GE Electrical Distribution & Control

Application Engineering Information

Ground-Fault Protection for Solidly Grounded Low-Voltage Systems

Arcing Fault Review

Introduction

The intent of this publication is to provide a clearer understanding of the many considerations associated with the application of ground fault protection to solidly grounded, low voltage systems operating at 600 Volts or less.

It does not propose any short-cut method for arriving at the settings of ground fault relays, since such a method may lead to questionable system protection and/or poor continuity of service.

Arcing Fault Current Review

Arcing faults represent an abnormal condition of great concern to the system designer and operator. Although several publications have discussed this subject, its importance deserves a review:

Several types of ground currents[1] can exist in any power system, three of which are:

a. Insulation leakage current, such as in appliances, portable tools etc. Normally, current magnitude is very low, in the order of milliamperes. This important subject is discussed in other bulletins.

b. Arcing fault ground current (subject of this bulletin), commonly caused by insulation failure, loose connections, construction accidents, rodents, debris, etc. The current magnitude may be very low in relation to the three-phase fault current.

c. Bolted fault ground current, commonly caused by improper connections or metallic objects wedged between phase and ground. In this fault the current magnitude may be equal to, or less than, the three-phase fault current.

Arcing Faults

The major problems arising from arcing faults are the interruption of electrical power, destruction of electrical equipment and associated hazard to personnel. Arcing faults have been responsible for damage to virtually all types of electrical equipment, regardless of manufacturer or mode of operation. The energy released during an arcing fault is localized and can be so intense that it vaporizes copper or aluminum conductors and surrounding steel enclosures. This energy can also destructively distill toxic gases from organic insulation systems.

Continued arcing at the point of fault can release tremendous amounts of energy in the fault area and the electromagnetic forces can cause the arc to travel. This tends to spread the fault and transfer it to areas not originally within the fault zone. In fact, the point-of-fault origin and the point-of-maximum damage are practically never the same.

Experience has shown that arcing in grounded electrical systems inevitably involves ground even though it may start between phases. This makes possible a separate means of arcing fault detection by sensing ground current quite apart from the phase-overcurrent protection requirements. This is fortunate, since arcing faults can exist at very low current magnitudes and thus may be very difficult to sense with phase-overcurrent devices.

Arcing faults can exhibit low current levels due to the apparent impedance of the arc itself. It should be noted that arcing-fault-current magnitudes are subject to wide variations as functions of the fault circuit impendance. Also, the arc current may be discontinuous, requiring a sparkover voltage equal to the restrike voltage to cause arc reignition. This discontinuous current has a greatly reduced rms value and its discontinuous nature is one explanation of why single-phase-arcing faults can have very low magnitudes. The probable minimum values of arcing-fault current, although difficult to determine, are an important consideration in designing protection schemes.

Bolted Faults

Bolted line-to-ground faults rarely occur in practical circuits. When they do occur, they generally do not display the very low current magnitudes possible in an arcing line-to-ground fault. They may be low in magnitude compared to a three-phase fault condition since they are dependent upon the total impedance path (phase and ground return). Because of this, bolted line-to-ground faults may or may not be sensed by phase-overcurrent devices. When ground fault protective devices are used for a given fault location, they are sensitive to arcing ground fault current magnitudes. The bolted line-to-ground fault currents at the same location will also be detected because of their higher magnitude.

Solutions to the Arcing Fault Problem

Solutions to the arcing fault problem involve a two-pronged approach.

1. Minimize the probability of arcing fault initiation by:

a. Careful attention to system design and to the settings of protective devices.

b. Selecting equipment that is isolated by compartments within grounded metal enclosures.

c. Selecting equipment with draw-out, rack-out, or stab-in features, thereby reducing the necessity of working on energized components.

d. Providing proper installation practices and supervision.

e. Protecting equipment from unusual operating or environmental conditions.

f. Insisting on a thorough clean up immediately before initial energization of equipment to remove construction debris, such as wire clippings, misplaced tools, etc.

i. Executing regular and thorough maintenance procedures.

j. Maintaining daily good housekeeping practices.

2. Sense and remove the arcing fault quickly (within cycles on a power frequency base) so that damage is minimal, thus allowing relatively rapid restoration of power after the damage is repaired. To remove the arcing fault current promptly from the system, protective devices with the following characteristics are required:

a. Sensitivity to detect low-level ground fault current magnitudes.

b. Speed to operate within cycles to remove the fault from the system.

c. Selectivity to provide coordination with other protective devices so that a minimum portion of the system is shut down under ground fault conditions.

d. An adjustment and setting of each protective device which can be tailored to the specific system.

[1] Additional ground currents can occur due to lightning discharge, static charge, capacitor charging current, etc.

Expected Magnitude of Arcing Fault Currents

In designing an electrical power system, it is always customary to consider maximum conditions. Maximum fault currents are calculated to determine the equipment interrupting capacity requirements. Phase protective devices are set for the load conditions and to achieve selective tripping and avoid nuisance tripping. However, under arcing conditions, short-circuit levels may be at their ***minimum*** levels and the phase protective tripping devices set to meet the load requirements may be insensitive to these low-level fault currents.

Exact minimum values of arcing ground current are difficult to compute precisely for several reasons:

1. Results are influenced by the geometry, spacing, environmental and supply circuit characteristics.
2. Current wave shape is generally irregular with a harmonic content.
3. Current is frequently discontinuous.

Mathematically, the general expression for a fundamental frequency line-to-ground fault current in a three-phase system is generally expressed in symmetrical component parameters:

$$I_f = \frac{3E_{L-N}}{Z_1 + Z_2 + Z_0 + 3Z_g} \qquad (1)$$

Where I_f = line-to-ground fault current
E_{L-N} = line-to-neutral voltage
Z_1 = positive sequence impedance
Z_2 = negative sequence impedance
Z_0 = zero sequence impedance
Z_g = ground return impedance

Both positive (Z_1) and negative (Z_2) sequence impedances are associated only with the source and phase impedance of the equipment supplying the fault current since the currents of each of these two sequences combine to zero at the ground fault location. Impedances Z_1 and Z_2 are equal for the circuit equipments involved (transformers, buses, cables) and are the values familiarly utilized in three-phase fault calculations. Typical values are listed in application bulletin EESGII-AP-1 and GET-3550①. The zero sequence impedance system, however, involves in-phase currents in each of the three-phase circuits with each circuit consisting of the source and phase conductors of the equipment to the point of fault. Those impedance-to-ground fault currents for this network can be identified as the zero sequence, impedance Z_0. The sum of the zero sequence currents in the phase conductors, $3I_0$, must then be returned to the power supply via the ground return path identified as Z_g. This path may consist of building steel, conduit, ground conductors, grounded neutral conductors, ground buses, bonding jumpers, grounding rods, earth, equipment grounded housings, etc. The ground return path results in an additional impedance voltage drop of $3I_0Z_g$. By considering the voltage drop term, $3I_0Z_g$, to be the product of $3Z_g$ and I_0, it becomes evident that it can be correctly accounted for by adding an impedance, $3Z_g$, to the zero sequence impedance network. Thus, the total zero sequence impedance network is (Z_0 + $3Z_g$), and each term need not be measured independently (which would be difficult to do) but one may obtain a value for the total term. It is important to recognize that both terms are present.

Values for ($Z_0 + 3Z_g$) have been presented at technical conferences in the form of $(Z_0 + 3Z_g)/Z_1$ ratios for some system components (cable, busway) and are tabulated in Appendix A for convenience. Since Z_1 has been defined and is known, ($Z_0 + 3Z_g$) can be computed from the above mentioned ratios for cable and busway. Recalling that the calculation of the ***minimum*** fault current is desired, any system component that would introduce additional impedance should be included.

The mathematical expression thus far does not consider the effects of the voltage drop due to the arc in an arcing fault condition, but expresses a bolted-to-ground condition. Due to the voltage drop across the arc, the resultant ground fault current may be considerably lower than the bolted-ground fault current. This reduction can be accounted for by a multiplier K which relates the arcing to bolted-ground fault current as follows.

$$I_f \text{arcing} = K \frac{(3E_{L-N})}{(Z_1 + Z_2 + Z_0 + 3Z_g)} \qquad (2)$$

Values for K are given in Appendix B and are used only in low voltage systems since the effect of arc voltage is significant in comparison with the driving voltage. It is important to remember that this calculation procedure for determining the ground fault current is only an approximation. ***The minimum fault current value is dependent on actual system conditions at the time of fault.*** Typical conditions that would increase the system impedance and thereby cause a lower ground fault current than that calculated would be:

a. Installation changes that depart from design, such as greater conductor spacings (phase-to-phase and/or phase-to-ground) or ground return path alterations (ground conductors, bonding jumpers, etc.).
b. Operating conditions such as opening of one phase to the transformer primary, changes in the ground return path due to loose connections, open-ground conductors, etc.

It is interesting to note that when a line-to-ground arcing fault occurs at the secondary terminals of a source power transformer delta connected on the primary and wye-solidly grounded on the secondary; the approximate magnitude of ground fault current will be "K" times the three-phase short-circuit current value at the transformer terminals. Therefore, for a 480Y/277-Volt, solidly-grounded system the approximate transformer terminal arcing-ground-fault current would be 38% × $I_{3\phi S.C.}$. This value ($0.38I_{3\phi S.C.}$) comes from realizing, in the basic I_f equation (2), that the ground return path impedance, Z_g, from a transformer phase terminal to its neutral is for all practical purposes, zero. Furthermore, the zero sequence impedance, Z_0, approaches the values of positive (Z_1) and negative (Z_2) impedances.

Therefore $Z_1 = Z_2 = Z_0$; while $Z_g = 0$ and then

Equation (2)

$$I_f \text{arcing} = K \frac{3E_{L-N}}{(Z_1 + Z_2 + Z_0 + 3Z_g)} \qquad (2)$$

becomes (approximately) I_f arcing =

$$K\left(\frac{3E_{L-N}}{3\,Z_1}\right) = K\left(\frac{E_{L-N}}{Z_1}\right)$$

Since E_{L-N}/Z_1 expresses the three-phase short-circuit current, then

I_f arcing = K $I_{3\phi S.C.}$

where K for the line-to-ground fault condition, as shown in Appendix B, is 40% for a 575-volt system, 38% for a 480-Volt system and approaches zero for a 208-Volt system.

It should be observed, however, that for line-to-ground arcing faults at locations in the system other than at the source transformer, the ground return impendance (Z_g) is not zero. The ($Z_0 + 3Z_g$) value becomes increasingly greater than the positive (Z_1) or negative sequence (Z_2) values as one advances into the system away from the source transformer.

①See your GE sales representative to obtain a copy.

Detection Methods

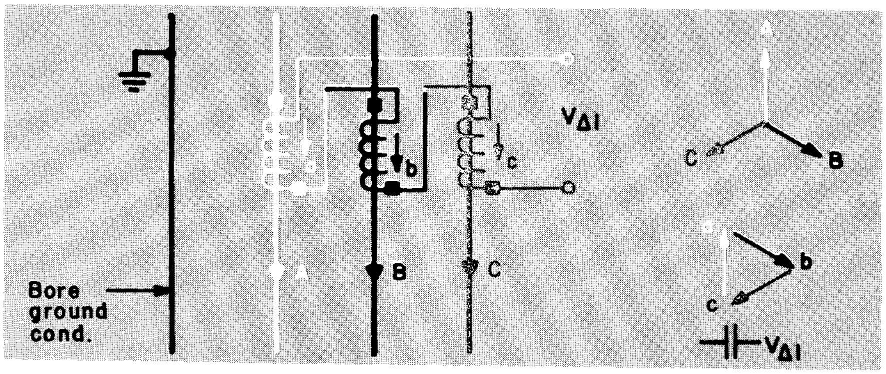

Fig. 1. Broken delta-voltage ground-fault sensing. For balanced three-phase, operation, in three-phase, three-wire systems, V Δ 1 equals 0.

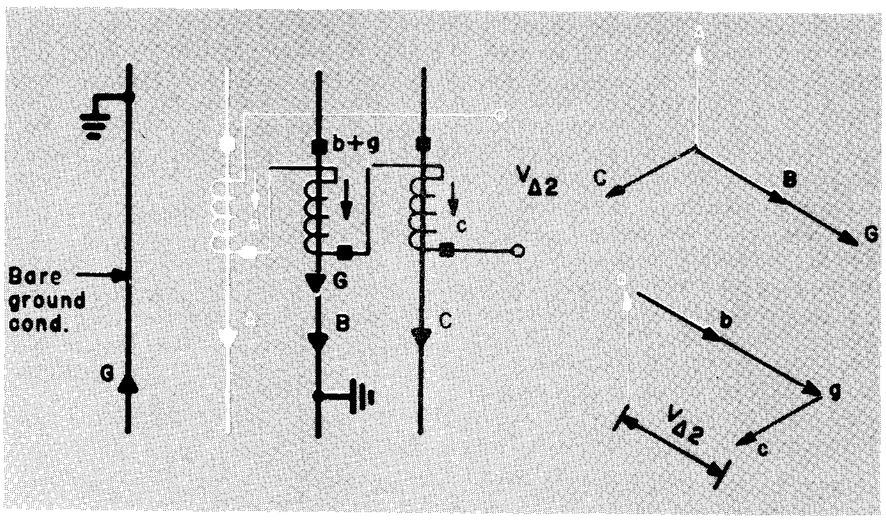

Fig. 2. Broken delta-voltage ground-fault sensing. For ground-fault condition in three-phase, three-wire systems, V Δ 2 is not equal to 0.

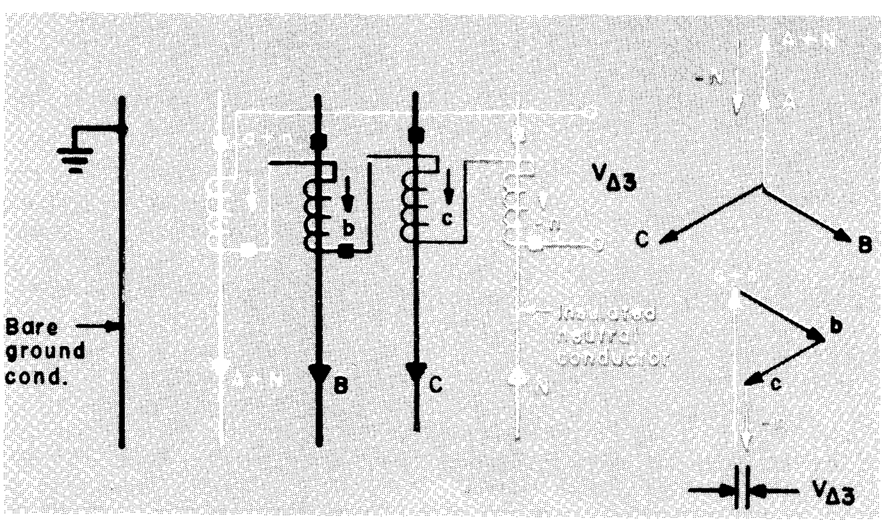

Fig. 3. Broken delta-voltage ground-fault sensing. For unbalanced line to netural load operation in three-phase, four-wire systems, V Δ 3 equals 0.

Another observation can be made from basic equation (1). If a resistor is inserted between the source (transformer or generator) neutral and grounded, it becomes part of the ground return impedance (Z_g).

When the ohmic value of the resistor far exceeds the other system phase and ground return impedance values, it then becomes the controlling impedance element determining the line-to-ground fault current magnitude. It may cause the arcing line-to-ground fault current to be self-extinguishing by limiting the voltage across the arc below the required restrike voltage.

From a system point of view, however, insertion of a resistor in the neutral circuit precludes that no neutral loads are to be served.

The results thus far can be summarized as follows:

1. Arcing fault protection involves computing the ***minimum*** ground fault current to determine the desired protective device setting.
2. Mathematically, an approximate ***minimum*** arcing-ground-fault current can be attained for the "drawing board" system.
3. In practical systems, ***lower*** fault currents may be realized due to system impedance increases and/or system conditions at the time of fault.
4. The mathematical expression representing the arcing ground fault current is:

$$I_f \text{ arcing} = K \frac{(3E_{L-N})}{(Z_1 + Z_2 + Z_0 + 3Z_g)}$$

5. The mathematical expression I_f arcing = k I (three-phase short-circuit current) is ***only*** true when the ground fault is ***at the source transformer secondary terminals***. Should the fault occur further downstream in the system, I_f arcing value will be decreasing. For instance the ground fault current in the system example calculations (page 11) varies from 18 to 24%.

Methods of Ground Fault Detection

The ground fault current can be monitored either as it flows out to the fault or on its return to the neutral point of the source transformer or generator. When monitoring the outgoing fault current, the currents in all power conductors are monitored either individually (Figs. 1 through 6, 11 and 12), or collectively (Figs. 7 through

10). When monitoring the return fault current, only the ground fault return conductor is monitored (Fig. 13). Caution is required to help assure that the returning ground fault current bypasses the outgoing monitoring current transformer, but does not bypass the current transformer monitoring the returning ground fault current.

Ground fault responsive devices can consist of a static relay or programmer and mated current sensors or an over-current relay (electro-magnetic or static) using any properly rated standard window or bar-type current transformer. The relay or programmer pick-up level is adjustable and the relay may be equipped with an adjustable time-delay feature. Operation of the relay or programmer activates a trip mechanism on the interrupting device. Selectivity is achieved through a time delay and/or current setting or blocking function. Zone selectivity can be achieved by using a differential, or blocking scheme.

Broken Delta Ground Fault Protection

A ground responsive relay connected to measure V_{Δ}, shown in Figs. 1 through 4, monitors the outgoing ground fault current by sensing the broken delta voltage of series connected sensors, or transformers. During normal operation, the vectorial addition of voltages from three or four sensors is essentially zero (see Figs. 1 and 3). When a downstream ground fault occurs, the outgoing ground fault current causes a voltage to appear at the terminals of the relays (Figs. 2 and 4). If the current magnitude is sufficient to produce a voltage equal to, or greater than, the selected operating level of the relay, the interrupter trip device is activated. The variable operating level and time-delay features in the relay provide for selectivity requirements. For a four-wire system, four sensors are required (Figs. 3 and 4).

Residual Ground Fault Protection

A residually connected relay, as shown in Figs. 5 and 6, monitors the outgoing ground fault current by using three or four current transformers. The operation is based on the concept that the phase currents in a balanced three-phase system add vectorially to zero. If current transformers correctly transform phase currents to secondary currents, these secondary quantities will also add up to zero. As a consequence, a residually connected ground fault relay will sense zero current during normal, balanced, three-phase operation.

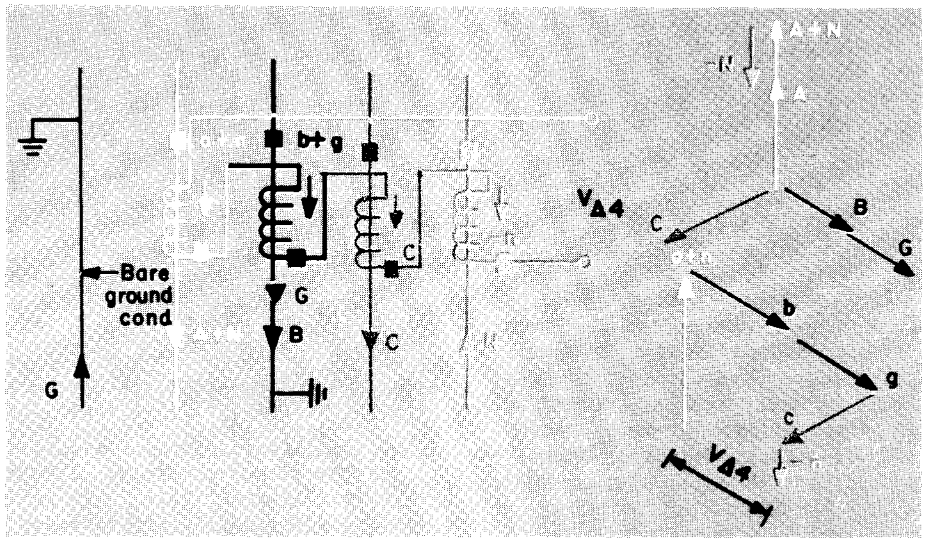

Fig. 4. Broken delta-voltage ground-fault sensing. For ground-fault condition in three-phase, four-wire systems and unbalanced load operation, V Δ 4 is not equal to 0.

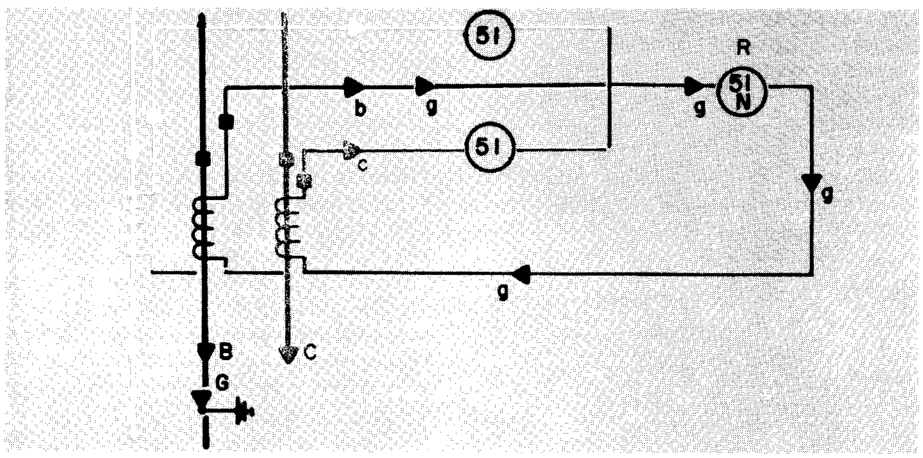

Fig. 5. Residual ground-fault sensing. For ground-fault condition in three-phase, three-wire systems relay R senses only ground-fault-current component.

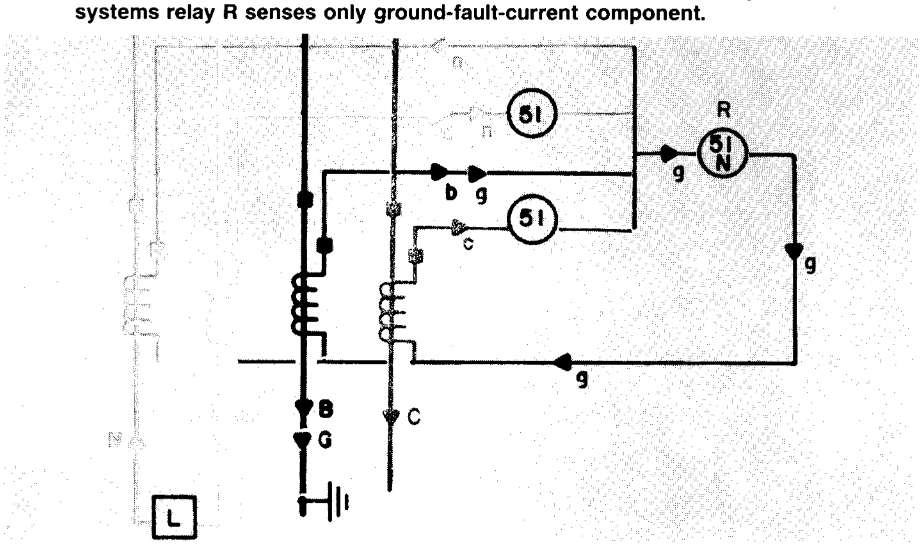

Fig. 6. Residual ground-fault sensing. For ground-fault condition in three-phase, four-wire systems, relay R responds only to ground-fault-current component provided fourth current transformer is present.

Detection Methods

When using this scheme, two limitations should be observed:

1. The sensitivity is influenced to a large extent by the phase current transformer ratio, which is selected on the basis of relatively large phase currents. Hence, the ground fault sensitivity suffers as the current transformer ratio increases.
2. Transformation inaccuracies, caused by slight differences in characteristics of the phase current transformers, may not cause the secondary currents to add up to zero, even though the primary currents do so. This characteristic may become a problem during inrush currents or "through" faults which contain a dc component of subtransient current. These current transformer error currents usually decay rapidly in a matter of cycles, but sometimes not quickly enough to avoid false operation of a residually connected instantaneous type relay. Hence, only time overcurrent type relays should be used. Note that these limitations are avoided in the design and construction of protection programmers which are an integral part of low voltage circuit protectors.

For three-phase, three-wire systems, only three current transformers are required (Fig. 5). Three-phase, four-wire systems require four current transformers to "blind" the residually conected relay to any unbalanced line-to-neutral loading current (Fig. 6). The fourth current transformer makes it possible to set the relay at a sensitive pick-up level regardless of the anticipated unbalanced load current magnitude. If the anticipated worst-case unbalanced line-to-neutral load current is lower than the pick-up setting of the ground relay, the neutral current transformer shown in Fig. 6 can be omitted.

Ground Sensor Protection

Ground sensor protection is provided by a combination of a window or donut type current transformer, which surrounds all power conductors, and a specifically matched relay, with either instantaneous and/or time delay characteristics.

In a balanced three-phase system (Fig. 7), or even in an unbalanced three-phase, four-wire system (Fig. 8), the magnetic flux produced by each of the phase and neutral currents has a mutual cancelling effect as observed by the current transformer. A ground fault current, however, will return through a circuit external to the

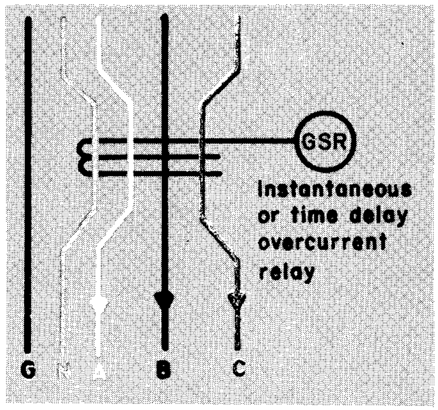

Fig. 7. Ground sensor protection. Relay is insensitive to balanced 3-phase load currents.

current transformer (Fig. 9) and therefore not produce a cancelling magnetic flux to that produced by the ground current flowing in the phase conductor. Thus, the current transformer produces a current output to the relay only for ground fault currents but no significant current output to the relay for normal phase currents. Phase currents of high magnitude, however, due to local saturation of the current transformer iron core, may create a sufficient current output to the relay to cause relay operation. The current magniture at which operation occurs is dependent on the current transformer configuration and turns ratio, spacial distribution of the power conductors within the window or donut current transformer, and sensitivity of the relay. Hence, manufacturers' instructions

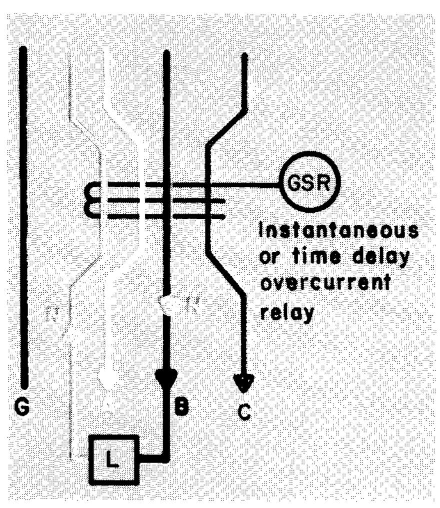

Fig. 8. Ground sensor protection. Relay is insensitive to line-to-neutral load, if neutral conductor is inserted inside current transformer.

pertaining to application and installation procedures should be followed. Like the residual ground fault protection units, when the pickup setting of the relay is above the anticipated worst case unbalanced line-to-neutral load current, the neutral conductor can be placed external to the current transformer as shown in Fig. 10.

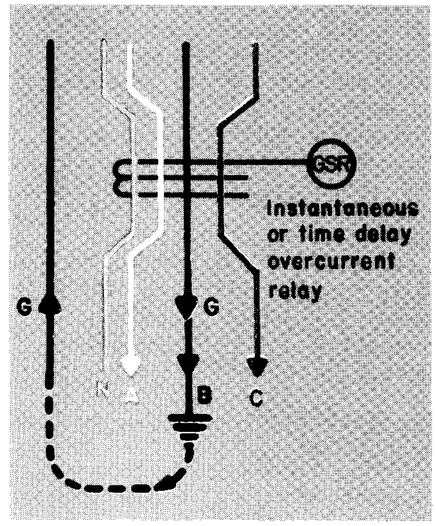

Fig. 9. Ground sensor protection. For ground fault condition, relay senses only the ground fault components of currents.

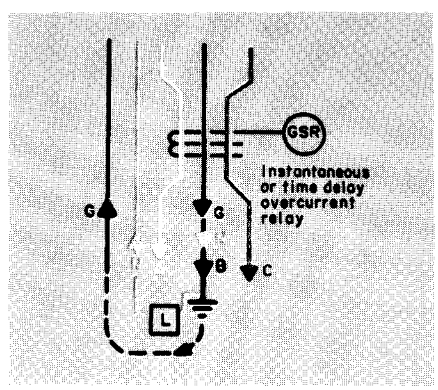

Fig. 10. Modified ground sensor protection. Relay is sensitive to both the neutral and ground fault components of current.

Integral Ground Fault Protection

The ground fault function shown in Figs. 11 and 12 is an integral part of the static trip programmer unit applied on low voltage circuit breakers. Operation is similar to the residual ground fault protection previously described. The current transformers are defined as current sensors since these transformers are designed for use only with the low burden programmer unit. For a three-phase, three-wire system three current sensors, mounted within the circuit breaker, are required (Fig. 11). For a three-phase, four-wire system a fourth current sensor monitoring the neutral is mounted externally from the circuit breaker (Fig. 12) provided the neutral conductor is radial and not grounded after passing through the current sensor. Similar to the residual ground fault protection if the anticipated worst-case unbalanced line-to-neutral is lower than the pick-up setting of the static relay, the neutral current transformer shown in Fig. 12 can be omitted.

Ground Return Protection

Ground fault currents must return to the transformer neutral to complete the circuit. The most reliable application of this principle is in the transformer neutral connection to ground. A current transformer installed in this location will sense all ground currents returning to the source transformer, (Fig. 13). Operation of the ground return relay (GRR) indicates that the ground fault may be on the bus, in the transformer winding, or on its extension to the line terminals of the main secondary breaker. To provide the proper protection, the relay should be wired to trip the main secondary breaker and to start a timer so that in approximately five to ten cycles after breaker operation, if the fault is ***still*** sensed by the ground return relay, the timer will signal the transformer primary protector to trip. Application of this form of protection in locations other than the transformer neutral-to-ground connection must be carefully applied to assure that the ground sensor relay will sense all or most of the ground return current.

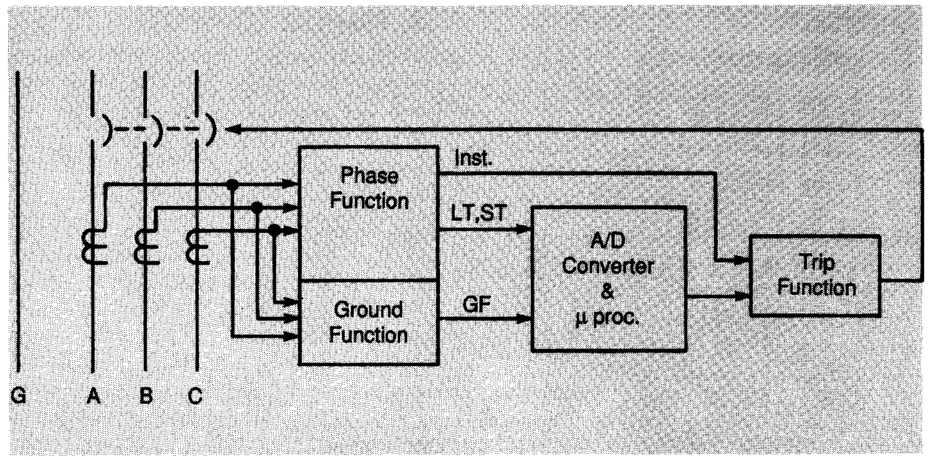

Fig. 11. Integral ground fault sensing utilizing the static trip unit integral with low voltage circuit breakers. For three-phase, three-wire power systems.

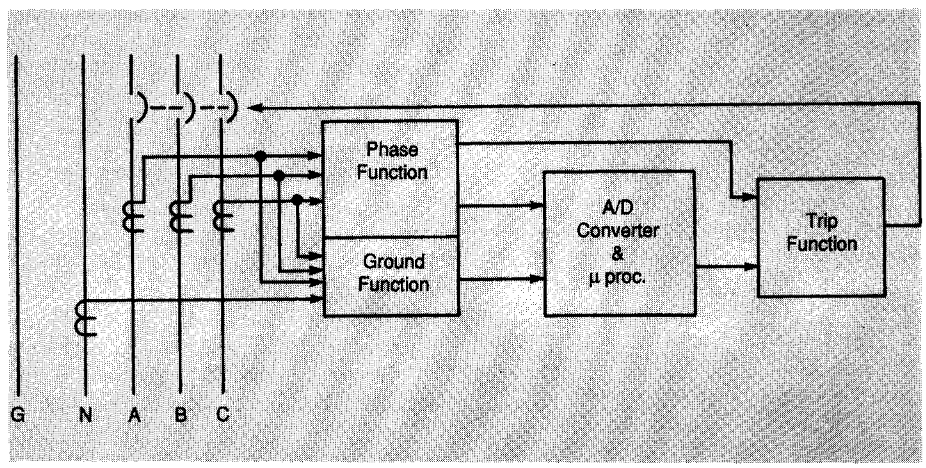

Fig. 12. Integral ground fault sensing utilizing the static trip unit integral with low voltage circuit breakers. For three-phase, four-wire power systems.

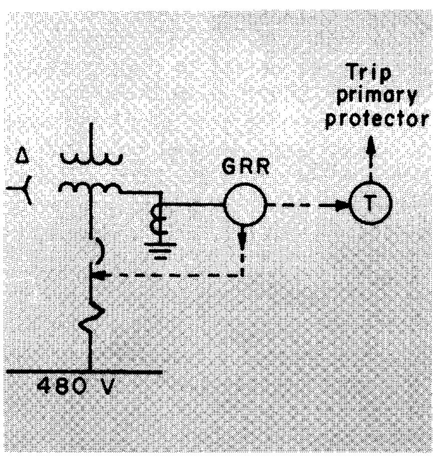

Fig. 13. Ground return fault protection as applied to transformer neutral ground.

Ground Differential Protection

The differential protection scheme is an extension of the ground sensor monitoring units where the current transformers are installed in the incoming power circuit and outgoing feeder circuit. The output of these current transformers is connected to one relay, thereby monitoring for ground faults only within the zone; that is, between incoming and outgoing current transformers. False operation due to dissimilar response of the ground sensor current transformers to high through-fault currents should be recognized and remedied.

Ground Summation Protection

The summation scheme is an extension of the residual (or ground sensor) or ground return monitoring units where additional current transformers inputs are supplied to the relay. Various schemes are outlined in Appendix C.

System Considerations

System Considerations

The system designer must balance economics against cost of outage and potential cost of equipment damage to arrive at a practical system. There is no single solution for all systems; each system must be analyzed individually.

Six important factors must be considered:

1.—Type of system
2.—Reliability
3.—Neutral circuit
4.—Ground return path
5.—Protective devices
6.—Settings

1. Type of System

Fortunately, the most widely used circuit—the simple radial—is the easiest to analyze and lends itself to a straightforward protection system design. The problem becomes more difficult and involved with secondary selective, primary selective, or spot network systems. Each of these more complex systems has factors favoring its selection if the economic-reliability balance so indicates.

2. Reliability

In the normal sense of reliability, radial systems are quite reliable for general use. However, specific applications—particularly critical processes, life support and high value continuity uses—deserve the redundancy offered by the higher order systems. The system designer must face the increased engineering analysis which accompanies the higher levels including continuity of service, reduction in false outages and the improved level of equipment protection—all balanced against cost. These improvements all cost more and this expense must be factored against the use benefit values.

Ground fault protection applied to the mains only, with no application on the feeders or branch circuits of a power system, can be justified if total loss of power to the system is acceptable under an arcing fault condition. If not acceptable, then ground fault protection should be considered on successive downstream protectors (feeders, branches) until an acceptable level of system outage is attained. The degree of acceptable protection will dictate the protector requirements to determine whether protection by use of ground fault units is required, or direct acting phase protectors are adequate.

3. Neutral Circuit

A simple radial system with a radial neutral presents few problems. For three-wire (three-phase conductors), four-wire (three-phase and one ground, or neutral conductor), five-wire (three-phase, one neutral and one ground conductor) where the neutral conductor is a radial conductor (not looped or continuous between alternate power sources) and grounded only at the source, either the ground sensor or the ground return monitoring modes may be used. The ground sensor mode is preferred, thus avoiding the installation problem associated with the return mode.

The more complex systems, however, with neutral circuits which connect between alternate power sources require very careful analysis and design to avoid unintended relay operation. When the neutral conductor is looped or continuous between alternate power sources and grounded only at the source or grounded downstream, extreme care must be taken in applying ground fault protection. Every circuit should be checked for stray returning neutral and/or ground fault currents that could cause the ground fault unit to be desensitized, to misoperate, or not operate. A simple method to check the application is to draw a one line diagram of the system and superimpose assumed neutral loads and ground faults then trace the current flow to determine the effects on the ground fault units. Keep in mind that the return current flow tends to seek the lowest impedance path. A given path, although initially the lowest impedance path, may not remain so as the magnitude of current increases. It might be determined that the neutral conductors because of the interties present such good paths for stray returning currents that the only solution to providing ground fault protection is to use a modified ground sensor (GS) or residual (without neutral current transformer) mode. Either mode consists of monitoring the phase conductors only and avoids the serious problem of non operation when operating is desired, since the neutral conductor which may be carrying ground-fault currents is not monitored. It may or may not avoid nuisance operation due to neutral current loading, specifically if its maximum setting is limited to 1200 Amperes, to meet NEC Article 230-95 (1990) even though the minimum ground fault available for the protective zone being considered permits a higher current setting.

The popular double-ended switch-gear, or switchboard, represents a good example of a looped neutral condition and a solution lies in utilizing various schemes which consist of basic ground sensor or residual or ground return modes with additional current transformer inputs as outlined in Appendix C.

Secondary and spot networks due to neutral interties, multiple grounding and normal lack of bus tie protectors in spot network systems require ground fault protection solutions that must be tailored to the particular system arrangement by engineers skilled in the art of ground fault protection. For secondary selective networks, consisting of load center type equipment, having mains and tie protectors, the summation scheme outlined in Appendix C might be a good application. For spot networks consisting of network collector buses, the only solution might be the use of a modified ground sensor [GS), or residual mode, that monitors phase conductors only or a ground return (GR) mode where each source neutral is insulated and passed through the current transformer before it is grounded and extended to the system neutral. In all cases, consideration should be given to providing protection for components on the line side of the mains such as incorporating a timer that would transfer trip the source protector should the ground fault current persist after the main protector trips.

4. Ground Return Path

The ground return path should be designed to present a low impedance path to (a) permit sensitive detection of ground fault currents as well as to provide adequate ground fault current carrying capability, and (b) to hold the voltage gradients along its path to less than shock hazard threshold values.

As can be seen from Appendix A, the $(Z_0 + 3Z_g)/Z_1$ ratio can be kept low, leading to a low impedance (Z_g) ground return path. This is obtained by using ground conductors and/or buses in conduit runs, in cable construction in equipments and by repeated bonding of these ground conductors or buses to the building steel, steel enclosures and ground.

In all systems and circuits great care must be exercised, in both the design and installation, to ground the neutral at ***only*** the intended point(s). Unintentional multiple grounds on the neutral may completely upset the operation of an otherwise well designed ground fault protection system.

5. Protective Devices

In addition to the system consideration, neutral loops, ground return paths, etc., equipment ratings and applications also have to be considered:

1. Current transformer ratings—
   a. Voltage, current, thermal, mechanical and burden capability for those current transformers enveloping, or in series, with individual conductors.
   b. Voltage, mechanical and burden capability for those current transformers enveloping all power conductors.
2. Continuous and thermal capability of the relays.
3. Rating and compatibility of tripping function of ground fault unit with protector trip devices.
4. Fault magnitude at which ground fault unit will respond and operate on through fault currents involving phase conductors only. Include effects of power conductor placements within window of current transformer.
5. Control power requirements. Low-voltage interrupters do not normally require control power. The inclusion of ground fault protection by a ground fault unit usually requires a reliable control power source to actuate breaker or solenoid trips, as well as to power the static circuitry of some ground fault units. Factor in the effects, if any, to the control power during fault conditions when the system voltage may be depressed.
6. Ground fault unit sensitivity to arcing fault currents. As previously discussed, the arcing fault current can be a restricted pulsating current.
7. Selectivity requirements with phase overcurrent trip functions. Recognizing that ground fault units may cost 25–40 percent of the basic interrupter price, the utilization of low-set short time and/or instantaneous phase-over-current trip functions, or protector, sensitive to ground fault currents is expected to gain in importance. This will require that ground fault units be sufficiently versatile in current and time settings to achieve selectivity with downstream phase overcurrent protectors.

6. Settings

As in other relay or protective trip areas, there is no single answer in arriving at the choice of a device and its setting. Rather, it is experience and the judgment of the system designer to choose the combination from a number of possible devices and time current settings which will give the best overall result.

To assist in determining settings, two basic concepts should be kept in mind:

1. A ground fault current in one system will not appear as a ground fault current in another system where the transformer windings between systems are (a) electrically separate and (b) connected delta-wye (Fig. 14) or, when connected wye-wye, one connection is ungrounded (Fig. 15).
2. Protection that provides maximum equipment protection and maximum service continuity through selectivity

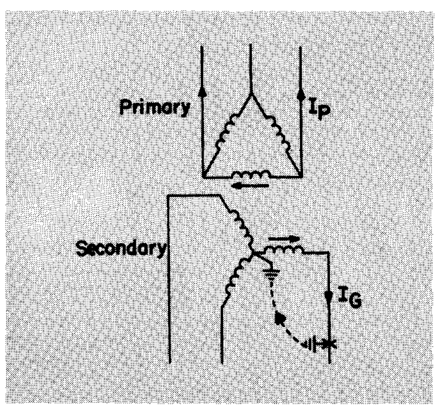

Fig. 14. Secondary ground fault (I_G) appears as phase-to-phase overcurrent (I_p) in primary of delta-wye connection.

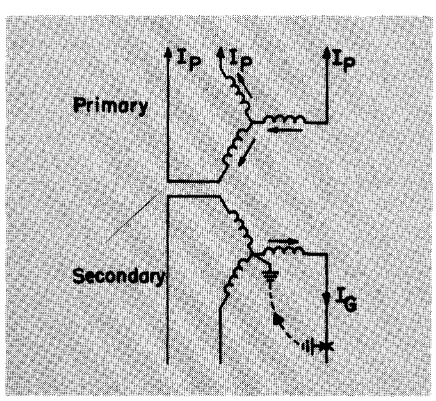

Fig. 15. Secondary ground fault (I_G) appears as phase-to-phase overcurrent (I_p) in primary of wye-wye connection.

are inconsistent or conflicting goals. In choosing alternatives—protection vs. selectivity—it is better to favor protection by utilizing low settings and accepting the occasional problem of nuisance tripping rather than to utilize high settings to achieve selectivity and the risk of extensive equipment damage.

Branch Circuits

In a branch circuit where there is no coordination requirement with downstream protective devices, such as a transformer or motor load, a ground fault unit (static or electromagnetic) set at 5-15 Amperes and instantaneous time would be a good choice.

Feeder Circuits

For a feeder circuit which requires coordination totally or partially with downstream devices, a ground fault unit (static or electromagnetic) with current and time delay settings to meet coordination requirements should be considered. This feeder circuit protector should be selectively set, either partially or totally, with respect to the downstream protectors capabilities.

Mains and Bus Ties

Ground fault units applied to mains and bus ties are normally static or electromagnetic with current and time delay settings. If applied to the mains only (none on feeders or bus ties), the units are set dependent upon the degree of acceptable equipment nuisance outages vs. risk of equipment damage desired. Ground fault relay units are customarily applied to the mains and bus ties to supplement the units on the feeders. These units are set to be selective with and protect down to at least the feeder units without neglecting the protection requirements set forth for the system. In all cases the NEC requirements, if applicable, should be taken into account.

Equipment Identification

Equipment Identification

Listed in Table 1 are various relay types utilized for ground fault monitoring in low-voltage systems.

The pickup of the ground fault electromagnetic (overcurrent) relay type unit in terms of primary amperes depends on the current transformer ratio and relay pickup settings. Therefore, the primary amperes:

$$I_{pickup} = \text{(CT ratio) (relay ampere setting)} \quad (3)$$

The pickup of the electromagnetic (instantaneous) relay type unit is 13 to 16 A in terms of primary amperes, when the relay is set to 0.5 A and connected to a specific 50/5 ratio current transformer.

For static relays and matched current transformers, commonly referred to as current sensors, pickup settings are expressed either in primary amperes (Ground Break®) or programmer settings times current sensor ampere rating (MicroVersatrip®).

The MicroVersatrip ground units are captive units. That is, the unit is part of the static trip which is an integral part of low voltage circuit breakers. If desired the static trip unit can be supplied without the ground function thus permitting other ground fault relays to be applied.

Table 1—Standard ground fault units utilized in low voltage systems

Identification		Static Relays		Electromagnetic Relays		
		MicroVersatrip	Ground Break	Instantaneous	Time-Delay	Residual
Current Transformer	Type	Window	Window	Window	Window	Window or Bar
	Number of CT's	3 or 4	1 or 3 or 4	1	1	3 or 4
	Ratio	Matched	Matched	50/5 or 100/5	150/5 through 4000/5	Phase Current Rating
	Location	Internal plus external 4th C.T.	External	External		
Relays	Type	Static	Static	HFC21B1A	IFC95AD-A	IFC95AD-A
	Tap Range	0.2–0.6 or 0.2–0.37 or 0.2–0.3 times sensor rating	none - pickup given in primary amperes	0.5–4	0.5–4 or 1–12	0.5–4 or 1–12
	External Control Power	None Required	Required	None Required		
Current Settings	Pick up Primary Amperes	150–2000 AC.S. × 0.2–0.6 2500–3200 AC.S. ×0.2–0.37 4000 AC.S. × 0.2–0.3	5–60 A or 100–1200 A	14–16 A if set at 0.5 A tap	CT ratio times relay ampere tap	
	Adjustments	8 or 6	Continuous	Continuous	7	7
Time Settings	Average time (seconds)	0.15–0.4	0.03 to 1.0	No intentional delay	Function of time dial settings	
	Adjustments	3	Continuous	None	Continuous	Continuous
Application	Type Interrupter	MCCB ICCB LVPCB	Any	Any	Any	Any
	Shunt Trip Reg.	No	Yes	Yes	Yes	Yes
	Tripping Cont. Power	No	Yes	Yes	Yes	Yes
	Usage	Cable-bus	Cable-bus	Cable	Cable	Cable-bus
Protection Mode	Normal use	Residual	Ground-sensor	Ground-sensor	Ground-sensor	Residual
	Possible use	GS5	GR[1], GRT[2], GSM[3], GS[4]	GR[1]	GR[1], GRT[2], GSM[3], GS[4]	Modified
Publications		GET 2779 GET 6211 GET 6218	GET 2964	GER 2370 GEK 49826	GEK49950	GEK49950
Time Current Curves		GES 6228	GES 6135	GEK 49826	GES 7019	GES 7019

NOTES: GR[1]—Ground return mode. GRT[2]—Double ended one-point neutral ground mode per Figs. C-1 and C-2. GSM[3]—Ground sensor modified mode (phase conductor only). GS[4]—Ground summation per Fig. C3. GS[5]—Ground summation per Fig. C4.

Simple Radial System Example

Consider a representative one line diagram of a simple radial system, (Fig. 16). From a 1000 kVA transformer, a switchboard or switchgear is fed thru a 1600 Ampere busway. Located in the switchboard or switchgear are the incoming line breaker (E) and several feeder breakers. Feeder breaker (D) feeds a distribution bus which could be a mcc or switchboard or power panelboard, etc. Located in the distribution equipment are: feeder breaker (A) feeding a downstream 100 Ampere panelboard equipped with 20–30 Ampere branch breakers (A'), branch-fused line switch (B) powering a distribution transformer and motor controller (C) consisting of a circuit breaker and starter powering a 250 hp motor.

Impendance Data

1. Assumptions and definitions

   a. Three-phase, fault current magnitudes, desired to compare with equipment ratings, are calculated at the time of fault initiation using subtransient reactance values for rotating machines.

   b. Phase-to-ground fault current magnitudes, desired to determine protection equipment needs, are calculated to attain minimum current values. Thus, impedance vectors will be added, ignoring phases and angles. Motor impedance values will not be considered.

   c. Utility ground current will not flow during a low voltage ground fault due to the delta primary connection of the 1000 kVA transformer. Viewed from the 480 Volt bus, the utility Z_0 impendance value does not exist.

   d. The 1000 kVA transformer has a three leg core and a Z_0 impedance that is 85% of Z_1; impedance viewed from the WYE connected secondary.

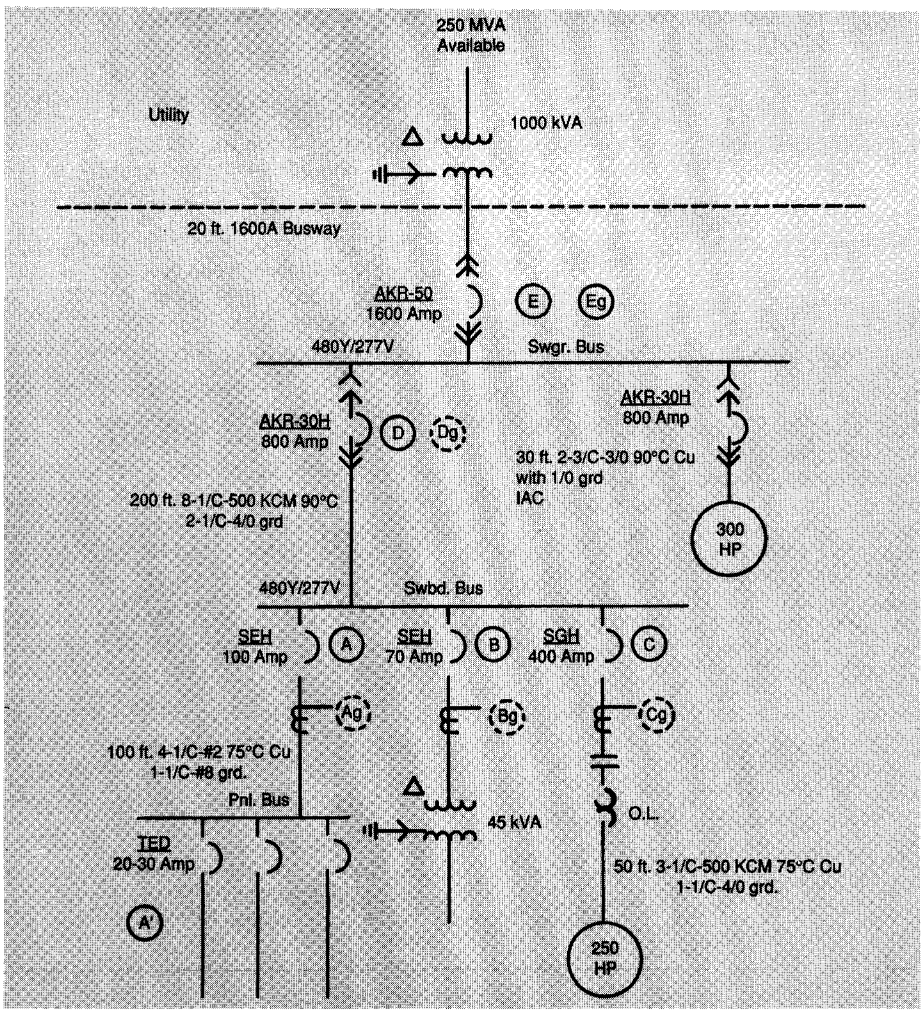

Fig. 16. One-line diagram of a simple radial system.

   e. Motors have an X/R ratio of 14 and the 1000 kVA transformer has an X/R ratio of 6.

   f. Impedances are converted from percent to ohmic values using:

   $$\text{Ohms} = \frac{\text{percent}}{100} \times \frac{kV^2}{\text{mVA rating}}$$

   g. Impedance, resistance and reactance are related as follows:

   $\tan\phi = X/R$
   $\sin\phi = X/Z$
   $\cos\phi = R/Z$

   h. Remaining impedance data is obtained from 11-AP-1 or GET-3550 and appendixes A and B.

2. Data ($R+jX''_d$) in Ohms referred to 480 Volt system:

   a. Utility Source:

   $$\frac{kV^2}{MVA} = \frac{(0.480)^2}{250} = 0 + j.0009 \text{ Ohms}$$

   b. Motors

   $$MVA = 0.95\ \text{hp}/1000, > 100\ \text{hp}$$
   $$X''_{dnet} = 1.2X''_d > 50\ \text{hp, 1800 rpm}$$
   $$X''_d = 16.7\%$$
   $$X/R = 14$$
   $$R = 1.19\%$$
   $$R + jX''_d = (1.19 + j16.7)\ \%$$

   300-hp motor:

   $$1.2\,\frac{(R + jX''_d)\%}{100}\,\frac{(kV)^2}{MVA} =$$
   $$(0.0119 + j0.167)\,\frac{(.48)^2}{(.285)} =$$
   $$0.0115 + j0.1620 \text{ ohms}$$

   250-hp motor:

   $$1.2\,(R + jX''_d)\%\,\frac{(kV)^2}{MVA} =$$
   $$1.2\,(0.0119 + j0.167)\,\frac{(.48)^2}{(.2375)} =$$
   $$0.0139 + j0.1944 \text{ ohms}$$

   c. 1000-kVA Transformer

   $$z = 5.75\%$$
   $$X/R = 6$$
   $$\tan\phi = 6$$
   $$\phi = 80.54°$$
   $$X = Z\sin\phi$$
   $$= (5.75\%)\sin 80.54°$$
   $$= 5.6718\%$$
   $$R = Z\cos\phi$$
   $$= (5.75\%)\cos 80.54°$$
   $$= 0.9453\%$$
   $$R + jX''_d = (0.9453 + j5.6718)\%$$
   $$\frac{(R + jX''_d)\%}{100}\,\frac{(kV)^2}{MVA} =$$
   $$(0.009453 + j0.056718)\,\frac{(0.480)^2}{1} =$$
   $$.0022 + j0.0131 \text{ ohms}$$

   d. Busway (aluminum, Spectra™ 20 ft—1600 Ampere:

   $$\frac{20'}{100'}\,(0.00112 + j0.00036) =$$
   $$0.0002 + j0.00007 \text{ ohms}$$

System Example

e. Cable—(copper in magnetic duct) with appropriate ground conductor 30 ft—2-3/c-#3/0:

$$\frac{30\text{ ft}}{1000\text{ ft}}\left(\frac{1}{2}\right)(0.0775 + j0.0333) =$$

0.0012 + j0.0005 ohms

200 ft—8-1/c-500 kcm:

$$\frac{200\text{ ft}}{1000\text{ ft}}\left(\frac{1}{2}\right)(0.0287 + j0.0402) =$$

0.0029 + j0.0040 ohms

50 ft—3-1/c-500 kcm:

$$\frac{50\text{ ft}}{1000\text{ ft}}(0.0287 + j0.0402)$$

0.0014 + j0.0020 ohms

100 ft—4-1/c #2:

$$\frac{100\text{ ft}}{1000\text{ ft}}(0.1959 + j0.0466)$$

0.0196 + j0.0047 ohms

3. Data (Z_1, Z_2, Z_0) in ohms

Z_1 Z_2 $(Z_0 + 3Z_g)/Z_1$ $Z_0 + 3Z_g$

a. Utility Source

0.0009 0.0009

b. 1000 kVA Trans.

$$\frac{(Z\%)}{100}\frac{(kV)^2}{MVA} = 0.0575\frac{(0.480)^2}{1} =$$

0.0132 0.0132 0.85 0.0112

c. 20 ft Busway (aluminum, Spectra™)

$$\frac{20\text{ ft}}{100\text{ ft}}(0.00112)$$

0.0002 0.0002 4 0.0008

d. Cable (copper in magnetic duct) 30 ft 2-3/c- #3/0

$$\frac{30\text{ ft}}{1000\text{ ft}}\left(\frac{1}{2}\right)(0.0844) =$$

0.0013 0.0013 4 0.0052

200 ft—8-1/c- 500 kCM:

$$\frac{200\text{ ft}}{1000\text{ ft}}\left(\frac{1}{2}\right)(0.0494) =$$

0.0049 0.0049 4 0.0196

50 ft—3-1/c-500 kCM:

$$\frac{50\text{ ft}}{1000\text{ ft}}(0.0494) =$$

0.0025 0.0025 4 0.01

100 ft—4-1/c-#2:

$$\frac{100\text{ ft}}{1000\text{ ft}}(0.2014) =$$

0.0201 0.0201 4 0.0804

Three-phase Fault Currents

1. Main Bus.

a. Impedance-utility to main bus:

Utility = 0 + j0.0009

1000 kVA transformer = 0.0022 + j0.0131

1600 Ampere busway = 0.0002 + j0.00007

Total ohms = 0.0024 + j0.0141

b. Impedance-300-hp motors to main bus:

300-hp motor = 0.0115 + j0.1620

30 ft—2-3/c-#3/o = 0.0012 + j0.0005

Total ohms = 0.0127 + j0.1625

c. Impedance-250 hp motor to main bus:

250 hp motors = 0.0139 + j0.1944

50 ft—3-1/c-500 kCM = 0.0014 + j0.0020

200 ft—8-1/c-500 kCM = 0.0029 + j0.0040

0.0182 + j0.2004

Fault currents to swgr. bus from:

Utility =

$$\frac{E_{L-N}}{\Sigma R + jX''_d} = \frac{277}{0.0024 + j0.141} =$$

3249.74 − j19092.24 Amperes

300-hp motor =

$$\frac{E_{L-N}}{\Sigma R + jX''_d} = \frac{277}{0.0127 + j0.1625} =$$

132.4 − j1694.3 Amperes

250-hp motor =

$$\frac{E_{L-N}}{\Sigma R + jX''_d} = \frac{277}{0.0182 + j0.2004} =$$

124.5 − j1370.9 Amperes

Total = 3506.6 − j22,157.4 Amperes

22,433 Amperes

2. Switchboard bus

a. Impedance-utility & 300-hp motor to switchgear bus

Utility to swgr. bus = 0.0024 + j0.0141

300-hp motor to swgr. bus = 0.0127 + j0.1625

Σ Utility and 300-hp motor to swgr. bus =

$$\frac{(0.0024 + j0.0141)(0.0127 + j0.1625)}{(0.0024 + j0.0141) + (0.0127 + j0.1625)}$$

= 0.0021 + j0.0130

200 ft 8-1/c-500 kCM = 0.0029 + j0.0040

Total ohms = 0.0050 + j0.0170

b. Impedance 250-hp motor to switchboard bus:

250-hp motor = 0.0139 + j0.1944

50 ft 3-1/c-500 kCM = 0.0014 + j0.0020

Total ohms = 0.0153 + j0.1964

Fault currents to switchboard bus from:

Utility and 300-hp motors =

$$\frac{E_{L-N}}{\Sigma R + jX''_d} = \frac{277}{0.0050 + j0.0170} =$$

4,410.83 − j14,996.82A.

$$\text{250-hp motor} = \frac{277}{0.0153 + j0.1964} =$$

109.21- j 1,401.88A.

Total = 4520.04-j 16398.70A.

= 17,010 Amperes

3. Panelboard bus

a. Impedance-utility, 300-hp & 250-hp motors to panelboard bus

Σ Utility, 300-hp motor and 250-hp motor to distribution bus =

$$\frac{(0.0050 + j0.0170)(0.0153 + j0.1964)}{(0.0050 + j0.0170) + (0.0153 + j0.1964)} =$$

0.0043 + j0.0157

100 ft 4-1/c-#2 = 0.0196 + j0.0047

Total ohms = 0.0239 + j0.0204

Fault current to panelboard bus from utility, 300-hp and 250-hp motors:

$$= \frac{E_{L-N}}{\Sigma R + jX''_d} = \frac{277}{0.0239 + j0.0204} =$$

6704.98 − j5723.08 Amperes

8815 Amperes

Arcing Ground Fault Current Magnitude

Z_1 Z_2 $Z_0 + 3Z_g$

1. Switchgear Bus

Utility = 0.0009 0.0009

1000 kVA Transformer = 0.0132 0.0132 0.0112

1600 Amp Busway = 0.0002 0.0002 0.0008

Total 0.0143 0.0143 0.0120

I arcing fault (L − G)

$$= 0.38\left(\frac{3E_{L-N}}{Z_1 + Z_2 + Z_0 + 3Z_g}\right)$$

$$= 0.38\left(\frac{3\ (277)}{0.0143 + 0.0143 + 0.0120}\right)$$

= 7778 Amperes

2. Switchboard bus

Z_1 Z_2 $Z_0 + 3Z_g$

Utility to main bus = 0.0143 0.0143 0.0120

200 ft 8-1/c-500 kCM = 0.0049 0.0049 0.0196

Total 0.0192 0.0192 0.0316

I arcing fault (L − G)

$$= 0.38\left(\frac{3E_{L-N}}{Z_1 + Z_2 + Z_0 + 3Z_g}\right)$$

$$= 0.38\left(\frac{3\ (277)}{0.0192 + 0.0192 + 0.0316}\right)$$

= 4511 Amperes

3. Panelboard bus

	Z_1	Z_2	$Z_0 + 3Z_g$
Utility to switchboard bus =	0.0192	0.0192	0.0316
100 ft 4-1/c-#2 =	0.0201	0.0201	0.0804
Total	0.0393	0.0393	0.1120

I arcing fault (L − G)

$$= 0.38\left(\frac{3E_{L-N}}{Z_1 + Z_2 + Z_0 + 3Z_g}\right)$$

$$= 0.38\left(\frac{3\ (277)}{0.0393 + 0.0393 + 0.1120}\right)$$

= 1657 Amperes

The phase-overcurrent time current plot (Fig. 17) was determined by the load conditions and calculated three-phase fault currents. References to how time current plots are developed can be found in the IEEE Std. 242 entitled "Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems."

From Fig. 17, the switchgear main protector (E) clearing time is approximately 0.6 second at 7778 Amperes. Switchboard bus protector (D) clearing time is approximately 0.9 second at 4511 Amperes. Panelboard bus protector (A) clearing time is approximately 0.032 second at 1657 Amperes. The sensitivity of these plots to the calculated arcing ground fault currents appear to be acceptable; however, in further analysis, several limitations exist in the phase-overcurrent settings with regard to protection for arcing ground fault currents:

A. If protector (E) is a service entrance disconnect, it violates NEC article 230-95 which requires protector (E) to sense and clear a 1200 Ampere or high ground fault current. It is true that protector (E) long-time function could be set to meet the code requirements; however, due to protector manufacturing tolerance, it would have to be set at 1080 Amperes to assure tripping at 1200 Amperes. This setting has several objections: it prevents the use of the transformer full load capability and has an excessive clearing time of 220 seconds at 1200 Amperes.

B. If the actual arcing ground fault current during fault conditions only attains values that are slightly less than calculated, the protector clearing time increases to unacceptable values. Protector (E) increases to 14 seconds at 6000 Amperes while protector (D) increases to 15 seconds at 4000 Amperes.

C. The back-up protection is unacceptable. Protector (E) could only clear in 25 seconds at 4511 Amperes in event of protector (D) failure to clear a switchboard bus ground fault. Protector (D) could sense a panelboard bus ground fault in the event of protector (A) failure to clear, but only in 100 seconds.

By the addition of ground fault units, various degrees of increased ground fault protection will be realized dependent on the units involved and settings utilized.

A. **One ground fault unit applied on switchgear main protector (E) and identified as (E_g).**

An integral ground unit is used due to the ease of addition to the MicroVersaTrip® RMS-9 phase overcurrent functions. A Ground Break® or electromagnetic unit could be used in preference to the MicroVersaTrip ground unit.

When (E_g) is set at 320 Amperes and minimum time-delay (Fig. 18), it provides a high degree of protection. At this setting, however, it would cause deenergization of the entire system for an arcing ground fault current magnitude of 350 Amperes or more throughout the system except for currents flowing through and of sufficient magnitude to operate protector (A), (B) or (C) instantaneous function.

When (E_g) is set at 960 Amperes and maximum time-delay (Fig. 18), protection has been reduced and deenergization of the entire system is still prevalent for arcing ground fault current magnitudes of 1200 or 6000 Amperes on the switchboard bus, or 1200 to 3000 Amperes on protector (C) load circuit.

B. **Two ground fault units—one applied on main protector (E) identified as (E_g) and one applied on feeder protector (D) identified as (D_g).**

Integral ground units are once again utilized due to the ease of addition to the MicroVersaTrip RMS-9 phase overcurrent functions. Ground-Break and/or electromagnetic units are applicable, if desired.

When (D_g) and (E_g) are set at 480 Amperes and instantaneous time-delay and 960 Amperes and maximum time-delay respectively (Fig. 19), the deenergization of the main bus due to a ground fault on the load side of protector (D) is eliminated except when protector (D) fails to clear the fault. This improves the service reliability to the other feeders fed from the switchgear bus. Feeder (D), however, can be deenergized by (D_g) for a ground fault condition on the switchboard branches.

C. **Three ground fault units—one applied to switchgear main protector (E) identified as (E_g), one applied on feeder protector (D) identified as (D_g), and one applied on branch protector (C) identified as (C_g).**

A Ground Break unit is utilized for (C_g). Since protector (C) is a branch feeder, its ground fault unit (C_g) (Fig. 20) is set at 15 Amperes and instantaneous in time as shown at 0.15 second time-delay. Note that as for all other ground fault protectors, the time current plot of (C_g) includes breaker clearing time. With the units set at: (C_g) 15 Amperes and 0.15 second in time, (D_g) 480 Amperes and intermediate time, and (E_g) 960 Amperes and maximum time, the system is now completely selective with a reasonable degree of protection.

D. **Five ground fault units—one applied for protector (A) identified as (A_g), one unit for protector (B) identified as (B_g), one unit for protector (C) identified as (C_g), one unit for protector (D) identified as (D_g) and one unit for protector (E) identified as (E_g).**

A Ground Break unit is utilized for unit (A_g), (B_g) and (C_g) (Fig. 20) and set at 15 Amperes and 0.15 second time. Unit (A_g) provides additional protection to the branch circuits feed by protectors (A) and panelboard bus. From Fig. 17, it can be seen that long clearing times of one second or more occur for breakers (A') and (A) at current magnitudes below 600 Amperes. As ground faults occur further downstream on the branch circuit conductor powered by (A'), current magnitudes less than 500 Amperes will occur, indicating that the phase-overcurrent functions will not provide adequate protection.

These additional ground fault units also allow units (D_g) and (E_g) to be lowered in time and still maintain selectivity, thereby decreasing equipment damage.

The results can be summarized as follows: The degree of acceptable risk of equipment damage, and acceptable system selectivity all weighed against cost, determines the extent of ground-fault protection required for any given system. There is no short cut method for arriving at the relay settings required for a given system.

System Example

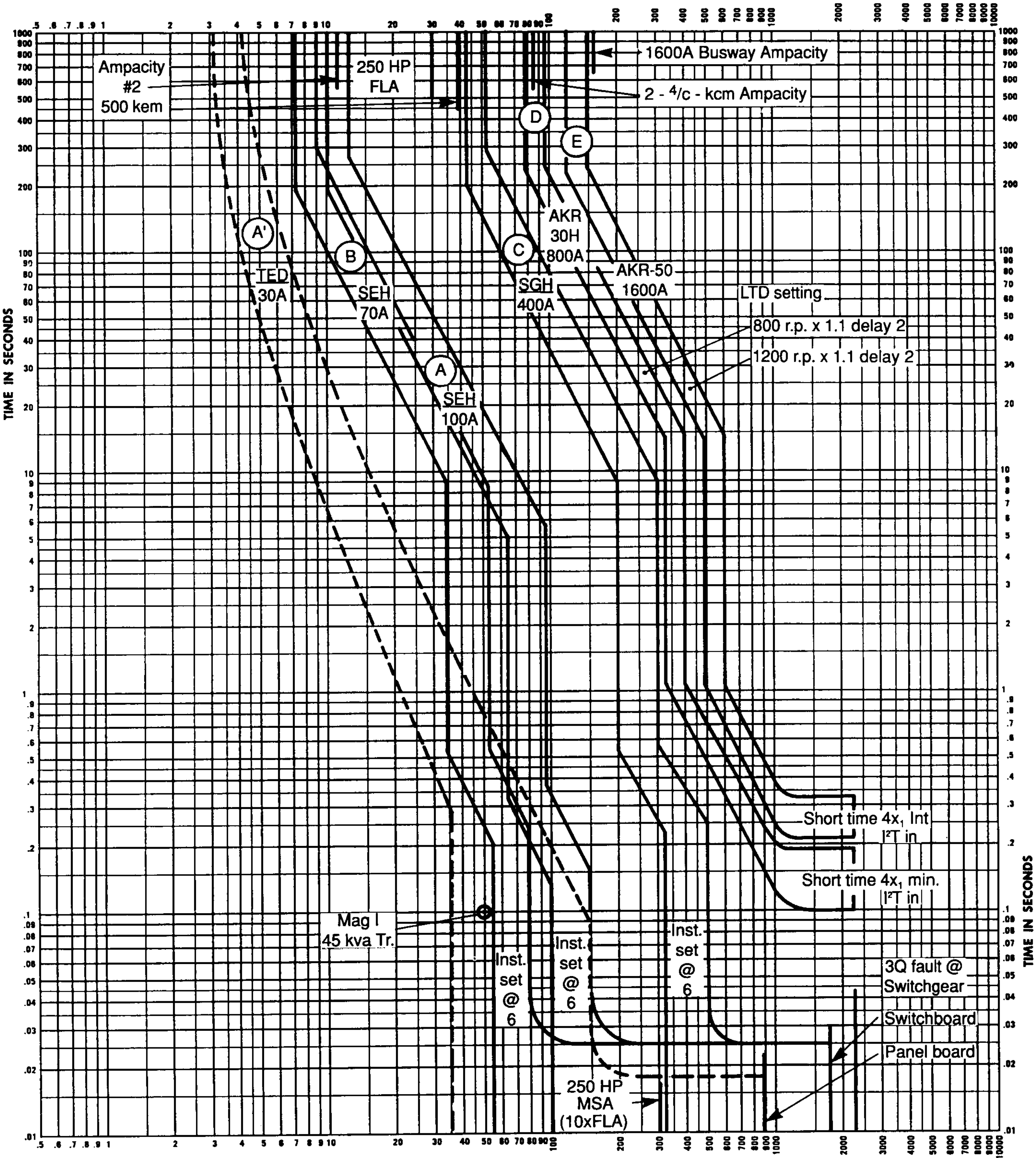

Fig. 17. Phase-overcurrent plots of load conditions and three-phase fault currents for illustrated example. Current (X10) at 480 Volts.

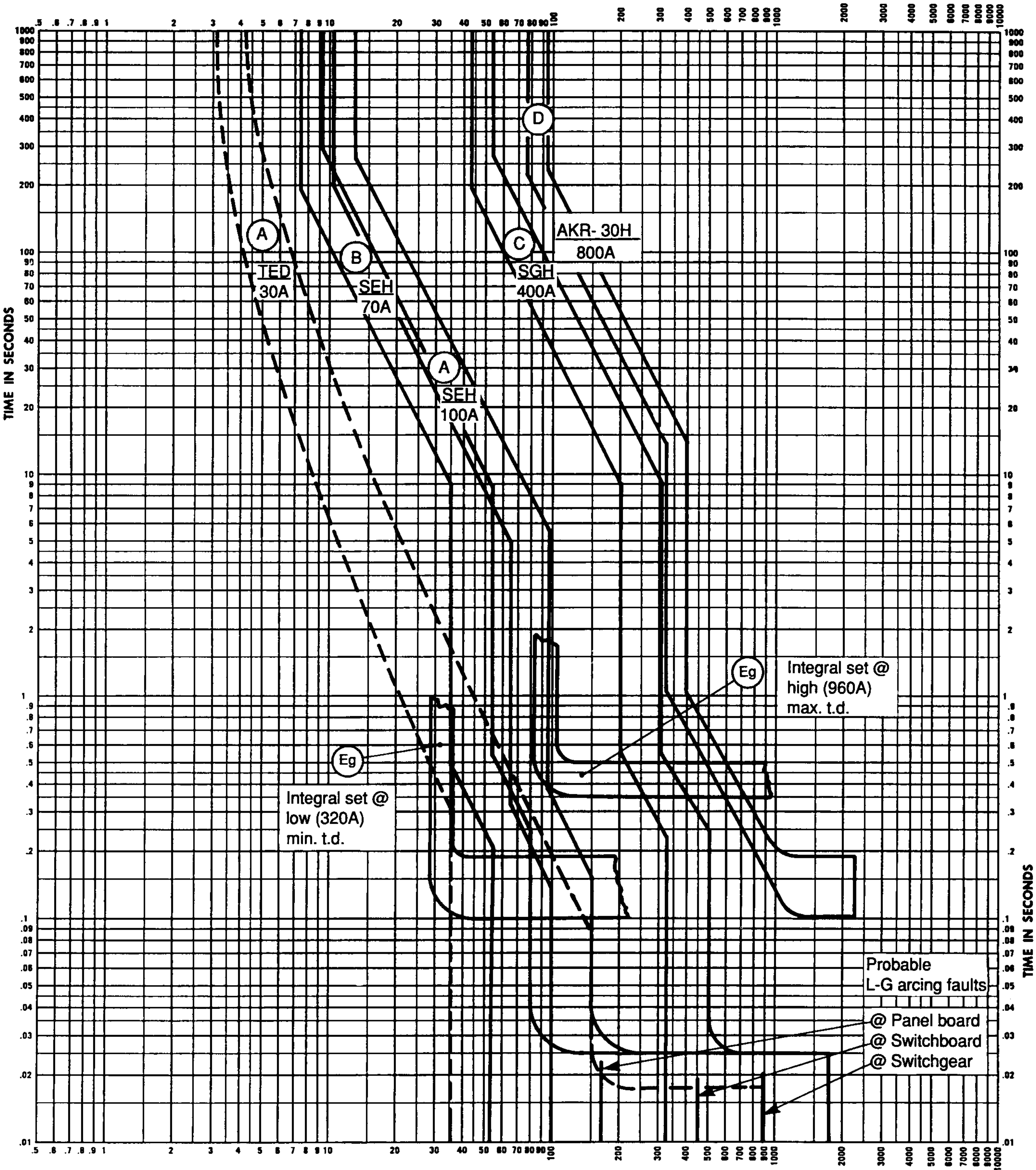

Fig. 18. Phase-overcurrent plots with one ground fault unit on main protector (E_g) set at 320 Amperes, min. time delay or 960 Amperes, max. time delay. Current (X10) at 480 Volts.

System Example

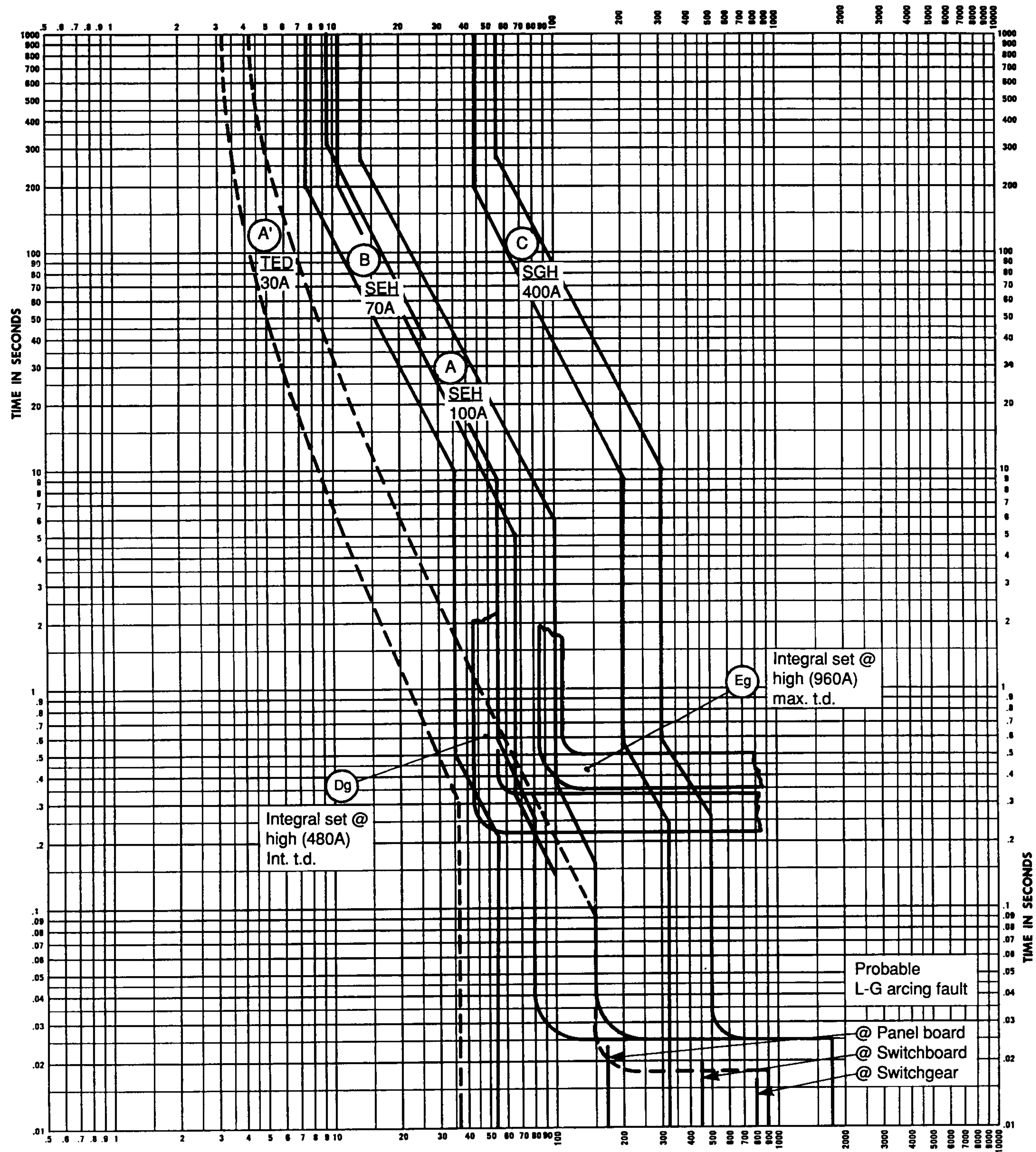

Fig. 19. Phase-overcurrent plots with ground fault unit on main protector (E_g) set at 960 Amperes, max. time delay on feeder protector (Dg) set at 480 Amperes, min. time delay. Current (X10) at 480 Volts.

System Example

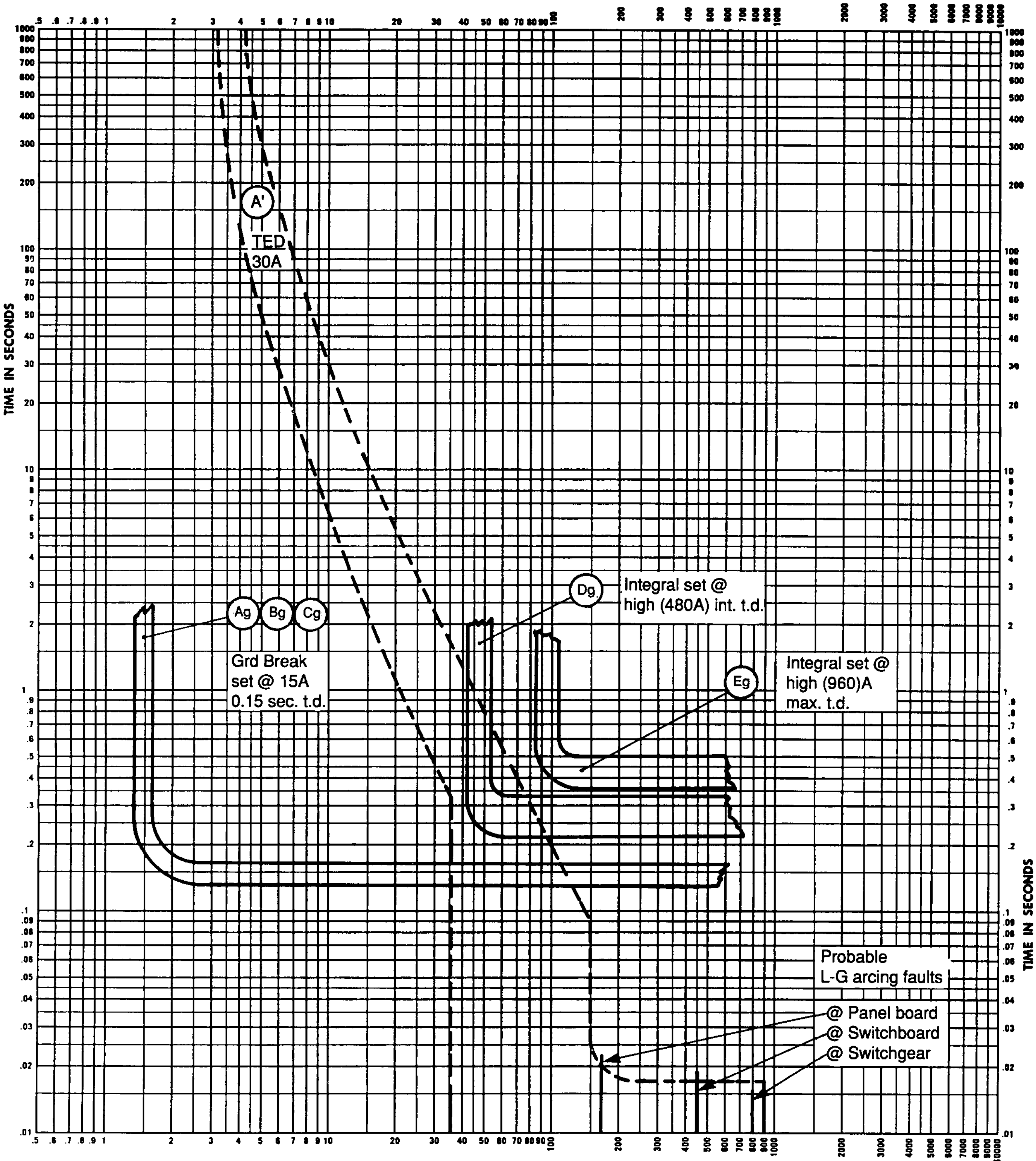

Fig. 20. Phase-overcurrent plots with ground fault units on main protector (E_g), feeder protector (D_g), and switchboard feeder protectors (A_g), (B_g) and (C_g). Current (X10) at 480 Volts.

Appendix A – Z Ratios
Appendix B – K Factors

Appendix A
Z Ratios

Practical Circuit $(Z_0 + 3Z_g)/Z_1$ Ratios

As stated by R. H. Kaufmann (6), it is the vectorial evaluation of $(Z_0 + 3Z_g)$ and Z_1 that is required. Only when Z_0, Z_g and Z_1 all have the same phase angle it is strictly proper to handle these quantities as scalars. The positive sequence impedance Z_1 for the heavier circuit construction will exhibit phase angles generally in the 45 to 90 degree zone. While it is possible that $(Z_0 + 3Z_g)$ may sometimes be highly resistive, producing 0 to 20 degree phase angles, it is also true that in this case the $(Z_0 + 3Z_g)/Z_1$ ratio tends also to be a large value. These conditions minimize the need for accurate phase angle information and practical useful results can be obtained with $(Z_0 + 3Z_g)$ and Z_1 considered simply as scalar.

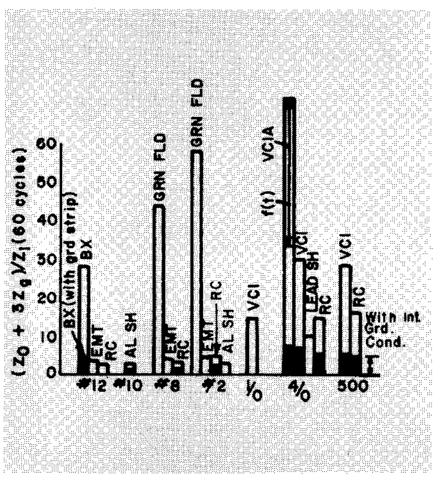

Fig. A-1 Typical $(Z_0 + 3Z_g)/Z_1$ ratios for cable circuit construction.

Cable Circuit Construction $(Z_0 + 3Z_g)/Z_1$ Ratios

Representative values of $(Z_0 + 3Z_g)/Z_1$ ratios for a wide variety of cable conductor circuits as measured under conditions of simulated severe fault (current magnitudes of 20 times continuous rating or more), are shown in Fig. A-1. These data are based directly on copper conductors and a raceway sized to accommodate three power conductors of the size indicated. The variety of raceways examined include rigid conduit (RC), thin wall (EMT), extruded aluminum sheath (AL. SH.), lead sheath, steel interlocked armor cable (VCI), aluminum interlocked armor cable (VCIA), greenfield (GRN. FLD.), and No. 12 conductor (BX). The shaded block segments indicate the $(Z_0 + 3Z_g)/Z_1$ ratio when an internal grounding conductor is present.

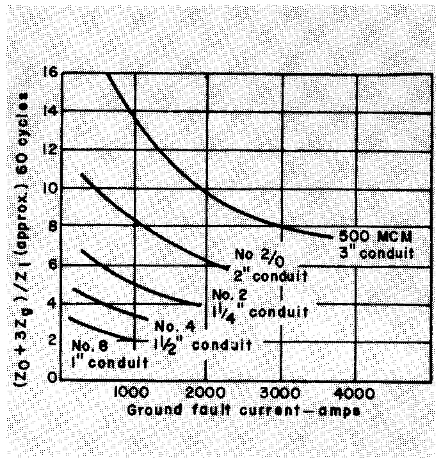

Fig. A-2. The effect of rigid steel conduit on cable circuit $(Z_0 + 3Z_g)/z_1$ ratio.

The upper portion of the block on 4/0 cable with aluminum armor is associated with a marked reduction which occurs in $Z_0 + 3Z_g$, which was observed to occur during the first several cycles of fault current flow. The presence of internal grounding conductors or the installation of such cable in metallic channel or on metallic racks renders this property unimportant.

From the exploratory work reported by Geinger, Davidson, and Brendel (4) comes quantitative information on the effective $(Z_0 + 3Z_g)/Z_1$ ratios of conductors in steel conduit (See Fig. A-2).

It is the tendency for the return ground-fault current to be forced to flow on a thin inner skin of the conduit, which accounts for the elevated $(Z_0 + 3Z_g)/Z_1$ ratio at low current. Increased current magnitude produces magnetic saturation of successive shells of conduit material, thus lessening the effect. At higher currents, increased magnetic saturation causes the performance to approach that of non-magnetic conduit. The presence of a full-size internal cable grounding conductor was observed to hold the $(Z_0 + 3Z_g)/Z_1$ ratio to a value not greater than about 4 at any current level. Aluminum conduit was observed to exhibit a slightly lower value value of $(Z_0 + 3Z_g)/Z_1$, remaining close to a value of 2, quite independent of current.

Low Voltage Busway $(Z_0 + 3Z_g)/Z_1$ Ratios

Typical values of $(Z_0 + 3Z_g)/Z_1$ ratio for low voltage busways relative to the housing as the ground return circuit shown in Fig. A-3.

It is important to distinguish between the $Z_0 + 3Z_g$ relative to the busway housing and the $Z_0 + 3Z_g$ relative to internal insulated netural conductors. These two $Z_0 + 3Z_g$ values will generally be different and may be greatly different. The $Z_0 + 3Z_g$ value relative to the neutral conductor would be significant in relation to voltage unbalance created by neutral unbalance current. The bus construction commonly used for low-voltage-drop feeder busway accounts for a high $(Z_0 + 3Z_g)/Z_1$ ratio because the Z_1 has been purposely reduced to low level. In the case of current-limiting busway, a low $(Z_0 + 3Z_g)/Z_1$ ratio is to be expected because the Z_1 has been made intentionally large. In the case of Spectra™ busway, which has an aluminum housing and compact design, the $(Z_0 + 3Z_g)/Z_1$ ratio remains close to four, independent of current.

Appendix B
K Factors

Use the multiplier "K" to approximate minimum values of arcing fault current in per unit of bolted vault values. These values are based on test data.

Type of Fault	Nominal System Voltage		
	575V	480V	208V
Single-phase (L-G)①	0.40	0.38	0
Single-phase (L L)②	0.85	0.74	0.02
Three-phase②	0.94	0.89	0.12

① For the single-phase line-to-ground fault condition at 208V, the K factor may approach 0.
② Note that these type faults do not involve ground. They are included as matter of interest.

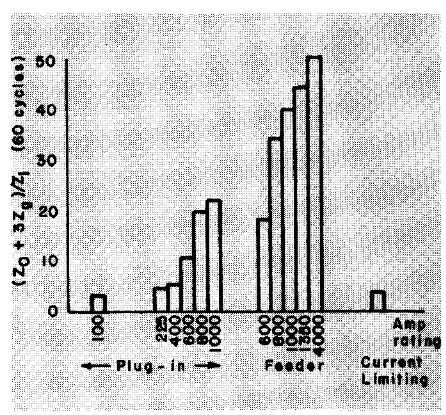

Fig. A-3. Typical $(Z_0 + 3Z_g)/Z_1$ ratios for low voltage busway circuits.

Appendix C
Double-ended Switchgear

Ground fault protection schemes can be used in a double-ended switchgear or switchboard, having a neutral loop and single-point ground. In Fig. C-1, assume the return monitoring scheme is replaced with a GS unit at "a" and "b". A neutral load from source 1 would produce zero current through the monitor since the outgoing phase current would be cancelled by the neutral return current. Therefore, no operation would occur, which is desirable. Unfortunately, the same results occur for a downstream ground fault which is definitely ***not*** desirable. Thus, this scheme should not be used.

Now consider the return monitoring mode shown in Fig. C-1. This mode provides excellent protection if no neutral load connections are permitted between current transformers. Normally, no neutral current passes through the current transformers. When neutral current occurs between sources, the current is monitored by both current transformers and, due to their polarity connections, the generated secondary currents flow in the outer relay loop. Since the relays require both coils to be energized before operation occurs, no effect is caused by the neutral current. For a ground fault on the left bus when the tie and both mains are closed, the ground currents returning to their sources produce a current flow in each internal loop. After a time delay due to its lower setting, the RT relay trips (T). Immediately the current flow in the right loop ceases, since source 2 can no longer supply fault current and the R2 relay resets, but the left loop current continues to flow and upon exceeding its time delay, relay R1 trips (M1). The right source continues servicing its load. By observing the current flow, it can be seen that when the tie is open, only (M1) will be tripped. When the tie and (M2) are closed and (M1) open, only the tie will be tripped. If a ground connection exists ***at the sources*** or ***between the sources*** and respective CT, this return scheme is not reliable and should not be used.

Similarly, the GRT mode can also be accomplished with the static Ground Break® relay as shown in Fig. C-2. Normally, no neutral current passes through the current transformer. When neutral current occurs between sources, the current is seen by both GBR-1, and GBR-2, but both relays are inoperative due to lack of control power.

For a ground fault on the left bus, when the tie and both mains are closed, the ground current initiates GBR-T either instantaneously or after a time delay dependent on its setting.

Upon closure of the GBR-T contacts, breaker (T) is tripped and control power is applied to time-delayed GBR-2 and GBR-1. Immediately, the ground current flow from source No. 2 ceases with (T) open, but current continue to flow from source No. 1. Upon exceeding the time delay set on GBR-1, GBR-1 trips (M1). Source No. 2 continues servicing its load.

By observing the current flow, it can be seen that when (T) is open, only (M1) will be tripped, and when (T) and (M2) are closed and (M1) open, only (T) will be tripped.

A ground fault protection scheme for double-ended, or multifeed switchgear or switchboards having multigrounds is shown in figure C-3. This illustrates a summation scheme of protection where the transformer neutrals are grounded at the transformers. The service equipment connections to ground are made in the switchgear or switchboard on the line side of the main protectors as required by the NEC Code. The sets of current transformers and relays are interconnected so that for a line-to-ground fault on bus 1, or feeder circuits supplied from this bus, a secondary current proportional to the fault current will flow in relay G1. Likewise, for a line-to-ground fault on bus 2, or feeder circuits supplied from this bus, a secondary current proportional to that fault current will flow in relay G2. If these currents flowing in the relays are above the relay current setting, and persist beyond the time-delay settings, relay G1 will trip breakers (T) and (M-1) and relay G2 will trip breakers (T) and (M-2).

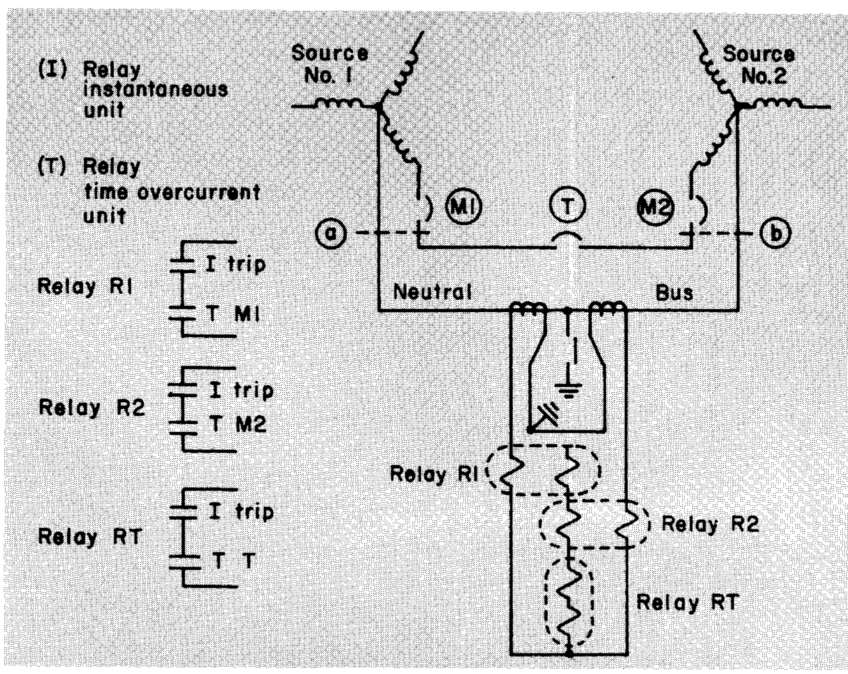

Fig. C-1. Return monitoring mode utilizing electromagnetic time-delay relays for four-wire, double-ended switchgear or switchboard.

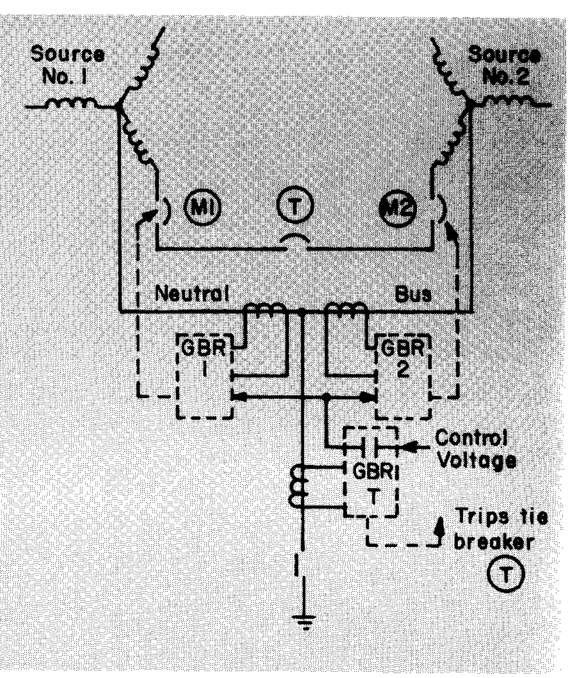

Fig. C-2. Return monitoring mode utilizing static time-delay relays for four-wire, double-ended switchgear or switchboard.

Appendix C – Double-ended Switchgear

Relays G1 and G2 may be selectively coordinated with the ground fault protection relays applied on the feeder breakers by the selection of suitable current and time-delay settings. With relays G1 and G2 connected as shown, maintaining proper polarity markings, there will be no current flow through the relay coils for three-phase, phase-to-phase or phase-to-neutral currents. Furthermore, the line-to-ground fault current may return over either of the ground paths and the neutral conductor or it may be divided between the two in any proportion, without upsetting the proper flow of the current through the relay coils. Also, the line-to-neutral load caused by unbalanced line-to-neutral current on a feeder circuit has two parallel paths by which it may return to its source at one or both of the transformers. One path is by means of the neutral conductor, the other is partially by the neutral conductor to the ground point near one transformer and then by ground to the neutral of the source transformer. With the current transformers and relays connected as shown, these extraneous currents flowing in the netural conductors will cause no adverse action on either of the relays. That is, it will not add to or subtract from the required ground fault current flow in the relay coils, nor will it introduce any current flow in the relay coils for non-ground fault conditions. These conditions are true for any combination of breaker positions (open or closed) of (M1), (M2) and (T).

This summation scheme can be applied with the proper modifications on multifeed systems; namely, three or more transformers each with its own ground connections, feeding a switchgear or switchboard line-up and each switchgear or switchboard grounded on the line side of the main protector and intertied through tie breakers. Practical limits on the number of multisources that this summation scheme can accommodate is set by the complexity of the power system circuitry and the burdens imposed on the current transformers.

This summation scheme can be used where one or more of the sources are emergency generators. Admittedly, the arrangement of feeder circuits might be different, but the scheme is applicable. As in the case of multiple transformer sources, when the connections between relays and current transformers become lengthy, the burden imposed on the current transformers has to take into account the lead impedance.

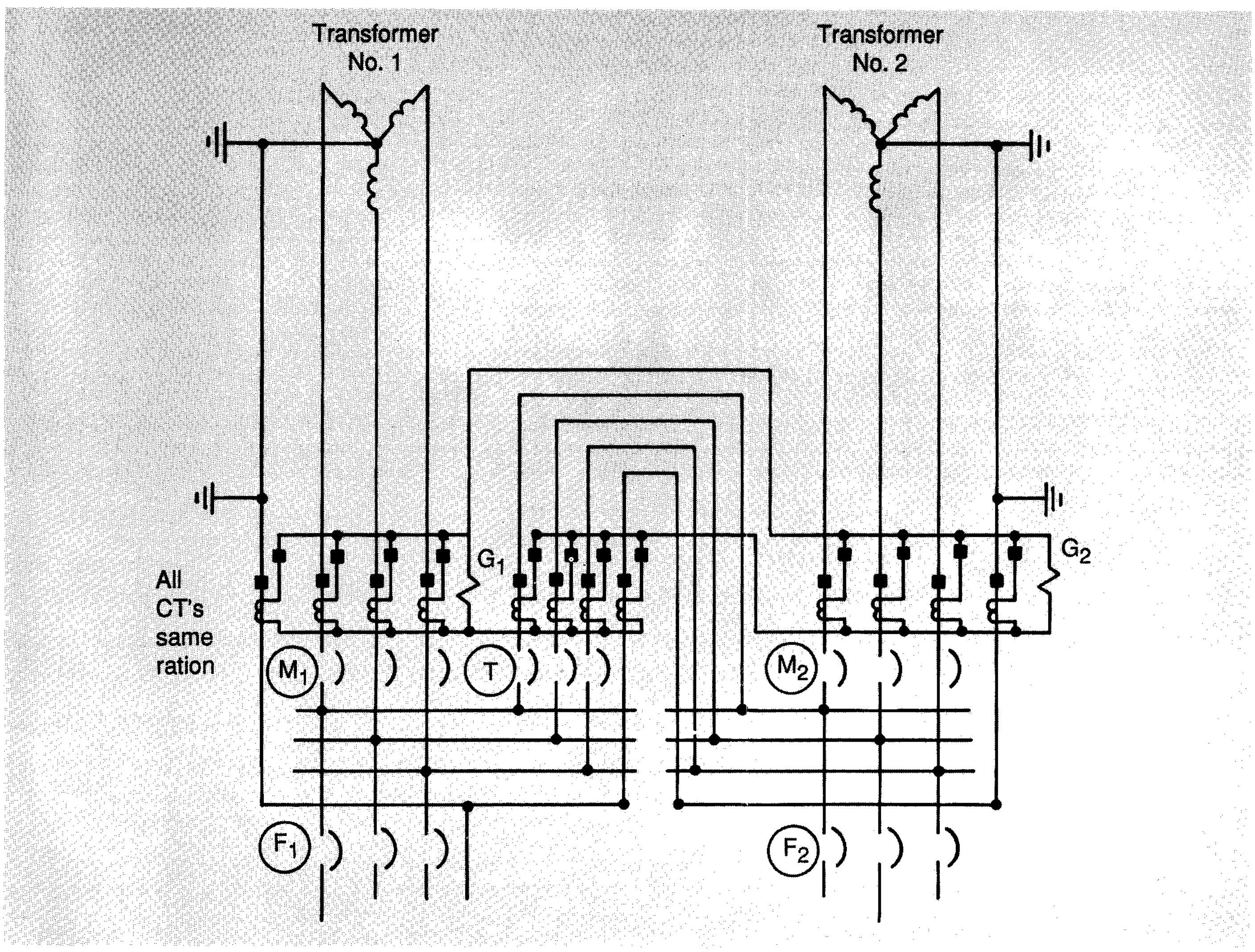

Fig. C-3. Summation scheme utilizing electromagnetic time-delay relays for four-wire, multiple source switchgear or switchboards having multiple ground points.

Appendix C – Double-ended Switchgear

A ground fault protection scheme for double-ended switch gear or switchboard, utilizing the integral ground fault available in the electronic trip programmers, is shown in Fig. C-4. This illustrates a summation scheme of protection where the transformer neutrals are grounded at the transformers. The service equipment connections to ground are made in the switchgear of switchboard on the line or source side of the main protectors as required by the NEC Code. The phase current sensors and electronic programmer are mounted within the breaker assembly while the neutral current sensors are mounted external from the breaker but most likely within the equipment. For a line-to-ground fault on the left bus or feeder(s) fed from the left bus, a secondary current porportional to the fault current will flow in the electronic programmer associated with breaker 52-1/M1. Likewise; for a line-to-ground fault on the right bus or associated feeder(s), a secondary current proportional to the fault current will flow in the electronic programmer associated with breaker 52-2/M2. If these currents are above the electronic programmers current settings; and persist beyond the time-delay settings, the respective breakers will trip. The electronic programmers may be selectively coordinated with the tie breaker 52-BT/T and feeder breakers by the selection of suitable current and time-delay settings. The neutral current sensor secondary windings, in addition to being connected to their associated electronic programmer, are interconnected with each other in a loop circuit. This insures that the system remains nonresponsive to normal neutral loading, regardless of the possible diverse paths taken by the neutral return current, yet be responsive to ground fault current regardless of its return path to the source supplying fault current. Each breaker has an auxiliary "a" contact which controls when the neutral current sensor secondary winding and associated electronic programmer are interconnected. The contact mode open or close is similar to the breaker; that is, when the breaker is closed the associated contact is closed and vice versa. As long as one breaker remains open, any neutral current returning to one of the sources via the main neutral bus of the other source and the neutral point ground interconnection is accounted for via the circulating currents circulating in the loop circuit. If ground fault current total or partial for a given fault enters at the ground point of the source ***not*** supplying the fault it can travel through the neutral conductor back to the neutral point of the source supplying the fault. As it passes through the neutral sensors, it induces secondary currents which result in a flow of current in the sensor loop circuit. By requiring one breaker to remain open, it is insured that at least one of the three neutral sensors will be disconnected by an open auxiliary contact from its associated breaker electronic circuitry. This sensor then provides the driving force to assure that the current flows around the sensor loop circuit instead of entering the breaker electronic circuitry. This prevents any mitigation of the ground fault signal produced by ground fault current flowing through a phase sensor of the circuit breaker. The secondary loop circuit helps provide accurate response to the flow of the ground fault current. This summation scheme can be applied if one or both sources are emergency generation. Admittedly, the arrangement of feeder circuits might be different but the integral summation scheme is applicable.

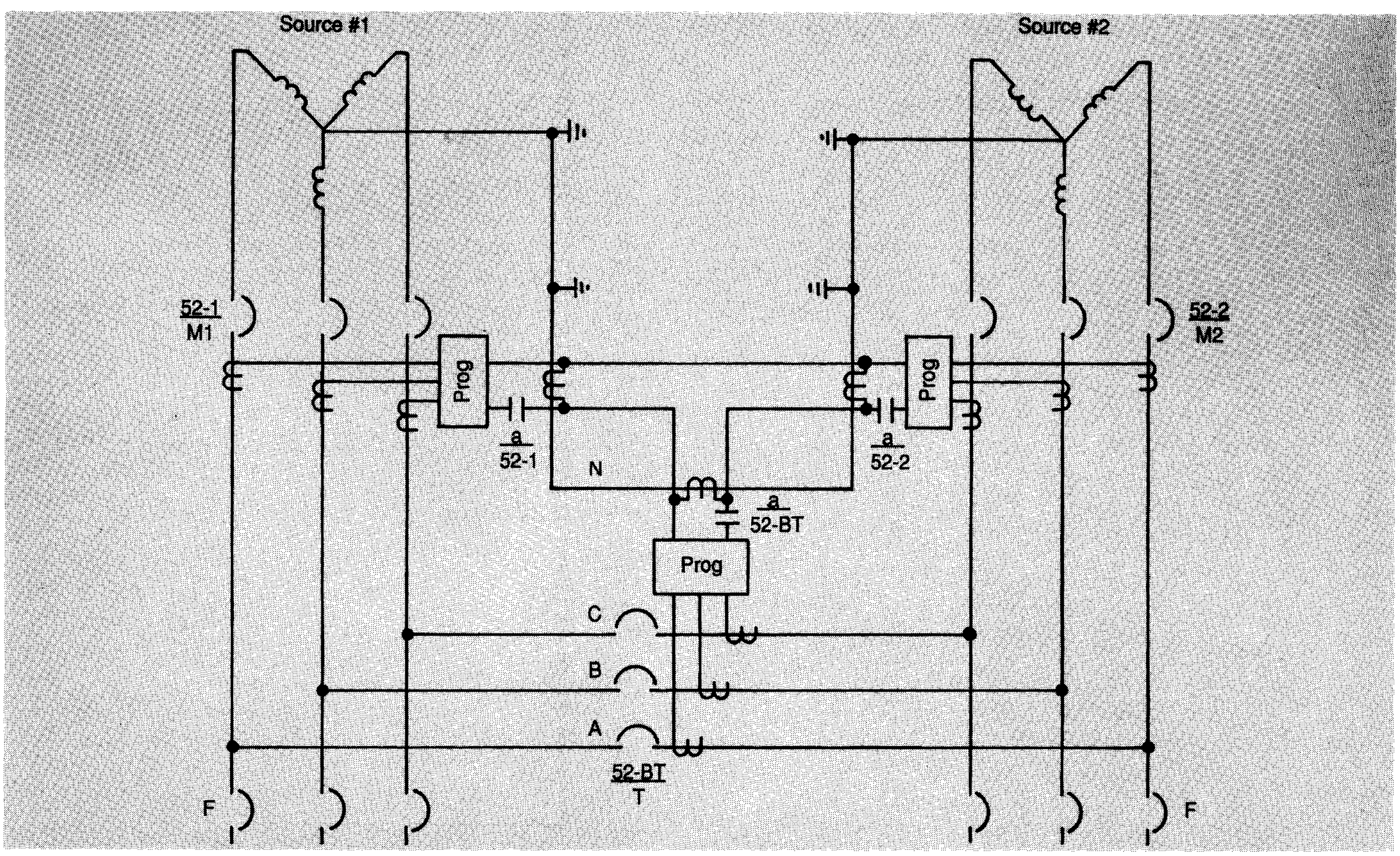

Fig. C-4. Summation scheme utilizing extension of integral for four-wire double-ended switchgear or switchboards.

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