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October, 1980

GROUND FAULT AND OVERCURRENT PROTECTION CRITERIA FOR COAL MINE AC DISTRIBUTION SYSTEMS

Contract J0395035
KETRON, INC.

BUREAU OF MINES ★ UNITED STATES DEPARTMENT OF THE INTERIOR
Minerals Health and Safety Technology

DISCLAIMER

CERTIFICATION OF ABSENCE OF PATENTS AND INVENTIONS

This statement certifies that at the contract report date, no inventions have been developed under Contract No. J0395035. Consequently, no patents are pending.

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GROUND FAULT AND OVERCURRENT PROECTION CRITERIA FOR COAL MINE AC DISTRIBUTION SYSTEMS

by

John A. Kiefer1/ and Jeffery L. Kohler2/

ABSTRACT

Ground fault and overcurrent protection criteria for coal mine a.c. distribution systems were examined under a Bureau of Mines funded investigation. The report begins with a literature review which discusses relaying topics including instrument transformers, ground-fault pickup methods, static relaying, and comparison of relaying techniques. A chapter on ground-fault relaying provides recommendations for maximum and minimum pickup levels as a function of maximum ground current and power system line-to-ground capacitance. Research in the area of phase overcurrent protection has resulted in a complete set of procedural recommendations for the selection and setting of overcurrent relays and current transformers, molded-case circuit breakers, and distribution system fuses in coal mine power systems. The final chapter, which discusses relay system maintenance, introduces a unique test set which was developed by KETRON and used to test the performance of relaying systems in coal mines.

1/ Research Engineer, KETRON, INC.
2/ Senior Research Engineer, KETRON, INC.

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1.0 INTRODUCTION

1.1 General

The Department of Interior's Bureau of Mines faces a serious challenge in trying to improve mine electrical safety. This is especially apparent in the coal mining industry where the majority of the mining equipment is electric powered and the need for increased production involves correspondingly larger electric power system sizes and capacities. In spite of the higher costs of maintaining a safe electric power system, experience has proven that elimination of hazardous electrical practices results in not only a safer system, but a more reliable one as well. It is also worth noting that safe electrical practices cannot be obtained by legislation alone; they must also evolve from good engineering.

Even the best designed and maintained power systems occasionally experience faults and overloads. The proper installation of protective circuitry should prevent personnel hazards during the occurence of such events. However, some aspects of relaying on high voltage distribution systems are not well defined, such as the relay pickup levels. In order to clarify the methodology by which distribution system fault and overload protection is obtained, the Bureau of Mines issued a contract (J0395035) to KETRON, INC. for the purpose of establishing criteria for coal mine ac distribution system protection. The results of the KETRON study are contained in this report.

1.2 Scope of Work

The problem areas which were investigated by KETRON are summarized as follows:

(1) The use of high-resistance grounding has been a U.S. coal industry standard for a number of years. There is still much debate, however, concerning the proper pickup setting of ground fault relays. The optimal pickup setting, in percent of maximum ground fault current, must be determined.

(2) A need exists to specify the time delays which are required to obtain coordination of protective system ground fault relays.

(3) The use of solid state protective relays is becoming more prevalent in many industries. Their suitability for use in coal mines must be investigated.

(4) The selection of pickup levels for, and coordination of phase overcurrent protection gear must be clearly defined.

(5) The use of relaying techniques other than overcurrent must be investigated as to their suitability for use in coal mine power system protection.

1.3 Report Format

This report is divided into four areas of concentration. Chapter Two is a review of existing protective relaying technology. Besides exploring several relaying topics in detail, the Literature Review provides an extensive list of relevant reference material. Chapter Three defines ground fault relaying in terms of designing a system that will provide maximum performance and personnel safety.

Chapter Four provides complete design information for coordination of both the distribution and utilization relaying systems. The procedure is then illustrated using an example mine power system. Chapter Five details the experimental work which was performed by KETRON personnel.

1.4 Conclusions and Recommendations

An analytical approach to the determination of an optimal pickup level for ground fault relays has resulted in a recommended value of 45 percent of the maximum ground fault current. This value is an appropriate setting for instantaneous electromechanical units and solid state relays both of which perform well at pickup current. Induction disc relays do not perform reliably below about 1.5 times their pickup current and should be set to pick up at 30 percent of the maximum ground current. For proper coordination, the ground fault relay protecting a branch circuit in the distribution system should be set to pick up at a current that is greater than the total phase-to-ground charging current of the branch circuit. In addition, the most inby ground fault relays should be set to pick up instantaneously with coordination time added in 0.4S increments for outby relays. Further research in the area of ground fault relaying should consist of an investigation of voltage drops across arcing ground faults. Although literature on the subject of electric arcs indicates that arc voltages are small in comparison to distribution system line-to-neutral voltages, no information was found concerning arcing ground fault voltages in high resistance grounded systems. This type of investigation should include arcing ground faults at utilization voltages, where the arc voltage may be a significant percentage of the utilization system line-to-neutral voltage.

Specific recommendations have been made for phase relay pickup settings and time delays used to achieve protection and coordination of the distribution and utilization systems during phase-to-phase and three-phase faults. The protective system specification process is illustrated using an example mine power system, the result of which provides design criteria and tradeoffs encountered in protective system design. Other research in this area has resulted in recommendations for the location of protective gear in the power system to achieve maximum personnel protection and system performance. Additional research in the area of phase overcurrent relaying should consist of an investigation of load diversity in both the utilization and distribution systems. Good estimates of load diversity permit overcurrent relaying to better protect the power system.

Protective relaying schemes other than overcurrent were investigated as to their applicability for use in coal mine power system protection. The results indicate that overcurrent protection is the best overall scheme although unit methods (such as differential) may be effectively used to protect motors and transformers with ratings greater than about one MVA. Although unit methods could be used to provide coordinated instantaneous protection of all the electrical equipment in a coal mine, it is doubtful that the increase in protective system performance can justify the cost of purchasing and maintaining such equipment.

An investigation into the use of static relays in coal mining application indicates that they have the potential to offer improved performance of the protecton system. This is espcially apparent in the area of ground fault relaying, where the capability for extremely low burden makes static relays an obvious choice in ground fault applications. Information concerning the reliability of static relays in a mining environment is scarce, however, conversations with people who have had experience in this area indicate that static relays are at least as reliable as their electromechanical counterparts.

2.0 LITERATURE REVIEW

2.1 Introduction

It is the intent of this literature review to provide the reader with an extensive list of references dealing with topics such as instrument transformers, relays, and system protection. In addition, where the authors felt it necessary, the review goes into considerable detail on certain key areas of mine power system protective relaying. Sources of information include textbooks which cover the subject of protective relaying in a general sense, as well as publications addressing specific applications or problems encountered in the use or design of protective relaying systems.

The subject of protective relaying covers a vast amount of material. Therefore, the literature review begins by focusing on the specific configurations encountered in coal mine distribution systems. Once the system has been described it is possible to discuss those aspects of relay types, instrument transformers, phase overcurrent relaying, ground fault relaying, and coordination which are applicable. The review covers standard practices in relay system design as well as existing techniques, such as static relaying, which are not currently being used in the mining industry but may have an application.

2.2 System Description

The type of distribution system most commonly found in deep coal mines is the expanded radial system, as shown in Figure 2-1. The expanded radial system consists of a single source providing power at distribution voltage (typically 4.16kV, 7.2kV or 13kV) with load centers located near each working place, or utilization point, to step the voltage down to suitable levels. Many surface mines also use an expanded radial system although voltage levels may be higher at both the distribution and utilization levels due to the increased load requirements of large surface mining equipment.

A more elemental version of the expanded radial system, referred to as simply a radial system (Figure 2-2), involves a single source-single voltage arrangement in which the distribution and utilization voltages are the same. For deep mine applications, the radial system can only be used in physically small operations, such as punch mines, where distribution at utilization levels does not present voltage regulation problems. The same reasoning applies to small surface installations. Larger surface mines may use a combination of expanded radial and radial systems in that larger equipment is powered at distribution voltage while smaller equipment requires step-down transformation.

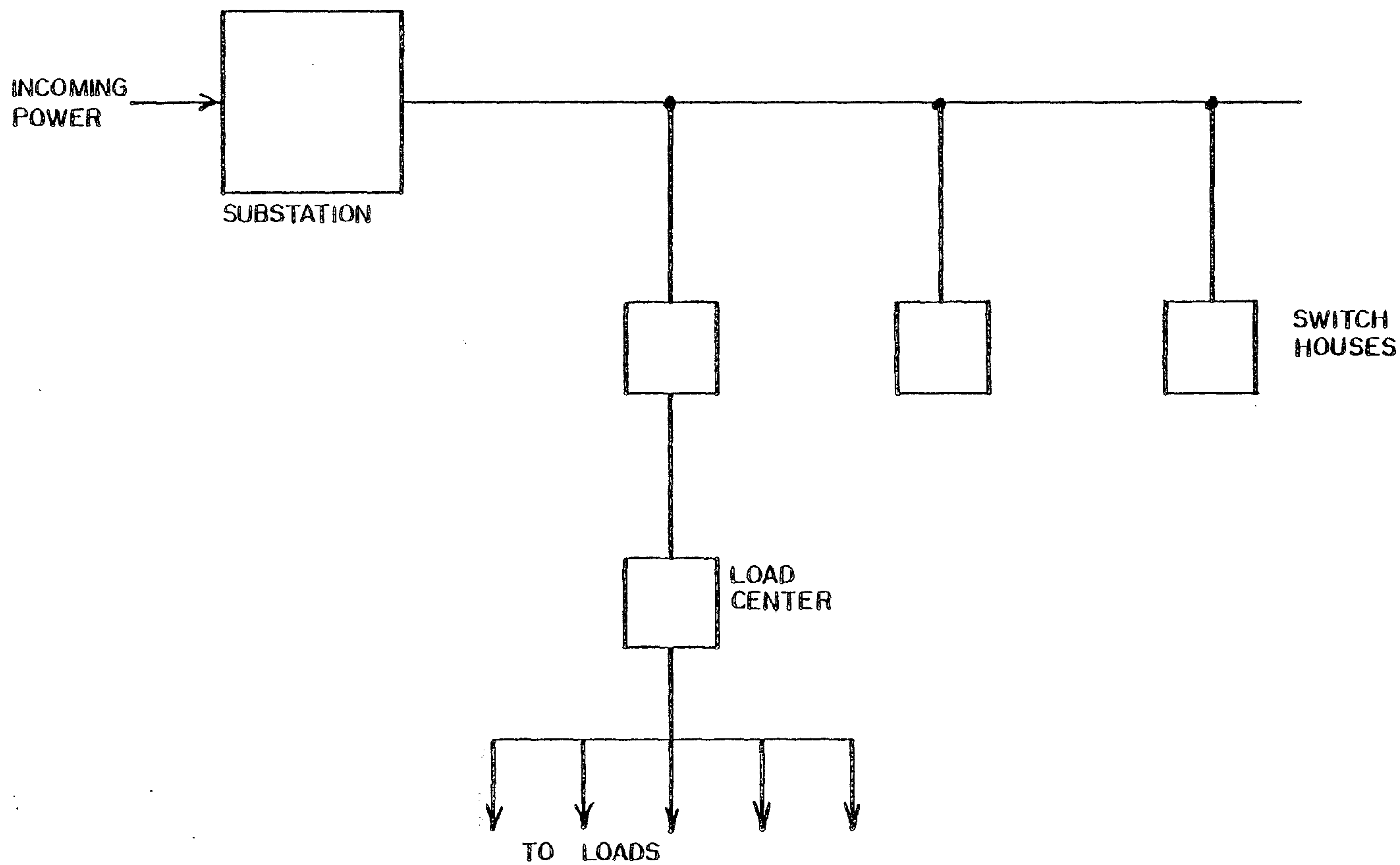


FIGURE 2-1

Expanded Radial System

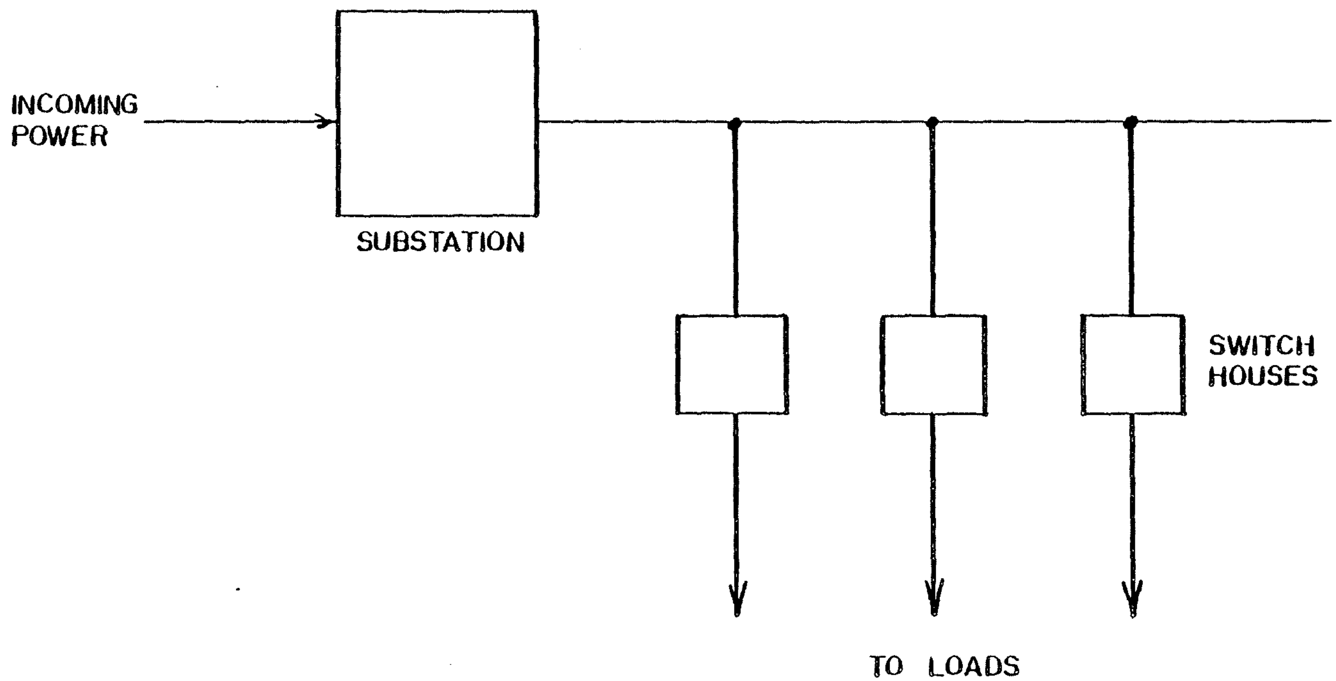


FIGURE 2-2

Radial System

A modification of the expanded radial system, which provides greater system reliability, is the secondary selective system, as shown in Figure 2-3. The secondary selective system consists of two separate expanded radial systems with the secondarys of the substation transformers connected together using a normally open switch called a tie breaker. In the event of a substation malfunction the tie breaker could be closed and power would be available throughout both systems.

A primary selective system (Figure 2-4) is similar to the secondary selective system, except, as its name implies, there are two primary sources and one substation instead of one primary source and two substations. Again, the objective is increased system reliability.

The last system type to be considered is the primary loop system, shown in Figure 2-5. Found in some larger surface operations, the primary loop system offers better voltage regulation and continuity of service than the expanded radial system.

From a protective relaying viewpoint, the primary and secondary selective systems both degenerate into an expanded radial system (with the exception of the relaying associated with the tie breaker). In each case the protection is designed for a single source supplying multiple loads through step-down transformers. The zone of protection covers all elements of the distribution system from the substation transformer primary to the individual step-down transformer secondaries.

Protective relaying concepts for radial systems differ from the above only in that the zone of protection extends right to the rotating machines in the mining equipment.

The design of a relaying network for loop systems is more complicated than for the aforementioned systems, in that power is supplied from two directions. Consequently, the relays must be able to determine in which direction a fault or overload current is flowing so that the proper breaker is tripped.

Coal mine electric power distribution systems can be further defined by referring to Title 30 of the Code of Federal Regulations, Parts 75 and 77, which contains regulations pertaining to deep and surface coal mine electrical power distribution systems. These circuits are required to have circuit breakers equipped with under-voltage, grounded phase, short circuit, and overcurrent protection.[1,2] Coal mine power systems tems, with few exceptions, are resistance grounded.[3,4] Maximum ground fault current is 25A for low and medium voltage circuits (<1000V).[5,6] The ground fault current in high voltage systems (>1000V) must be limited to the extent that the voltage drop

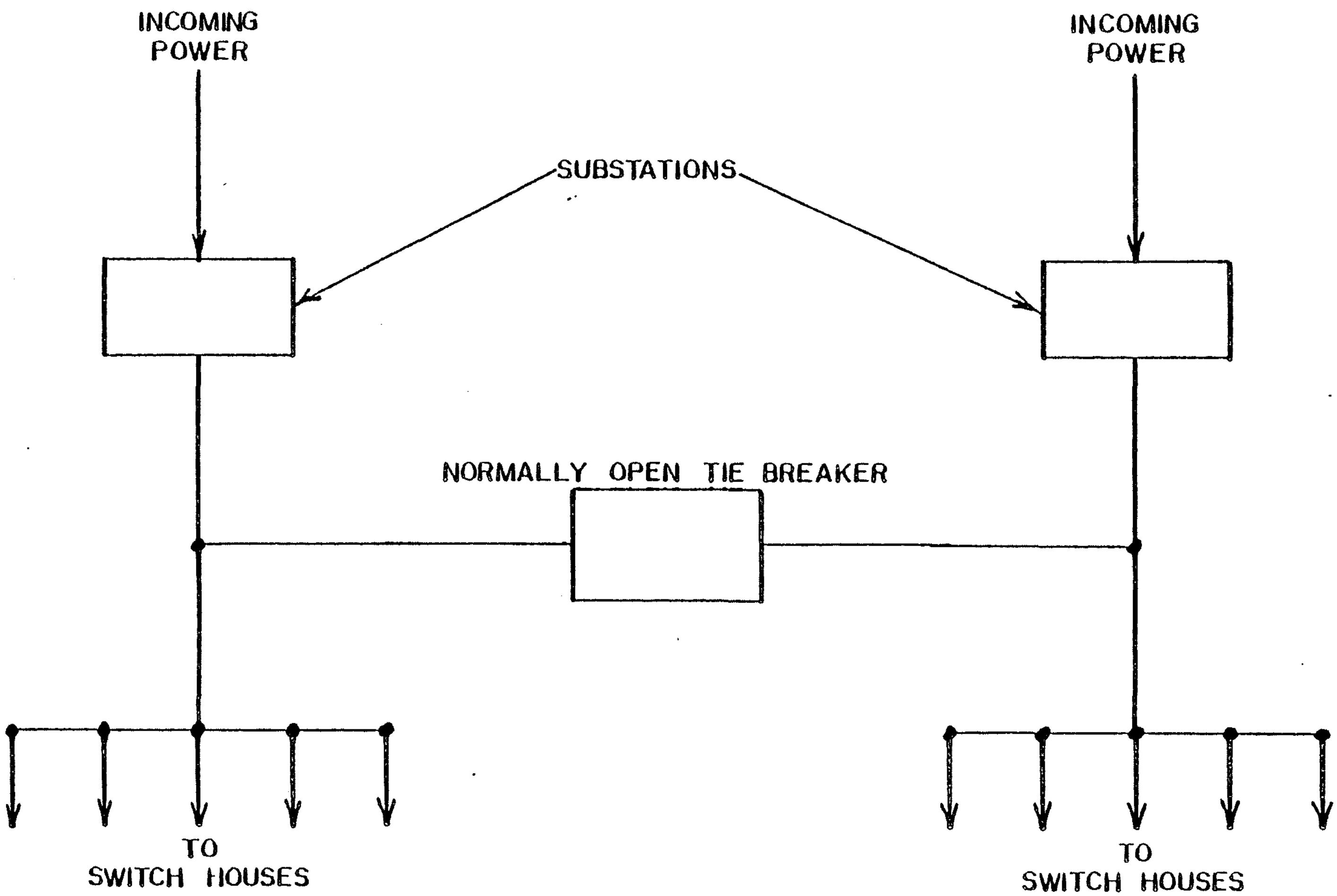


FIGURE 2-3

Secondary Selective System

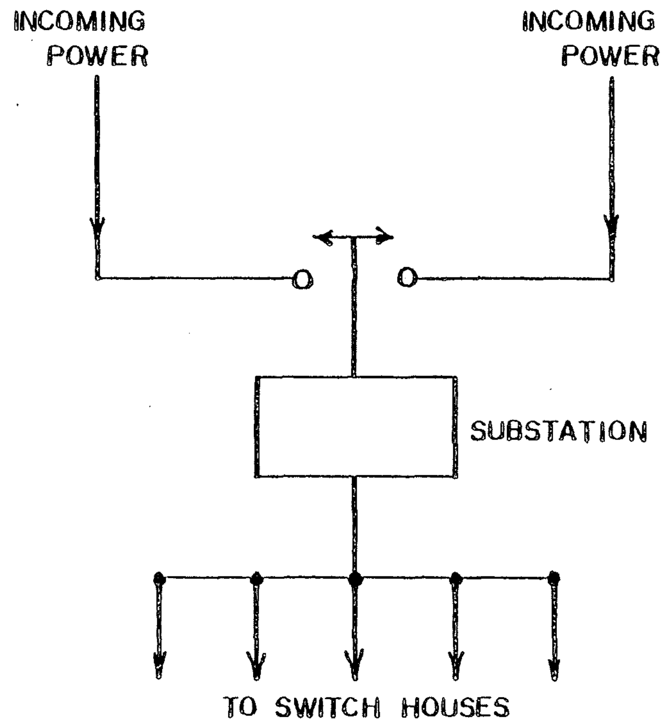


FIGURE 2-4

Primary Selective System

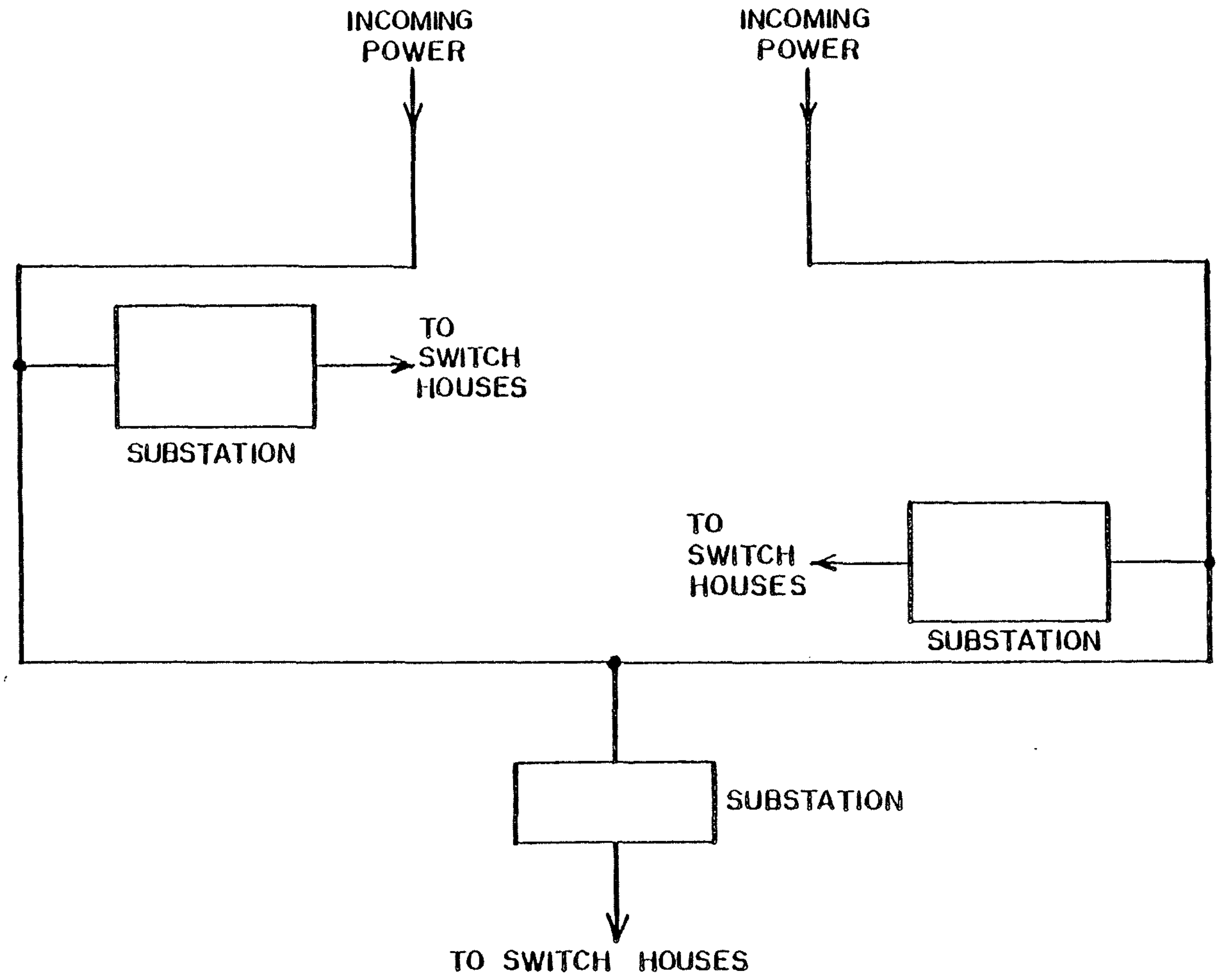


FIGURE 2-5

Primary Loop System

in the grounding circuit external to the grounding resistor will not exceed 100 V.[7,8] Typical values of maximum ground fault current in high voltage systems range from 25A to 50A or 75A.[9,10,11,12,13,14]

The power transmission method from the substation to the load has a considerable effect on relaying methods. Deep coal mines use multi-conductor insulated cable as do many surface mines. The alternative for surface mines is a combination of insulated cable and overhead transmission lines. In both cases, the impedance of the conductors has a large bearing on phase relay settings.

A final consideration in the selection of protective relays and their settings is the nature of the connected load. Three-phase induction motors and rectifiers account for most of the a.c. load in deep coal mines. Motor sizes range from 5 hp motors in non-production equipment (such as dewatering pumps) to 200 hp to 300 hp motors used in belt drives, longwall shearers and face haulage, and other large production equipment. Rail haulage rectifiers which use silicon diodes are commonly sized up to 1000 KVA in deep mines using rail haulage for the movement of ore in addition to men and materials.

Electrical loads presented by surface mine equipment include induction motors of sizes previously mentioned as well well as large (up to 10,000hp) synchronous motors used on the bigger draglines and stripping shovels.

References 9-19 contain additional background information on coal mine electric power systems.

2.3 Instrument Transformers

Instrument transformers are used to electrically isolate the relay circuit from the power system and to permit relay devices to operate at reasonable values of current and voltage. The performance of instrument transformers is a key factor in relay system design because the relays are only as accurate as the instrument transformers which energize them.

2.3.1 Current Transformers

Current transformers can be divided into three categories by the method of their construction.[20] The bushing type of current transformer has an insulated secondary which is wound on an iron core. The primary conductor, which may be one or more cables, or a buss bar, passes through the core window. The bar, or through-type, of current transformer is similar to the bushing type with the exception that it has a permanent primary winding usually consisting of a bar-type con-conductor. Primary connections must be made to either end of the bar.

Wound primary current transformers have more than one primary turn, which permits higher accuracy at lower turn ratios.[20]

Each of the three types of current transformers is further specified by its turns ratio. Standard ratios for single and multiratio current transformers are shown in Tables 2-1 and 2-2, respectively.[20] The values shown in Tables 2-1 and 2-2 also indicate the current ratings of the current transformers and it should be noted that 5A is a standard rating for current transformer secondaries. This does not mean that the transformer should not be operated above 5A secondary current. In fact, IEEE Standard 242-1975 recommends a secondary current of 3 or 4A at full load resulting in currents considerably higher during a fault.[20] Another source[20] recommends 5A secondary current at full load. If fault currents will exceed 20 times the current transformer rating, the manufacturer should be consulted for high overcurrent performance.[20]

Another current transformer rating is the thermal short-time rating which is the RMS primary current that the current transformer can carry for one second with the secondary shorted, without exceeding a specified temperature in any winding.[20] A rating which applies only to wound primary current transformers is the mechanical short time rating. This is the maximum current the current transformer is capable of withstanding with the secondary short-circuited, without mechanical damage.

Current transformers for industrial applications have standard voltage ratings which are 600, 2500, 5000, 8700, and 15,000V.[10] Current transformers also have impulse and high potential ratings, as shown in Table 2-3.[20]

A primary consideration in the application of current transformers is accuracy at both load current and fault current levels. The overall performance of any current transformer is a function of the type and cross section of the core iron and the transformer turns ratio.[20] More core iron allows greater flux to be developed and increasing the the number of secondary turns permits a given amount of flux to develop a larger amount of voltage across the secondary winding without saturating the transformer. Another significant parameter in the application of current transformers is the load, or burden, placed on the secondary. In general, lower burdens result in smaller saturation effects and greater accuracy.

The performance of a current transformer over its dynamic range with different magnitudes and waveshapes of primary current and different burdens is a complex, nonlinear

TABLE 2-1

Current Transformer Ratings
Other than Multiratio Bushing Type

Single Ratio (amperes)	Double Ratio with Series-Parallel Primary Windings (amperes)	Double Ratio with Taps in Secondary Winding (amperes)
10/5	25 x 50/5	
15/5	50 x 100/5	25/50/5
25/5	100 x 200/5	50/100/5
40/5	200 x 400/5	100/200/5
50/5	400 x 800/5	200/400/5
75/5	600 x 1200/5	300/600/5
100/5	1000 x 2000/5	400/800/5
200/5	2000 x 4000/5	600/1200/5
300/5		1500/3000/5
400/5		2000/4000/5
600/5		
800/5		
1200/5		
1500/5		
2000/5		
3000/5		
4000/5		
5000/5		
6000/5		
8000/5		
12000/5		

TABLE 2-2

Current Transformer Ratings
Multiratio Bushing Type

Current Ratings (amperes)		Secondary Taps
600/5	50/5	X2-X3
	100/5	X1-X2
	150/5	X1-X3
	200/5	X4-X5
	250/5	X3-X4
	300/5	X2-X4
	400/5	X1-X4
	450/5	X3-X5
	500/5	X2-X5
	600/5	X1-X5
1200/5	100/5	X2-X3
	200/5	X1-X2
	300/5	X1-X3
	400/5	X4-X5
	500/5	X3-X4
	600/5	X2-X4
	800/5	X1-X4
	900/5	X3-X5
	1000/5	X2-X5
	1200/5	X1-X5
2000/5	300/5	X3-X4
	400/5	X1-X2
	500/5	X4-X5
	800/5	X2-X3
	1100/5	X2-X4
	1200/5	X1-X3
	1500/5	X1-X4
	1600/5	X2-X5
	2000/5	X1-X5
3000/5	1500/5	X2-X3
	2000/5	X2-X4
	3000/5	X1-X4
4000/5	2000/5	X1-X2
	3000/5	X1-X3
	4000/5	X1-X4
5000/5	3000/5	X1-X2
	4000/5	X1-X3
	5000/5	X1-X4

phenomenon which in general cannot be determined by analytical methods.[22] However, for sinusoidal primary currents of limited magnitude, there are simple methods for estimating current transformer accuracy.

TABLE 2-3

Current Transformer
High-Potential and Impulse Ratings

Nameplate Rating (kV)	60Hz High-Potential Rating (kV)	Impulse (BIL) Rating (kV)
0.6	4	10
2.5	15	45
5.0	19	60
8.7	26	75
15.0	34	95

An equivalent circuit of a current transformer is shown in Figure 2-6.[22,23] The circuit contains five elements. The ideal transformer provides the turns ratio. The series resistance and inductance represent the winding resistance and leakage reactance, respectively. Winding resistance is equal to the sum of the secondary winding resistance and the primary winding resistance as seen from the secondary. Primary winding resistance is zero for current transformers without wound pri-primaries. Winding leakage reactance is applicable only to current transformers with non-distributed secondary windings (i.e., the windings are not evenly distributed around the core) such as split core transformers. Leakage reactance is generally not known and must be determined by laboratory measurement. Current transformers with non-distributed windings will not be considered here because they are seldomly used in mine power system protection systems.

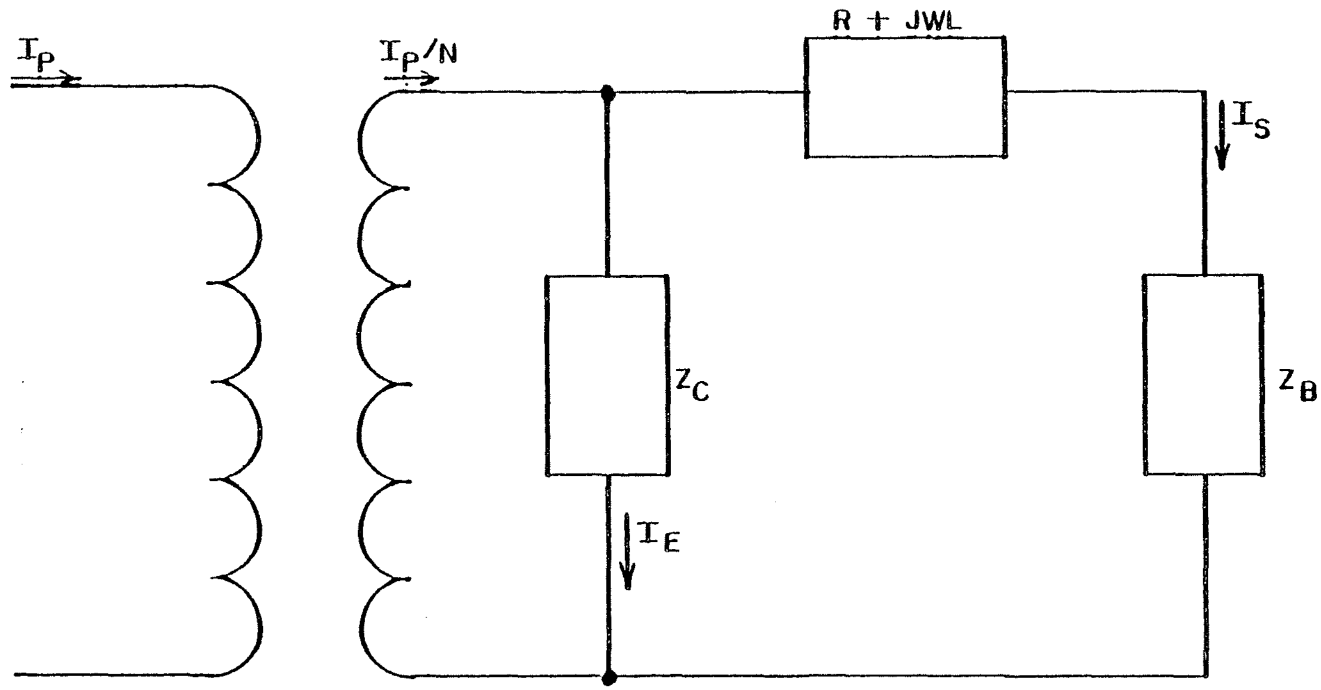


FIGURE 2-6

Equivalent Circuit For a Current Transformer

The shunt impedance, Z_C, is nonlinear, and represents the physical phenomenon of saturation in a current transformer. The significance of Z_C is made apparent by a typical secondary excitation curve shown in Figure 2-7.[20] The exitation curve is a log-log plot of secondary exciting current, I_E, as a function of secondary voltage. Since a current transformer always requires some excitation current it can be said that saturation is always present to some degree and that the actual transfer function is never equal to the turns ratio.[22]

The burden impedance, Z_B, represents the total impedance connected to the current transformer secondary, including connection wire, meters, and relays.

The use of an excitation curve to calculate current transformer performance is a simple process and is well documented in references[21] and[23]. However, there are some limitations involved in using the excitation curve. One limitation results from the nonlinear properties of magnetic materials. More specifically, a sinusoidal flux produced by a sinusoidal primary current results in non-sinusoidal exciting current.[24] Since the current transformer secondary current is equal to the difference between the primary current divided by the turns ratio and the exciting current, the secondary current is necessarily nonsinusoidal for a sinusoidal primary current.[22] The extent of the nonlinearity is dependent upon the ratio of the exciting current to the current transformer secondary current. The nonlinearity is important because most relays, especially induction disk relays, are designed to operate on a 50 to 60Hz sinusoid.[22] Other waveshapes or frequencies do not produce as much relay torque and more RMS current is required to trip the relay. The secondary exciting curve method should only be used for ratio errors (approximated by the exciting current divided by secondary current) of 10 percent or less.[23]

Another constraint in the use of current transformer exciting curves is saturation resulting from dc offsets. Flux produced from dc offset current does not induce a voltage in the current transformer secondary but it does contribute to excitation current, thus pushing the current transformer closer to or into saturation. Direct current offsets occur at the initiation of a line-to-line or three-phase fault because circuit inductance prevents the pre-fault current from instantly changing magnitude and phase to the fault value. Short circuit currents in three-phase systems can contain a decaying dc component of an initial value equal to the short circuit ac component. The duration of the dc offset is dependent on the time constant of the current transformer primary circuit.[25] Time constant, which is defined as the ratio of circuit inductance in Henrys to circuit resistance in Ohms, is the amount of time in seconds for the dc offset to decay to 36.8 percent of its original value.[26]

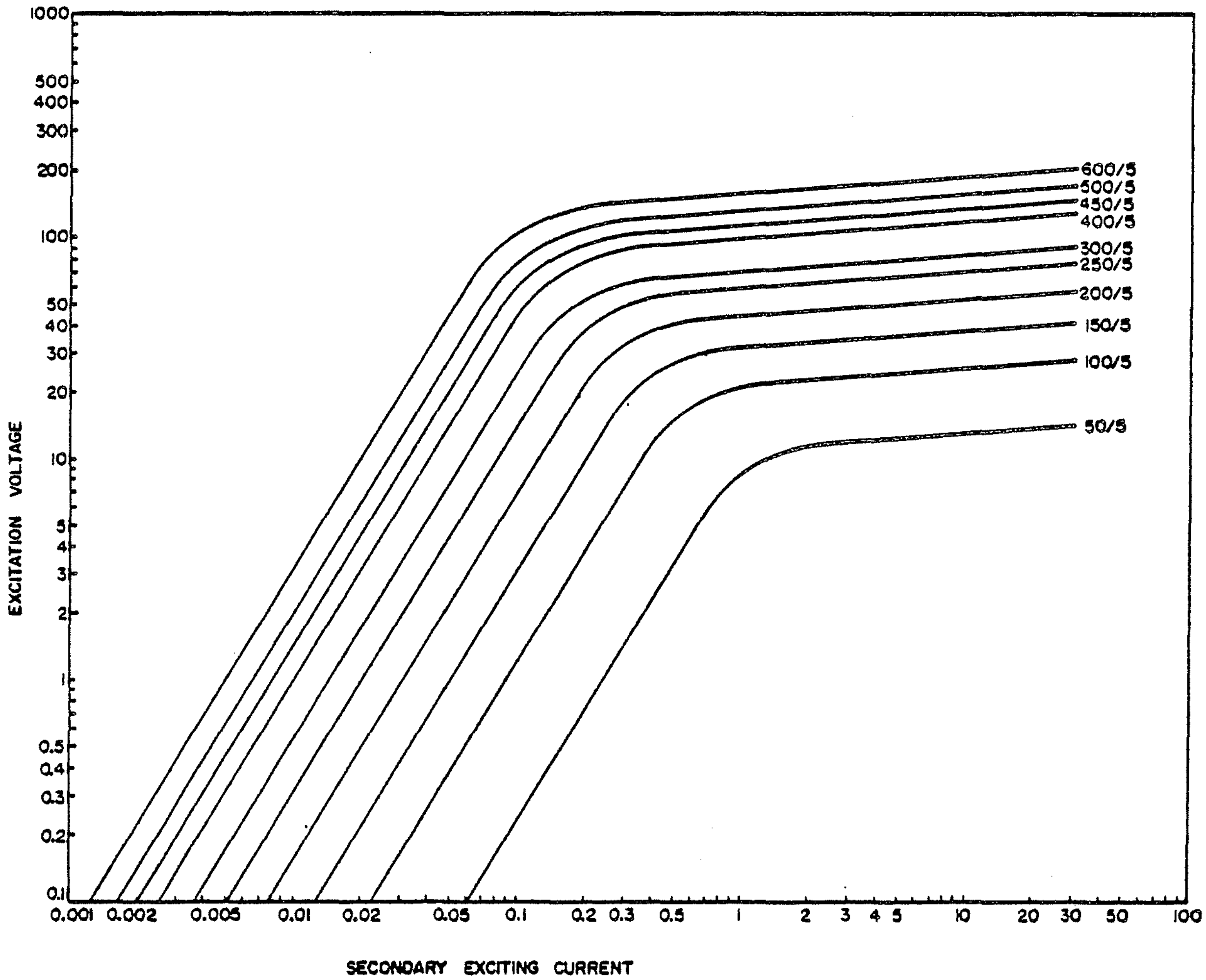


FIGURE 2-7

Typical Secondary Excitation Curve

For example, a 500 MCM mine power feeder cable has a time constant of about 2.8 mS.[27] A 1000A dc offset, correspond-ponding to a 1000A symmetrical ac fault, would decay to 368A in 2.8 mS and 135A in 5.6 mS (two time constants).

In applications where saturation must be completely prevented, the current transformer must be sized to carry twice the peak flux associated with the symmetrical ac fault current. In many applications, however, it is not necessary to completely prevent saturation to accomplish successful relaying.[28] For instance, in this example involving a fault on 500 MCM cable, the current transformer might be sized to handle the maximum symmetrical ac fault current (1000A) plus 135A of dc offset current. The current transformer would be badly saturated at the initiation of the fault, but one third of a cycle later the current transformer would be performing properly. In mining applications, where trip time may be three or four cycles for a phase to phase or three-phase fault, the one third of a cycle delay would not be significant. The effects of circuit inductance on the production of an offset or asymmetrical current wave during a fault are discussed in the section on phase overcurrent relaying.

Another source of error when using the excitation curves is residual flux.[22] Residual flux remains in a magnetic core after the magnetic field intensity has been reduced to zero.[29] Residual flux can add to the core flux induced by the primary current causing a deficiency of secondary current due to saturation effects.[30] Since residual flux has its major effect on current transformer performance during the first half-cycle of a fault it is not a significant factor in most mine relaying applications.[30]

A second method for determining the accuracy of a current transformer is by using ratio-correction factor curves. The term "ratio-correction factor" is defined as "that factor by which the nameplate ratio of a current transformer must be multiplied to obtain the true ratio."[23] The curve is a plot of the ratio-correction factor as a function of current transformer secondary current. Each curve applies to one value of current transformer burden and a family of curves must be provided for different values of burden.

Current transformer accuracy may also be specified using an ASA accuracy classification [23]. The ASA method assumes that the current transformer is supplying 20 times its rated secondary current to its burden, and the classification consists of the maximum RMS voltage that the current transformer can maintain at its secondary terminals without the ratio error exceeding a specified amount.[23]

The ASA classifications are shown in Table 2-4. The letters "L" and "H" stand for low and high impedance secondaries, respectively. Low impedance secondaries are a characteristic of current transformers with distributed windings (such as bushing current transformers) and high impedance secondaries are characteristic of current transformers with concentrated secondary windings. The number before the letter is the maximum specified ratio error in percent and the number after the letter is the maximum secondary voltage that the current transformer will develop at 20 times its rated secondary current without exceeding the specified error. For example, a 300:5 current transformer with a 10L200 rating will supply 100A at 200V to its burden at a ratio error of 10 percent or less, which is equivalent to saying that it will drive a two ohm burden.

Another method of specifying current transformer accuracy is contained in ANSI standard C57.13-1978. The method is identical to the ASA specification with the exception that the letters "C" and "T" are used in place of "L" and "H" respectively and the specified maximum ratio error is 10 percent instead of 2.5 percent or 10 percent. Thus, a T200 ANSI specification is equivalent to a 10H200 ASA specification. Table 2-5 shows the ANSI standard burdens for current transformers.

2.3.2 Voltage Transformers

A voltage transformer is basically a conventional transformer with the primary and secondary winding wrapped on a common core.[20] Voltage transformers are selected according to system voltage level and basic impulse level.[21] Most voltage transformers are designed to provide 120 VAC at the secondary terminals at rated input voltage.[20]

Voltage transformers have accuracy classifications similar to those of current transformers. However, the ratio and phase-angle inaccuracies for a given class are small enough to be neglected for protective relaying purposes if the burden is within the "thermal" volt-ampere rating of the transformer.[20]

For more information on instrument transformers see References 13-32.

2.4 Ground Fault Overcurrent Relaying

2.4.1 Pick-up Methods

The type and configuration of relays used for ground fault protection is dependent on power system grounding. Federal Regulations require a direct or derived neutral grounded through a suitable resistor at the power source. The most

TABLE 2-4

ASA Accuracy Classifications

10H10	10L10
10H20	10L20
10H50	10L50
10H100	10L100
10H200	10L200
10H400	10L400
10H800	10L800
2.5H10	2.5L10
2.5H20	2.5L20
2.5H50	2.5L50
2.5H100	2.5L100
2.5H200	2.5L200
2.5H400	2.5L400
2.5H800	2.5L800

TABLE 2-5

Standard Burdens for Current Transformers

Standard Burden Designation	Characteristics: Resistance (ohms)	Characteristics: Inductance (mH)	Characteristics for 60 Hz and 5 A Secondary Current: Impedance (ohms)	Apparent Power* (VA)	Power Factor
B-0.1	0.09	0.116	0.1	2.5	0.9**
B-0.2	0.18	0.232	0.2	5.0	0.9**
B-0.5	0.45	0.580	0.5	12.5	0.9**
B-1	0.5	2.3	1.0	25	0.5***
B-2	1.0	4.6	2.0	50	0.5***
B-4	2.0	9.2	4.0	100	0.5***
B-8	4.0	18.4	8.0	200	0.5***

* At 5 A; note that $VA = I^2Z$, or 2Ω at 5 A = 2×5^2 = 50 VA.

** Usually considered metering burdens, but data sheets may give metering accuracies at B-1.0 and B-2.0.

*** Usually considered relaying burdens.

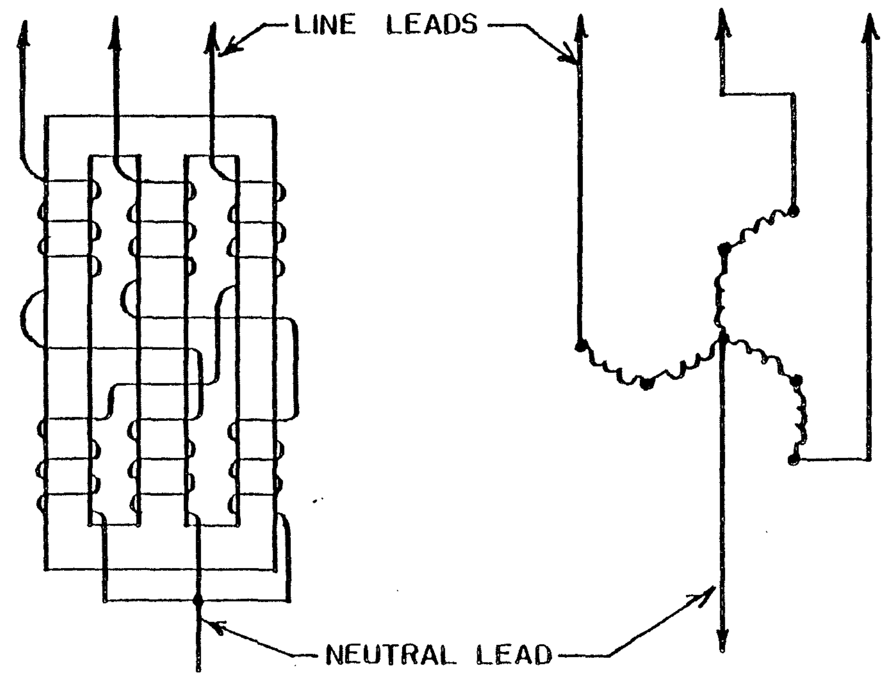
common way to obtain the system neutral is to use a source transformer with a wye-connected secondary winding.46 On delta systems a grounding transformer may be used to derive a system neutral. The type of grounding transformer most commonly used is a three-phase zig-zag transformer.46 The internal connection of a zig-zag transformer is shown in Figure 2-8. The transformer is designed so that it has very high impedance to three-phase currents and very low impedance to ground currents.46 On systems in which the line-to-neutral voltage voltage exceeds 7200V, the grounding resistor may be coupled to the mine ground through a step-down transformer. Such a configuration becomes desirable when the size and cost of a higher voltage resistor outweighs the extra cost of a step-down transformer.

There are four methods used to detect ground current in resistance-grounded power systems. These are the source neutral method, the residual method, the balanced flux or core balance method, and the neutral resistor potential relaying method.14,20 The characteristics of each method are discussed below.

Source neutral relaying (Figure 2-9) uses a current transformer placed around the ground wire. Since the current transformer is sized for ground current only, the method provides good sensitivity. One drawback of source neutral relaying results from the presence of ground return paths which do not include the ground conductor in the switchhouse. In applications where multiple ground current paths exist, the use of source neutral relaying is not recommended. Thus, for mining applications, source neutral relaying should be used only at the source transformer where the current transformer can be placed between the system ground and the source neutral.

Residual relaying requires the use of three current transformers, one in each phase. The secondary circuits of the current transformers form a wye connected source and three phase - overcurrent relays form a wye connected load. The ground relay is located in the neutral conductor between the source and load circuits (Figure 2-10). Residual relaying has good selectivity in that a set of current transformers and relays can be placed in each outgoing circuit fed from a common bus. The sensitivity is dependent on the three current transformers having similar transfer functions, i.e., unequal saturation of the current transformers during heavy load conditions will cause current to flow in the ground relay. In mining applications, where sensitivities down to a few amperes may be required, the residual method requires expensive wound type current transformers and thus it is not frequently used.

Figure 2-11 shows the core balance method of ground fault relaying. All three phase conductors pass through the same current transformer, and the current transformer secondary current



(a) WINDINGS SHOWN ON CORE

(b) SCHEMATIC DIAGRAM OF CONNECTIONS

FIGURE 2-8

Internal Windings and Schematic Diagram of Zig-Zag Transformer

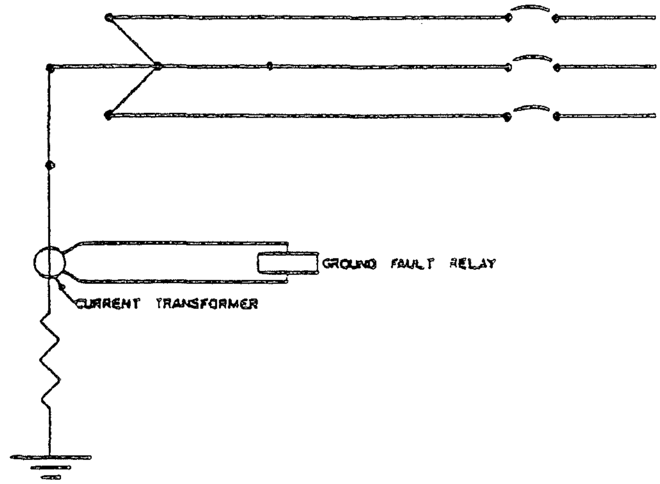


FIGURE 2-9
Source Neutral Relaying

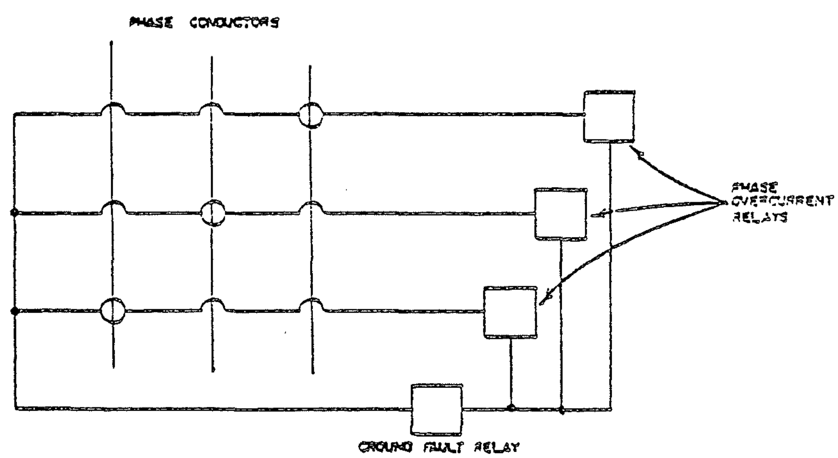


FIGURE 2-10
Residual Relaying

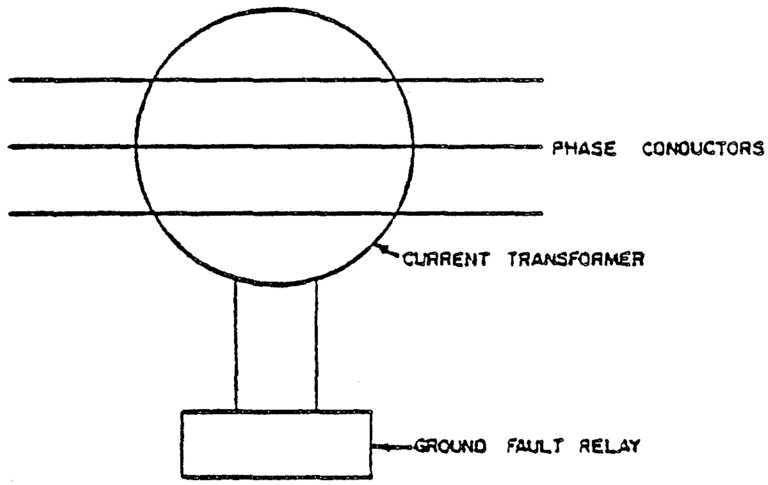


FIGURE 2-11

Core Balance Relaying

is proportional to the system ground current. Because of its good sensitivity and selectivity, the core balance method is frequently used for ground fault relaying on distribution as well as utilization circuits.

Ground resistor potential relaying (Figure 2-12) uses the increase in voltage across the grounding resistor to operate an overvoltage relay during a ground fault. Since the overvoltage relay must be connected across the grounding resistor, it follows that this method can only be used at the distribution system source where the source neutral can be accessed. Ground resistor potential relaying, which is generally used as a backup for one of the previously mentioned methods, is unique in that it will function correctly even if the grounding resistor is opened.

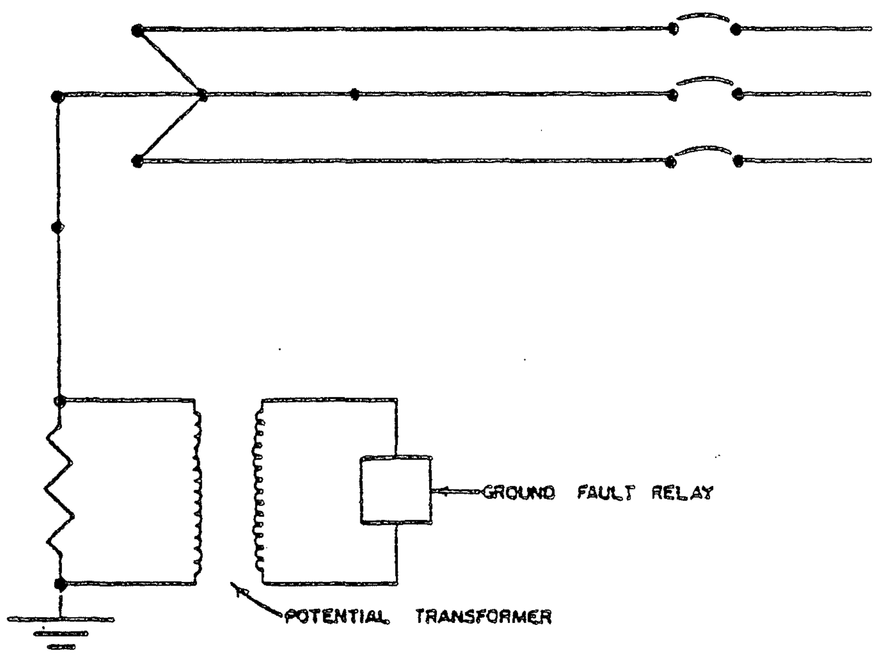


FIGURE 2-12

Ground Resistor Potential Relaying

2.4.2 Resistor Sizing

The upper limit on allowable ground current flow is that value which will impress no more than 100V between equipment frames and earth during a ground fault. When used with ground continuity check circuits the 100V maximum frame potential seems adequate.

There are, however, no legal restrictions on minimum allowable ground fault current. One benefit of reduced ground current is that smaller ground fault current results in less energy dissipation at the fault location, thus reducing equipment damage and improving the personnel safety factor. Another is that the possibility of a ground fault escalating into a phase-to-phase fault (before the faulted circuit can be removed) is reduced with lower ground fault currents.[47,48]

From a practical standpoint there are two factors which establish minimum recommended ground currents. One is that the ground current should exceed the system capacitive charging current in order to damp out transients which could otherwise occur during a ground fault. The other limitation is the ability of existing relay systems to operate on low levels of current. These issues will be dealt with in detail in a later section.

2.5 Cable Protection

Adequate cable protection requires limiting the current flow in the cable such that the internal cable temperature does not exceed the thermal stress limits of the dielectric. For example, the IPCEA specification for the ampacity of a three conductor mine power cable with 85°C insulation is that steady state current which will cause the insulation to reach 85°C in 40°C ambient conditions. Instantaneous and overload trip settings are generally based on both minimum fault currents in cables and cable thermal limitations. Figure 2-13 shows maximum fault currents for different sizes of mine power cable. Further information on cable ampacities and relay settings may be found in References 20, 49, and 50.

Ampacity standards for overhead lines are different from those for insulated cables because there is no dielectric to protect, and the only thermal constraint is that the copper must not be allowed to heat to destruction. For example, the IPCEA specification for the ampacity of a 4/0 15KV, three conductor mine power cable, at 40°C ambient, 75°C insulation, is 238A while the ampacity of a bare 4/0 stranded copper wire under similar conditions is 425A.[51,52] Information on overhead line protection is available in references 21 and 23.

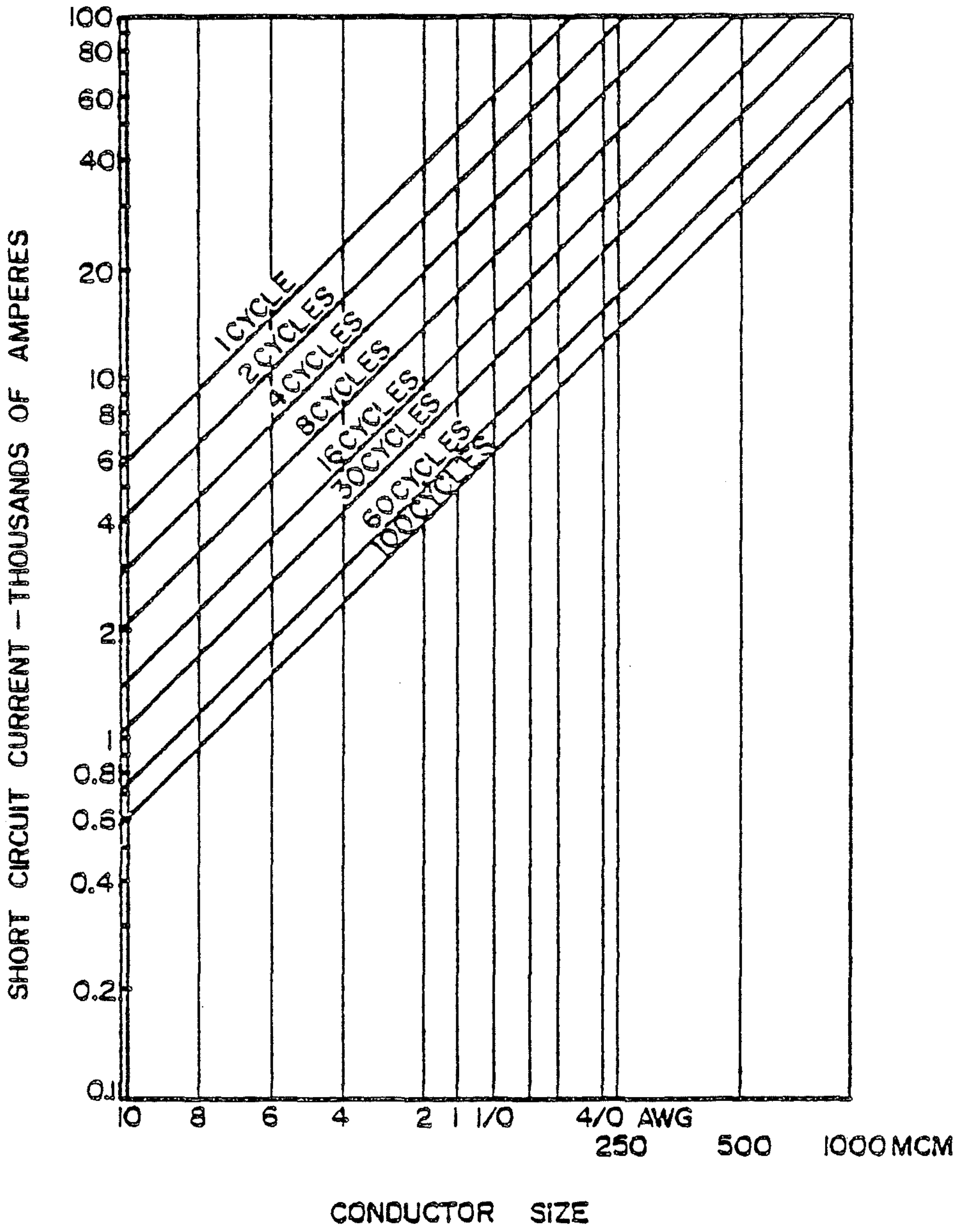


FIGURE 2-13

Maximum Recommended Fault Current For Insulated Copper Mine-Power-Feeder Cable. (27)

2.6 Motor Protection

Motor protection for mining equipment typically consists of instantaneous overcurrent, thermal overload, ground fault, and undervoltage devices. Instantaneous devices, which operate on phase-to-phase and three-phase short circuits are generally set just above the maximum motor starting current. Motor starting current may be calculated from locked rotor and system impedance data, or, settings can be determined on a trial and error basis. The latter method becomes especially useful when a machine with several motors is protected by one instantaneous device. A discussion of instantaneous settings can be found in Reference 20.

Thermal overload relays are designed to protect the motor from overheating due to sustained mechanical overload. The most common type of overload protection utilizes a bimetallic element which carries the motor supply current, either directly, or through a current transformer.[20] The References 20, 21, 53, 54 and 55 provide discussions on motor overload protection using conventional electromechanical relays. In addition, reference 56 describes a solid-state thermal overload relay.

2.7 Transformer Protection

Protective relays designed specifically for transformer protection are generally not found on transformers rated below 10 MVA.[21] Thus, most load center and substation transformers used for coal mine applications rely on existing overcurrent relaying to remove transformer faults.

Overcurrent protection criteria for transformers are generally based on the transformer's KVA rating and the ANSI withstand values shown in Table 2-6.[57] It should be noted that the winding current in a transformer with a delta connected primary is 0.707 times the per-phase current supplying the transformer.[26] Also, for a line-to-line fault on the secondary of a delta-wye transformer, the per-unit fault current on one of the primary phase conductors will be 116 per cent of the per-unit secondary fault current.[20]

TABLE 2-6

ANSI Transformer Withstand Values

Transformer Impedance	RMS Symmetrical Current in Any Winding	Time Period in Seconds
4 percent	25 times base current	2 seconds
5 percent	20 times base current	3 seconds
6 percent	16.6 times base current	4 seconds
7 percent	14.3 times base current	5 seconds

2.8 Major Electromechanical Relay Types and Operating Principles

The purpose of this section is to provide a general background in the various types of phase relaying techniques commonly used for utility or industrial power system protection. Since these procedures are complex and variable, only a short description of the most common or potentially advantageous techniques for coal mine applications will be given. For a more in-depth study, the reader is referred to one of the many texts or standards on this subject.[20,21,23,58,59,60,61]

2.8.1 Overcurrent

The overcurrent relay is perhaps the most obvious type of relay for fault or overload protection in that in its elementary form, there is only one actuating quantity - the current flowing in the lines or equipment to be protected. This actuating quantity is supplied to the relay through a current transformer such that for secondary currents less than the pickup setting of the relay, no response occurs, while for secondary currents greater than this pickup setting, the relay operates its contacts. Similar types include undercurrent, overvoltage, and undervoltage relays with the corresponding actuating quantities. Actuating signals to the voltage types are supplied either directly or through a potential transformer. Most, if not all, mine power systems use overcurrent relaying for overload and short circuit protection.

Overcurrent relays may operate either instantaneously (no intentional time delay) or with an inverse current-time delay characteristic. They may be voltage controlled as an aid in distinguishing fault currents from overloads, and may also include directional units for application in loop systems. Combinations of types in a single unit is common practice. A short description of overcurrent relays of interest in mining applications is as follows:

<u>Instantaneous</u> -- No intentional time delay such that the relay contacts operate in 10 m sec. or less when the current pickup setting is exceeded. Most often used in combination with an inverse time delay relay to decrease fault clearance times while maintaining coordination.

<u>Inverse Time</u> -- May be of the long-time, short-time, inverse, very inverse, or extremely inverse types as shown in Figure 2-14. The more highly inverse characteristics can be used to greatest advantage in systems where fault currents at a given location are essentially independent of the connected generation (i.e., distribution networks). All inverse time types are equipped with a time dial setting (in addition to a pickup setting) which allows the time delay to be adjusted as shown in Figure 2-15 for an extremely inverse relay. This time dial setting provides a means for coordination of relays in a system.

<u>Directional</u> -- Provides a means for relay operation only if the pickup current is exceeded and the power flow is in a specified direction. These units are normally required as a supplement to inverse time and/or instantaneous relays for loop systems in order to achieve selectivity and coordination. They are usually not utilized in radial systems. These units may require a voltage input in addition to a current input.

<u>Voltage Controlled</u> -- Requires a voltage input in addition to the current actuating quantity. Since the system voltage drops to a low value when a fault occurs, this device may provide fast fault protection while ignoring small overloads. The voltage control decreases the inverse time characteristic proportional to the drop in system voltage.

2.8.2 <u>Distance</u>

This type of relaying, also known as impedance relaying, is widely utilized in the protection of utility transmission lines. It is rarely used to protect industrial power equipment. Two input quantities are required -- the system voltage (usually supplied through a potential transformer) and the line current (normally supplied through a current transformer). These quantities are compared in amplitude and/or phase in order to produce a relay which will close its contacts based upon a component of impedance (or admittance) seen looking into the power system at the relay location. Thus, for example, a specific type of distance relay known as an impedance relay will operate its contacts when the magnitude of the system impedance seen by the relay is

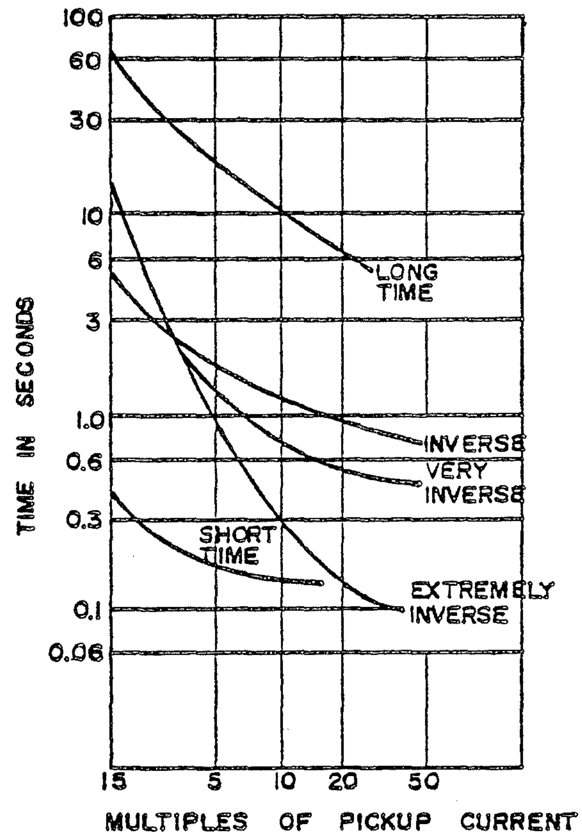


FIGURE 2-14

Characteristics of Various
Types of Induction Disc Relays

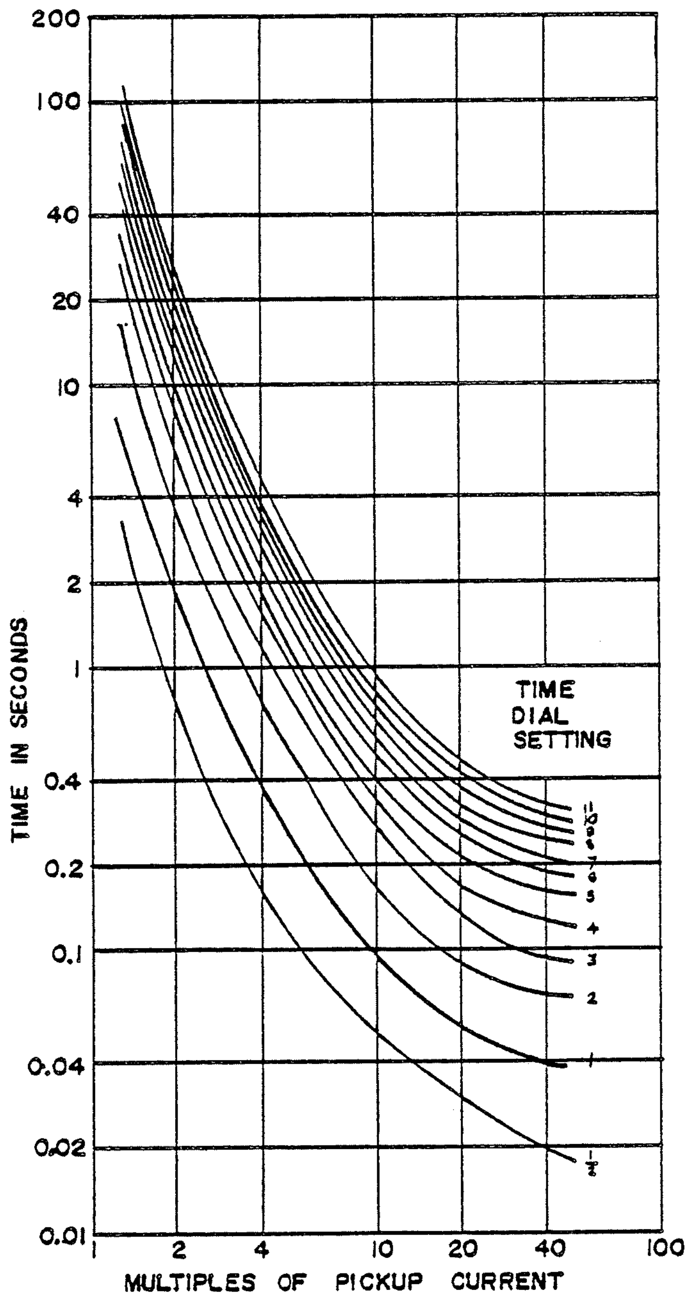


FIGURE 2-15
Characteristics of an Extremely Inverse Relay

below a specified value. This value is adjustable and is the setting of the distance relay. Thus, the actuating quantity in this special type of distance relay is the impedance magnitude. Distance relays with other impedance or admittance actuating quantities are also possible giving rise to special types known as reactance relays, admittance or mho relays, offset mho relays, and so forth. Directional units may also be incorporated into distance relays such that the relay operates based upon its actuating quantity for current flow in one direction only.

Distance relay units are normally constructed such that there are three different settings of the actuating quantity with a time delay between operation for each setting. This situation is shown in Figures 2-16 and 2-17 for an impedance-type, distance relay.

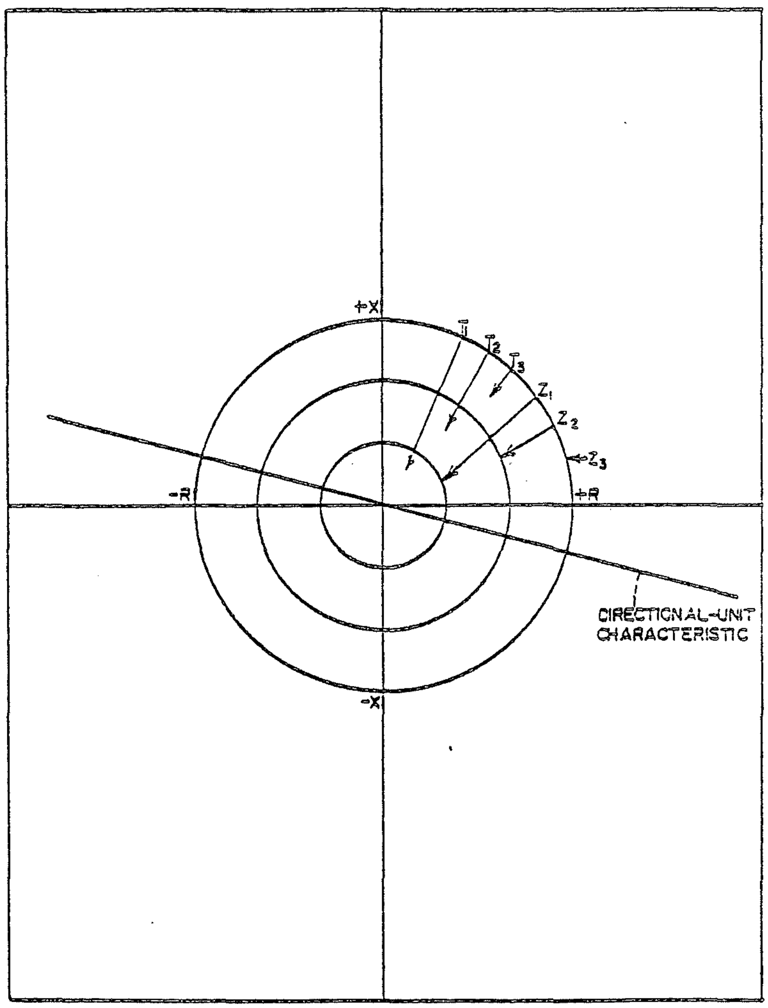


FIGURE 2-16

Impedance Diagram Showing Time Delays and Impedance Zones of a Distance Relay

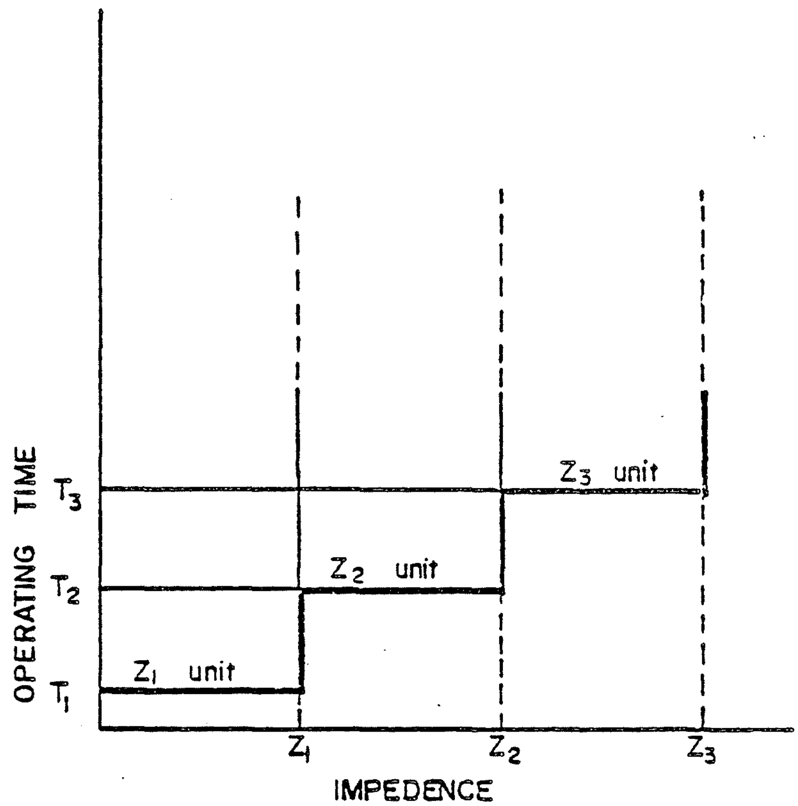


FIGURE 2-17

Cartesian Coordinate Plot Showing the
Time-Impedance Characteristics of a Distance Relay

There are now three separate zones of protection such that if the impedance magnitude seen by the relay is less than the setting Z_1, the relay operating time will be T_1; if this impedance is less than Z_2, but greater than Z_1, the relay operating time will be T_2; and if this impedance is less than Z_3, but greater than Z_2, the relay operating time will be T_3. For impedances greater than Z_3, the relay will not operate. The directional unit shown on the R-X diagram (Figure 2-16) prevents operation for impedance phase angles which lie beneath the directional unit characteristic.

Construction of distance relay units with three zones of protection in this manner allows proper application of these relays for both primary and backup fault protection. In addition, the tendency of a distance relay to over-reach (operate at an impedance larger than its setting value) due to d-c offsets in fault currents, or under-reach (restrain at the set value or impedances lower than the set value) due to fault resistance, may be incorporated into application settings.

As previously stated, distance relays are used by electric utilities to protect transmission lines from faults. The power flow characteristics of transmission lines are such that the only transient overcurrent effects are the result of faults. The power flow characteristics of a mine distribution system are different in that transient overcurrents also occur when large motors or transformers are energized. In the example on distance relay application to coal mine power systems, which appears in the next section, it is assumed that inrush and starting currents are limited to the full load current of the system. Additional research would be required to determine whether or not this assumption is required for the proper application of distance relays.

Another consideration in the application of a protective relaying system is its cost. Electric utility companies can justify the high cost (see section 2.9.2) of distance relays in terms of cost per mile of lines which may be hundreds of miles long. It is questionable whether or not distance relaying provides a large enough increase in system performance, compared to overcurrent relaying, to justify its use with the relatively short cable lengths found in mining applications.

2.8.3 Differential

As opposed to the overcurrent and distance relays discussed previously, differential relaying is a form of unit protection, i.e., these devices protect a particular component (or combination of components) in the system. Therefore, a unit scheme provides absolute discrimination by operating for faults within a clearly defined region bounded by the location of the sensing transformers. Its operating principle is the comparison of some quantity (current magnitude, current phase, power direction, etc.) at the ends of the protected zone.

A typical application of differential relaying is in the protection of large power system transformers. For most applications, percentage-differential relaying with current sensing is utilized as shown in Figure 2-18. From this figure, it may be seen that for normal load conditions, or for a fault external to the protected zone, the secondary currents in the two identical current transformers will be equal and no current will flow through the relay operating coil. Therefore, I is zero. However, if a fault were to occur within the protected element, the load side current (I_2) would change direction resulting in a change in direction of its current transformer's secondary current. The sum of the secondary currents would then flow through the relay operating coil resulting in instantaneous contact operation. The function of the restraining coil is to provide an opposing zone to relay operation proportional to the current flowing in the restraining coil. This prevents operation when large through currents flow due to an external fault. In theory, such operation should not occur, but in practice mismatches between current

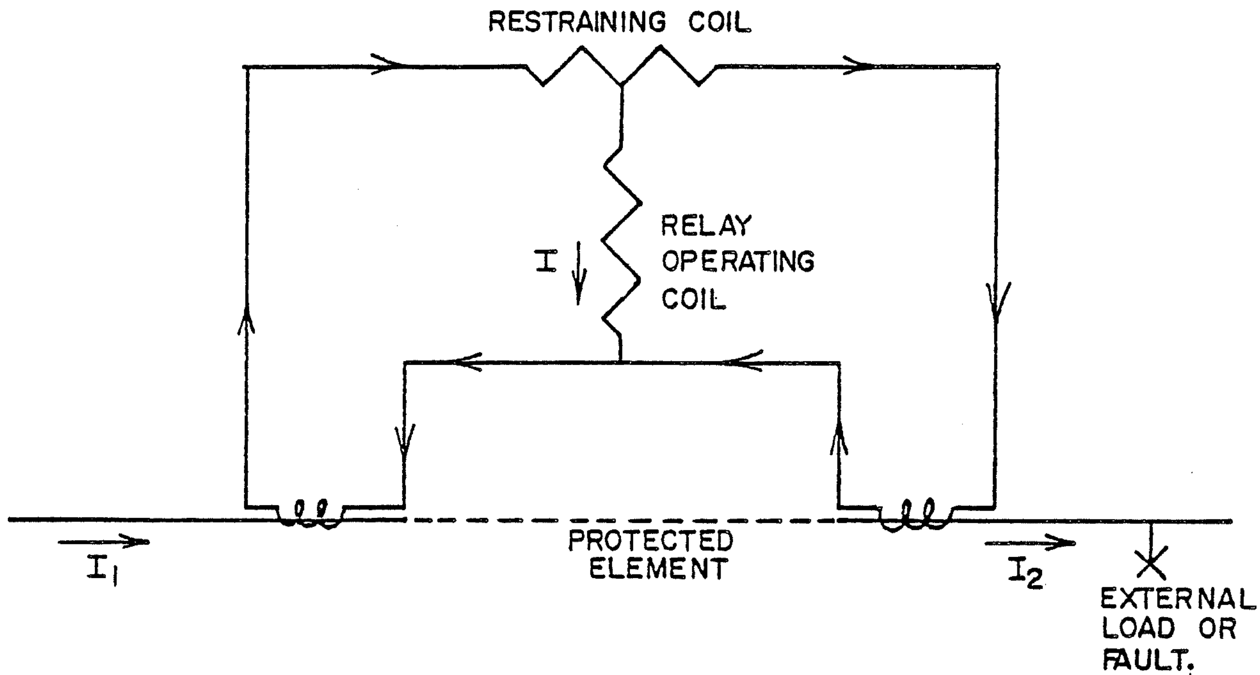


FIGURE 2-18

Basic Percentage -- Differential
Type of Relaying System

transformers could cause sufficient current to flow through the operating coil.

A similar procedure to that shown in Figure 2-18 may be applied to zones with more than two terminals. In this case, the sum of all currents flowing into the zone must equal the sum of all currents flowing out of the zone to prevent relay operation.

When differential relay schemes are utilized for the protection of transformers, special considerations are required to prevent operation on magnetizing inrush currents. In this case, discrimination between magnetizing inrush and fault currents is achieved through the pronounced harmonic content of the inrush currents. Various methods of harmonic restraint have been developed for this purpose.

2.8.4 Pilot

Pilot relaying is a form of unit protection which may be applied to the protection of long transmission lines and cables; and is generally not used to protect mine power systems. It employs the principles of differential relaying except that the protected zone terminals are separated by too great a distance to interconnect the current transformer secondaries in the manner described for differential relaying. Thus, an interconnecting channel must be employed to convey information between ends of the protected zone. The three types of channels in common use include the wire pilot, carrier current pilot, and microwave pilot. A short description of each type is as follows.

Wire Pilot Generally a two-wire telephone type circuit. Usually the most economical form of pilot protection for distances up to 5 or 10 miles.

Carrier Current Pilot Low voltage, high frequency (around 120 kHz) currents are transmitted along a power conductor to a receiver. This type of pilot becomes economical for distances too great for wire pilot protection.

Microwave Pilot A UHF radio system which normally operates at a frequency greater than 900 MHz. Microwave pilots are used when system complexity exceeds the technical or economic capabilities of a carrier current pilot.

Many different actuating schemes have been devised for the various types of pilot relaying. One simple example is that of current phase comparison. If the current at one end of a line is shifted by an angle of approximately 180° with respect to the current at the other end of the line, then one of these currents has has reversed and it is assumed that a fault has occurred. Instantaneous relay operation will then insure fast fault clearance.

2.9 Comparison of Electromechanical Relay Types For Phase Relaying

2.9.1 Coordination and Selectivity

Relay coordination and selectivity is a process of providing the fastest possible protection against faults and overloads while insuring that only the faulty element of the system is removed from service and the remaining healthy sections are left intact. In addition, backup protection should be provided for fault conditions in case of primary relaying failure.

Of the relaying schemes discussed previously, the unit protection devices (differential and pilot relaying) act instantaneously to clear the fault only if the fault is located in their zone of protection. Thus, selectivity is automatically maintained and no coordination with other protective devices is required. However, overload or backup protection is not provided by unit schemes. This protection must, therefore, be provided by supplementary relaying or fuses. It is common practice for the backup relaying to be of non-unit type in order to avoid common failure mechanisms in both primary and backup relaying. This is true even though unit protection is considered to be the most reliable type of relaying.

The non-unit protection schemes (overcurrent and distance relaying) do require coordination between devices in order to maintain selectivity. As a result, operating times are increased resulting in greater fault clearing times. Normally, this time increase is less pronounced for distance relaying than for overcurrent relaying. In addition, overcurrent relaying is more difficult to coordinate and requires more adjustment when the power system changes than does distance relaying.

One of the major advantages of non-unit protection, however, is that backup fault protection is inherent in the coordination scheme. Therefore, supplementary backup protection is not required as is the case with unit schemes. An additional advantage of non-unit schemes is that overload protection may be incorporated into the coordination procedure.

As a simplified example of relay coordination, consider the radial power system shown in Figure 2-19. In this example, it is desired to coordinate the path from the utility (bus 1) to the motor connected to bus 6. Circuit breakers and their associated relaying are assumed to be located on the inby sides of buses 1, 3 and 5 as shown. The maximum possible fault currents at buses 3 and 5 are assumed to be 3,000 A and 1,000 A respectively, when referred to the 7,200 V distribution system. Maximum load currents at buses 1, 3, and 5 are 500, 100, and 25 A referred to the distribution system. Motor starters are assumed which limit starting currents to less than the maximum load currents.

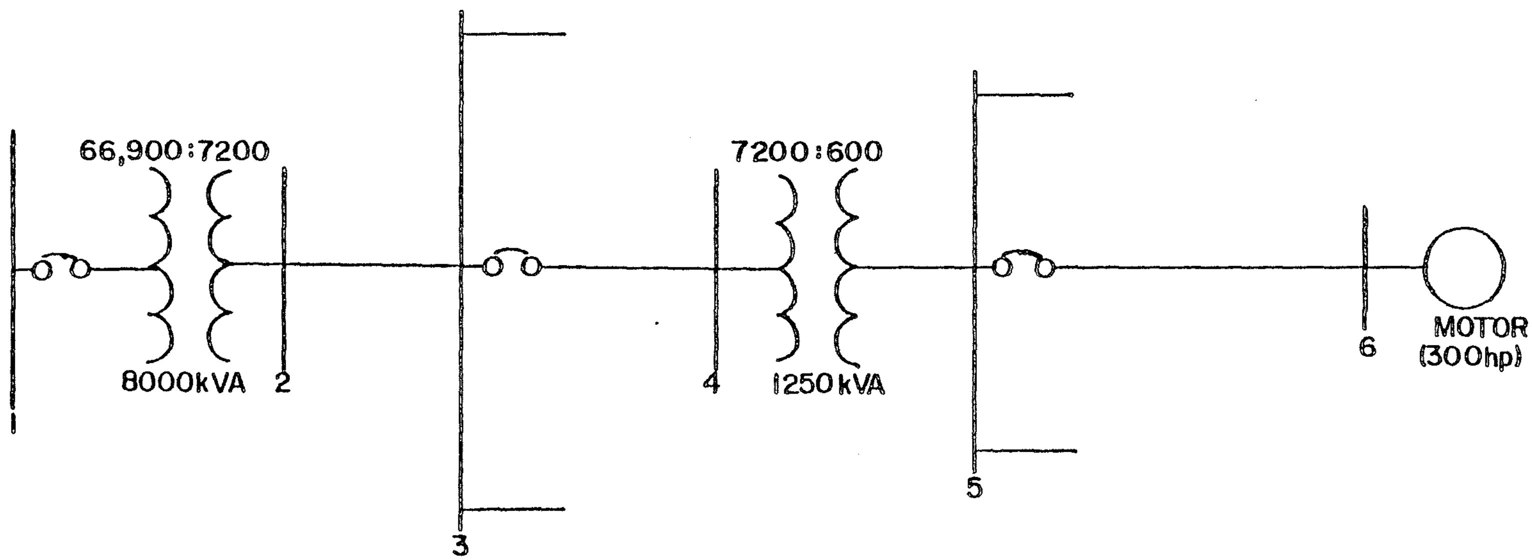


FIGURE 2-19

Example Power System

To coordinate this path using inverse-time overcurrent relaying, the pickup current and time dial setting for each relay must be determined. Consideration must also be given to the selection of current transformer ratios. Pickup settings are normally evaluated based upon overload protection requirements while time dial adjustments are usually made as a result of required selectivity between primary and backup relays. These relays are coordinated in pairs at maximum fault current. To check for proper coordination throughout the range of possible fault currents, it is common procedure to plot the inverse-time relay characteristics as shown in Figure 2-20. Such a graph becomes even more important for systems using mixed inverse-time overcurrent relays or other protective devices.

Construction of the coordination graph is a complex procedure which involves calculation of fault and load currents, referring these currents to the graph reference, and the determination of pickup and time dial settings (see Section 4.3). In this simplified example, however, the pickup currents are assumed as 500, 100, and 25 A and the time dial settings are determined based upon a 0.4 second coordinating time interval (allowed time for breaker operation and over-travel plus a safety factor) between relays. All currents are already referred to the distribution system and current transformer ratios are assumed to be unity for simplicity. Extremely inverse relays (Westinghouse CO-11) are used and the resulting log-log coordination curves are given in Figure 2-20.

Aside from the complexity of the coordination process, a second major disadvantage of inverse-time overcurrent relaying should be apparent from Figure 2-20. Due to the necessity of maintaining selectivity, fault clearance times increase as the fault is moved nearer to the source. At the same time, fault currents increase. Thus, the greatest fault currents may require the longest time for clearance.

This situation may be eased somewhat by the addition of instantaneous overcurrent units to the inverse-time relays. These units are assumed to operate in 10 m sec. and are set at 3,600 A, 1,200 A and 100 A for the relays at buses 1, 3, and 5. The time savings achieved may be seen by comparing Figure 2-20 with Figure 2-21. Since a significant improvement with little added cost can sometimes be obtained in this manner, it is common practice to combine inverse-time and instantaneous protection in a single package.

Coordination of distance relays is a simpler procedure than that for overcurrent relays. The definite-distance method provides the fastest fault clearance and will be the one considered here. As an example, a proposed procedure will be applied to the simplified system shown in Figure 2-19 using the directional impedance type relay. Impedance settings will be given referred

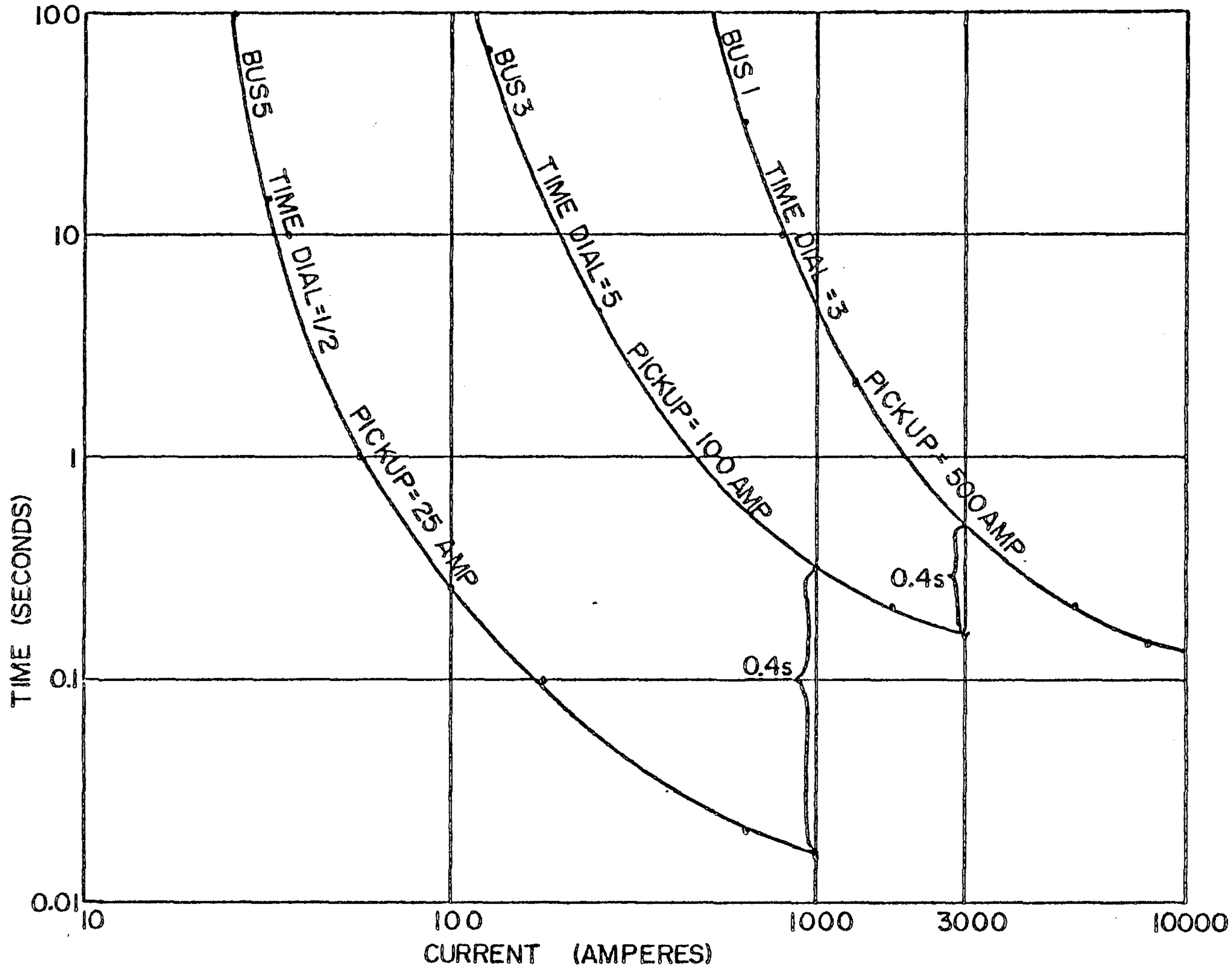


FIGURE 2-20

Plot of Inverse-Time Relay Characteristics
for the System Shown in Figure 2-19

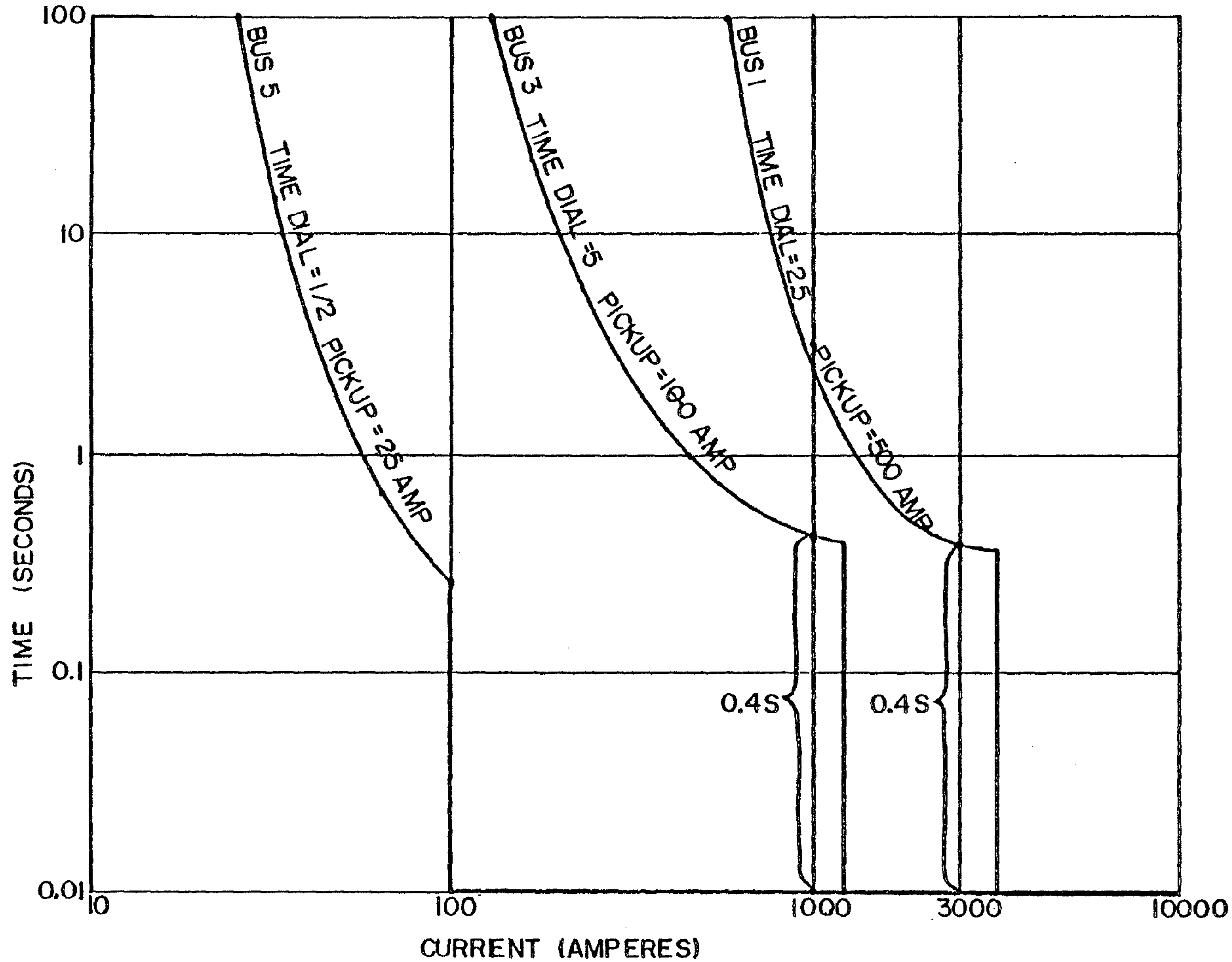


FIGURE 2-21

Addition of Instantaneous Characteristics to Figure 2-20 to the distribution system although actual settings would have to be referred to the relay's location using transformer turns ratios. For simplicity, the current and potential transformers supplying the relays are assumed to have unity turns ratios.

Results of applying this proposed coordination procedure are shown in Figure 2-22. Instantaneous settings are again assumed to be 10 m sec., the coordinating time interval is maintained at 0.4 seconds, and motor starters are still assumed to limit starting currents. The impedance relay at bus 5 is a single zone unit, bus 3 has a two zone unit, and the relay at bus 1 is a three zone device. The impedance values (referred to the distribution system) are determined as follows. These calculations assume that the utility voltage is maintained during a fault and that the relays are equipped with voltage memory which will allow zone 1 circuit breaker operation if the voltage at that unit approaches zero during a fault condition.

<u>At Bus 5</u>

$$\frac{\frac{7200}{3}}{25} = \frac{4157}{25} = 166\,\Omega$$ = impedance for normal load on bus 5

$$0.8\,(166) = 133\,\Omega$$ = setting for zone 1. (instantaneous)

NOTE: 0.8 is a safety factor to prevent false tripping due to relay overreach.

<u>At Bus 3</u>

$$(0.8)\left(\frac{4160}{1000}\right) = 3.3\,\Omega$$ = setting for zone 1 (instantaneous)

$$(0.8)\left(\frac{4160}{100}\right) = 33.3\,\Omega$$ = setting for zone 2 (time delay backup for for the load connected to bus 5)

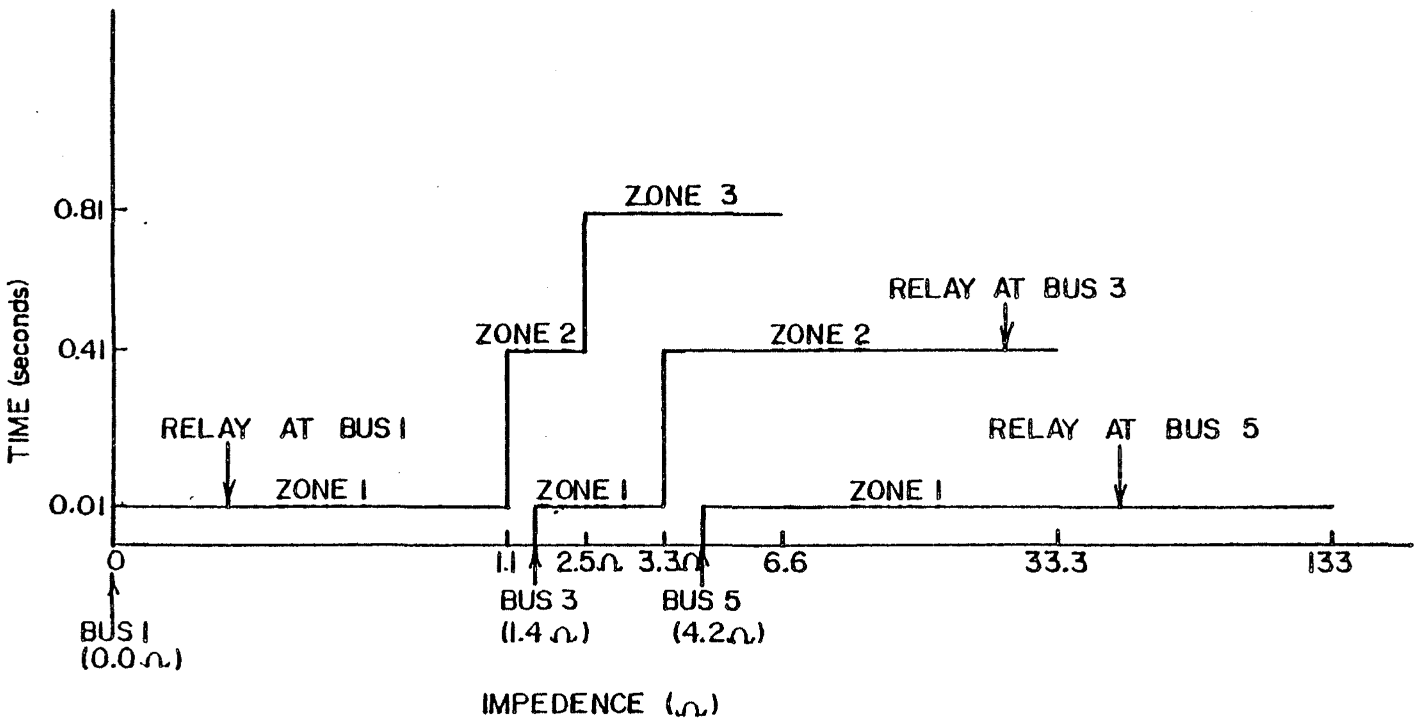


FIGURE 2-22

Results of Using Distance Relays to
Protect the System Shown in Figure 2-19

At Bus 1

$(0.8) \ (\frac{4160}{3000}) = 1.1\Omega =$ setting for zone 1 (instantaneous)

$1.4 + 0.4\ (4.2 - 1.4) = 2.5\,\Omega =$ setting for zone 2 (time delay backup)

NOTE: 40% of the connection from bus 3 to bus 5 is backed up by this zone of protection. Refer to Figure 22 for a graphic illustration of how these figures are obtained.

$(0.8) \ (\frac{4160}{500}) = 6.6\,\Omega =$ setting for zone 3 (time delay backup)

A second advantage of a distance relaying scheme, other than simplified coordination, is that the time for initiation of fault clearance is not cumulative towards the power source as is the case for overcurrent relaying. This can be seen by comparing Figures 2-21 and 2-22 for a 1,000 A arcing fault (non-zero fault impedance) in the 8,000 kva transformer. This corresponds to an impedance of $4.16\,\Omega$ such that the zone 3 protection of the distance relay at bus 1 would operate this relay in 0.81 seconds. The corresponding overcurrent relay at bus 1 would operate in approximately 4.5 seconds. For a 2,000 A fault ($2.1\,\Omega$), the corresponding times are 0.41 and 0.8 seconds.

It should be pointed out that this proposed procedure for distance relaying in mine power systems differs somewhat from standard application of these relays for utility transmission line protection. As such, additional research would be required to insure the feasibility of this approach.

Combinations of relaying schemes, both unit and non-unit, are also possible giving rise to many approaches for system protection. Of these, the addition of unit devices to existing overcurrent protection schemes appears to offer a potential for improvement. This can be seen by considering again the simplified power system shown in Figure 2-19. If differential protection were added to the 8,000 and 1,250 kva transformers, then all faults within these transformers would be cleared by instantaneous (no intentional delay) relay operation. The existing overcurrent relaying (Figures 2-20 or 2-21) would then provide backup protection for these transformers. Thus, for the 1,000 and 2,000 A arcing faults in the 8,000 kva transformer discussed previously, fault clearance would be initiated in approximately 50 msec. by the primary relaying. In some situations, speed improvement of the overcurrent relaying may also be possible. Similar comments could also be made for wire pilot protection of cable/transformer combinations (i.e., buses 3, 4 and 5 in Figure 2-19). The limiting factor would be the increased cost for this additional protection.

2.9.2 Cost

The cost of a relaying system cannot be accurately measured until the combination of schemes to be utilized is accurately defined. This difficulty is compounded by the need for additional back-up protection when unit schemes are applied. However, a relative cost estimate is possible and will be presented in this section.

The least expensive means of system relaying is with inverse-time overcurrent protection as shown in Figure 2-20. The relative cost of this protection scheme will be designated as 1.0 for reference. This corresponds to a minimum of $400.00 (1980 dollars) for a single phase relay and its current transformer. An estimate of relative costs for other protective schemes is then as given in Table 2-7. Only those types considered to have potential application in coal mines are listed. Thus, for example, carrier and microwave pilot schemes are not included due to their very high cost and the lack of sufficient distance between protection points in coal mines to justify their application. Also, if combinations of procedures are utilized such as differential or wire pilot protection with overcurrent backup, the relative costs are cumulative.

2.9.3 Summary

The comparison of phase relaying schemes for mining applications is summarized in Table 2-8. Based upon this comparison and the preceding discussions, it may be seen that the procedure normally used for coal mine power system protection, inverse-time overcurrent relaying with instantaneous attachments (Figure 2-21), is a reasonable compromise between cost and performance. Distance relaying techniques, although they offer advantages in operating speed and ease of coordination, would not appear attractive due to high initial cost. In addition, applications of distance relaying in conjunction with across the line motor starting and/or short feeders would cause additional difficulties.

The greatest potential for improvement of existing overcurrent protection schemes appears to be in the application of unit protection which will complement existing phase overcurrent techniques. Ideally, this would include wire pilot

TABLE 2-7

Estimated Relative Costs of Protective Schemes

Type of Protection	Relative Cost
Inverse-time overcurrent	1.0
Inverse-time overcurrent with instantaneous unit	1.2
Inverse-time overcurrent with directional unit	2.0
Inverse-time overcurrent with directional unit and instantaneous directional unit	3.0
Voltage controlled overcurrent	3.5
Phase sensitive overcurrent	3.5
Percentage differential	3.5
Zone distance	6.0
Wire pilots	7.5

TABLE 2-8

Comparison of Phase Relaying Schemes

	Over-current	Distance	Differen-tial	Wire Pilot
Cost	Low-Medium	High	Medium	High
Difficulty in achieving coordination and selectivity	High	Medium	Low	Low
Dependence on power system changes	High	Medium	Low	Low
Difficulty of installa-tion and maintenance	Medium	Medium-High	Medium-High	Medium-High
Provides backup protection	Yes	Yes	No	No
Provides overcurrent protection	Yes	Yes	No	No
Time for initiation of fault clearance	Low-High	Low	Low	Low
Time for clearance of overloads	High	Low	Infinite	Infinite
Reliability	Medium	High	Very High	Very High

protection between breaker points and differential protection of buses, with the existing overcurrent scheme serving as coordinated backup protection. However, the cost of such an arrangement would be very high, such that its use could not be justified economically. A possible approach which would offer improved protection and may have some economic justification, however, would be the use of differential protection on the main and section transformers. From an economic point of view, manufacturers recommend differential protection of all transformer banks rated 1000 kva or higher. Utilities differ somewhat from this view in that transformers rated between 1000 and 5000 kva are often not provided with differential protection. Transformers above 5000 kva are commonly protected in this manner. Thus, section transformers would normally be within or below the discretionary range, while main transformers would normally be rated within or above this range.

2.10 Static Overcurrent Relaying

The following text describes four commercially available static overcurrent relays and makes a comparison between static relays in general and electromechanical relays.

A static relay consists of two basic operational units. The first, called the sensor or input circuit, receives information describing the status of the power system (typically from current and/or potential transformers) and, through the use of solidstate circuits, makes the decision whether or not a circuit breaker should be opened. The second unit, called the trip initiation circuit or output circuit, contains a solid-state switch (a transistor, SCR, or triac) which, when instructed to do so by the sensor circuit, permits current to flow into the trip coil of a circut breaker thus causing the breaker to open. An alternative to using a solid-state device for trip initiation is to use a set of mechanical contacts in the output circuit. Both types of output circuits are available in the various static relays currently being manufactured.

2.10.1 Commercially Available Static Overcurrent Relays

In order to gain an understanding of how static relays work, specifications for four commercially available static relays were obtained. The four relays are listed in Table 2-9. It should be noted that no attempt is made to compare the operational performance of the four relays discribed as this would require extensive testing and is beyond the scope of work.

TABLE 2-9

Relay Models and Manufacturers Used in Study

Relay Manufacturer	Model
Basler Electric Co.	BE1-51
General Electric Co.	SFC
Gould-Brown Boveri	ITE-51
Westinghouse Electric Inc.	SCO-T

Basler Electric Digital Overcurrent Relay (BE1-51). The elementary diagram of the Basler BE1-51 relay is shown in Figure 2-23. (63) The input circuit consists of a rectifier and a burden resistor. The ac current from the CT is fed through the burden resistor and the resultant voltage is rectified by the rectifier bridge. In the instantaneous relay circuit, the rectified output voltage is compared to a dc reference signal established by the instantaneous tap control. When the rectifier signal becomes greater than the instantaneous reference signal, the Instantaneous Pickup Sensing circuit energizes the Output Driver to trigger the trip circuit.

The time-overcurrent relay functions in a very different way. The time-overcurrent tap is designed so that when the input current from the CT has reached the tap setting, the input voltage to the rectifier is approximately 30VAC. The rectified output voltage, produced by this input, will be sufficient to allow the Time Pickup Sensing circuit to start the counter. This counter keeps track of the time that the input current has exceeded the current tap value selected. Simultaneously, the output voltage of the rectifier is digitized by the Analog to Digital Converter (ADC). The output of the ADC, representative of the input voltage level, acts as an input address to Memory. At the location in memory corresponding to the input address a value is stored which corresponds to the amount of time (i.e., counter value) that the present overcurrent condition may exist before a trip is desired. Since each current value causes the ADC to produce a different address and consequently a different output allowable time (i.e., count) from memory, every value of overcurrent will be allowed a different amount of time to persist; thus the time characteristic of the relay is generated. The comparator simply compares the allowable count from memory with the counter value and energizes the output driver once the allowable count is surpassed by the counter. As the magnitude of the overcurrent condition changes, so does the input to memory; thus the allowable time delay is updated. Updating takes place 180 times each second. If the overcurrent condition is removed, the

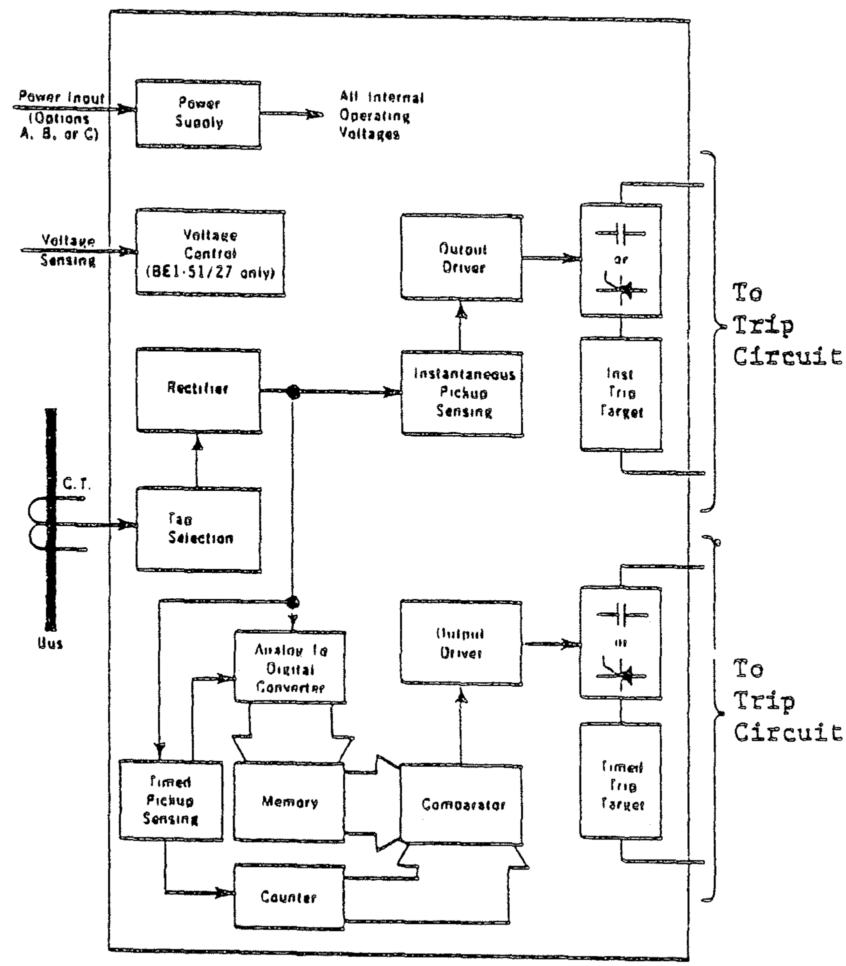


FIGURE 2-23

Elementary Diagram of the Basler BE1-51 Relay

Time Pickup Current Sensing circuitry aborts the time delay trip sequence by resetting the counter. By changing the contents of the memory, any desired time-current characteristic can be obtained, including those available with an electromechanical relay. The user of the BE1-51 has the option of selecting either a static (SCR) or mechanical type of output circuit. The BE1-51 may be powered by an external supply or by an additional CT placed on the power conductor.

General Electric Static Time Overcurrent Relay (SFC) An elementary block diagram of the SFC relay is shown in Figure 2-24.[64] The instantaneous-overcurrent unit is an electromagnetic unit that operates on the same principle as the General Electric electromagnetic IAC type relay. The time-overcurrent relay works as follows: The power circuit CT secondary current flows through the signal sensing CT primary where a second transformation reduces further the current to the rectifier. The rectified current is fed through one of six burden resistors which is chosen by means of the Current Tap Block. The voltage across this burden resistor is e_i of Figure 2-24 and is proportional to the power circuit CT current. The voltage e_i is then delivered simultaneously to the Function Generator and Pickup Level Detector. The Pickup Level Detector switches its output voltage, e_o, to the pickup state which enables the time circuitry only when e_i is greater than the pickup value set by the Pickup Calibrate control. When e_i is smaller than the Pickup Calibrate voltage, the timing circuitry is reset.

The timing circuitry consists of the Function Generator, Time Dial and Linear Ramp Generator. The Function Generator is a wave shaping circuit, composed of operational amplifiers, diodes and resistors, which operates nonlinearly on e_i to give e_f. The signal e_f in conjunction with the Linear Ramp Generator and Time Dial, gives the characteristic time-current curve desired. The Linear Ramp Generator simply integrates e_f to obtain these various functions. The Time Dial sets the integrating time constant by switching in one of ten discrete resistors to give one of the discrete curves normally available with an electromechanical relay.

The output signal of the timing circuitry, e_r, is applied to the level detector which compares e_r with a fixed reference value. The fixed reference value is precisely adjustable by means of the Time Calibrate control. When e_r exceeds the reference value, e_t takes on a negative voltage which causes the output circuitry to trip the output relay. Otherwise, e_t is sufficiently positive to inhibit any tripping action.

The output circuit of the SFC is electromechanical in nature, and the SFC receives its input power from the power circuit CT, or from an external supply.

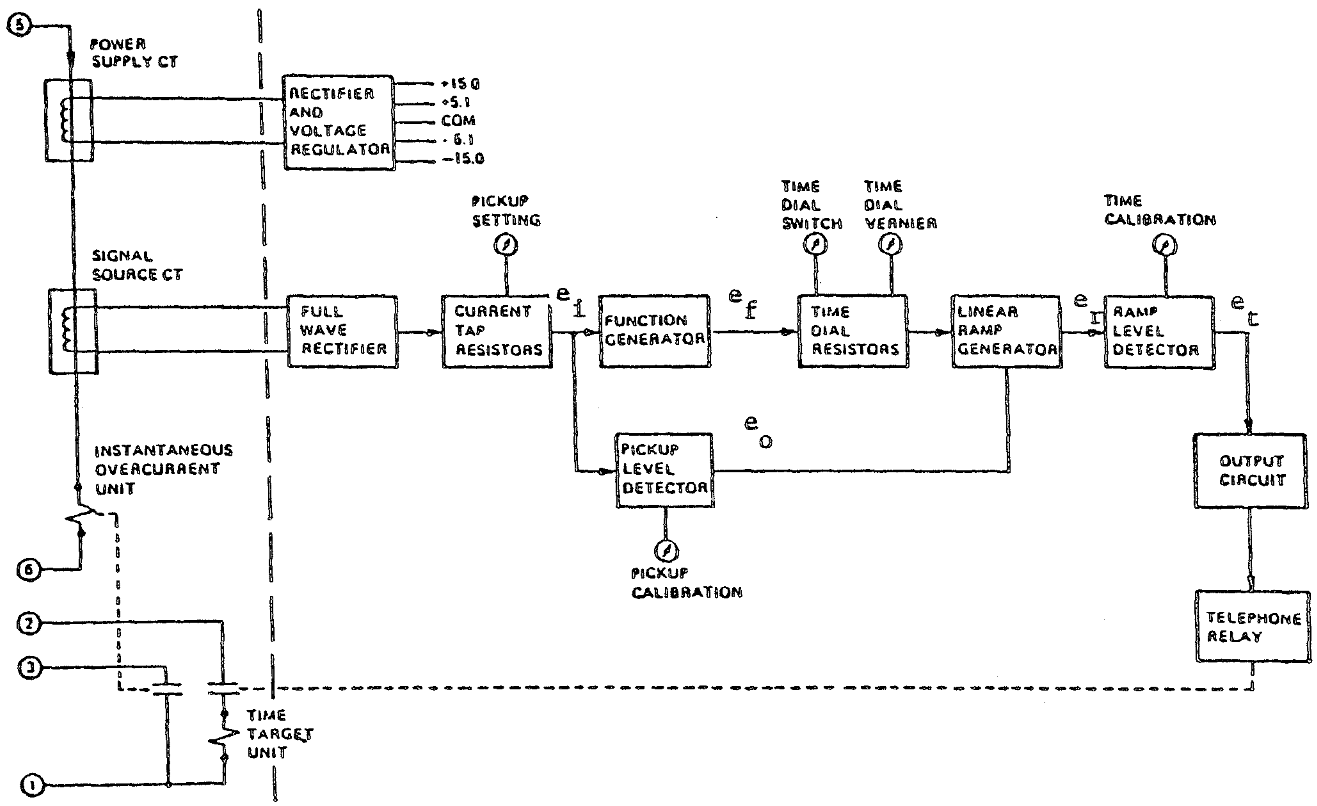


FIGURE 2-24

Elementary Diagram of General Electric SFC Relay

Gould-Brown Boveri Solid State Overcurrent Relay (ITE-51) Figure 2-25 shows the ITE-51 circuit which can be constructed to perform either a time-overcurrent or instantaneous function.[65] The input circuit of the ITE-51 is similar to that of the SFC unit. The difference is that the current derived from the power circuit CT is fed first through a tapped burden resistor, then the ac voltage is rectified by the diode bridge to give V_1.

The dc rectified voltage, V_1, produced by the diode bridge is made available to the Reference, Pickup/Reset, and Timing circuits. The Reference circuit uses V_1 to derive a fixed reference voltage V_F. The Pickup/Reset circuit derives its test pickup value, V_P, from a potential divider and compares V_P with V_F. The pickup value is changed by using either the taps on the primary of the input transformer (not shown) or by varying the value of the burden resistor, R_B. For example, by increasing R_B, the value of current I_1 needed to exceed the fixed reference voltage V_F, decreases; thus the pickup value is decreased.

The Timing circuit is enabled by the Pickup/Reset circuitry only if $V_P > V_F$. Enabling of the Timing circuit is achieved by preventing the pickup transistor from conducting

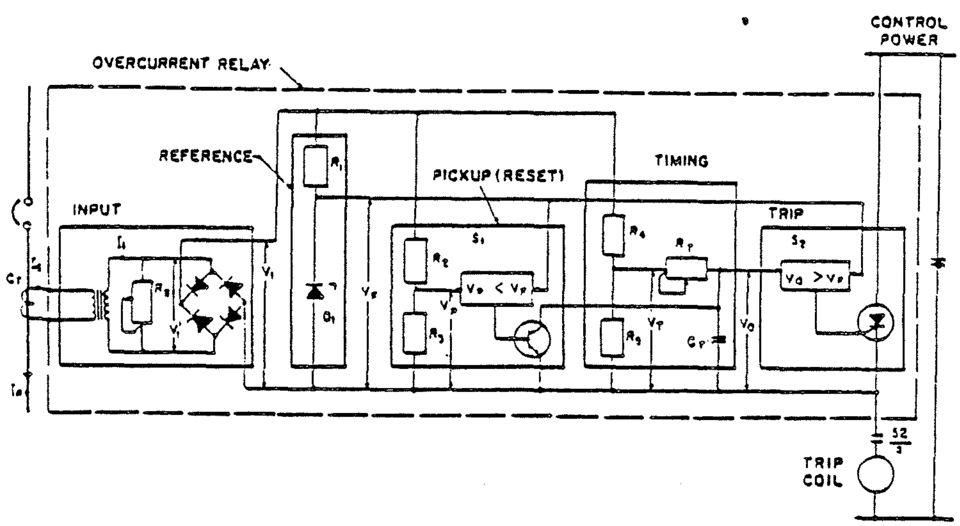


FIGURE 2-25

Elementary Diagram of Gould-Brown Boveri ITE-51 Relay (i.e., preventing any charge delivered to C_T from being bled off by the transistor). The Timing circuit consists of a variable resistor, R_T, which is in series with C_T and fed by V_T. The voltage V_T is a portion of the dc input voltage V_1 and is obtained using a potential divider. When enabled, C_T will acquire a charge and develop a voltage V_O at a rate approximately proportional to

$$V_O = V_T e^{-t/R_T C_T} \qquad (2\text{-}1)$$

where the variable t represents time. Once V_O exceeds V_F, the output SCR is tripped.

The charging time of the simple RC circuit gives the characteristic curve desired. Varying R_T, which can be done in a continuous rather than discrete manner, shifts the characteristic in time. The characteristic curve generated by this simple time constant is inverse in nature. More complex charging networks, such as RC ladder networks, can be used to achieve other characteristics (i.e., very inverse, extremely inverse, etc.).

The instantaneous-overcurrent circuit functions analogously with the instantaneous curve also being generated by a simple RC circuit. An adjustable potentiometer provides the variable instantaneous-overcurrent pickup level.

Westinghouse Electric Solid State Overcurrent Relay (SCO-T). An elementary diagram of the input circuitry of the SCO-T relay is shown in Figure 2-26. As with the other relays previously discussed, this relay has the option of including an instantaneous trip unit. The input circuitry operates as follows. A signal source CT feeds a bridge rectifier which feeds a burden resistor to develop a voltage proportional to the line current. The input voltage is supplied simultaneously to the instantaneous and time-overcurrent relay circuits.

The instantaneous-overcurrent circuitry uses a continuously variable potentiometer as the Instantaneous Tap Multiplier to change the pickup level. The output of this pot is compared with a manually set reference voltage, V_{REF}. Whenever the pot output voltage exceeds V_{REF}, the Instantaneous Trip Level detector enables the Line Drive which trips the output circuitry.

The time-overcurrent circuitry of the SCO-T relay uses an approach which is a combination of the technique of RC approximation used in the ITE-51 relay and the digital-counter time-delay approach used in the BE1-51 relay. The voltage across the burden resistor is applied to an RC curve shaping network to obtain the relay's characteristic curve. The output of the RC network is compared to reference voltage, V_{REF}. If the output of the RC network exceeds V_{REF}, the comparator changes state which

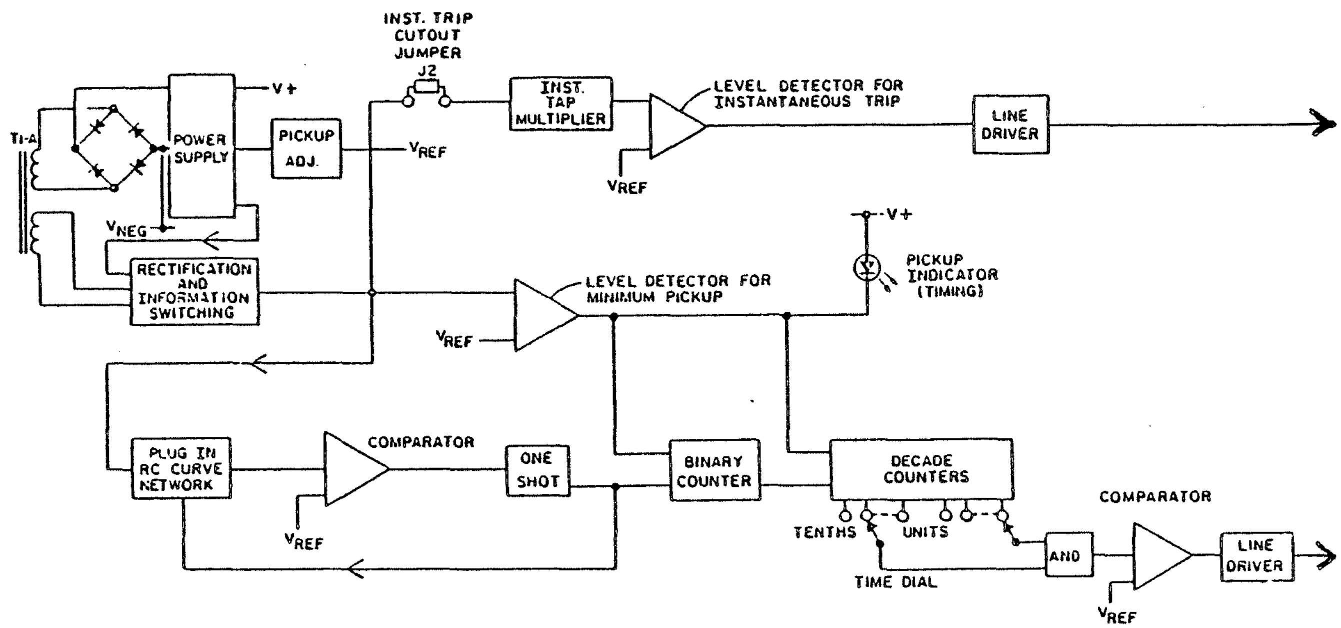


FIGURE 2-26

Elementary Diagram of Westinghouse SCO-T Relay triggers the one shot to reset the RC timing circuit and advance the Binary Counter. Note that the Binary Counter is enabled by the Minimum Pickup Level Detector only if the input current is above the minimum pickup level. Otherwise, the Binary Counter is kept inactive.

After reset, the RC network begins charging again, repeating the above sequence until the proper binary count is reached. The proper count is determined by the time-curve characteristic desired. When the correct count is attained, the Decade Counter/Decoder circuit is incremented. The decoder output is connected to the Time Dial thumbwheel switch which is set manually to detect one of 99 possible states of the Decade Counter. For example, if the Time Dial thumbwheel switch is set on 54, then the Binary Counter must cycle through its correct count 54 times in order for the Decade Counter output to energize the line driver. Since two digits are used, both thumbwheel switches and both decade counters must be precisely matched in order to activate the comparator and enable the time-overcurrent line driver. The time-overcurrent line driver is used to trip the time-overcurrent relay.

The line drivers in Figure 2-26 are connected to solid state circuits which operate electromechanic relays in the trip circuit.

The preceeding material illustrates four approaches to solid state relay design. Relays are also available which are specifically designed for use as ground-fault relays on high resistance grounded power systems. Although specifications on these relays are not included here, it should be apparent that relays are available which meet the specifications discussed in the chapter on ground-fault relaying.

2.10.2 Comparison of Static and Electromechanical Relays

The following material consists of a topic-by-topic comparison of static and electromechanical relays. Some of the subjects in the comparison were gathered in a mining industry survey designed to find the prevalence, acceptance, problems with, and comments about the use of solid state overcurrent relays. Many of the people contacted asked that their names be withheld. Where this information is included, it will specifically be referenced as[66], which is the personal communication reference listed in the references.

Environmental Contaminants

Many static relays (SR's) use hermetically sealed components and epoxy-coated printed-circuit boards for protection from environmental contaminants. Electromechanical relays (EMR's), however, usually have metal components which are exposed to the environment. High humidity and dust can increase the rate of corrosion and oxidation of metal components including relay contacts. Increasing contact resistance due to corrosion and oxidation causes heat production in the contacts (during relay operation) which further enhances this problem.[62,67,68,69] It has also been reported that metal filings which interfere with proper operation have been found on the discs of induction disc relays.[66]

Shock and Vibration

SR's which have no moving parts are more resistant to false tripping due to seismic activity than are EMR's. This may be particularly important in areas where blasting or vibration of electric machinery can cause nuisance tripping. It has also been reported that induction disc relays are sometimes broken while in transit due to rough handling, while SR's are unaffected.[66]

Burden

The burden of SR's is typically lower than that of EMR's, as is illustrated in Table 2-10 which compares the burden of the SFC with that of the IFC relay. Where extremely low burdens are required, some SR's have the capability of using an external power supply. The burden of an SFC relay on the lowest tap, with an external power supply, is 0.06 ohms.[64]

Size

A typical overcurrent SR occupies approximately one-third the panel space of a typical EMR. While this is of little consequence with new equipment, it presents a problem with existing equipment since an SR may not fit into the EMR case, thus requiring retrofitting.

Reset Time, Overtravel, Ratchetting

When the input to an induction disc relay exceeds the pickup value, the disc begins to move. The inertia of the disc causes continued motion after the actuating force is removed. This continued motion is known as overtravel. Overtravel constitutes a disadvantage since a relay may continue to close and disconnect a sound portion of the power system after a downstream relay has disconnected the faulty section. The overtravel in a relay is a function of the relay design, pickup setting, time dial setting, and the fault current magnitude.

Ratchetting may be defined as the accumulation of overtravel due to successive power system transients. Successive transients closely spaced in time may cause the relay actuating quantity to oscillate above and below the pickup value. Each

TABLE 2-10

Burden Comparison of SFC and IFC Relays

Time Overcurrent Relay Burdens
(Complex impedance in Ohms on Lowest Tap)

Relay	(0.5-4) Range				(1.5 -12) Range			
	1X	3X	10X	20X	1X	3X	10X	20X
Inverse-Electromechanical*	22.0	10.00	5.00	3.66	1.45	0.65	0.32	0.24
Inverse-Static	6.42	1.5	0.42	0.31	0.72	0.174	0.046	0.033
Very Inverse-Electromechanical	4.15	4.15	2.90	2.20	0.59	0.50	0.40	0.25
Very Inverse-Static	6.42	1.5	0.42	0.31	0.72	0.174	0.046	0.033
Extremely Inverse-Electromechanical	1.60	1.60	1.60	1.60	0.17	0.17	0.17	0.17
Extremely Inverse-Static	6.42	1.5	0.42	0.31	0.72	0.174	0.046	0.033

* The inverse electromechanical is not available in the (1.5-12) ampere range. The burdens given above are for the 2-16A relay on the 2.0 ampere tap. Since the burden of the inverse static relay is essentially constant irrespective of tap, the static relay burdens can be compared with the inverse electromechanical directly.

time the actuating quantity exceeds the pickup value, a torque is applied to contacts which are found in a partially closed condition due to the previous transient's torque, non-zero reset time and overtravel characteristic. Ratchetting to an undesired trip is usually caused by successive downstream faults or successive motor startings.

The reset to pickup ratio of an induction disc relay is inherently high; typically between 95% to 100% with friction keeping the value below 100%. Once the actuating quantity drops below the reset value the relay will begin resetting which may take from 15sec to 60sec for an extremely inverse relay. If another fault occurs during this time, the relay will not be in the correct reference position and may falsely trip due to the modified time-overcurrent characteristic.

Solid state time-overcurrent relays have reset times on the order of .01 seconds and, therefore, exhibit negligible overtravel and ratchetting. SR's also have reset to pickup ratios which are typically in excess of 98%.[70]

Accuracy

SR's are far more accurate than their EMR counterparts for several reasons. First, the SR curves rely on either preprogrammed data, an RC time constant or a nonlinear curve shaping network which does not change with time; hence, their time-overcurrent characteristics are highly repeatable. Because of the electronic nature of the relays, high input sensitivity can be achieved if desired. Time delay data for overcurrent EMR's is specified only for overcurrent conditions which are greater than or equal to 1.5 times the pickup setting. Time delays for less severe overcurrent conditions are inaccurate since the small torque generated and mechanical losses are comparable in magnitude. Most solid state relays are capable of accurate time delays when the actuating quantity is only 1.1 times the pickup setting.

As the time dial setting of an EMR is decreased, the relay operates faster and more of the power delivered to the induction disc is converted into kinetic energy. Thus as the time dial setting changes so does the shape of the time-overcurrent characteristic. SR's have characteristics which are independent of the time dial setting.

The frequency content of the signal applied to a relay is another source of error. The uniformity of the SR's frequency response makes their performance more predictable.

As mentioned earlier, the lower burdens associated with SR's also contribute to the accuracy of the relay by lessening the problem of power circuit CT saturation when the CT secondary current is many times the pickup value.[70,71,72]

Reliability

Reliability of electromagnetic relays is known to be high. The reliability of SR's is known to have the potential for exceeding that of EMR's but the actual reliability in a mine environment is largely unknown. As a first approximation at estimating the reliability of EMR's, published reliability data was reviewed from a survey of industrial plants conducted by the Reliability Subcommittee of the IEEE Industrial and Commercial Power Systems Committee. The results of this survey set the failure rate of protective relays in industrial applications at .0002 failures/unit year with an average down time of 5.0 hours. This result is based on a sample size of 3 industrial plants, 30,600 unit years and 6 reported failures. This is believed to reflect the EMR failure rate since SR's make up only a small portion of all industrial protective relays. It is interesting to note that out of the 12 industry classifications used to group data, 3 industries had zero participation in the survey; these were auto, cement and mining.

A mining industry survey was conducted by telephone with one purpose being to get a feel for SR reliability. Seventeen engineers, electricians and managers were contacted with an accumulation of 132.2 unit years of SR service time between them. This survey found 75 time-overcurrent SR's in service with 0.2 years to 5 years service life and mean sample service life of 1.76 years.

Of the 17 people interviewed, only one reported an unsuccessful application of SR's. The problem consisted of nuisance tripping and was believed to be a result of severe electrical transients on the power system. The overall impression of people who had experience with SR's in mining applications was very favorable.

Cost of Procurement

The survey of time-overcurrent relay manufacturers set the cost of procurement of a single-phase time-overcurrent electromechanical relay with no instantaneous attachment at about $190.00. The corresponding SR costs about $270.00. A general rule of thumb is to add a 30% to 40% premium on the cost of an EMR to get the price of an SR.66

Total Cost

Total cost is the ultimate characteristic which will determine whether SR's capture a major portion of the mine power system protecting relay market. Any cost analysis must take the following items into consideration:

- Initial Cost
- Maintenance Cost
- Replacement Cost
- Cost of Faulty Operation

Only when all of these factors are considered can a valid comparison be made between SR's and EMR's.

2.11 Summary

The preceding material has served to introduce the reader to many of the concepts involved in designing a protective relaying system for a coal mine, and to provide a list of references for those interested in a more in depth study of any of the subjects covered. Some of the more significant topics covered include:

- power system physical layout
- use of instrument transformers
- pertinent Federal regulations
- function and use of overcurrent relays

The material in the following chapters expands on topics of phase and ground overcurrent relaying. If the reader intends to perform a relaying system design or evaluation using the material presented here, it is highly recommended that one or more of the following references be obtained for "backup" support.[20,21,23,27,46,60]

3.0 GROUND FAULT RELAYING

3.1 Introduction

The purpose of this section is to establish guidelines which can be used in the design of ground-fault relaying for coal mine electric power distribution systems. The first topic discussed is relay system coordination using time delays to isolate faulted portions of the power system. The next section covers ground resistor sizing. Current transformer burden driving capability, an area in which many coal mine power systems are deficient, is covered next. The next topic discussed is groundovercurrent relays, followed by a section which introduces an analytical approach for determining optimal pickup settings for ground-overcurrent relays.

3.2 Coordination

One method of implementing a ground-fault relaying system is to use instantaneous ground-overcurrent relays in all switchhouses, and set them slightly higher than the phase unbalance current in the power system. This would result in a maximally safe system with respect to ground fault sensitivity and fault removal time. Unfortunately, with this scheme, a ground fault occurring anywhere in the system would cause the entire system to be deenergized, which negatively impacts power system availability and hinders fault location.

An alternate method is to coordinate the ground-fault relays with suitable time delays and trip levels so that a faulted section of the power system can be isolated, thereby maximizing power system availability during and after a ground fault. Although this alternative may appear to compromise personnel safety for system performance, safety is not compromised for the following reasons:

- all components of the distribution system are in intake air

- the amount of energy available at a ground fault is limited by the grounding resistor

- machine frame-to-ground voltage during a ground fault is limited by the grounding resistor to less than 100 volts

In coal mine ground-fault protection systems, coordination is achieved, in part, by providing increasingly large circuit breaker trip delays for switchhouses starting at the load and moving back to the source. The most inby switchhouses, i.e., those directly connected to load centers, should use instantaneous relays. The next outby switchhouse should have a time delay of about 0.4 seconds, the next 0.8 seconds, and so forth. This time interval, 0.4 seconds, between switchhouses, is a generally accepted coordination interval which includes delay for opening of the next inby breaker, relay overtravel, and a safety factor. Figure 3-1 illustrates the use of time delay to achieve coordination of ground fault relays.

In addition to providing suitable time delays, there are several other system parameters which must be considered when designing a ground fault relaying system. These parameters are discussed in the following sections.

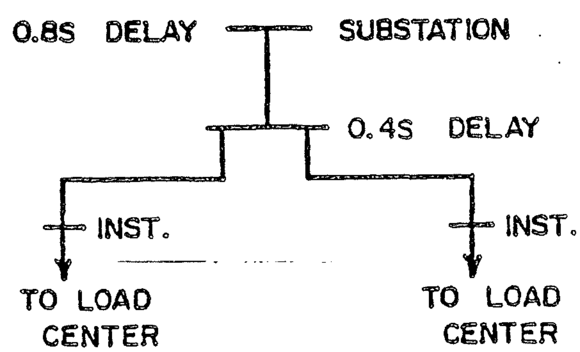


FIGURE 3-1

Use of Time Delays to Achieve Coordination of Ground-Fault Relays

3.3 Ground Resistor Sizing

The size of resistor used to ground the neutral of a mine power system determines the maximum amount of current that can flow in the ground during a ground fault. The upper limit on the magnitude of ground current flow is defined as that current which will cause no more than 100 volts to be dropped across the mine ground system, external to the grounding resistor (Sections 75.801, 77.801 of CFR 30). Ground system voltage drop is a function of the following parameters:

- o number and size of ground conductors
- o coupler and connection contact resistance (usually neglected)
- o maximum ground current

When sizing a grounding resistor, it is generally good practice to limit ground current to as low a value as possible to minimize burning damage which may occur at the fault location. However, care must be taken to ensure that the ground-fault current is not limited below established design guidelines.

Minimum ground-fault current is not specified by any mining law. However, it can be approximated by the generally accepted rule that resistive ground current should equal or exceed system capacitive charging current in order to damp out transients which might otherwise occur during faults. System capacitance to ground is a function of the following parameters:

- o phase conductor-to-shield capacitance in cables
- o capacitance of surge and power factor correcting capacitors which are connected line to neutral
- o coupler, bussbar, and transformer capacitance to ground (usually neglected)

Cable capacitance can be calculated by treating the individual shielded conductor as a coaxial cable and using Equation 3-1, which gives the cable capacitance to ground in Farads per Meter of cable length.

$$C = \frac{2\pi\varepsilon}{\ln \frac{d_o}{d_i}} \qquad (3\text{-}1)$$

where:

C = capacitance in Farads/Meter (F/M)

ε = permittivity constant of cable dielectric (F/M)

d_o = outer diameter of cable dielectric (cm)

d_i = inner diameter of cable dielectric (cm)

Approximate capacitance to ground for various sizes of mine power feeder cable are given in Table 3-1.

TABLE 3-1

Approximate Capacitance to Ground for Various Sizes of Mine Power Feeder Cable

Conductor Size	#2	1/0	2/0	4/0	250	300	350	500
Line To Ground Capacitance Per Conductor* (pF/M)	259	270	331	393	419	449	479	553

* These values were calculated for 175 mil conductor insulation with a relative permitivity constant of four.

Equation 3-2 gives the total capacitive charging current as a function of phase-to-ground capacitance and line-to-neutral voltage.

$$I_c = 3 \frac{V_{l-n}}{X_c} \quad (3\text{-}2)$$

where:

I_c = total capacitive charging current

V_{l-n} = system line-to-neutral voltage

X_c = per phase capacitive reactance to ground = $\frac{1}{377C}$ for phase to ground capacitance, C, in Farads

3.4 Current Transformers

Current transformers are used to electrically isolate the relay circuit from the power system and to permit relay devices to operate at reasonable values of current and voltage. The performance of current transformers is a key factor in relay system design because the relays are only as accurate as the current transformers which energize them.

The most important parameters involved in the selection of a current transformer are turns ratio and accuracy classification. Turns ratio is generally expressed as a function of the primary current which will produce five amperes of secondary current. Typical current-transformer ratios for ground fault relaying systems in coal mines are 25:5 and 50:5.

Accuracy classification refers to the ability of the current transformer to drive some maximum relay coil impedance without exceeding a specified ratio error. There are several methods for specifying the accuracy of a current transformer, including ratio correction factor curves, secondary excitation curves, ASA accuracy classifications, and ANSI accuracy classifications. Modern bushing- and bartype current transformers are generally classified according to the ANSI system, which appears in Table 3-2. The ANSI accuracy classification consists of a letter which indicates whether the accuracy has been determined by a test (T) or has been calculated (C). The number after the letter represents the maximum voltage that the current transformer can develop across its secondary at 20 times rated current without exceeding 10 percent error. For example, a C200 current transformer will develop 200V at 5A x 20 = 100A secondary current, which is equivalent to saying that a C200 current transformer should not be used to drive a load greater than 2 ohms. Current transformers can also be classified by a standard burden designation. Standard burden designations are shown in the left hand column in Table 3-2. The number after the "B" represents the maximum burden impedance that should be placed on the current transformer secondary. Thus, a C200 classification is equivalent to a B-2 standard burden designation.

TABLE 3-2

Current Transformer Burden Classifications

Std. Burden Designation	ANSI Accuracy Class		Max. Burden (Ω)
B-1	C-100	T-100	1
B-2	C-200	T-200	2
B-4	C-400	T-400	4
B-8	C-800	T-800	8

On a multi-tap current transformer, the accuracy classification applies only when the highest ratio tap is used. The ability of a current transformer to drive a load without saturating is inversely proportional to the tap setting. For example, if a multi-tap current transformer has a burden classification of B-2 at a ratio of 600:5, its classification on a 300:5 tap would be B-1.

3.5 Relays

When selecting an overcurrent relay for ground fault protection the following relay parameters must be taken into consideration:

- time-current characteristic
- burden

Time-current requirements are satisfied when the relay time characteristics permit coordination at the pickup levels of interest. The following example helps to illustrate this concept. A ground fault relay is required for a power system with the following parameters:

- 25A grounding resistor
- 25:5 ground current transformer
- relay pickup set at 10A

The first requirement of the relay (time or instantaneous) is that it have a two ampere tap, which corresponds to ten amperes of ground current. The second requirement (time only) is that the relay have suitable time-current characteristics. A relay with characteristics as shown in Figure 3-2 could be set to provide tripping in 0.4 second time delay increments at full ground current (i.e., 2.5 times pickup), however, at lower currents the delay time becomes unsuitably large due to the relay's extremely inverse characteristic. The characteristic shown in Figure 3-3 is more appropriate, although the time delay still increases with decreasing current. Figure 3-4 shows the ideal characteristic where time delay is not a function of current. Such a characteristic can be obtained using solid state relays.

Relay burden must be taken into consideration when selecting current transformers. Burdens of some commonly used electromechanical relays at different tap settings and current levels are shown in Table 3-3. As an example of relay and current transformer matching, an inverse relay set on the two ampere tap would require a current transformer with a rating of at least B-1.

3.6 Pickup Level

Selection of pickup level involves determining an upper and lower limit of relay setting which will cause the system to perform as desired during a ground fault.

The lower limit of relay pickup level is determined by coordination requirements. More specifically a ground fault on one segment of a mine power system causes an imbalance of capacitive charging current in that segment and in all other parallel segments. The ground fault relays in these parallel segments must be set above the charging current imbalance or they will perform

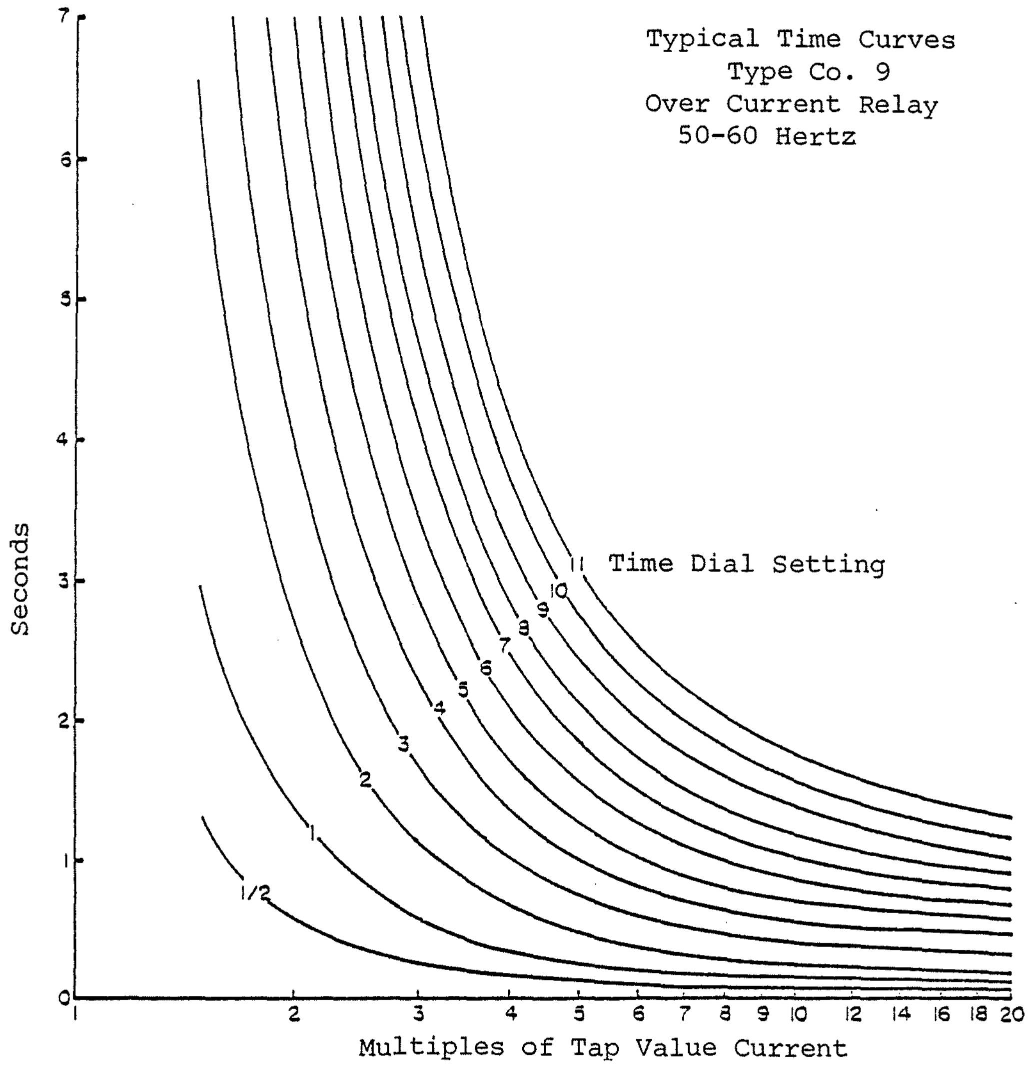


FIGURE 3-2

Time Current Characteristic of Very Inverse Relay

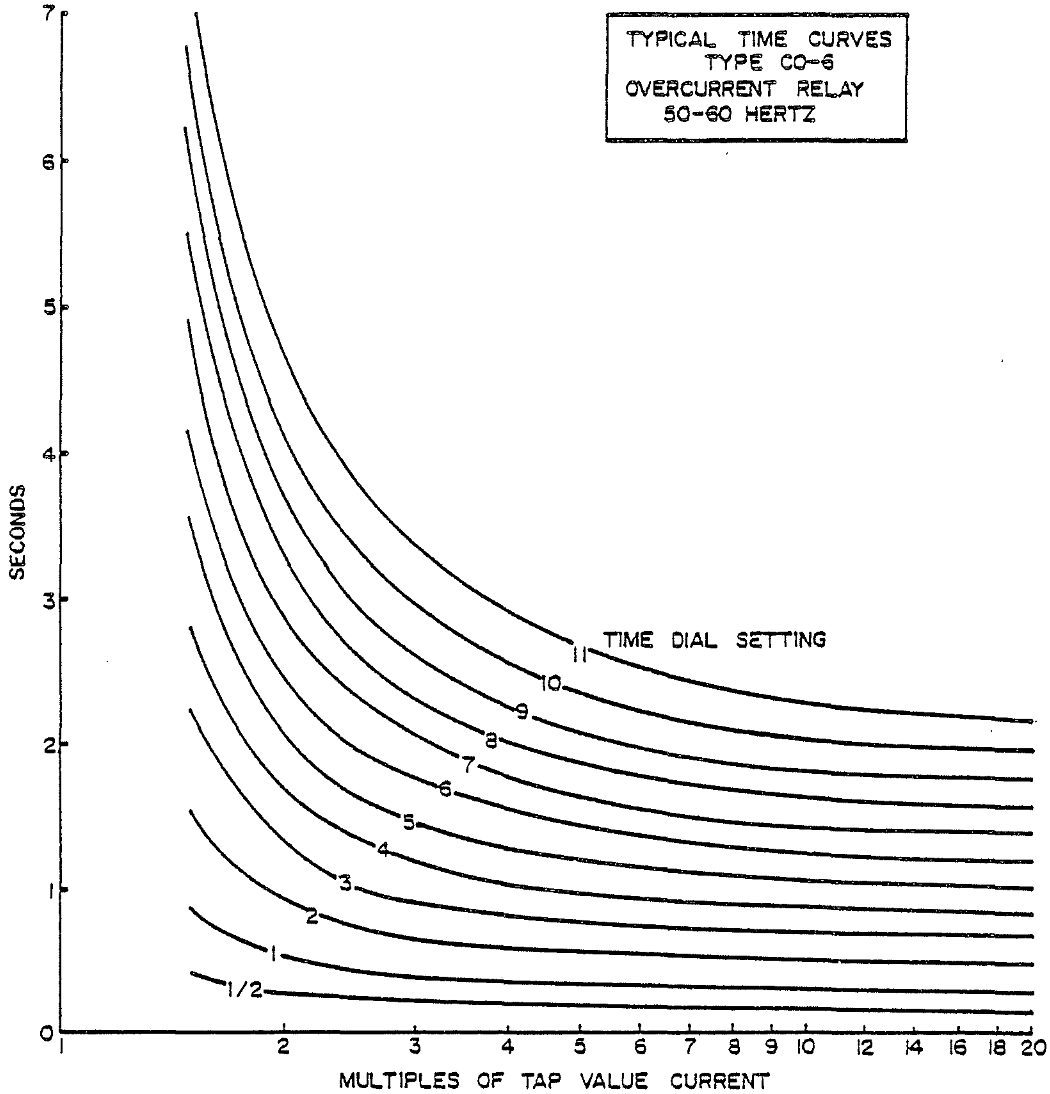


FIGURE 3-3
Time Current Characteristic of
a Definite Minimum Time Relay

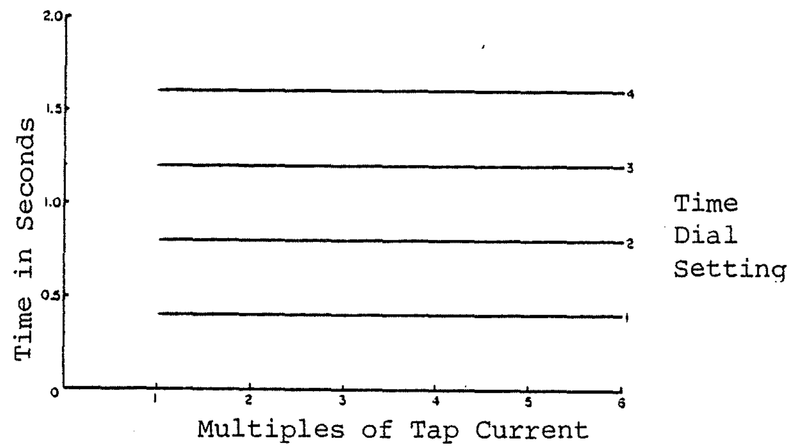


FIGURE 3-4

Characteristics of an Ideal
Ground-Fault Relay

TABLE 3-3

Burdens (in ohms) of Commonly Used
Electromechanical Relays

TYPE	RANGE	TAP	AT PICKUP	AT 10X PICKUP
Inverse And Very Inverse	0.5/2.5	0.5 1.0 2.0	9.52 2.42 .66	5.28 1.50 .5
Extremely Inverse	0.5/2.5	0.5 1.0 2.0	2.88 .89 .32	2.87 .93 .25
Inst.	2-48	2.0	.80	.67

incorrectly. This concept is illustrated in Figure 3-5 where it can be seen that a ground fault on branch "A" causes the line-to-neutral capacitance on branch "B" to be shorted in one phase.

In order for capacitance to contribute to charging current imbalance, it must be connected in a grounded wye configuration. An example of this is phase conductor-to-shield capacitance in mine power feeder cable. The phase conductor-to--shield capacitance for various sizes of mine power feeder cable was shown in Table 3-1. Table 3-4 shows the charging current and charging current imbalance for various connection configurations for faulted faulted and unfaulted conditions. It is assumed in Table 3-4 that the capacitive load consists of balanced 1 μF loads and a line-to-neutral voltage of 7200 V.

By setting ground fault relays at least 25 percent above the calculated charging current of inby grounded wye connected loads it is possible to avoid tripping a circuit breaker for a ground fault on other segments of the power system. The relay pickup current must be set above the calculated charging current because the capacitance calculations do not include contributions from transformers, couplers, etc.

TABLE 3-4

Effects of Capacitance on System Imbalance During a Ground Fault*

Connection	Fault Type	Charging Current/Phase	Current Imbalance
delta	unfaulted	4.7A	0.0A
grounded wye	unfaulted	2.7A	0.0A
ungrounded wye	unfaulted	2.7A	0.0A
delta	line-neutral	4.7A	0.0A
grounded wye	line-neutral	**	8.1A
ungrounded wye	line-neutral	2.7A	0.0A

* Assumes a balanced capacitive load of 1 μF/phase and a line-neutral voltage of 7200 V. It also assumes a resistance-grounded, wye-connected source.

** The charging current in the faulted phase is zero amperes. The other two phases each carry 4.7 amperes of charging current.

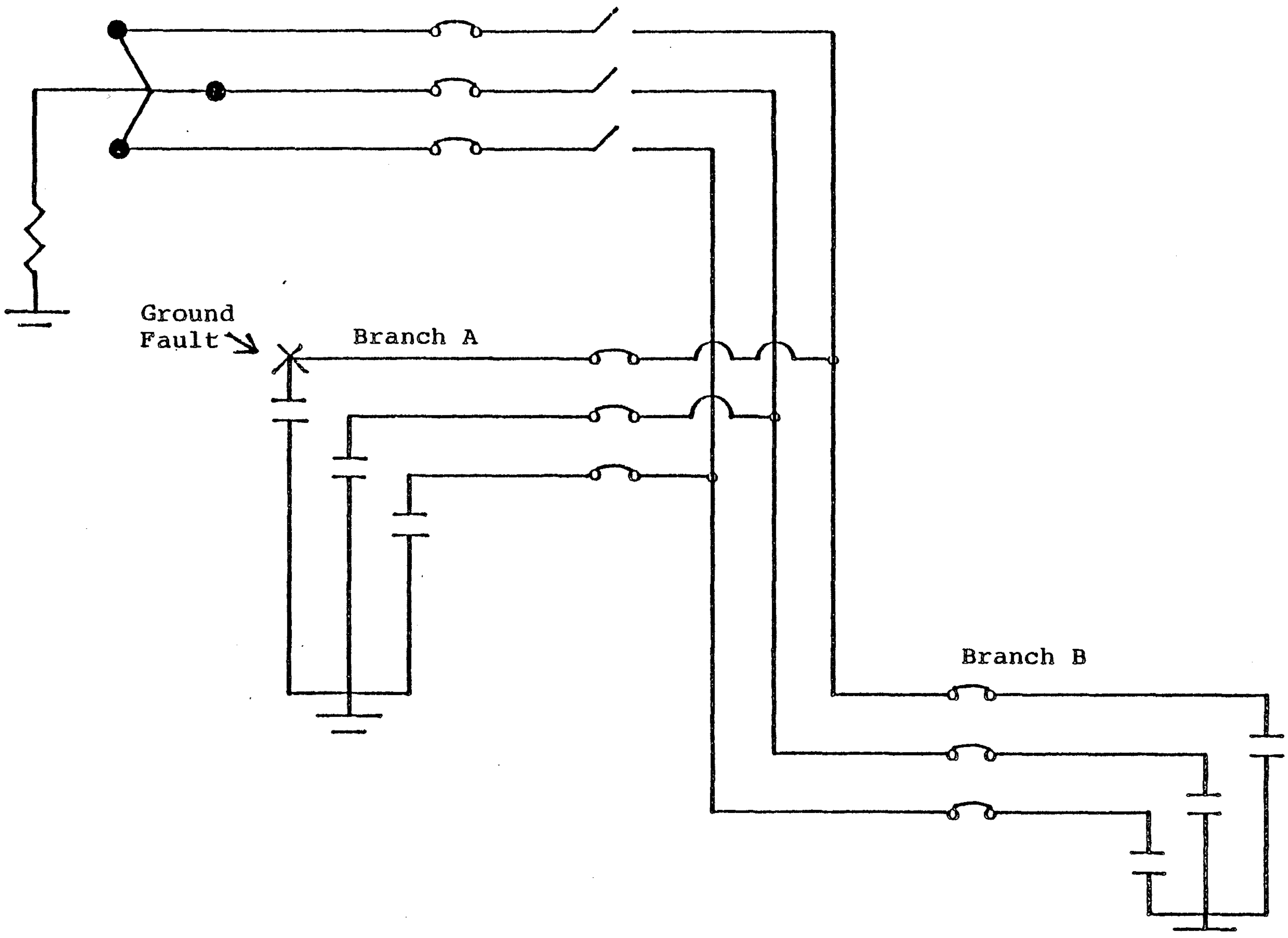


FIGURE 3-5

Power System Showing Line-To-Ground Capacitance

The upper limit on pickup level is much more difficult to quantify. The selection must be based on a maximum voltage drop external to the grounding resistor, during a ground fault, and still cause the fault to be cleared. This concept is illustrated in Figures 3-6 and 3-7 for a 7200 V_{l-l} system with a 25A grounding resistor.

Figure 3-6 is a lumped element circuit equivalent of a segment of a mine power system during a ground fault. The elements are described as follows:

SOURCE (V_{l-n}): line-to-neutral voltage of the power distribution system (4160 V for this example)

Z_{pc}: impedance of the phase conductor in the faulted phase, the voltage drop across this element is proportional to the ground fault current plus the symmetrical current drawn by legitimate loads

Z_f: the voltage drop across this representative impedance consists of the following:

- voltage drop across transformer windings which have an internal fault, or
- voltage drop across arcing or bolted faults

Z_{gc}: impedance of ground conductors, the voltage drop across this element is proportional to ground current

R_{gr}: resistance of grounding resistor (166.4Ω in this example)

Figure 3-7 is a plot of V_x vs. I_g in Figure 3-6. Regardless of the values of Z_{pc}, Z_f, Z_{gc}, and the symmetrical load current, the intersection of V_x and I_g will occur on the straight line in Figure 3-7.

The selection procedure for voltage drops across the three unknown impedances will include the following assumptions:

- The dependence of the procedure on actual component values will be minimized in order to provide as general a solution as possible. System dependence may be added. However, certain parameters are difficult to quantify precisely.
- The solution will be based, within reason, on "worst case" values.

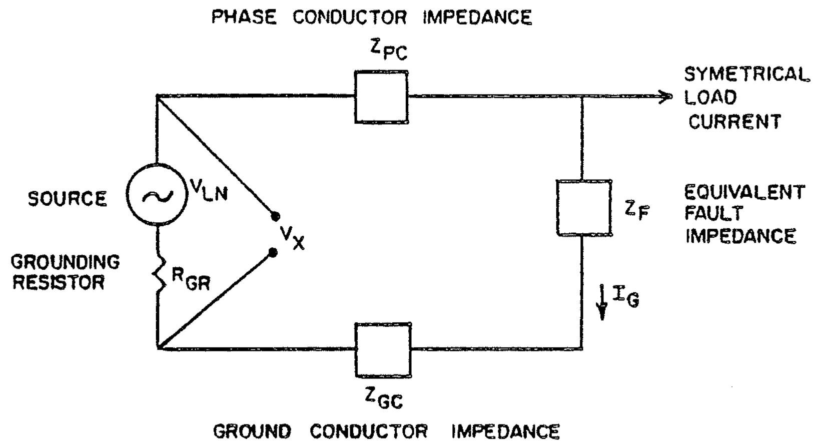


FIGURE 3-6

Ground Fault Model

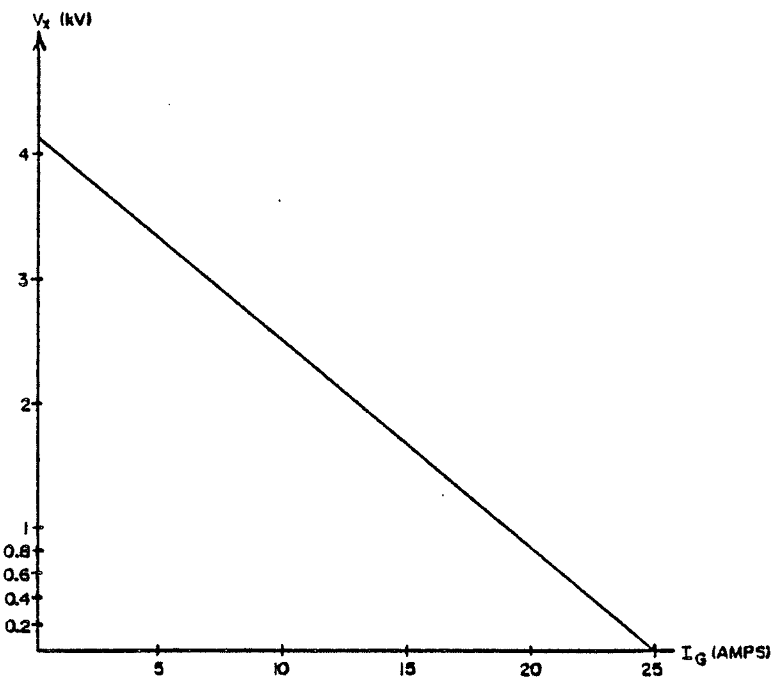


FIGURE 3-7

V-I Characteristic of Ground Fault Model in Figure 3-6

- The effect of arcing faults will not be considered in the solution. After a solution is reached, a general equation for arc resistance will be used to verify the validity of the solution.

- The solution will consist of an upper boundary for ground fault relay setting. A lower setting might provide a small increase in system performance; however, it would be difficult to justify.

- The voltage drops across the various elements will be assumed to be in phase. This will provide a worst case condition since the magnitude of the sum of several vectors is at a maximum when the vectors are in phase.

The assumed voltage drops across the impedances are as follows:

Z_{pc}: On most systems, the maximum voltage drop permitted between source and load is 10 percent of the source voltage. In the example system this corresponds to a 416 volt drop.

Z_f: The worst case ground fault consists of a fault in the electrical center of one winding on the primary of a delta-connected transformer. As illustrated in Figure 3-8, this corresponds to a fault at one-half the system line-to-neutral voltage at the transformer. On a wye-connected winding, protection down to one half of the line-to-neutral voltage would provide protection for that half of the winding that is under the highest voltage-to-neutral stress.

Delta-connected windings were selected for full protection since they represent the majority of the loads on a mine power distribution system.

Z_{gc}: The voltage drop across Z_{gc} will not be included in the analysis since, at most, this can be 100V for a bolted ground fault at full line-to-neutral voltage.

Thus, the maximum V_x (see Figure 3-6) is:

$$V_x = 1/2\,(V_{l-n} - 0.1\,V_{l-n}) + 0.1\,V_{ln} \qquad (3\text{-}3)$$

$$= 0.55\,V_{ln}$$

$$= 2288\ \text{V}$$

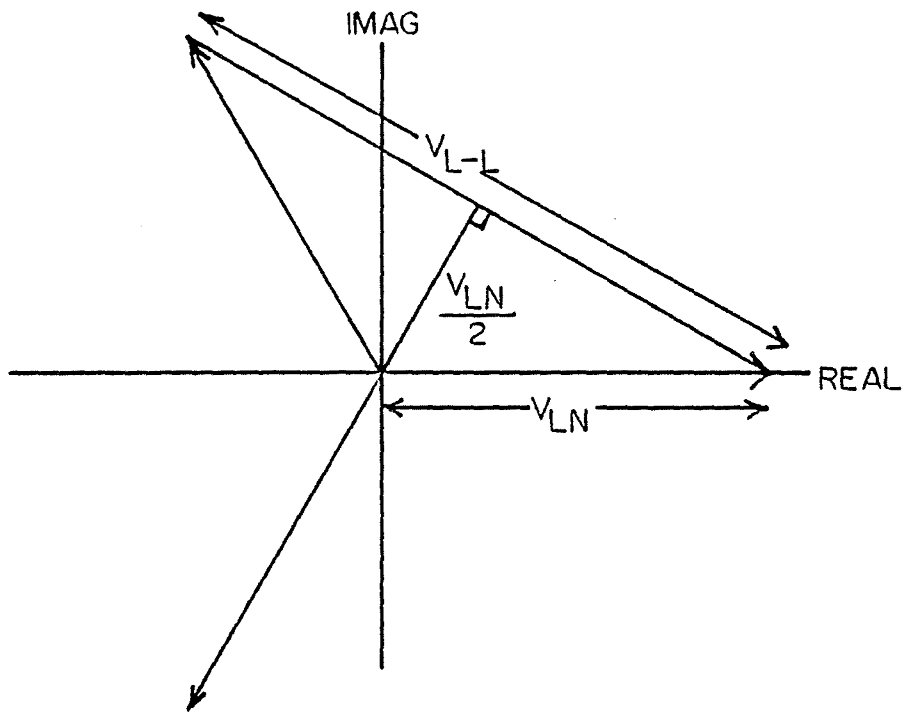


FIGURE 3-8

Voltage Distribution Across One Leg of a Delta-Connected Transformer

From Figure 3-7 this corresponds to a ground current of 11.25A, or forty five percent of the maximum ground current. Adding a safety factor of 1.5 to the relay setting results in a setting of about 8 amperes. The safety factor is used because induction-disc relays, which are the most common type in use, develop very low torque at pickup current and it is difficult to predict their performance at less than 1.5 times the tap setting. Instantaneous and solid-state relays could be set to pick up at 11.25A because they have adequate performance at pickup current.

The above analysis shows that a ground fault relay setting of one-third of the maximum ground current will provide good protection against bolted ground faults. The analysis is a general one and does not require consideration of specific systems.

The effect of arc voltage drop on ground current flow can be approximated (based on an idealized model) through the use of a generalized arcing equation for an arc between two copper electrodes in still air[75].

$$V = 30 + 10\,L + \frac{10 + 30L}{I} \qquad (3\text{-}4)$$

where:

V = arc volts
L = arc length in cm.
I = arc current in amperes

Equation 3-4 is plotted in Figure 3-9 for several arc lengths. Also plotted in Figure 3-9 is the VI characteristic for the ground system modeled in Figure 3-6. The intersections of the arc characteristics and the VI characteristic represent the stable burning points for arcs of different lengths. (It should be noted that these arcs are not self-initiating. A prerequisite is an ionized path between the electrodes which, for testing purposes, is provided by a thin copper wire connected between the electrodes that vaporizes when power is applied).

Figure 3-9 shows that, because of the physical dimensions involved, an arc in a power cable (which is where a fault is most likely to occur) would have a voltage drop under 200V. The same is true for a coupler fault where the arc length is limited by the dimensions of the coupler. It is conceivable that longer arcs could occur inside of switchgear. An arc occurring external to a transformer would have to be on the order of one meter in length before relaying problems could occur. Arcs occurring in a transformer are limited in length, as was the case of cables and cable couplers.

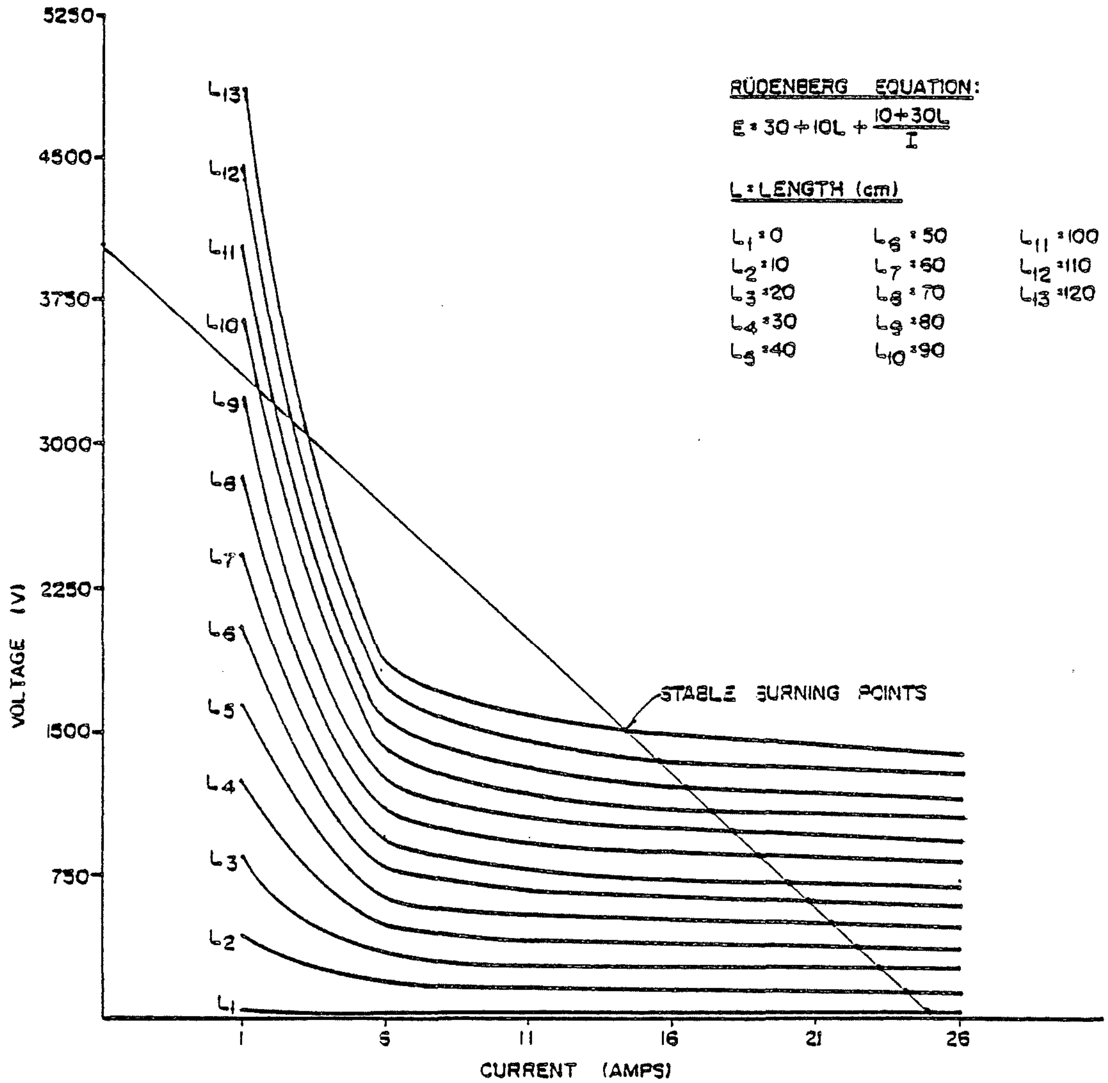


FIGURE 3-9

Plot of Arcing Equation Showing Stable Burning Points for Circuit in Figure 3-6

Although the arc equation represents the results of an idealized model, it provides the most reasonable results available for the purposes of this study.

In order to better quantify the characteristics of phase to ground arcing in mine distribution systems, it would be necessary to simulate arcing ground faults using actual mine power distribution gear.

3.7 Summary

Burden matching of current transformers and relays is the biggest problem in existing systems. If existing system hardware prevents relay performance as outlined in this paper, then a backup system, such as ground resistor potential relaying, should be used to provide protection from low level ground faults. In addition to insuring that relays are picking up at the levels which they are set, the following should be considered in the design or evaluation of a ground fault relaying system:

- relay pickup delay over the range of available ground fault current
- magnitude of system charging current and effects of charging current imbalance on relay performance during ground faults
- effect of ground resistor size on the energy available at a ground fault and ease of pickup at ground current levels discussed in this paper

4.0 PHASE OVERCURRENT RELAYING

4.1 Introduction

The purpose of this section is to provide procedures which may be used for the design or evaluation of phase overcurrent relaying as applied to the protection of coal mine electric power distribution systems. The procedure has been divided into three sections. Section 4.2 deals with the optimal location of circuit protection elements to provide maximum system performance. This is followed by recommended procedures for power system representation, fault current computation, and relay coordination. An example of the coordination process for a mine power system is presented in Section 4.4.

As was the case in the previous chapter on ground fault relaying, it is assumed that relay coordination is desirable from both a personnel safety and system performance point of view.

4.2 Protection Points

The first decision to be made in the design of a protective relaying system is where to use circuit protection. The expanded radial configuration is the most common power system type found in coal mines; therefore, it will be used to illustrate the protection point selection and coordination process. The following subsections discuss the various protection points, proceeding from the source to the load.

4.2.1 Substation

The mine substation contains two protection points. Fuses are generally located on the primary of the substation transformer and a circuit breaker is placed on the secondary. The circuit breaker is controlled by time overcurrent relays with instantaneous units.

4.2.2 High-Voltage Feeder

The power cable or overhead lines that extend from the substation into the mine are referred to as the high-voltage feeder. The high-voltage feeder normally does not have any circuit breakers in series with it, i.e., it is not sectionalized. The exception to this occurs in large systems or systems where the feeder splits in two directions once inside the mine. In either case, a coordination study will reveal whether a sectionalizing breaker can be used without increasing circuit breaker trip delays beyond the point where cables and transformers can be adequately protected.

4.2.3 Tap-Off Points

A tap-off point is any point along the high-voltage feeder where a branch circuit is connected. Each tap-off point should have a switchhouse which contains a feed-through for the high voltage feeder and a circuit breaker controlled by overcurrent relays in series with the branch circuit. It is good design practice to use a circuit breaker for each load center connected to the high voltage feeder. Although it is not uncommon, for example, to find both a panel belt load center and the section load center connected to the high-voltage feeder through the same breaker, this practice makes it difficult or impossible to protect both load centers from overload or low level faults. In this case, it is better design practice to use a double switchhouse.

4.2.4 Load Centers

For the purposes of this study, section load centers will contain two protection point types. One is the main breaker, which is a molded case circuit breaker connected between the transformer secondary and the load center bus. The other is the molded case circuit breakers connected between the bus and the individual machine trailing cables. Belt load centers will be assumed to have one molded case circuit breaker which protects the belt motor and its cable, and fuses on the transformer primary for backup protection.

4.2.5 Rectifiers

Neither haulage-nor section-rectifiers will be specifically included in this study. For haulage rectifiers, it is assumed that circuit breakers on the secondary of the transformer protect both the transformer and rectifier from overloads and short circuits. The switchhouse connecting the haulage rectifier to the high-voltage feeder serves the same function as a switchhouse connecting a section or belt load center to the high-voltage feeder. Section rectifiers are assumed to be connected to the section load center secondary through a suitable molded case circuit breaker, and thus are treated in the same manner as ac face equipment. In either case, circuit breaker time-current characteristics are required for each circuit breaker type in order to perform a coordination study.

4.2.6 Other Configurations

There are many equipment and system configurations which cannot be covered in a study of reasonable length. These include fuses in switchhouses, different types of circuit breakers, different system configurations, etc. However, the techniques presented are general enough that they should enable the reader to deal with many situations not covered in this text.

4.3 Procedure

4.3.1 System Representation

The first step in any coordination procedure is the construction of a single line diagram representing the power system. The diagram should include information on the utility short circuit capacity, transformer ratings and impedances, cable sizes and lengths, and load voltage and horsepower ratings. An example of such a diagram is given in Figure 4-1, in Section 4.4.

In addition, any information which may be available concerning motor starting currents, motor subtransient reactances, machine full load currents, transformer inrush currents, transformer withstand levels, load diversity, and typical mine temperatures should also be collected. Although the procedure to be outlined may be performed using estimates of this data, the availability of actual values would improve the accuracy and reliability of the study.

Additional information required includes specifications (including time-current curves) for the overcurrent relays, molded case circuit breakers, and fuses to be used in the protective system. Operating times for circuit breakers to be activated by overcurrent relays may also prove useful.

Finally, information relating to cable impedances and ampacities should also be acquired. Additional data concerning maximum instantaneous settings for trailing cable protection will be given later in this section.

4.3.2 Fault-Computations

The second step in the relay specification procedure should be the selection of protection points and determination of rated currents, full load and starting currents, maximum fault current, and minimum fault current at each point of protection. All currents should be referred to the distribution system. Pre-fault currents are assumed to be small compared with post-fault values and the impedances of current transformers, circuit breakers, and switches are usually neglected.

In order to calculate the required currents, the system single-line diagram should be converted to an impedance diagram with all impedances referred to the distribution system. Equivalent representations should also be constructed for sections of the mine not specifically included in the study. The general procedures for performing these computations are as follows.

4.3.2.1 Utility Reactance - The utility reactance, X, in ohms per phase, referred to the secondary of the substation transformer is given by:

$$X = \frac{(\text{Secondary } kV_{LL})^2}{(\text{Utility Short Circuit Capacity in MVA})} \tag{4-1}$$

The utility resistance is normally neglected.

4.3.2.2 Transformer Impedances - The resistance, R, and reactance, X, of the mine substation transformer in ohms per phase referred to the distribution system are:

$$R = \frac{R_T(\%)}{100} \times \frac{(\text{Secondary } kV_{LL})^2}{(\text{Rated Transformer 3-Phase MVA})} \tag{4-2}$$

$$X = \frac{X_T(\%)}{100} \times \frac{(\text{Secondary } kV_{LL})^2}{(\text{Rated Transformer 3-Phase MVA})} \tag{4-3}$$

For the section or utilization transformers, these values become:

$$R = \frac{R_T(\%)}{100} \times \frac{(\text{Primary } kV_{LL})^2}{(\text{Rated Transformer 3-Phase MVA})} \tag{4-4}$$

$$X = \frac{X_T(\%)}{100} \times \frac{(\text{Primary } kV_{LL})^2}{(\text{Rated Transformer 3-Phase MVA})} \tag{4-5}$$

4.3.2.3 Cables - The resistance and reactance of mine-power distribution system cables may be determined in ohms/1000 ft./phase from the appropriate cable handbook. For distribution cables, the appropriate values are then given by:

$$R = (r) \times \frac{(\text{Actual Length in Feet})}{1000} \tag{4-6}$$

$$X = (x) \times \frac{(\text{Actual Length in Feet})}{1000} \tag{4-7}$$

Where: r and x = per 1000'/phase values

Cable capacitance is neglected in accordance with the assumption that pre-fault currents are small. For utilization cables, the appropriate values are:

$$R = (r) \times \frac{L \quad V_{P2}}{1000 \quad V_S^2} \qquad (4\text{-}8)$$

$$X = (x) \times \frac{L \quad V_P^2}{1000 \quad V_S^2} \qquad (4\text{-}9)$$

Where:

r = cable resistance per 1000 feet
x = cable reactance per 1000 feet
L = actual cable length
V_P = transformer primary kV line-to-line
V_S = transformer secondary kV line-to-line

4.3.2.4 Motor Subtransient Reactances - Subtransient reactances of a motor in per-unit on the motor base may be obtained from manufacturer's specifications. This data may be given in terms of percent inrush (starting) current; in which case the inrush current (in percent) should be divided into 100 to get the per-unit substransient reactance. The subtransient reactance in ohms/phase referred to the distribution system is then:

$$X'' = X''\,(pu) \times \frac{(V_o)^2\,(V_m)^2\,(1000)}{(hp)\,(V_u)^2} \qquad (4\text{-}10)$$

Where:

X"(pu) = per unit subtransient reactance
V_o = distribution kV line-to-line (kV)
V_m = motor line-to-line rated voltage (V)
V_u = utilization line-to-line voltage (V)

where it has been assumed that one kVA input corresponds to one output horsepower; this is a standard assumption for three-phase induction motors. For synchronous motors, this correspondence may vary depending upon the machine's field excitation level. The resistance is usually neglected in all cases.

If the per-unit subtransient reactance is not available, a value of 0.25 p.u. is usually assumed for induction motors rated less than 600V with a corresponding value of 0.17 for induction motors rated greater than 600V.[20] Subtransient reactances of synchronous motors may range from 0.15 - 0.28 p.u.

4.3.2.5 Impedance Diagram - Once all system impedances have been evaluated, the single-line impedance diagram may be drawn assuming that all motors are connected through their subtransient reactances to a common reference voltage which has a value equal to the distribution voltage. Equivalents may then be formed, by series/parallel combinations of impedances, to represent portions of the system not under study. The maximum symmetrical fault current in amperes at any system bus (bus N) may then be computed from:

$$I'_{f(max)} = \frac{(\text{Distribution } V_{LL}) / \sqrt{3}}{Z_{eq}}, \qquad (4\text{-}11)$$

where Z_{eq} is the impedance between bus N and reference and is obtained by series/parallel combinations of individual impedances between these two points. The maximum fault current which may flow at any system bus includes a dc transient component which depends upon the X/R ratio of Z_{eq}. To account for this additional component of current, a multiplying factor from Table 4-174 may be utilized such that the maximum asymmetrical current becomes:

$$I_f(max) = \begin{matrix}\text{Factor from Table 4-1} \\ \text{Based upon X/R ratio}\end{matrix} \times I'_f(max) \qquad (4\text{-}12)$$

This current is normally assumed to be the maximum fault current which can flow through a relay located at bus N. This assumption is conservative in that the maximum fault current may actually be less than this value since all motor contributions may not flow through the relay. An alternative to this approach is to neglect such paths when computing Z_{eq}. The latter is used in the mining example presented in Section 4.4.

TABLE 4-1

Asymmetrical Current Factors

X/R Ratio	Factor	X/R Ratio	Factor
1000.0	1.73	5.0	1.25
100.0	1.70	4.0	1.19
50.0	1.67	3.0	1.12
33.3	1.63	2.0	1.04
20.0	1.57	1.0	1.00
10.0	1.44	0.0	1.00

The minimum fault current which may be seen by any phase relay for a fault in its primary zone of protection is assumed to occur for an arcing line-to-line fault located at the most inby point of this zone. This assumes a resistance grounded system which will limit ground fault currents to 25A or less. Asymmetrical current factors and motor contributions are neglected. Thus the minimum fault current becomes:

$$I_f(min) = (0.866) x [AFF] \times \frac{(\text{Distribution } V_{LL}) / \sqrt{3}}{|Z_{eq}|} \qquad (4\text{-}13)$$

Where:

AFF is the Arcing Fault Factor

The arcing fault factor depends upon system voltage at the fault point and varies from 0.8545 at 480V to 0.9 at 600V to 0.95 at 1040V.[74] The arcing fault factor at distribution voltage levels is usually assumed to be 1.0.

Although it is recognized that high impedance faults may occur which will temporarily limit fault currents to a lower value than the minimum value given, it is this current (I_f (min)) which is normally used in a system protection analysis.

Rated and full load currents at each point of protection may be determined based upon device specifications. Thus, for a transformer with given voltage and kVA ratings, the current rating is given by:

$$I_{rated} = \frac{(\text{kVA rating})}{(\text{Rated } kV_{LL}) \; (\sqrt{3})}, \qquad (4\text{-}14)$$

where the rated voltage to be utilized corresponds to the side of the transformer connected to the distribution system.

For cables, the cable ampacity may be considered as analogous to a rated value. These values are obtained from a cable handbook[27] and should be corrected for ambient temperature and/or when one or more layers of cable are used in a reel. Typical correction factors for copper cables are given in Table 4-2.[27]

TABLE 4-2

Typical Ampacity Correction Factors

Ambient Temperature	Insulation Rating 90°C	75°C	Layers in Reel	Correction Factor
10°C	1.26	1.36	1	0.85
20°C	1.18	1.25	2	0.65
30°C	1.10	1.13	3	0.45
40°C	1.00	1.00	4	0.35
50°C	0.90	0.85		

The full load currents of three-phase induction motors connected to the system may be estimated from:

$$I_{full\ load} = \frac{(\text{Rated Horsepower})}{(\text{Rated } kV_{LL}) \times \sqrt{3}} \qquad (4\text{-}15)$$

where it has again been assumed that one horsepower output corresponds to one kVA input. For synchronous motors, the full load current is dependent upon the field excitation. In this case, the full load current may be estimated from

$$I_{full\ load} = \frac{(\text{Rated Horsepower}) \times 746}{(\text{Rated } kV_{LL})\ (\text{Power Factor}) \times \sqrt{3}} \qquad (4\text{-}16)$$

where the power factor is estimated based upon the field excitation. All full load motor currents should be referred to the distribution system using the section transformer's turns ratio.

Full load currents of individual motors are usually added without consideration of phase angles in order to obtain the full load currents of machines or groups of machines. A diversity factor may also be employed to account for the fact that not all motors are likely to be running at full load at the same time. Diversity factors might range from 1.0 to 2.0 depending upon system operating procedures.

If the starting currents of motor loads are not available from the manufacturer, they may be estimated based upon the per-unit subtransient reactance, x", and the full load current. In this case:

$$I_{starting} = 1.25 \times \frac{1}{X''\ (\text{per unit})} \times I_{full\ load} \qquad (4\text{-}17)$$

4.3.3 Relay Coordination

The final step in a coordination study is the selection of fuses, molded case circuit breaker ratings and instantaneous trip settings; and the specification of current transformers, relay tap, and time dial settings. After these parameters are determined, graphs showing the time-current characteristic of each protective device in all paths of protection should be constructed. Inspection of the graphs will then provide the designer with a convenient means for checking system coordination, backup protection, and speed of protection for any given fault or overload situation.

To begin the coordination procedure, the desired points of protection must have been selected. These include:

1. A molded case circuit breaker (thermalmagnetic) to protect each machine and trailing cable.

2. A molded case circuit breaker on the secondary of each section or utilization transformer having multiple machine loads.

3. Fuse protection on the primary of utilization transformers.

4. Current transformers, overcurrent relays with instantaneous trip attachments, and circuit breakers at the inby side of each high voltage feeder junction.

5. A current transformer, overcurrent relay with instantaneous trip attachment, and circuit breaker on the secondary of the main substation transformer.

6. Fuse protection on the primary of the main substation transformer.

In order to simplify the selection of settings for items one through six above, a set of guidelines have been established. The guidelines consist of the various overload and fault currents which are used in a coordination study. The guidelines are as follows:

4.3.3.1 Molded Case Circuit Breakers Protecting Individual Machines

Overload (Thermal Setting)

R_1 = 1.0 x (full load current of the machine including lights and any diversity factor)

R_2 = 1.0 x (ampacity of machine trailing cable corrected for ambient temperature and reeling)

Normally, R_2 will be greater than R_1 and the molded case circuit breaker rating may be selected as the next available size greater than R_1. This rating should be less than or equal to R_2. It should be noted that both R_1 and R_2 are referred to the utilization voltage.

Short Circuit (Magnetic Setting)

S_1 = 1.2 x (maximum motor starting current)

S_2 = 1.2 x (full load current of the machine including lights and diversity factor)

S_3 = 0.8 x (minimum arcing fault current at the load end of the trailing cable)

S_4 = the maximum instantaneous settng specified for the trailing cable in Section 75.601-1, Title 30, CFR, Part 75. (See Table 4-3)

Normally, S_3 and S_4 will be greater than S_1 and S_2 such that the instantaneous setting may be selected such that it is less than S_3 and S_4 and approximately equal to the largest of S_1 and S_2. Again, S_1 - S_4 are referred to the utilization voltage.

4.3.3.2 Main Molded Case Circuit Breakers

Overload (Thermal Setting)

R_1 = 1.0 x (sum of the full load currents of all machines connected including any diversity factor)

R_2 = 1.0 x (Secondary current rating of the section transformer)

TABLE 4-3

Instantaneous Settings of Circuit Breakers for Short-Circuit Protection of Trailing Cables

Conductor Size AWG or MGM	Maximum Allowable Circuit Breaker Instantaneous Setting (A)
14	50
12	75
10	150
8	200
6	300
4	500
3	600
2	800
1	1000
1/0	1250
2/0	1500
3/0	2000
4/0	2500
250	2500
300	2500
350	2500
400	2500
450	2500
500	2500

Normally R_2 would be greater than R_1. The circuit breaker rating may then be selected as the next available size greater than R_1.

Short Circuit (Magnetic Setting)

S_1 = 1.2 x (sum of the full load current of all machines connected including diversity factor plus the starting current of the largest motor)

S_2 = 1.1 x (maximum fault current at the section transformer secondary bus)

As can be seen from the definitions of S_1 and S_2, the use of an instantaneous (magnetic) setting on the main breaker presents coordination problems. Setting S_1 would provide maximum system safety; however, coordination with the individual machine breakers is lost because, in general, a line-to-line or three-phase fault in a trailing cable would trip the main breaker. Setting S_2 would result in the breaker never tripping instantaneously since this setting is above the maximum fault current. The decision to use S_1 or S_2 must be based on whether or not the corresponding increase in safety is significant enough to justify the S_1 setting.

4.3.3.3 Belt Transformer Primary Fuses

Fuses are specified for the belt load center primary because the high impedance of the transformer limits secondary fault current to the point where backup protection is difficult. Fuse specifications are based on transformer inrush and ANSI withstand currents and the maximum secondary fault current.

4.3.3.4 Distribution System Overcurrent Relays

The next set of devices which would normally be specified are the distribution system current transformers, and overcurrent relays. The procedure begins at the primary side of the section or utilization transformers and proceeds to the secondary of the substation transformer. Relays are coordinated in pairs taking care to ensure that sufficient selectivity and backup protection are provided. Guidelines are as follows:

Pickup Current

P_1 = 1.25 x (sum of the full load currents of all machines connected including any diversity factor)

P_2 = 1.0 x (ampacity of smallest cable in the relay's primary zone of protection)

P_3 = F x (current rating of smallest transformer in the relay's primary zone of protection)

F = 1.0 if transformer does not have main secondary protection

F = 2.0 if transformer is protected by main secondary breakers rated at 100% or less of the transformer current rating.

P_4 = 0.8 x (minimum short circuit current in the relay's backup zone of protection)

The relay pickup current should be greater than or equal to P_1 and less than P_2, P_3, and P_4. As this setting is moved closer to P_1, a greater degree of backup protection is provided since the pickup setting is less than P_4.

Instantaneous Setting

S_1 = 1.1 x (maximum fault current at the most inby point of the relay's primary zone of protection)

S_2 = 1.1 x (maximum inrush currents of inby transformers)

S_3 = 1.0 x (allowable short circuit cable current)

For maximum coordination, the instantaneous setting should be greater than S_1 and S_2, and less than S_3. It should be noted that the value of S_3 is not calculated. Instead, the allowable short circuit characteristic can be taken from Figure 2-1327 and plotted on the coordination graph.

Transformer inrush currents should be available from the manufacturer. These range from 8-12 times full load current for a duration of 0.1 second.

Current Transformer and Relay Tap Setting

1. The current transformer and relay tap setting should be chosen such that the tap setting is 0.5 x (the current transformer secondary rating) or greater. If this cannot be achieved, current transformer accuracy should be checked.

2. 20 x (the current transformer primary rating) should exceed the instantaneous relay setting. If this cannot be achieved, current transformer accuracy should be checked.

The current transformer ratio and relay tap setting should be selected in accordance with items 1 and 2.

Time Dial Setting

The time dial setting of the relay should be adjusted so that its operating time will exceed that of all inby relays, for which it serves as a backup, by 0.4 seconds. Normally, this criterion will be achieved by assuring that this time interval exists for the maximum fault current available at the inby relays or at the maximum instantaneous setting of these relays. For maximum speed of protection, this time interval should not be exceeded.

In the case where the inby protective device is a molded case circuit breaker, this time interval should be 0.1 seconds greater than the maximum operating time of the breaker, regardless of the interrupted current. In either situation, this coordinating time interval should be checked when the time-current curves are constructed. At this time, a check should also be made to verify that ANSI withstand values for all transformers in the system are above protective system operating times. These values should be available from the manufacturers, and usually range from 25 times full load current for 2 seconds for transformers with 4% or less impedance, to 14.3 times full load current for 5 seconds for transformers with 7% impedance.

4.3.3.5 Substation Transformer Fuse

The final protective device to be specified would be the fuse protection for the substation transformer primary. This is done based upon comparison of the fuse's time-current curves with those of the relay protecting the secondary of this transformer. For complete coordination, the minimum operating time of the fuse should exceed the relay time-current characteristic by 0.3 seconds for all currents. Fuse currents are, of course, referred to the high-voltage side of this transformer.

4.3.3.6 Summary

The first step in the coordination procedure is the construction of the power system single-line diagram. Data must be obtained on the following parameters:

- utility short circuit capacity
- transformer ratings and impedances
- cable sizes and lengths
- load voltage and horsepower ratings

The second step is to convert the single-line diagram into an impedance diagram, which contains the following quantities:

- utility reactance (use Equation 4-1)
- substation transformer resistance and reactance (use Equations 4-2 and 4-3)
- power cable resistance and reactance (get data from a cable handbook and use Equations 4-6, 4-7, 4-8, and 4-9)
- motor subtansient reactance (in lieu of manufacturers data, Equation 4-10 may be used along with values given in the text)
- utilization transformer resistance and reactance (use Equations 4-4 and 4-5)

The single-line impedance diagram is drawn assuming that all motors are connected through their subtransient reactances to the reference bus, which has a voltage equal to the mine distribution voltage.

Once the impedance diagram is completed, the following system parameters may be computed for each circuit breaker.

- Maximum Asynchronous Fault Current (I_f max) - This is calculated assuming a bolted, three phase fault on the load side of the breaker. It contains current flow from the electric utility, and, depending on breaker location, from various ac loads (motors) connected to the power system. The maximum asynchronous fault current also contains a dc offset which is dependent on the reactance to resistance ratio (X/R) of the total impedance between the fault location and the reference bus (see Table 1 and Equation 4-12). This calculation is used to ensure that circuit breakers do not trip instantaneously for faults that are in the breaker's back-up zone of protection.
- Minimum Fault Current - Minimum fault current is calculated by assuming a line-to-line fault at the furthest inby point of a breaker's primary zone of portection. It is also assumed that current flows only from the electric utility and that there is no dc offset. This calculation is used to ensure that circuit breakers trip instantaneously for faults in their primary zone of protection. See Equation 4-13.

In addition to fault currents, the rated currents of all components in the power system must be calculated. These are given by Equation 4-14 for transformers, Equation 4-15 for induction motors, and Equation 4-16 for synchronous motors. Motor starting current, if unavailable from the manufacturer, can be estimated using Equation 4-17.

Finally, it is necessary to compute transformer inrush and ANSI withstand values. The ANSI withstand is based on transformer impedance and is calculated using information contained in Table 2-6. Transformer inrush current can be obtained from the manufacturer or the standard assumption that the inrush is 8 to 12 times the transformer rated current can be used.

The last step in the coordination process is the selection of fuses, molded case circuit breaker ratings and instantaneous trip settings, and the specifications of current transformers, relay tap, and time dial settings. Each time a protective device is specified, its characteristic is plotted on the system coordination graph. The coordination graph, which is a plot of protective device trip time as a function of current, enables the system designer to graphically depict the performance of a relaying system. It should be noted that the "current" axis of the coordination plot represents current flow at the mine distribution voltage. Any time a transformer is used in the power system the following calculations must be used before information can be displayed on the coordination plot.

- o Substation Fuse. The current rating of the substation fuse must be referred to the mine distribution voltage using the substation transformer turns ratio

- o Molded Case Brakers. The current rating of molded case breakers must be referred to the mine distribution voltage using the utilization transformer turns ratio.

- o Overcurrent Relays. Overcurrent relay time-current characteristics must be referred to the mine distribution system using the ratio of the current transformer which energizes the relay.

The preceeding material represents an ideal approach to the coordination of mine-power-system protective gear. In actual protective system specification, it may be found that some of the guidelines stated cannot be strictly adhered to. Inaccurate data input (machine full load and starting currents, diversity, etc.) may require that some settings be "fine tuned" to fit the needs of a particular system. Incompatible protective device time-current curves may require a sacrifice of coordination for adequate backup protection. The following example on protective system specification illustrates some of the difficulties encountered encountered in the coordination process, and offers solutions and compromises which are sometimes necessary in a protective system design.

4.4 Coal Mine Power System Example

A coal-mine-electrical-power system selected to illustrate the coordination procedure is shown in Figure 4-1. The system represents a large underground coal mine and the coordination process is illustrated from one working section and its panel belt drive back to the mine substation. Calculations of all required parameters are given in the text. However, it will become apparent that the use of a load flow/fault analysis program is desirable for analysis of medium and large systems.

4.4.1 Fault And Overload Computations

4.4.1.1 Utility Reactance

The utility reactance in ohms/phase referred to the distribution system is:

$$X = \frac{(7.2)^2}{1000} = 0.052\,\Omega$$

4.4.1.2 Substation Transformer

The main 7.5 MVA transformer's resistance and leakage reactance in ohms/phase referred to the distribution system are computed using Equations 4-2 and 4-3 respectively:

$$R = \frac{0.5}{100} \times \frac{(7.2)^2}{7.5} = 0.035\,\Omega$$

$$X = \frac{5}{100} \times \frac{(7.2)^2}{7.5} = 0.346\,\Omega$$

4.4.1.3 Utilization Transformers

The belt (225 kva) transformer's resistance and reactance referred to the distribution system are computed using equations 4-4 and 4-5 respectively:

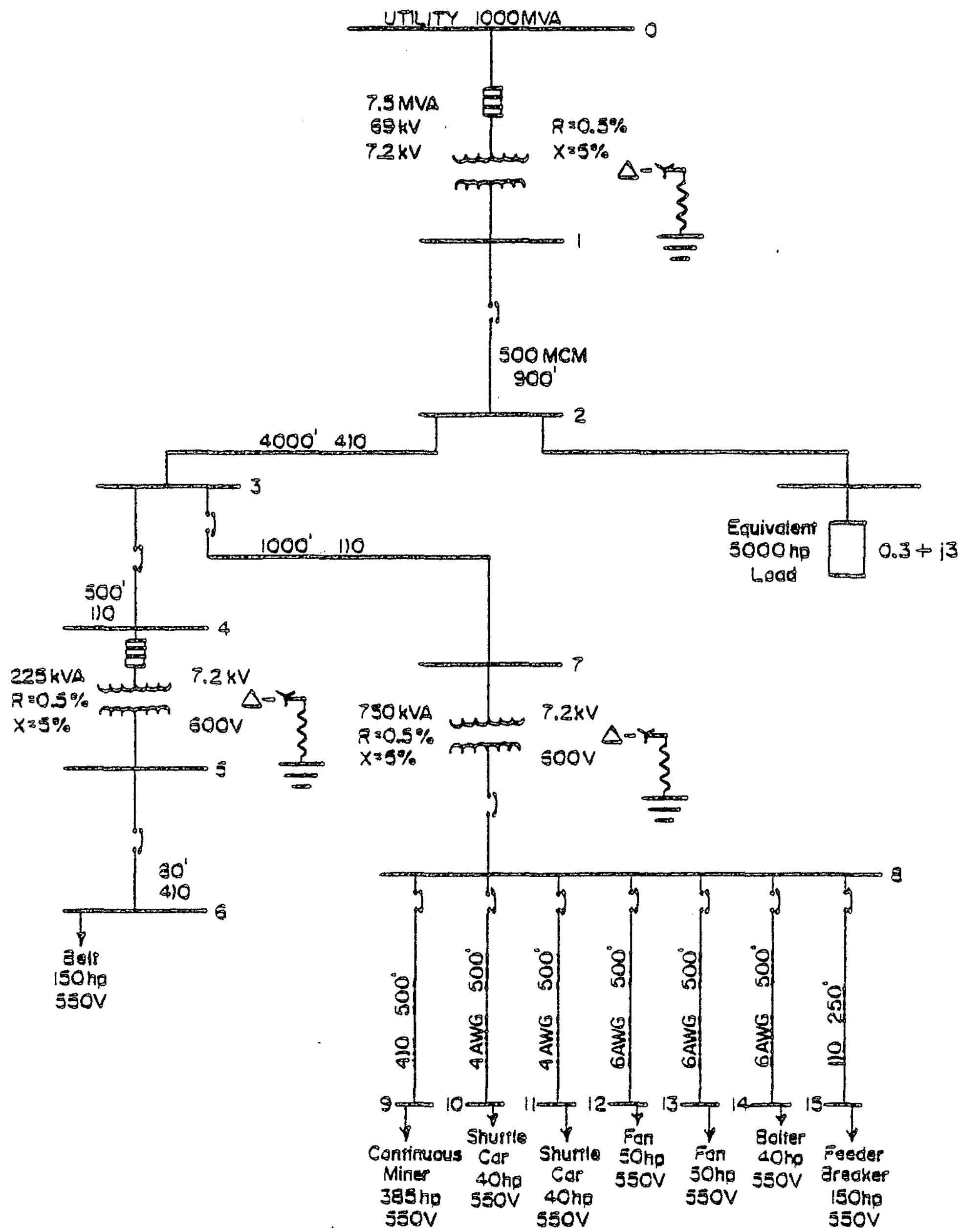


FIGURE 4-1

Example Mine Power System

$$R = \frac{0.5}{100} \times \frac{(7.2)^2}{.225} = 1.152\,\Omega$$

$$X = \frac{5}{100} \times \frac{(7.2)^2}{.225} = 11.52\,\Omega$$

and similarly for the 750 kva section transformer:

$$R = \frac{0.5}{100} \times \frac{(7.2)^2}{.75} = 0.346\,\Omega$$

$$X = \frac{5}{100} \times \frac{(7.2)^2}{.75} = 3.456\,\Omega$$

4.4.1.4 Cables

The resistances, r, and reactances, x, per 1000 ft. for the power cables are taken from a cable handbook. For convenience, these values have been summarized for the cables used in this example:

500 MCM (8 kV):	$r = 0.028\,\Omega/1000$ ft. $x = 0.02\,\Omega/1000$ ft.
4/0 (8 kV):	$r = 0.065\,\Omega/1000$ ft. $x = 0.034\,\Omega/1000$ ft.
4/0 (2 kV):	$r = 0.065\,\Omega/1000$ ft. $x = 0.029\,\Omega/1000$ ft.
1/0 (8 kV):	$r = 0.128\,\Omega/1000$ ft. $x = 0.037\,\Omega/1000$ ft.
1/0 (2 kV):	$r = 0.128\,\Omega/1000$ ft. $x = 0.032\,\Omega/1000$ ft.
4 AWG (2 kV):	$r = 0.332\,\Omega/1000$ ft. $x = 0.035\,\Omega/1000$ ft.
6 AWG (2 kV):	$r = 0.528\,\Omega/1000$ ft. $x = 0.038\,\Omega/1000$ ft.

The actual cable impedances, referred to the distribution system diagram, are computed using Equations 4-6 and 4-7:

Z_{1-2}: $(.028 + j.03)(.9) = .025 + j.027\Omega$

Z_{2-3}: $(.065 + j.034)(4) = 0.26 + j.136\Omega$

Z_{3-4}: $(.128 + j.037)(.5) = .064 + j.019\Omega$

Z_{3-7}: $(.128 + j.037)(1) = .128 + j.037\Omega$

Z_{5-6}: $(.065 + j.029)(.08)(12)^2 = .749 + j.334\Omega$

Z_{8-9}: $(.065 + j.029)(.5)(12)^2 = 4.680 + j2.088\Omega$

Z_{8-10} and Z_{8-11}: $(.332 + j.035)(.5)(12)^2 = 23.904 + j2.52\Omega$

Z_{8-12} and Z_{8-13} and Z_{8-14}: $(.528 + j.038)(.5)(12)^2 = 38.016 + j2.736\Omega$

Z_{8-15}: $(.128 + j.032)(.25)(12)^2 = 4.607 + j1.152\Omega$

4.4.1.5 Motor Subtransient Reactances

For this system, all motors are rated at 550 V so that their subtransient reactance may be assumed equal to 0.25 pu on the motor base. Equation 4-10 is used for the computation of these reactances. The subtransient reactance, in ohms referred to the distribution system is:

$$X'' = \frac{(.25)\ (7.2)^2}{(hp)} \frac{(550)^2}{(600)^2} \times 1000 = \frac{10,890}{hp} \qquad (4\text{-}18)$$

The individual motor subtransient reactances are then computed by substituting the motor size into Equation 4-18, as shown in the following:

$$X'' = \frac{10,890}{385} = 28.28\Omega$$ for the continuous miner (all motors running)

$$X'' = \frac{10,890}{40} = 272.25\Omega$$ for each shuttle car

$$X'' = \frac{10,890}{50} = 217.8\Omega$$ for each section fan

$$X'' = \frac{10,890}{40} = 272.25\Omega \quad \text{for the bolter}$$

$$X'' = \frac{10,890}{150} = 72.6\Omega \quad \text{for the feeder breaker}$$

$$X'' = \frac{10,890}{150} = 72.6\Omega \quad \text{for the belt}$$

4.4.1.6 Equivalent Networks

The main coordinating path for this system is from the utility to the continuous miner and includes buses 1, 2, 3, 7, 8, and 9. The loads on buses 10 through 15 will, therefore, be represented by an equivalent network.

The impedances of the network to be modeled are shown in Figure 4-2. All motor impedances are connected to the reference bus (bus 0). The impedances shown are combined by addition in series and by the addition of reciprocals in parallel to give an equivalent impedance of $3.288 + j30.121\ \Omega$ between buses 8 and 0. A similar procedure has been applied to the remainder of the system (connected to bus 2) in order to obtain the equivalent shown between buses 2 and 0 in Figure 4-3, which is the complete system impedance diagram. Selected protection points are as shown in this figure. Circuit breakers at points A, B, and C are actuated by overcurrent relays and molded case breakers are located at points D, E, and F. The substation transformer and the belt motor transformer are fuse protected. Additional molded case breakers are used to protect the cables from bus 8 to the shuttle cars, section fans, bolter and feeder breaker. These will all have shorter tripping times than the molded case breaker at E and will, therefore, be coordinated automatically. A similar comment also applies to the protective system modeled by the equivalent impedance from bus 2 to reference.

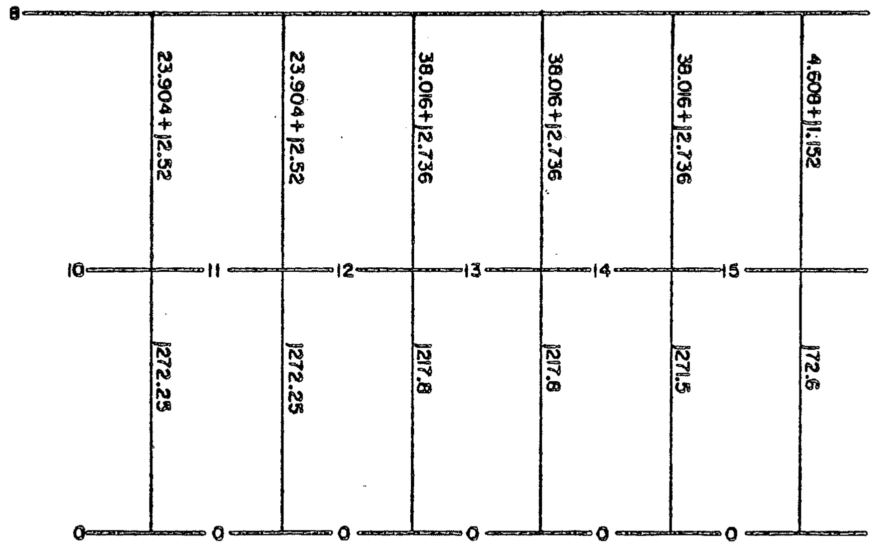


FIGURE 4-2

System to be Represented by an Equivalent Network

4.4.1.7 Maximum Fault Currents

Maximum fault currents are calculated using the magnitude of the impedance from the fault location (the load side of the circuit breaker of interest) to the reference buses. The maximum fault current is equal to the reference bus voltage divided by the impedance magnitude. Only that current which flows through the circuit breaker should be used. For example, only the impedance between buses "1" and "0" is used for the calculation at "A". This is because the fault current from bus "2" does not flow through the circuit breaker at "A" during a fault at the load side of the breaker at "A". At location "B", fault current flows from buses "2" and "8".

Maximum asymmetrical fault currents are calculated using the values in Table 4-1 as shown in Equation 4-12. Linear interpolation may be used to obtain factors not given in Table 4-1.

The calculations for protection point "A" are explained in detail. The calculations for the remaining protection points follow the same format as those for "A", and are summarized below.

<u>At A</u>

The maximum sysmetrical fault current is equal to the distribution system line-to-neutral voltage divided by the magnitude of the equivalent impedance (Zeg) from the fault to the reference bus. From Equation 4-12, the maximum symetrical fault current is:

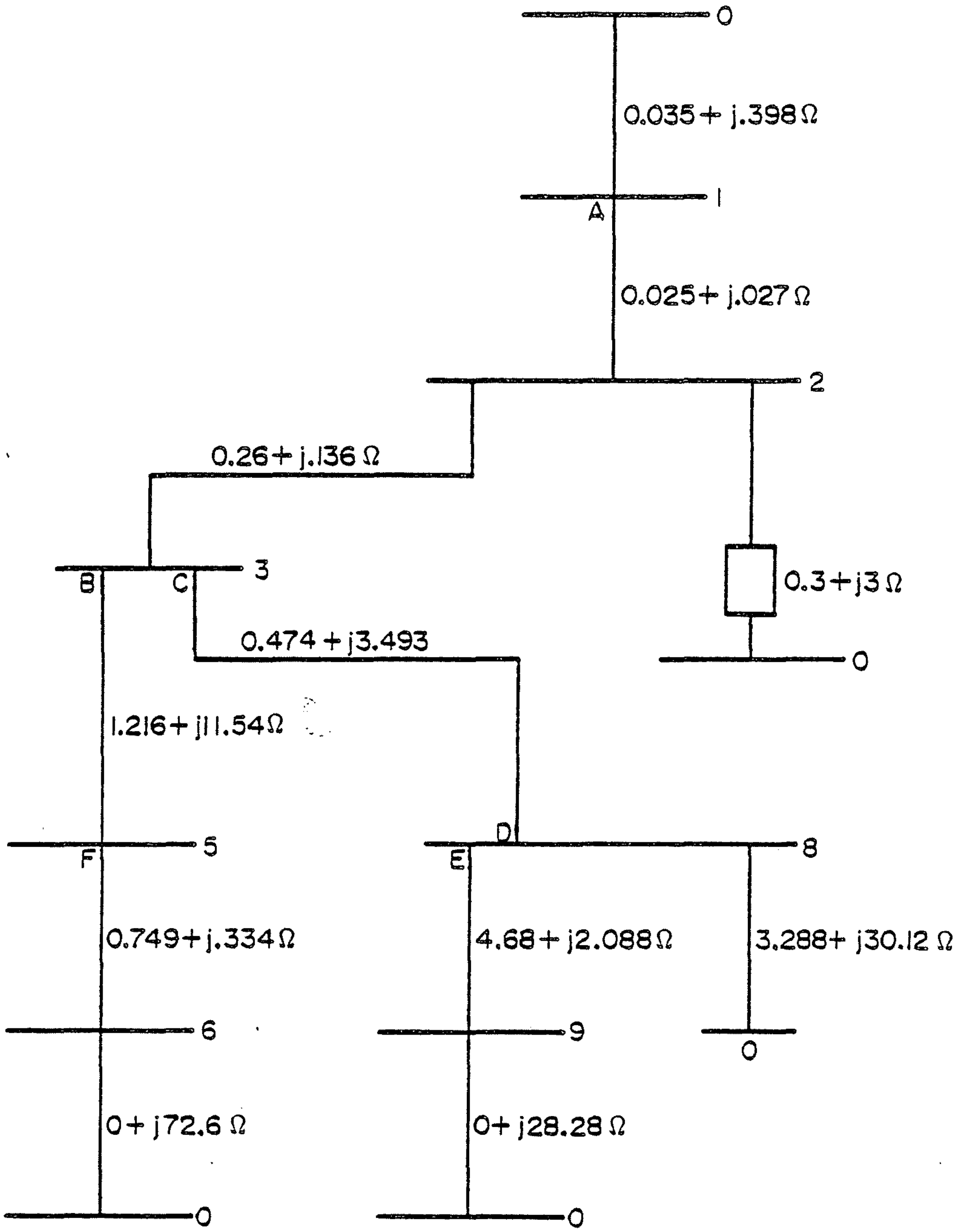


FIGURE 4-3

System Impedance Diagram

$$I'_f\ (max) = \frac{\frac{7200}{\sqrt{3}}}{\sqrt{(.035)2 + (.398)2}} = \frac{4156.9}{.3995} = 10{,}404A \text{ symmetrical}$$

The maximum asymetrical fault current is calculated using the X/R ratio of the equivalent impedance. From Table 4-1, an X/R ratio of 11.37 gives an asymetrical fault factor of 1.46.

$$\frac{X}{R} = \frac{.398}{.035} = 11.37$$

The asymetrical fault factor and the maximum symetrical fault current are combined using Equation 4-12 to get the maximum asymetrical fault current.

$$I_f\ (max) = (1.46)\ (10{,}404) = 15{,}200A \text{ Asymetrical}$$

<u>At B</u>

$$Z_{3-8-0} = .474 + j3.493 + \frac{(4.68 + j2.088 + j28.8)\ (3.288 + j30.12)}{4.68 + j2.088 + j28.8 + 3.288 + j30.12}$$

$$Z_{3-8-0} = 2.456 + j18.75$$

$$Z_{3-2-0} = .26 + j.136 + \frac{(.035 + j.398 + .025 + j.027)\ (.3 + j3)}{.035 + j.398 + .025 + j.027 + .3 + j3}$$

$$Z_{3-2-0} = .31 + j.508$$

$$Z_{eq} = \frac{(.31 + j.508)\ (2.456 + j18.75)}{.31 + j.508 + 2.456 + j18.75} = .295 + j.497$$

$$I'_f(max) = \frac{4156.9}{\sqrt{(.295)2 + (.497)2}} = 7191.8 \text{ A Symmetrical}$$

$$\frac{X}{R} = \frac{.497}{.295} = 1.68$$

$$I_f(max) = (1.03)\ (7191.8) = 7410 \text{ A Asymmetrical}$$

All motor contributions except that from the belt motor equivalent system are included since they flow through this relay.

At C

$$Z_{3-5-0} = 1.216 + j11.54 + .749 + j.334 + j72.6$$

$$= 1.96 + j84.5$$

$$Z_{3-2-0} = .31 + j.508$$

$$Z_{eq} = \frac{(1.96 + j84.5)(.31 + j.508)}{1.96 + j84.5 + .31 + j.508}$$

$$= .306 + j.505$$

$$I'_f(\max) = \frac{4156.9}{\sqrt{(.306)^2 + (.505)^2}} = 7034 \text{ A Symmetrical}$$

$$\frac{X}{R} = \frac{.505}{.306} = 1.65$$

$$I_f(\max) = 1.03\ (7034) = 7240 \text{ A Asymmetrical}$$

At D

$$Z_{eq} = .306 + j.505 + .474 + j3.493 = .78 + j3.998$$

$$I'_f(\max) = \frac{4256.9}{\sqrt{(.78)^2 + (3.998)^2}} = 1020.5 \text{ A Symmetrical}$$

$$\frac{X}{R} = \frac{3.998}{.78} = 5.12$$

$$I_f(\max) = 1.25\ (1020.5) = 1275.6 \text{ A Asymmetrical}$$

At E

$$Z_{eq} = \frac{(.306 + j.505 + .474 + j3.493)\ (3.288 + j30.12)}{.306 + j.505 + .474 + j3.493 + 3.288 + j30.12}$$

$$Z_{eq} = .652 + j3.53$$

$$I'_f(max) = \frac{4156.9}{\sqrt{(.652)^2 + (3.53)^2}} = 1157.9 \text{ A Symmetrical}$$

$$\frac{X}{R} = \frac{3.53}{.652} = 5.41$$

$$I_f(max) = (1.27)\ (1157.9) = 1470 \text{ A Asymmetrical}$$

At F

$$Z = .295 + j.497 + 1.126 + j11.539 = 1.421 + j12.036$$

$$I'_f(max) = \frac{4156.9}{\sqrt{(1.421)^2 + (12.036)^2}} = 343 \text{ A Symmetrical}$$

$$\frac{X}{R} = \frac{12.036}{1.421} = 8.47$$

$$I_f(max) = (1.38)\ (343) = 474 \text{ A Asymmetrical}$$

4.4.1.8 Minimum Fault Currents

The following assumptions are used in the calculation of minimum fault current:

1. Motor contributions are neglected, i.e., fault current flows only from the mine substation.

2. Asymmetrical factors are assumed equal to 1.0.

3. Faults are assumed line-to-line. For a high resistance grounded system, this is 0.866 times the three-phase fault current.

4. Arcing fault factors of 0.9 and 1.0 times the line-to-line fault current are assumed for the 600 V and 7200 V systems respectively.

5. Faults are assumed to occur at the most inby point of the relay's primary zone of protection.

The minimum fault currents are then computed as follows (see Equation 4-13):

At A

The minimum symetrical fault current that can flow through the circuit breaker at location "A" is calculated using the impedance from the electric utility to the most inby point in breaker's primary zone of protection which is assumed to be bus 3. Also included in the calculation is the distribution system line-to-neutral voltage (4156.9V), the line-to-line fault factor (0.866), and the arcing fault factor (1.0 at distribution voltage). From Equation 4-13, the minimum symetrical fault current is:

$$I_f(\min) = (.866)(1.0) \frac{4156.9}{\sqrt{(.32)^2 + (.561)^2}} = 5573 \text{ A}$$

At B

$$I_f(\min) = (.866)\ (.9) \frac{4156.9}{\sqrt{(.32 + 1.216)^2 + (.561 + 1154)^2}}$$

$$= 266\text{A}$$

Note: The equivalent impedance is the sum of the impedances between bus "5" and the electric power utility lines.

At C

$$I_f(\min) = (.866)\ (.9) \frac{4156.9}{\sqrt{(.32 + 474)^2 + (.561 + 3.493)^2}} = 785 \text{ A}$$

At D (using buses 8-12)

$$I_f(\min) = (.866)\ (.9) \frac{4156.9}{\sqrt{(.794 + 38.016)^2 + (4.054 + 2.736)^2}} = 822 \text{ A}$$

At E

$$I_f(min) = (.866)(.9)\frac{4156.9}{\sqrt{(.794 + 4.68)^2 + (4.054 + 2.088)^2}} = 394 \text{ A}$$

At F

$$I_f(min) = (.866)(.9)\frac{4156.9}{\sqrt{(1.536 + .749)^2 + (12.1 + .334)^2}} = 255 \text{ A}$$

4.4.1.9 Machine Full Load Currents (see Equation 4-15)

The machine full load currents are calculated using the maximum connected horsepower of the machine (or machines) and the utilization system line-to-line voltage (550V for the example system). For example, it is assumed for the continuous miner that a maximum of 270hp (270 kVA) is connected to the power system. Thus, from Equation 4-15:

Continuous Miner: $$\frac{270\ 000}{\sqrt{3}\ (550)} = 288.7 \text{ A}$$

$$\text{or } \frac{288.7}{12} = 24.1\text{A @ 7200V}$$

Remaining load on bus 5: $$\frac{370\ 000}{\sqrt{3}\ (550)} = 388.4 \text{ A}$$

$$\text{or } \frac{388.4}{12} = 32.4\text{A @ 7200V}$$

(all motors assumed connected)

Belt drive: $$\frac{150\ 000}{\sqrt{3}\ (550)} = 157.5 \text{ A}$$

$$\text{or } \frac{157.5}{12} = 13.1\text{A @ 7200V}$$

$$\underline{\text{Load on bus 2:}} \qquad \frac{5\ 000\ 000}{\sqrt{3}\ (550)} = 5249\ A$$

$$\text{or} \quad \frac{5249}{12} = 437.4\ A\ @\ 7200V$$

(all motors assumed connected)

4.4.1.10 <u>Transformer Current Ratings (see Equation 4-14)</u>

<u>7.5 MVA</u>

$$I_{rated} = \frac{7500}{(7.2)\ \sqrt{3}} = 601.4\ A$$

<u>750 kva</u>

$$I_{rated} = \frac{750}{(7.2)\ \sqrt{3}} = 60.1\ A$$

<u>225 kva</u>

$$I_{rated} = \frac{225}{(7.2)\ \sqrt{3}} = 18.0\ A$$

4.4.1.11 <u>Transformer Inrush Current</u>

Transformer inrush currents should be available from the manufacturer. For the purposes of this example, they are assumed to be as follows:

<u>7.5 MVA</u>

$$\text{Inrush} = (12)(I_{rated}) = (12)(601.4) = 7216\ A$$

<u>750 kVA</u>

$$\text{Inrush} = (8)(I_{rated}) = (8)(60.1) = 480.8\ A$$

<u>225 kVA</u>

$$\text{Inrush} = (8)(I_{rated}) = (8)(18) = 144.3\ A$$

Cable ampacities are found in Reference 27. It is assumed that the ambient temperature is 40°C and that no reeling of the cables occurs.

4.4.1.12 Summary of Results

Results of these computations are summarized in Table 4-4. All currents are referred to the 7200V distribution system.

4.4.2 Coordination

The first step in the coordination process is the construction of the coordination graph. This graph consists of a log-log plot of circuit breaker and fuse interruption times (in seconds) as a function of current (in amperes referred to the distribution voltage).

The coordination graph for the example is shown in Figure 4-5. The first points to be located on the graph are the transformer inrush and ANSI withstand values. The inrush currents are given in section 4.4.1.11. They are assumed to have a duration of 0.1S. The ANSI withstand values are equal to 20 times the transformer full load current for 3S, for transformers having an impedance of 5 percent (see Table 2-6). The ANSI withstand, when applied to delta-wye connected transformers, must be derated by 42 percent to protect the secondary winding.[20] Thus, the ANSI withstands for the three transformers in the example are 209 A (225 kVA), 696 A (750 kVA), and 6970 A (7.5 MVA).

TABLE 4-4

Results of Overload and Fault Calculations

Relay or Breaker Location	Maximum Fault Current	Full Load Current	Minimum Fault Current	Cable Ampacity	Transformer Current Rating
A	15,200 A	400 A+	5573 A	536 A	601A
B	7410 A	13.1 A	266 A	211 A	18
C	7240 A	48.0 A*	785 A	211 A	60 A
D	1276 A	48.0 A*	82.2 A	-	60 A
E	1470 A	24.1 A	394 A	26.75 A	-
F	474 A	13.1 A	255 A	26.75 A	18 A

* Diversity factor of 1.18 assumed

\+ Diversity factor of 1.25 assumed

The coordination process is continued by solving for the current factors given in section 4.3.3 as follows:

At E

R_1 = (24.1) (12) = 289.2 A @ 600V (continuous miner full load current)

R_2 = (26.75) (12) = 321 A @ 600V (cable ampacity)

Select a 300 A molded case circuit breaker.

$$\text{Rating} = \frac{300}{12} = 25 \text{ A @ 7.2kV}$$

The time-current curves for the circuit breaker are given in Figure 4-4.

It is assumed that the largest motor to be started on the continuous miner is 100 hp and that the per-unit subtransient reactance of the motor is 0.25. The starting current of the motor is then (from Equations 4-15 and 4-17):

$$I_{starting} = 1.25 \times \frac{(1)\ (100)}{(0.25)(\sqrt{3})(.550)} = 525 \text{ A @ 600V}$$

S_1 = 1.2 (525) = 630 A @ 600V (starting current)

S_2 = 1.2 (289.2) = 347 A @ 600V (full load current)

S_3 = 0.8 (394) (12) = 3782 A @ 600V (minimum fault current)

S_4 = 2500 A for 4/0 cable

From Figure 4-4, it may be seen that the minimum magnetic setting of the 300 A breaker is 900 A. This is the setting which will be chosen. At 7.2 kV, this setting is:

$$\frac{900}{12} = 75 \text{ A @ 7.2 kV}$$

At F

R_1 = 13.1 (12) = 157 A @ 600V

R_2 = 26.75 (12) = 321 A @ 600V

Select 175 A molded case breaker. The time-current curve for this breaker is given in Figure 4-4.

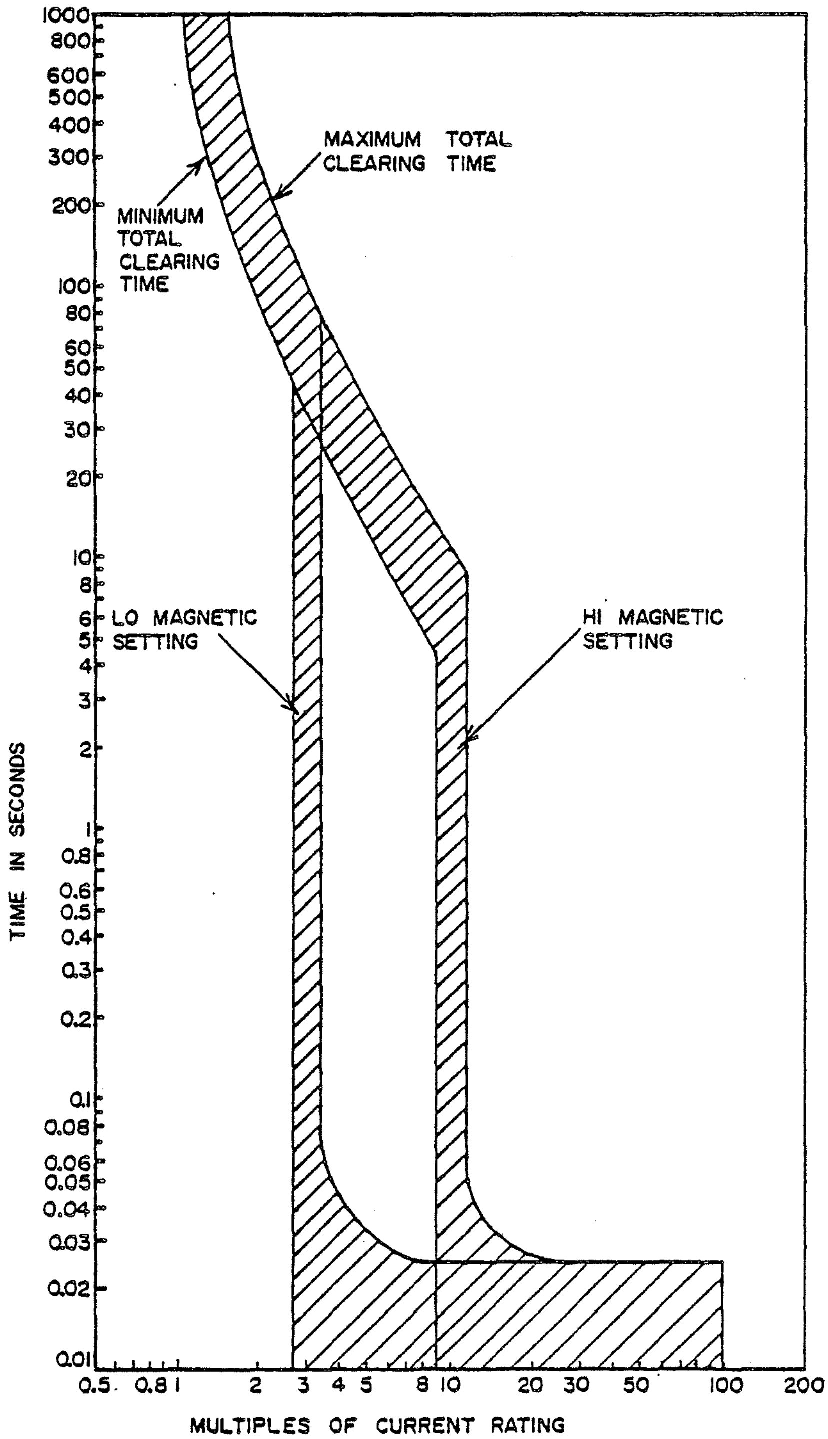


FIGURE 4-4

Molded Case Breaker Time-Current Characteristics

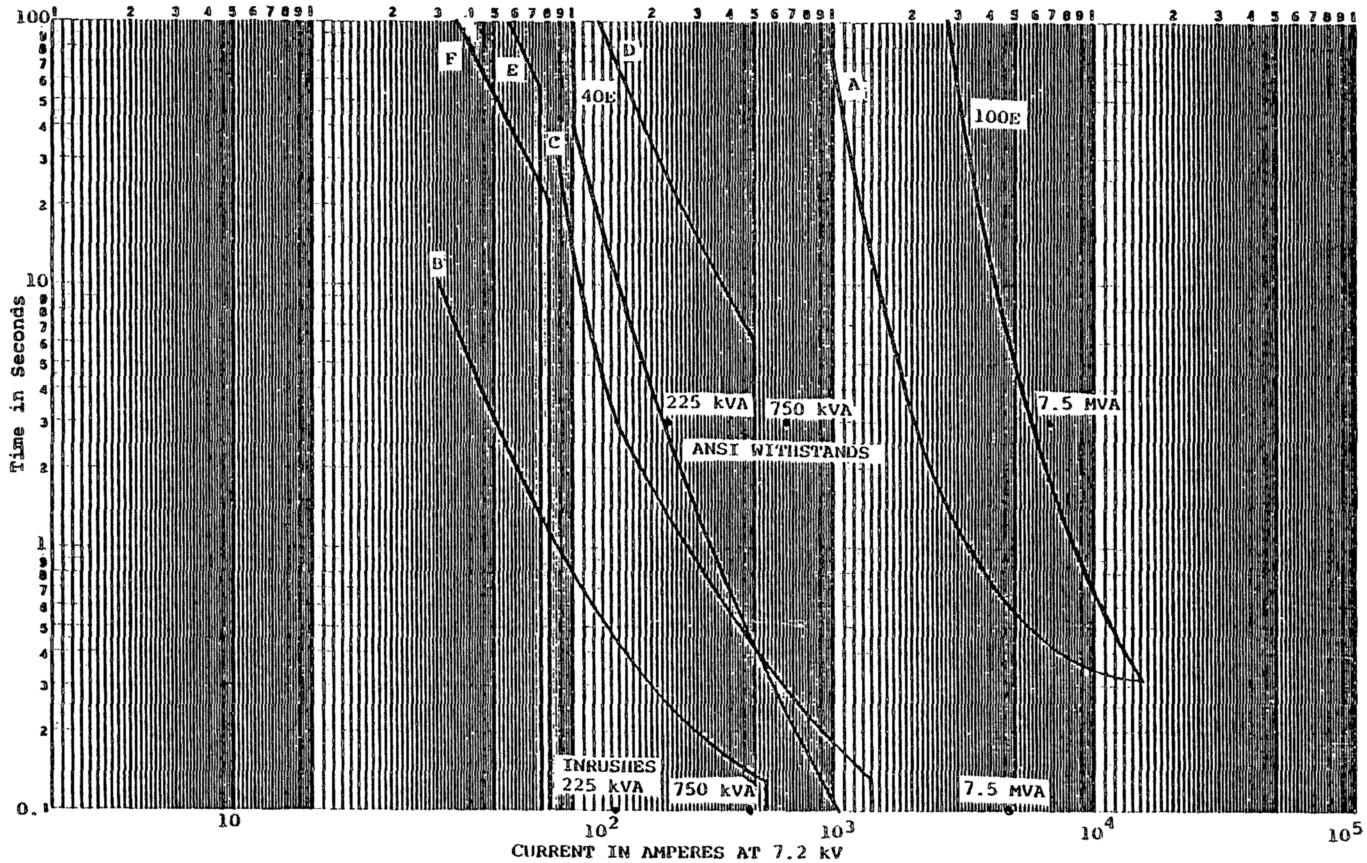


FIGURE 4-5
Coordination Plot for Example

$$\text{Rating} = \frac{175}{12} = 14.6 \text{ A @ } 7.2 \text{ kV}$$

$$S_1 = 1.2 \left(1.25 \frac{1}{0.25}\right) (13.1)(12) = 934 \text{ A @ } 600V$$

$$S_2 = 1.2 \ (13.1) \ (12) = 188.6 \text{ A @ } 600V$$

$$S_3 = 0.8 \ (225) \ (12) = 2448 \text{ A @ } 600V$$

$$S_4 = 2500 \text{ A for } 4/0 \text{ cable}$$

Magnetic setting is chosen as 950 A @ 600V. At 7.2 kV this setting is:

$$\frac{950}{12} = 79.2 \text{ A @ } 7.2 \text{ kV}$$

Similar procedures may be used to select and set the molded case circuit breaker to protect the shuttle cars, section fans, bolter, and feeder-breaker. The molded case breaker which protects the 150 hp feeder-breaker is assumed to have the same rating as that which protects the 150 hp belt drive. Its magnetic setting is also 950 A. The magnetic settings and ratings of the remaining breakers inby from bus 8 are all lower than those of the feeder-breaker and, therefore, need not be considered further in the coordination example.

The next element to be specified is the main molded case breaker located on the secondary of the section transformer at D.

<u>At D</u>

$$R_1 = (48.0) \ (12) = 576 \text{ A @ } 600V$$

$$R_2 = (60) \ (12) = 720 \text{ A @ } 600V$$

A 600 A molded case breaker will be chosen (see Figure 4-4).

$$\text{Rating} = \frac{600}{12} = 50 \text{ A @ } 7.2 \text{ kV}$$

$$S_1 = 1.2 \ (576 + 786) = 1634 \text{ A @ } 600V$$

Note: 150 hp considered to be the largest motor.

$$S_2 = 1.1 \ (1470) \ (12) = 19,400 \text{ A @ } 600V$$

For complete coordination, no magnetic element would be included. For increased safety, a setting of 1800 A (minimum setting) might be chosen, however, coordination with the magnetic element of inby breakers is lost.

The first element to be specified in the high-voltage distribution system is the fuse protecting the belt load center transformer. The specifications for this fuse are based on the transformer inrush (144.3A for 0.1S) and the ANSI withstand (209A for 3S). In addition, the fuse must coordinate with the molded case circuit breaker located at F and the circuit breaker located at B. In both cases, it is probably desirable to use the fuse as a backup, thus the fuse should have a longer clearing time than breakers F and B. The maximum fault current at F is 474A. At this current, the circuit breaker at F will open within 0.03S. Adding a 0.3S coordination interval gives a total time delay of 0.33S at 474A. From Figure 4-8, a 40E fuse satisfies these requirements.

The next protective element to be specified is the over-current relay located at C. This relay will be coordinated with the molded case circuit breakers inby from bus 8. It will not be coordinated with the molded case breaker at D since no gain in selectivity would be achieved. Although such a scheme would aid in fault location, it would also increase fault clearance times significantly.

<u>At C</u>

$P_1 = 1.25\ (48) = 60$ A @ 7.2 kV

$P_2 = 211$ A for 1/0 cable

$P_3 = 2\ (60) = 120$ A @ 7.2 kV

$P_4 = 0.8\ (82.2) = 65.8$ A @ 7.2 kV

Pickup for this relay is selected at 60 A.

$S_1 = 1.1\ (1276) = 1404$ A @ 7.2 kV

$S_2 = 1.1\ (8)\ (60) = 528$ A @ 7.2 kV

The instantaneous setting may be chosen at 1400 A or 550 A depending upon the degree of coordination desired. If 550 A is chosen, coordination with the magnetic elements of inby circuit breakers is lost.

The current transformer is chosen to have a 100:5 current ratio. The relay tap setting is, therefore:

$$\frac{60}{20} = 3 \text{ A}$$

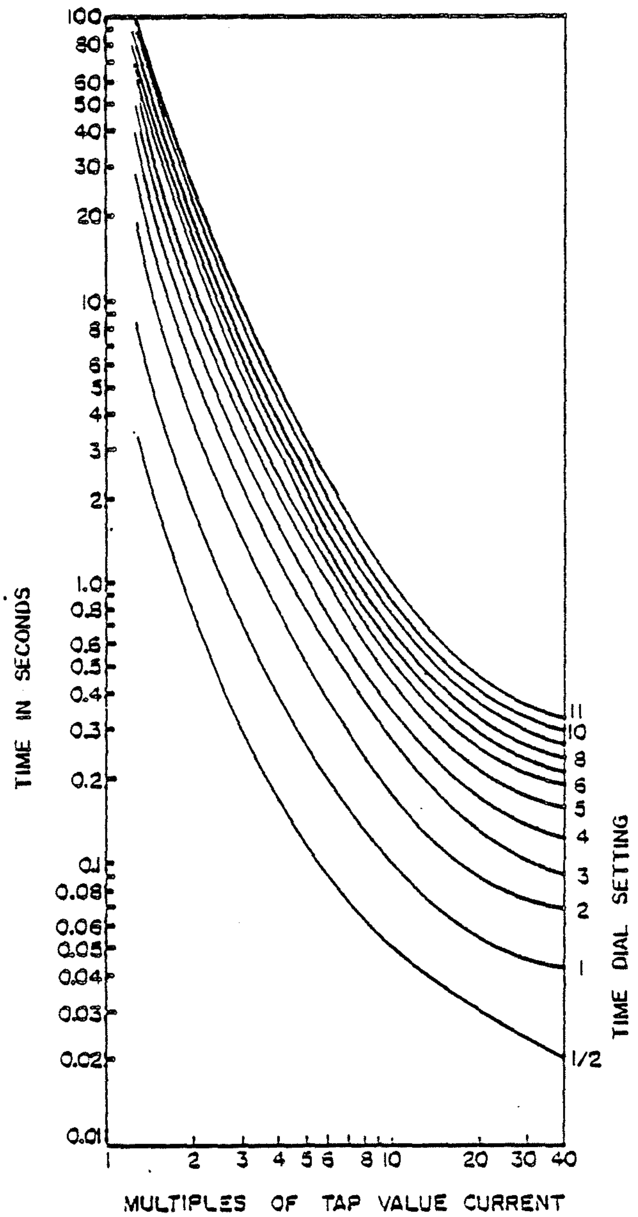


FIGURE 4-6

Time-Current Characteristic for Extremely Inverse Relay

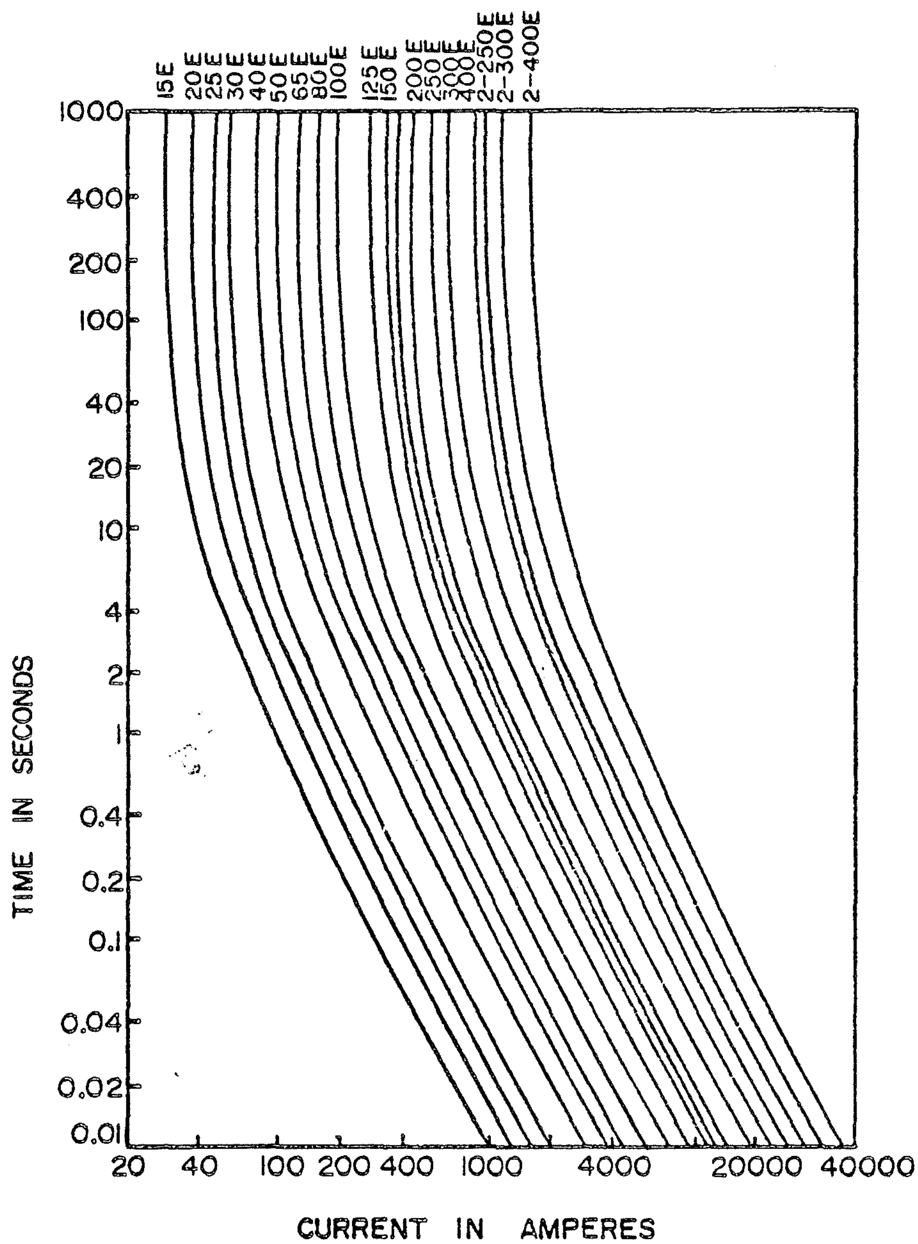


FIGURE 4-7

Typical Minimum Melting Time -- Current Characteristics for High-Voltage Solid-Material Boric-Acid Power Fuses

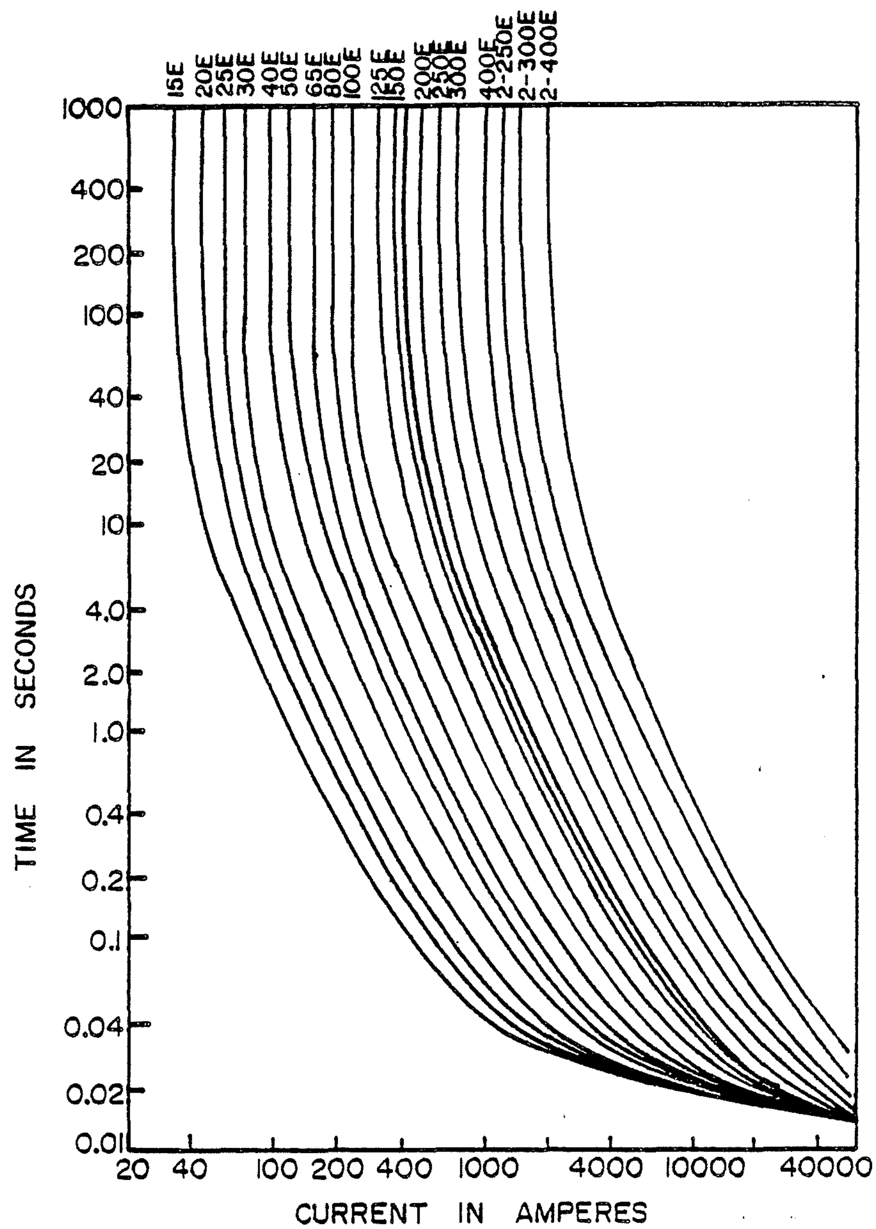


FIGURE 4-8

Typical Total Clearing Time -- Current Characteristics for High-Voltage Solid-Material Boric-Acid Power Fuses

Also,

20 x (100) = 2000 A which is greater than the 1400 A instantaneous setting (see Section 4.3.3.4).

The actual instantaneous relay settng would be:

$$\frac{1400}{20} = 70 \text{ A} \quad \text{or} \quad \frac{550}{20} = 27.5 \text{ A}$$

The time-current curves for the molded case circuit breakers located at E, F, and D are shown in Figure 4-5. To simplify this example, the time-current curve for the 150 hp feeder breaker protection is assumed to be identical with the molded case breaker at F.

The molded case circuit breakers inby from bus 8 have a maximum instantaneous operating time of .03 seconds. If a 0.1 second coordinating time interval is allowed, the operating time for the overcurrent relay at C should be 0.13 seconds for a current of 1276 amperes. From Figure 4-6, this corresponds to a time-dial setting of about 3.0 for an extremely inverse (CO-11) relay. The time-current characteristic of this relay with the selected time-dial setting is then added to Figure 4-5. Examination of the result indicates that if the 1400 A instantaneous setting is selected, coordination has been achieved for all fault or overload currents. In addition, backup protection is provided for all fault currents. This is in addition to the backup protection provided by the main breaker at D.

It should also be noted that the fuse and relay curves are properly located with respect to the transformer inrush and ANSI withstands.

The next relay to be set is located at B. The settings are determined as follows. If selectivity were the only requirement, there would not be any need to coordinate the relay with the molded case circuit breaker at F or the fuse on the belt transformer primary since their protective elements are in series. However, this relay will be partially coordinated in order to ensure that the fuse will back it up and not vice-versa.

<u>At B</u>

P_1 = 1.25 (13.1) = 16.4 A @ 7.2 kV

P_2 = 211 A for 1/0 cable

P_3 = 2(18) = 36 A @ 7.2 kV

P_4 = 0.8 (255) = 204 A @ 7.2 kV

Pickup for this relay is selected at 17.5 A.

$$S_1 = 1.1\ (474) = 521\ \text{A @ } 7.2\ \text{kV}$$

$$S_2 = 1.1\ (8)\ (18) = 158.4\ \text{A @ } 7.2\ \text{kV}$$

The instantaneous setting may be chosen as 530 A or 160A depending upon the degree of coordination desired.

The current transformer is chosen to have a 25:5 current ratio. The relay tap setting is, therefore:

$$\frac{17.5}{5} = 3.5\ \text{A}$$

Also,

$$20\ (25) = 500\ \text{A}$$

If the 530 A instantaneous setting is chosen, current transformer accuracy should be checked. An alternative is to reduce this setting to 500 A.

The molded case breaker at F has a maximum instantaneous operating time of 0.03 seconds. For a 0.1 second coordinating time interval, the operating time for the overcurrent relay at B should be 0.13 seconds for a current of 480 amperes. From Figure 4-6 this corresponds to a time-dial setting of about 4.0 for an extremely inverse relay. However, when the time characteristic is added to Figure 4-5, it becomes apparent that the belt motor may trip the relay at B when it starts with the belt loaded. (A time setting of 4 permits motor starting current to flow for approximately 2.0S). Increasing the time setting results in slightly longer fault clearance time. However, relay coordination remains unchanged. If a time setting of 4 is used and the 530 A instantaneous setting is selected, coordination has been achieved from maximum fault current to a current slightly less than 100 A. Backup protection is provided for all fault or overload currents, and coordination with the fuse is such that the fuse backs up the relay at B.

<u>At A</u>

$$P_1 = 1.25\ (400) = 500\ \text{A @ } 7.2\ \text{kV}$$

P_2 = 536 A @ 7.2 kV (Note that the substation relaying is not set to protect the 4/0 cable between busses 2 and 3. Protection of the 4/0 cable would require an extra switchhouse at bus 2 which would significantly increase fault clearance time. The 4/0 cable is adequately protected at its load end (bus 3) from overloads).

P_3 = 601 A @ 7.2 kV

P_4 = 0.8 (785) = 628 A @ 7.2 kV. (Note that this value provides backup protection for the relay at C but not the relay at B. The fuse on the belt load center primary backs up the relay at B.)

Pickup for this relay is selected at 500 A.

S_1 = 1.1 (7410) = 8151 A @ 7.2 kV

The current transformer is chosen to have a 1000:5 current ratio. The relay tap setting is then:

$$\frac{500}{200} = 2.5 \text{ A}$$

Also,

20 (1000) = 20000 which is greater than the maximum fault current.

Since this relay is to be coordinated with the relay at C, it should have a minimum operating time of 0.4 + 0.016 = 0.416 seconds at 7410 A (the overcurrent relay at C has an instantaneous trip of time of 0.016S). An extremely inverse relay is, therefore, selected with a time-dial setting of 9.0. The time-current curve for this relay is then added to Figure 4-5.

The primary of the 7.5 MVA transformer would normally be fuse protected. This fuse will be coordinated with the relays at bus 1. Thus, selectivity will be maintained for all faults other than low impedance faults on the 500 MCM cable connecting buses 1 and 2, where coordination is marginal. Since such faults would require removal of the entire mine from service, all that has been lost by this procedure is an aid in fault location.

A 100E fuse is selected for this purpose. Its continuous rating is slightly greater than the 7.5 MVA transformer primary rating and its minimum operating times provide fairly good coordination with the relays at bus 1 as well as provision for transformer inrush. Its maximum operating time is also less than the withstand of the 7.5 MVA transformer. The operating curve for this fuse is now added to Figure 4-5 (see Figures 4-7 and 4-8).

4.5 Summary

The first step in the design of a protective relaying system for coal mine power systems is the selection of protection points. Enough protection points must be included so that each protected zone has both primary and backup coverage. The use of too many protection points, however, can cause problems because time-current curves must be "stacked" to achieve coordination. In certain cases, non-coordinated backup protection may be used to advantage, as was the case in the example, where fuses were used as backup protection for the belt load center.

Once the physical layout of the power system has been defined, the various load and fault currents must be calculated. The importance of obtaining accurate input data for these calculations cannot be overstressed. The final result of the coordination study, i.e., the coordination time-current plot, is meaningless without good input data.

The various power system load and fault currents are then used in conjunction with the criteria presented in Section 4.3.3 to arrive at circuit breaker, fuse, and relay selection and settings. Each time a protective device is specified, its time-current characteristic is graphed on the coordination plot. The coordination plot is the most powerful tool of the overcurrent relaying system designer because it allows instant evaluation of system performance.

5.0 EXPERIMENTAL PROCEDURES

5.1 Introduction

The experimental work conducted during the course of this investigation is addressed in this section. The scope of work required that a quantitative determination of the relative number of ground faults versus phase faults be made. This work is discussed in Section 5.2. A new type of protective circuit test set was developed and used to collect data for this project; it is described in Section 5.3. The main utility of the device described in Section 5.3 is preventive maintenance testing; the role of this testing in an overall protective system test and maintenance program is described in Section 5.4.

5.2 Fault Detection and Classification

The scope of work for this contract required that the relative number of ground faults versus phase faults be determined. This aspect of the study was to be performed at ten (10) coal mines. In accordance with these contractural requirements ten mines were selected, of which three (3) were surface and seven (7) were underground, and instrumentation systems were designed, constructed, and installed within four (4) months after the contract start date. The instruments were installed for an average of eight (8) months, resulting in approximately 80 mine-months of accumulated data. Prior to a discussion of the instrumentation, later in this section, the results of this work will be examined.

The results of this experiment indicated that phase faults occur 1.25 times more frequently than ground faults. This number should be interpreted cautiously, however, for two reasons. First, the data cannot be statistically validated due to the small sample size, event frequency, and the number of parameters which could modify these results. Second, the concept of determining the relative frequency of the faults, as required by the scope of work, is somewhat meaningless. Unfortunately, this was not apparent until other tasks of the project were completed. If it had been possible to perform this experiment at the end of the project rather than the beginning, the experiment would have been modified as described in the following paragraph.

The relative number of faults which occurs is of little interest, primarily because the fault type on a distribution system will depend on the voltage level, the number of roof falls along the power distribution entry, and so forth. These parameters are highly dependent upon the actual mine. Similarly, the quality of the relay system, as well as its coordination, will have an impact on this relative number. For example, if a ground fault occurs, especially at the higher distribution voltages of 7.2 kV or 13kV, it will usually convert to a phase fault, unless the ground fault relaying has been carefully designed. A much more meaningful number to experimentally determine would have been the conversions from ground to phase faults. However, it was not until after the mine visits that the researchers confirmed the wide-spread application of incorrect relay setting procedures, which would cause fault conversion. This problem was addressed in Sections 2, 3, and 4 of this report and will not be repeated here. The reader will recall, however, that a selection of the wrong instrument transformer size will cause inaccurate relay performance.

If taken at face value, the results of this study would indicate that the occurrence of faults is uniformly distributed between those involving phase conductors and those which only involve ground. Based on the mechanics of the situation, and the experiences of other industries, it would be more reasonable to expect a ratio of two or more ground faults to every phase fault. The following information serves to substantiate this statement.

- The use of shielded distribution-voltage cable precludes the possibility of a phase fault, in the cable, which does not include ground.
- Phase faults could occur in switchhouses, load centers, or couplers without involving ground, but the tendancy is toward an arcing ground fault.
- Coupler, load centers and switchhouse faults are rare in 4.16 kV systems.

The only logical explanation for the collected data is that some, relatively high, percentage of the ground faults did convert to phase faults. This indicates that ground faults are not being cleared fast enough to prevent dielectric damage (due to the localized heat concentration, and the attendant arc to other phase conductors). The protective system's ability to immediately clear the fault is heavily dependent on the relay settings. The experiences of the field personnel involved in this study indicated that the settings, as well as instrument transformer sizing are many times done incorrectly; the results of this experiment tend to substantiate this.

Another cause of fault conversion from ground to phase is repeated closing of the circuit breaker on a faulted branch. This procecure, which was reported as being not uncommon at some mines, is practiced by uninformed mine personnel with the expectation that the fault will "go away" if the breaker is reclosed often enough. Thus, even if the ground fault relaying clears a ground fault before it can escalate into a phase fault, multiple reclosures may cause enough dielectric damage at the fault point to result in a phase fault.

The ground/phase fault event detector and recorder is shown schematically in Figure 5-1. Functionally, the unit can be divided into four sections. These are the voltage dividers, the threshold detector circuits, the electromechanical counter driver circuits, and the electromechanical counters. There are four channels in the circuit, three are connected to the phase relaying circuit and one is connected to the ground relaying circuit of the power system. The purpose of the voltage dividers is to select the proper input range of the instrument. Phase and ground current magnitude are measured by sensing the voltage across the coils of the corresponding phase and ground fault relays. Although the coil impedance is nonlinear, a relay coil threshold voltage can be related to the current transformer primary current of interest. The voltage divider ratio is switch selectable, providing an input range from about 0.05 volts to 160 volts. The input impedance of the instrument ranges from about 100 ohms of the most sensitive setting to 1,000,000 ohms at the least sensitive setting.

The threshold detector circuits initiate a count when the input exceeds a predetermined valve. The threshold detector circuits also contain a potentiometer which enables the threshold voltage to be fine-tuned within a particular input range. Phase-to-phase and three-phase faults are not counted on a per phase basis, rather, a fault between any two or all three phases will increment the phase counter once. Consequently, the three input circuits which are connected to phase CT's are combined using an analog "OR" circuit. The output of this circuit is connected to the threshold detector.

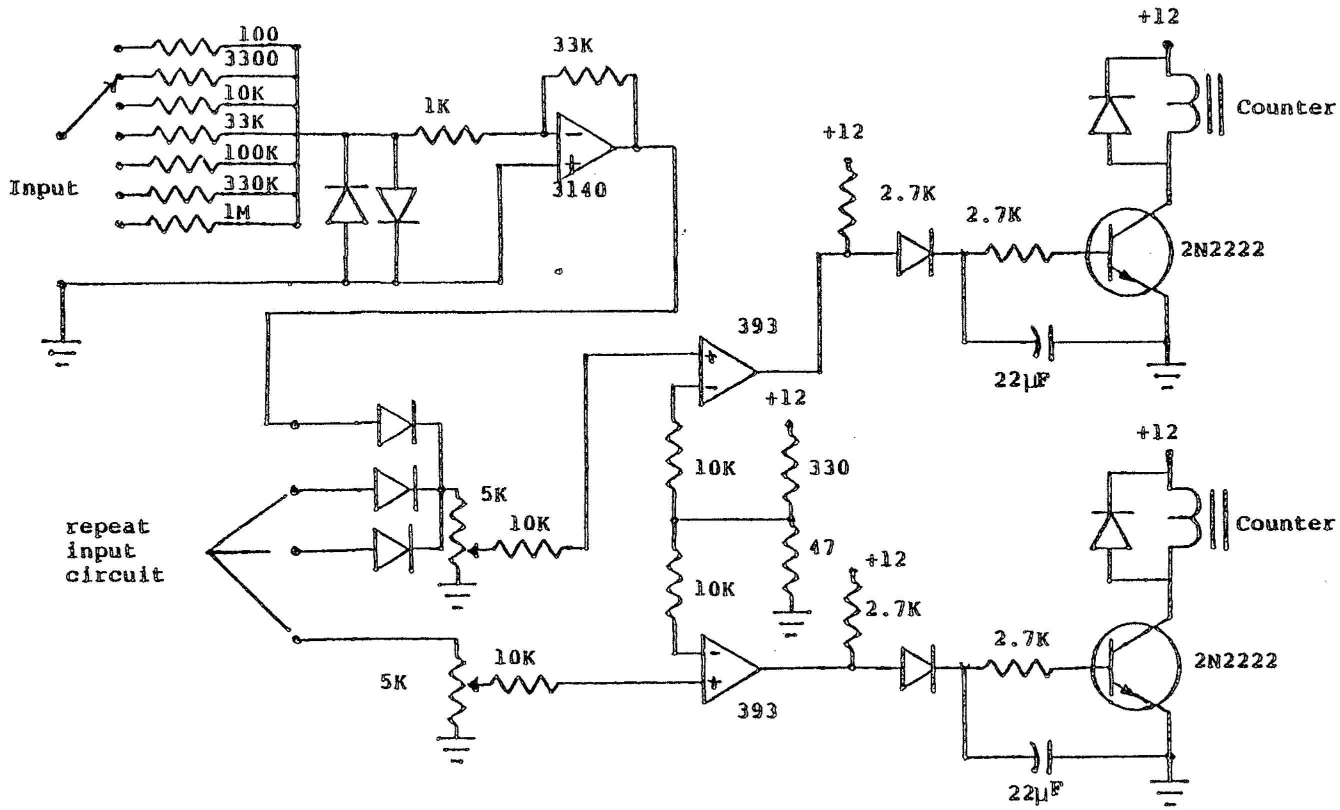
The electromechanical counter driver circuits and the counter itself are constructed so that the input signal must increase above the threshold and decrease below the threshold before a counter is incremented. This ensures that a fault which is not cleared immediately will not cause multiple counts.

In addition to the use of these devices to count ground/ phase faults, they could also be used in load studies. The circuits are essentially electromechanical integraters, and as such, they can be used to count the number of events which occur over a large period of time regardless of the event type.

5.3 Protective Circuit Testing

The integrity of any protective relaying system must be ensured by a regular test and maintenance program. There are five parts to a thorough relay system test:

- Instrument Transformer
- Relay
- Trip Circuit
- Circuit Breaker



All diodes: IN4004
All resistors are 1/4 watt except those in the selector switches which are 1/2 watt.

FIGURE 5-1
Event Detector Circuit

- o The system formed by interconnecting these subsystems

It would be ideal if each of these items could be bench tested on a daily basis. Such an approach, however, would hardly be prudent in light of established historical failure rates. Instrument transformers and circuit breakers have such a low failure rate in the mining industry that extensive testing could never be justified, except occassionally, e.g., once every two years. There is a justifiable need, however, to test the relay, trip circuit, and the system. Yet existing Federal Code requires that only the trip circuit be tested.[76]

In the early stages of this research the capability of the individual components to function as a system was questioned. This issue was particularly perplexing in ground fault relay applications where it appeared that a properly functioning current transformer, relay, trip circuit, and circuit breaker could not clear a ground fault. As a first step in resolving this problem the procedures for specifying the protective circuitry in a switchhouse or substation were investigated. It was found that the specifications were sometimes developed by the mining company, but were more often generated by the manufacturer. A spot check of seven recently constructed switchhouses, all of different manufacturers, revealed that six of seven had incorrectly matched the current transformer and relay. The degree of mismatch varied between units. One had a current transformer that simply couldn't drive its relay. The others were mismatched in the sense that current transformer saturation would cause large errors concerning actual pickup current versus relay setting. No determination was made as to who was responsible for the specification. The situation is changing as manufacturers begin to use the low-burden solid state relays which have become available over the last few years, however, the fact remains that many switchhouses in service have less than ideal ground fault relaying systems.

The questions surrounding the incorrect specification of protective circuitry are rather academic. The fact is that some protective circuits of dubious value are finding their way into the mine. Not only is the safety and welfare of the miner at stake when this happens, but also the quality of the production environment. The failure of the protective circuit to clear a fault may result in the destruction of another power system component. The replacement cost and lost production time costs may be an order of magnitude greater than if the fault had been cleared.

An experimental test set was developed to investigate the aforementioned issues in greater detail. The function of the test set is to measure the performance of the system, as well as certain subsystems. Figure 5-2 illustrates the connection

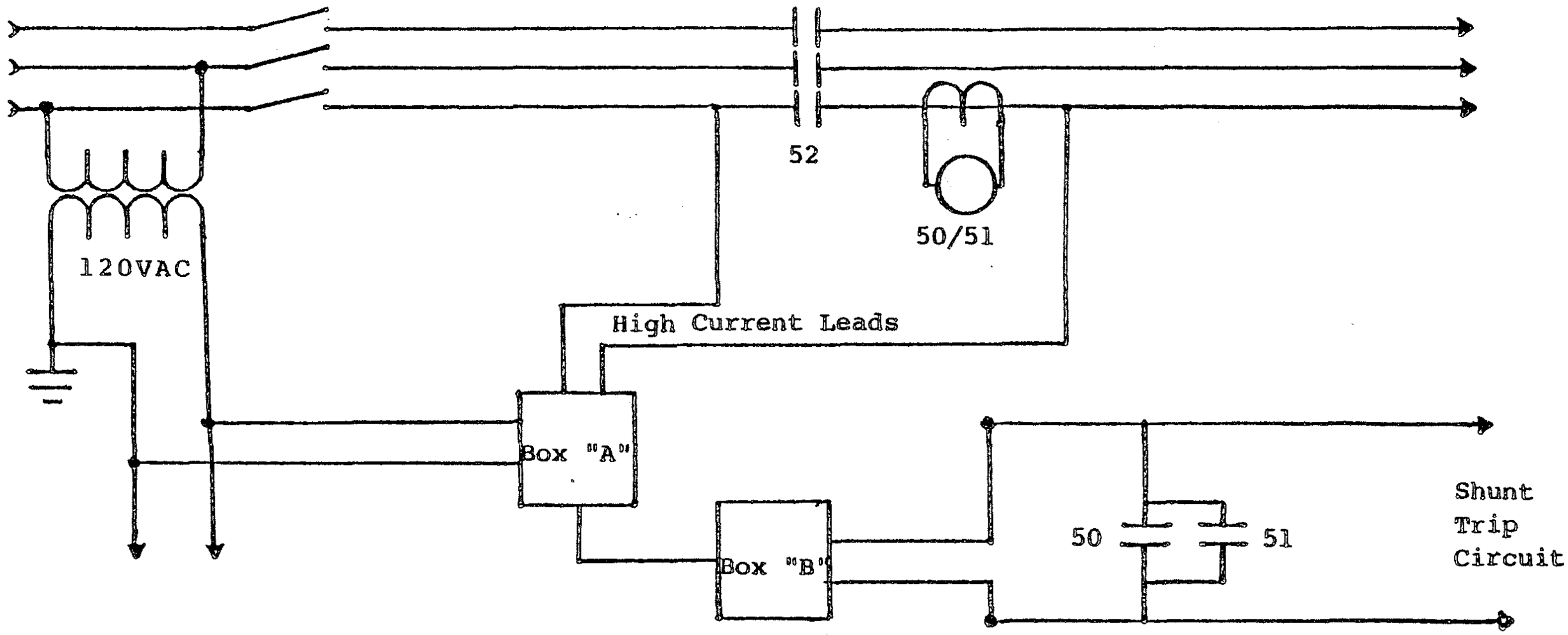


FIGURE 5-2

Block Diagram Showing Application of
Circuit Breaker Test Set

and functions of the test set in a switchhouse or substation. Referring to the figure, the application of the test set is described in the following:

1. Open the air break switch (visible disconnect).

2. Pass one high-current lead of Box A through the current transformer under test and connect the end of the lead to one side of circuit breaker.

3. Connect the second high current lead of Box A to the other side of the circuit breaker.

4. Connect the two leads of Box B across a set of relay contact tips in the shunt trip circuit.

5. Connect the power input leads to the 120 V control transformer in the switchhouse.

The test set is now installed and ready for use.

6. Set the dial on Box B for the current at which the circuit breaker should trip (based on the relay tap setting and current transformer ratio).

7. Set the dial on Box A for the same circuit level which was selected on Box B.

8. Throw the switch on Box A to start the test.

When this switch is turned to the on position, a high-current at a low voltage, flows through the high-current cable. Simultaneously Clock A begins timing. When the relay picks up its trip circuit contacts close. At this instant Clock A stops timing and Clock B begins timing. When the circuit breaker opens, Clock B stops timing.

It is recommended that the circuit breaker opening time be measured using the ground fault relaying in the switchhouse. This is because the test set may have insufficient power to pick up a phase overcurrent relay when the added resistance of the circuit breaker and extra cable are added to the high current circuit. Once the circuit breaker opening time has been obtained, the pickup time of the phase overcurrent relays may be measured by placing short leads from the test set to the appropriate current transformer.

The use of the time displayed on Clock A is apparent. It should correspond directly to the relay curves. If it does not, the following items should be checked:

- relay tap and time curve settings
- calculations
- relay operation (by using a Multi-Amp, or equivalent)
- current transformer operation (by using the test set and an ammeter connected on the CT secondary)

The use of the time displayed on Clock B is not as straightforward. The time measured is the circuit breaker operating time, and not the fault clearing time since arc extinguishing time is not included in the test (no arc is generated). The measured value could be compared to values obtained from the manufacturer or simply recorded and compared to previous tests. Any trend such as increasing operating times could be used to determine the time for replacement or more extensive tests.

Although this test set was originally conceived to facilitate the research of this project, it is well-suited to application by the mining industry. It is easy to install and use. Oil circuit breakers are, however, a slight nuisance to test due to the extensive amount of dielectric putty used on their terminals. In the case where vacuum bottles are used, the entire test procedure can be executed in less than sixty minutes.

The test will detect the following:

- burden mismatch between the CT and Relay
- faulty CT operation
- faulty relay operation
- incorrect setting of tap or time characteristics
- trip circuit malfunction

This test set fills a void in the existing market of commercially available test equipment. It is not suggested that it can replace existing equipment. Rather it is an inexpensive, easily constructed, and portable test set suitable for use in the mine. For optimum benefit, it is suggested that a mine utilize the test set for all switchhouse and substations according to the following schedule:

- Surface test all new and rebuilt units before mine installation
- Test all units at least once a year

- Setup an installation program to permanently install the "Box A" functions inside each unit, and to mount the appropriate connectors on a dead front panel. Then Box B could be easily and safely plugged into this panel prior to the test.

- After this installation program is complete perform tests concurrently with required testing of trip circuit.

5.4 Protective Circuit Testing and Maintenance

Routine testing and maintenance of protective circuitry is necessary to ensure that it will always perform its intended function. Earlier sections of this report have been concerned with theoretical procedures for developing and implementing a coordinated power system. This is, however, only one half of the total process. It is equally important that the system be tested to ensure that the original calibrations and settings have not been altered, or if they have been altered to meet ever changing load conditions, the appropriate test procedures will ensure that the design engineers will be aware of these changes and can make necessary changes in the system coordination.

It is a common practice of maintenance personnel in the mining industry to reset relay settings to meet changing load conditions, and to eliminate nuisance tripping of the devices. After this has occurred several times, and particularly when it occurs in different places of the power system, the coordination factors have become so distorted that system coordination is virtually impossible. Unfortunately, this often results in inordinately long fault clearing times, and in some cases, situations where faults are not cleared. Consequently, it is in the best interest of the mining company to set up and maintain an adequate test program.

Perhaps the most important aspect of this program is having self contained and portable test sets which will be easy to use and save time. The test set described in the previous section is one such device. In addition to supplying the proper test equipment, it is also necessary that an easily read and standardized set of test procedures exist for maintenance personnel. This booklet of test procedures could be developed using the book, "Inspection and Test of Electrical Equipment", which is published by the Westinghouse Electric Service Division of the Westinghouse Corporation. This book is probably the most complete compilation of test procedures for electric power system equipment. However, it is much too detailed and extensive for use by mine maintenance personnel. It could be used as a basis for developing a more customized and condensed version for a given mine. Equipped with the appropriate test equipment, manufacturers manuals, and a catalog of test procedures, mine maintenance personnel will be able to ensure continued reliability and safety of the mine power system. The following paragraphs briefly summarize some of the more important tests which should be performed on the relay protective circuitry.

Protective relays should be inspected and serviced as required, on an annual basis. As a minimum, the following general items should be addressed:

- o relays should be clean and friction free
- o contacts should be maintained and properly aligned
- o all leads and terminal hardware should be tightfitting

Specifically, the following test should be performed for overcurrent relays:

- o <u>Zero Set Test</u> - This test determines that the relay contacts close when the dial is set to zero.
- o <u>Pickup Test</u> - This test is used to determine the minimum operating current for the relay.
- o <u>Time/Current Characteristics</u> - This test is used to check the time/current characterstics of the given relay.
- o <u>Target and Sealing Test</u> - This test determines the correct action of the targets or annunciators in the relay.

The trip circuit should be checked for proper operation. Typically, this is performed by either manually rotating the induction disc of the overcurrent relay or actuating one of the auxilliary trip circuits such as the ground check monitor.

The circuit breakers should be tested in accordance with manufacturer recommended procedures, which should include among others:

- o general condition of the operating mechanism
- o friction and moving parts
- o tightness of power connections
- o loose, broken, or missing hardware
- o excessive wear on mechanical parts

- the function of auxilliary switch linkages and hardware, all relay contacts, coils, and moving parts
- contacts, main contacts should be inspected and checked for overtravel as well as spring pressure settings
- main contact resistence should be measured under normal operating conditions
- arc interrupters should be thoroughly inspected and repalced if badly burned or broken.

Federal law requires testing of distribution system protective equipment at one month intervals (Sections 75.800-3, 77.800-1 of CFR 30). The tests must include breaking the continuity of the ground check circuit and actuating two (deep mine) or one (surface mine) of the auxiliary protective relays. The test also includes a visual examination.

Table 5-1 consists of a recommended form for recording results of distribution equipment tests. The form is designed for a switchhouse with one circuit breaker and two load side circuits. Besides providing spaces for test results, the form also includes information on relay settings. The comments space could be used for maintenance information. Overall, the form, when properly filled out, provides an excellent means for evaluating the performance of a relay system.

Relay maintenance hints are available from most relay manufacturers as part of a standard documentation package describing the relay's performance. The subject is also covered in References 20 and 21.

TABLE 5-1

Form for Recording the Results of
Power Distribution Equipment Tests

Switchhouse Location:	Relay Settings	Inst.	Time
Installation Date:	Phase:		
Relay Types	Ground:		
Phase:	Current Transformers	Ratio	Accuracy
Ground:	Phase:		
	Ground:		

Comments:

1980	Ground Check		Inst. Relays				Time Relays				Visual	INL
Date	CKT-A	CKT-B	A	B	C	GND	A	B	C	GND		
JAN __	*	*	*				*				*	*
FEB __	*	*		*				*			*	*
MAR __	*	*			*				*		*	*
APR __	*	*				*				*	*	*
MAY __	*	*	*				*				*	*
JUN __	*	*		*				*			*	*
JUL __	*	*			*				*		*	*
AUG __	*	*				*				*	*	*
SEP __	*	*	*				*				*	*
OCT __	*	*		*				*			*	*
NOV __	*	*			*				*		*	*
DEC __	*	*				*				*	*	*

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APPENDIX I

COORDINATION PROCEDURE

The following material is an outline of the coordination procedure which is detailed in Chapter 4. The outline is presented as a step-by-step procedure for the reader's convenience. Many of the calculations involve design decisions which cannot be summarized in a table, or even provided by anyone, other than the engineer examining a specific system. Consequently, it is imperative that the Section 4 material be thoroughly understood before any attempts are made to apply this streamlined procedure to mine power system protection problems. Steps 2 through 14 in the outline involve computation of power system fault, full load, and rated currents. Although these computations may be done by hand, it will become apparent that the use of a load flow/fault analysis computer program is the logical alternative for all but the smallest systems.

Step 1. Construct the power system single-line diagram.

This consists of:

- electric utility voltage and short circuit capacity
- ratings, impedances, and connections of all transformers
- cable sizes and lengths
- load voltages and horsepower ratings

Step 2. Compute the electric utility reactance:

$$X = \frac{(\text{substation transformer secondary } kV_{LL})^2}{(\text{utility short circuit MVA})}$$

Step 3. Compute substation transformer resistance and reactance:

$$R = \frac{R_T\ (\%)}{100}\ \frac{(\text{secondary } kV_{LL})^2}{(\text{rated transformer MVA})}$$

$$X = \frac{X_T\ (\%)}{100}\ \frac{(\text{secondary } KV_{LL})^2}{(\text{rated transformer MVA})}$$

Step 4. Compute distribution system cable resistance and reactance:

$$R = \left(\text{cable resistance}/1000'\right)\left(\begin{array}{l}\text{cable length in}\\ \text{thousands of feet}\end{array}\right)$$

$$X = \left(\text{cable reactance}/1000'\right)\left(\begin{array}{l}\text{cable length in}\\ \text{thousands of feet}\end{array}\right)$$

Step 5. Compute utilization transformer resistance and reactance:

$$R = \frac{R_T\ (\%)}{100} \quad \frac{(\text{primary } kV_{LL})^2}{(\text{rated transformer MVA})}$$

$$X = \frac{X_T\ (\%)}{100} \quad \frac{(\text{primary } kV_{LL})^2}{(\text{rated transformer MVA})}$$

Step 6. Compute utilization system cable resistance and reactance:

$$R = \left(\text{cable resistance}/1000'\right)\left(\begin{array}{c}\text{cable length in}\\ \text{thousands of feet}\end{array}\right)(Z)$$

$$X = \left(\text{cable reactance}/1000'\right)\left(\begin{array}{c}\text{cable length in}\\ \text{thousands of feet}\end{array}\right)(Z)$$

$$\text{where:} \quad Z = \frac{(\text{transformer primary } kV_{LL})^2}{(\text{transformer secondary } kV_{LL})^2}$$

Step 7. Compute the subtransient reactance of all induction motors which are connected to the power system:

$$X'' = X''\ (\text{per unit}) \quad \frac{(V_o)^2\ (V_m)^2\ (1000)}{(HP)(V_s)^2}$$

where: V_o = distribution system voltage (kV)
V_m = rated motor voltage (V)
HP = rated motor horsepower (hp)
V_s = rated utilization system voltage (V)

NOTE: If motor subtransient reactances are not available from manufacturers, a value of 0.25 per unit may be assumed for induction motors rated less than 600V with a corresponding value of 0.17 for induction motors rated greater than 600V. Motor subtransient reactances are used in the calculation of maximum asynchronous fault current. Electric lights and dc loads connected to the power system through rectifiers do not enter into fault calculations because they do not supply any current during a fault.

Step 8. Construct the system impedance diagram using the values obtained in Steps 2 through 7. Motors are connected to the reference bus through their subtransient reactances.

Step 9. Compute the maximum asymetrical fault current at the load side of each circuit breaker:

$$I_f \text{ (max)} = (F) \frac{(V_{L-N})}{Z_{eg}}$$

where: F = asymetrical fault factor from Table 4-1

V_{L-N} = distribution system line-to-neutral voltage (V)

Z_{eg} = the total impedance from the fault, through the circuit breaker, to the reference bus.

NOTE: I_f (max) represents the maximum fault current which can flow through a circuit breaker. It is used to ensure that a circuit breaker does not trip instantaneously for a fault that is not in the breaker's primary zone of protection.

Step 10. Compute the minimum fault current in each breaker's primary zone of protection:

$$I_f \text{ (min)} = (0.866)(A) \frac{(V_{L-N})}{Z_{eg}}$$

where: 0.866 = line-to-line-fault factor

A = arcing fault factor (0.85 at 480V; 0.9 at 600V; 0.95 at 1040V; 1.0 at distribution voltage)

V_{L-N} = distribution system line-to-neutral voltage

Z_{eg} = impedance from fault point (most inby point in breaker's primary zone of protection) to the electric utility

NOTE: I_f (min) represents the minimum fault current (with the exception of ground fault current) that can flow through a circuit breaker. I_f (min) is used to ensure that a circuit breaker trips instantaneously for a fault in its primary zone of protection. It is also used to ensure that a breaker will trip (after a suitable time delay) for a fault in the breaker's backup zone of protection.

Step 11. Compute the rated current of the substation transformer:

$$I_{rated} = \frac{\text{(transformer KVA rating)}}{\text{(transformer secondary } kV_{LL}\text{)}(\sqrt{3})}$$

NOTE: Transformer currents are calculated at the mine distribution voltage. Thus, the rated current of the substation transformer refers to the rated secondary current.

Step 12. Compute the rated currents of the utilization transformers:

$$I_{rated} = \frac{\text{(transformer KVA rating)}}{\text{(transformer primary } kV_{L-L}\text{)}(\sqrt{3})}$$

Step 13. Compute the full load current of all machines:

$$I_{full\ load} = \frac{\text{(machine horsepower)}}{\text{(machine rated } kV_{L-L}\text{)}(\sqrt{3})}$$

NOTE: It is assumed that one horsepower is equivalent to one KVA. Machines with more than one motor, such as continuous miners, generally don't have all motors connected at one time. In such cases, a judgement must be made concerning the maximum connected horsepower.

Step 14. Compute the starting current of motor loads:

$$I_{starting} = (1.25) \frac{1}{X'' \text{ (per unit)}} (I_{FL})$$

where: X'' (per unit) = motor subtransient reactance
I_{FL} = motor full-load current

Step 15. Obtain cable ampacities from the cable manufacturers specifications.

Step 16. Compute the ANSI withstand for the substation and utilization transformers. The ANSI withstand values, which are given in Table 2-6, represent the maximum current that the transformer can carry without damage for the time period given. The ANSI values must be derated by 43 percent for delta-wye transformers. The withstands are calculated as follows for delta-wye transformers:

$$I_{withstand} = (0.57)(\text{ANSI value})(I_{FL})$$

where: ANSI value is found in Table 2-6
I_{FL} = transformer full-load current

Step 17. Compute the inrush current for the substation and utilization transformers. Inrush currents may be assumed to be 8 to 12 times the transformer full-load current, in lieu of manufacturers data. Inrush currents are usually assumed to flow for 0.1 second.

Step 18. Construct the coordination graph. The coordination graph is a log-log plot of distribution system current against circuit breaker opening time. The plot can usually be placed on three-cycle by four-cycle paper with a time range of 0.1S to 100S and current range of 10A to 10,000A.

Step 19. Place the ANSI-withstand and transformer inrush currents on the coordination plot. In order for a circuit breaker or fuse to properly protect a transformer, its time-current characteristic must fall to the right of the inrush and to the left of the withstand.

Step 20. Begin selecting circuit protection devices by starting with the molded-case breakers protecting the individual machines. Circuit breaker time-current curves must be obtained from the breaker manufaturer. The following criteria have been developed for the thermal and short circuit settings.

<u>thermal overload</u>:

- o R_1 = 1.0x (full load current of the machine including lights and any diversity factor)
- o R_2 = 1.0x (trailing cable ampacity)

Normally, R_2 is greater than R_1 and the circuit breaker rating is selected as the next size greater than R_1. The setting must not be greater than R_2.

<u>short circuit</u>:

- o S_1 = 1.2x (maximum motor starting current)
- o S_2 = 1.2x (full load current including lights and diversity)
- o S_3 = 0.8x (minimum fault current at the load end of the trailing cable)

  NOTE: This is I_f(Min).

- o S_4 = 1.0x (maximum trailing cable current from 75.601-1, CFR30)

The setting should be approximately equal to the larger of S_1 and S_2, and less than S_3 and S_4.

NOTE: Step 20 is repeated for all breakers at each utilization point.

Step 21. Draw and label the molded case circuit breaker time current characteristics on the coordination plot. When using breakers with common characteristics, only the characteristics of the larger breakers of each utilization point are drawn on the plot. This is because the larger breakers will, in general, have longer clearing times than the smaller ones.

Step 22. Select the setting of the main molded case breaker (if used) at each utilization point. The following criteria have been developed:

thermal overload

- o R_1 = 1.0x (sum of the full load currents of all machines including diversity)
- o R_2 = 1.0x (secondary current rating of the utilization transformer)

Select a breaker that is the next size greater than R_1. The breaker setting must not be greater than R_2.

short circuit

- o S_1 = 1.2x (sum of the full load current of all machines connected, including diversity factor, plus the starting current of the largest motor).
- o S_2 = 1.1x (maximum fault current at the utilization transformer secondary bus)

  NOTE: This is I_f(Max).

For complete coordination, the setting S_2 is selected (note that the breaker will not trip instantaneously at this setting). For increased back-up protection with some sacrifice in selectivity, setting S_1 may be chosen.

Step 23. Plot the characteristic of the main breakers on the coordination graph. If setting S_2 was selected, do not plot the instantaneous part of the characteristic.

Step 24. Select the distribution system current transformers, overcurrent relays, and their settings. The procedure begins at the utilization transformers and proceeds to the mine substation. Relays are coordinated in pairs taking care to ensure that sufficient selectivity and back-up protection are provided. Relays which provide primary protection for a bus having two or more radial feeders should be coordinated with the feeder relay which has the longest operating time. Time-current curves for distribution system overcurrent relays and fuses must be obtained from the respective manufacturer.

Step 25. Select the pickup and instantaneous setting of each overcurrent relay as follows:

pickup current:

P_1 = 1.25x (sum of the full load currents of all machines connected, including any diversity factor)

P_2 = 1.0x (ampacity of the smallest cable in the relay's primary zone of protection)

P_3 = Fx (current rating of the smalles transformer in the relay's primary zone of protection)

F = 1.0 if the transformer does not have main secondary protection.

F = 2.0 if the transformer is protected by main secondary breakers rated at 100 percent or less of the transformer current rating.

P_4 = 0.8x (minimum short circuit current in the relay's backup zone of protection)

NOTE: This is I_f(Min).

The relay pickup current should be greater than or equal to P_1 and less than or equal to P_2, P_3, and P_4.

instantaneous setting:

S_1 = 1.1x (maximum fault current at the most inby point of the relay's primary zone of protection)

NOTE: This is I_f(Max) at the nearest inby relay

S_2 = 1.1x (maximum inrush currents of inby transformers)

S_3 = 1.0x (allowable short circuit cable current)

The instantaneous setting should be greater than or equal to S_1, and S_2, and less than or equal to S_3.

Step 26. Select current transformers to drive the relays selected in Step 25. The current transformer turns ratio should be selected such that the current transformer supplies the relay with between 2.5A and 5A at relay pickup. Determine the required current transformer burden driving capability using the methods described in Chapter 2.

Step 27. Select the relay time dial setting. The time dial setting of the relay should be adjusted such that its operating time will exceed that of all inby relays for which it serves as a backup by 0.4s. This criteria is achieved by assuring that a 0.4s time interval exists for the maximum fault current available at inby relays or at the instantaneous setting of these relays.

Step 28. Plot the time-current characteristic of each relay on the coordination plot. Be sure these curves are correctly located with respect to transformer inrushes and withstands.

Step 29. Fuse selection criteria. Fuses are frequently used for backup protection of utilization transformers and for protection of substation transformers from internal or heavy through faults. In either case, the fuse rating should be equal to or slightly larger than the rated transformer current. In many cases, it is desirable to coordinate the protective relays so that they are backed up by fuses. This permits faults to be cleared without having to replace fuses.

Step 30. Plot the time-current characteristic of each fuse on the coordination plot. Be sure that these curves are properly located with respect to transformer inrushes and withstands.

remaining after treatments. In particular, items d, e, and f described in the plans section of Progress Report #5 will be pursued.

6. Administrative Items:

Procurement Operations indicates they will issue a time extension for this work order to May 29, 1981.

APPENDIX II

TEAR-OUT SECTION

This section consists of tables, figures, and other information which is used in the Section 4-4 example on mine power system coordination. This information is best utilized by removing it from the binder and referring to it while reading Section 4-4.

Circuit Breaker and Relay Selection and Setting Criteria

Face Equipment Breakers:

R_1 = 1.0 x machine full load current

R_2 = 1.0 x trailing cable ampacity

S_1 = 1.2 x machine starting current

S_2 = 1.2 x machine full load current

S_3 = 0.8 x minimum fault current

S_4 = maximum allowable trailing cable current

The breaker thermal rating should be less than R_1 and R_2. The breaker instantaneous setting should be equal to or greater than S_1 and S_2 and less than S_3 and S_4.

Main Molded Case Breakers

R_1 = 1.0 x full load current of connected loads

R_2 = 1.0 x transformer rating

S_1 = 1.2 x (full load current of connected loads and starting current of largest motor)

S_2 = 1.1 x maximum asymetrical fault current in backup zone.

The breaker thermal rating should be less than R_2 and greater than R_1. The breaker instantaneous setting should be greater than S_1 and less than or equal to S_2, depending on coordination requirements (see Text).

Overcurrent Relays

P_1 = 1.25 x full load current of connected loads

P_2 = 1.0 x power cable ampacity

P_3 = 2.0 x rating of smallest inby transformer if that transformer has backup protection on its secondary

= 1.0 x rating of smallest inby transformer if that transformer has no backup protection on its secondary

P_4 = 0.8 x minimum fault current in the backup zone

S_1 = 1.1 x maximum asynchronous fault current in the backup zone

S_2 = 1.1 x maximum inrush current of inby transformers

The relay pickup should be greater than or equal to P_1 and less than or equal to P_2, P_3, and P_4. The instantaneous setting should be greater than or equal to S_1 and S_2.

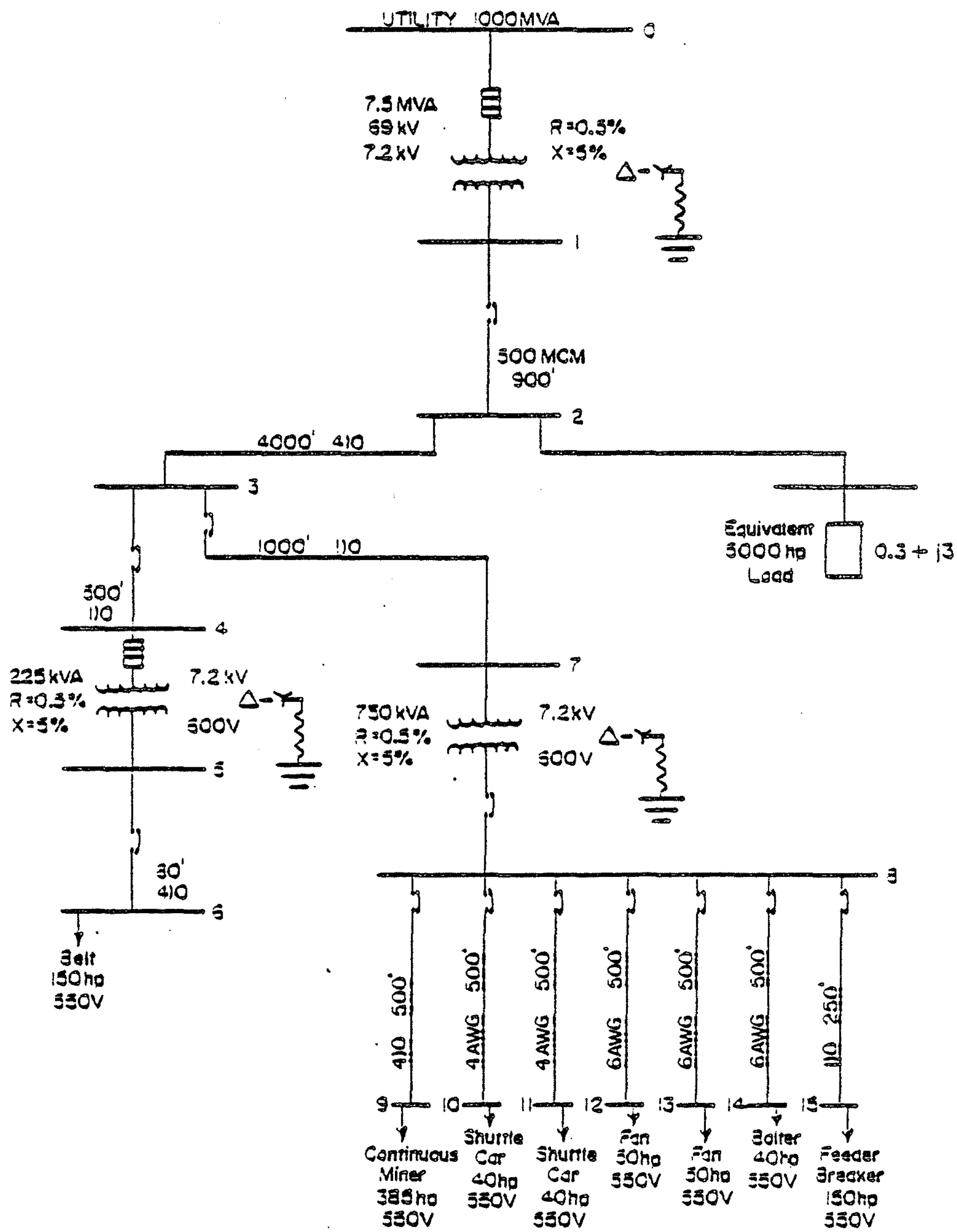

FIGURE 4-1

Example Mine Power System

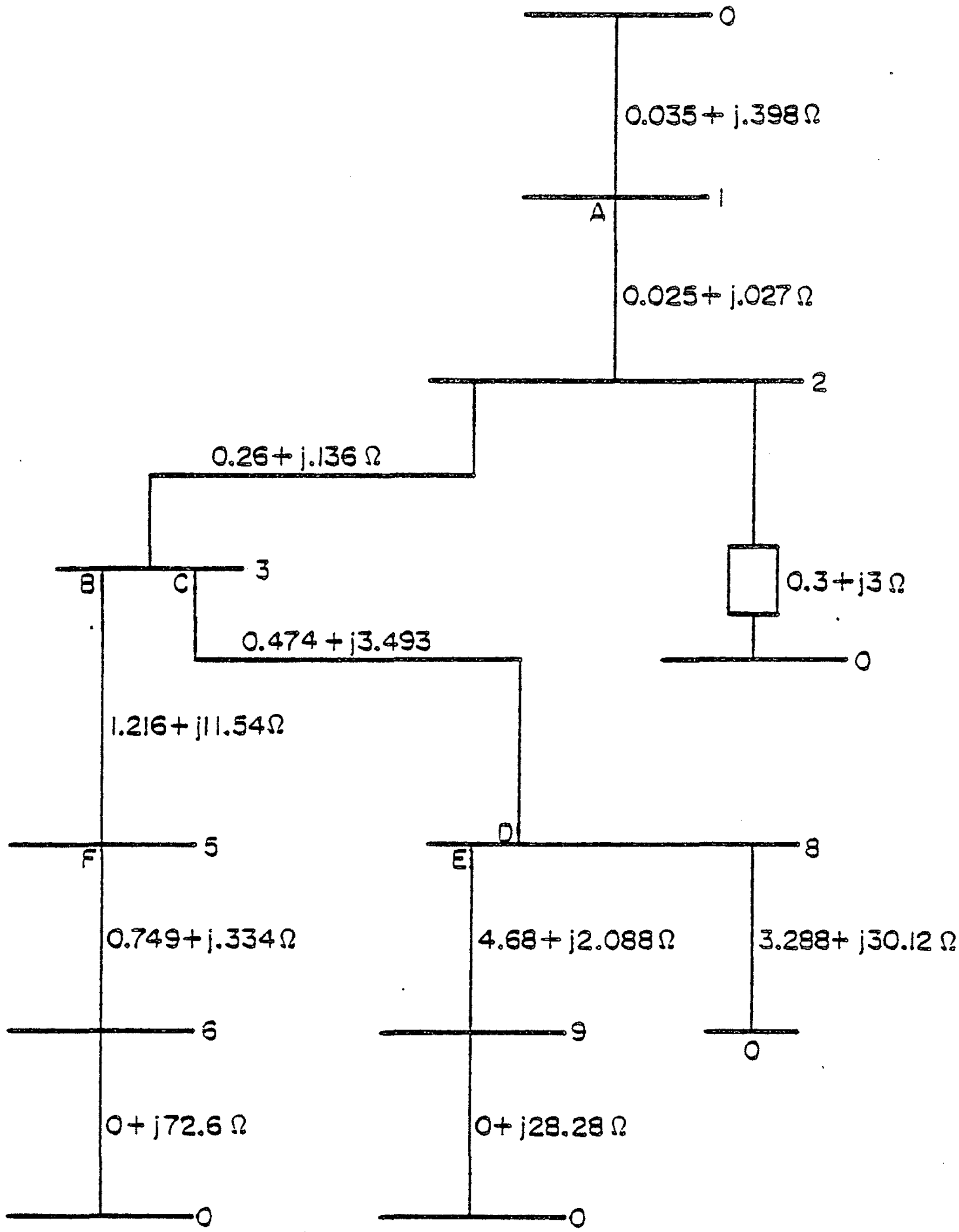

FIGURE 4-3
System Impedance Diagram

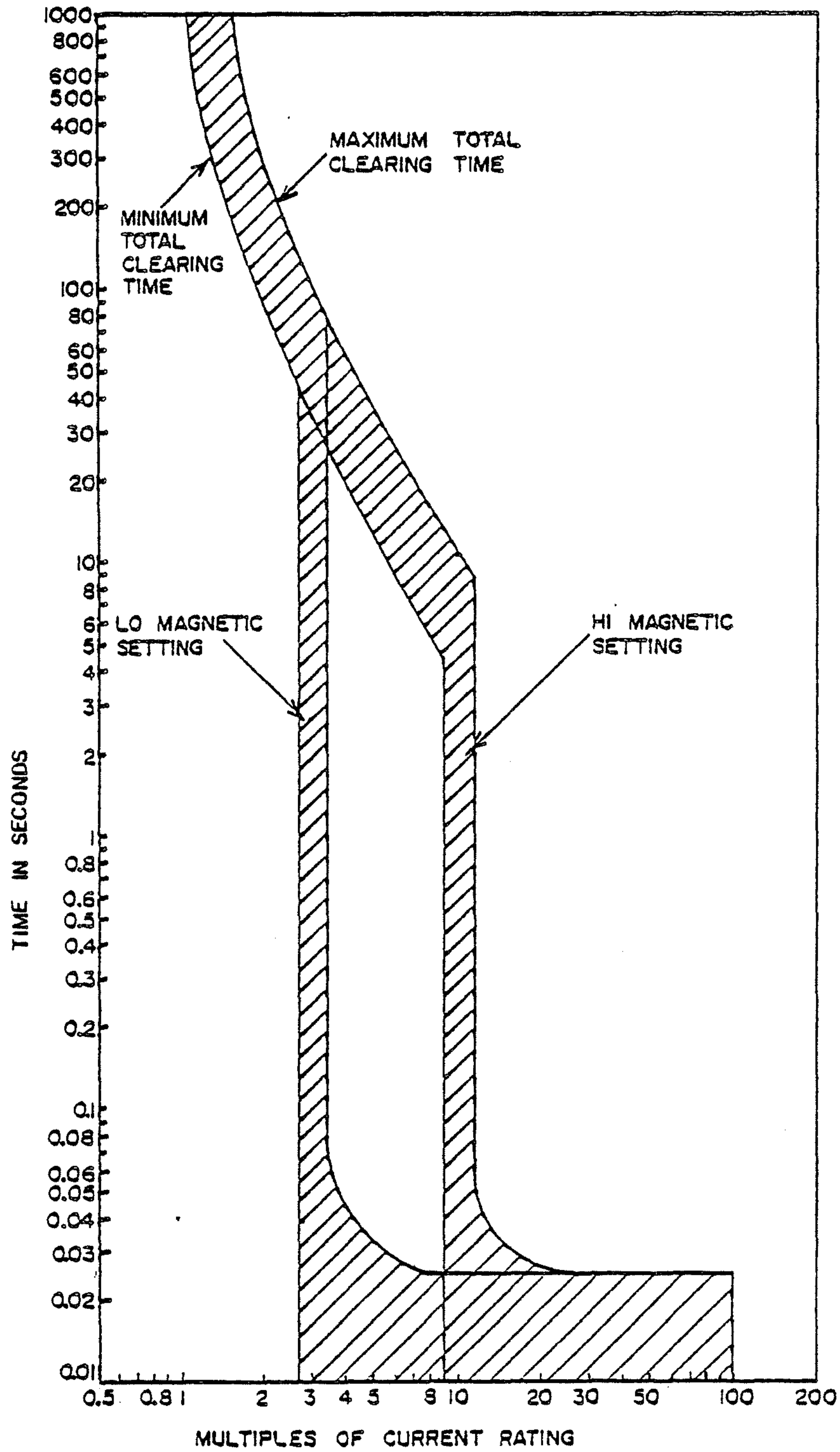

FIGURE 4-4

Molded Case Breaker Time-Current Characteristics

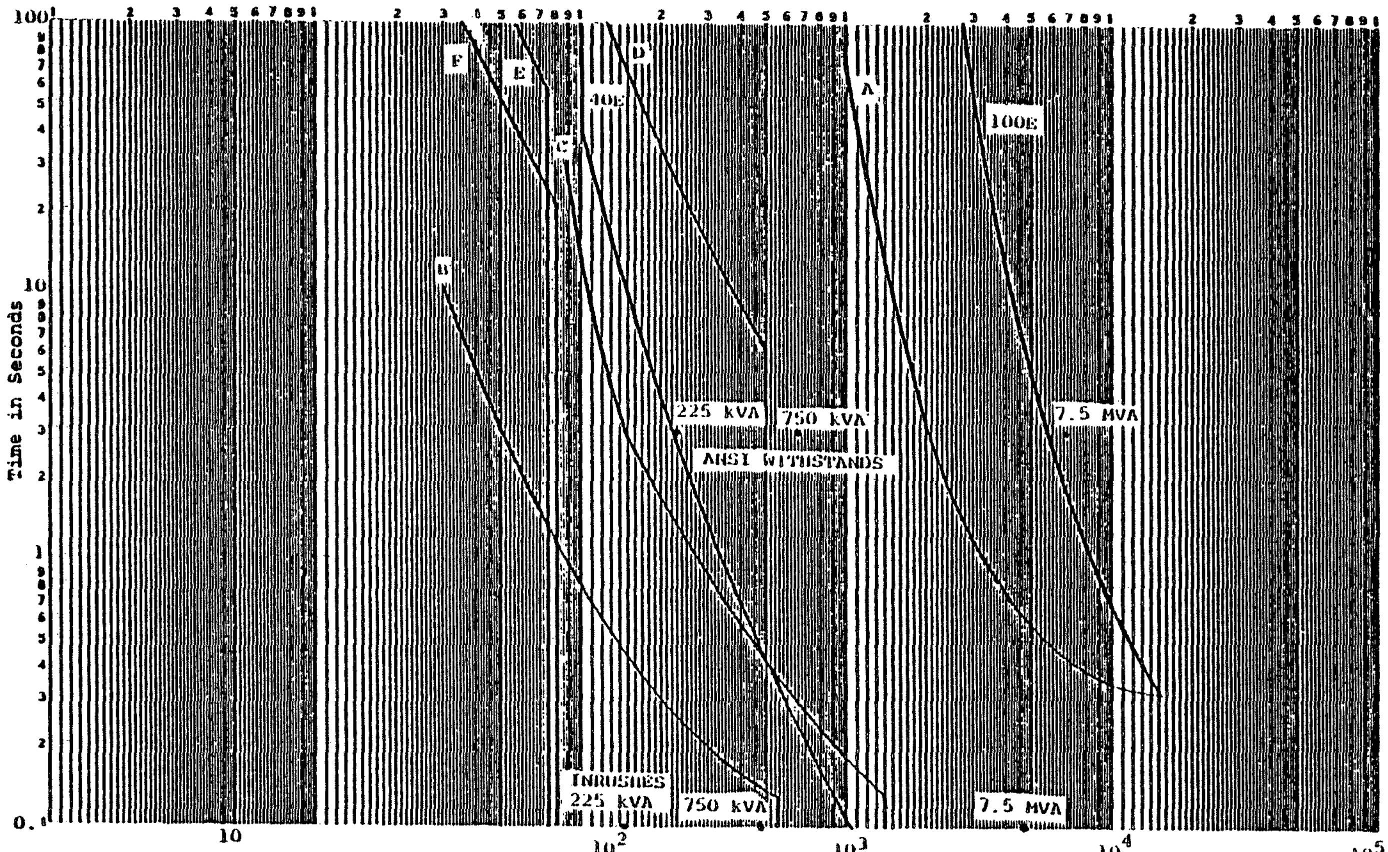

FIGURE 4-5
Coordination Plot for Example

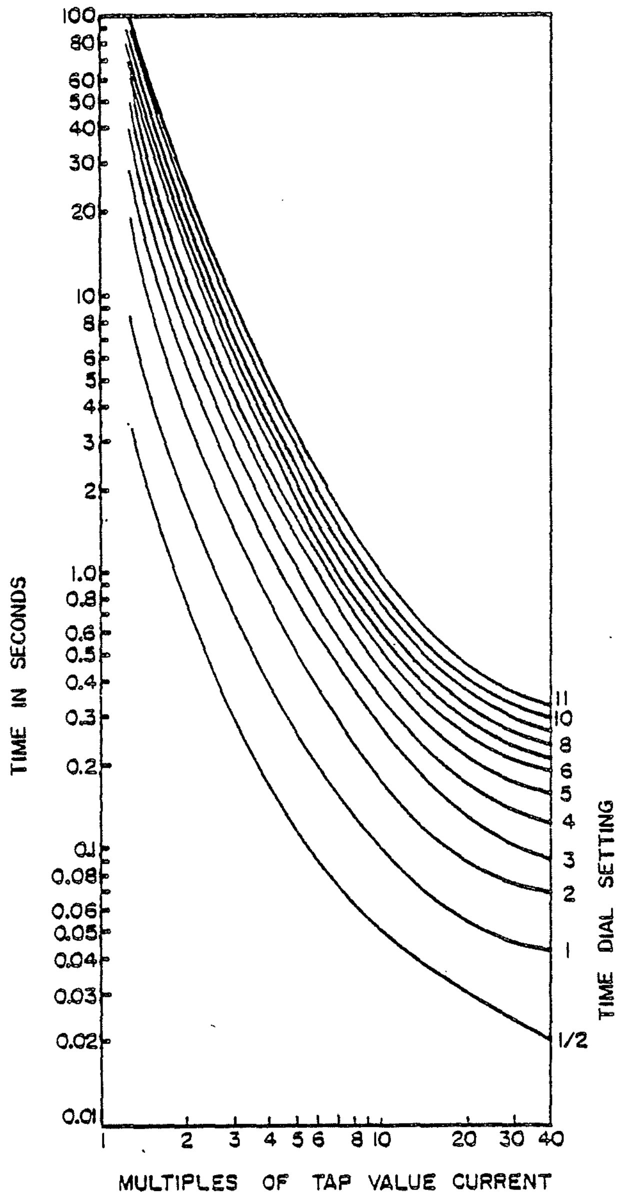

FIGURE 4-6
Time-Current Characteristic for Extremely Inverse Relay