GET-6450

Distribution System Feeder Overcurrent Protection

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INTRODUCTION

With the increasing loads, voltages and short-circuit duty of distribution substation feeders, distribution overcurrent protection has become more important today than it was even 10 years ago. The ability of the protective equipment to minimize damage when failures do occur and also to minimize service interruption time is demanded not only for economic reasons but also because the general public just expects “reliable” service.

This publication will attempt to review some of the present distribution practices, particularly with regard to relaying, in view of some of these new developments. It is not the purpose of this publication to settle the controversy surrounding some of the problems dealt with, but rather to give the reader a better understanding of distribution overcurrent protection problems and some of the methods being used to solve them.

Among the areas covered will be such things as: cold-load pickup, ground-fault detection, tripping methods, current-transformer (CT) connections, line burndown, and coordination between various devices.

RELAY FUNDAMENTALS

REQUIRED CHARACTERISTICS

The required characteristics necessary for protective equipment to perform its function properly are: sensitivity, selectivity, speed and reliability. This is especially true for relays.

Sensitivity

Sensitivity applies to the ability of the relay to operate reliably under the actual condition that produces the least operating tendency. For example, a time-overcurrent relay must operate under the minimum fault current condition expected. In the normal operation of a power system, generation is switched in and out to give the most economical power generation for different loads which can change at various times of the day and various seasons of the year. The relay on a distribution feeder must be sensitive enough to operate under the condition of minimum generation when a short circuit at a given point to be protected draws a minimum current through the relay. *(NOTE: On many distribution systems, the fault-current magnitude does not differ very much for minimum and maximum generation conditions because most of the system impedance is in the transformer and lines rather than the generators themselves.)*

Selectivity

Selectivity is the ability of the relay to differentiate between those conditions for which immediate action is required and those for which no action or a time-delayed operation is required. The relays must be able to recognize faults on their own protected equipment and ignore, in certain cases, all faults outside their protective area. It is the purpose of the relay to be selective in the sense that, for a given fault condition, the minimum number of devices operate to isolate the fault and interrupt service to the fewest customers possible. An example of an inherently selective scheme is differential relaying; other types, which operate with time delay for faults outside of the protected apparatus, are said to be relatively selective. If protective devices are of different operating characteristics, it is especially important that selectivity be established over the full range of short-circuit current magnitudes.

Speed

Speed is the ability of the relay to operate in the required time period. Speed is important in clearing a fault since it has a direct bearing on the damage done by the short-circuit current; thus, the ultimate goal of the protective equipment is to disconnect the faulty equipment as quickly as possible.

Reliability

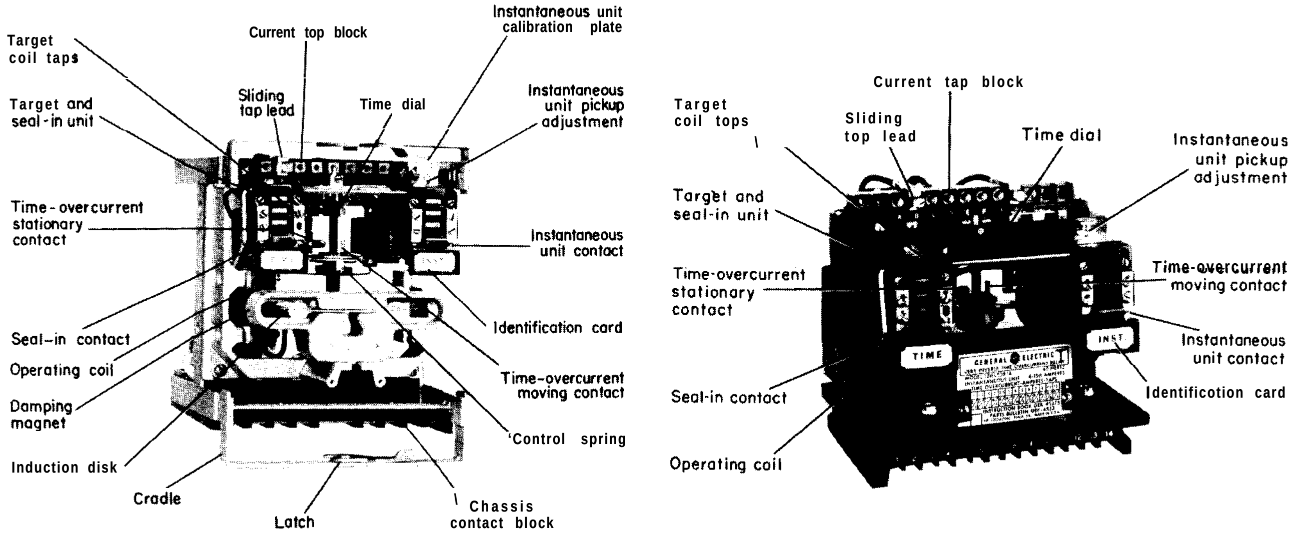
A basic requirement of protective relaying equipment is that it be reliable. Reliability refers to the ability of the relay system to perform correctly. It denotes the certainty of correct operation together with the assurance against incorrect operation from all extraneous causes. The proper application of protective relaying equipment involves the correct choice not only of relaying equipment but also of the associated apparatus. For example, lack of suitable sources of current and voltage for energizing the relay may compromise, if not jeopardize, the protection.

CHARACTERISTICS OF OVERCURRENT RELAYS

The overcurrent relay is the simplest type of protective relay. (See Fig. 1.) As the name implies, the relay is designed to operate when more than a predetermined amount of current flows into a particular portion of the power system. There are two basic forms of overcurrent relays: the instantaneous type and the time-delay type.

The instantaneous overcurrent relay is designed to operate with no intentional time delay when the current exceeds the relay setting. Nonetheless, the operating time of this type of relay can vary significantly. It may be as low as 0.016 seconds or as high as 0.1 seconds. The operating characteristic of this relay is illustrated by the instantaneous curve of Fig. 2.

The time-overcurrent relay (IAC, IFC, or SFC) has an operating characteristic such that its operating time varies inversely as the current flowing in the relay. This type of characteristic is also shown in Fig. 2. The diagram shows



Typical IAC relay mechanism with standard hinged armature instantaneous unit withdrawn from case (Model 12IAC51B)

Typical IFC relay mechanism with standard hinged armature instantaneous unit withdrawn from case (Model 12IFC53B1A)

Fig. 1. Typical IAC and IFC time-overcurrentrelays

the three most commonly used time-overcurrent characteristics: inverse, very inverse, and extremely inverse. These curves differ by the rate at which relay operating time decreases as the current increases.

Both types of overcurrent relays are inherently nonselective in that they can detect overcurrent conditions not only in their own protected equipment but also in adjoining equipment. However, in practice, selectivity between overcurrent relays protecting different system elements can be obtained on the basis of sensitivity (pickup) or operating time or a combination of both, depending on the relative time-current characteristics of the particular relays involved. These methods of achieving selectivity will be illustrated later. Directional relays may also be used with overcurrent relays to achieve selectivity.

The application of overcurrent relays is generally more difficult and less permanent than that of any other type of relaying. This is because the operation of overcurrent relays is affected by variations in short-circuit-current magnitude caused by changes in system operation and con-

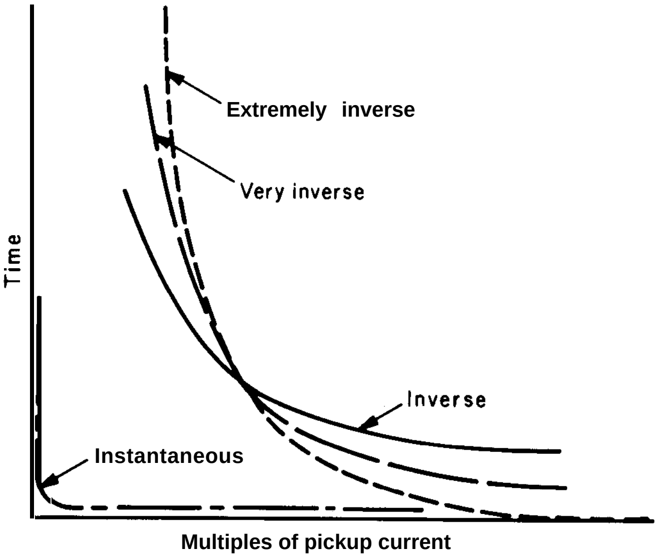


Fig. 2. Time-current characteristics of overcurrent relays

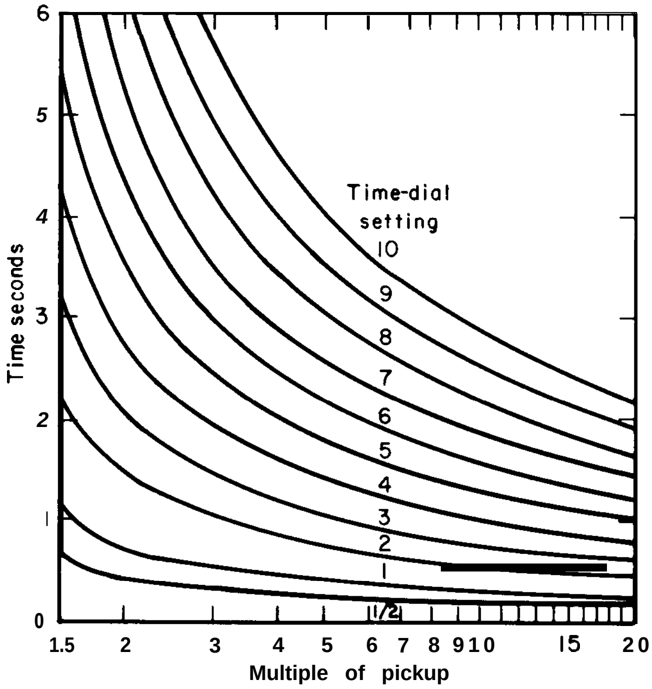


Fig. 3. Inverse time curves

figuration. Overcurrent relaying in one form or another has been used for relaying of all system components. It is now used primarily on distribution systems where low cost is an important factor.

Figure 3 shows a family of inverse-time curves of the widely used IAC relay, which is an induction disc type. The time curves for the new design IFC relay are similar.

A curve is shown for each numerical setting of the time dial scale. Any intermediate curves can be obtained by interpolation since the adjustment is continuous.

It will be noted that the curves shown in Fig. 3 are plotted in terms of multiples of pickup value, so that the same curves can be used for any value of pickup. This is possible with induction-type relays where the pickup adjustment is by coil taps, because the ampere-turns at pickup are the same for each tap. Therefore at a given multiple of pickup, the coil ampere-turns, and hence the torque, are the same regardless of the tap used.

The time-current curves shown in Fig. 3 can be used not only to determine how long it will take the relay to close its contacts at a given multiple of pickup and for any time adjustment, but also how far the relay disc will travel toward the contact-closed position within any time interval. For example, assume that the No. 5 time-dial adjustment is used and that the multiple of pickup is 3. It will take the relay 2.45 seconds to close its contacts. We see that in 1.45 seconds, the relay would close its contacts if the No. 3 time-dial adjustment were used. In other words, in 1.45 seconds the disc travels a distance corresponding to 3.0 time-dial divisions, or three fifths of the total distance to close the contacts.

For the most effective use of an inverse-time relay characteristic, its pickup should be chosen so that the relay will be operating on the most inverse part of its time curve over the range of values of current for which the relay must operate. In other words, the minimum value of current for which the relay must operate should be at least 1.5 times pickup, but not very much more.

Figure 4 shows the application of time-overcurrent relays to a radial feeder and the total tripping time characteristics for faults at any location along a circuit. The figure shows the increase in the minimum tripping time as faults occur nearer to the distribution substation — an increase inherent with overcurrent relaying. It also shows the effect of the inverse-time characteristic in reducing this increase. Obviously, the more line sections there are in series, the greater is the tripping time at the source end. It is not at all unusual for this time to be as high as 2 or 3 seconds. This is not a very long time according to some standards, but it would be intolerable if system stability or line burndown were an important consideration.

During light loads, some of the generators are usually shut down. At other times, the system may be split into several parts. In either case, the short-circuit current tends to vary with the amount of generation feeding it. It should be appreciated that a reduction in the magnitude of short-circuit current raises all of the characteristic curves of Fig. 4.

For locations where inverse time-overcurrent relays must be mutually selective, it is generally a good policy to use relays whose time-current curves have the same degree of inverseness. Otherwise, the problem of obtaining selectivity over wide ranges of short-circuit current may be difficult.

Instantaneous or undelayed overcurrent relaying is used only for primary relaying to supplement inverse-time relaying and is presently being used by most utilities. It can be used only when the current during short circuit is substantially greater than that under any other possible condition — for example, the momentary current that accompanies the energization of certain system components. The zone of protection of undelayed overcurrent relaying is established entirely by adjustment of sensitivity and is terminated short of the far end of the line. For instance, the instantaneous-overcurrent relay is usually set so that its pickup is 25 percent higher than the maximum current the relay will see for a three-phase fault at the end of the line. With this setting, the instantaneous relay will provide fault protection for about 80 percent of the line section.

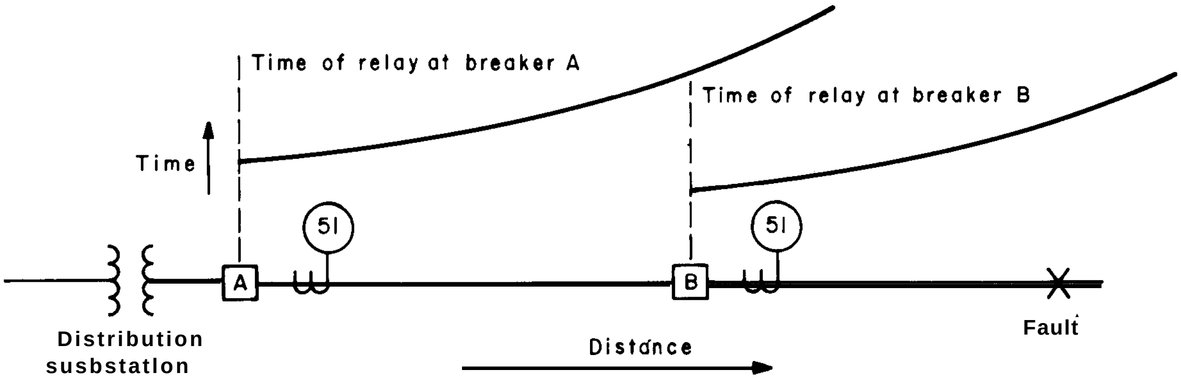


Fig. 4. Operating time of overcurrent relays with inverse time characteristics

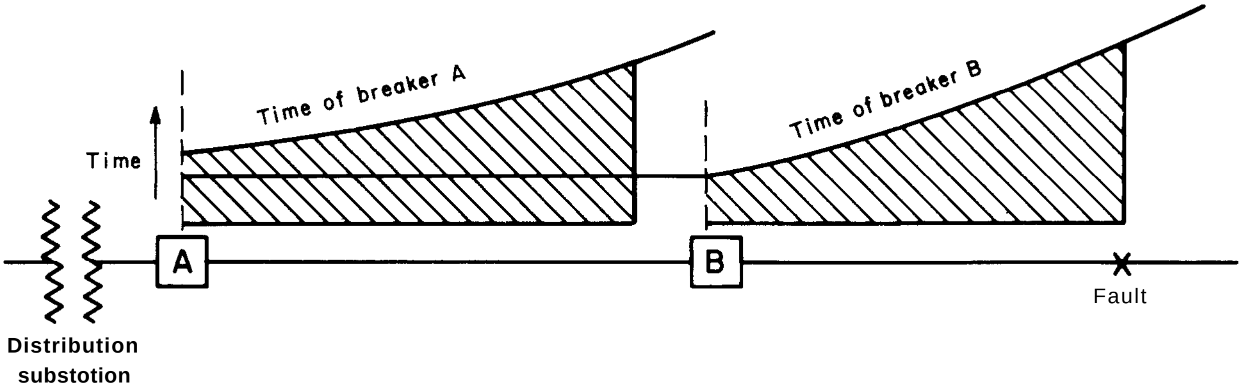


Fig. 5. Reduction in tripping time using instantaneous relaying

Undelayed ("instantaneous") trips can frequently be added to inverse-time relaying and effect a considerable reduction in tripping time. This is shown in Fig. 5 where the two sets of characteristics are superimposed. The time saved through the use of the instantaneous relays is shown by the shaded area. A reduction in the magnitude of short-circuit current shortens the distance over which the instantaneous unit operates and may even reduce this distance to zero. However, this fact is usually of no great importance since faster tripping under the maximum short-circuit conditions is the primary objective.

Instantaneous tripping is feasible only if there is a substantial increase in the magnitude of the short-circuit current as the short circuit is moved from the far end of a line toward the relay location. This increase should be at least two or three times. For this reason, it often happens that instantaneous relaying can be used only on certain lines and not on others.

On systems where the magnitude of short-circuit current flowing through any given relay is dependent mainly upon the location of the fault to the relay, and only slightly or not at all upon the generation in service, faster clearing can usually be obtained with very-inverse-time-overcurrent relays (IAC 53, IFC 53, or SFC 153). Where the short-circuit current magnitude is dependent largely upon system-generating capacity at the time of the fault, better results will be obtained with relays having inverse-time operating characteristics (IAC 51, IFC 51, or SFC 151).

However, towards the ends of primary distribution circuits, fuses are sometimes used instead of relays and breakers. In the region where the transition occurs, it is frequently necessary to use overcurrent relays having extremely inverse characteristics (IAC 77, IFC 77 or SFC 177) to coordinate with the fuse characteristics.

The extremely inverse relay characteristic has also been found helpful, under certain conditions, in permitting a feeder to be returned to service after a prolonged outage. After such a feeder has been out of service for so long a period that the normal "off" period of all intermittent loads (such as furnaces, refrigerators, pumps, water heaters, etc.) has been exceeded, reclosing the feeder throws all of these loads on at once without the usual diversity. The total inrush current, also referred to as cold-load pickup, may be approximately four times the normal peak-load current. This inrush current decays very slowly and will be approximately 1.5 times normal peak current after as much as three or four seconds. Only an extremely inverse characteristic relay provides selectivity between this inrush and short-circuit current.

CT CONNECTIONS

A *minimum* of three overcurrent relays and a total of three current transformers is required to detect all possible faults in a three-phase a-c system. Two of the relays are usually connected in the phase circuits and the third relay is usually connected in the residual circuit of the current transformers as shown in Fig. 6. Sensitive ground-fault protection and protection against simultaneous grounds on different parts of the system is provided by this arrangement whether the system is grounded or ungrounded. On ungrounded systems, current flows in the residual relay when grounds occur on different phases on opposite sides of the current transformer location as indicated in Fig. 6.

On three-phase, four-wire systems (which represent a large percentage of the new installations), it is not always possible to balance perfectly the single-phase loads among the three phases. The use of a sensitive residual ground-overcurrent relay may not be feasible if the relay picks up under normal load conditions. For such systems, the three overcurrent relays are often connected in the phase circuits of the current transformers and the sensitive ground-fault protection sacrificed. An alternative is to use the residual connection of the ground relay in Fig. 6 and to set the pickup of the relay above the maximum expected unbalance phase current.

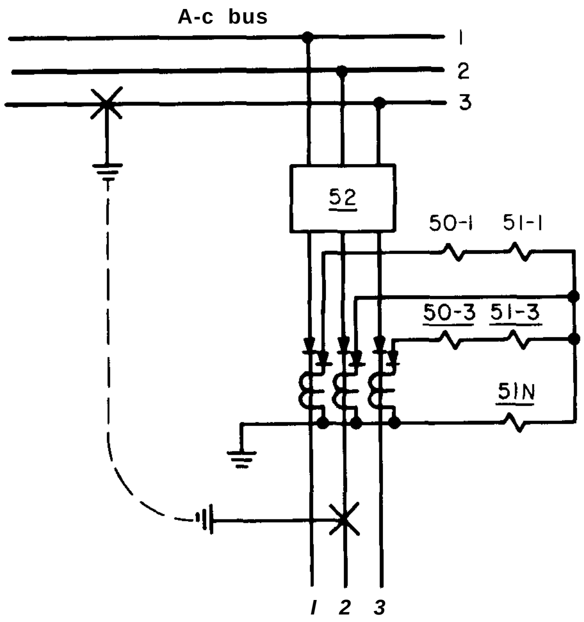


Fig. 6. Elementary diagram of overcurrent relays used for phase- and ground-fault protection of three-phase circuit

It is the practice of some operating companies to block the residual relay to prevent false tripping of the circuit breaker during periods of routine maintenance or when balancing loads on the feeders. This leaves feeders without protection for a line-to-ground fault on the phase without an overcurrent relay, while the residual relay is blocked. It is the usual practice of these companies to request three-phase overcurrent relays in addition to one residual-ground relay for these feeders. This gives complete overcurrent protection to the feeders at all times.

SEAL-IN (OR HOLDING) COILS AND SEAL-IN RELAYS

To protect the contacts from damage resulting from a possible inadvertent attempt to interrupt the flow of the circuit-breaker trip-coil current, some relays are provided with a holding mechanism comprising a small coil in series with the contacts. This coil is on a small electromagnet that acts on a small armature on the moving contact assembly to hold the contacts tightly closed once they have established the flow of trip-coil current. This coil is called the "seal-in" or "holding" coil. Other relays use a small auxiliary relay whose contacts by-pass the protective relay contacts and seal the circuit closed while tripping current flows. This seal-in relay may also display the target. In either case, the circuit is arranged so that, once the trip-coil current starts to flow, it can be interrupted only by a circuit-breaker auxiliary switch (that is connected in series with the trip-coil circuit) and that opens when the breaker opens. This auxiliary switch is defined as an "a" contact. The circuits of both alternatives are shown in Fig. 7.

TRIPPING METHODS

The substation circuit-breaker tripping power may be from either a d-c or an a-c source. A d-c tripping source is usually obtained from a tripping batttery, but may also be obtained from a station service battery or a charged capacitor. The a-c tripping source is obtained from current transformers located in the circuit to be protected.

D-c Battery Trip

When properly and adequately maintained, the battery offers the most reliable tripping source. It requires no auxiliary tripping devices, and uses single-contact relays that directly energize a single trip coil in the breaker as shown in Fig. 8. A battery trip supply is not affected by the power-circuit voltage and current conditions during time of faults, and therefore is considered the best source for all types of protective relay tripping. An additional advantage is that only one battery is required for each substation location and it may be used for other equipment; e.g., high-voltage breaker trip circuits and ground switches.

A tripping battery is usually the most economical source of power for tripping a number of breakers. When only one or two breakers are involved, however, it may be more economical to use a-c current or capacitor trip.

Long service can be obtained from batteries when they receive proper maintenance and when they are kept fully charged and the electrolyte is maintained at the proper level and density. When lead-acid batteries are subjected to extremely low ambient temperatures, their output is considerably reduced. In outdoor unit substations, this necessitates larger ampere-hour capacities. For substations in outlying locations where periodic maintenance is difficult, such as many single-circuit substation applications, other types of tripping sources may be more satisfactory.

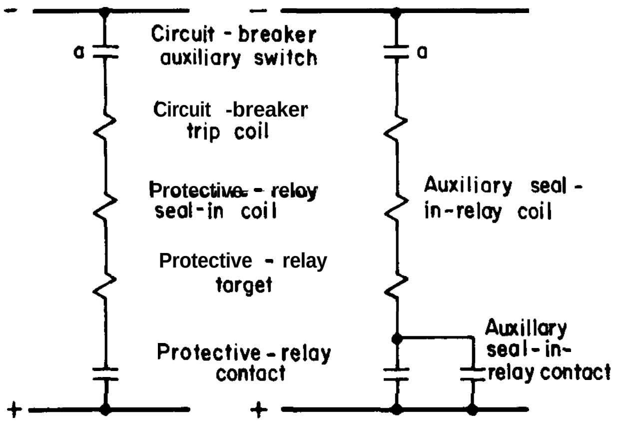


Fig. 7. Alternative contact seal-in methods

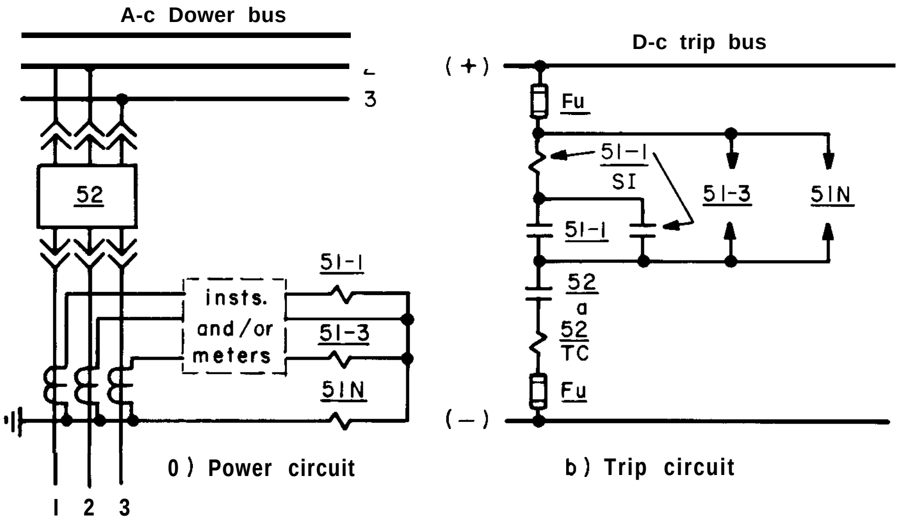


Fig. 8. Elementary diagram of overcurrent relays used with d-c battery tripping

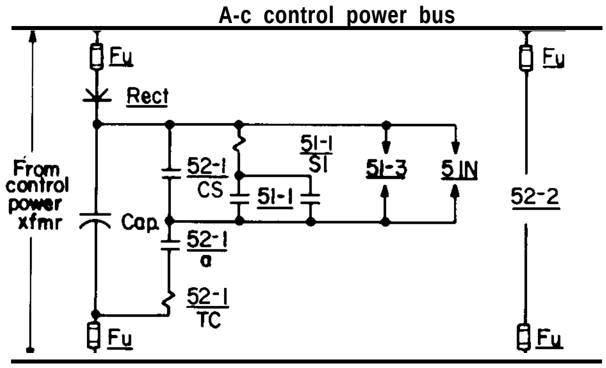


Fig. 9. Elementary diagram of overcurrent relays used with capacitor tripping

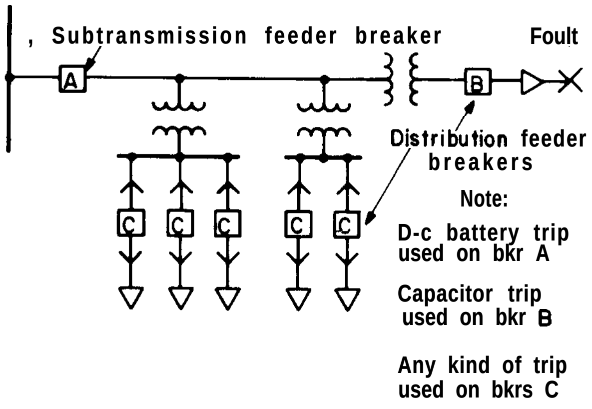


Fig. 10. One-line diagram of feeder breaker using capacitor trip with back-up breaker using battery trip

Capacitor Trip

An a-c potential source is required for charging the capacitors used in the capacitor trip unit. This source may be either a control power transformer or a potential transformer connected where voltage is normally present. A control power transformer is usually used because it is required for a-c closing of the circuit breakers. Capacitor trip uses the same standard single-closing contact relays as d-c battery trip (see Fig. 9). A separate capacitor trip unit is required for each breaker in the substation. The charging time for the unit is approximately 0.04 second and any failure in the charging source for a period longer than 30 seconds renders the trip inoperative. This time must be factored into time-delay settings of relays.

The capacitor trip unit *can be used only with low-energy tripping* devices such as the impact trip device used on modern breaker-operating mechanisms. Due to the limited amount of energy available from this device, the breaker must be well maintained to assure successful operation. This unit provides tripping potential *independent of the magnitude of fault current,* which makes it particularly applicable on lightly loaded, high-impedance circuits where a-c current trip cannot be used and a battery cannot be justified.

The capacitor trip unit has an additional limitation which is illustrated in Fig. 10. Assume that Breaker A has been open long enough for the capacitor trip unit at Breaker B to become de-energized; further assume that a fault has occurred on the feeder of Breaker B during the time that Breaker A was open. Under these conditions, when Breaker A is reclosed, it will re-energize the feeder of Breaker B on a fault. Due to the fault holding the voltage down, the capacitor may not be charged to provide tripping energy upon closing of the protective relay contacts and backup Breaker A would have to clear the fault. The load fed by Breakers C would be without service until Breaker B was manually tripped and Breaker A was reclosed. However, the probability of such a chain of coincident circumstances occurring is relatively small.

A-c Current Trip

If adequate current is always available during fault conditions, the current transformers in the protected circuit provide a reliable source of tripping energy which is obtained directly from the faulted circuit. The tripping may be either instantaneous or time delay in operation; but in all cases, it is applicable only to *overcurrent* protection.

The trip circuit is more complex than for d-c tripping because three trip circuits, complete with individual trip coils and auxiliary devices, are required for each breaker for overcurrent tripping. A potential trip coil is also required for each breaker for normal switching operations. This permits manual tripping of the breaker by means of the breaker control switch.

The three trip coils are normally connected in each phase circuit, rather than two phase coils and one residual coil. This is because adequate trip current may not be available under all ground-fault conditions – e.g., when a ground fault occurs at some distance out on the feeder so that there is sufficient neutral impedance to limit the fault current to a value insufficient to cause tripping, or when applied to a system grounded through a neutral impedance. A residual relay, which trips the breaker by means of a potential trip coil, is used to provide ground-fault protection under conditions such as these.

A minimum of three or four amperes CT secondary current is required to energize the three-ampere current-trip coils used for this method of tripping. The use of 0.5- to 4.0-ampere range time-overcurrent relays is not recommended because they are more sensitive than the a-c trip coils.

A-c current trip may be by means of reactor trip (circuit-closing relays) or auxiliary relay trip (circuit-opening relays). The reactor trip method is usually recommended because of its simplicity and because it uses the more standard type overcurrent relays.

Application Considerations

The choice of the proper source of tripping energy should be based on the application considerations listed here. Any of the foregoing methods are reliable when properly applied; however, each possesses certain advantages and disadvantages. The following general recommendations can be made:

1. Where several breakers are involved and maintenance is good, the storage battery is the most economical. This method also has the added benefit of reliability, simplicity, and ability to be used with all types of protective relays.

2. Where only one or two breakers are used, or maintenance is difficult, one of the other sources could be applied.

   a. A-c current trip should be used when adequate current is available.

   b. Capacitor trip could be used where adequate trip current is not available.

FEEDER PROTECTION

COLD LOAD PICKUP

Whenever service has been interrupted to a distribution feeder for 20 minutes or more, it may be extremely difficult to re-energize the load without causing protective relays to operate. The reason for this is the flow of abnormally high inrush current resulting from the loss of load diversity. High inrush currents are caused by:

1. magnetizing inrush currents to transformers and motors,
2. current to raise the temperatures of lamp filaments and heater elements, and
3. motor-starting current.

Figure 11 shows the inrush current for the first five seconds to a feeder which has been de-energized for 15 minutes. The inrush current, due to magnetizing iron and raising filament and heater elements temperatures, is very high but of such a short duration as to be no problem. However, motor-starting currents may cause the inrush current to remain sufficiently high to initiate operation of protective relays. The inrush current in Fig. 11 is above 200 percent for almost two seconds.

The magnitude of the inrush current is closely related to load diversity, but quite difficult to determine accurately because of the variation of load between feeders. If refrigerators and deep freeze units run five minutes out of every 20, then all diversity would be lost on outages exceeding 20 minutes.

A feeder relay setting of 200 to 400 percent of full load is considered reasonable. However, unless precautions are taken, this setting may be too low to prevent relay misoperation on inrush following an outage. Increasing this setting may restrict feeder coverage or prevent a reasonable setting of fuses and relays on the source side of this relay.

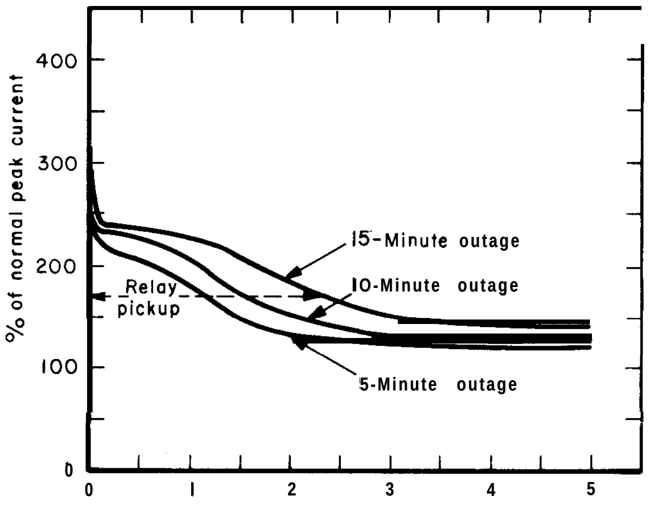


Fig. 11. Five-, ten-, and fifteen-minute outage pickup curves for first five seconds after restoral

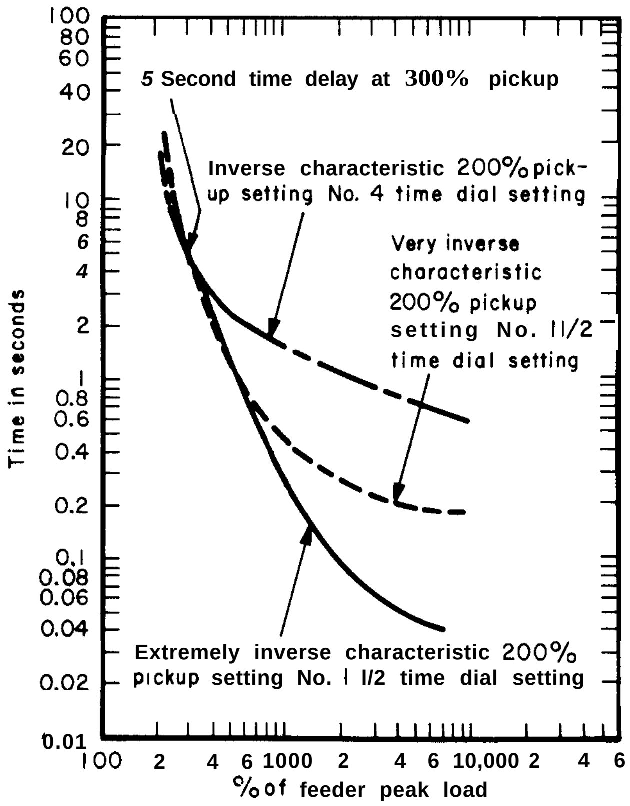


Fig. 12. Comparison of overcurrent relay characteristics

A satisfactory solution to this problem is the use of the extremely inverse relay. Figure 12 shows three overcurrent relays which will ride over cold-load inrush. However, the extremely inverse curve is superior in that substantially faster fault-clearing time is achieved at the high-current levels.

This figure, for the purpose of comparison, shows each characteristic with a pickup setting of 200 percent peak load and a five-second time delay at 300-percent peak load to comply with the requirements for re-energizing feeders.

It is evident that the more inverse the characteristic, the more suitable the relay is for feeder short-circuit protection. The relay operating time, and hence, the duration of the fault can be appreciably decreased by using a more inverse relay. Comparing the inverse characteristic shows that the extremely inverse characteristic gives from 30-cycles faster operation at high currents to as much as 70-cycles faster at lower currents.

Unfortunately, the extremely inverse relay may not always take care of the problem. As the feeder load grows, the relay pickup must be increased and a point may be reached at which the relay cannot detect all faults. At this time, it may be necessary to either move the fuses or reclosers closer to the substation or use automatic sectionalizing.

COORDINATION WITH THE TRANSFORMER PRIMARY FUSE

The practice of fusing the distribution substation is controversial. This is mainly because:

1. the fuse must be replaced every time it blows,
2. the possibility of blowing one fuse and single-phasing three-phase motors exists,
3. the operating time of the fuse must be quite slow so that it coordinates with secondary and feeder breaker relays, and finally
4. the fuse will detect few transformer internal faults since a fault across one-half the winding may be required to cause a fuse to operate.

The fuse must be sized so that it will be able to carry 200 percent of transformer full-load current continuously during emergencies and so that transformer inrush current of 12 to 15 times transformer full-load current can be carried for 0.1 seconds.

Coordination with substation transformer primary fuses requires that the total clearing time of the main breaker (relay time plus breaker interrupting time) be less than 75 percent to 90 percent of the minimum melt characteristics of the primary fuses at all values of current up to the maximum available fault current at the secondary bus.

Figure 13 shows a plot of a 50E fuse which satisfies the inrush and emergency criterion mentioned above and another curve of 75 percent of this minimum melt curve.

To prevent the extremely inverse relay from operating on cold-load pickup, its minimum pickup should not be less than 200 to 250 percent of full-load current. In this case, it will be about 90-amperes primary current. As Fig. 13 shows, the two devices are coordinated only if the maximum secondary fault current is less than 1500 amperes. If such is not the case, then the size of the fuse must be increased, which in turn limits its transformer-overload protection capabilities.

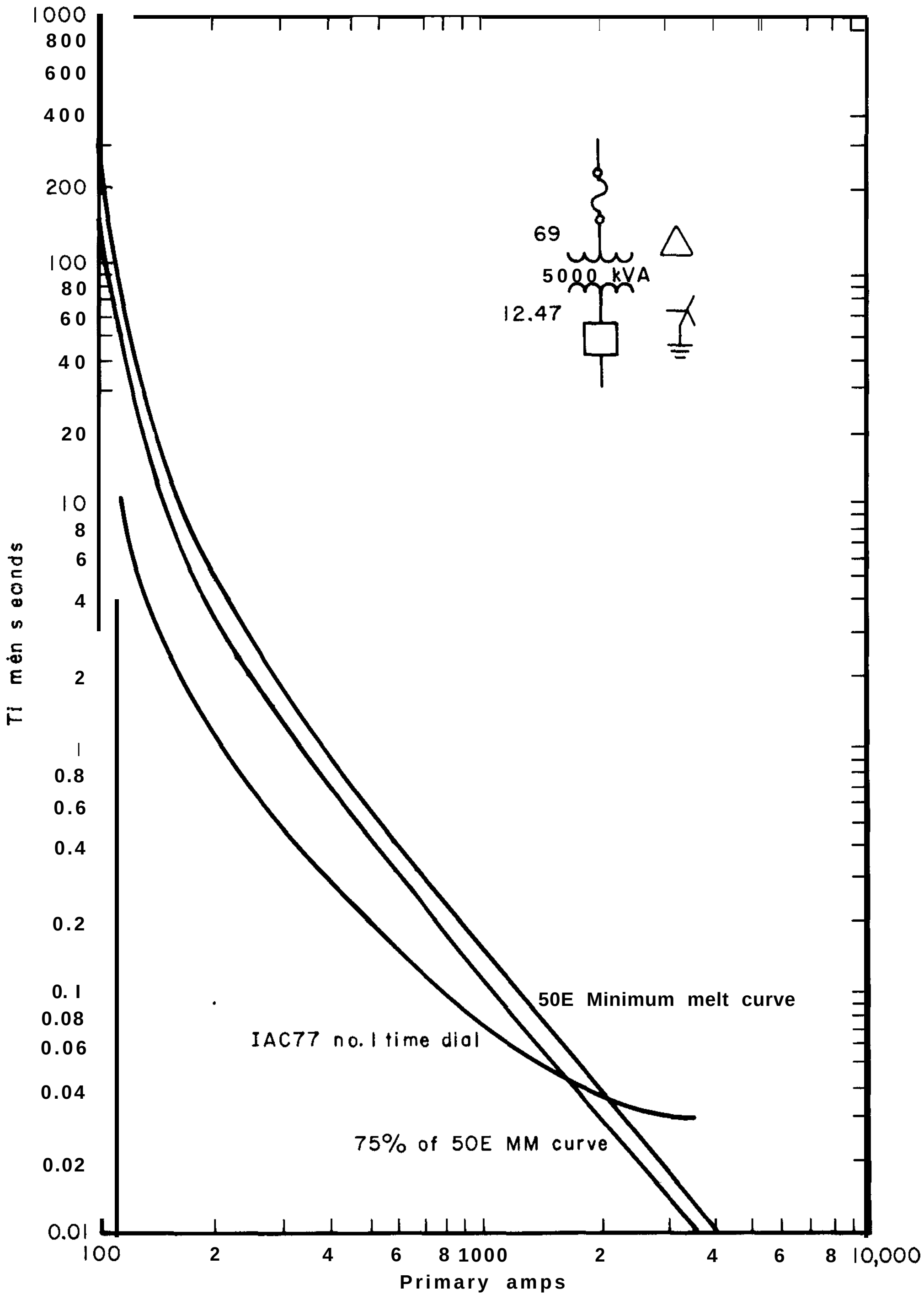


Fig. 73. Plot of a 50E fuse satisfying inrush and emergency criterion

COORDINATION BETWEEN FEEDER BREAKERS AND THE SECONDARY BREAKER

Coordination between feeder breakers and the transformer secondary breaker requires the total clearing time of the feeder breaker (relay time plus breaker interrupting time) to be less than the relay time of the main secondary breaker by a margin which allows 0.1 seconds for electromechanical relay overtravel plus a 0.1 to 0.3-second factor of safety. This margin should be maintained at all values of current through the maximum fault currents available at the secondary bus.

FAULT SELECTIVE FEEDER RELAYING

The reclosing relay recloses its associated feeder breaker at preset intervals after the breaker has been tripped by overcurrent relays. A recent survey indicates that approximately 70 percent of the faults on overhead lines are nonpersistent. Little or no physical damage results if these faults are promptly cleared by the operation of relays and circuit breakers. Reclosing the feeder breaker restores the feeder to service with a minimum of outage time.

If any reclosure of the breaker is successful, the reclosing relay resets to its normal position. However, if the fault is persistent, the reclosing relay recloses the breaker a preset number of times and then goes to the lockout position.

The reclosing relay can provide an immediate initial reclosure plus three timedelay reclosures. The immediate initial reclosure and/or one or more of the time-delay reclosures can be made inoperative as required. The intervals between timedelay reclosures are independently adjustable.

The primary advantage of immediate initial reclosing is that service is restored so quickly for the majority of interruptions that the customer does not realize that service has been interrupted. The primary objection is that certain industrial customers cannot live with immediate initial reclosing. The operating times of the overcurrent relays at each end of the tie feeder will be different due to unequal fault-current magnitudes. For this reason, the breakers at each end will trip and reclose at different times and the feeder circuit may not be de-energized until both breakers trip again.

The majority of utilities use a three-shot reclosing cycle with either three timedelay reclosures or an immediate initial reclosure followed by two time-delay reclosures. In general, the interval between reclosures is 15 seconds or longer, with the intervals progressively increasing (e.g., a 15-30-45second cycle), giving an over-all time of 90 seconds.

Fault-selective feeder relaying allows the feeder breaker to clear non-persistent faults on the entire feeder, even beyond sectionalizing or branch fuses, without blowing the fuses. In the event of a persistent fault beyond a fuse, the fuse will blow to isolate the faulty section. Operating engineers report reductions of 65 to 85 percent in fuse blowing on non-persistent faults through the use of this method of relaying.

The feeder circuit-breaker overcurrent relays (No. 150/151) are provided with inverse-time overcurrent tripping and also instantaneous tripping. When a fault occurs, the instantaneous relay (No. 150) trips the circuit breaker before any of the branch-circuit fuses can blow. When the breaker opens, the instantaneous-trip circuit is automatically opened by the reclosing relay (No. 179) and remains open until the reclosing relay has completely timed out the reset (see Fig. 14). If the fault is non-persistent, service to the entire feeder is restored when the breaker recloses, after which the reclosing relay times out to the reset position and the instantaneous trip function is automatically restored.

If the fault is persistent, the circuit breaker recloses on the fault and must trip on the time-delay characteristic since the instantaneous trip is effective only on the first opening. The timedelay trip is adjusted to be slower than the sectionalizing or branch-circuit fuses; consequently, this gives the fuses a chance to blow and isolate the faulted section, leaving the remainder of the feeder in service.

The success of fault-selective feeder relaying depends on proper coordination between the branch-circuit fuses and the feeder-breaker overcurrent relays.

The feeder breaker, when tripped instantaneously, must clear the fault before the fuse is damaged. Therefore, the breaker-interrupting time plus ,the operating time of the relay-instantaneous attachment must be less than 75 percent of the fuse minimum-melting current at the maximum-fault current available at the fuse location. In turn, the fuse must clear the fault before the breaker trips on time delay for subsequent operations. Therefore, the total clearing characteristic of the fuse must lie below the relay charac-

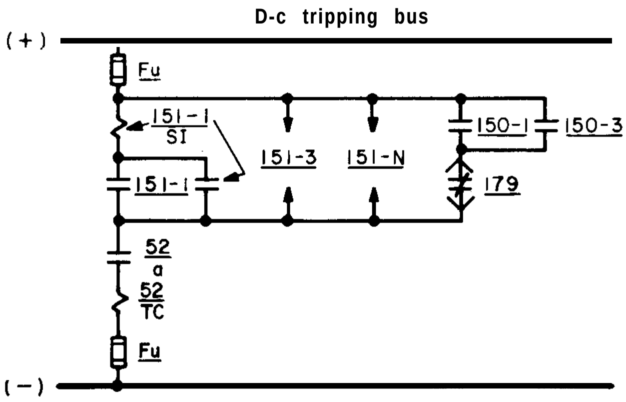


Fig. 14. Elementary diagram of breaker trip circuit showing connections for fault-selective feeder relaying

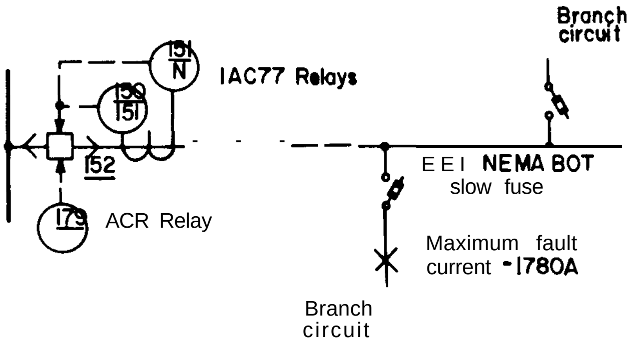


Fig. 15. One-line diagram of typical feeder circuit protected by fault-selective feeder relaying

teristic at all values of current up to the maximum current available at the fuse location. The margin between the fuse and relay characteristics must include a safety factor of 0.1 to 0.3 second plus 0.1 second for relay overtravel.

An example of fault-selective feeder relaying is illustrated in Figs. 15 and 16. The one-line diagram of the feeder circuit is shown in Fig. 15 and the co-ordination curves are shown in Fig. 16. The overcurrent relay (No. 150/151) has an extremely inverse characteristic (No. 151) with a pickup setting of 480 amperes and 1-1/2 time-dial setting. The instantaneous element (No. 150) has a pickup setting of 600 amperes. The EEI-NEMA 80T (slow) fuse is the largest "slow"fuse which will co-ordinate with this combination of relay characteristics and settings. At 1780 amperes, the time delay of the relay-instantaneous element, plus the breaker-interrupting time, are just equal to

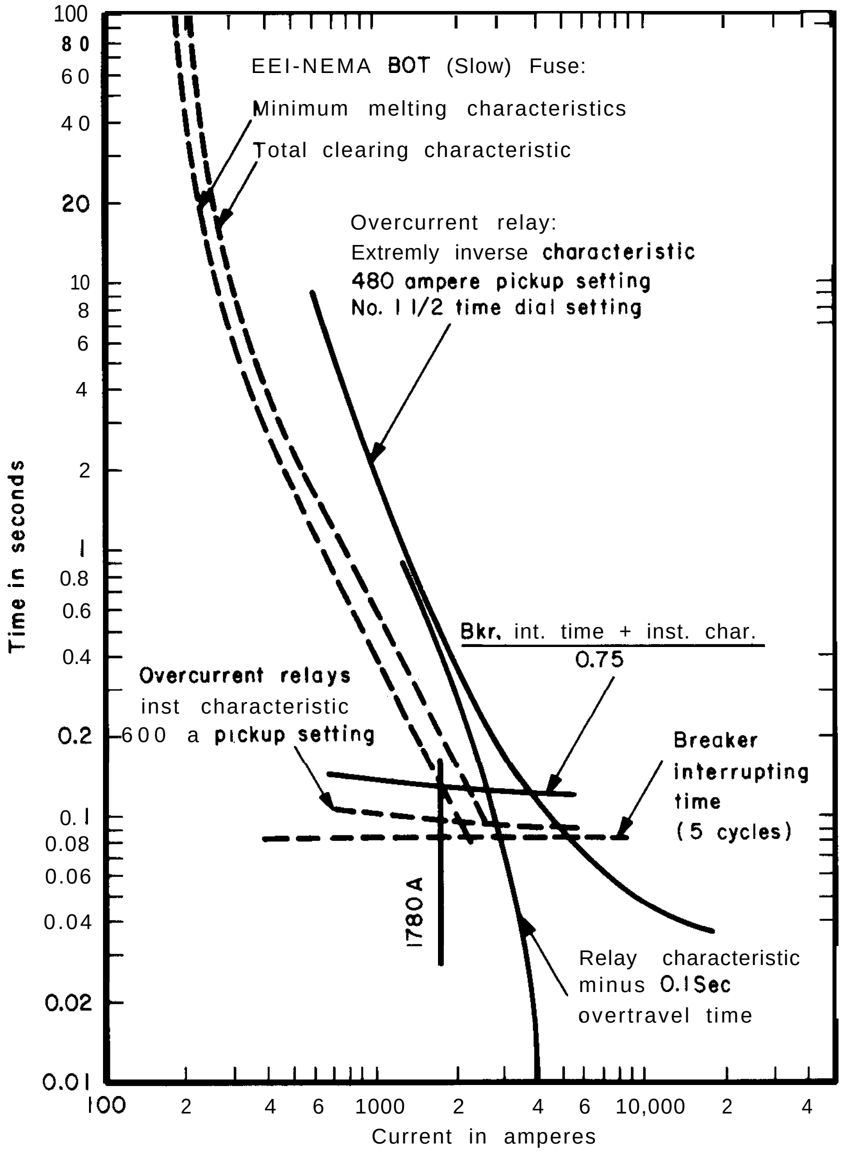


Fig. 16. Co-ordination of relay and fuse characteristics for fault-selective feeder relay

75 percent of the fuse minimum-melting time. At this same current magnitude, the fuse total clearing time is less than the relay time-delay characteristic by a suitable margin. Therefore, the fuse and relay co-ordinate for current magnitudes of 1780 amperesor less.

For certain applications, the maximum available fault current will exceed the maximum current which will permit co-ordination. There are two reasons for this:

1. the maximum current for co-ordination is lower for lower-rated fuses and is also lower for Type K (fast) fuses, and
2. fault currents may be quite high at fuse locations comparatively near the substation.

Of course, if the branch circuit is single phase, it is only necessary to consider the maximum line-to-line or line-to-ground fault current, both of which are less than the maximum three-phase fault current. For such applications, co-ordination can be relied upon only when there is sufficient additional impedance to limit the fault current to the maximum current which will permit co-ordination. This additional impedance can either be in the fault itself or in the branch circuit between the fuse and the fault location. Therefore, while co-ordination will be questionable for faults near the fuse, there will be complete co-ordination for faults which occur father out on the branch circuit.

COORDINATION OF FEEDER RELAYS AND RECLOSERS

If a permanent fault occurs anywhere on the system beyond a feeder, the recloser device will operate once, twice, or three times instantaneously (depending upon adjustment) in an attempt to clear the fault. However, since a permanent fault will still be on the line at the end of these instantaneous operations, it must be cleared away by some other means. For this reason, the recloser is provided with one-, two-, or three-time delay operations (depending upon adjustment). These additional operations are purposely slower to provide coordination with fuses or allow the fault to “self clear”. After the fourth opening, if the fault is still on the line, the recloser will lock open.

Figure 17 represents the instantaneous-and time-delay characteristics of a conventional automatic circuit recloser.

At substations where the available short-circuit current at the distribution feeder bus is 250 MVA or more, the feeder circuits are usually provided with circuit breakers and extremely inverse-time overcurrent relays. The relays of each feeder should be adjusted so that they can protect the circuit to a point beyond the first recloser in the main feeder but with enough time delay to be selective with the recloser during any or all of the operations within the complete recloser cycle.

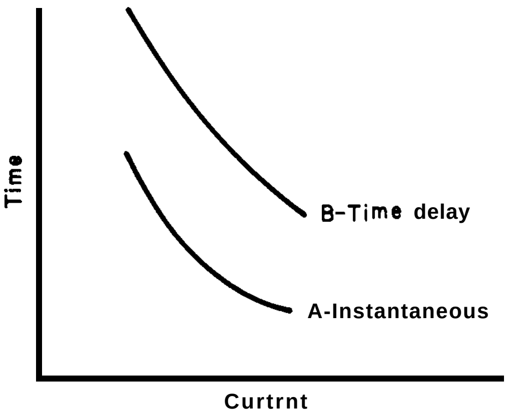


Fig. 17. Tripping characteristic for conventional automatic circuit recloser

An important factor in obtaining this selectivity is the reset time of the overcurrent relays. If, having started to operate when a fault occurs beyond the recloser, an overcurrent relay does not have time to completely reset after the recloser trips and before it recloses (an interval of approximately one second), the relay may “inch” its way toward tripping during successive recloser operations. Thus it can be seen that it is not sufficient merely to make the relay time only slightly longer than the recloser time.

It is a good “rule of thumb” that there will be a possible lack of selectivity if the operating time of the relay at any current is less than twice the time-delay characteristic of the recloser. The basis of this rule, and the method of calculating the selectivity, will become evident by considering an example.

First, it should be known how to use available data for calculating the relay response under conditions of possibly incomplete resetting. The angular velocity of the rotor of an inverse-time relay for a given multiple of pickup current is substantially constant throughout the travel from the reset (i.e., completely open) position to the closed position where the contacts close. Therefore, if it is known (from the time-current curves) how long it takes a relay to close its contacts at a given multiple of pickup and with a given time-dial adjustment, it can be estimated what portion of the total travel toward the contact-closed position the rotor will move in any given time. Similarly, the resetting velocity of the relay rotor is substantially constant throughout its travel. If the re-set time from the contact-closed position is known for any given time-delay adjustment, the reset time for any portion of the total travel can be determined. The re-set time for the longest travel (when the longest time-delay adjustment is used) is generally given for each type of relay. The re-set time for the number 10 time-dial setting is approximately six seconds for an inverse Type IAC relay, and approximately 60 seconds for either a very inverse or any extremely inverse Type IAC relay.

The foregoing information may be applied to an example by referring to Fig. 18. Curves A and 8 are the upper curves of the band of variation for the instantaneous and timedelay characteristics of a 35-ampere recloser. Curve C is the time-current curve of the very inverse Type IAC relay set on the number 10 time-dial adjustment and 4-ampere tap (160-ampere primary with 200/5 current transformers). Assume that it is desired to check the selectivity for a fault current of 500 amperes. It is assumed that the fault will persist through all of the reclosures. To be selective, the IAC relay must not trip its breaker for a fault beyond the recloser.

The operating times of the relay and recloser for this example are:

Recloser:

Instantaneous — 0.036 second
Time delay — 0.25

Relay:

Pickup - 0.65 second
Reset - (1.0/10)(60) = 6.0 second

The percent of total travel of the IAC relay during the various recloser operations is as follows, where plus means travel in the contact-closing direction and minus means travel in the re-set direction:

Recloser Operation	Percent of Total Relay Travel
First instantaneous trip (0.036/0.65)	x (100) = + 5.5
Open for one second (1/6)	x (100) = -16.7

It is apparent from this that the IAC relay will completely reset while the recloser is open following each instantaneous opening.

Recloser Operation	Percent of Total Relay Travel
First time-delay trip	(0.25/0.65) x (100) = +38.5
Open for one second	(1/6) x (100) = -16.7
Second time-delay trip	(0.25/0.65) x (100) = +38.5

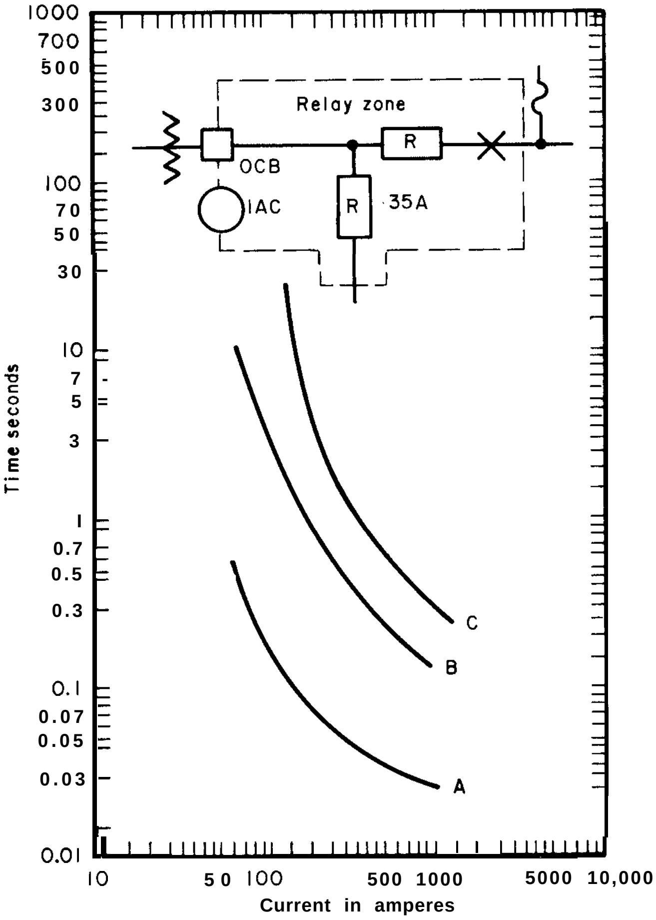
From this analysis, it appears that the relay will have a net travel of 60.3 percent of the total travel toward the contact-closed position.

From the foregoing, it is seen that the relay travel lacks approximately 40 percent (or 0.4 x 0.65 = 0.24 second) of that necessary for the relay to close its contacts and trip its breaker. On the basis of these figures, the IAC will be selective. A 0.15- to 0.2-second margin is generally considered desirable to guard against variations from published characteristics, errors in reading curves, etc. (The static overcurrent relay Type SFC, overcomes some of these problems since the overtravel of such a relay is about 0.01 seconds and the reset time is 0.1 seconds or less.)

If the automatic circuit reclosers are used at the substation as feeder breakers, it is necessary to select the proper size to meet the following conditions:

1. The interrupting capacity of the recloser should be greater than the maximum calculated fault current available on the bus.

2. The load-current rating (coil rating) of the recloser should be greater than the peak-load current of the circuit. It is recommended that the coil rating of the recloser be of sufficient size to allow for normal load growth and be relatively free from unnecessary tripping due to inrush cur-



A. Time-current characteristic of one instantaneous recloser opening
B. Time-current characteristic of one extended timedelay recloser opening
C. Time-current characteristic of the IAC relay

Fig.18. Relay-recloser coordination

rent following a prolonged outage. The margin between peak load on the circuit and the recloser rating is usually about 30 percent.

3. The minimum pickup current of the recloser is two times (2X) its coil rating. This determines its zone of protection as established by the minimum calculated fault current in the circuit. The minimum pickup rating should reach beyond the first-line recloser sectionalizing point, i.e., overlapping protection must be provided between the station recloser and the first-line recloser. If overlapping protection cannot be obtained when satisfying requirement (I), it will be necessary to relocate the first-line recloser to have it fall within the station recloser protective zone.

COORDINATION OF RECLOSERS AND FUSES

Figure 19 shows the time-current characteristic curves of the automatic circuit recloser. On these curves, the time-current characteristics of a fuse C is superimposed. It will be noted that fuse curve C is made up of two parts: the upper portion of the curve (low-current range) representing the total clearing time curve, and the lower portion (high-current range) representing the melting curve for the fuse. The intersection points of the fuse curves with recloser curves A and B, define the limits between which coordination will be expected. It is necessary; however, that the characteristic curves of both recloser and fuse be shifted or modified to take into account alternate heating and cooling of the fusible element as the recloser goes through its sequence of operations.

Figure 20 shows what occurs when the current flowing through the fuse link is interrupted periodically. The oscillogram shows typical recloser operation. The first time the recloser opens and closes due to fault or overload, the action is instantaneous, requiring only two cycles. The second action is also two cycles, while the third action is delayed to 20 cycles, as is the fourth. Then the recloser locks itself open.

For example, if the fuse link is to be protected for two instantaneous openings, it is necessary to compare the heat input to the fuse during these two instantaneous recloser openings. The recloser-fuse coordination must be such that during instantaneous operation the fuse link is not damaged thermally.

Curve A’, Fig. 21, is the sum of two instantaneous openings (A) and is compared with the fuse damage curve which is 75 percent of the melting-time curve of the fuse.

This will establish the high-current limit of satisfactory coordination indicated by intersection point b’. To establish the low-current limit of successful coordination, the total heat input to the fuse represented by curve B’ (which is equal to the sum of two instantaneous (A) plus two time-delay (B) openings) is compared with the total clearing-time curve of the fuse. The point of intersection is indicated by a'.

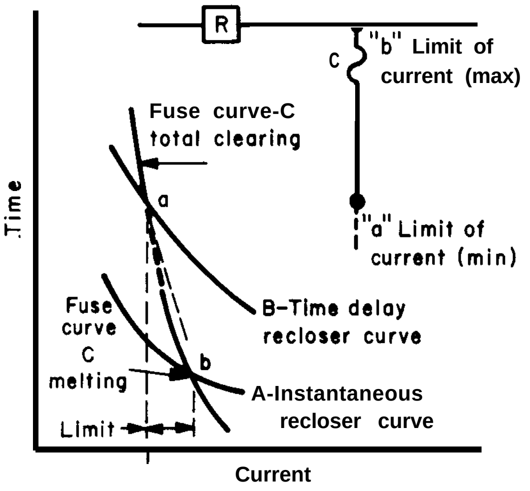


Fig. 19. Time-current characteristic curves of recloser superimposed on fuse curve C

For example, to establish how coordination is achieved between the limits of a’ and b’, refer to Fig. 21. It is assumed that the fuse beyond the recloser must be protected against blowing or being damaged during two instantaneous operations of the recloser in the event of a transient fault at X. If the maximum calculated short-circuit current at the fuse location does not exceed the magnitude of current indicated by b’, the fuse will be protected during transient faults. For any magnitude of short-circuit current less than b’, but greater than a’ (see Fig. 21), the recloser will trip on its instantaneous characteristic once or twice to clear the fault before the fuse-melting characteristic is approached. However, if the fault is permanent, the fuse should blow before the recloser locks out. If the minimum (line-to-ground) calculated short-circuit current available at the end of the branch is greater than the current indicated by a’, the fuse will blow (see Fig. 21) before the time-delay characteristic of the recloser is approached.

STATIC OVERCURRENT RELAYS (SFC)

Since static over-current relays (SFC) are electronic analogs of conventional electromechanical relays, it is to be expected that the general principles of application covered earlier will still be pertinent. In general, this is true although there are several important differences which come about because the relay employs solid-state electronic operating principles.

In designing the SFC static overcurrent relay, it was recognized that the time-current characteristic could be built with any desired shape. Furthermore, the manner in which the relay operates ensures that the curve shape will remain essentially unchanged regardless of the actual time-

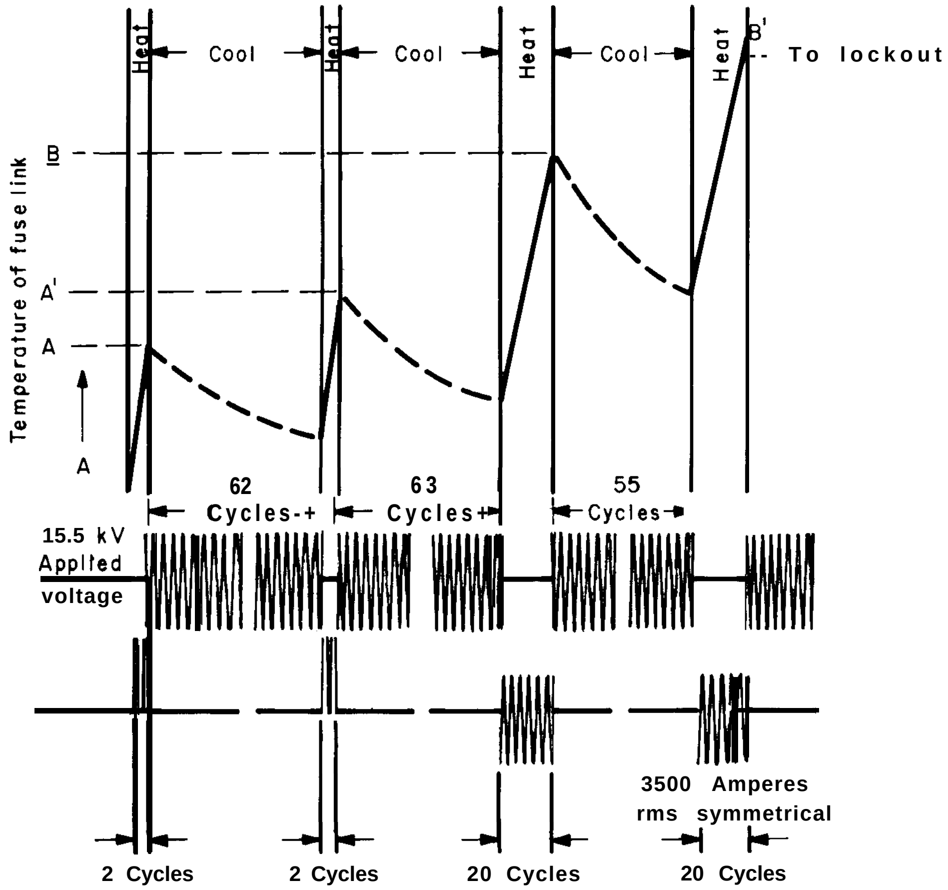


Fig. 20. Fuse link heating and cooling

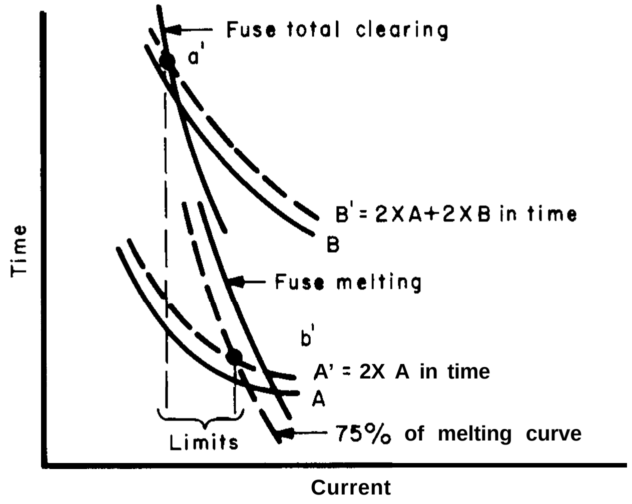


Fig. 21. Recloser-fuse coordination (fuse operated for heating and cooling)

dial setting. Thus, a critical decision in relay design was to choose a curve shape. It was judged to be important that the relay be designed so that it could easily be integrated into an existing system. This consideration essentially ruled out the use of totally new curve shapes and lead to a decision to duplicate the three basic time-current characteristics of IAC relays: inverse, very inverse, and extremely inverse. Because experience indicates that the lower time-dial settings on IAC relays tend to be used somewhat more frequently than the upper time-dial settings, the actual curves chosen for the new SFC relays were selected to match the lower time-dial curve from IAC relays. However, it should be noted that there is no reason to insist that this match be exact. IAC curves were selected as design goals for convenience only; other curves could have been selected as well.

Figure 22 illustrates the correlation between the curves of IAC (solid lines) and SFC (dashed lines) relays in the inverse, very inverse, and extremely inverse characteristics, respectively. A brief comparison of the curves reveals that the characteristics match very closely for lower time-dial

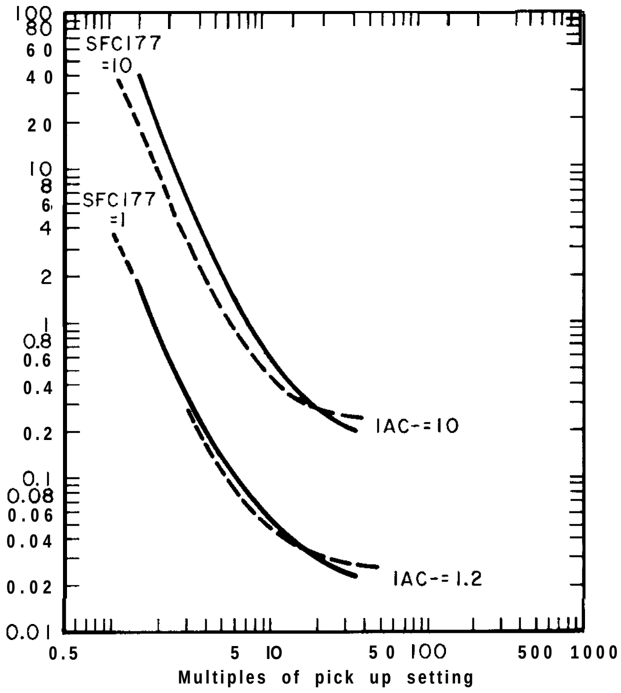


Fig. 22. Comparison of extremely inverse time-current characteristics of SFC 177 and IAC 77 relays

settings, but at higher time dials there are noticeable differences both in time and shape. Therefore, it is very important to recognize that the SFC is functionally equivalent to an IAC of corresponding characteristic and that it may be used to advantage as a backup relay for an electromechanical relay or vice versa; however, it is equally important to recognize that a static SFC relay cannot be substituted for an electromechanical relay in an existing application without first determining an appropriate setting for the SFC in that application. Specifically, this means that equivalent settings for IAC and SFC relays will have identical pickup taps, but the time-dial calibration will be different.

Two specific areas where the electromechanical (IAC and IFC) and static (SFC) relay differ are overtravel and reset.

Overtravel in electromechanical relays is a function of the design of the relay, its pickup and time-dial settings, and the magnitude of fault current. It is not an easy number to determine precisely and traditionally an estimate of 0.1 seconds has proved to be sufficiently long. Overtravel in the SFC static overcurrent relay is 0.01 seconds or less. Based upon these numbers, the following minimum coordination margins can be determined:

	IAC	IFC	SFC
Breaker time	0.0833	0.0833	0.0833
Overtravel	0.1000	0.1000	0.0100
Safety factor	0.1000	0.1000	0.1000
	0.2833	0.2833	0.1933

For practical purposes, these numbers can be given as 0.3 seconds for IAC and IFC electromechanical relays and 0.2 seconds for SFC static relays.

Reset time is the time required for the relay to return to its fully reset position after the recloser has interrupted the short circuit. For conventional electromechanical relays, reset time is very long. The IAC 77 takes a full minute to return to the reset position from the contact-closed position when set on the number 10 time dial.

However, the static SFC relay resets in 0.1 seconds or less regardless of the characteristic or time dial used, which is faster than the reclosing time of any distribution recloser or breaker available today. This difference is best illustrated by an example,

Consider the system of Fig. 23. The pole-type recloser is set for one fast and three time-delay trips and its reclose time is two seconds. In coordinating relays and reclosers, a margin of 0.15 to 0.2 seconds is normally considered the minimum safe tolerance. In this instance, in anticipation of possible problems with reset, a longer margin (0.3 seconds) was selected as a point of departure. The feeder breaker is equipped with an instantaneous-overcurrent relay set at 5362 amperes (primary) for an equivalent coverage of approximately 1.5 miles of 13.8-kV circuit. The instantaneous unit is blocked after the first trip and the reclosing relay on the feeder breaker is adjusted for a CO+5+CO+5+CO+5+CO operating cycles. The backup relay at the substation is shown as a partial differential (summation overcurrent) connection, although this is not significant to the example.

Figure 24 shows the time-current curves for this system using electromechanical IAC 77 relays. The trial

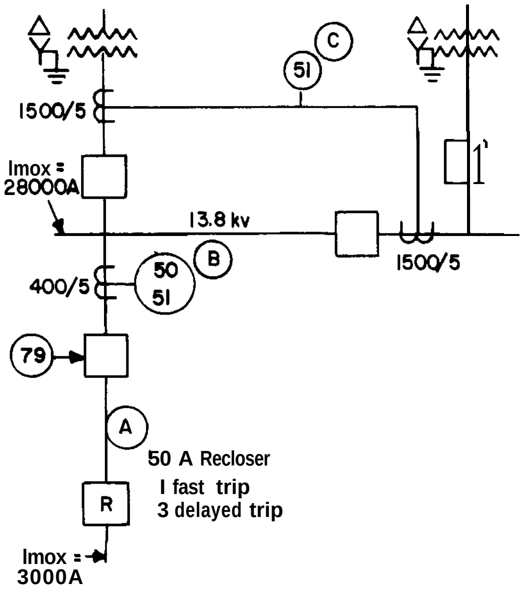


Fig. 23. Sample system for recloser-relay coordination illustration

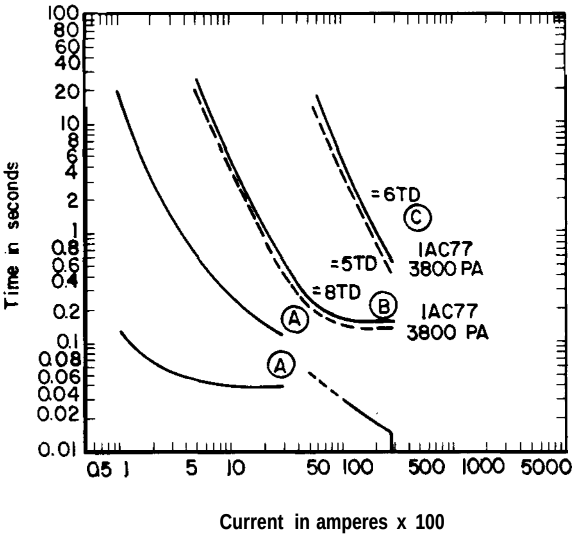


Fig. 24. Pole-type recloser vs IAC 77 relay coordination example

setting for the feeder relay is shown as the dashed curve B and a 320-ampere pickup and number 7 time dial. With this time dial, the reset time of the IAC 77 is about 42 seconds. It is significant to observe that even though the curves show an apparent margin of 0.3 seconds, the true margin between the IAC 77 and the recloser is only 0.103 seconds as determined in Table 1. Thus the number 8 time dial is required as noted by the solid curve B in Fig. 24. Similarly, the apparent margin for the backup relay is not sufficient because of reclosing by the feeder breaker, and a higher time dial must be used to assure a minimum of 0.3-second margin between relays.

In Fig. 25 the system curves are again drawn, but this time for static SFC 177 relays on the feeder breaker and as the backup relay, The reset time of the SFC (0.1 seconds) is faster than the reclosing delay of either the automatic recloser or the reclosing feeder breaker. Therefore, no consideration at all need be given to "notching" and the relay settings can be determined by the time-current curves alone. Also, because overtravel is negligible, the margin between the backup and feeder relays can be reduced to 0.2 seconds at the maximum fault level. The result is that the backup clearing time is 0.15 seconds faster at the maximum fault level when static SFC overcurrent relays are used; at a fault limited to 1.5 times the pickup of the backup relay, static relays are a full 10 seconds faster in operation.

GROUND FAULT DETECTION

A complex problem, for which there is no ready solution, is high impedance ground-fault detection and protection. This is also a very serious problem in that personnel safety is involved, particularly so when a live conductor drops to the ground and there is insufficient fault current available to operate protective devices. Sensitivity is determined by the permissible unbalance in a four-wire grounded system and/or the number of breaker operation interruptions that can be tolerated. Where the majority of all faults that occur on a four-wire distribution system initiate as line-to-ground faults and where many are of the self-clearing type, it must be evaluated whether or not very sensitive ground tripping can be justified with the acceptance of the many unnecessary interruptions that can be expected.

Table 1

Calculation of IAC 77 Relay Margin Against Pole-type Recloser

Recloser Operation	IAC 77 Feeder-relav Oneration
Trip No. 1 (Instantaneous) = 0.04 sec	$\frac{0.04}{0.44}$ 100 = 9.091% Travel
Reclose Time = 2 sec	$\frac{2}{42}$ 100 = 4.762% Reset
Trip No. 2 (Time) = 0.12 sec	$\frac{0.12}{0.44}$ 100 = 27.273% Travel
Reclose Time = 2 sec	$\frac{2}{42}$ 100 = 4.762% Reset
Trip No. 3 (Time) = 0.12 sec	$\frac{0.12}{0.44}$ 100 = 27.273% Travel
Reclose Time = 2 sec	$\frac{2}{42}$ 100 = 4.762% Reset
Trip No. 4 (Time) = 0.12 sec	$\frac{0.12}{0.44}$ 100 = 27.273% Travel

Lockout 9.091 - 4,762 + 27.273 4.762 ± 27.273
- 4.762 t 27.273= 76.624% Travel

True Margin = Remaining Travel = (1 0.76624) (0.44 set) = 0.103 sec

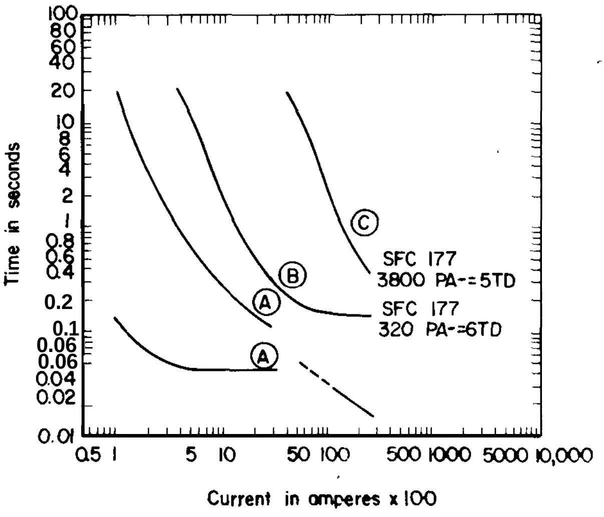


Fig. 25. Pole-type recloser vs SFC 177 relay coordination example

UNBALANCE

The problem of setting ground-relay sensitivity to include all faults, yet not trip for heavy-load currents or load inrush, is not as difficult as it is for phase relays. If the three-phase load is balanced, normal ground current is near zero. Therefore, the ground relay should not be affected by load current and can have a sensitive setting. Unfortunately, it is difficult to keep the loads on the distribution system balanced to the point where ground relays can be set to pick up on as little as 25 percent of load current. Most ground relays are set to pick up at about 50 percent of load current.

FAULTS

The two basic factors affecting low-magnitude ground current are *line impedance* and *fault impedance.*

The line impedance can be readily calculated on the basis of a "bolted" fault. However, it is often recognized that in many cases the magnitude of measurable short-circuit current is less than indicated by calculations. This is understandable in view of the many variables not accounted for in calculations. For example, conductor-splice resistance, reduced generating capacity, low system voltage at time of fault, voltage reduction due to the fault at the time of interruption, and error in calculations due to incorrect circuit footage, transpositions, and configurations. In addition, a big factor known to exist, but not possible to calculate or obtain from industry records, is fault impedance. This factor in itself can vary due to the type of fault, ground resistivity, contact pressure and weather and tree conditions. This factor has a decided effect in reducing the short-circuit current magnitude.

In 7.2/12.47 kV short-circuit calculations, a factor of 30, 35 or 40 ohms is often used as the fault resistance in determining minimum values of line-to-ground current available. However, these values are purely imaginative values without ample substantiation. The closest reference to this appears in AIEE Paper 49-175, *Overcurrent Investigation on Rural Systems.*

With the general acceptance by utility operators of the use of the coordinated recloser-fuse method of distribution line sectionalizing, the problem of high-impedance ground-fault protection is greatly simplified in the fringe areas. However, the problem is further complicated in protection of the main circuit close to the substations. Where ground relays are generally accepted as a means of ground fault detection and protection, the minimum setting is usually established by the maximum unbalance that could exist with the heaviest loaded single-phase branch interrupted. In all probability, this setting will be less than the minimum pickup value of the nearest automatic circuit recloser. Hence, if reclosers are to be used out on the distribution feeder, ground relays must be adjusted to have a minimum pickup higher than 200 percent of the largest rated recloser or be disconnected entirely. When the ground relay is adjusted as high as required, it loses its effectiveness as ground protection.

It is possible to add time delay to the ground relays so that they may be set lower than the reclosers and still achieve coordination. This feature could be utilized to achieve back-up protection for some of the ground faults that are in the recloser protective zone and disconnect the feeder if the recloser fails to function.

The combination of low-rated reclosers and fuses properly coordinated and located on the branch and fringe ends of the circuit will provide the possibility of interrupting low values of ground current, i.e., where reclosers can be applied with thermal ratings approximately 30 percent greater than full-load current at the point of installation and do have adequate interrupting capacity. Thus the possibility of operating on low-magnitude ground current is more assured than if operation is dependent upon the ground-current relays at the substation.

In a few cases, detection of a fallen conductor has been considered so important that loads have been connected line-to-line, so there could be no neutral current due to unbalance. The neutral has been grounded through high resistance to limit the ground current thus minimizing the effect of fault resistance on fault-current magnitude. Very sensitive ground relays have been installed with this system to assure clearing of conductors that have fallen.

CONDUCTOR BURNDOWN

Conductor burndown is a function of (1) conductor size (2) whether the wire is bare or covered (3) the magnitude of the fault current (4) climatic conditions such as wind and (5) the duration of the fault current.

If burndown is less of a problem today than in years past, it must be attributed to the trend of using heavier conductors and a lesser use of covered conductors. However, extensive outages and hazards to life and property still occur as the result of primary lines being burned down by flashover, tree branches falling on lines, etc. Insulated conductors, which are used less and less, anchor the arc at one point and thus are the most susceptible to being burned down. With bare conductors, except on multi-grounded neutral circuits, the motoring action of the current flux of an arc always tends to propel the arc along the line away from the power source until the arc elongates sufficiently to automatically extinguish itself. However, if the arc encounters some insulated object, the arc will stop traveling and may cause line burndown.

With bare conductors, on multi-grounded neutral circuits, the motorizing effect occurs only on the phase wire since current may flow both ways in the neutral. When the 25 percent of the burndown and the protective equipment should be installed to limit the currents and times to less than those given.

With tree branches falling on bare conductors, the arc may travel away and clear itself; however, the arc will generally re-establish itself at the original point and continue this procedure until the line burns down or the branch fails off the line. Limbs of soft spongy wood are more likely to burn clear than hard wood. However, one-half inch diameter branches of any wood, which cause a flashover, are apt to burn the lines down unless the fault is cleared quickly enough.

Figure 26 shows the burndown characteristics of several weatherproof conductors. Arc damage curves are given as arc is extended by traveling along the phase wire, it is extinguished but may be re-established across the original path. Generally the neutral wire is burned down.

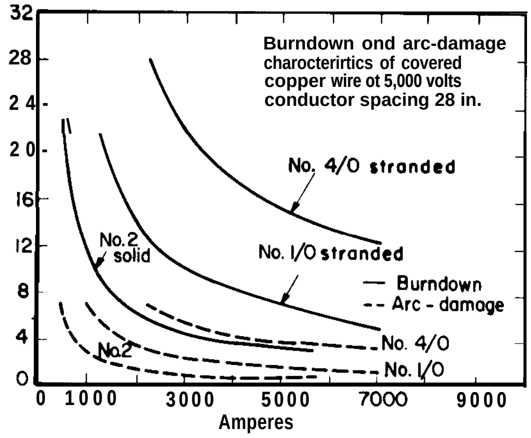


Fig. 26. Burndown characteristics of several weatherproof conductors

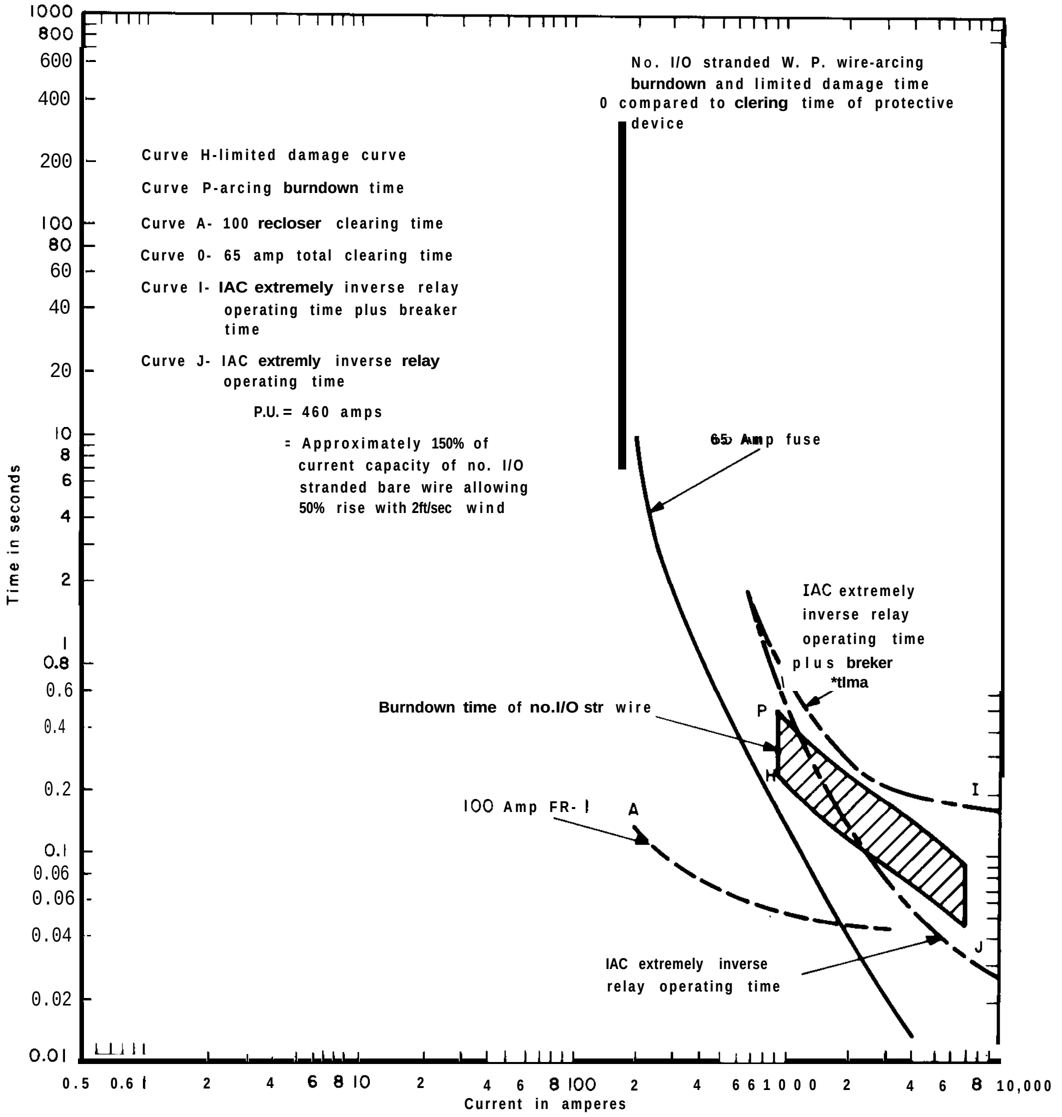


Fig. 27. Curves illustrating coordination between the arc damage and burndown characteristics for a No. I/O conductor land the protective devices which must operate to prevent serious conductor damage

Figure 27 shows the coordination between the arc damage and burndown characteristics for a No. I/O conductor and the protective devices which must operate to prevent serious conductor damage. This curve shows that with the present breaker operating times, the feeder breaker would afford little protection. It should be realized that the breaker time used was assumed to be eight cycles regardless of the fault current. In an actual case, the breaker time would probably be less than one half this value at its nameplate interrupting rating.

The use of automatic circuit reclosers and fuses will greatly improve the protection of conductors against burndown as shown in Fig. 27. Proper utilization of reclosers and fuses should provide protection for all conductors within the current range shown.

As systems increase in size, many engineers are worried about burndown becoming more of a problem since the available short-circuit current will increase. This problem may be delayed by the sectionalizing of buses and the addition of current-limiting reactors. It is quite possible that proper sectionalizing may delay the problem indefinitely for some systems.

The proper use of reclosers and fuses, along with higher speed breakers, should prevent most conductor burndown problems.

APPENDIX A

FUNCTIONS AND DEFINITIONS

The devices in the switching equipments are referred to by numbers, with appropriate suffix letters (when necessary), according to the functions they perform. These numbers are based on a system which has been adopted as standard for automatic switchgear by the American Standards Association.

Device No.	Function and Definition
11	CONTROL POWER TRANSFORMER is a transformer which serves as the source of a-c control power for operating a-c devices.
24	BUS-TIE CIRCUIT BREAKER serves to connect buses or bus sections together.
27	A-C UNDERVOLTAGE RELAY is one which functions on a given value of single-phase a-c undervoltage.
43	TRANSFER DEVICE is a manually operated device which transfers the control circuit to modify the plan of operation of the switching equipment or of some of the devices.
50	SHORT-CIRCUIT SELECTIVE RELAY is one which functions instantaneously on an excessive value of current or on an excessive rate of current rise, indicating a fault in the apparatus or circuit being protected.
51	A-C OVERCURRENT RELAY is one which functions when the current in an a-c circuit exceeds a given value.
52	A-C CIRCUIT BREAKER is one whose principal function is usually to interrupt short-circuit or fault currents.
64	GROUND PROTECTIVE RELAY is one which functions on failure of the insulation of a machine, transformer or other apparatus to ground. This function is, however, not applied to devices 51N and 67N connected in the residual or secondary neutral circuit of current transformers.
67	A-C POWER DIRECTIONAL OR A-C POWER DIRECTIONAL OVERCURRENT RELAY is one which functions on a desired value of power flow in a given direction or on a desired value of overcurrent with a-c power flow in a given direction.
78	PHASE-ANGLE MEASURING RELAY is one which functions at a pre-determined phase angle between voltage and current.
87	DIFFERENTIAL CURRENT RELAY is a fault-detecting relay which functions on a differential current of a given percentage or amount.

The above numbers are used to designate device functions on all types of manual and automatic switchgear, with exceptions as follows:

FEEDERS – A similar series of numbers starting.with 101 instead of 1, is used for the functions which apply to automatic reclosing feeders.

HAND RESET -The term “Hand Reset” shall be added wherever it applies.

LETTER SUFFIXES -These are used with device function numbers for various purposes as follows:

1. CS – Control Switch
X – Auxiliary Relay
Y – Auxiliary Relay
YY – Auxiliary Relay
Z – Auxiliary Relay

2. To denote the location of the main device in the circuit or the type of circuit in which the device is used or with which it is associated, or otherwise identify its application in the circuit or equipment, the following are used:

N – Neutral
SI – Seal-in

3. To denote parts of the main device (except auxiliary contacts as covered under (4) below), the following are used:

H – High Set Unit of Relay
L – Low Set Unit of Relay
OC – Operating Coil
RC – Restraining Coil
TC – Trip Coil

4. To denote parts of the main device such as auxiliary contacts (except limit-switch contacts covered under (3) above) which move as part of the main device and are not actuated by external means. These auxiliary switches are designated as follows:

"a" – closed when main device is in energized or operated position
"b" – closed when main device is in de-energized or non-operated position

5. To indicate special features, characteristics, the conditions when the contacts operate, or are made operative or placed in the circuit, the following are used:

A – Automatic
ER – Electrically Reset
HR – Hand Reset
M – Manual
TDC – Time-delay Closing
TDDO – Time-delay Dropping Out
TDO – Time-delay Opening

To prevent any possible conflict, one letter or combination of letters has only one meaning on an individual equipment. Any other words beginning with the same letter are written out in full each time, or some other distinctive abbreviation is used.

HOW TO SET AN IAC RELAY

Time and current settings of IAC relays are made by selecting the proper current tap and adjusting the time dial to the number which corresponds to the characteristic required. The following example illustrates the procedure.

Assume an IAC inverse-time relay in a circuit where the circuit breaker should trip on a sustained current of approximately 450 amperes, and that the breaker should trip in 1.9 seconds on a short-circuit current of 3750 amperes. Assume further that current transformers of 60:1 ratio are used.

Find the current tap setting by dividing the minimum primary tripping current by the current transformer ratio:

$$\frac{450}{60} = 7.5$$

Since there is no 7.5-ampere tap, use the 8-ampere tap.

To find the time setting which will give 1.9-second time-delay at 3750 amperes, divide 3750 by the transformer atio. This gives 62.5-amperes secondary current, which is 7.8 times the 8-ampere tap setting.

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Model	TYPE		
	IAC	IFC	SFC
51	GES-7001	GES-7014	GES-7011
53	GES-7002	GES-7015	GES-7012
77	GES-7005	GES-7016	GES-7013

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