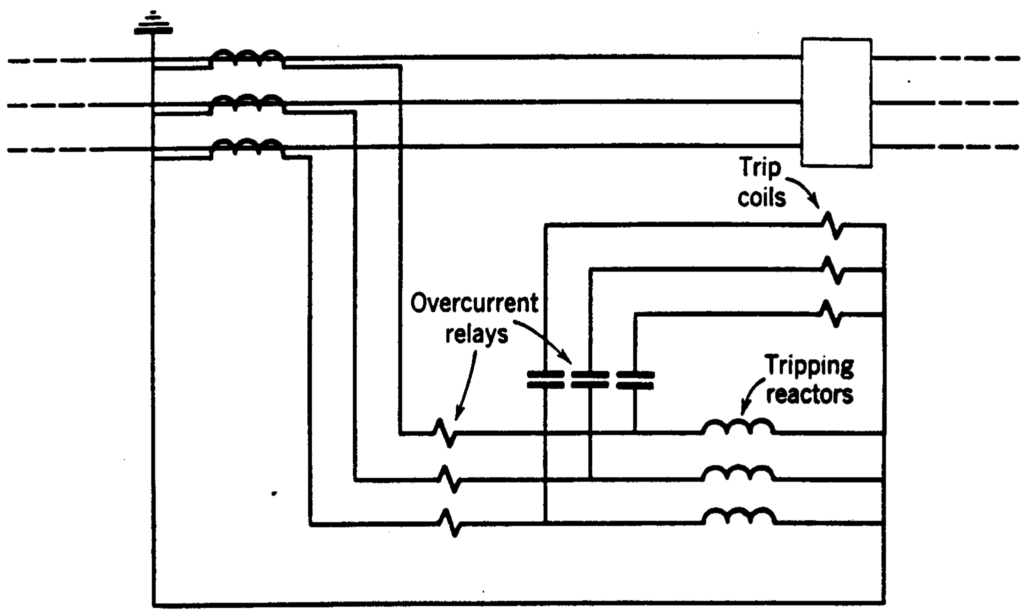

Fig. 26. A-c tripping with tripping reactors.

When the fault current for a single-phase-to-ground short circuit is less than the pickup of the phase overcurrent relays, phase-to-phase voltage from the secondary of a potential transformer may be used for tripping by a ground overcurrent relay in conjunction with a separate voltage trip coil. For a single-phase-to-ground fault, the phase-to-phase voltage will usually be large enough so that reliable tripping will be assured. A-c voltage can be used for tripping by other types of protective relays that operate for other than short circuits, or, in other words, when the voltage is not badly affected.

A-c tripping is inferior principally in its limited sensitivity for interphase faults, and also because of more severe relay contact duty which requires more maintenance. Also, the burden imposed on the CT’s is high, and, unless the CT’s are good enough to support this burden, the relaying sensitivity will be poor. Because of the high burden, accurate metering cannot be provided from the same CT’s. A minor limitation is that single-phase relays must be used; a poly-phase directional relay having but one contact could not be used because there would not be a suitable source for operating an auxiliary relay to provide the necessary additional contacts.

Capacitor tripping uses the stored energy of a charged capacitor to actuate a trip-coil mechanism. The capacitor is charged through a rectifier from a-c voltage obtained from the system. Its principal advantage over a-c tripping is greater sensitivity for interphase faults. Also, it permits the use of polyphase relays that do not need auxiliary relays, although an additional capacitor tripping device has been used to operate an auxiliary tripping relay. Its principal disadvantage is that the circuit-breaker trip mechanism gets only one impulse and not a steady force as with a-c tripping; this fact makes some people feel that the breaker requires a more "hair-triggered" trip mechanism, and consequently that it is apt to be less reliable.

PROBLEM

Given a simple loop system as shown in Fig. 27, where the impedances are in percent based on the rating of one of the generators.. Adjust overcurrent relays having time characteristics of Chapter 3, Fig. 3, for the protection of all the lines against phase faults, assuming and indicating directional elements, wherever necessary, by an arrow pointing in the tripping direction. Neglect the fact that the pickup should be well above load current. Make your adjustment on the basis of per unit primary current, assuming that any desired pickup can be obtained.

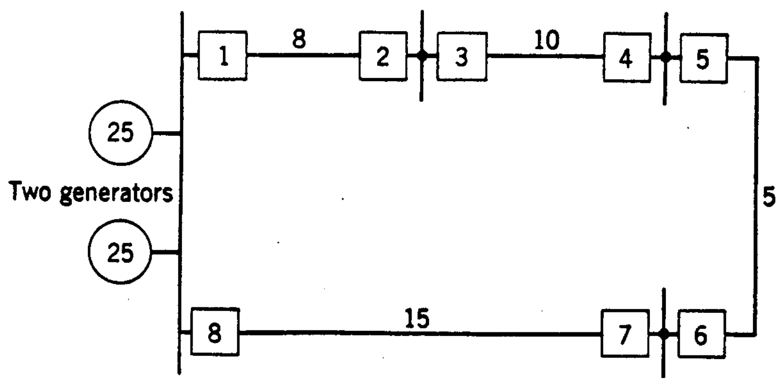

Fig. 27. Illustration for problem.

BIBLIOGRAPHY

1. "Long 60-Cycle Arcs in Air," by A. P. Strom, *AIEE Trans., 65* (1946), pp. 113-117. Discussions, pp. 504-507.

2. "Power System Faults to Ground, Part II Fault Resistance," by C. L. Gilkeson, P. A. Jeanne, and E. F. Vaage, *A1EE Trans., 56* (1937), pp. 428-433, 474.

3. "Application of the Ohm and Mho Principles to Protective Relays," by A. R. van C. Warrington, *AIEE Trans., 65* (1946), pp. 378-386. Discussions, pp. 490-491.

"Reactance Relays Negligibly Affected by,Arc Impedance," by A. R. van C. Warrington, *Elec. World, 98,* No. 12 (Sept. 19, 1931), pp. 502-505.

4. "Sensitive Ground Protection for Radial Distribution Feeders," by Lloyd F. Hunt and J. H. Vivian, *AIEE Trans., 59* (1940), pp. 84-87. Discussions, pp. 87-90.

"Some Recent Relay Developments," by Lloyd F. Hunt and A. A. Kroneberg, *AIEE Trans., 53* (1934), pp. 530-535.

5. "Effect of Fault Resistance on Ground-Fault Current," by Martin J. Lantz, *AIEE Trans., 72,* Part III (1953), pp. 1016-1019.

6. "Instantaneous Overcurrent Relays for Distance Relaying," by C. B. Frier, *AIEE Trans., 54* (1935), pp. 404-407. Discussions, pp. 883-884.

7. *Silent Sentinels,* Westinghouse Electric Corp., Meter Division, Newark, N. J.

8. "A Study of Directional Element Connections for Phase Relays," by W. K. Sonnemann, *AIEE Trans., 69,* Part II (1950), pp. 1438-1450. Discussions, pp. 1450-1451.

9. "Ground Fault Relay Protection of Transmission Lines," by J. L. Blackburn, *AIEE Trans., 71* (1952), pp. 685-691. Discussions, pp. 691-692.

10. "Ground Relays Set for Simultaneous 1-Ph Faults," by John M. Showman, *Elec. World,* Sept. 6, 1954, p. 102.

11. "Earth-Leakage Relays; with Use of Ring-Type Current Transformers," by E. T. B. Gross, *Electrician (London),* 123 (July, 1939), pp. 93-95.

"Sensitive Ground Protection," AIEE Committee, *AIEE Trans., 69,* Part I (1950), pp. 473-475. Discussions, pp. 475-476.

12. "Some Utility Ground-Relay Problems," by H. C. Barnes, and A. J. McConnell, *AIEE Trans., 74,* Part III (1055), pp. 417-428. Discussions, pp. 428-433.

13. "A New Single-Phase-to-Ground Fault-Detecting Relay," by W. K. Sonnemann, *AIEE Trans., 61* (1942), pp. 677-680. Discussions, pp. 995-996.

14. "Criteria for Neutral Stability of Wye-Grounded-Primary Broken-Delta Secondary Transformer Circuits," by H. S. Shott and H. A. Peterson, *AIEE Trans., 60* (1941), pp. 997-1002. Discussions, pp. 1394-1395.

15. "Neutral Inversion of a Single Potential Transformer Connected Line-to-Ground on an Isolated Delta System," by Lyle L. Gleason, *AIEE Trans., 70,* Part I, pp. 103 110. Discussions, pp. 110-111.

16. “Sensitive Ground Protection for Transmission Lines and Distribution Feeders,” E. T. B. Gross, *AIEE Trans., 6*0 (1941), pp. 968-971.

17. *Circuit Analysis of A-C Power Systems,* Vol. I, by Edith Clarke, John Wiley & Sons, New York, 1943.

18. “Dual-Polarized Directional-Ground Relays,” by W. C. Morris, *Distribution,* April, 1952, pp. 8, 9.

19. United States Patent 2378800.

20. “Ground Relay Polarization,” by J. L. Blackburn, *AIEE Trans., 71* (1952), pp. 1088-1093. Discussions, pp. 1093-1095.

21. “Directional Overcurrent Ground Relaying,” by B. V. Hoard and S. C. Leyland, *Elec. J.,* 36, No. 3, March, 1939, pp. 97-101.

22. “Faster Reclosing Breakers Needed,” by J. T. Logan, *Elec. World, 103,* No. 16 (April 21, 1934), pp. 571-573.

23. “”Progress Report on Coordination of Construction and Protection of Distribution Circuits Based on Operating Data for Year 1949,” by AIEE Committee, *Technical Paper 52-13.*

“Reclosure Sequence and Coordination,” by R. C. Kirk, *Elec. Light and Power,* Dec., 1954, pp. 99-100, 148.

24. “Relay Protection of 33-Kv Tie Feeders to a Large Industrial Customer,” by W. H. O’Connor and H. D. Ruger, Elec. Eng., Feb., 1952, p. 165.

“Protective Relaying on Industrial Power Systems,” by Carl M. Lathrop, and Charles E. Schleckser, *AIEE Trans., 70,* Part II, pp. 1341-1344. Discussions, pp. 1344-1345.

“Protection for an Industrial Plant Connected to a Utility System with Reclosing Breakers,” by D. F. Langenwalter, *Distribution, 15,* No. 5 (Nov., 1953), pp. 17-20.

“Parallel Operation of Industrial Power Plants with Public Utilities,” by L. G. Levoy, *Distribution, 15,* No. 5 (Nov., 1953), pp. 10-16.

“Frequency Relays Disconnect Synchronous Motors,” by A. J. Meyers, *Power Generation,* July, 1949, p. 82.

“Application and Tests of Frequency Relays for Load Shedding,” by L. L. Fountain and J. L. Blackburn, *AIEE Trans., 73,* Part III (1954), pp. 1660-1664. Discussions, pp. 1664-1668.

“Selecting A-C Overcurrent Protective Device Settings for Industrial Plants,” by F. P. Brightman, *AIEE Trans., 71,* Part II (1952), pp. 203-211.

“More about Setting Industrial Relays,” by F. P. Brightman, *AIEE Trans., 73* (1954), pp. 397-405. Discussions, pp. 405-406.

“Inertia Relay ‘Anticipates’ to Facilitate Reclosure,” by J. T. Logan and J. H. Miles, *Elec. World,* 113 (April, 1940), pp. 1061-1064.

Industrial Power Systems Handbook, McGraw-Hill Book Co., New York, 1955.

25. “A New Approach to Cold Load Restoration,” by Oliver Ramsaur, *Elec. World,* Oct. 6, 1952, pp. 101-103.

"New Relay Assures Feeder Resumption after Outage," by M. H. Pratt, L. J. Audlin, and A. J. McConnell, *Elec. World,* Part I, Sept. 10, 1949, pp. 99-103. Part II, Sept. 24, 1949, pp. 95-98.

"Diversity a New Problem in Feeder Pickup," by C. E. Hartay and C. J. Couy, *Elec. Light and Power,* Oct., 1952, pp. 142-146.