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Ground-fault Protection for Solidly Grounded Low-voltage Systems

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INTRODUCTION

Ground-fault protection has been applied in high-voltage electric power distribution systems for many years. In recent years, cases of electrical equipment destruction caused by arcing faults-to-ground have made clear the need for this type of protection for grounded low-voltage systems.

This bulletin intends to provide a clearer understanding of the many considerations associated with the application of ground-fault protection to solidly grounded, low-voltage systems operating at 600 Volts or less.

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

ARCING FAULT CURRENT REVIEW

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

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

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

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

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

Arcing Faults

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

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

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

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

Bolted Faults

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

Solutions to the Arcing Fault Problem

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

1. Minimize the probability of arcing fault initiation by:

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

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

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

d. Providing proper installation practices and supervision.

e. Protecting equipment from unusual operating or environmental conditions.

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

i. Executing regular and thorough maintenance procedures.

j. Maintaining daily good-housekeeping practices.

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

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

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

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

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

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

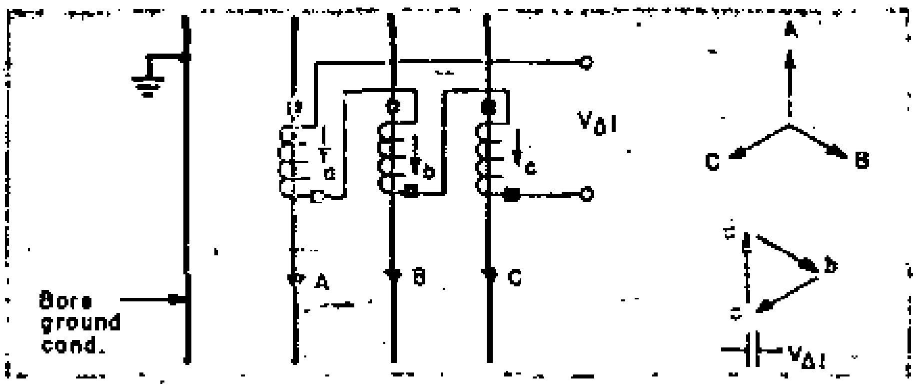

Fig. 1. Broken delta-voltage ground-fault sensing. For balanced three-phase, operation, in three-phase, three-wire systems, V Δ 1 equals 0.

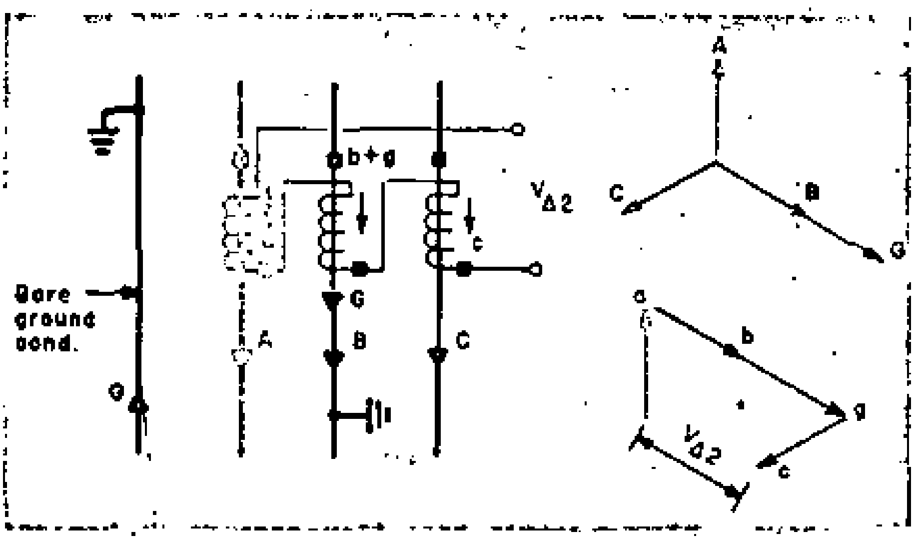

Fig. 2. Broken delta-voltage ground-fault sensing. For ground-fault condition in three-phase, three-wire systems, V Δ 2 is not equal to 0.

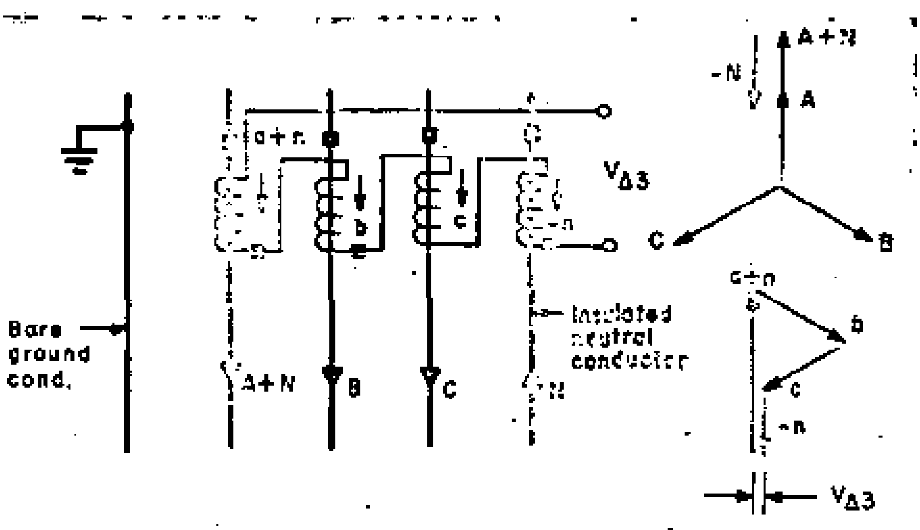

Fig. 3 Broken delta-voltage ground-fault sensing. For unbalanced line to neutral load operation in three-phase, four-wire systems, V Δ 3 equals 0.

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

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

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

The results thus far can be summarized as follows:

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

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

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

METHODS OF GROUND-FAULT DETECTION

The ground-fault current can be monitored either as it flows out to the fault or on its return to the neutral point of the source transformer or generator. When monitoring the outgoing fault current, the currents in all power conductors are monitored either individually (Fig. 1 through 6), or collectively (Fig. 7 through 10). When monitoring the return fault current, only the ground-fault return conductor is monitored (Fig. 11). Caution is required to help assure that the returning ground-fault current bypasses the outgoing monitoring current transformer, but does not bypass the current transformer monitoring the returning ground-fault current.

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

Broken Delta Ground-Fault-Protection

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

Residual Ground-Fault Protection

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

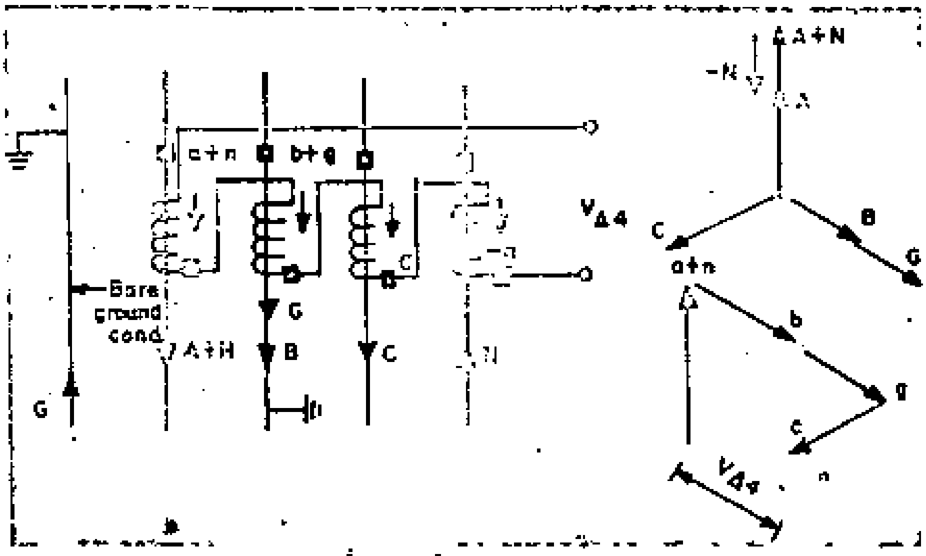

Fig. 4. Broken delta-voltage ground-fault sensing. For ground-fault condition in three-phase, four-wire systems and unbalanced load operation, $V \Delta 4$ is not equal to 0.

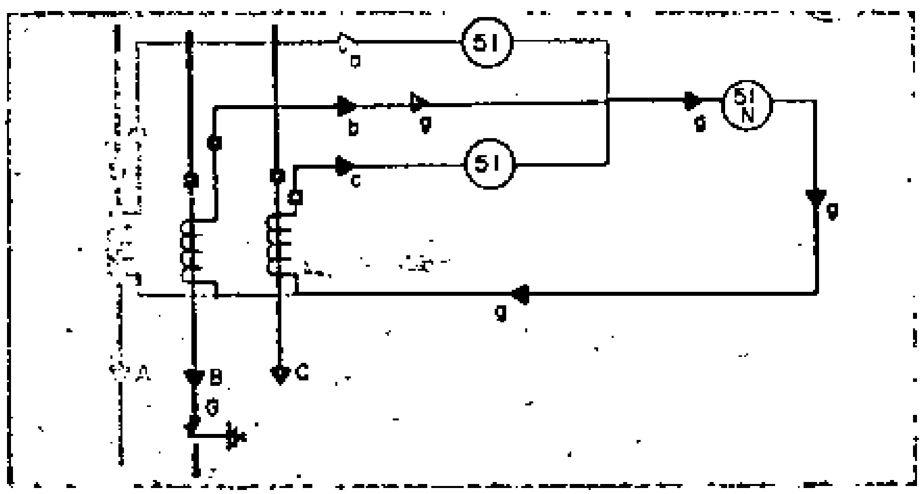

Fig. 5. Residual ground-fault sensing. For ground-fault condition in three-phase, three-wire systems relay R senses only ground-fault-current component.

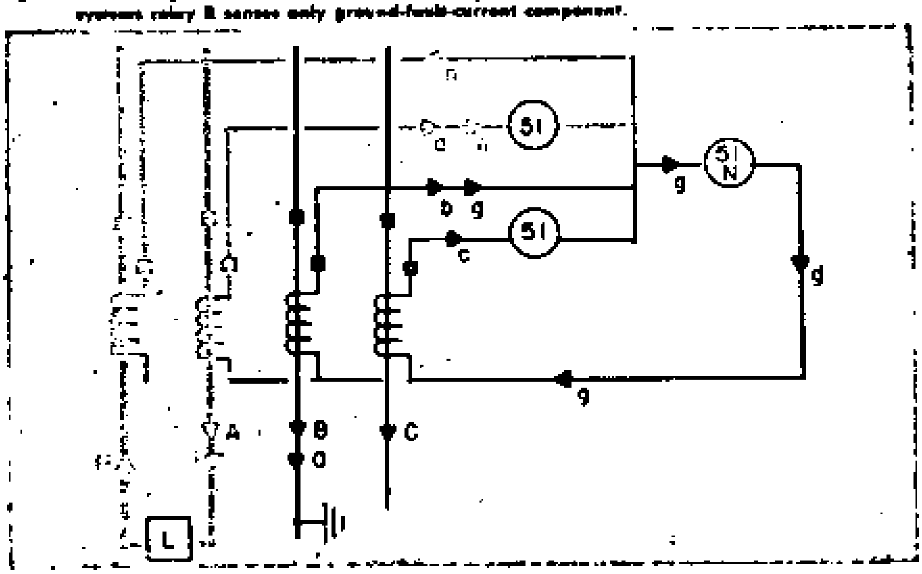

Fig. 6. Residual ground-fault sensing. For ground-fault condition in three-phase, four-wire systems, relay R responds only to ground-fault-current component provided fourth current transformer is present.

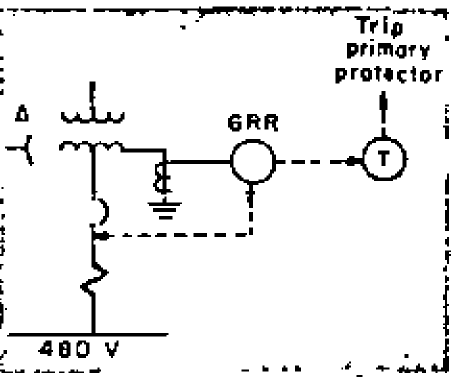

Fig. 11. Ground-return fault protection as applied to transformer neutral ground.

winding, or on its extension to the line terminals of the main secondary breaker. To provide the proper protection, the relay should be wired to trip the main secondary breaker and to start a timer so that in approximately five to ten cycles after breaker operation, if the fault is *still* sensed by the ground-return relay, the timer will signal the transformer primary protector to trip. Application of this form of protection in locations other than the transformer neutral-to-ground connection must be carefully applied to assure that the ground sensor relay will sense all or most of the ground return current.

Ground Differential Protection

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

Ground Summation Protection

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

SYSTEM CONSIDERATIONS

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

Six important factors must be considered:

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

1. Type of System

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

2. Reliability

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

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

3. Neutral Circuit

A simple radial system with a radial neutral presents few problems. For three-wire (three-phase conductors), four-wire (three-phase and one ground, or neutral conductor), five-wire (three-phase, one neutral and on ground conductor) where the neutral conductor is a radial conductor (for looped or continuous between alternate power sources) and grounded only at the source, either the ground sensor or the ground-return monitoring modes may be used. The ground sensor mode is preferred, thus avoiding the installation problem associated with the return mode.

The more complex systems, however, with neutral circuits which connect between alternate power sources require very careful analysis and design to avoid unintended relay operation. When the neutral conductor is looped or continuous between alternate power sources and grounded only at the source or grounded downstream, extreme care must be taken in applying ground-fault protection. Every circuit should be checked for stray returning neutral and/or ground-fault currents that could cause the ground-fault unit to be desensitized, to misoperate, or not operate. A simple method to check the application is to draw a one-line diagram of the system and superimpose assumed neutral loads and ground faults. Then trace the current flow to determine the effects on the ground-fault units. Keep in mind that the return current flow tends to seek the lowest impedance path. A given path, although initially the lowest impedance path, may not remain so as the magnitude of current increases. It might be determined that the neutral conductors because of the interties, present such good paths for stray returning currents that the only solution to providing ground-fault protection is to use a modified ground sensor (GS) or residual (without neutral current transformer) mode. Either mode consists of monitoring the phase conductors only, and avoids the serious problem of non operation when operating is desired, since the neutral conductor which may be carrying ground-fault currents is not monitored. It may or may not avoid nuisance operation due to neutral current loading, specifically if its maximum setting is limited to 1200 Amperes, to meet NEC Article 230-95 (1971 and 1975), even though the minimum ground fault available for the protective zone being considered permits a higher current setting.

to achieve selectivity and the risk of extensive equipment damage.

BRANCH CIRCUITS

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

FEEDER CIRCUITS

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

MAINS AND BUS TIES

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

EQUIPMENT IDENTIFICATION

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

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

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

For a static relay and matched current transformer unit, pickup settings are expressed directly in primary amperes. Although the current transformer has a fixed ratio rating, there is no need to treat this unit as the conventional relay and current transformer approach.

The VersaTrip® ground and Power Sensor® ground units are captive units. That is, the VersaTrip® grounded unit can be added only to molded-case circuit breakers (MCCB) that are equipped with VersaTrip® phase overcurrent protection. The same applies to Power Sensor® ground units untilized on Type AK low-voltage power circuit breakers (LVPCB). In both cases, the static phase overcurrent function can be supplied without the ground function or with any of the other ground functions, that is, GROUND-BREAK® or Electromagnetic units.

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

IDENTIFICATION		STATIC GROUND FAULT RELAYS			ELECTROMAGNETIC GROUND FAULT RELAYS		
		VersaTrip® Ground	Power Sensor® Ground	GROUND-BREAK®	Instantaneous	Time-Delay	Residual Ground
CURRENT TRANS-FORMERS	Type	window	window	window, round or rectangular	window	window	window or bar
	No. of CT's	3 or 4	3 or 4	1	1	1	3 or 4
	Ratio	matched	matched	matched	50/5 or 100/5 specific	150/5 through 4000/5	phase current rating
	Location	internal, plus external 4th C.T.		external to breaker	external to breaker on all models		
RELAYS	Type	static	static	static	PJC11A	IAC95HA	IAC95HA
	Tap Range	.3–.7 or .25–.45 times sensor rating	same as pickup primary amperes		.5–2A	1.5–6A	1.5–6A
	External Power Cont.	none	none	yes	none	none	none
CURRENT SETTINGS	Pickup Primary Amperes	45–1120A 500–1125A	100–490A 300–1700A 750–3000A	5–60A 100–1200A	15A if set at 0.5 A Tap	CT ratio times relay ampere tap	CT ratio times relay ampere tap
	Adjustments	5	4	continuous	continuous	7	7
TIME SETTINGS	Average Tm. (in seconds)	0.2–0.4	0.06–0.30	0.03 to 1.0	no intentional delay	function of time dial setting	
	Adjustments	3	5	continuous	continuous	continuous	continuous
APPLICATION	Type Interrupter	molded-case breaker	low voltage power circuit breaker	any	any	any	any
	Shunt Trip Required?	no	no	yes	yes	yes	yes
	Tripping Cont. Part	no	no	yes	yes	yes	yes
	Usage	cable—bus	cable—bus	cable—bus	cable	cable	cable—bus
PROTEC. MODE	Normal Use	residual	broken-delta	ground-sensor	ground-sensor	ground-sensor	residual
	Possible Use	GR¹, GRT²	none	GR¹, GRT², GSM³	GR¹	GR¹, GRT², GSM³	modified residual
PUBLICATIONS		GET-6202	GEA-3592 GEA-8733	GET-2964	GEH-2170 GEH-1790	GEK-41852	GEK-41652
TIME CURRENT CURVES		GES-6134	GES-6030	GES-6135	GEH-1790	018384250	018384250

NOTES: GR¹—Ground return mode. GRT²—double ended one-point neutral grounding mode per Figs. C-1 and C-2. GSM³—Ground sensor modified mode (phase conductor only).

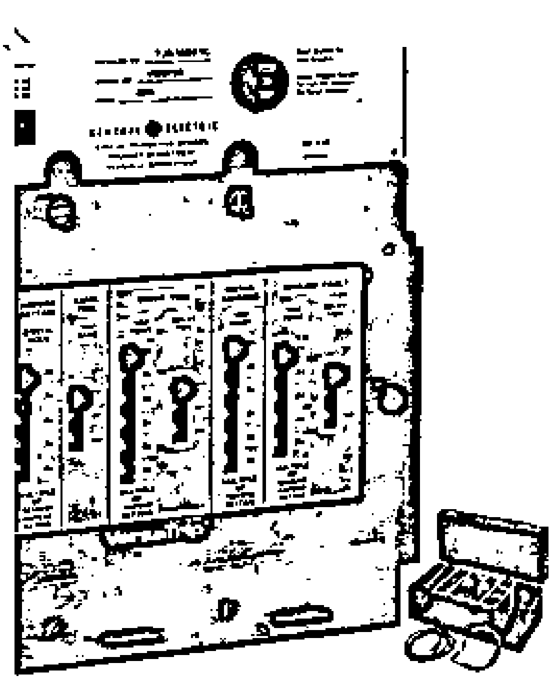

Fig. 14. Insulated case power breaker equipped with VersaTrip® phase and ground-trip functions and test set.

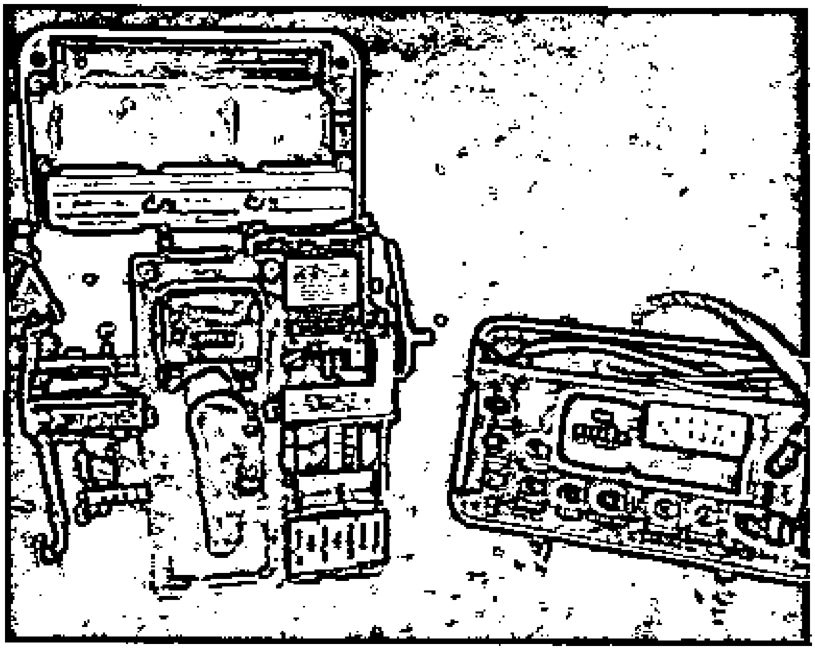

Fig. 15. Type AK low-voltage power breaker equipped with power sensor phase and ground-trip functions and test set.

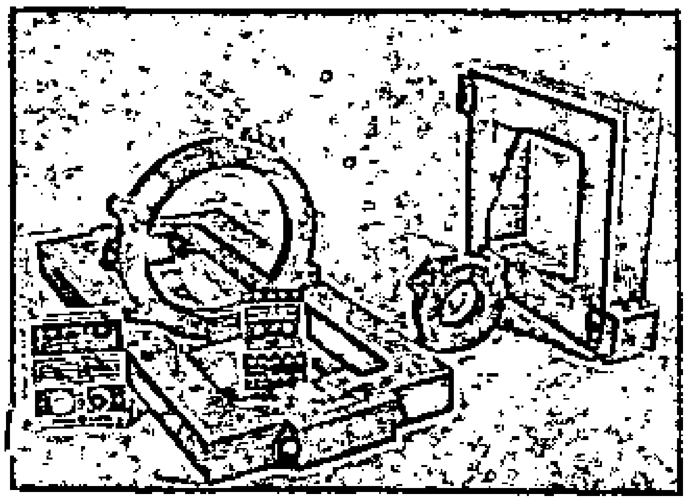

Fig. 16. GROUND-BREAK®—array of current transformers test panel (left), relay (center).

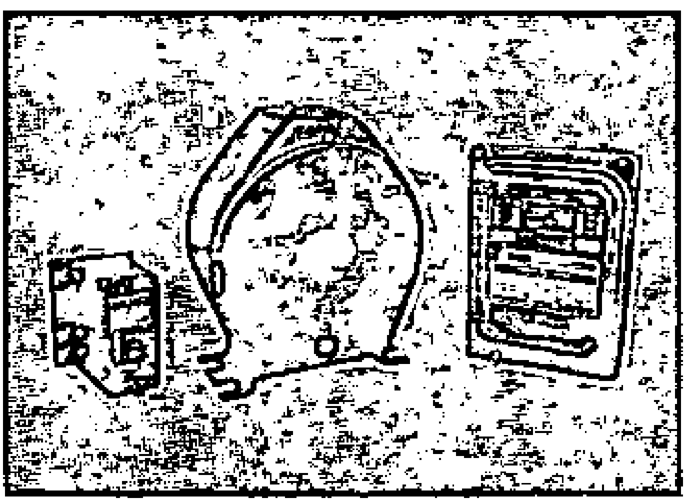

Fig. 17. Electromagnetic relays Type PJC (left), Type IAC (right), current transformer Types JCS-0 available with 2½" to 12" window (2½" shown).

Figures 14 thru 17 illustrate the physical equipment offered by General Electric Company.

SIMPLE RADIAL SYSTEM EXAMPLE

Consider a representative one-line diagram of a simple radial system. (Fig. 18). From a 1000 kVA transformer, a switchboard or switchgear is fed thru a 1200-Ampere busway. Located in the switchboard or switchgear are the incoming line breaker (E) and several feeder breakers. Feeder breaker (D) feeds a distribution bus which could be a mcc or switchboard or power panelboard, etc. Located in the distribution equipment are: feeder breaker (A) feeding a downstream 100-Ampere panelboard equipped with 20-30-Ampere branch breakers (A[1]), branch-fused line switch (B) powering a distribution transformer and motor controller (C) consisting of a circuit breaker and starter powering a 250-hp motor.

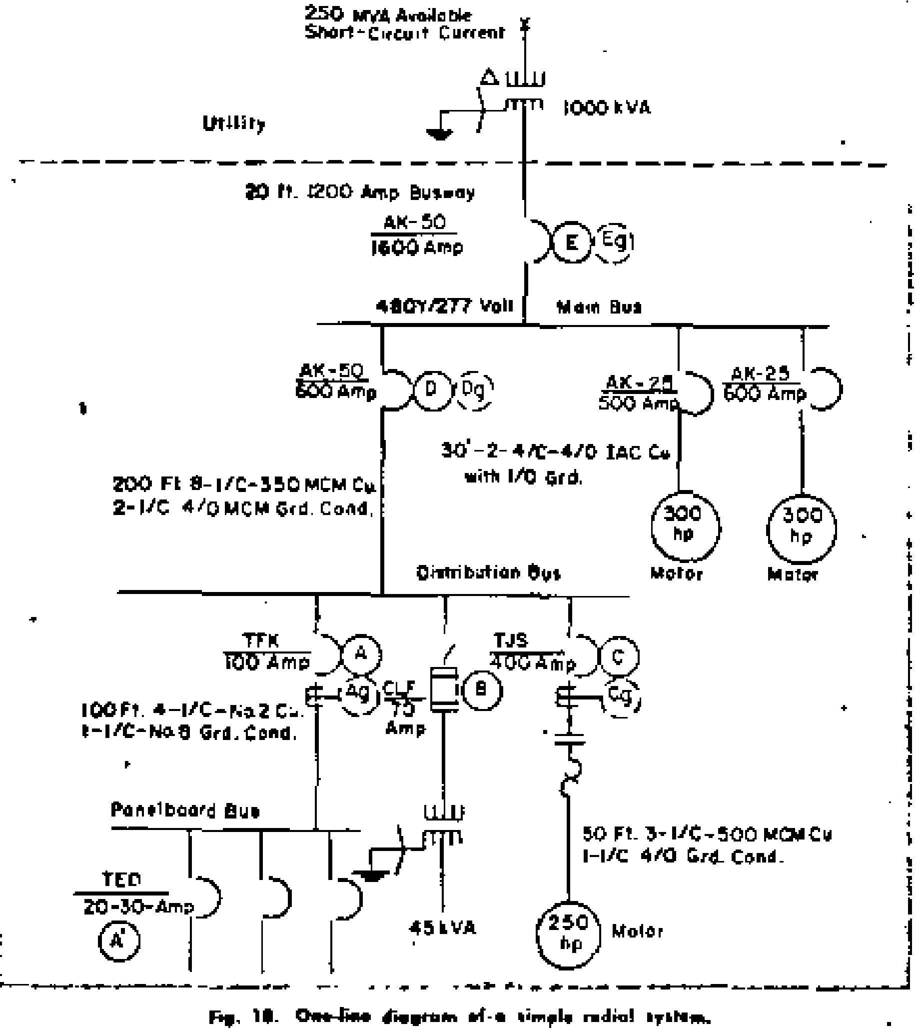

Fig. 18. One-line diagram of a simple radial system.

Impedance data

1. Assumptions and definitions
   a. Three-phase, fault-current magnitudes, desired to compare with equipment ratings, are calculated at the time of fault initiation using subtransient reactance values for rotating machines.
   b. Phase-to-ground fault current magnitudes, desired to determine protection equipment needs, are calculated to attain minimum current values. Thus, impedance vectors will be added, ignoring phases and angles. Motor impedance values will not be considered.
   c. Utility ground current will not flow during a low voltage ground fault due to the delta primary connection of the 1000 kVA transformer. Viewed from the 480-Volt bus, the utility Z_0 impedance value does not exist.
   d. The 1000 kVA transformer has a three leg core and a Z_0 impedance that is 85% of Z_1; impedance viewed from the WYE connected secondary.
   e. Motors have an X/R ratio of 10 and the 1000 kVA transformer has an X/R ratio of 5.
   f. Impedances are converted from percent to ohmic values using:
   $$\text{Ohms} = \frac{\text{percent}}{100} \times \frac{kV^2}{\text{mVA rating}}$$
   g. Impedance, resistance and reactance are related as follows:
   $\tan\phi = X/R$
   $\sin\phi = X/Z$
   $\cos\phi = R/Z$
   h. It is assumed that one horsepower of motor rating is equivalent to one kVA.
   i. Remaining impedance data is obtained from 11-AP-1 and appendixes A and B.
2. Data $(R+jX''_d)$ in Ohms referred to 480-Volt system:
   a. Utility Source:
   $$\frac{kV^2}{MVA} = \frac{(0.480)^2}{250} = 0+j.0009 \text{ Ohms}$$
   b. Motors
   $X''_d = 17\%$
   $X/R = 10$
   $R = 1.7\%$
   $R+jX''_d = (1.7+j17)\%$
   300-hp. Motor:
   $$\frac{(R+jX''_d\%)}{100}\frac{(kV)^2}{MVA} =$$
   $$(0.017+j0.17)\frac{(0.480)^2}{0.300} =$$
   $$0.0131+j0.1306 \text{ Ohms}$$
   250-hp Motor:
   $$\frac{(R+jX''_d\%)}{100}\frac{(kV)^2}{MVA} =$$
   $$(0.017+j0.17)\frac{(0.480)^2}{0.250} =$$
   $$0.0157+j0.1567 \text{ Ohms}$$
   c. 1000-kVA Transformer
   $Z = 5.75\%$
   $X/R = 5$
   $\tan\phi = 5$
   $= 78.69°$
   $X = Z \sin\phi$
   $= (5.75\%) \sin 78.69°$
   $= 5.6390\%$
   $R = Z \cos\phi$
   $= (5.75\%) \cos 78.69°$
   $= 1.1277\%$
   $R+jX''_d = (1.1277+j5.639)\%$
   $$\frac{(R+jX''_d)}{100}\frac{(kV)^2}{MVA} =$$
   $$(0.0113+j0.0564)\frac{(0.480)^2}{1} =$$
   $$0.0026+j0.0130 \text{ Ohms}$$
   d. Busway (aluminum, ARMOR-CLAD®)
   20 ft—1200 Ampere:
   $$\frac{20 \text{ ft}}{100 \text{ ft}}(0.00133+j.00053) =$$
   $$0.0003+j0.0001 \text{ Ohms}$$

c. Cable—(Copper in magnetic duct) with appropriate ground conductor

50 ft—3-1/c-500MCM:

$$\frac{(50\ \text{ft})}{(1000\ \text{ft})}(0.0294+j0.0466)=$$

0.0015+j0.0023 Ohms

200 ft—8-1/c-350MCM:

$$\frac{(200\ \text{ft})}{(1000\ \text{ft})}(1/2)\,(0.0378+j0.0491)=$$

0.0038+j0.0049 Ohms

30 ft—2-4/c-4/o:

$$\frac{(30\ \text{ft})}{(1000\ \text{ft})}(1/2)\,(0.064+j0.0381)=$$

0.0010+j0.0006 Ohms

100 ft—4-1/c-#2:

$$\frac{(100\ \text{ft})}{(1000\ \text{ft})}(0.202+j.0585)=$$

0.0202+j0.0058 Ohms

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

	Z_1	Z_2	$(Z_0+3Z_g)/Z_1$	Z_0+3Z_g
a. Utility Source	0.0009	0.0009		
b. 1000-kVA Trans. $\frac{(Z\%)\,(kV)^2}{100\ \text{MVA}}=\frac{0.0575(0.480)^2}{1}=$	0.0132	0.0132	0.85	0.0112
c. 20 ft Busway (aluminum, ARMORCLAD*) $\frac{20\ \text{ft}\ (0.00143)}{100\ \text{ft}}=$	0.0003	0.0003	42	0.0126
d. Cable (copper in magnetic duct) 50 ft-3-1/c500MCM etc: $\frac{50\ \text{ft}\ (0.0551)}{1000\ \text{ft}}=$	0.0028	0.0028	4	0.0112
200 ft—8-1/c-350MCM etc: $\frac{200\ \text{ft}\ (1/2)\,(0.0617)}{1000\ \text{ft}}=$	0.0062	0.0062	4	0.0248
30 ft—2-4/c-4/o etc: $\frac{30\ \text{ft}\ (1/2)\,(0.0745)}{1000\ \text{ft}}=$	0.0011	0.0011	4	0.0044
100 ft—4-1/c-#2 etc: $\frac{100\ \text{ft}\ (0.210)}{1000\ \text{ft}}=$	0.0210	0.0210	4	0.0840

Three-phase Fault Currents

1. Main Bus.

a. Impedance-utility to main bus:

Utility =	0+j0.0009
1000 kVA transformer =	0.0026+j0.0130
1200 Ampere busway =	0.0003+j0.0001
Total Ohms =	0.0029+j0.0140

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

300-hp motor =	0.0131+j0.1306
30 ft 2-4/c-4/o cable =	0.0010+j0.0006
Total Ohms =	0.0141+j0.1312

c. Impedance—250-hp motor to main bus:

250-hp motors =	0.0157+j0.1567
50 ft 3-1/c-500-MCM cable =	0.0015+j0.0023
200 ft 8-1/c-350-MCM cable =	0.0038+j0.0049
Total Ohms =	0.0210+j0.1639

Fault currents to main bus from:

Utility =
$$\frac{E_{L-N}}{\Sigma R+jX''_d}=\frac{277}{0.0029+j0.0140}=$$
3929.85-j18976.57 Amperes

300-hp Motor =
$$\frac{E_{L-N}}{\Sigma R+jX''_d}=\frac{277}{0.0141+j0.1312}=$$
224.31-j 2087.17 Amperes

300-hp Motor =
$$\frac{E_{L-N}}{\Sigma R+jX''_d}=\frac{277}{0.0141+j0.1312}=$$
224.31-j 2087.17 Amperes

250-hp Motor =
$$\frac{E_{L-N}}{\Sigma R+jX''_d}=\frac{277}{0.0210+j0.1639}=$$
221.14-j 1725.97 Amperes

Total = 4599.61-j24876.88 Amperes
= 25300 Amperes

2. Distribution bus

a. Impedance—utility & 300-hp motor to distribution bus:

Utility to main bus = 0.0029+j0.0140

Σ300-hp motors to main bus =
$$\frac{0.0141+j0.1312}{2}=0.0070+j0.0656$$

ΣUtility and 300-hp motors to main bus =
$$\frac{(0.0029+j0.0140)\,(0.007+j0.0656)}{(0.0029+j0.0140)+(0.007+j0.0656)}=$$
0.0022+j0.0116

200 ft 8-1/c-350MCM cable = 0.0038+j0.0049

Total Ohms = 0.0060+j0.0165

b. Impedance 250-hp motor to distribution bus:

250-hp motor =	0.0157+j0.1567
50 ft 3-1/c-500MCM cable =	0.0015+j0.0023
Total Ohms =	0.0172+j0.1590

Fault currents to distribution bus from:

Utility and 300-hp motors =
$$\frac{E_{L-N}}{\Sigma R+jX''_d}=\frac{277}{0.0060+j0.0165}=$$
5378.57-j14791.07 Amperes

250-hp motor =
$$\frac{277}{0.0172+j0.159}=$$
186.28-j 1721.99 Amperes

Total = 5564.85-j16513.06 Amperes
= 17426 Amperes

3. Panelboard bus

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

ΣUtility and 300-hp motor and 250-hp motor to distribution bus =
$$\frac{(0.0064+j0.0186)\,(0.0172+j0.159)}{(0.0064+j0.0186)+(0.0172+j0.159)}=$$
0.0053+j0.0167

100 ft 4-1/c-#2 cable = 0.0202+j0.0058

Total Ohms = 0.0255+j0.0225

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

$$=\frac{E_{L-N}}{\Sigma R+jX''_d}=\frac{277}{0.0255+j0.0225}=$$
6107.65-j5389.10 Amperes
= 8145 Amperes

Arcing ground fault current magnitude

1. Main bus

	Z_1	Z_2	Z_0+3Z_g
Utility =	0.0009	0.0009	
1000-kVA Transformer =	0.0132	0.0132	0.0112
1200-Amp. Busway =	0.0003	0.0003	0.0126
Total =	0.0144	0.0144	0.0238

$$I_{\text{arcing fault (L-G)}}=0.38\left(\frac{3E_{L-N}}{Z_1+Z_2+Z_0+3Z_g}\right)$$
$$=0.38\left(\frac{3(277)}{0.0144+0.0144+0.0238}\right)$$
= 6003 Amperes

2. Distribution bus

	Z_1	Z_2	Z_0+3Z_g
Utility to main bus =	0.0144	0.0144	0.0238
200 ft 8-1/c-350MCM Cable =	0.0062	0.0062	0.0248
Total =	0.0206	0.0206	0.0486

$$I_{\text{arcing fault (L-G)}}=0.38\left(\frac{3E_{L-N}}{Z_1+Z_2+Z_0+3Z_g}\right)$$
$$=0.38\left(\frac{3(277)}{0.0206+0.0206+0.0486}\right)$$
= 3516 Amperes

3. Panelboard bus

	Z_1	Z_2	Z_0+3Z_g
Utility to distribution bus =	0.0206	0.0206	0.0486
100 ft 4-1/c-#2 Cables =	0.0210	0.0210	0.0840
Total =	0.0416	0.0416	0.1326

$$I_{\text{arcing fault (L-G)}}=0.38\left(\frac{3Z_{L-N}}{Z_1+Z_2+Z_0+3Z_g}\right)$$
$$=0.38\left(\frac{3(277)}{0.0416+0.0416+0.1326}\right)$$
= 1463 Amperes

The phase-overcurrent time current plot (Fig. 19) was determined by the load conditions and calculated three-phase fault currents. References to how time current plots are developed can be found in the IEEE Industrial Commercial Power System Text entitled "Guide of Protection Fundamentals for Low-voltage Electrical Distribution Systems in Commercial Buildings", IEEE JH2112-1.

From Fig. 19, the main line protector (E) clearing time is approximately 0.58 second at 6003 Amperes. Distribution bus protector (D) clearing time is approximately 0.35 second at 3516 Amperes. Panelboard bus protector (A) clearing time is approximately 0.022 second at 1463 Amperes. The sensitivity of these plots to the calculated arcing ground fault currents appear to be acceptable; however, in further analysis, several limitations exist in the phase-overcurrent settings with regard to protection for arcing-ground-fault currents:

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

B. If the actual arcing-ground-fault current during fault conditions only attains values that are slightly less than calculated, the protector clearing time increases to unacceptable values. Protector (E) increases to 13 seconds at 5400 Amperes while protector (D) increases to 9 seconds at 3300 Amperes.

C. The back-up protection is unacceptable. Protector (E) could only clear in 28 seconds at 3516 Amperes in event of protector (D) failure to clear a distribution bus ground fault. Protector (D) could never sense a panelboard bus ground fault in the event of protector (A) failure to clear.

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

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

A Power Sensor® ground unit is used due to the ease of addition to the Power Sensor phase overcurrent functions. A Ground Break or electromagnetic unit could be used in preference to the Power Sensor ground unit.

When (E_g) is set at 300 Amperes and 0.06 second in time (Fig. 20), it provides a high degree of protection. At this setting, however, it would cause de-energization of the entire system for an arcing-ground-fault current magnitude of 300 Amperes or more throughout the system except for currents flowing through and of sufficient magnitude to operate protector (A) instantaneous function.

When (E_g) is set at 1200 Amperes and 0.30 second in time (Fig. 21), protection has been reduced and de-energization of the entire system is still prevalent for arcing ground fault current magnitudes of 1200 to 3200 Amperes on the distribution bus, or 1200 to 2200 Amperes on protector (C) load circuit.

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

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

When (D_g) and (E_g) are set at 900 Amperes and 0.18 second and 1200 Amperes and 0.30 second, respectively (Fig. 22), the de-energization of the main bus due to a ground fault on the load side of protector (D) is eliminated except when protector (D) fails to clear the fault. This improves the service reliability to the other feeders fed from the main bus. Feeder (D), however, can be de-energized by (D_g) for a ground fault condition on the branch protected by (C).

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

A PJC electromagnetic unit is utilized for (C_g). Since protector (C) is a branch feeder, its ground fault unit (C_g) (Fig. 23) is set at 15 Amperes and instantaneous in time. Note that as for all other ground-fault protectors the time current plot of (C_g) includes breaker clearing time. With the units set at: (C_g) 15 Amperes and instantaneous in time, (D_g) 900 Amperes and 0.18 second in time, and (E_g) 1200 Amperes and 0.30 second in time, the system is now completely selective with a reasonable degree of protection.

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

A Ground-Break unit is utilized for unit (A_g) (Fig. 24) and set at 15 Amperes and instantaneous in time. Unit (A_g) provides additional protection to the branch circuits fed by protectors (A) and panelboard bus. From Fig. 19, it can be seen that long clearing times of one second or more occur for breakers (A_1) and (A) at current magnitudes below 500 Amperes. As ground faults occur further downstream on the branch circuit conductor powered by (A_1), current magnitudes less than 500 Amperes will occur, indicating that the phase-overcurrent functions will not provide adequate protection.

Except in rare cases, cost today prevents applying a ground fault unit for each branch breaker and unit (A_g) was applied. This additional ground-fault unit also allows unit (D_g) and (E_g) to be lowered in time and still maintain selectivity, thereby decreasing equipment damage.

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

System Example

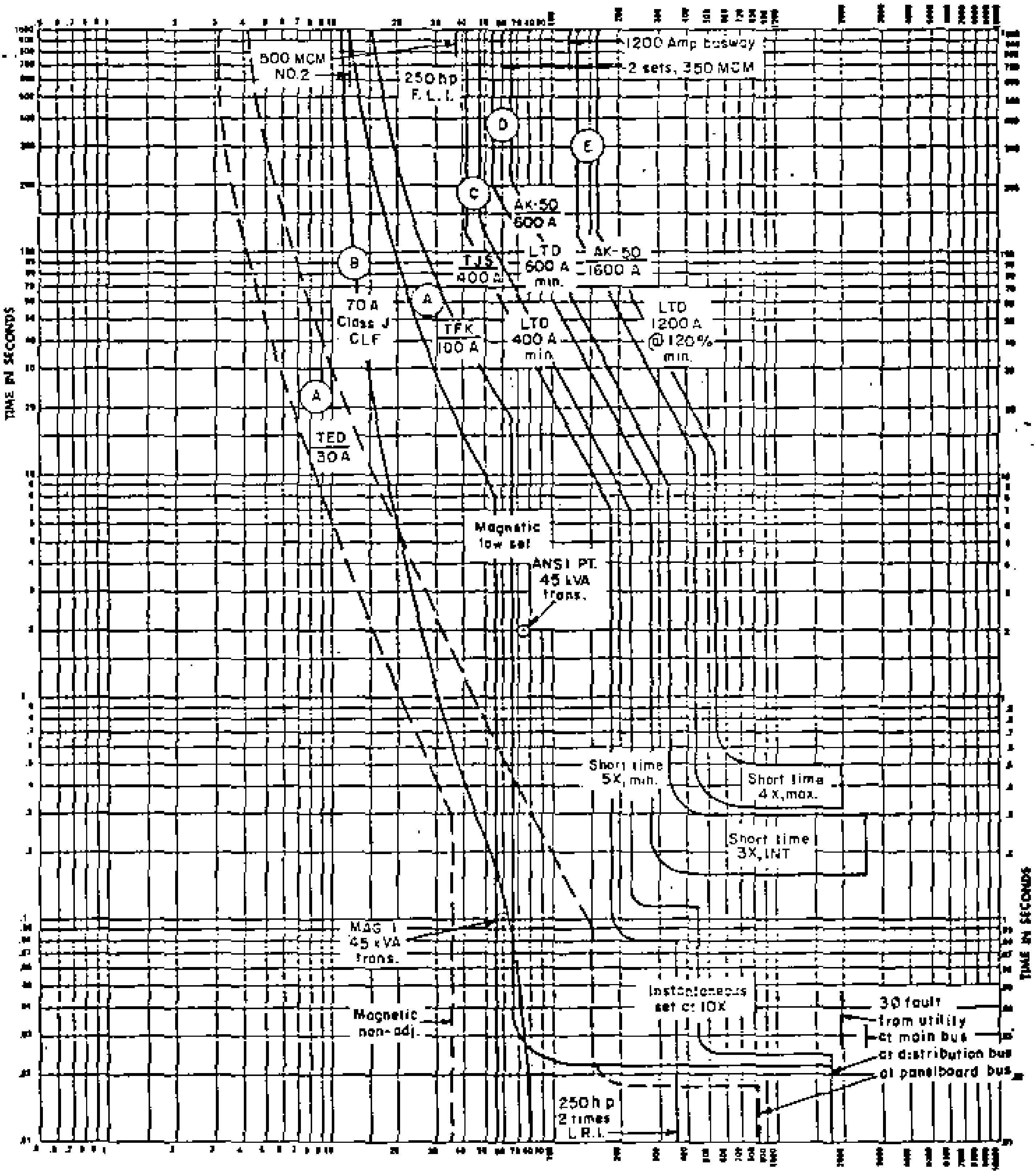

Fig. 19. Phase overcurrent plots of load conditions and three-phase fault currents for illustrated example. Current (X10) at 480 Volts.

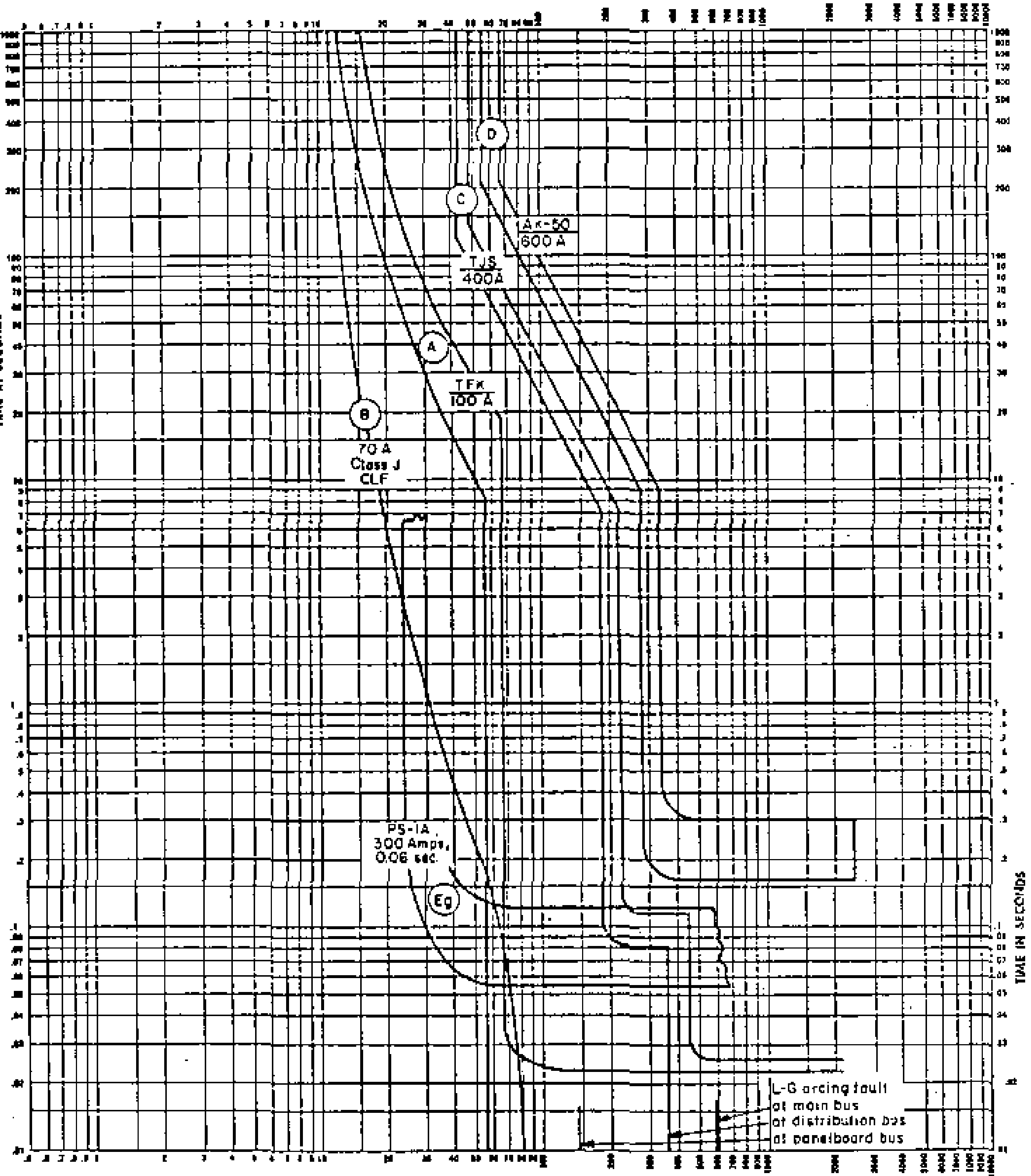

Fig. 20. Phase overcurrent plots with one ground-fault unit on main protector (E_g) set at 300 Amperes and 0.06 second. Current (X10) at 480 Volts.

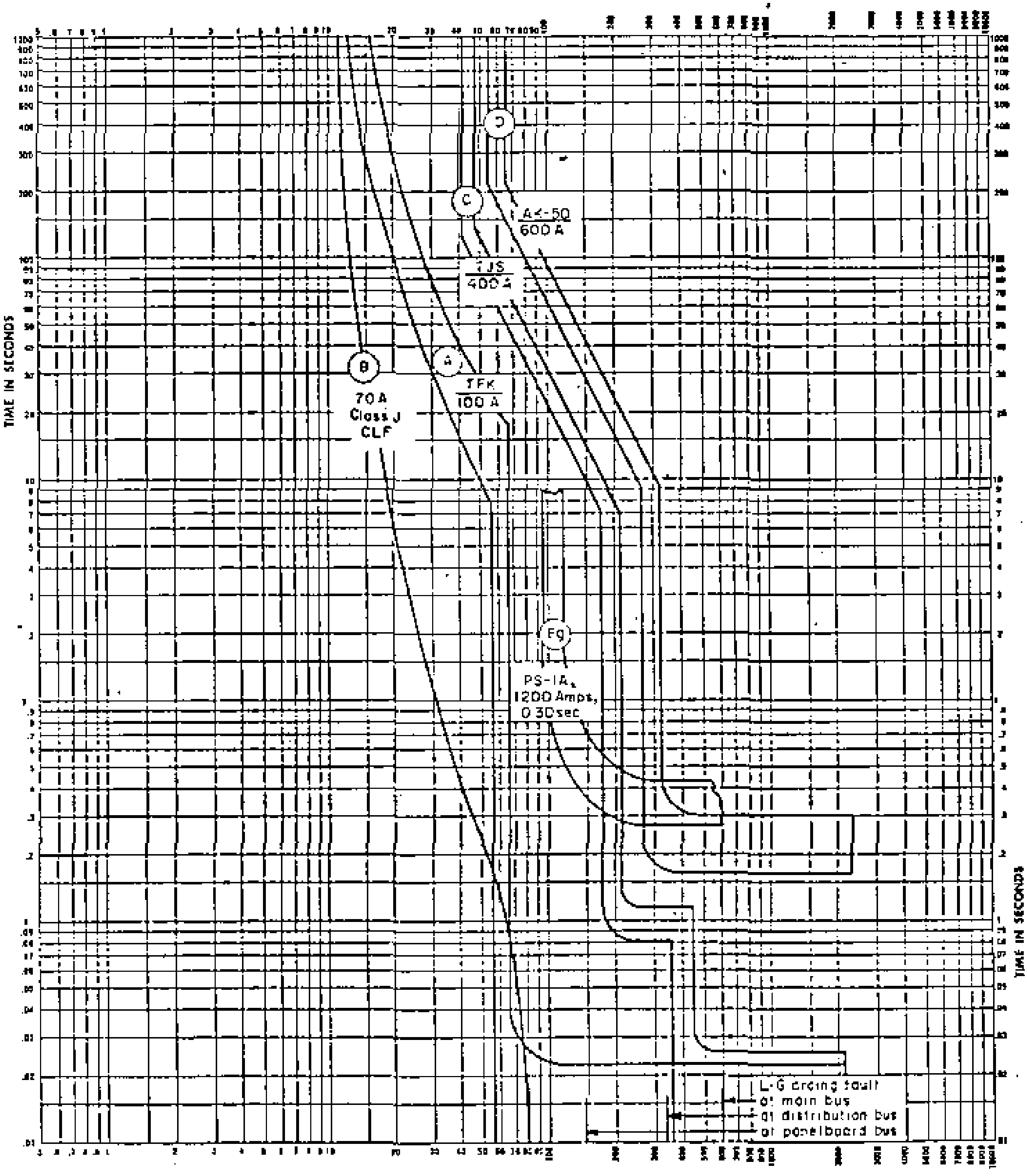

Fig. 21. Phase overcurrent plots with one ground-fault unit on main protector (E_g) set at 1200 Amperes and 0.30 second. Current (X10) at 480 Volts

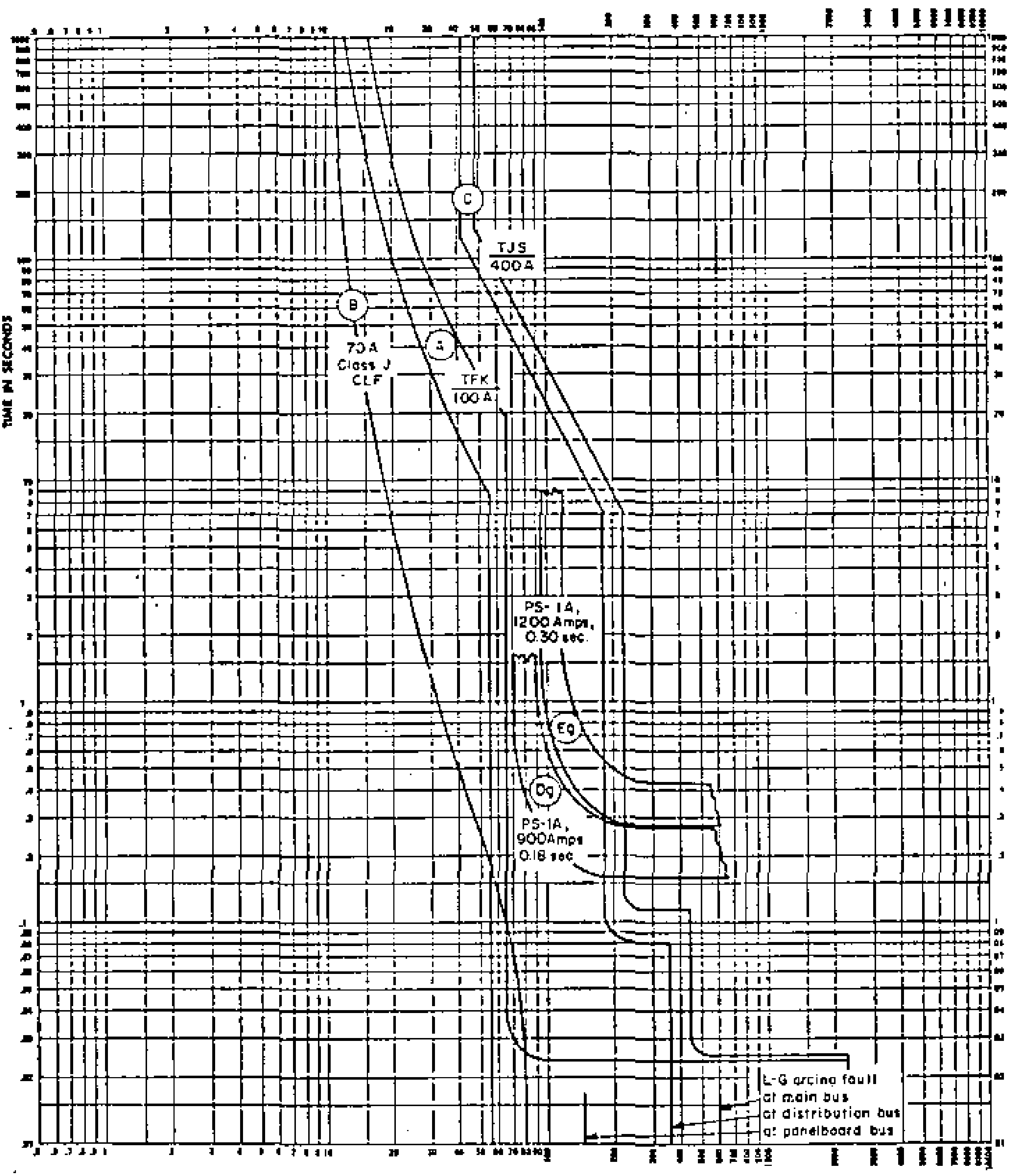

Fig. 22. Phase overcurrent plots with ground-fault units on main protector (E_g) and feeder protector (D_g) respectively. Main protector set at 1200 amperes and 0.30 second; feeder protector set at 900 Amperes and 0.18 second. Current (X10) at 480 Volts.

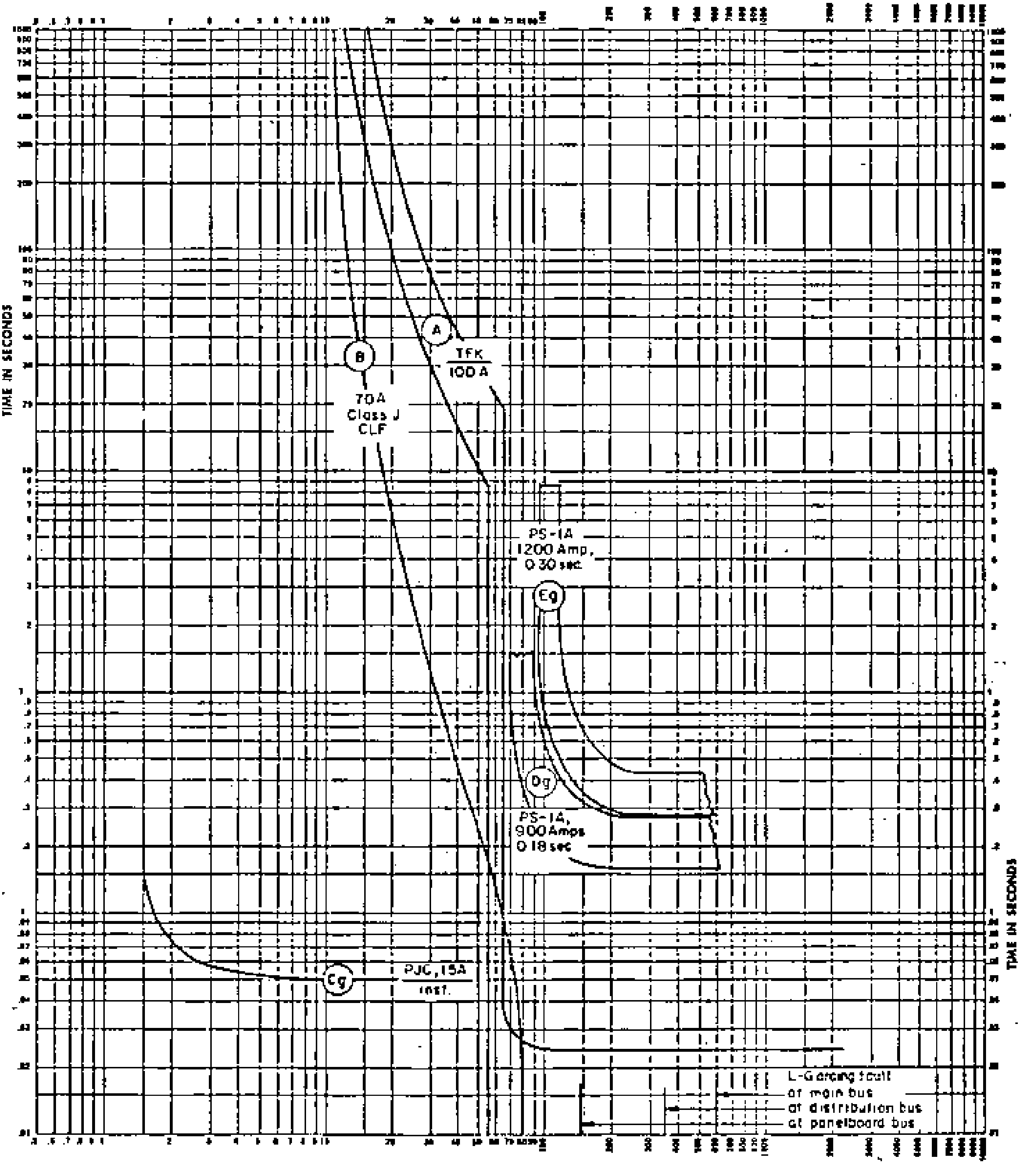

Fig. 23. Phase overcurrent plots with ground-fault units on main protector (E_g), feeder protector (D_g) and branch protector (C_g) respectively. The branch protector is set at 15 Amperes instantaneous with the [illegible] as [illegible] in Fig. 22. Current (X10) at [illegible]

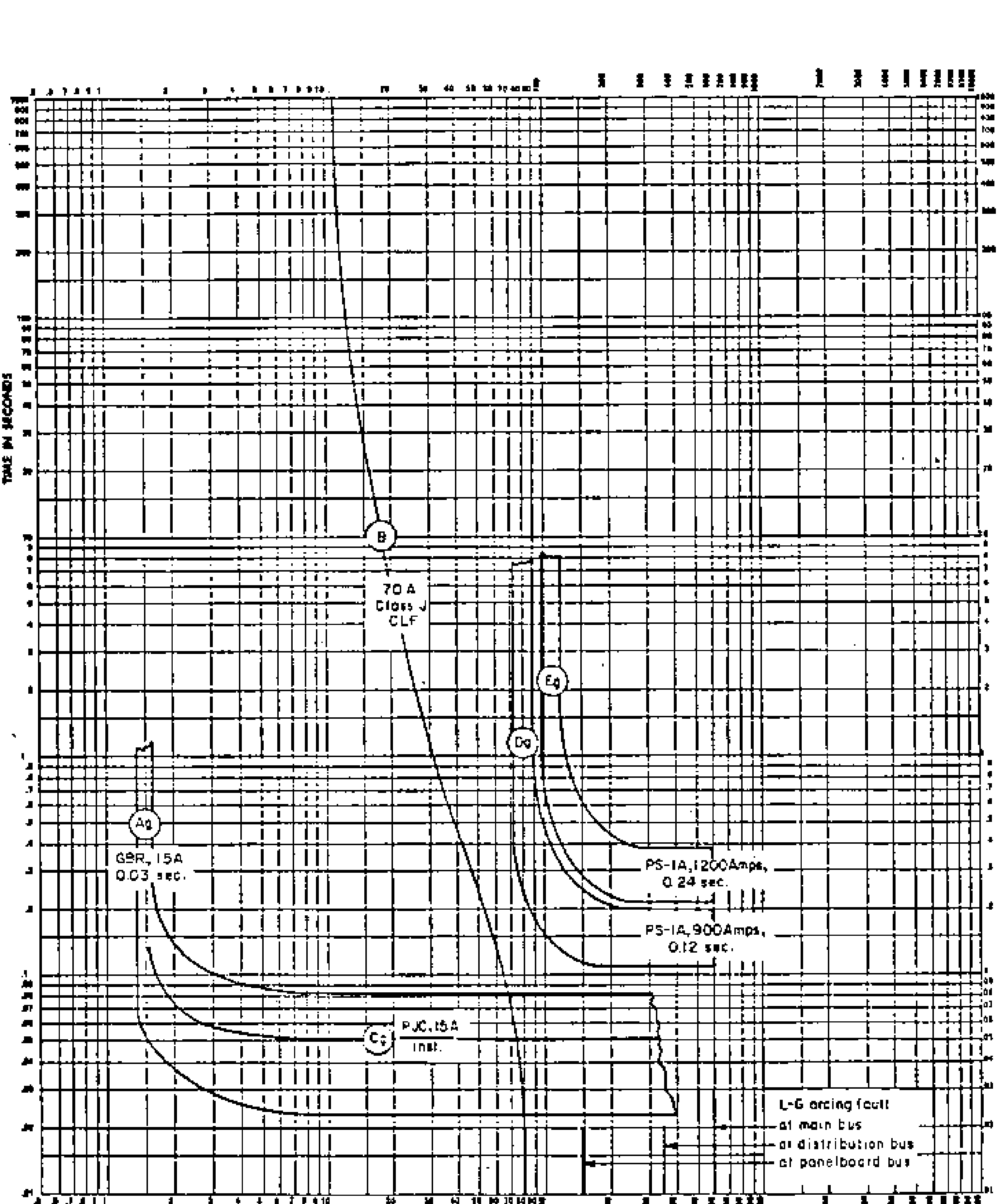

Fig. 24. Phase overcurrent plots with four ground-fault units. Ground-break unit (A_g) set at 15 Amperes instantaneous offers additional protection to the branch circuits at the panelboard. Current (X10) at 480 Volts.

APPENDIX A
Z Ratios

PRACTICAL CIRCUIT $(Z_0 + 3Z_e)/Z_1$ RATIOS

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

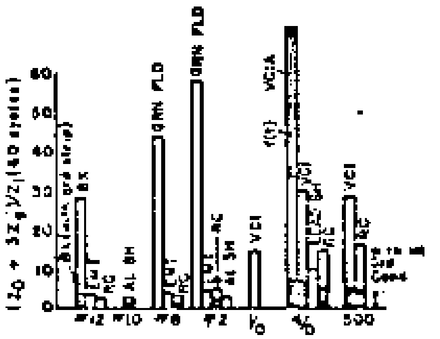

Fig. A-1. Typical $(Z_0+3Z_e)/Z_1$ ratios for cable circuit construction.

CABLE CIRCUIT CONSTRUCTION $(Z_0 + 3Z_e)/Z_1$ RATIOS

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

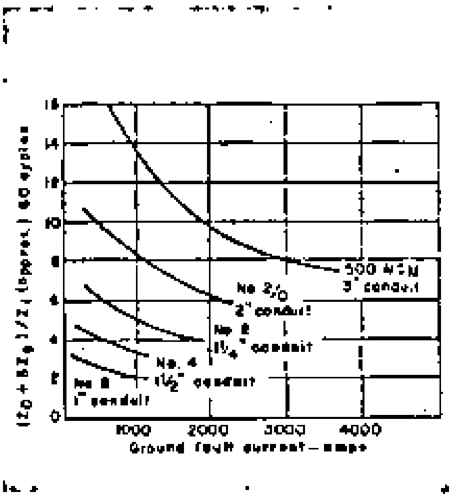

Fig. A-2. The effect of rigid steel conduit on cable circuit $(Z_0+3Z_e)/Z_1$ ratio

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

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

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

LOW VOLTAGE BUSWAY $(Z_0 + 3Z_e)/Z_1$ RATIOS

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

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

APPENDIX B
K Factors

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

TYPE OF FAULT	NOMINAL SYSTEM VOLTAGE		
	575V	480V	208V
Single Phase (L-G)*	0.40	0.38	0
Single Phase (L-L)†	0.85	0.74	0.02
Three Phase†	0.94	0.89	0.12

* For the single-phase line-to-ground fault condition at 208V, the K factor may approach 0.

† Note that these type faults do not involve ground. They are included as matter of interest.

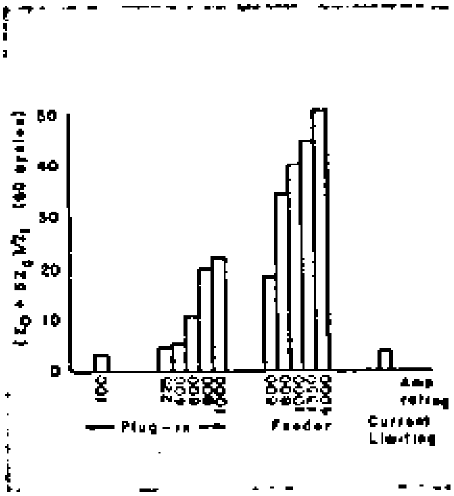

Fig. A-3. Typical $(Z_0+3Z_e)/Z_1$ ratios for low-voltage busway circuits.

APPENDIX C Double-ended Switchgear

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

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

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

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

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

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

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

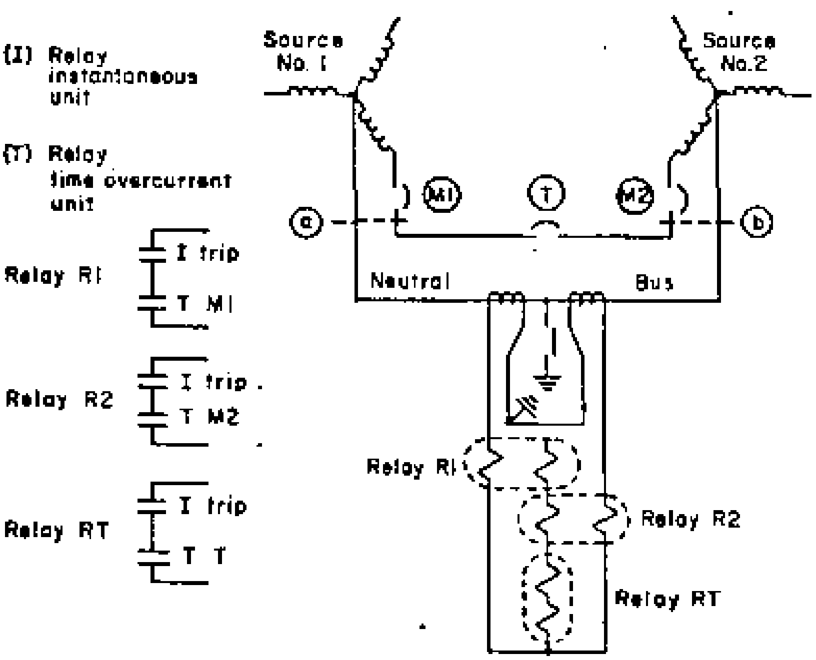

Fig. C-1. Return monitoring mode utilizing electromagnetic time-delay relays for four-wire, double-ended switchgear, or switchboard

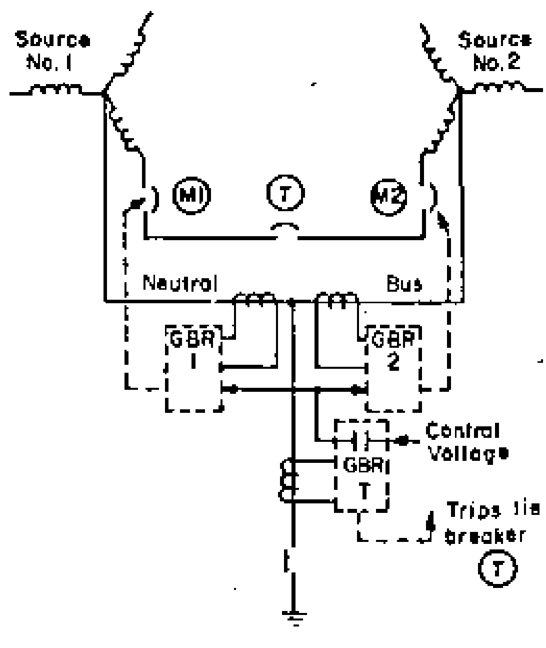

Fig. C-2. Return monitoring mode utilizing static time-delay relays for four-wire, double-ended switchgear, or switchb[illegible].

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

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

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

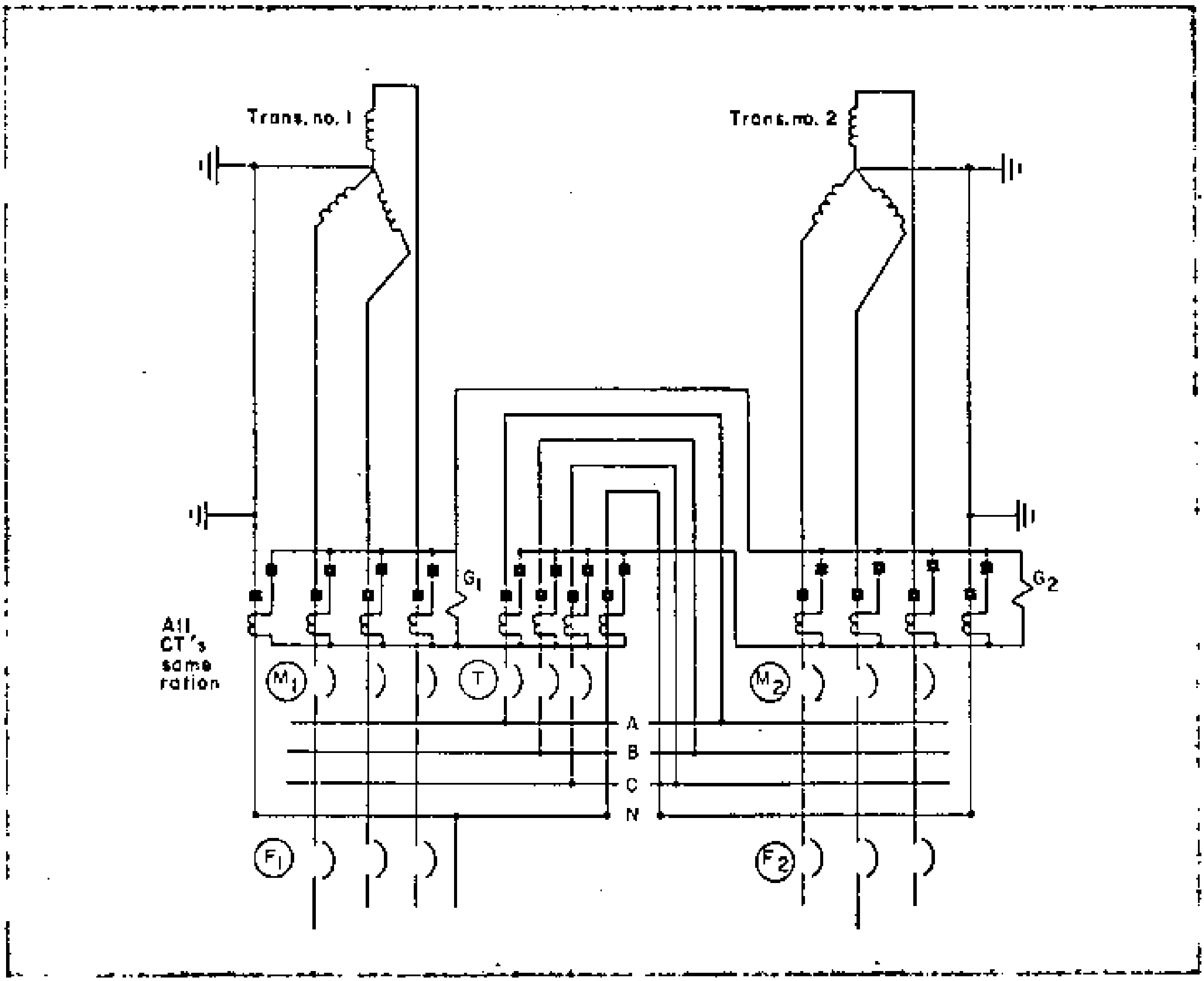

Fig. C-3. Summation scheme utilizing electromagnetic time-delay relays for four-wire, multiple-source switchgear or switchboards having multiple ground points.

① A. J. Bisson and E. A. Rochan—"Iron Conduit Impedance Effects in Ground Circuit Systems" AIEE TRANS. POWER APPARATUS AND SYSTEMS, Vol. 73, Part II, Pages 104-106, July 1954.

② W. F. Mackenzie—"Impedance and Inducted Voltage Measurements on Iron Conduits" AIEE TRANS. POWER APPARATUS AND SYSTEMS, Vol. 73, Part I, Pages 577-581, January 1955.

③ R. H. Kaufmann—"Some Fundamentals of Equipment Grounding Circuit Design" AIEE TRANS. POWER APPARATUS AND SYSTEMS, Vol. 73, Part II, Pages 227-232, November 1954 (GER-957).

④ J. A. Gienger, D. C. Davidson and R. W. Brendel—"Determination of Ground-fault Current on Common Ac Grounded Neutral Systems in Standard Steel or Aluminum Conduit" AIEE TRANS. POWER APPARATUS AND SYSTEMS, Vol. 79, Part II, Pages 84-90, May 1960.

⑤ R. H. Kaufmann and J. C. Page—"Arc Fault Protection for Low-voltage Power Distribution Systems—Nature of the Problem" AIEE TRANS. POWER APPARATUS AND SYSTEMS, Vol. 79, Part III, Pages 160-167, June 1960 (GER-1683).

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⑩ P. J. Savoie—"Ground-fault Protectors on Low-voltage Systems"—American Power Conference Proceedings 1972.

⑪ J. R. Dunki Jacobs—"The Effects of Arcing Ground Faults on Low-voltage System Design" IEEE TRANS. Industry Applications, Vol. 1A8, Pages 223-230, May/June 1972.

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SYSTEMS ENGINEERING
APPARATUS DISTRIBUTION SALES DIVISION

GENERAL ELECTRIC

FEBRERO DE 1980.

REPORTE TECNICO DE LA FALLA OCURRIDA EN EL TABLERO "D" DEL SERVICIO DE ESTACION DE LA S.E. NONOALCO EL MES DE ENERO DE 1980.

PREPARADO POR LA SECCION DE DISEÑO DE LA SUPERINTENDENCIA DE NUEVOS METODOS, SUBGERENCIA ELECTRICA.

Este estudio está encaminado a determinar la naturaleza de la falla de corto circuito ocurrida en un tablero de distribución de baja tensión (220 volts C.A.) perteneciente al servicio de estación de S.E.Nonoalco y a presentar las recomendaciones pertinentes a fin de evitar que en el futuro se presenten daños semejantes al ocurrido en esos tableros.

1.- DATOS DEL EQUIPO.

Los datos más sobresalientes del equipo se encuentran resumidos en el diagrama unifilar o Anexo N° 1. Por ser de interés particular en el estudio de la falla se resumen a continuación los datos de placa de los interruptores electromagnéticos principales:

INTERRUPTORES ELECTROMAGNETICOS	1A (EMERGENTE)	2A (PREFERENTE)
MARCA	FPE	FPE
MARCO Y TIPO	65 H-2	65 H-2
CAP.INTERRUPTIVA A 220 VOLTS.	85 KA (SIM)	85 KA (SIM)
AMPERES DE CALIBRACION (X)	2000	2000
CONTROL	125 V.C.D.	125 V.C.D.
RELE	SS-2 TIEMPO LARGO, TIEMPO CORTO.	SS-2 TIEMPO LARGO, TIEMPO CORTO.
CALIBRACION AL MOMENTO DE LA FALLA.		

INTERRUPTORES ELECTROMAGNETICOS	1A (EMERGENTE)	2A (PREFERENTE)
PICK-UP TIEMPO LARGO	1 X	1.1 X
CURVA " "	MAX	MAX
PICK-UP TIEMPO CORTO	4 X	6 X
CURVA " "	0.25 (seg.)	0.45 (seg.)

El tablero dañado era una sección de tablero construída de acuerdo a un -- antiguo diseño en el año de 1973. Esta Sección estaba unida con un cable - de 500 MCM al bus del nuevo tablero de servicio de estación fabricado en - el año de 1978. Las barras principales de esta sección estaban seccionadas con una barrera de micarta (ver detalle N° 2 foto 5 anexa) pues original-- mente se construyó para tener tensión regulada en una sección de bus y no- regulada en otra. Durante su instalación ésto se modificó uniendo las - -- barras con el cable que aparece en las fotos.

2.- REPORTE DE DAÑOS

La serie de fotografías anexas nos muestran los daños sufridos en el table ro. Se ha comentado verbalmente que la falla se originó por una herramien- ta olvidada dentro del tablero la cual originó posteriormente el corto - - circuito. Al momento de la falla el tablero se encontraba sin sus tapas -- posteriores, por lo que fué posible controlar el incendio en su interior - mediante extinguidores (polvo blanco en fotografías) y afortunadamente - - ésto anuló el efecto de la elevada presión que se produjo por los gases -- del arqueo y del incendio.*

Los interruptores termomagnéticos se carbonizaron especialmente del lado - de línea; las barras puente de cobre se fundieron en sus puntas por un - - claro efecto de arqueo trifásico y a tierra en sus extremos (ver fotos 3.- 4. 6 y 7). En las barras principales verticales se observan arqueos en - -

toda su longitud, pero el efecto más drástico se ve en el lugar en que se encuentra la barrera de fibra epóxica y micarta que -- secciona el bus; ahí se consumió apreciablemente el cobre (detalle N° 2, foto 5).

Sin embargo, en los detalles N° 1 de la foto 4 y 3 de la foto 5 se observa que tanto los dos interruptores termomagnéticos como esa pequeñísima sección del bus y los conectores de los cables - localizados todos en la parte inferior del tablero no sufrieron los daños que el resto del tablero experimentó.

El cable de 500 MCM que alimentaba esta sección dañada aparentemente no sufrió daños ni tampoco las barras de 2000 A. en el - - tablero principal.

3.- ANALISIS DE LA FALLA

Del reporte de daños se presume que la falla fué originada en el bus principal en su parte inferior (detalle N° 3 foto 5) y de- - ahí se formó un arco que se propagó a la parte superior de las - barras principales. En la barrera que secciona al bus este arco se estacionó causando el mayor daño apreciable a las barras principales (detalle N° 2, foto 5). Debido a que la distancia entre fases en las barras puente es relativamente pequeña, hubo arqueo en todas ellas y la presencia del aire ionizado generalizó el -- arqueo en todo el tablero, inclusive al gabinete de lámina (foto N° 7).

¿ Porqué no operaron tanto el interruptor principal como el fusible en el lado de 6 KV?

El valor de la falta sólida trifásica, es decir aquella que no - es de arqueo, calculada para el tablero dañado es F3 en el diagrama unifilar. El valor de F4 es el valor anterior menos la - - aportación de motores, por lo que representa la contribución a - la falla que circula a través de los transformadores y los interruptores electromagnéticos. Este valor de 16,047 ampers habría disparado en un tiempo de 0.5 seg. el interruptor electromagnético o el fusible la habría interrumpido en un tiempo de 0.65 seg. según se aprecia en las curvas tiempo corriente, anexo N° 2. - - Es de notar ahí la falta de coordinación existente entre la curva del interruptor y la del fusible, debido a una incorrecta - - calibración del primero. Ninguna de las dos protecciones actuó,- por lo que la corriente de falla fué menor a F4 e incluso menor a 12000 ampers (6 X) valor de Pick-Up de la banda S.T. del - -- interruptor y si se sigue la versión de los operadores de que la falla fué librada en un tiempo de 1 a 3 minutos en forma manual, la corriente pudo haber tenido un valor menor a 5300 o hubiera - operado el fusible en ese tiempo.

Lo anterior es congruente con la teoría de fallas de arqueo que predice la posibilidad de que una falla de arqueo pueda tener un valor entre el 19 y el 38% de la falla sólida (3000 a 6000 A.) y no extinguirse por si sola, de ahí que se deduce que la falla -- fué de arqueo y de un valor menor al necesario para operar las - protecciones.

Los artículos que se han escrito sobre fallas de arqueo indicanque estas fallas son más probables en sistemas de 480/277 volts y - muy poco probables en sistemas de 220/127 volts debido a que en - - estos últimos la tensión no es suficiente para reencender el arco. Sin embargo, el caso de Nonoalco es uno de los raros casos en que - esto sucede y se presume que la falla se originó entre fases (por - haber la mayor tensión) y después incluyó arqueos a tierra.

En la gráfica del anexo N° 2 se incluye la curva de daños admisi--- bles en el cable de 500 MCM que alimentaba el tablero dañado y la - curva de los daños admisibles en un circuito de capacidad nominal - de 600 A. (que es la del tablero "D") para fallas de arqueo, calcu- lada a partir de la ecuación:

$$250\ I\ \text{nominal} = I\ \text{arc}^{1.5}\ t$$

que representa los daños admisibles en un circuito de cierta I nomi nal (capacidad de diseño) ante una corriente de falla I arc y en el tiempo T. Esta ecuación fué tomada del TRANSACTIONS ON INDUSTRY - - APPLICATIONS de la IEEE de agosto de 1977. Puede observarse que ni- el cable de 500 MCM ni el tablero "D" estaban adecuadamente protegi dos.

En el Anexo N° 3 se muestra la inclusión de un interruptor termomag nético de 3 x 400 A., como protector del circuito del tablero "D",- ajustado en su disparo magnético a 400% (1600 A.) Obsérvese que - - este interruptor (curva N° 3) protege adecuadamente el cable alimen tador de 500 MCM (curva N° 4) y proporciona protección contra daños por arqueo en ese mismo tablero (curva N° 5) para corrientes de - -

falla mayores de 1600 A. (10% de la falla sólida); como es muy poco probable encontrar corrientes de arqueo menores al 10%, el circuito estará bien protegido.

En el mismo Anexo N° 3 aparece la curva característica del interruptor principal (curva N° 2). La corriente del sensor (x) se ha modificado de 2000 A. a 1600 A. cambiando el tap del propio T.C. integrado al interruptor. Esto se sugiere para estar más cerca de la corriente nominal del transformador de 500 KVA (1312 ampers) y tener a su vez coordinación con los derivados. También se ha desplazado su curva característica para que exista coordinación con el fusible en 6 KV.

En el caso en que se presentara una falla de arqueo en el tablero principal, su valor mínimo probable sería 19% de la falla sólida en ese punto, es decir:

F1 = Falla sólida = 20,309 ampers.

(ver Anexo N° 1)

Falla de Arqueo = 20,309 x 0.19 = 3859 ampers.

El Pick-Up de la banda de tiempo corto sugerido en el Anexo N° 3 es 2 X, o sea 3200 A. Esto representa que estamos protegiendo a partir del 16% de la falla sólida un poco más allá del valor probable del 19%.

4.- CONCLUSIONES

a).-La falla ocurrida fué del tipo de arqueo, con un valor de corriente menor al que se presentaría en el caso en que la falla fuera sólida en ese punto de la red y menor a su vez a -

la corriente necesaria para poner en servicio las protecciones de acuerdo a la forma en que estaban calibradas el día de la falla.

b).-Se confirma que las corrientes de arqueo pueden ser de una magnitud mucho menor que las correspondientes a la falla franca, pero altamente destructivas, debido a su larga duración al no detectarlas las protecciones y a la gran cantidad de energía que se libera en el arco.

c).-El interruptor electromagnético estaba incorrectamente calibrado y en el anexo N° 3 se muestra como puede ajustarse de manera tal que el tablero principal quede protegido contra fallas de arqueo. El tablero "D" y su cable alimentador no alcanzan a ser protegidos por este interruptor principal, por lo que se muestra como usando un termomagnético ese circuito puede protegerse.

d).-El caso de Nonoalco es excepcional por la teóricamente baja probabilidad de que se presente y se sostenga una falla de arqueo en un sistema de 220/127 volts, por lo que debe discutirse si la protección contra estas fallas debe incluirse en sistemas de esa tensión como política de protección en la Compañía.

5.-RECOMENDACIONES

a).-Calibrar interruptores electromagnéticos de acuerdo a los valores indicados en el anexo N° 3. Cambiar los taps de los sensores de corriente a 1600 ampers.

b).-Instalar un interruptor termomagnético de 3 x 400 A. nominales en la Sección "B" del tablero de servicios de estación, cali-- brado de acuerdo a la curva del anexo 3, como protector del -- circuito del tablero "D". (NOTA: Su calibración debe verificar se contra las cargas conectadas al tablero).

c).-Colocar una barra de tierra en el tablero "D", eléctricamente- conectada al gabinete y a la red de tierras (barra de 1 x - -- 1/4").

d).-Cambiar los termomagnéticos 15, 16, 17 y 21 de la sección "B"- que son de capacidad interruptiva normal a otros de alta - -- capacidad interruptiva, debido a que el valor de corco circui- to en su punto de aplicación rebasa su capacidad interruptiva.

e).-Se recomienda hacer pruebas a las unidades de disparo SS-2 de- los interruptores electromagnéticos mediante la unidad de prue bas F.P.E., DDT.

f).-El cable alimentador no sufrió daños visibles pero se recomien da verificar el estado en que se encuentra o cambiarlo.

g).-Cada vez que se instale un tablero semejante al dañado como -- ampliación a un servicio de estación existente, debe verificar se que al interruptor principal de ese servicio existente real mente esté protegiendo el cable alimentador y el tablero anexo contra este tipo de fallas.

Preferentemente se debe instalar un protector del circuito en- el tablero existente.

h).-La distancia entre barras puente que por diseño es menor a lo- que fija la norma para potenciales opuestos a través del aire-

(1") debe aumentarse mediante el uso de barreras de micarta o aislando estas barras puente.

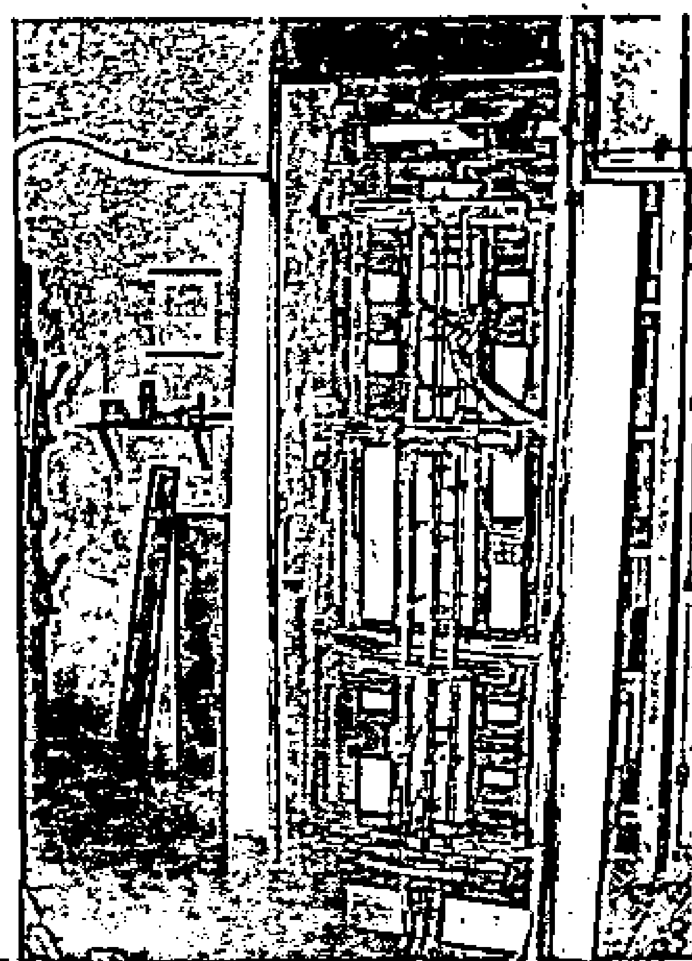
i).-Se recomienda que en las instalaciones de la Compañía donde existan tableros de distribución de fuerza en baja tensión e- interruptores electromagnéticos principales, se verifique la- calibración y coordinación de éstos.

j).-En el caso de que se incluya la protección contra fallas de arqueo en sistemas de 220/127 V., se recomienda ajustar la banda de tiempo corto o la instantánea del protector para operar en un valor entre el 19% y el 38% de I 3 Ø sólida, siempre y cuando las condiciones de carga lo permitan; de no ser así, usar un sistema de detección de falla de arqueo a tierra, pues aunque la falla se origine entre fases, inevitablemente incluirá después la tierra.

ACHS'CGP'BTH'mltm.

FOTO 1.- VISTA FRONTAL
(Sin tapas)

FOTO 2.- VISTA POSTERIOR
(Sin tapas)



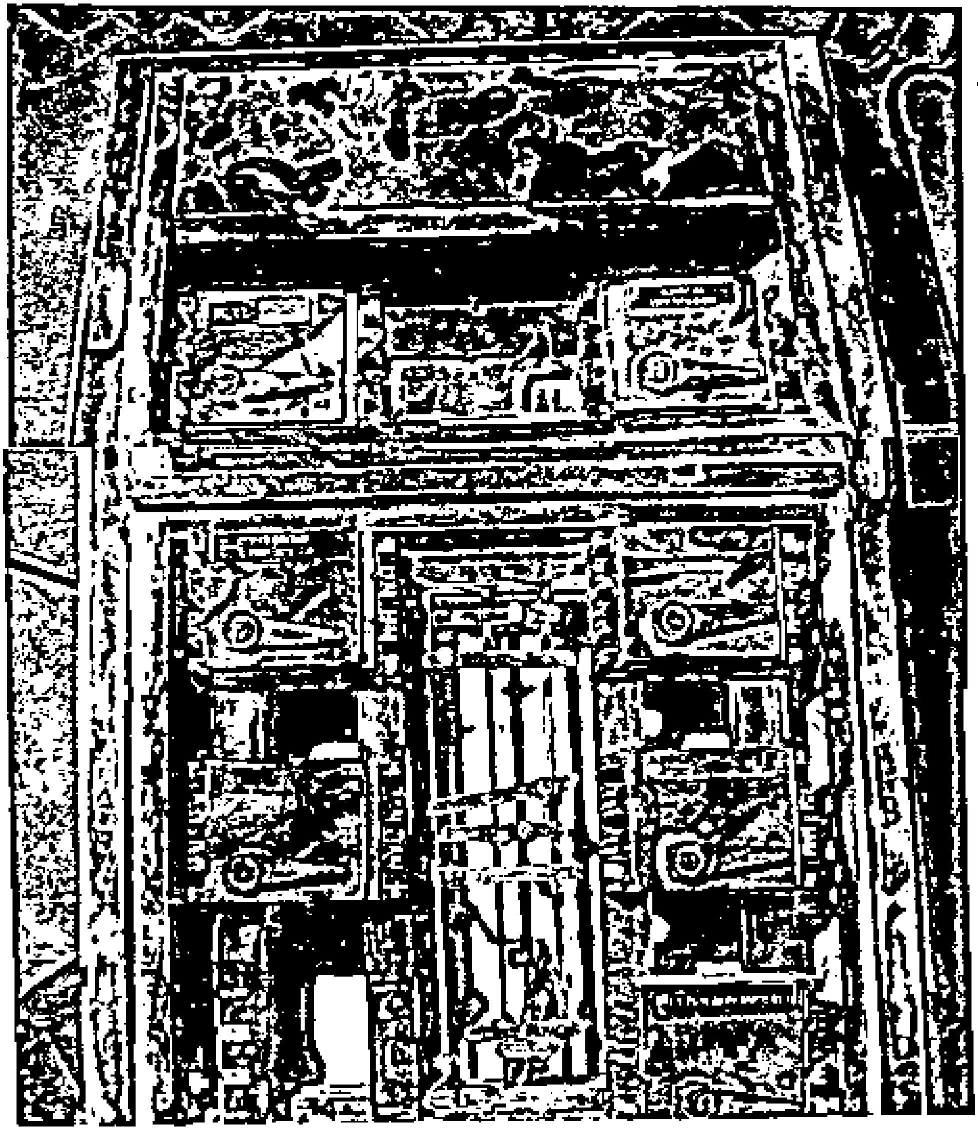
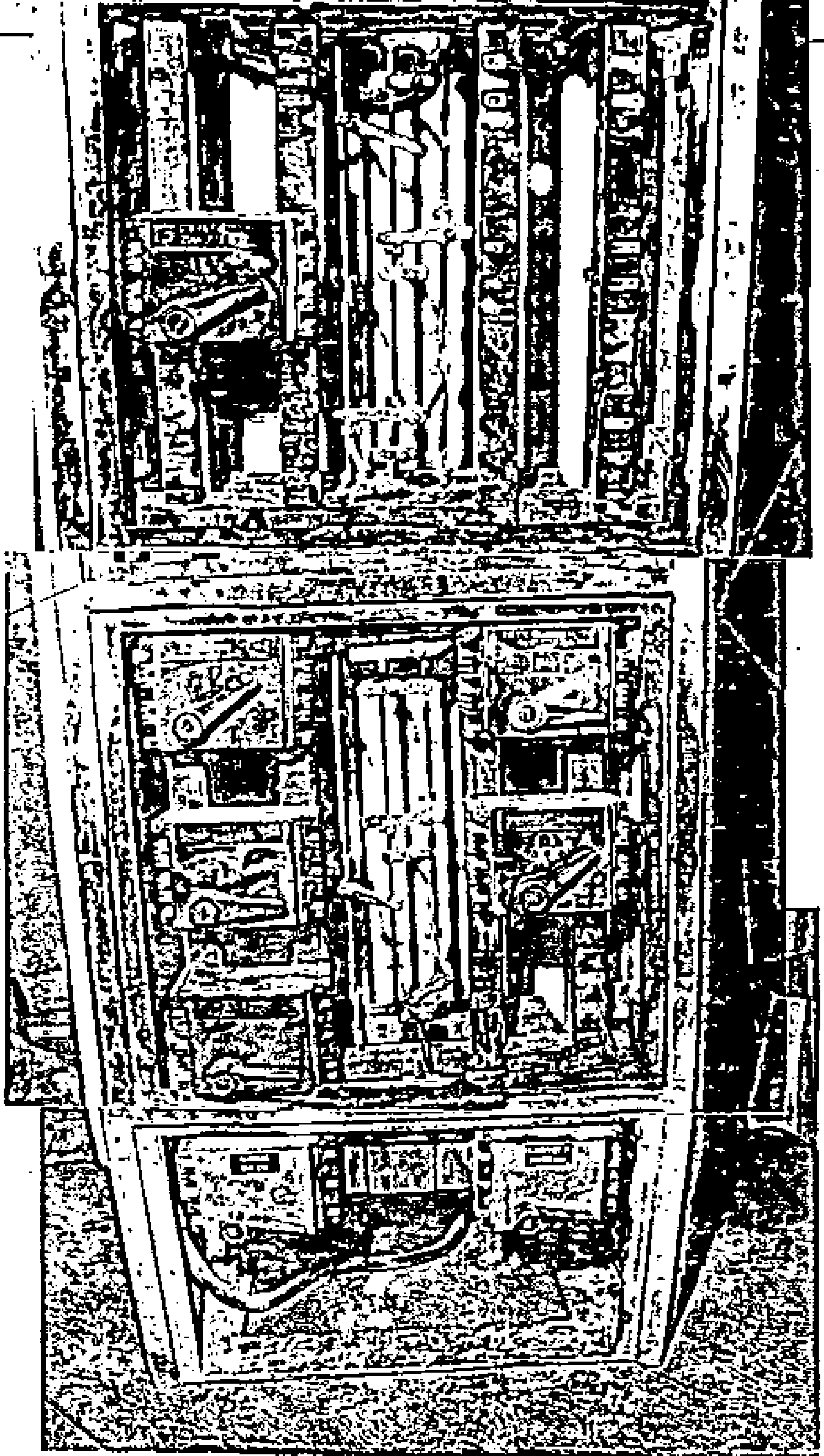


FOTO 3.- VISTA SUPERIOR FRONTAL SIN TAPAS DEL TABLERO.



DETALLE No. 1

FOTO 4.- VISTA FRONTAL, MEDIA E INFERIOR DEL TABLERO.

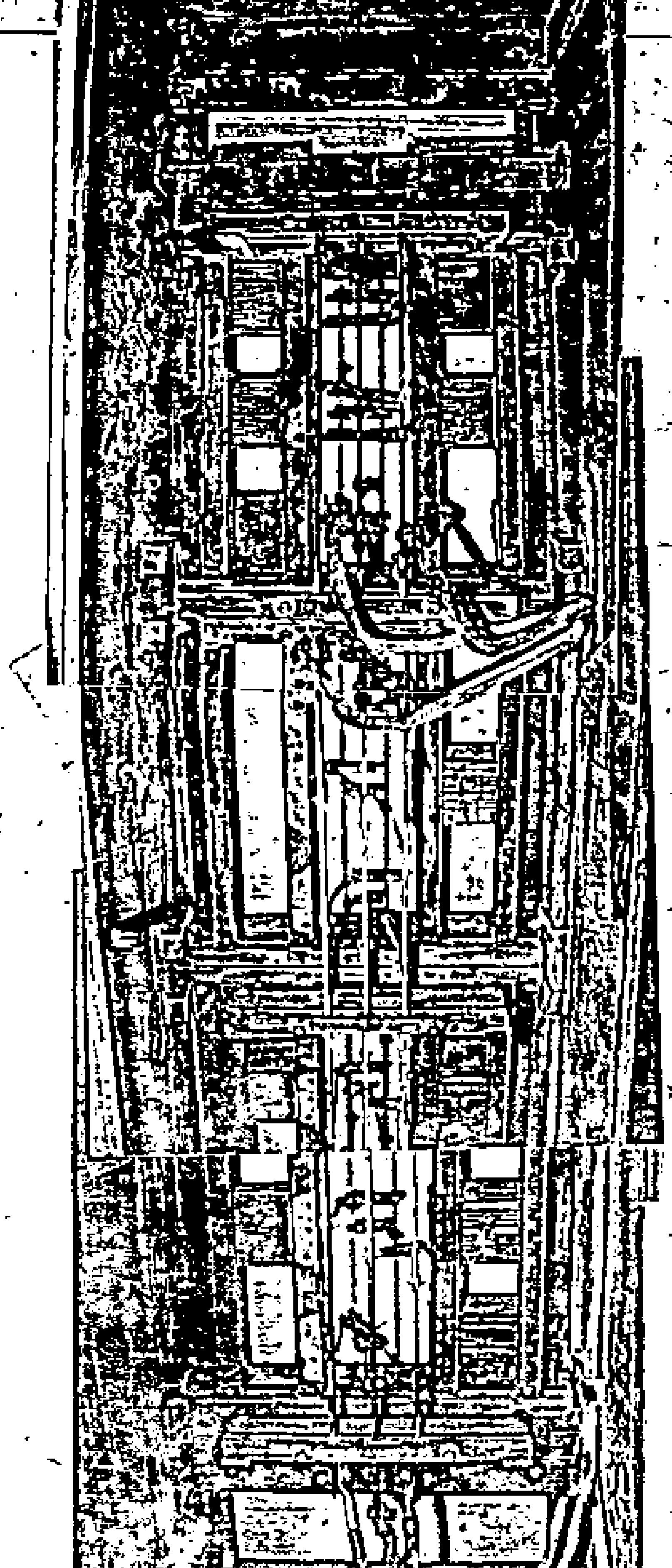


FOTO No. 5 VISTA POSTERIO[illegible]
DEL TABLERO.

DETALLE No. 2 , DE LA FOTO 5

DETALLE No. 3 , DE LA FOTO 5

FOTO 6.- ASPECTO DE LOS INTERRUPTORES Y LAS BARRAS PUENTE.

FOTO 7.- DETALLE DE BARRAS PUENTE.

DETALLES DE LOS INTERRUPTORES TERMOMAGNETICOS

FOTO 8

FOTO 9

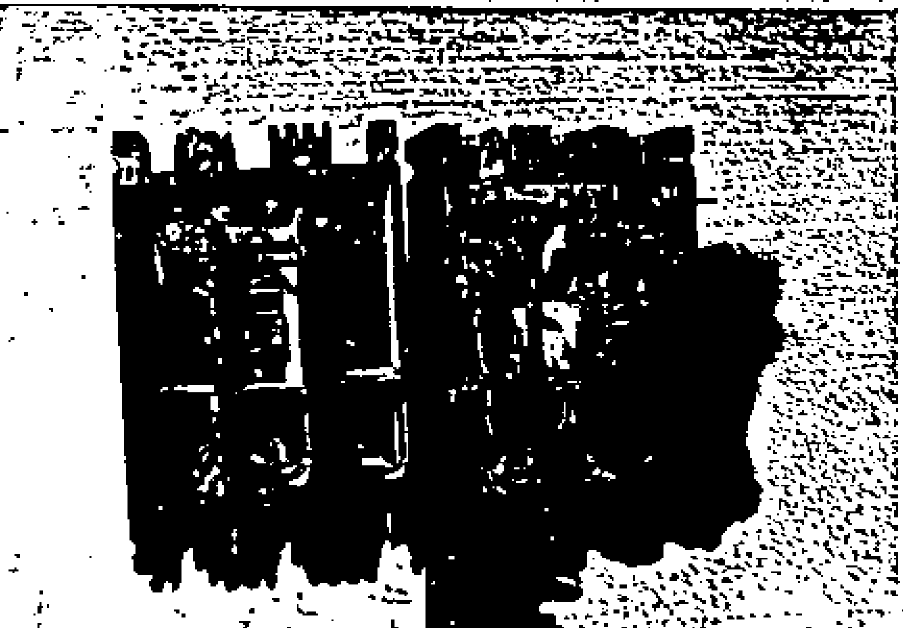


FOTO 10

ANEXO Nº 4 DEL REPORTE TECNICO.
FALLA EN EL TABLERO "D" DEL SERVICIO DE ESTACION DE LA S. E. NONOALCO.
TIPOS DE FALLAS EN BAJA TENSION.

Falla franca ó sólida	Limitada por la impedancia del sistema. Raramente ocurre en circuitos prácticos. 3 Ø, 2 Ø, Ø-T.
Falla de arqueo.	Puede originarse entre fases pero inevitablemente involucrará la tierra. Puede ser causada por fallas de aislamientos, accidentes de construcción, roedores, etc.
Corrientes de fuga en aislamientos.	Del orden de miliampers, sucede en herramientas portátiles, aparatos electrodomésticos, etc.

La falla de Nonoalco fué una falla de arqueo.

¿ Qué son estas fallas?

FALLAS DE ARQUEO

* Aunque la falla se origine entre fases, inevitablemente se manifestará a tierra.

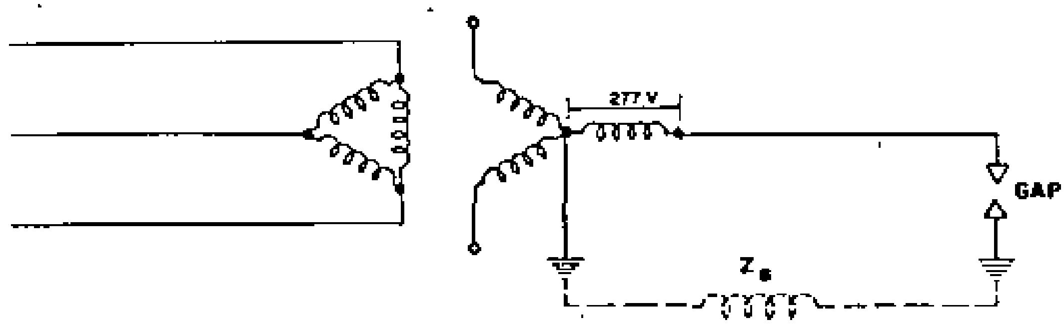
* El valor de la falla sólida a tierra:

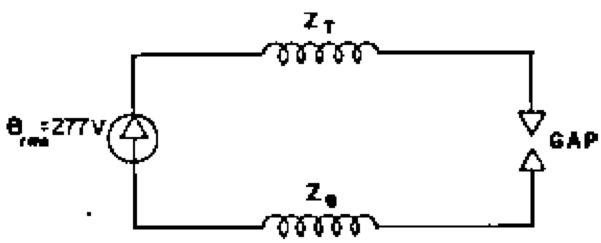
$$I_F = \frac{3\ E_{L-N}}{Z_1+Z_2+Z_0+3Z_G}$$

Z1-Sec(+)
Z2-Sec(-)
Z0-Sec(0)
ZG-Impendancia circuito de tierra variable.

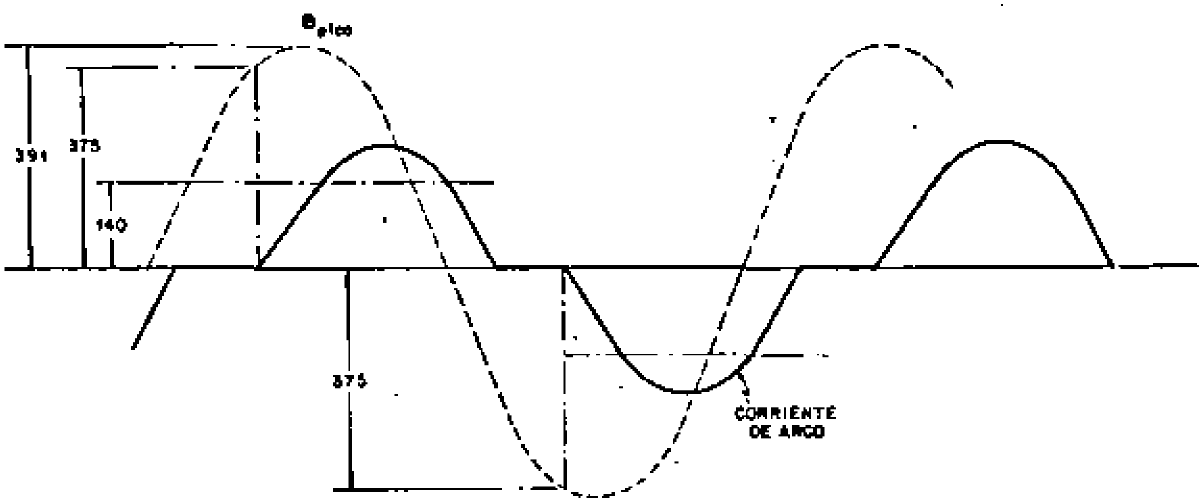
* Cuando la falla no es sólida, existe un arco cuya corriente es un % de la falla sólida, pero de un valor de I_{ARC} y V_{ARC} difíciles de predecir. Sin embargo, las recomendaciones de protección aconsejan situar el valor mínimo entre un 19% a un 38% de de la falla sólida en un sistema de 480/277 V. más abajo de este rango se considera que la falla se autoextingue.
* Dado los bajos valores que pueda tener IARC, es probable que la protección de sobrecorriente de fase (PSCF) no la detecte.
* Si esto sucede, la corriente puede durar varios segundos ó minutos y su efecto es altamente destructivo, dada la gran cantidad de energía que se libera a través del arco y no se disipa en el resto del sistema(buses, cables, etc.) como en el caso de la falla sólida.
* Otra característica de las fallas de arqueo es que en la inmensa mayoría de los casos se presenta exclusivamente en sistemas de 480/277 V, debido a que la tensión teórica necesaria para la reignición del arco es 375 volts y este sistema si la proporciona ($277 \times \sqrt{2} = 391 > 375$ V)

MODELO TEORICO DE LA FALLA





TENSION EN EL GAP
MAYOR DE 375 V → NO HAY CHISPA
MENOR DE 375 V → SI HAY CHISPA



$I_{\phi\text{-}T}$ = 20,000 A

I_{ARC} = 7600 A (38 %)

V_{ARC} = 140 V

Así resulta que es teóricamente poco probable que en un sistema de 220/127 volts se presente una falla de arqueo y no se -- autoextinga. Las recomendaciones no aconsejan proteger contra- este tipo de falla en sistemas de 220/127 V: (NEC, etc.) sin - embargo existen algunos casos reportados donde estas fallas no se autoextinguieron...y el caso de Nonoalco es uno de ellos.

* ¿Como se debe proteger un circuito contra fallas de arqueo - a tierra?

1° Calibrar si las condiciones de carga lo permiten, la P.S.C.F. entre un 19 - a un 38 % del valor de la falla sólida - - (para efectos prácticos) si estamos cerca del transformador

$$I_{FASE\ A\ TIERRA} = I_{3\emptyset}$$

2° Si las condiciones de carga o de coordinación no permiten - calibrar la PSCF en forma adecuada, se recomienda un sistema de protección de fallas a tierra.

* Sistemas de protección de fallas a tierra (PFAT)

- Desbalanceo de tensiones en Δ abierta.
- Corriente residual
- Sensor dona abrazando tres fases y neutro.
- Sensor corriente de regreso neutro transformador.

Ya se ha seleccionado el equipo, ¿existe algún critero para -- determinar la frontera de los daños admisibles en fallas a - - tierra? SI:

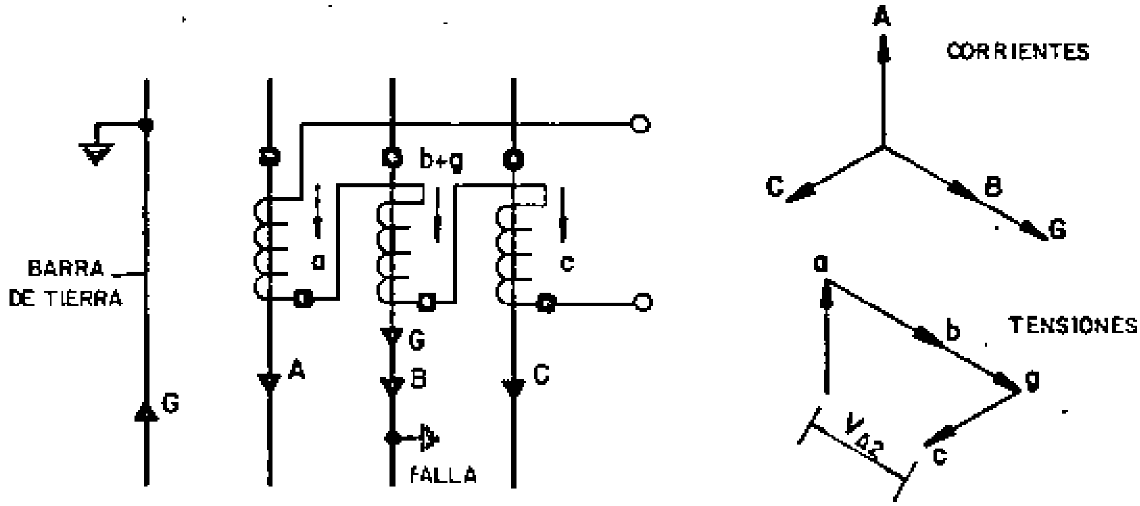
$$250\ In = I_{arc}^{1.5} \times t$$

ALUMINIO : $Y = 1.519 \times 10^{-6}\ I_{arc}^{1.5}$ (pulg-cub-seg)

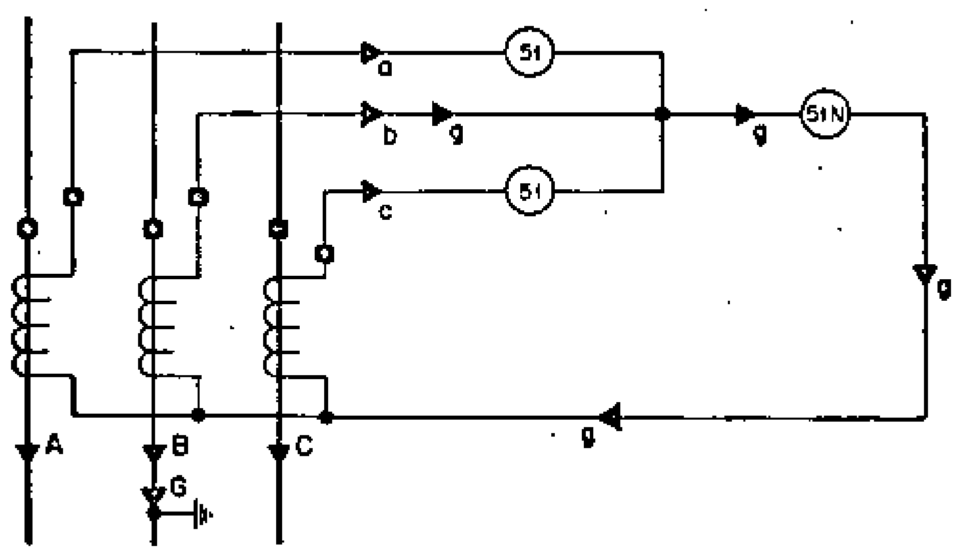
COBRE : $Y = 0.723 \times 10^{-6}\ I_{arc}^{1.5}$ (pulg-cub-seg)

envolvente de acero : $Y = 0.6564 \times 10^{-6}\ I_{arc}^{1.5}$ (pulg-cub-seg)

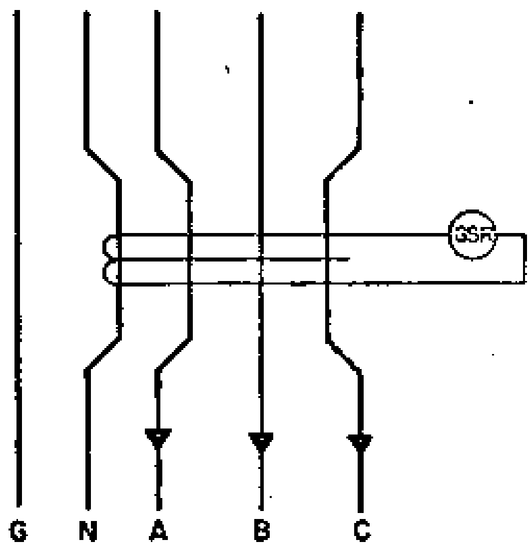
SISTEMAS DE P.F.A.T.



DELTA ABIERTA

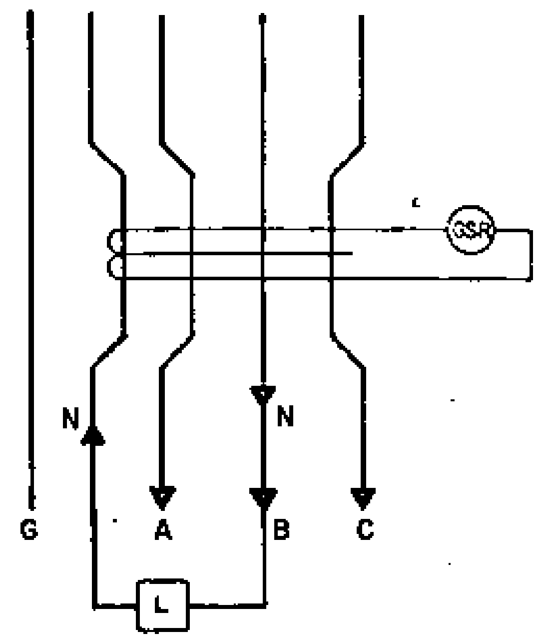


CORRIENTE RESIDUAL



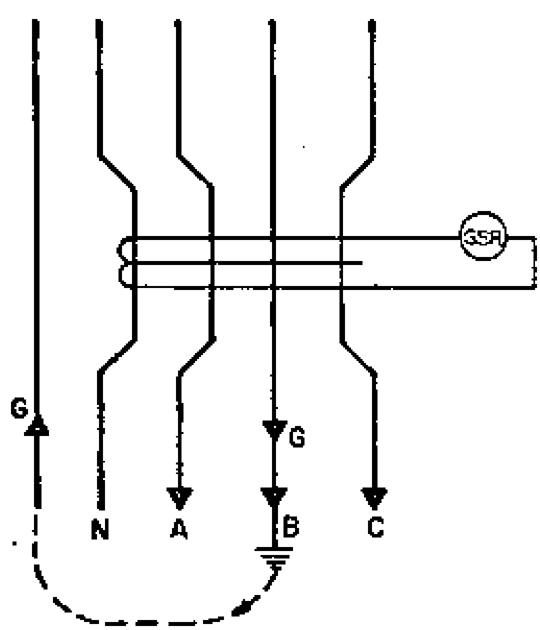
SENSOR DE TIERRA

(CORRIENTES BALANCEDAS)



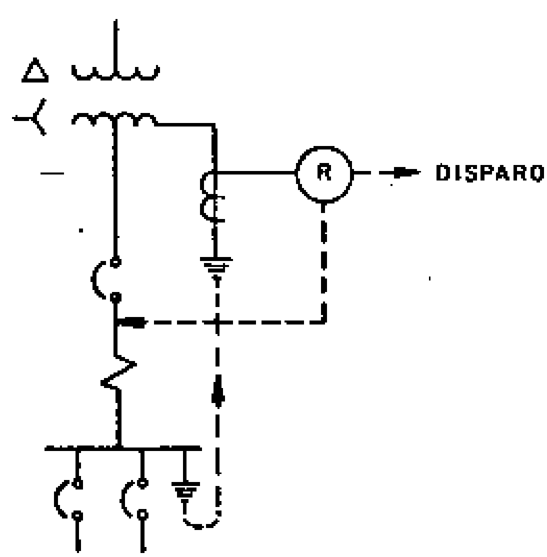
SENSOR DE TIERRA

(MAXIMO CASO DE DESBALANCEO)



SENSOR DE TIERRA

(CONDICION DE FALLA, EL RELEVADOR OPERA)

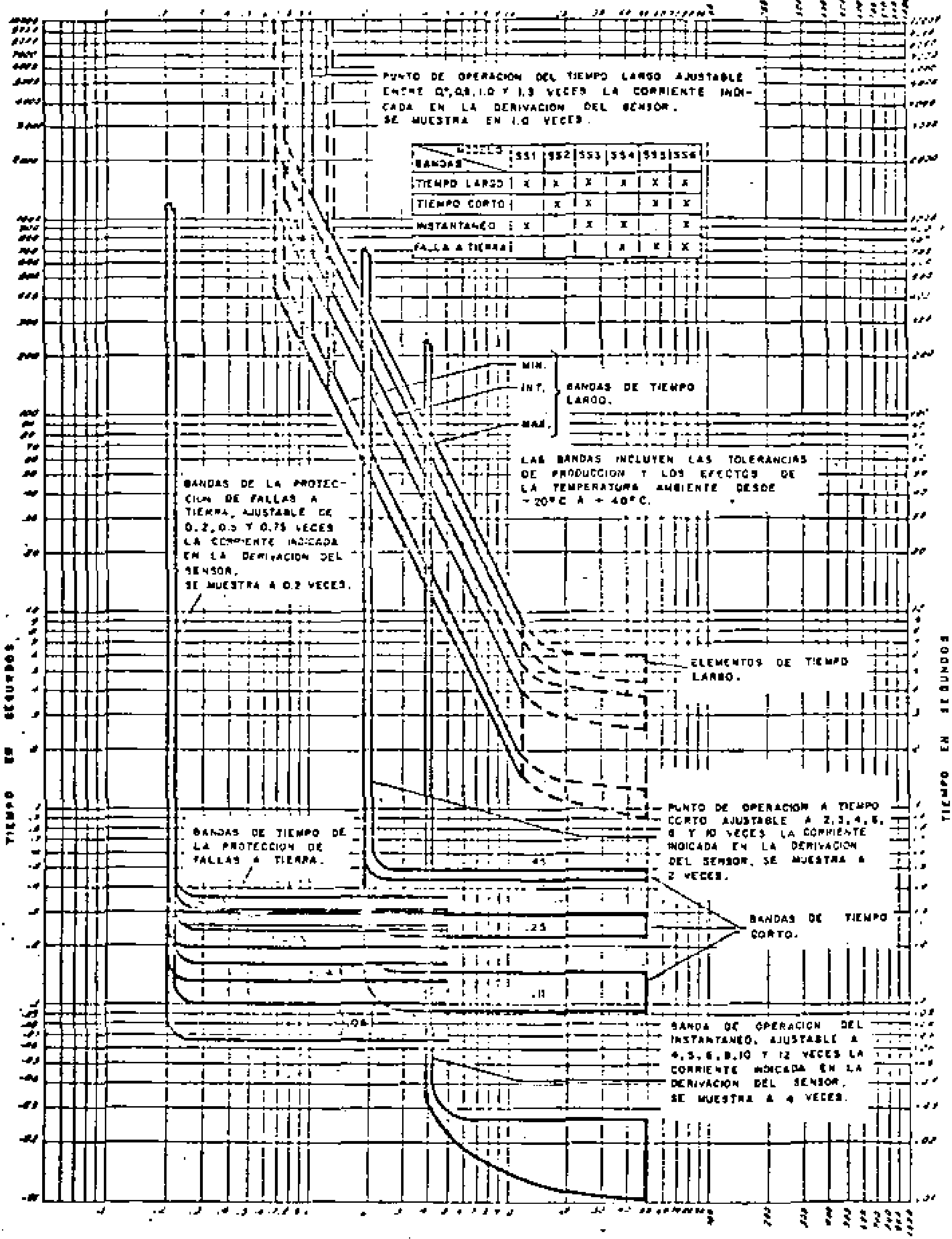


PROTECCION EN REGRESO

CIRCUITO DE TIERRA

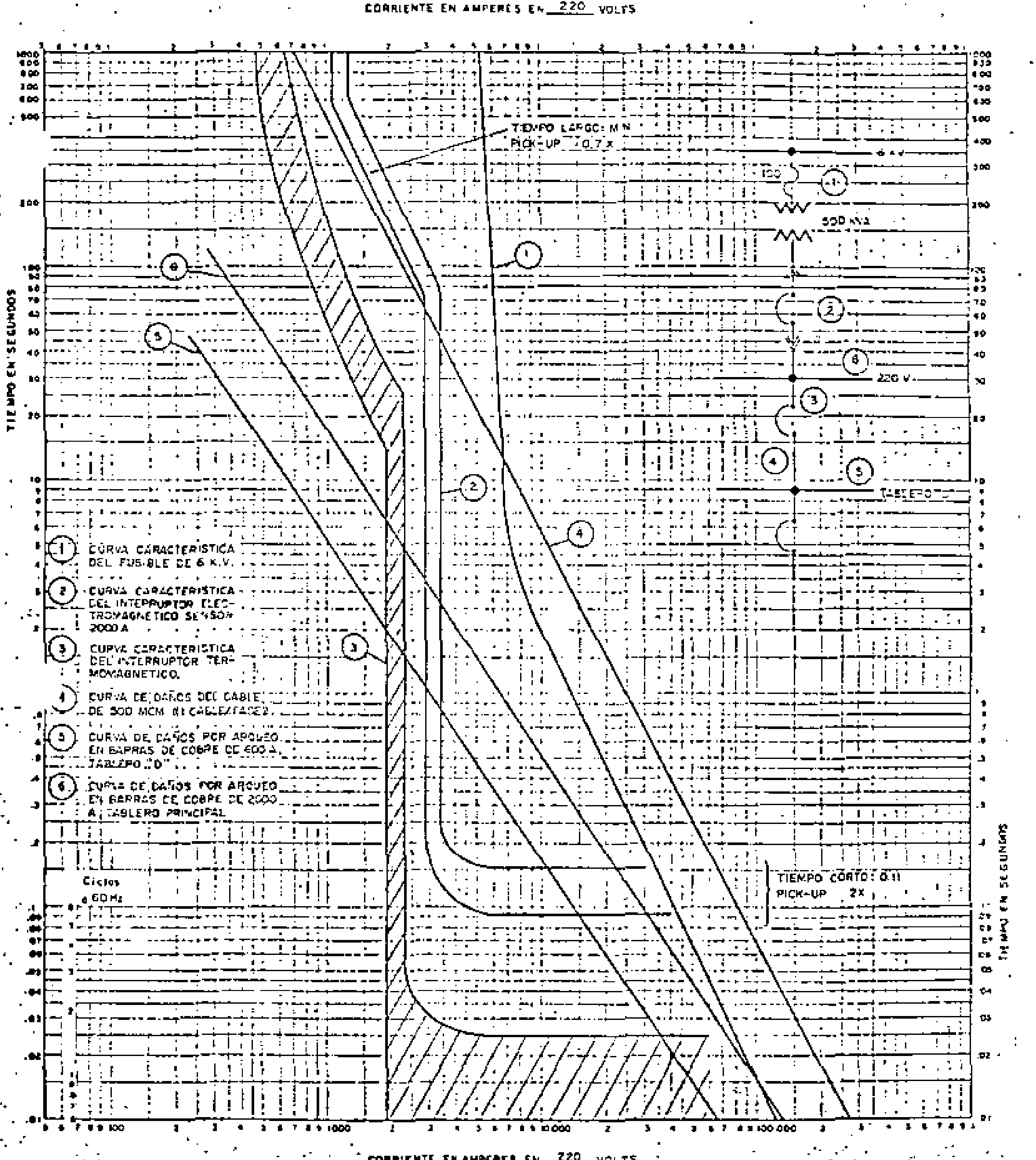
CURVAS TIEMPO - CORRIENTE C-3-285 DE LOS RELES DE SOBRE-CORRIENTE TRANSISTORIZADOS TIPO SS

CORRIENTE EN MULTIPLOS DE LA CORRIENTE INDICADA EN LA DERIVACION DEL SENSOR



CORRIENTE EN MULTIPLOS DE LA CORRIENTE INDICADA EN LA DERIVACION DEL SENSOR

FEDERAL PACIFIC ELECTRIC DE MEXICO S. A. DE C. V.



CURVAS TIEMPO-CORRIENTE

NO. ANEXO No. 3

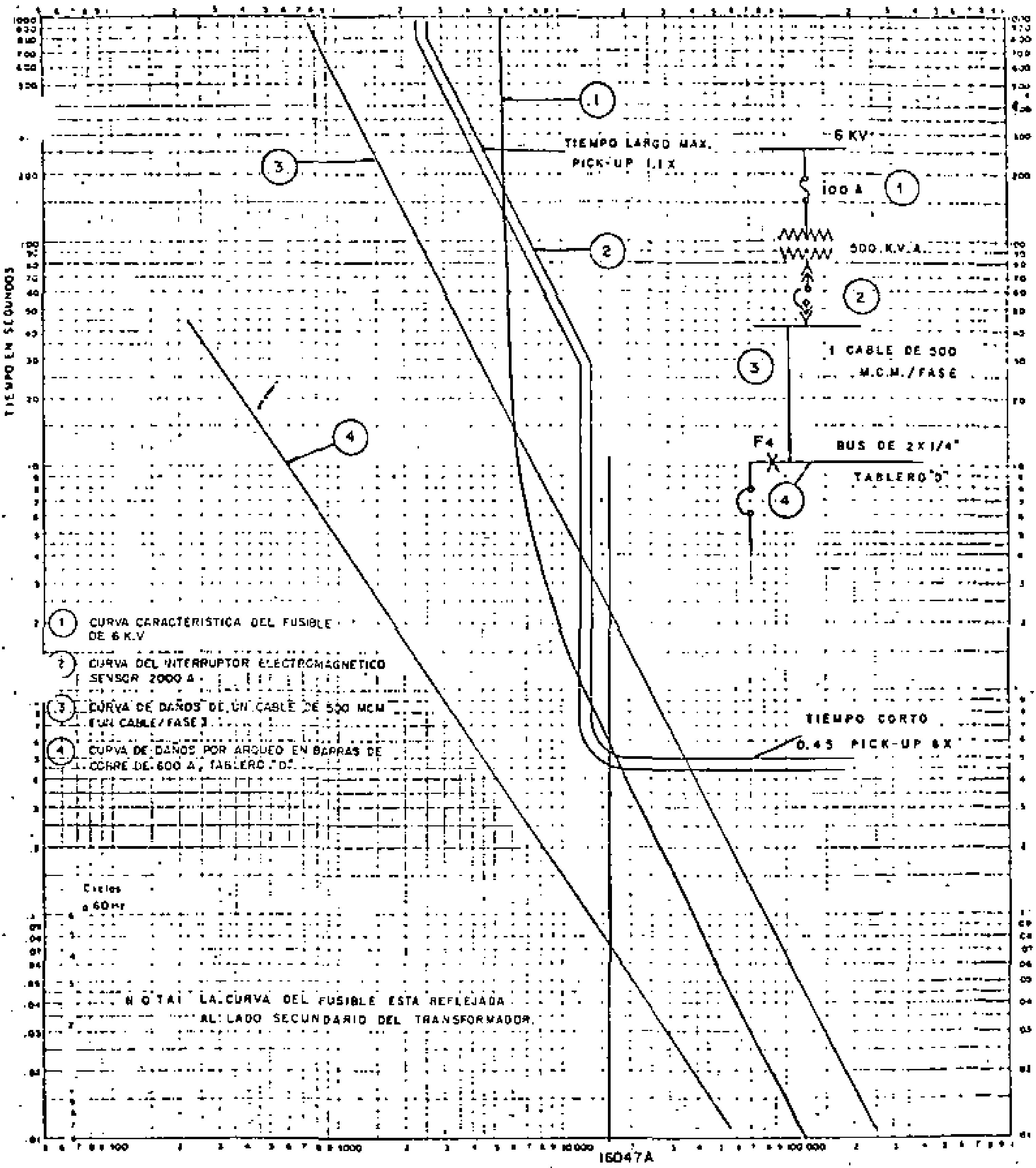
FECHA ENERO - 1980

DIBUJADO POR

COMPONENTE

LOCALIZACION

CORRIENTE EN AMPERES EN 220 VOLTS



CORRIENTE EN AMPERES EN ______ VOLTS

CURVAS TIEMPO-CORRIENTE

NO. ANEXO No. 2

SITUACION EN QUE SE ENCONTRABA EL EQUIPO DE PROTECCION DEL SERVICIO DE ESTACION DE NONOALCO.

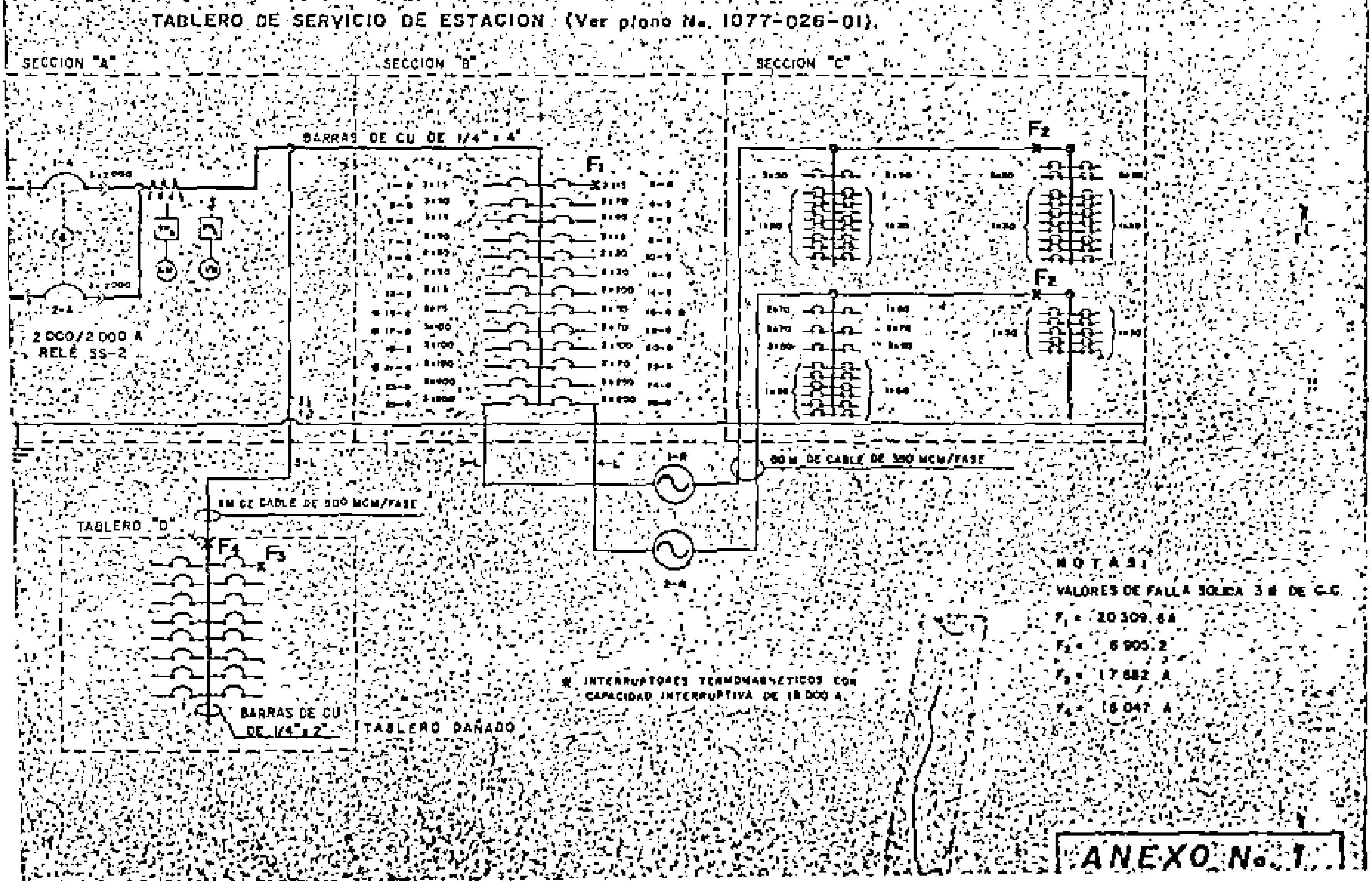
FECHA ENERO / 1980

DIBUJADO POR ______

COMPONENTE ______

LOCALIZACION ______

RAMA UNIFILAR EXPLICATIVO DE LA FALLA OCURIDA EN EL TABLERO DE SERVICIOS PROPIOS DE LA S.E. NONOALCO (ENERO DE 1980).



ANEXO No. 1

Application Guide — Spot networks and connected equipment

for:
Commercial buildings,
shopping centers,
industrial plants
supplied at 480Y/277 volts ac

GENERAL ELECTRIC

CONTENTS

Introduction

Distributed or grid-type secondary network systems have been used for many years by power companies to serve high density load areas at 208Y/120 volts in a number of cities throughout the country. These systems consist of grids of interconnecting cables energized at numerous points by transformers which feed the grid through network protectors as shown in Fig. 1.

Due to the multiplicity of transformers and paths over which current can flow to any one load served from the network, a high degree of service continuity is maintained under various operating contingencies. Voltage regulation is good not only under normal operating conditions but also during periods of system trouble. These characteristics make the network system very desirable for the supply of power to buildings with large power requirements in metropolitan areas.

Over the years, as loads have increased to several thousand kVA in single buildings, the practice of some power companies has been to set up banks of transformers in underground vaults close to these buildings. Paralleling of the transformers in the banks is accomplished by connecting them to a common service bus through network protectors. Groups or banks of transformers such as these are known as spot networks in contrast to distributed or grid-type networks.

In some cases, where the magnitude of the load or the size of the building complex is sufficiently large, several groups of transformers are located around the property to supply the total load. High-rise buildings lend themselves to the installation of groups of transformers at various floor levels within the building. These groups of transformers each feed a number of floors and may be interconnected within the building by secondary ties.

The increasing use of, and dependence upon, electric energy in modern commercial buildings and some types of industrial plants, makes it economically sound for both the power company and the user to set up 480Y/277-volt systems rather than 208Y/120-volt systems. The size and importance of these installations requires service continuity that is available only from multiple sources of supply continuously paralleled by a network. Consequently, the 480-volt spot network has been coming into use more and more during the past 10 years.

Experience acquired in the operation of 208Y/120-volt systems has furnished much background that has been found very useful in the operation of 480-volt systems. *One important difference observed between the two voltage systems is that secondary faults do not tend to "burn clear" as readily on 480-volt systems as on 208-volt systems.* This, plus the levels of available short-circuit current which prevail on spot network systems, generally places greater emphasis on the importance of selecting proper protective devices and coordinating their characteristics.

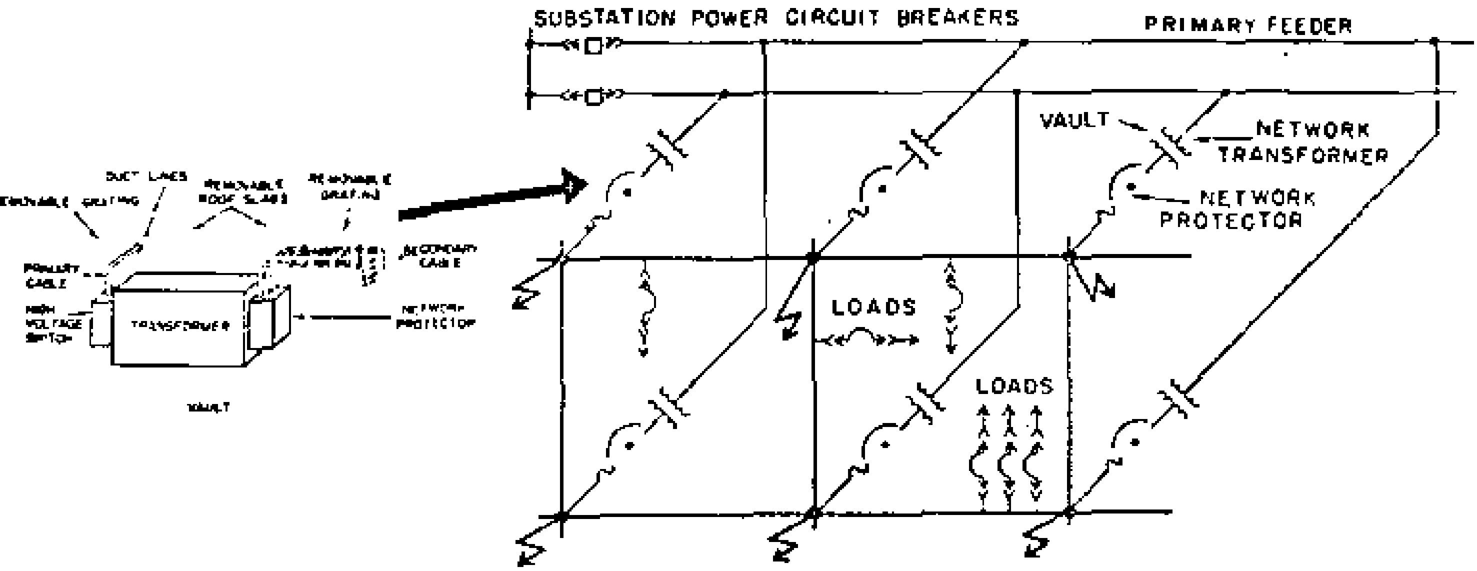


Fig. 1 Typical 208Y/120 volt distributed secondary network system.

Basic spot network

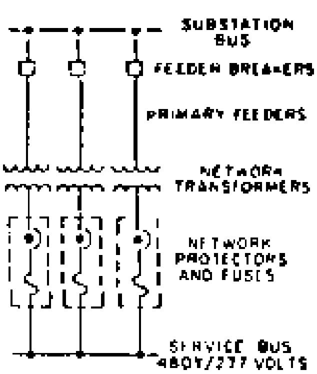


Fig. 2 One-line diagram for a typical three-unit spot network.

A one-line diagram for a typical three-unit 480Y/277-volt spot network is shown in Fig. 2. Three transformers, each fed by an individual primary feeder, are connected in parallel on the secondary by a service bus through network protectors. Normally, the primary feeders originate at the same substation bus in order to eliminate circulating power current. It is through the use of separate primary feeders to transformers, (which may be from two to six in number) and network protectors on their secondaries, that the spot networks achieve the high degree of service continuity provided. Without multiple primary feeders, a group of parallel-connected transformers is in reality a simple radial system which offers only a slight advantage over one large transformer of the required capacity.

Equipment and arrangement

The basic equipment—transformers, network protectors and service bus, shown in Fig. 2—may be located in a vault under the sidewalk or in an equipment room in the building being served. Ownership of the spot network, by either the power company or the building owners, will influence the equipment location.

Transformer ratings used are directly related to the current ratings of network protectors and may be from 300 to 2500 kVA. Primary voltages range from 5 to 34.5 kV. High-voltage termination facilities frequently include a three-pole, three-position disconnecting and grounding switch.

Network protectors are available in either submersible or non-submersible enclosures. Submersible units are designed for locations such as basement or underground vaults where flooding may occur. Non-submersible units are designed for use above ground or in locations where there is little or no chance of flooding. Both types have the same operating characteristics and electrical features.

Service buses consist many times of insulated cable which ties together the load terminals of the network protectors, and also serves as a connecting point for service take offs. Other types of bus construction also are used, including factory-assembled busway.

Basic network operation

OPERATION UNDER NORMAL CONDITIONS

The basic objective of the network system is to keep the transformers operating in parallel as much as possible and delivering power to the loads fed by the service take-offs. To assure power flow from the feeders into the network, the transformers are kept connected to the service bus as long as the voltages on the primary feeders are nearly equal in magnitude and phase angle.

Fluctuations in voltage on the primary feeders may cause power to be transferred from one feeder to another through the parallel connection of the transformer secondaries. One function of the sensing relays used with network protectors is, therefore, to continually monitor power-flow direction. Upon reversal, so that power flows out of the network through a transformer to a primary feeder, the transformer of that circuit should promptly be disconnected from the service bus by the network protector. Power flow out of the network to a primary feeder may be the result of low voltage on the feeder from normal loading or fault conditions. Either will be detected by the network protector through the flow of reverse power. In case the protector fails to operate on high fault currents, fuses are provided within the protector, which should open and disconnect the transformer.

The second function of the sensing relays is to reclose the network protector, causing power flow into the network, as soon as voltage on the primary feeder has the proper magnitude and phase angle.

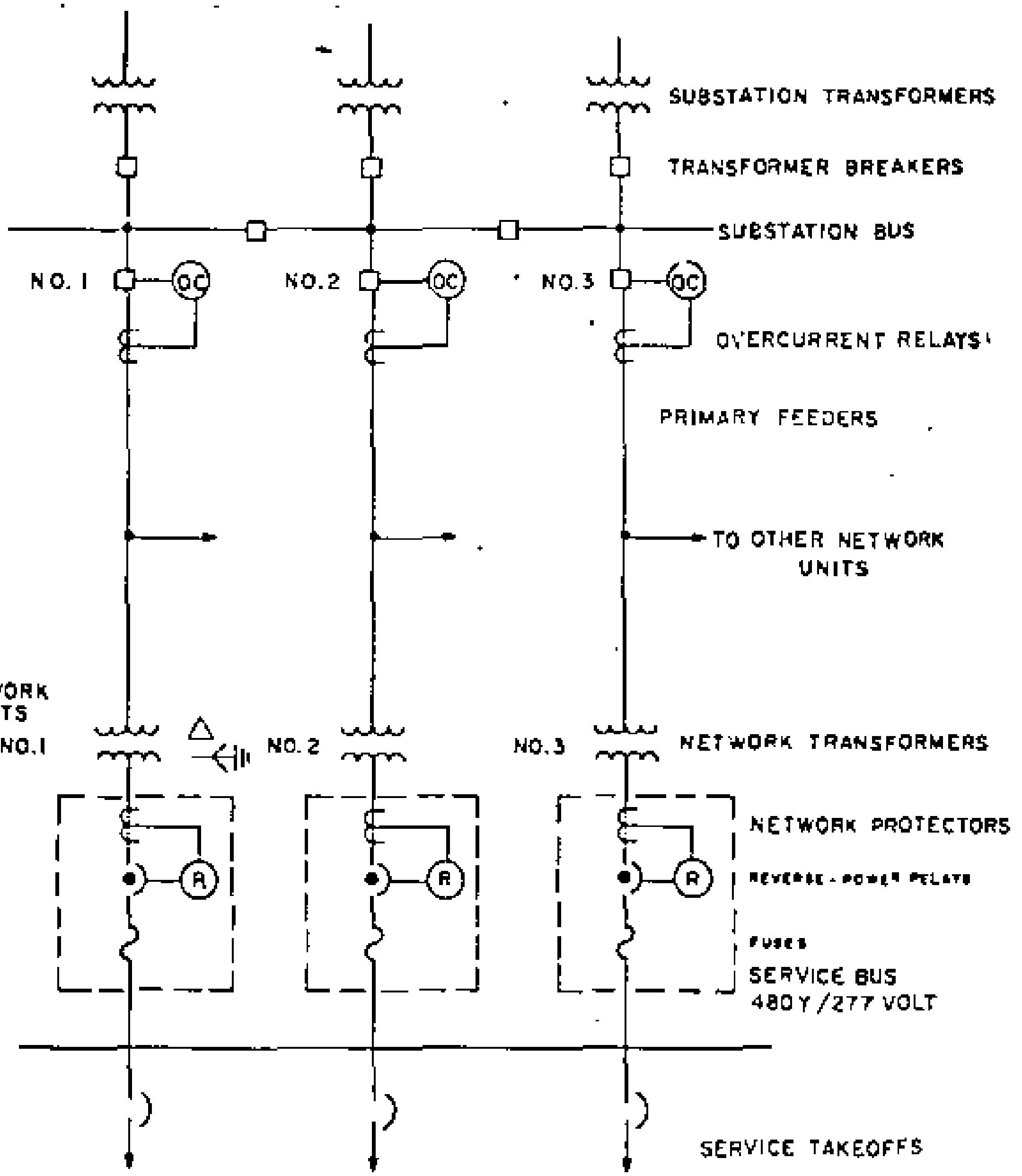


Fig. 3 Protective devices on typical three-unit spot network.

OPERATION UNDER FAULT CONDITIONS

Primary feeders are only one of five possible locations of faults on spot networks[1]. Faults may also occur at any one of four other significant points, namely:

- service bus
- service take-offs
- network protector
- network transformer

For each of these locations, the protection afforded by the primary-feeder overcurrent relays, the network protectors and the network protector fuses can be analyzed with the help of Fig. 3.

The arrangement shown is representative of a 480Y/277-volt spot network. Three network units, consisting of a network transformer and directly connected network protector, are illustrated. Note that each network unit is supplied by a separate primary feeder, and that all primary feeders originate at the same substation bus. Each network protector is connected to the 480Y/277-volt service bus. Service take-offs are fed from the service bus through protective devices such as circuit breakers (as shown), current-limiting fuses, or high interrupting-capacity cable limiters.

Primary Feeder Faults

A primary feeder fault on feeder #2, for example, is cleared first by the opening of feeder breaker #2. Then network units #1 and #3 supply fault current to faulted feeder #2 in reverse direction through network unit #2. This reversal of feed is noted by the reverse-power relay, and network protector #2 opens and clears faulted feeder #2 from the system. If the network protector fails to open as required, the network protector fuse provides "back-up" protection and clears the faulted feeder from the system.

Service Bus Faults

In accordance with conventional secondary network operation, the overcurrent relays controlling the primary feeder breakers at the substation are set high so that they do not reach through the network transformer to "see" secondary faults. Service bus faults, therefore, are not sensed by the primary-feeder overcurrent relays at the substation or by the reverse-power relays in the network protectors, and persist until the network protector fuses blow to clear the faults from the system. It is unlikely that these faults will "burn clear" at 480 volts. The fuses in all network protectors "see" service bus faults, and all fuses must clear to remove faults from the system. When this happens, the service bus is "dead" and all load at the spot network is lost.

The importance of the service bus must not be underestimated, for if the service bus is lost, all is lost. Therefore, this service bus should be designed and installed to have the highest possible integrity. This means that the service bus should preferably be of the phase-insulated type with adequate insulation between phases and between phase and ground.

For pad-mounted network units the network protector, in a dustproof enclosure, is installed in the metal cabinet on the side of the network transformer. The service bus paralleling the several network protectors, as shown in Fig. 3, may be constructed with 600-volt insulated cables. To minimize the chances of phase-to-phase or phase-to-ground faults on this type of service bus, only cables of the same phase should be installed in separate non-metallic conduits, or in equivalent duct space, between the several network units. The neutral cables may be buried directly, or run in a separate duct space.

Service Faults

To assure further the integrity of the service bus, all services should be connected to this bus through current-protective devices as illustrated in Fig. 3. On large spot networks the available secondary fault current tends to be quite large and it is important that these devices have adequate interrupting capacity.

Any fault on a service between the service fuse and the customer's service-entrance equipment should be cleared by the service fuse or other service-protective device before any of the network protector fuses start to blow. In some small spot networks this may require more than one service into the customer's building so that the selected service fuse size may be small enough to coordinate with the network protector fuses, even when one network unit is out of service. Also, it is apparent that the customer's service-entrance equipment should be sized to allow it to clear for a fault beyond it before the service fuse at the 480Y/277-volt service bus is damaged.

Network Protector Faults

The prevention of faults at the network protector, as on the service bus, is most important. An important feature of network protectors is the use of adequate insulating barriers between phases and between phases and ground. If the network protector fuse should be required to blow in providing "back-up" protection to the protector for a primary-feeder fault, these barriers help prevent the establishment of a secondary fault in the protector due to the splatter of molten metal from the clearing protector fuse which is not of the current-limiting type. This also emphasizes the importance of providing coordination between the service protective devices and the network protector fuses to avoid unnecessary exposure of the network protector to circuit interruption by the network protector fuse.

In many cases the network protector is installed in a dry location, such as a dry vault, an equipment room inside the building served, or in the metal cabinet of a pad-mounted unit. In such an environment it may be possible and practical to remove the network protector fuse from inside the protector enclosure and replace it with a current-limiting fuse mounted outside the enclosure, between the protector load terminals and the service bus. From a protection point of view, it would always be desirable to locate the fuse externally.

If, in spite of all the above precautions, a fault does occur in the network protector, the faulted protector may be cleared from the service bus by operation of the protector itself if the fault is on the transformer side of the current transformers. Should a fault occur on the load side of the current transformers, it may be cleared by the protector fuses, the operation of the protector, or both. The use of externally mounted current-limiting fuses improves the chances of clearing a faulted protector from the service bus.

Network Transformer Faults

After a faulted protector is thus cleared from the service bus it still may persist as a fault on the secondary side of its network transformer. Normally, the overcurrent relays on the primary feeder breaker at the substation are set high so they do not "see" through the transformer to a secondary fault. Thus this fault may persist until it involves the transformer primary winding and is sensed by the feeder-breaker relays. This is in accordance with conventional secondary network operation philosophy under which the network transformer has been considered expendable to maintain service continuity on the secondary bus.

Building service equipment

Any discussion of spot networks would not be complete without some consideration of the building service equipment downstream from the service take-offs.

The short-circuit current available from the service bus spot networks can be very high, sometimes in excess of 100,000 amperes, rms symmetrical. Good design practice dictates that this be held to lower values whenever possible. When faults develop in the building service equipments they can be disastrous, unless adequate equipment and protective schemes have been selected and properly installed.

From the experience gained from many installations, typical of which is that discussed in reference 2, a number of ideas have been formulated into principles in connection with the main building switchboard or switchgear fed from a spot network. These principles are considered under the following headings:

- Size and number of services
- Service entrance phase-overcurrent protective devices
- Subdivision and isolation of main bus
- Ground-fault protection

1. *Size and Number of Services*

The use of services rated less than 3000 amperes is strongly recommended[3] in the interest of improving protection and service continuity. Smaller service conductors permit lower-rated phase-overcurrent protective devices, and it follows that these will provide better protection at short-circuit current levels not only for the conductors but also for the service equipment. For a given load demand, the use of several services results in improved service continuity in the event of the loss of one service.

2. *Main Phase-Overcurrent Protective Devices (Service Entrance)*

Three different kinds of devices are normally used for the main overcurrent protective function in building switchboards or switchgear.

a. Fused Circuit Breakers—standard low-voltage power circuit breakers integrally mounted with current-limiting fuses.

b. Power Service Protectors—non-automatic low-voltage power circuit breakers in combination with Class L current-limiting fuses.

c. Bolted-contact Switches—high-capacity switches of special design equipped with Class L current-limiting fuses.

All of these devices generally have short-circuit current ratings of 200,000 amperes, rms symmetrical, making them equally applicable on this basis in practically all installations.

The protection which bolted-contact switches provide is strictly a function of the characteristics of the fuses used. Since fuses are single-pole interrupters, single-phasing as a result of the blowing of one fuse under fault conditions[4], may take place if specific protection against it is not provided.

Power service protectors, too, depend upon the characteristics of the fuses used for the protection which they provide. High-speed protection against single-phasing is quite easily provided, however, by anti-single-phase devices. Because of this, and because of the coordinated performance of contact interrupting ability and fuse melting characteristics of up to 12 times the continuous-current rating, power service protectors provide better overall protection than bolted-contact switches.

Fused low-voltage power circuit breakers provide the best phase-overcurrent protection. This results from carefully selecting and coordinating the breaker trip device characteristics with the fuses, so as to furnish an optimum combination of the characteristics of each device. Like power service protectors, high-speed protection against single-phasing is readily provided by anti-single-phase devices.

Because these three types of devices have sensitivity only to phase current magnitude and not to current path, they have limited ability to provide ground-fault protection. Circuit breakers have the advantage that their instantaneous trips can be set no higher than required to avoid nuisance tripping under normal conditions. The application of short-time trips is recommended to supplement or replace instantaneous trips wherever possible.

3. *Subdivision and Isolation of the Main Bus*

Mechanical separation through the use of barriers and sectionalizing, with tie breakers, add considerably to the integrity of the main bus. Equipment designs vary in the degree of mechanical separation and compartmentation used. In General Electric type AKD-5 Powermaster low-voltage switchgear, key functions are separated by compartmentation, and isolation is achieved by the additions of barriers to eliminate fault communication.

4. *Addition of Ground-fault Protection*

Even though attention is given to features which enhance the integrity of conductors, and to selection of the best phase-overcurrent protective devices, it is clear that complete elimination of arcing faults to ground is not possible in practical distribution systems. Therefore, when such faults occur, additional protective measures are necessary to avoid destructive burndowns. If the arcing-fault current is relatively high, the phase-overcurrent devices may sense its presence and quickly operate to remove the fault. It is possible, however, as many case histories have revealed[5], for the arcing current to have a magnitude which is less than the continuous-current rating of the protective device, or to be of such value that the protective device operates only after a relatively long period of time. In either of these cases, supplementary ground-fault protection is necessary to prevent

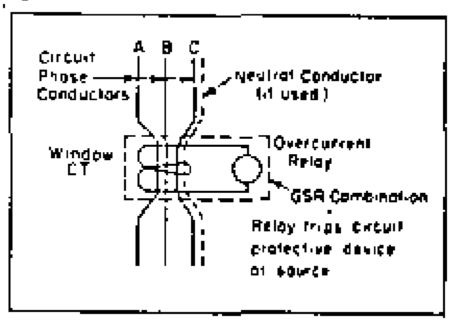


Fig. 4 Window current transformer and overcurrent relay (GSR) combination monitoring ground-fault currents.

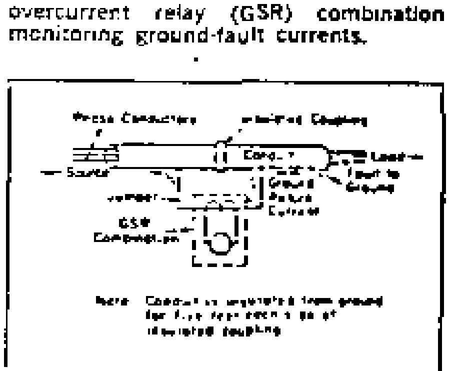


Fig. 5 Detection of ground fault current in return circuit of conductor enclosure.

the low-level arcing-fault current from causing a burndown[6,7].

In soundly grounded systems, arcing faults almost invariably involve ground itself in the fault circuit, thus providing the opportunity for readily detecting the presence of such faults with simple ground-overcurrent relaying. Under normal conditions, there is no significant flow of current in the ground path. The presence of appreciable current in the ground circuit is directly indicative of an electric-circuit fault. One method of monitoring these fault currents flowing in the ground path is provided by the ground sensor, which is a combination of a window-type current transformer and an overcurrent relay as shown in Fig. 4. All of the phase conductors to be monitored, including the neutral conductor, if used, are passed through the window of the CT. With this arrangement only circuit faults involving ground will produce a current in the CT secondary to cause operation of the relay. This combination may be made to operate on ground currents as low as 15 amperes.

A variation in applying the ground-sensor is the connection of the ground-overcurrent relay directly in the ground-current return path, as shown in Fig. 5. For ground faults on the load end of the circuit, most of the ground current will return along the metallic conduit or busway housing, as close as possible to the outgoing-phase conductor carrying the fault current. The use of the insulated conduit or housing joint in the return path forces the current to flow through the jumper and permits the ground-sensor relay to detect its presence.

The protection of the service-entrance equipment and distribution switchboard in a commercial building, using ground-sensor concepts, is illustrated in Fig 6. There are many arrangements possible—both electrical and physical—of the commercial building service-entrance and distribution switchboard equipment. The example shown in Fig. 6 is not necessarily typical or representative, but is used for purposes of illustration. The diagram shows the service-entrance conductors, including the neutral conductor, entering the premises at the service-entrance equipment and continuing on to the distribution switchboard.

In the illustration, both the service (system) and the equipment are grounded at the service-entrance equipment using a common grounding conductor. It is assumed that the network transformers are grounded at their neutral point. There may or may not be a metallic enclosure, such as conduit or raceway, enclosing the service conductors from the network service bus to the service-entrance equipment. If such an enclosure exists, it would be bonded to the service-entrance equipment.

Two steps of ground-fault relaying, of the types just described, are shown in this installation. For the feeder circuit at the bottom, the "first-step" ground-sensor utilizes a CT surrounding the outgoing phase and neutral conductors. For faults to ground beyond the switchboard, the feeder ground-sensor relay will be actuated to trip the feeder breaker. This relay will not operate on balanced or unbalanced feeder load currents, on feeder phase faults not involving ground, or for faults within the switchboard.

The ground-sensor relays at the service-entrance equipments are set 1-step of time-delay behind those on the feeders. They will operate for line-to-ground faults within the switchboard or within the busway or cable circuit supplying the switchboard, provided of course that the fault current exceeds the relay pickup value.

The feeder ground-sensor relay in the diagram sums the outgoing phase currents and the current returning in the neutral, to determine if unbalanced current, indicating a fault to ground, exists in the feeder circuit. On the other hand, the service entrance ground-sensor relay shown detects the presence of ground-fault current by actually measuring current in the ground return path to the system neutral. It is apparent that, depending on the equipment arrangement and the available deliberate connections of the transformer neutral and/or the neutral conductor to ground, the location of these main ground-sensor relays may vary among installations, in order to secure maximum sensitivity to ground faults. Complete discussions of ground-fault protective schemes utilizing relays are found in references 6 and 7.

When General Electric Type AK low voltage power circuit breakers are used in service-entrance and main switchgear equipments, the POWER SENSOR* solid-state trip device can provide simple and economical ground-fault protection. A complete discussion of the application of the POWER SENSOR trip device is presented in reference 8. With the POWER SENSOR, ground-fault protection becomes an integral part of the trip device on the breaker. Separate relays and current transformers are not required. In some applications it becomes advantageous to use combinations of the POWER SENSOR trip device and separate ground-sensor relaying.

In summary, it can be said that the products and the know-how are presently available for protecting distribution systems against the destructive effects of arcing-fault burndowns. Furthermore, the protection principles discussed continue to gain wider application in commercial building and industrial installations.

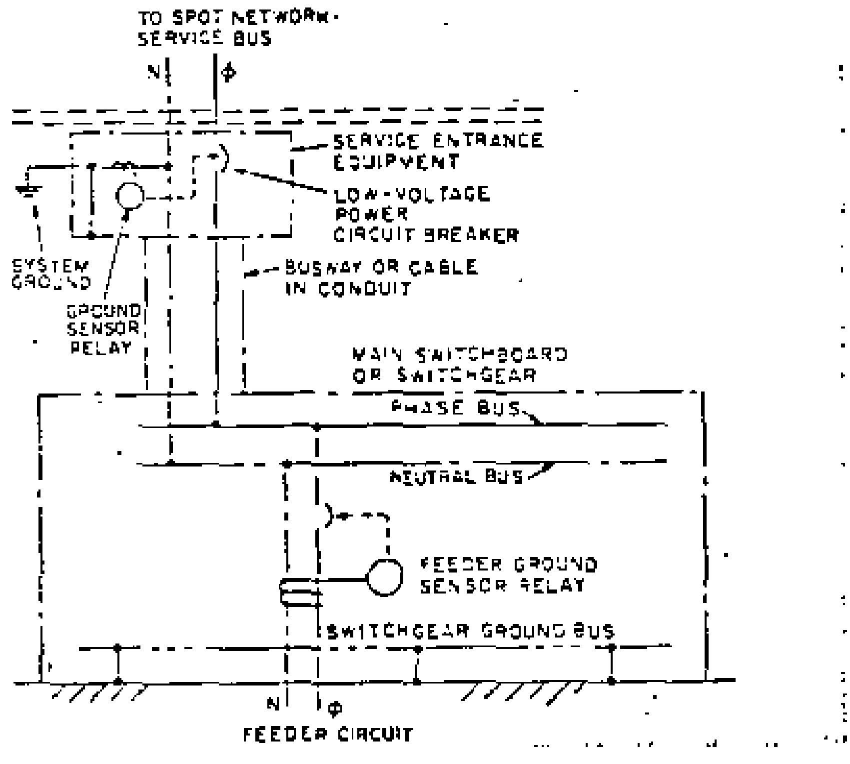


Fig. 6 Protection of service entrance equipment and main switchboard for commercial building.

*Trade-mark of General Electric Co.

Additional spot network protection

When the building distribution system is supplied from spot networks, a gap currently exists in the protection pattern. Even with the most careful provision of ground-fault protection within the building, all electrical service may be lost because of arcing faults occurring in the network vault or in the service take-offs. Consider first a typical utility spot network (*Fig. 7*) supplying the commercial building power system just examined.

If a fault to ground should occur in one of the services or on the service bus, the service fuses or the network protector fuses possibly may operate properly to extinguish the fault. Many case histories indicate, however, that such fuses either fail to detect low levels of destructive arcing-fault current, or may furnish interruption in only one phase of a polyphase system, leaving the arcing fault hanging on at reduced current levels. Thus the conventional utility spot network protective equipment cannot assure protection against arcing-fault burndowns.

Isolation of phases and the use of non-metallic cable or bus enclosures will help avoid the initiation of arcing faults. These measures are effective in minimizing the probability of arcing faults arising from the deterioration of insulation. Faults may still occur, however, caused by mechanical interference (physical accidents), personnel errors, or by splatter from fuses blowing in the network protector. Furthermore, these preventive measures do nothing about the occurrence of a fault within the service-entrance equipment.

It is wise to provide a means for removing such faults when they occur. The ground-sensor relay provides a method for detecting arcing faults to ground, and their removal can be effected by the network protector.

The diagram of the utility spot network can be recast in Fig. 8, to show the application of ground-sensor relays in conjunction with the network pro-

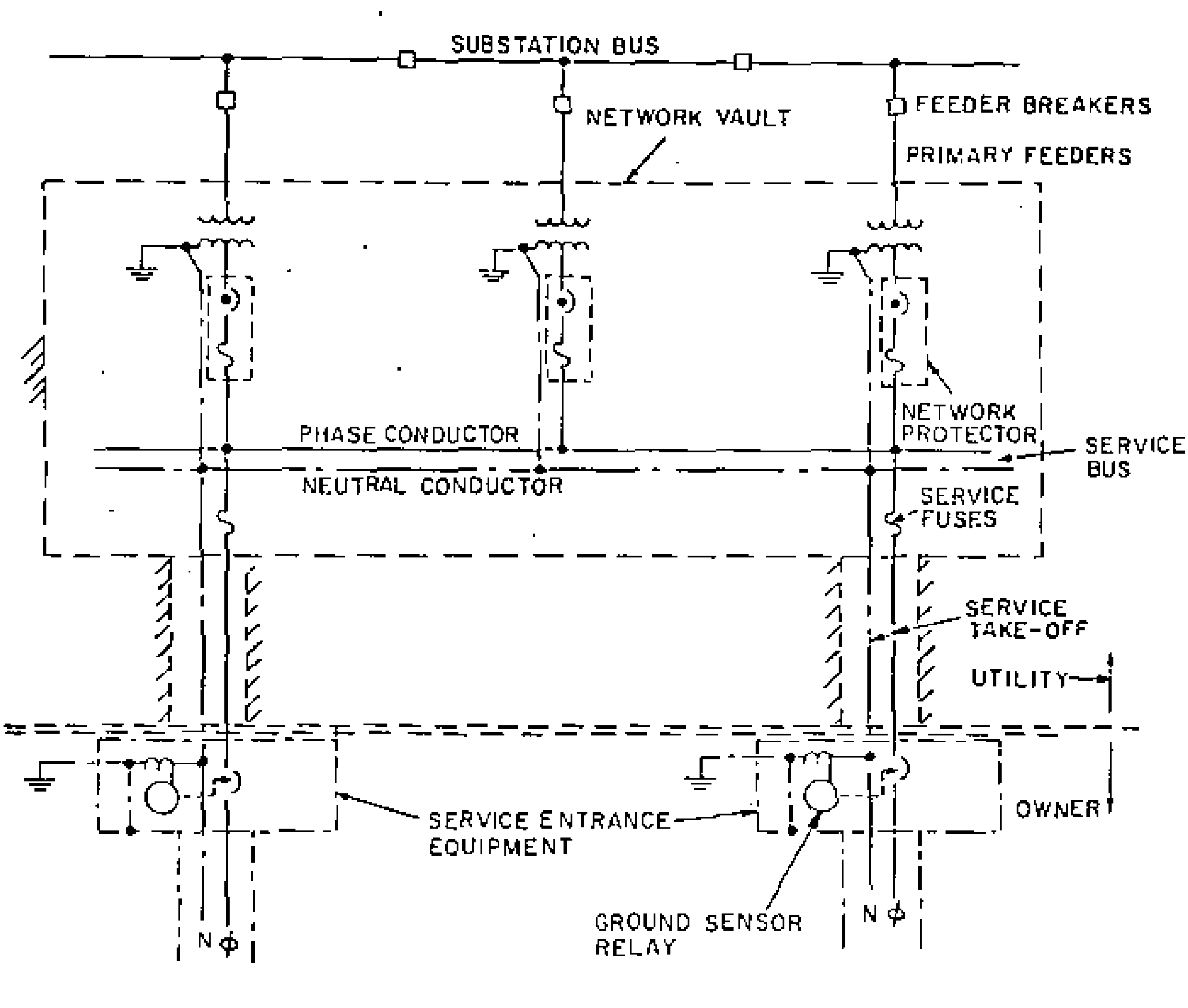


Fig. 7 Utility spot network supplying a commercial building.

tector for ground-fault removal. Only one of the network transformers and its network protector is shown, but the arrangement for the others would be similar. Also shown is the use of a nonmetallic enclosure for the service take-off and the service bus. If an arcing fault should develop in this area, it would be difficult for it to involve ground, and it would probably occur as a phase-to-phase fault. The network protector fuses and service take-off fuses would be the sole means of protection against such a fault, however, and in view of the case record, the reliability of such protection is uncertain, particularly since these are single-phase interrupters.

Arcing faults in or near the grounded network protector, on the other hand, would probably involve ground in the circuit. Thus a ground-sensor relay has been connected at the neutral of the network transformer and arranged to open the network protector. The path of the fault current from a network protector load terminal to the grounded enclosure is indicated. The use of an insulated neutral bushing on the transformer is necessary to segregate this fault current from the normal neutral current. Obviously, the ground-sensor relay, with a sensitive setting of, for example, 400 amperes, will be effective in promptly detecting such a fault. Also, if there were a metallic enclosure, such as a busway or conduit, around the service conductors, then a fault to ground in this area would also promptly be removed by the ground-sensor relay and network protector operation.

Compared to the traditional approach in protection of networks, the above arrangements are novel in the sense of requiring the network protectors to operate for *load-side* faults to ground occurring in the area between the protector and the service-entrance equipment. For the sake of service continuity, it is considered better to temporarily shut down the network rather than suffer a prolonged outage as a result of serious damage from sustained arcing.

The use of the network protector for clearing forward ground faults differs from the traditional approach, but has precedent in several recent applications. In these cases, network protectors are being tripped by ground-sensor relays for ground faults occurring downstream from the network protectors.

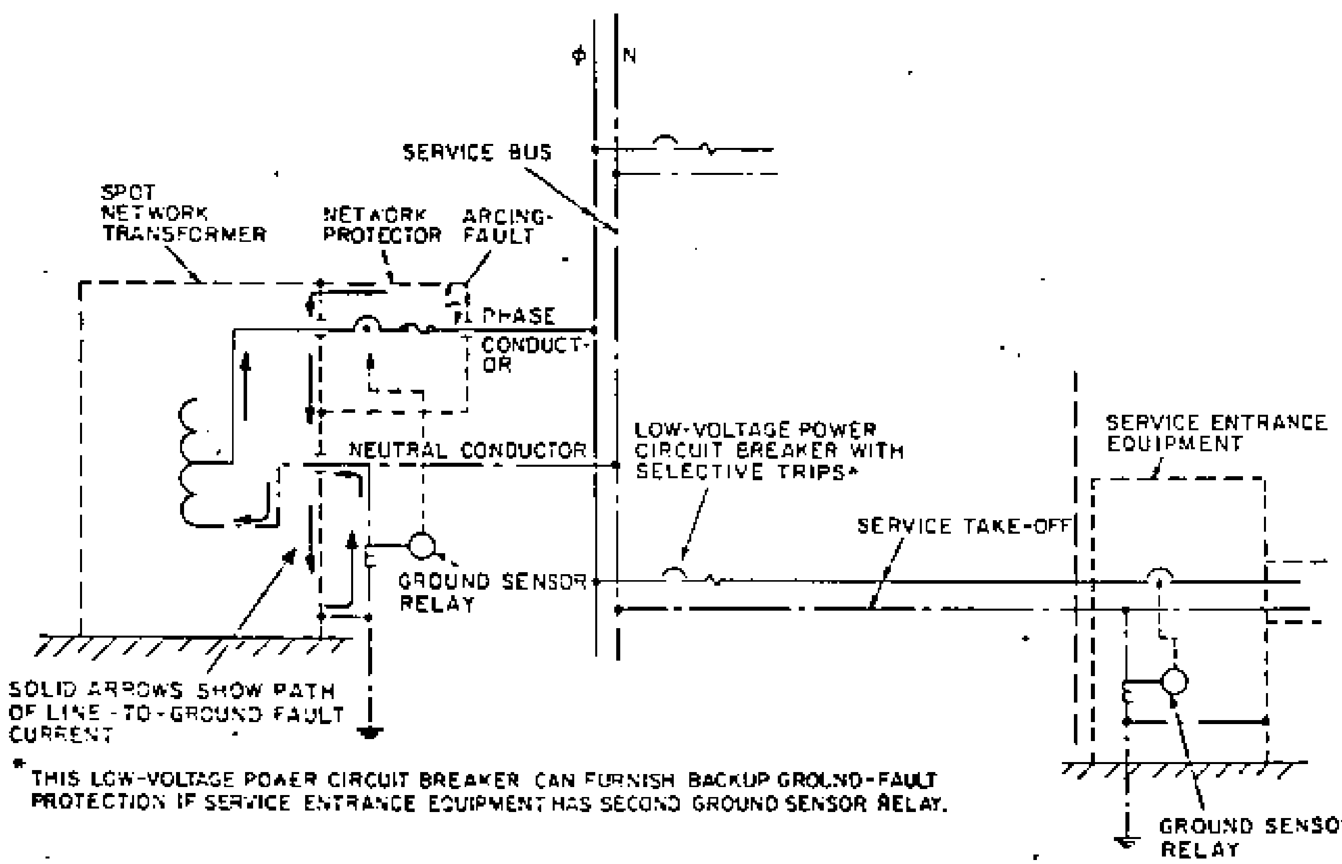


Fig. 8 Utility spot network equipped with ground-sensor relaying.

Variations from basic spot networks

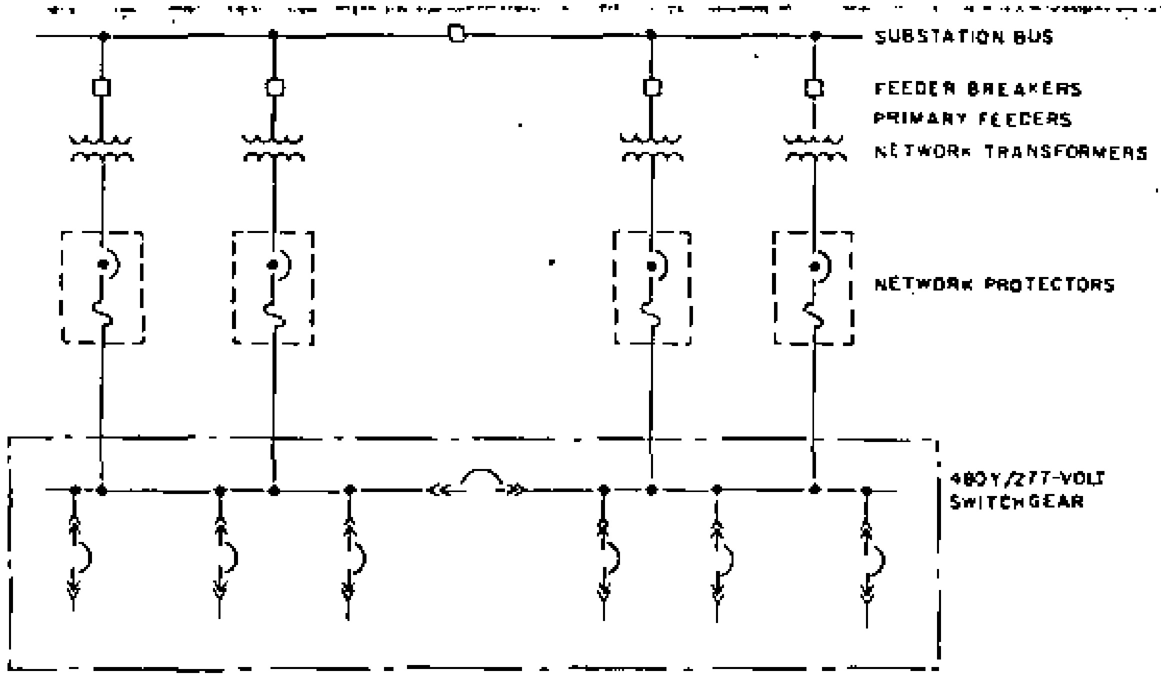


Fig. 9 One-line diagram of a typical variation from the basic spot network.

Spot networks involving variations from the basic circuitry are sometimes employed. These variations often combine the network service bus with the bus of the building main switchboard or switchgear. In these cases the transformers directly feed, through network protectors, the bus from which feeder circuits are supplied. Going a step further, the function of the network protector may be furnished with equivalent low-voltage power circuit breakers equipped with network relays. Tie breakers may be employed to sectionalize the main bus. Variations such as these are shown in Fig. 9. However, the basic network design considerations, particularly concerning protection, still apply even though additional considerations may be necessary in these cases.

It is interesting to note that the presence of the tie breaker provides the opportunity to keep one half of the bus in operation even though a fault may have occurred on the other half. This is accomplished by making the tie breaker selective with the network protectors under phase-overcurrent and ground-fault conditions. (Since the tie breaker is arranged to be closed only in the event of the loss of one of the four sources, one half of the bus could, after the tie opens, be energized by only one transformer.)

In the design of the protective scheme used, the requirements of the NEC and any local codes should be observed. In particular, the requirements for grounding must be kept in mind when departing from the basic spot network circuit.

Summary

Throughout the sections of this guide, suggestions have been made regarding the design and protection of spot networks and associated building service equipments.

As a guide in the design of new spot network installations the following suggestions are made:

1. Limit the size of the service take-offs to 3000 amperes or less, and provide multiple services, as required, to supply the building load requirements.

   Use protective devices with three-phase interrupters for service take-offs, service-entrance and main switchboard positions.
3. Use high-integrity connections between the transformer and the network protector, and from the network protector to the service bus. The service bus too, should be of very high integrity.
4. Wherever possible, use enclosed busway or cable in conduit for service take-offs, to facilitate detection, by ground-fault relaying, of arcing-fault currents involving ground.
5. Provide ground-fault protection that trips network protectors in response to fault currents detected in the transformer grounding conductor. Transformers must be equipped with insulated neutral bushings to permit insertion of a current transformer and relay in the neutral connection to ground.
6. Select the number and kVA ratings of transformers so that the available short circuit current is not in excess of 100,000 amperes, rms symmetrical, at the service take-offs.

By following these suggestions, it should be possible to design spot network systems which fulfill the objective of providing the highest degree of service continuity.

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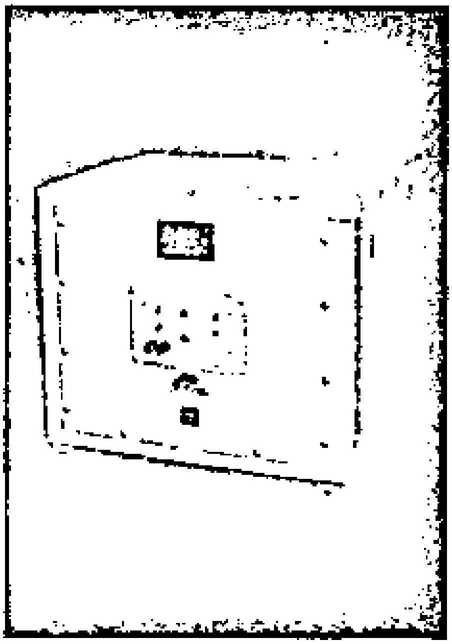

The Importance of Voltage Regulation in Today's Industrial System

GENERAL ELECTRIC

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The Importance of Voltage Regulation in Today's Industrial System

by Thomas R. Shortelle

Manufacturing today is a composite of man's scientific, automated, and co-operative abilities. It is a complex combination of many systems and talents all keyed to the end result—a marketable product. To exist in the cost-saving computerized world of today a business must obtain the greatest efficiency from all components of its operation. All systems must be GO, including the power distribution system.

Problems of Unregulated Voltage

In the supply of electric power to an industrial plant there are mutual obligations on the part of the manufacturer being served and the electric utility. Among these many obligations, the most vital from a standpoint of production efficiency is the regulation or maintenance of constant correct voltage throughout the plant.

After the utility has met its obligation of delivering proper voltage to the plant, voltage within the plant becomes the responsibility of the plant owner.

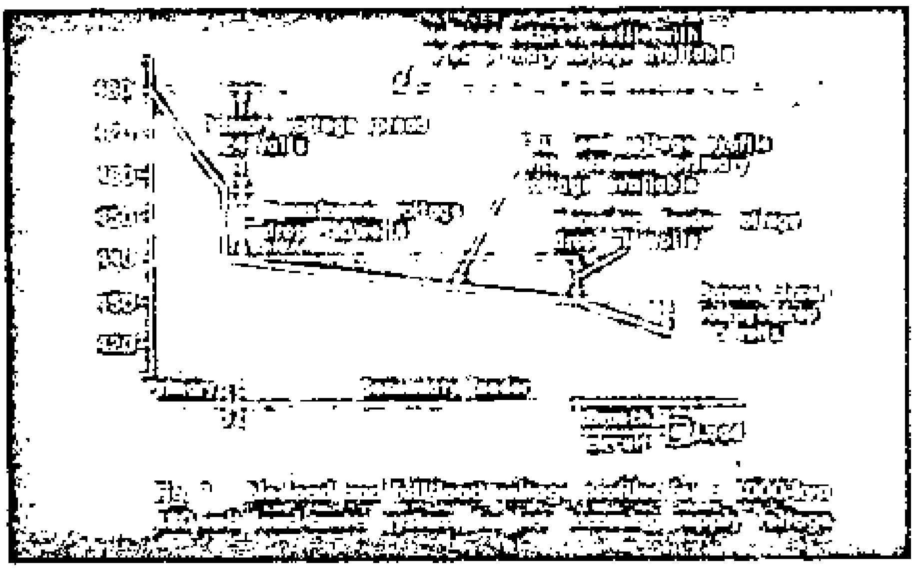
Voltage spread within the plant is caused by the same kind of basic factors that create the problem on utility feeders. These factors include the nature of the loads; the size, spacing, and length of the conductors in the main feeders and branches; and the power factor of the various pieces of equipment served.

The Typical Load-center System

The modern industrial system utilizes the *load-center* concept, however, voltage spread exists even in a load-center system in the following manner:

One of the most popular unit substations is rated 1000-kva, 480 volts secondary. Assuming an average load density of 10 volt-amperes per square foot, this unit could serve an area of approximately 100,000 square feet. If this were an ideal—or textbook—square load area with the unit substation in the center of the square, the longest feeder would be about 250 feet. If we were to assume a rectangular load area then a feeder could be as long as 400 feet.

Figure 1 shows the voltage profile of this system at no load and at full load as voltage drops enter the picture. A low, minus five percent voltage condition is assumed on the primary system. A voltage drop of 15 volts due to transformer regulation could also be expected. If the 400-foot feeder consists of one 4/0 cable fully loaded at 80 percent power factor, it will introduce another 11-volt drop. A minimum of five volts drop can be expected in the branch circuit. All of these voltage values, of course, vary with the loading. The result is a minimum voltage to the



utilization device of 425 volts, which is a voltage spread of about 11 percent. Voltage variations of this magnitude can seriously disturb production.

The Cost of Poor Voltage

Let's look at some of the inefficiencies of variable voltage in the plant system—inefficiencies that drain profit dollars more rapidly than water from the bathtub!

Every type of electric equipment utilized in the modern plant is designed to operate at a specified voltage. Moderate variations from this design voltage are tolerated, and even anticipated, but continuous efficient operation of heaters, automated machines, computers, and rectifying equipment depends on consistent design voltage.

Resistance Heating

Heat varies as the square of the voltage. Take a typical conveyer system using resistance heaters to dry painted tanks. An undervoltage of 10 percent results in a direct heat loss of 19 percent. This means the tanks will be tacky and become rejects or the cycle must be lengthened. The addition of more heaters to the line merely lowers the voltage to all heaters and the problem still exists.

How would this heat loss of 19 percent affect your production? Suppose you normally could process 50 tanks per hour at a value of $50 per completed tank—that's $2,500 of completed production per hour. That's on an efficient system. On our sample system you can only process 40 tanks per hour based on the 19 percent heat loss, resulting in a production loss of $500 per hour—profits right down the drain!

Locating and Correcting Voltage Problems

Sizing up the problem usually requires a study of voltage readings throughout the plant including incoming voltage. There are two reasons for this:

1. Voltage conditions may change at any hour.
2. Obvious trouble spots may not be the most critical in terms of dollars and cents.

The figures in Table 1 are based on careful analysis of modern plant operation and represent highly desirable limits for voltage drop.

The best method of solving any off-voltage problem has to be a compromise between money and time available. Here are the most commonly reported solutions, not necessarily in order of importance or usage:

1. Plants grow rapidly, sometimes more rapidly than the systems that serve them. One of the solutions to the voltage problem may be the shifting of loads from one feeder to another. In other words, balancing the loads between over- and under-loaded feeders.
2. Loads such as resistance welders, furnaces, large high-starting torque motors isolated to separate feeders can be even more effective. There the voltage drop they cause will be largely limited to the conductors feeding them. These loads can frequently be fed through special low-resistance busway or moved closer to the transformer to reduce voltage drop and improve performance.
3. A plant system should be considered as a separate distribution system in itself. A voltage regula-

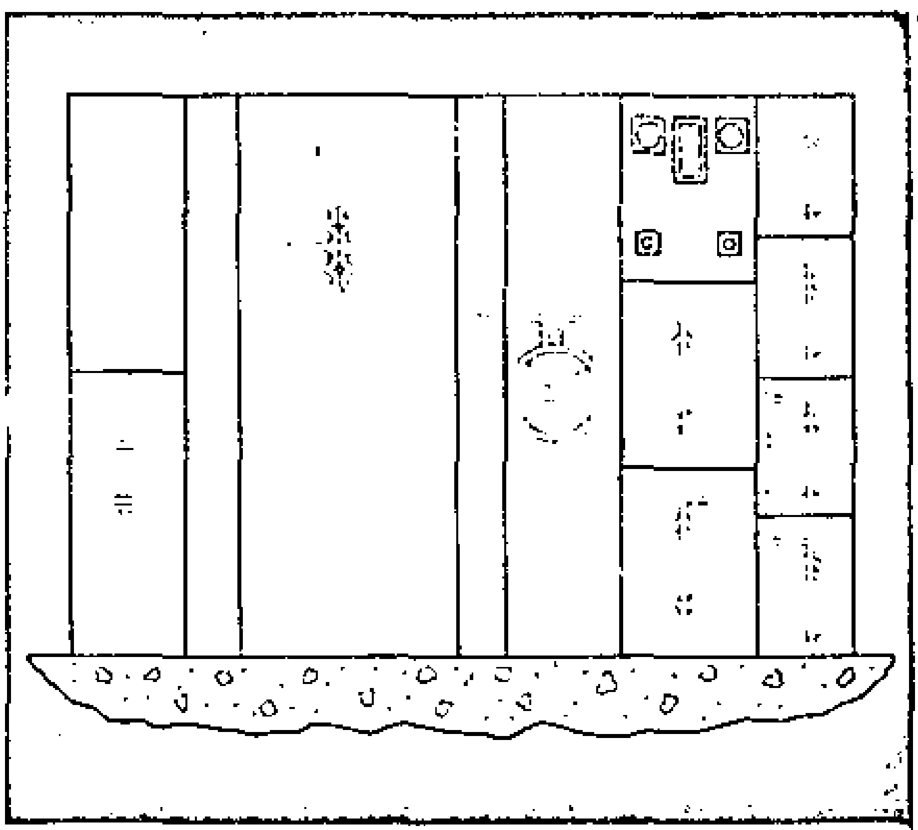


Fig. 2. Schematic diagram of regulated load-center unit substation.

tor can be applied in the same manner as it is used presently by the utilities, that is, to compensate for voltage drop. Rather than go to the expense and trouble of changing from a 208-volt system to a 480-volt system, or rewiring the system with large cable to take care of the voltage drop (over cabling) in primary feeders, simply add a voltage regulator. Such a regulator is the Inductrol* voltage regulator designed to compensate for voltage drop and at the same time maintain constant output under fluctuating load conditions.

The Regulator Itself

Inductrol voltage regulators are available for all low-voltage (600 volts and below) circuits up to 333 circuit kva single-phase and 1000 circuit kva three-phase. The regulator is basically a variable autotransformer built in a manner similar to a wound-rotor motor.

Dry-type induction voltage regulators have been widely used to regulate individual low-voltage feeders or loads. This provides what is known as *individual feeder regulation* with the voltage on a particular feeder or load being independently and automatically controlled by the associated regulator.

Induction Voltage Regulators In Unit Substations

Another approach incorporates an induction voltage regulator in the low-voltage side of the load-center unit substation. This provides what is known as *bus regulation* in the unit substation, or *group feeder regulation* since the feeders from a given unit substation are regulated as a group. In this way the plant area served by a given unit substation can be regulated independently of other plant areas served by other unit substations.

The schematic diagram for connecting an induction voltage regulator in a load-center unit substation is shown in Fig. 2. The regulator is located in a separate compartment between the transformer and the switchgear. The normal enclosing case for the dry-type regulator is omitted, since the compartment itself adequately houses the regulator.

Areas Where Regulators Are the Best Solution

- Where one large load or group of loads going through on-off cycling results in off-voltage to other loads on the same or adjacent feeders (here the adjacent loads may need the protection of voltage regulators —or isolation).
- Where the incoming supply-voltage spread is normally wide.
- Where a plant is near the utility's regulator, but the load-level pattern does not correspond to the general load pattern.
- When operators are actually unable to produce a satisfactory product because speed, color, dimension, and the like can't be held without accurate automatic control of voltage levels.

The voltage regulator can be the economical answer to the voltage problems in your power system that hobble the efficiency of your plant from the voltage entrance right through to the final product.

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Inductrol voltage regulator, dry-type construction, with solid-state automatic control for loads to 1000 kva and up to 600 volts.

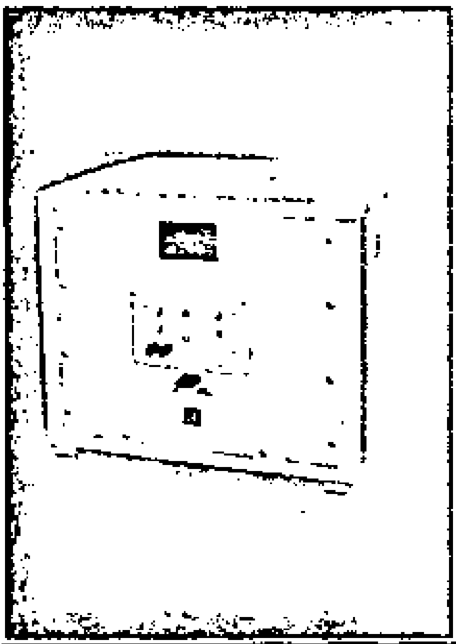

Table I—Effects of Inadequate Voltage

Equipment	Undervoltage	Overvoltage
Induction Motors	10% undervoltage decreases by 19% the starting and maximum running torque; decreases full-load current 11% and causes approximately 12% rise in temperature.	10% overvoltage decreases power factor 5%; increases starting current 10 to 12% often causing lighting to flicker; increases starting and maximum running torque.
Incandescent Lamps	10% undervoltage reduces the light output 30%.	10% overvoltage reduces lamp life by 70% to triple lamp replacement costs.
Fluorescent Lamps	10% undervoltage cuts light 15% and lamp life 20%. Low voltage often results in unsatisfactory starting.	10% overvoltage cuts lamp life 20%, reduces efficiency.
Mercury Vapor Lamps	10% undervoltage reduces light output as much as 30%. Lamps go out at 15% undervoltage.	Over 5% overheats lamps and shortens life. May damage lamp transformers.

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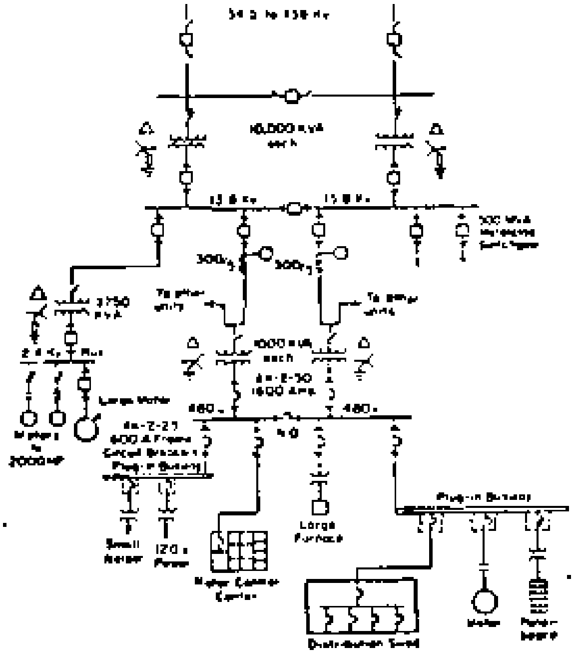


Industrial Power Systems Protective Device Co-ordination

GENERAL ELECTRIC

Service continuity and equipment protection are vital factors in . . .

Industrial Power Systems Protective Device Coordination

Part 1— *Low-voltage Systems*

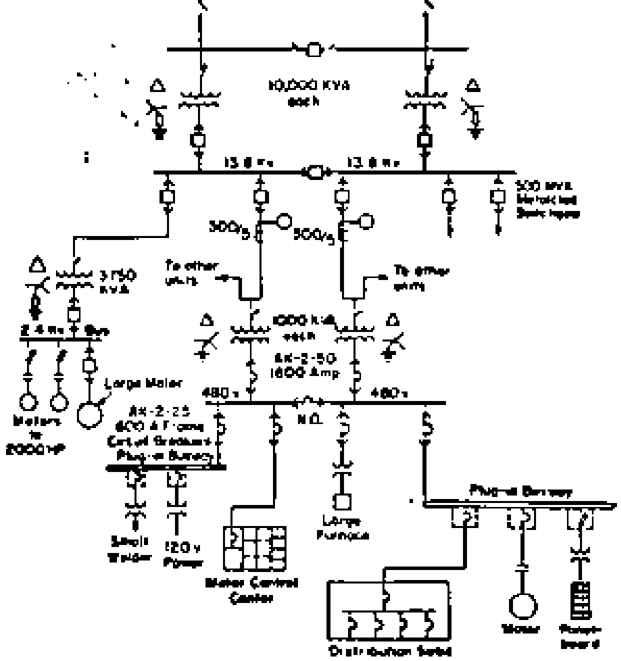


FIG. 1. ILLUSTRATIVE ONE-LINE diagram of industrial plant power distribution system.

by F. J. Shields

By the proper selection and adjustment of short-circuit protective devices, the industrial power system designer can effect a time-current coordination among these devices which achieves the maximum of circuit and equipment protection consistent with the requirements of service continuity. It is necessary to include the consideration of service continuity, since protective device coordination is generally a compromise between the mutually desirable but somewhat inconsistent goals of maximum protection and maximum service continuity. For a great many power systems, the optimum degree of protective device coordination consists of *selective coordination*, wherein only the protective device nearest the fault opens to remove a short circuit, and the other "upstream" protective devices remain closed.

Preliminary Steps in Coordination Study

Protective device coordination which balances protection against the needs of service continuity is achieved and maintained only as the result of following through to completion a multistep procedure. The initial step is making or securing a one-line diagram, Fig. 1, of the system to be coordinated. The diagram is used as a base on which to record pertinent data and information regarding relays, circuit breakers, fuses, current transformers, and operating equipment, while at the same time it provides a convenient representation of the relationship of circuit protective devices one with another. On the diagram will be entered the type and/or rating of all the protective devices and associated equipment (relays, direct-acting trips, fuses, current transformers).

The next step is to record the impedances and the ratings of the major circuit equipment, including transformers, rotating machines, cables, reactors or other components which contribute to or influence the flow of short-circuit current. Using these impedance values and ratings and the one-line diagram, a short-circuit study is then made to determine the maximum and minimum short-circuit currents available at any particular point in the system.

A further step is to ascertain the maximum load currents which will exist under normal operating conditions in each of the power system circuits. These maximum load currents, together with the maximum short-circuit currents, determine the lower and upper boundaries of current sensitivity within which the circuit protective devices must operate. To narrow this operating zone to reflect the requirements for maximum protection consistent with service continuity demands, it is necessary to have a knowledge of the special overcurrent protection requirements for special conditions which must be observed in effecting coordination. Examples of such items are, the National Electrical Code requirements for the protection of cables, motors and transformers, the American Standard requirement for the protection of transformers, the effect of transformer magnetizing inrush current on protective device operation, the starting current and accelerating time of large motors which may affect protective device selection and settings, and the thermal limitations of distribution and utilization equipment.

Also, the characteristic time-current curves of all the protective devices to be coordinated must be obtained. These should be plotted on standard log-log coordination paper to facilitate the coordination study.

When these preliminary steps in the quest for coordination have been completed, then the necessary paperwork study (the mechanics of coordination) is undertaken to achieve a satisfactory degree of coordination among the system protective devices. At the completion of the coordination study the theoretical achievement must be transformed to reality, by installation and adjustment in the field of the proper protective devices. Finally, the coordination which has been achieved must be preserved and maintained and, as necessary, modified to keep pace with changes in system components and layout.

Mr. Shields is an Application Engineer, Industrial Power Systems Engineering, Schenectady.

Mechanics of Achieving Coordination

The process of producing coordination among protective devices in series is essentially one of selecting individual units to match particular circuit or equipment protection requirements, and of plotting the time-current characteristic curves of these devices on a single overlay sheet of log-log coordination paper. The achievement of coordination is a "trial and error" or "cut and try" routine in which the various time-current characteristic curves of the series array of devices are matched one against another on the graph plot. This matching recognizes not only the limitations imposed by the protective devices on one another in the series array, but also those arising from the boundaries defined by the load current, short-circuit current, motor-starting current, thermal limits of equipment, American Standard and National Electrical Code requirements, and so forth. The protective devices must operate within these boundaries, yet as much as possible should provide selective coordination with other protective devices upstream and downstream.

Except for relay and certain fuse applications, selective coordination usually will be obtained in low-voltage systems when the log-log plot of time-current characteristics displays a clear space between the characteristics of the protective devices operating in series. That is, no overlap should exist between two time-current characteristics if selective coordination is to be secured. Nevertheless, the coordination study will often stop at a point short of complete selective coordination, when a satisfactory compromise has been effected between the opposite goals of maximum protection and maximum service continuity. Examples later in this article will illustrate this.

Coordination of Protective Device with Transformer

Let us examine the coordination of a protective device with respect to a transformer. Whatever the primary protective device which is applied to a transformer, it must allow at least rated full-load current of the transformer to flow continuously without tripping. Rated transformer current, in the long-time region of the curve plots, will stand as a lower limit, below which value the primary overcurrent protective device must not operate. Another lower limit is the magnetizing inrush current which must be passed to permit energizing the transformer. For fused General Electric secondary unit substation transformers, this limiting condition is observed by selecting a fuse which will not operate or be damaged by an inrush current

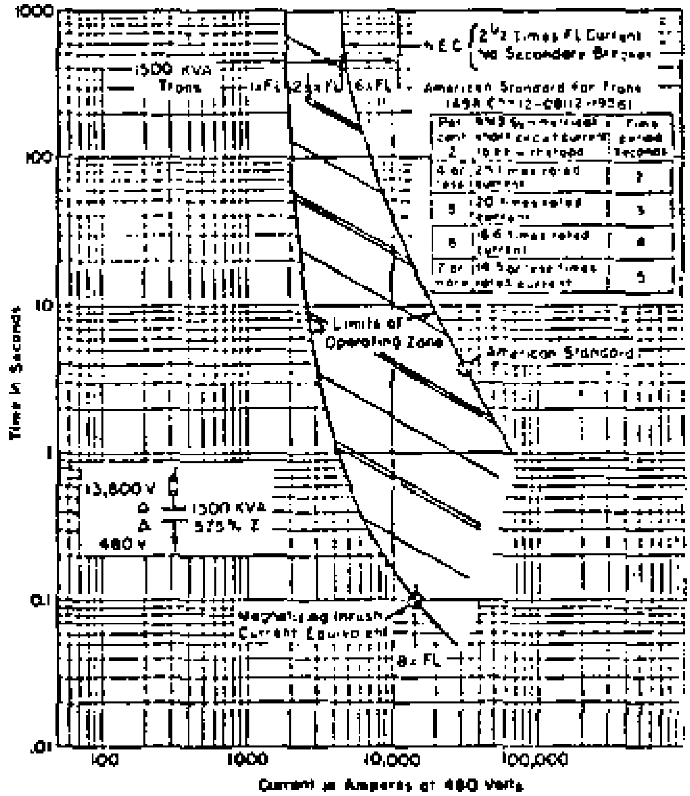


FIG. 2. ZONE OF OPERATION for transformer primary protective device. Delta-delta transformer, with no main secondary circuit breaker.

whose integrated time-current effect is the equivalent of eight times rated transformer current for 0.1 second. These two lower limiting points can broadly define a lower limiting curve, Fig. 2, below which the transformer protective device must not operate.

The National Electrical Code (NEC) requirement for transformers without a main secondary circuit breaker is that the primary device must be rated or set to operate at a current value no greater than two-and-a-half times transformer rated primary current. This determines a point on an upper limiting curve, Fig. 2. Another point on the curve is provided by the American Standard, which requires that a transformer must be able to withstand without injury for a specified time interval a short circuit on the terminal of any winding or windings. The specified time interval corresponds to the specific value of transformer impedance. This ASA point is illustrated for the selected transformer in Fig. 2. The shaded area between the upper and lower curves in the figure is the zone within which the transformer primary protective device must function.

Unit Substation Coordination

Figure 2 considers only the general relationship between the protective device and the equipment being protected, the transformer. It illustrates neither the selection of a specific primary protective device, nor the relationship of this device with other upstream or downstream protective devices. Figure 3, however, shows a specific primary protective device (relay), and also illustrates one degree of coordination which may be effected between the primary relay and the secondary switchgear. It is an illustration of over-all unit substation coordination.

The one-line illustration in the inset of the figure is taken from the industrial plant system of Fig. 1. For the transformer rating shown, the maximum pickup setting allowable for the primary relay, according to the principles of Fig. 2, is indicated as six times transformer full-load current. Since this substation has a properly set main secondary circuit breaker, the NEC permits the use of a primary device set to operate at a current value no greater than six times rated transformer current. The chosen pickup setting for the primary relay meets this limiting condition, and also stands well clear of the ASA point. The ASA point is shown at 58 percent of the three-phase bolted fault current value, to represent a single-phase line-to-ground fault at the transformer low voltage terminals.

The characteristic curve of the AK-25, 400-ampere feeder circuit breaker had to be chosen so as to allow full-load current to be carried in the 400-ampere busway, while at the same time preserving as much as possible selective coordination with the primary relay at the higher overcurrent values. The "cut and try" process reveals that these conditions may be met using a 400-ampere Type EC-2 trip, with a pickup setting of 110 percent, and a long-time delay characteristic of the intermediate type as defined by the NEMA Standards for Low Voltage Power Circuit Breakers. Combined with the long-time delay on the feeder breaker is an instantaneous characteristic set to pick up at the conventional 12 times trip-coil rating, or 4800 amperes. From rated busway current up to the highest available feeder short-circuit current it is apparent from the curve plots that selective coordination exists between the feeder breaker and the primary relay, so that a feeder fault does not operate the primary relay to shut down this substation and the companion units supplied from the same primary feeder. In this connection the dashed line at the knee of the feeder circuit breaker time-current curve represents the usual 16 percent margin required for selectivity between primary and secondary protective devices for single-phase line-to-line faults on the secondary of the wye-delta transformers.

The substation main secondary circuit breaker is selected to allow for short-time overloads, or substation operation with fan cooling, and is rated 1600 amperes. The main breaker's time-current characteristic is chosen to be selective with the feeder circuit breaker in the long-time region, and to have as low an instantaneous setting as the "cut and try" process shows possible under this condition. The intent is to achieve a satisfactory compromise between the objectives of continuity of service for the substation during feeder faults, and maximum speed of protection for the substation in the event of bus faults. Of course, when instantaneous trips are used on the main breaker, complete selective coordination with the feeder circuit breakers is not achieved.

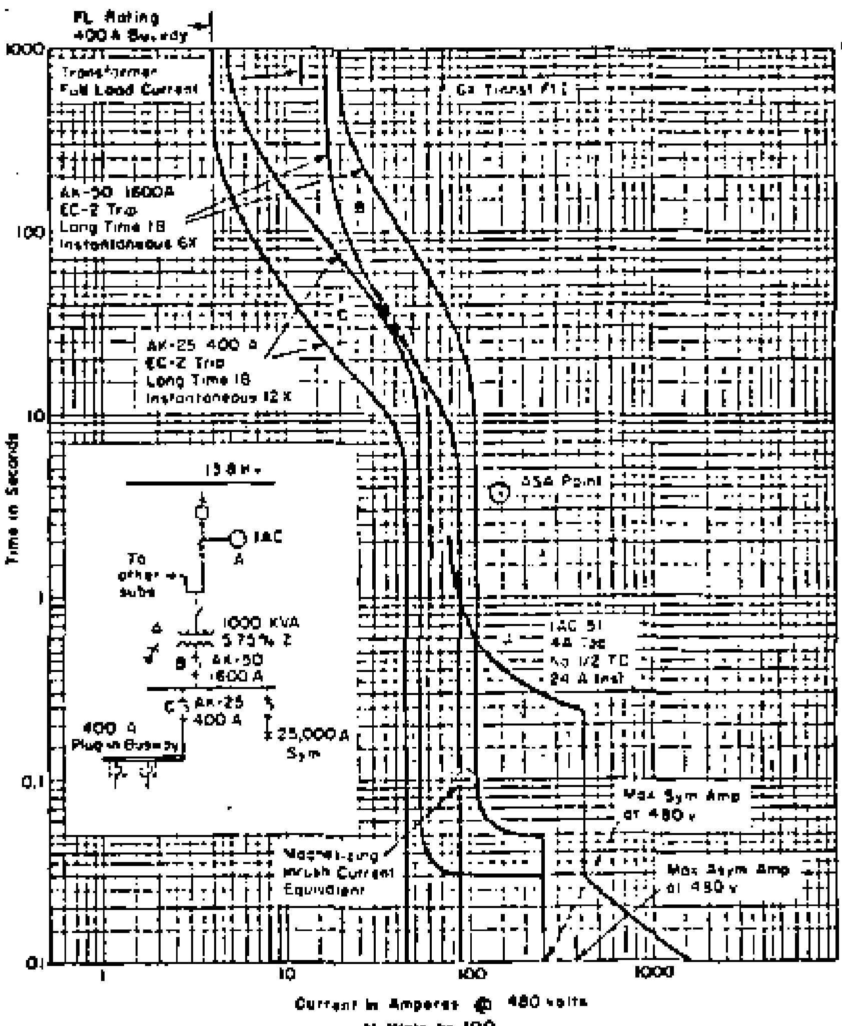
The curves of Fig. 3 are representative of the degree of coordination and protection achieved in many industrial low-voltage systems from the substation feeder breakers to the primary metal-clad breaker. The example shown is for a "fully rated" substation with instantaneous trips on all the substation circuit breakers. It may be considered typical of many such substations with respect to the over-all coordination established among the several protective devices. As suggested earlier, it is a compromise of objectives, arrived at through a trial and error fitting and plotting of various time-current characteristics available, matching one with another and also with the boundary points and limiting conditions which apply for each circuit interrupter. Since the degree of coordination which is necessary and sufficient for the proper operation of a particular power system is a matter of judgment, the number of workable combinations of protective devices is limitless. Thus further study and more exacting requirements for the system of Fig. 3 might result in the selection of a different combination of time-current characteristics to represent the desired coordination.

The primary relay and main secondary circuit breaker of Fig. 3 are selectively coordinated only for currents below 6910 amperes and above 10,560 amperes. From the viewpoint of service continuity on the companion substations fed by the same primary feeder, complete selective coordination between these two protective devices may be of major importance to avoid unnecessarily de-energizing these other substations for bus faults of the indicated current values on this substation. Also, for secondary bus faults with current values below 6910 amperes and above the maximum pickup of the instantaneous trip on the feeder circuit breaker, the main secondary breaker must wait for operation of its long-time delay element to remove the fault condition. The times involved, in the order of 10 seconds and more, are long enough to result in serious damage to the substation secondary equipment.

The Selective Substation

Improvement in the basic level of protection afforded by the substation main secondary circuit breaker, along with a higher degree of selective coordination, may be achieved by selection of the device characteristic time-current curves shown in Fig. 4 for a *selectively coordinated substation*. Here, the feeder circuit breaker characteristic curve is the same as in Fig. 3 for the fully rated substation. The main secondary circuit breaker, however, now has a short-time delay element to replace the instantaneous trip element

FIG. 3. ILLUSTRATION OF time-current coordination for "fully rated" substation and primary relay.



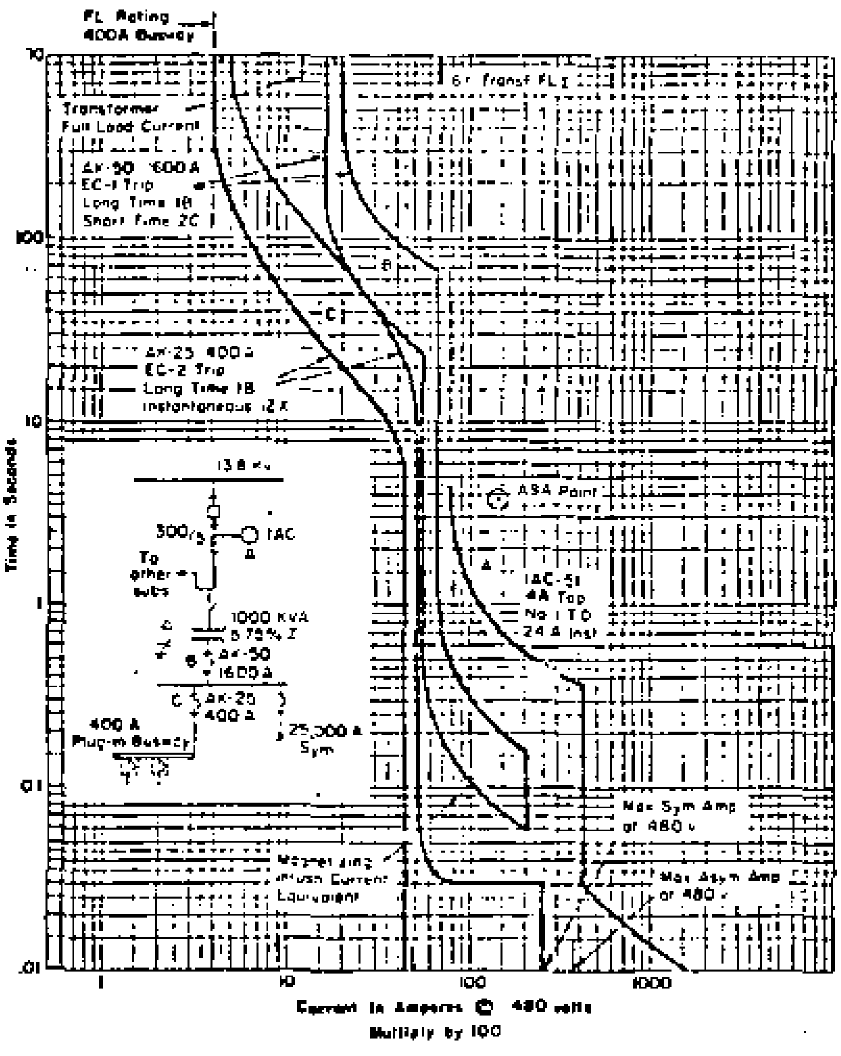
previously used, and the time dial setting of the primary relay has been increased slightly. The overall effect of these changes has been to make the main secondary and feeder circuit breakers completely selective for all values of short-circuit current, including a short circuit at the unit substation feeder circuit breaker terminals. Hence, the name *selectively coordinated substation*. In addition, the closer "nesting" of the main secondary and feeder circuit breaker characteristics provides a greatly increased speed of protection for bus faults at the lower current levels just above the maximum instantaneous pickup of the feeder breaker. In other words the "time-current gap" between the two substation breaker instantaneous trips shown in Fig. 3 has been largely eliminated by the use of the main breaker short-time trip in Fig. 4.

It should be noted also that the coordination existing between the primary relay and the main secondary circuit breaker has been greatly improved. Except for an extremely narrow band of fault currents below 7650 amperes (the dashed line 16 percent characteristic), which represents a single-phase line-to-line secondary bus fault, the coordination between the primary and secondary systems is completely selective.

In sum, the curve plots shown in Fig. 4 for a representative 1000-kva, 480Y/277-volt secondary unit substation and its primary feeder represent an excellent compromise between the goals of maximum protection and maximum service continuity. Both aims have been satisfied to a realistic degree by a careful selection and fitting of the characteristic curves for the major protective devices. Nevertheless, additional improvements might still be made, if judgment demanded them, by reducing the pickup settings of the instantaneous element on the feeder circuit breaker and of the short-time delay element on the main secondary circuit breaker. As an alternative, a short-time delay trip element in combination with the long-time delay and instantaneous elements could be used on the feeder circuit breaker. A careful study of Fig. 4 will show that with either of these alternatives, and by the proper selection of pickup settings, complete selective coordination for all types of faults and even faster protection for smaller fault currents could be secured.

The foregoing indicates that there are many ways in which a specific array of circuit protective devices can be coordinated. In each instance the degree of selective coordination achieved is different since in each case a different compromise is effected between the circuit and equipment protection requirements and the desire for maximum power service continuity. The examples illustrated are representative of actual installations, but hardly all-inclusive. Yet in individual cases the problems and the principles of solution are fundamentally the same. In each case, it is the industrial power distribution engineer's job to decide just what degree of coordination among protective devices is acceptable on his own power system. When he has reached that degree of coordination in the "cut and try" process of plotting coordination curves he has solved the actual problem—at least on paper.

FIG. 4. TIME-CURRENT coordination curves for "selectively coordinated substation" and primary relay.



From Theory to Fact

To translate paper achievements into reality, supplementary steps are necessary. For one, the selection and installation of protective devices with a proper range of adjustability to meet present and future requirements must be made. Thus, if an instantaneous trip setting of six times coil rating is required on a direct-acting trip, either a coil adjustable from four to nine times coil rating, or one from six to twelve times coil rating may be used. The specific choice, however, will depend on whether future settings of the instantaneous trip at, say, four times or at twelve times coil rating may be required.

After protective device ratings with the proper range of adjustability have been selected, the specific settings required, such as 130 percent rated current pickup on the long-time delay element, or five-and-a-half times coil rating on the instantaneous trip unit, must be stipulated. This must be done to assure factory calibration and setting of the protective devices whenever a setting in the field may be either inconvenient or perhaps virtually impossible to make with portable equipment.

Another supplementary step is to instruct electricians and maintenance personnel that protective device settings are not to be tampered with at any time, even on equipment received but not installed; further, that changes in protective device settings must be made only under the supervision of an engineer or other qualified individual.

Finally, since almost all industrial power systems change with time in both equipment composition and in protection and service continuity requirements, it is necessary to review the over-all protection plan periodically and keep it abreast of the times. Whenever conditions require it, readjustment of protective device settings should be made and checked, either with the aid of specially designed portable equipments which are available, or with the aid of equipment and technicians which certain insurance companies are ready to provide. Where satisfactory readjustments cannot be made in the field, replacement protective devices, factory calibrated and adjusted, should be ordered and installed.

Only when all these steps have been accomplished—the preliminary accumulation of data and information, the cut-and-try process of plotting protective-device characteristic curves, the decision as to the degree of coordination necessary, the specification of the particular devices and settings required, and the periodic re-examination of protection and service continuity requirements—only then will coordination of protective devices be secured both in theory and in fact.

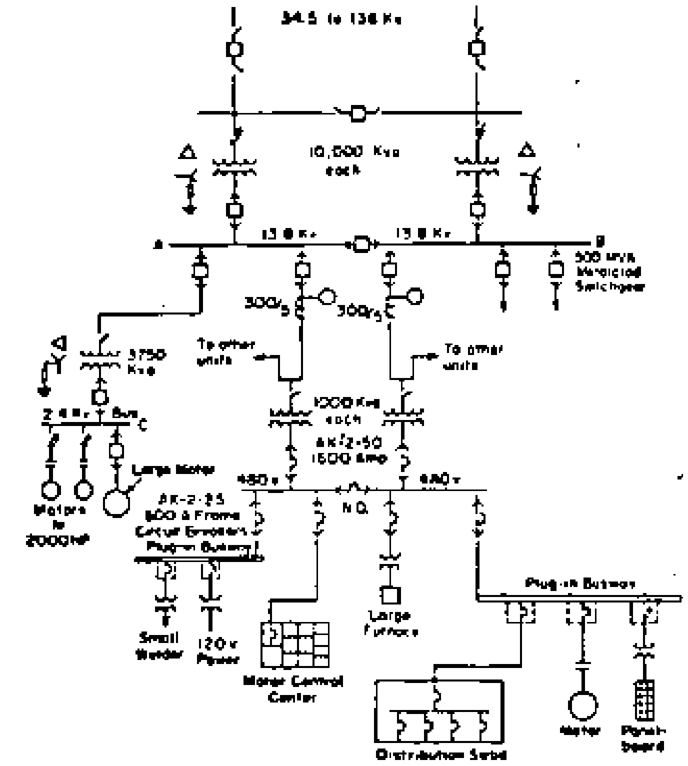
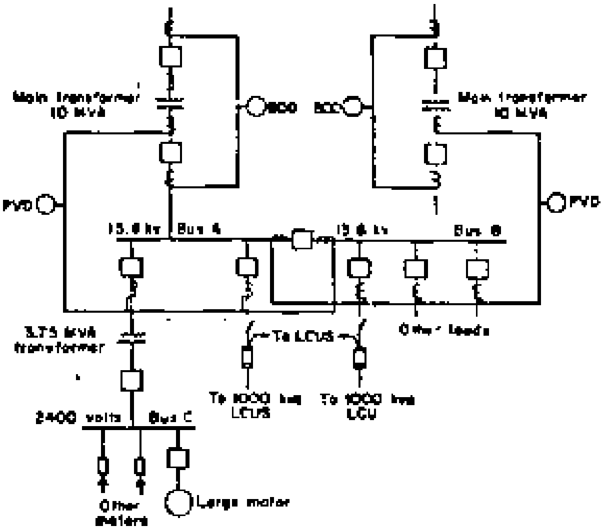


FIG. 1. ONE-LINE DIAGRAM of industrial plant power distribution system used for medium-voltage area relaying example.

FIG. 2. DIAGRAM OF TYPICALLY APPLIED complement to medium voltage area of the example system of Fig. 1.



Primary zone overcurrent protection, backup zone protection, and relay settings must be considered in . . .

Industrial Power Systems Protective Device Coordination

Part 2—Medium-voltage Systems

by G. W. Walsh

The development of a coordinated overcurrent protective system for medium-voltage industrial power systems is based upon the same basic principles and approach as outlined in Part 1 of this series which treats low-voltage system protection. However, there are differences in philosophy of overcurrent protection between these two system voltage areas.

Due to the usual greater cost and sensitivity of location of medium-voltage system components, preferred practice provides them with two somewhat separate overcurrent protective systems where practical. One such system, the primary (or first zone) functions as the primary protection against high short-circuit currents; therefore, it should be very fast. The other overcurrent protective system, the backup zone, functions as backup protection for the primary zone and also acts to clear faults occurring in areas not covered by the primary zone protection.

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Primary Zone Overcurrent Protection

The inherent selectivity of differentially connected Current Transformers in the differential relaying scheme makes possible very fast, sensitive settings. As such, differential relays are ideally suited for, and used extensively in, developing the first zone protection. By virtue of this inherent selectivity, only a knowledge of the system within the protected zone is required. Outside system detail does not normally affect differential relay settings.

The detail of the primary zone differential relaying as may be typically applied in the power system of Fig. 1 (the example system introduced in Part 1 of this series) is shown in Fig. 2. Four separate differential zones are established, one for each main transformer, and one for each 13.8-kv bus section. When a fault occurs within any one of these differential zones the associated differential relay acts to trip only the necessary breakers to isolate the zone. The importance of the 13.8-kv bus sections of this system would normally warrant the superior protection of the voltage-type differential relay, Type PVD as shown in Fig. 2. Similarly, the main transformers are of such size and importance to warrant the better protection of harmonically restrained transformer differential relays, Type BDD. A companion article on page 20 discusses these two types of relays.

Backup Zone Protection

Time-overcurrent relays are the predominate sensing elements used in developing the backup zone of protection in medium-voltage industrial power systems. Fuses, which embody the sensing and clearing protective functions in one element, are also used. Selectivity is not in-

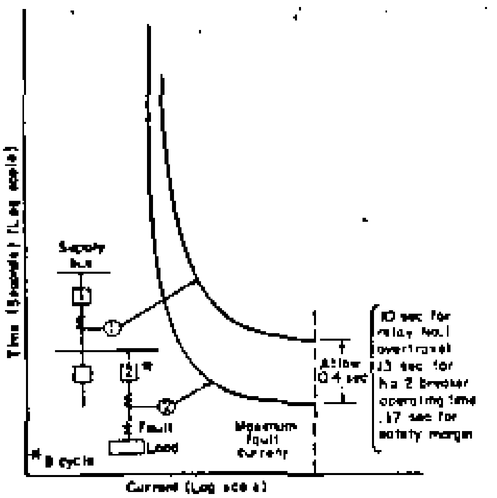


FIG. 3. TIME ALLOWANCES at maximum fault current to insure selectivity between two relays in series for indicated fault location.

herent in these devices but must be attained by a careful step-by-step procedure. This procedure will be demonstrated for the medium-voltage area of the system shown in Fig. 1, but first a review of a few basic considerations may be in order.

First—A properly coordinated overcurrent protective system obtains *selectivity* and equipment *protection*—two basically incompatible entities—within reasonable limits. The time-overcurrent relay tap selection (i.e., pick-up) positions the time-current characteristic with respect to current on the coordination plot. As such, it must accommodate the *long-time* selective and protective current limits. Usually the lowest tap that permits long-time selectivity is the first choice on establishing a relay setting as it provides the most sensitive protection. An exception to this rule may arise, as illustrated in the following example, when dissimilar time-current characteristics are involved and/or when fastest possible short-circuit protection is of paramount importance.

The time-dial setting of the overcurrent relay positions the time-current characteristic with respect to time in the short-time region. It must accommodate the *short-time* selective and protective considerations. As in the case of the tap setting and for the same reasons, the time-dial setting is usually set as low as possible without violating selectivity.

Selective limits are determined by the load time-current characteristics and/or load side (down stream) protective device time-current characteristics. Protective limits are determined by the time-current capability of the components being protected by the device under consideration.

Second—Where similar types of inverse-time-overcurrent protective devices are involved, and if selectivity is obtained at the extremities of the time-current characteristics, then selectivity will prevail throughout. Low-current, long-time selectivity is readily checked by comparing the selected tap positions on the coordination plot. To insure selectivity at maximum current, proper allowance must be made for (1) operating time of associated circuit-interrupting device(s), (2) margin for safety, and (3) relay overtravel. See Fig. 3.

Relay overtravel is the continued motion of the relay disk (due to inertia) after the relay operating quantity has been removed. In Fig. 3, the occurrence of the fault will initiate disk rotation in relays No. 1 and 2. However, relay No. 1 will overtravel after fault clearing by breaker No. 2 and will trip breaker No. 1 needlessly if the two relay characteristics are too close together. As indicated in Fig. 3, the usual allowance for relay overtravel is 0.10 second; also indicated is the usual allowance of 0.13 second for eight-cycle breaker operating time and 0.17 second margin for safety. The latter time additions may be reduced with the use of faster breakers and/or field-calibrated relays.

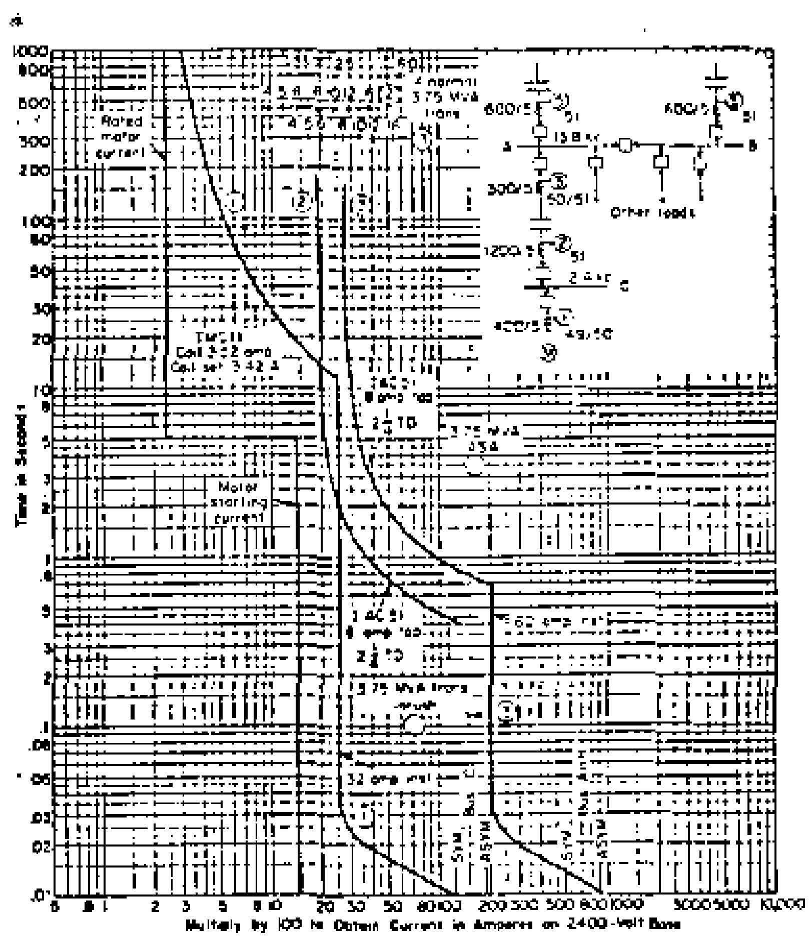
Third—With a given series of protective devices along the system chain between the power sources and the load, the time-current characteristics of the protective device closest to the load is established first—then the other protective-device characteristics are established successively toward the source.

Fourth—Standard time-overcurrent relay elements are electromechanical inductive devices and, therefore, sensitive only to the a-c or symmetrical component of short-circuit current. Instantaneous overcurrent-sensing solenoid devices (used as attachments with time-overcurrent relays or separately) are sensitive to the total or asymmetrical short-circuit current. Since the standard short-circuit current calculating procedure derives symmetrical current, the results of such calculations are used directly in time-overcurrent relay settings. When setting instantaneous devices, an appropriate d-c offset factor must be applied to the symmetrical short-circuit current calculation to obtain asymmetrical current. For medium-voltage systems the accepted offset factor for circuits above 5000 volts is 1.6; at 5000 volts and below it is 1.5.

Setting Overcurrent Relays on Medium-voltage Systems

Before actual plotting of coordination curves, system maximum short-circuit levels must be calculated to establish high-current, short-time coordination. "Selective" limits such as short duration load time-current characteristics and required maximum continuous circuit and equip-

FIG. 4. PHASE OVERCURRENT-RELAY coordination of the large motor branch-feeder relay through to the 10-mva supply transformer secondary relays.



ment loading must be established. Similarly, the "protective" limits such as defined by the National Electrical Code (where applicable) and American Standard Association protection requirements, etc., should be determined for the various system and utilization components. A coordinated time-current protective device characteristic must pass between these limits, above the selective limits and below the protective limits.

It is also very desirable to have all taps of all relays computed and indexed (see Fig. 1) on the coordination diagrams to facilitate quick survey of all possible relay pickups (for given CT ratios) when the coordination curves are drawn. Such a series of tap scales enables one to "look ahead" to the "up stream" relay pickups and thus permits a more educated tap selection that is less subject to change as the coordination study progresses.

Finally, when more than one system voltage level is involved in a given coordination diagram, the short-circuit currents, protective and selective current limits, and tap scale currents must be referred to a common voltage base to permit direct application of published relay time-current characteristics. This is usually the lowest system voltage involved in the coordination diagram.

The following steps outline a typical approach to time-overcurrent relaying of the medium-voltage areas of the example system of Fig. 1.

Relay Settings for 3750-kva Transformer Feeder and Associated 2400-volt Circuits (Fig. 4)

Step No. 1—Calculate maximum short-circuit currents and refer them to 2400-volt base. Assuming 13.8-kv bus tie breaker closed, both 10,000-kva transformers in service, standard transformer impedances and a representative primary system short-circuit capacity, the resulting short-circuit levels are as indexed along the bottom of the coordination plot.

Step No. 2—Calculate American Standard Association transformer withstand points (ASA C57.12-08.112) and National Electrical Code (NEC 450-3, 1959) protective limits. Locate these points on the coordination diagram.

Step No. 3—Locate the inrush time-current points for the transformers. For transformers of the size involved, eight times normal current at 0.1 second is usually taken as a selective point which must fall below the transformer primary-relay characteristics.

Step No. 4—To insure that desired overloads will be permitted without unwanted relay tripping, indicate such load levels in the long-time region of the coordination diagram so that associated relay taps will not be set below these current levels.

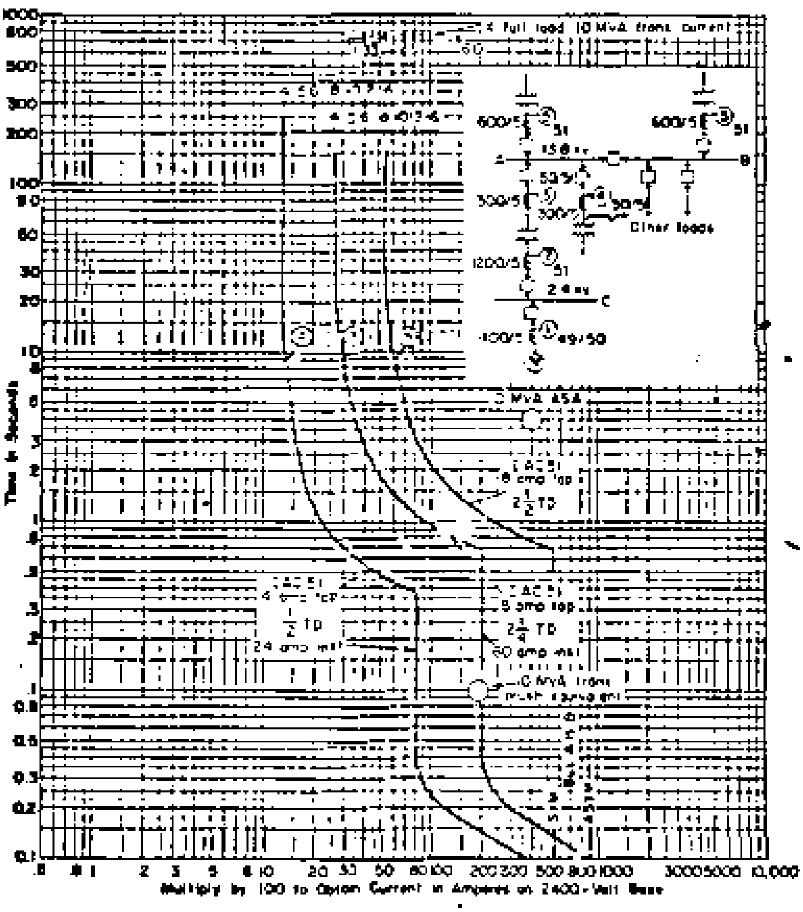
Step No. 5—Establish relay tap scales which indicate the power-system current (referred to a 2400-volt base) associated with the taps of all relays. These tap scales are as shown at the top of the coordination plot for the indicated CT ratios, assuming the use of standard 4- to 16-ampere range overcurrent relays with taps at 4, 5, 6, 8, 10, 12 and 16 amps.

Step No. 6—Determine the relay settings of each 2400-volt feeder relay. For brevity and clarity, only the feeder with the longest-time and highest-current coordinates, with which the succeeding protective devices must be selective, will be treated here and in Fig. 4. Assuming the large (1000-hp. induction) motor to be this determining load, establish its time-current characteristic on the coordination diagram. (Fig. 4 indicates starting current of six times rated current for five seconds during starting and rated current thereafter.)

Normally, for a motor of this size, a thermal relay (which approximates the motor-heating characteristics with instantaneous attachment is applied. The thermal element is set to permit a modest (say, 15 percent) continuous overload based on motor-rated current. Curve (1) of Fig. 4 is the time-current characteristic of such a relay and should be drawn on the diagram. Note that this characteristic permits high short-duration overloads on the motor and is selective with the specified motor time-current characteristic. The instantaneous attachment is set just above the expected maximum asymmetrical motor-starting current based on 1.6 offset factor and 1.1 system voltage factor.

Step No. 7—Set 3750-kva transformer secondary breaker relay (2). Tap scale (2), Fig. 4, shows that the relay tap selection possibilities are restricted to the 5-, 6-, and 8-amp taps to accommodate a continuous loading capability of at least 1.33 times normal transformer current but not to exceed the 2.5 times normal NEC limitation. Regardless of which of these taps is selected, excessive protection time results when a time dial is chosen that is selective with the large motor-feeder thermal relay. Furthermore, this slow protection will necessarily be reflected in the "up stream" relay settings that must be selective with relay (2). By going to a time-dial setting that results in the minimum necessary 0.4 second to insure selectivity at maximum (Bus C) symmetrical fault current, the protection time could be restored to the minimum at the cost of foregoing selectivity with relay (1) within a small range of fault current. The results of such an approach, deemed preferable in this case, is illustrated by Curve (2) established by the 8-amp tap and 2½ time-dial setting. The

FIG. 5. COMPARISON OF THE RELAY curves of the two basic type 13.8-kv feeders considered in this example shows that the 10-mva transformer secondary relays are set to be selective with the 3.75-mva transformer feeder.



highest tap within prescribed limits is used to minimize the overlap between curves (1) and (2).

Step No. 8—Set 3750-kva transformer primary breaker relay (3). By indexing the family of relay characteristics along tap scale (3), it is soon recognized that the eight-amp tap is the lowest that will be selective with relay curves (1) and (2) within a time-dial range which requires only minimum necessary time (0.4 second) for selectivity at maximum short circuit. The associated time-dial selection, 2½, also has sufficient margin to insure selectivity with relay (2) on line-to-line faults. Here, relay (3) will see approximately 15 percent more current than relay (2) for a line-to-line fault on the load side of relay (2), since the wye-delta transformer is between the two relays. A higher tap, lower time-dial setting could be used which would increase protection time below maximum Bus C symmetrical short-circuit current and decrease slightly the relaying time between maximum Bus C symmetrical current and the instantaneous attachment setting. However, this represents a very marginal practical gain at the expense of increased relaying time at lower currents; therefore, the above indicated setting will remain unchanged. Note the resulting setting is selective with the 3.75-mva transformer inrush point.

Relay Settings for Load Center Feeder (Fig. 5)

Step No. 9—Set relay (4). This feeder relay must be selective with its load protective devices, therefore, the unit substation(s) on this feeder must be coordinated first. This procedure has been detailed in Part 1 with the resulting proposed setting of relay (4) of four-amp tap, ½ time dial, and an instantaneous setting of 24 amperes.

Ten-MVA Transformer Secondary Relays (5) Setting (Fig. 5)

Step No. 10—Set relays (5). By the same reasoning given in Step No. 9, all the feeder relay settings on buses A and B must be determined before proceeding with the setting of relays (5). Assuming the settings of the remaining feeder relays result in their time-current characteristics falling below that established for relay (3), relays (5) must be set to be selective with relay (3), since relay (4) curve lies completely below relay (3) curve. An eight-amp tap is selected for these transformer secondary relays as it permits either of the associated 10-mva transformers to carry both buses in case of emergency. A time-dial setting of 2½ provides the necessary 0.4 second time margin at the maximum short-circuit current common to relays (3) and relays (5).

Although the fastest practical relaying obtainable with time-overcurrent relays has been achieved, relay No. 5 would be slow in clearing a bus fault. This proves the worth of primary zone differential relaying which would provide much faster clearing.

Ground Relaying of Medium-Voltage System

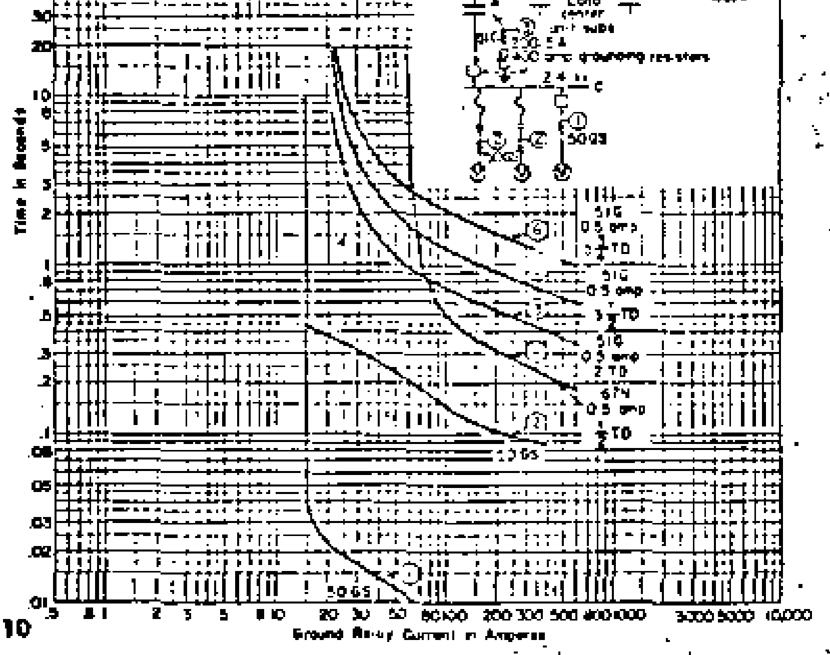
Preferred system grounding practice limits the value of ground fault current to that necessary for fast positive relaying. Ground fault current flowing in the system is detected by a relay connected into the secondary residual circuit of the (three) phase CT's or into the secondary of a donut CT through which all three-phase conductors pass. The latter "Ground Sensor" arrangement provides more sensitive and faster relaying (not being subject to the error currents that arise in the residual circuits of CT's) and as such is generally ideally suited for feeder protection, particularly motor and transformer feeders.

The available CT's for the Ground Sensor arrangement are not large enough to be applied to main metal-clad incoming line and bus tie bus circuits; therefore, residually connected relays must be used in these cases. To obtain reasonable relaying sensitivity in these cases the system grounding should permit a ground-fault current magnitude in the order of the rating of the CT. In this example, it will be assumed that the 10-mva transformer secondaries are connected via bus work to their respective load buses thereby precluding the use of Ground Sensors. Thus with 600/5-amp CT's in these circuits to be used for residual ground relays, each 10-mva transformer neutral is grounded through a 600-amp resistor. However, at the load bus of the 3.75-mva transformer, only Ground Sensors will be used and 400 amp is sufficient for their operation.

The detail of a recommended ground relaying arrangement for this example system is illustrated in the diagram and coordination curves of Fig. 6. The instantaneous Ground Sensors (50GS) provide sensitive high-speed protection for all feeders. Whether applied to switchgear or contactors, their pickup is not above 15-amp ground-fault current. Curve (2) includes relaying time plus contactor clearing time; therefore, it is not necessary that the time margin between it and the backup neutral relay (3) curve include breaker operating time. However, to insure relay (3) selectivity with the 2400-volt switchgear Ground Sensor curve (1), the usual time margin at maximum ground fault (of 400 amperes) is maintained between curves (1) and (3) with a two time-dial setting on relay (3).

continued→

FIG. 6 DIAGRAM AND COORDINATION CURVES of recommended ground relaying of the medium-voltage levels of the example system shown in Fig. 1.



Since relay (3) does not have to be selective with any other time-overcurrent relay and sees only ground-fault current, the lowest available tap in a standard relay coil is used, i.e., the 0.5-amp tap of a 0.5- to 2.0-ampere range coil. This completes the ground-relay coordination up to the two 13.8-kv load buses.

Each 10-mva transformer neutral has two time-overcurrent relays (51G devices) to provide backup ground-fault protection for feeder Ground Sensors and bus differential relays. Relay (5), which trips the bus tie breaker, is set as sensitive (0.5-amp tap) and as fast (3½ time dial) as possible without violating selectivity with the feeder Ground Sensors. Tripping the tie breaker severs the system and stops the flow of ground-fault current on the sound side of the system. Continued flow of ground-fault current on the faulted side causes its relay (6) to trip the transformer secondary breaker. A relay (6) setting of 0.5-amp tap, 5½ time dial is the most sensitive and fastest that will be selective with relay (5).

Faster relaying of transformer secondary-circuit ground faults, without interrupting power to either load bus, can be achieved by applying directional ground relays (67N devices) in the transformer secondary circuits. As indicated in the diagram of Fig. 6, these relays are polarized by their respective transformer grounded-neutral circuits, and are sensitive only to ground faults on the transformer side of the associated secondary breaker. Therefore, they are set as sensitive and fast as possible (0.5-amp tap, ½ TD) as there are no other protective devices with which they must coordinate. A transformer secondary-circuit ground fault will be cleared by tripping of the primary and secondary breakers by the directional ground relay.

Conclusion

This illustrates the basic approach to medium-voltage system overcurrent protection. Many variations and refinements may be instituted in a given system. One worthwhile, recommended practice is to adjust each relay by test to insure that it will function as intended.

Finally, the overcurrent protective study must be kept up to date. Each and every change in the system—addition of capacity or load or rearrangement—must be scrutinized and follow-up made as indicated.

SWITCHGEAR DEPARTMENT

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Shortcuts to

Selecting and Coordinating Electrical Trip Devices

By R. L. SMITH, JR., Application Engineer, Industrial Power Systems, General Electric Co., Schenectady, NY

"THE FAULT WAS SO SEVERE that the plant service entrance breaker tripped." This statement is often made to describe the severity of an electrical fault. Tripping of the plant main breaker is not necessarily a measure of fault severity; it is, quite often, an indication that there is a lack of coordination or selectivity in the trip settings of electrical protective devices.

A typical example of improper coordination is the case of a small plant in the south which experienced a fault on a large low voltage feeder a few years ago. The only protective device which opened was the service entrance breaker, Fig. 1.

This short circuit was of a limited nature, and not a "bolted 3-phase fault." Short circuit current was estimated to be about 10,000 amps at 480 v. Subsequent examination of the settings on protective devices revealed the following operating times:

Low voltage feeder breaker ...... 13 to 50 seconds
Transformer main secondary breaker .... 24 to 170 seconds
Plant service entrance breaker and relay .... 0.93 seconds

A bolted 3-phase fault of about 60,000 amps would have caused all three breakers to trip instantaneously.

Coordination, selectivity and backup. The example described illustrates a lack of coordination or selectivity between overcurrent protective devices in a typical power system. The words "coordination" and "selectivity" are, in a sense, complementary terms, and are used to describe the relative speeds at which two protective devices open when subjected to the same short circuit or ground fault.

By industry standard definition, a protective device is said to be *selective with* another, downstream, protective device if opening of the upstream device is intentionally delayed to permit the downstream device to operate first when they both "see" the same fault. Although not an industry definition, it is common practice for relay engineers to speak in terms of the downstream device *coordinating with* the upstream device. With such an arrangement, the selective device is sometimes called "backup" for the device set to operate first. It may also be the only protection (primary protection) for the circuit elements between the two devices. These relationships are shown in Fig. 2.

Protection and selectivity. Protection and selectivity are often contradictory goals. Fast removal of a faulty portion of a power system can cause nuisance tripping on short circuits in an adjacent portion of the system. Slowing a protective device to achieve selectivity with another protective device in an adjacent portion of a power system can result in more damage to the elements of the system for which the slower device is the only protection. Compromising of protection to limit the extent of a power outage must be balanced against the economics of possible increase in equipment damage and the increased potential safety hazard.

Protective device settings must be determined. Most protective devices received by the user are preset at an arbitrary point. Usually, low voltage power circuit breakers are shipped with the long-time delay preset at 100 percent and the instantaneous trip element preset at *maximum*. Time overcurrent relays frequently are received by the user with the time overcurrent tap preset at an arbitrary value such as 5 amps.

The time dial is preset either at "0" or "1" and blocked. The instantaneous element is preset at the *minimum*. Most molded case circuit breaker instantaneous elements are preset at *maximum*. Considering the settings of devices as received, it is apparent that neither the desired sensitivity nor selectivity can be achieved without onsite determination and readjustment.

Integrating with the power system. Often a load center or unit substation is planned and ordered prior to completion of the entire power system design. Sometimes primary system data are not available until after the load center is ordered; it is then difficult to accommodate any changes. General suggestions given here are applicable to both magnetic and static low voltage trip devices and protective relays.

The suggestions involve selection of ratings and settings for both primary and secondary trip devices, plus some general guides to feeder trip device size selection. Adherence to these recommendations will increase the probability that a given substation will integrate properly with the rest of the power system, and that any future, possibly more refined, coordination studies will present no unusual problems.

Primary system protective devices. Primary distribution system phase overcurrent relays protecting load centers or feeders to load centers usually are specified with tap ranges to allow pickup settings from 2½ to 6 times full load transformer current. These are the limits recognized by the National Electrical Code for liquid-filled transformers. Although a pickup point of six times full load current is permitted for protection of transformers with main secondary breakers, lower settings are often used to protect the primary feeder cable.

Low time dial settings and relatively high instan-

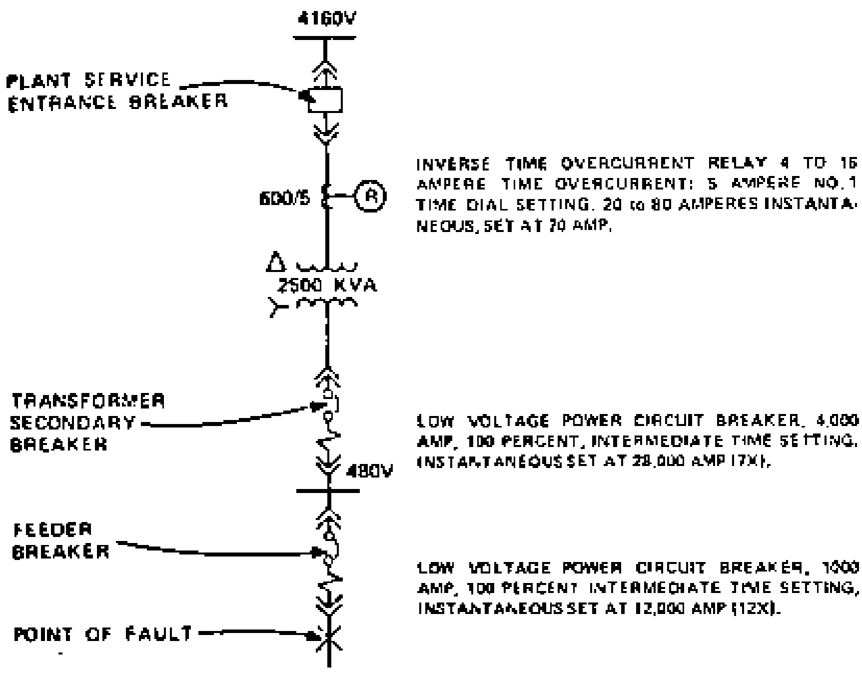
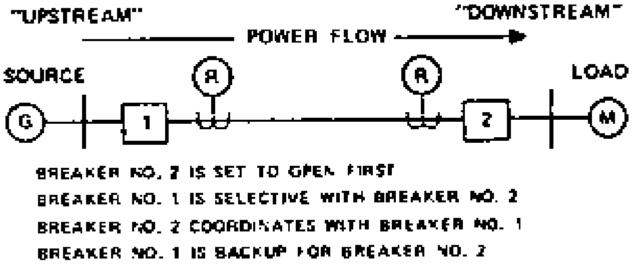


Fig. 1. One-line diagram of power system discussed in example. Lack of coordination caused service entrance breaker to trip on relatively light fault current of about 10,000 amps. A fault current of 60,000 amps would cause all three breakers in this system to open.

Fig. 2. Graphical description of expressions in common use to describe coordination (or lack of coordination). With proper coordination, only the first breaker upstream of the fault trips, preserving service to the rest of the system.



taneous trip element settings on the transformer primary provide fast operation for overload conditions and avoid instantaneous tripping for faults on the secondary. Primary fuses, if used, are usually rated from about 1½ to 2½ times full load transformer current. If a setting of 6 times transformer full load current is used, the primary cable may not be protected for overload by the primary relays.

However, if the sum of all the main secondary breaker settings allows a current in the primary cable within its rating, the primary relaying can be set to trip above the overload rating and below the short circuit heating limit of the cable. A low time dial setting and reasonably high instantaneous element setting usually affords adequate short circuit protection for primary cable.

The 1971 edition of the *National Electrical Code* requires that the maximum rating or setting of the primary overcurrent protective device for a dry type transformer be no more than 250 percent of rated full load current for a transformer equipped with a main secondary breaker that is rated or set at no more than 125 percent of transformer full load rating. Other rules applying to installations where no main breaker is present are set forth in Article 450-3 of the Code.

Main secondary circuit breakers. The continuous current rating of the main secondary circuit breaker trip device is usually 1¼ to 1½ times transformer full load current. This breaker should be equipped with long-time and short-time delay trip elements.

A long-time delay device is usually set at 100 percent of the trip coil rating, and it must not be set any higher than 250 percent of full load rating for liquid-filled transformers. This is the upper limit permitted by Code.

Adherence to these recommendations will help assure an adequately coordinated load center unit substation design:

- Equip main secondary circuit breakers with long-time delay trip elements set at 125 per cent of transformer full load current and short time delay trip elements set at 2 times trip device rating.
- Equip feeder circuit breakers rated no larger than 1/3 of transformer full load current with long-time delay and instantaneous elements. Set the instantaneous elements at 6 times the trip device rating.
- Equip feeder circuit breakers rated at more than 1/3 transformer full load current with long-time, short-time, and instantaneous elements. Set the short-time elements at 2 times the trip device rating. Set the instantaneous element at 6 times the trip device rating.
- Set primary relay pickup no lower than 2½ times transformer full load current and no higher than 6 times. Set the instantaneous element no lower than 20 times transformer full load current rating.
- Check the degree of protection afforded the primary cable by primary relaying. Overload protection may be obtained by lower settings on transformer secondary breakers, while relying on primary relaying for short circuit protection only.
- After finished design of the complete power system, perform a final, formal coordination study to verify selection of ratings and settings for protective devices.

Fig. 3. Trip characteristic curves are plotted for 1000 kva substation (where low voltage circuit breakers are equipped with magnetic overcurrent trips). Value of device ratings and settings were determined empirically from table in this article; trip characteristic curve plot verifies validity of criteria in table.

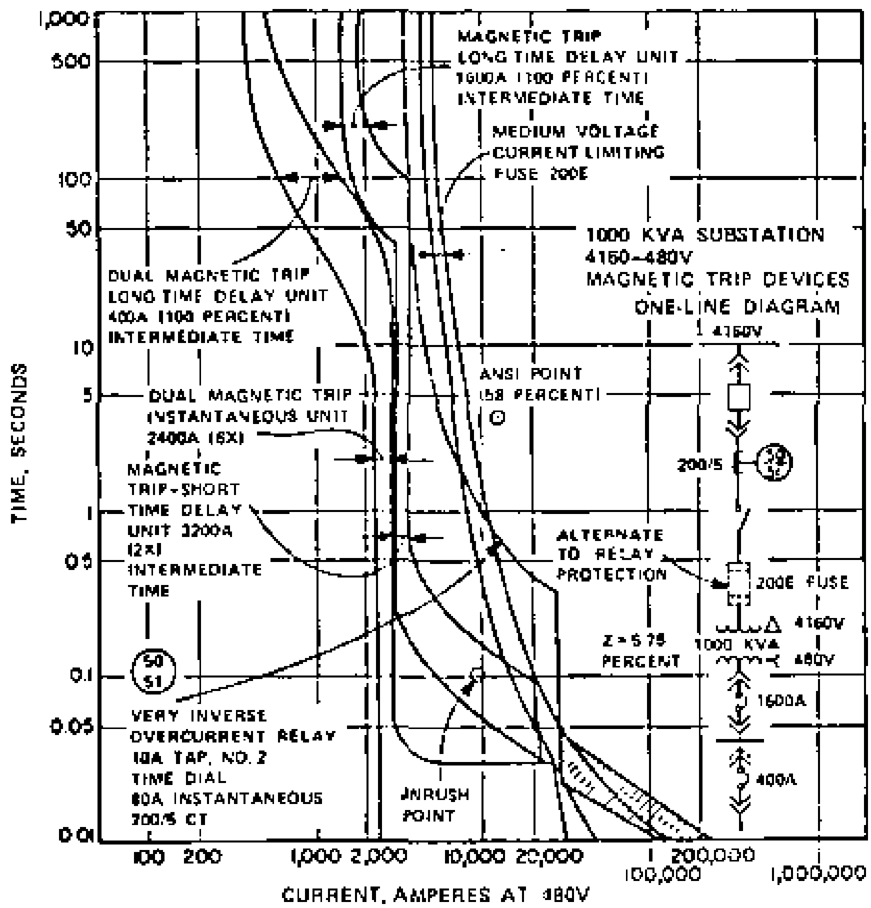
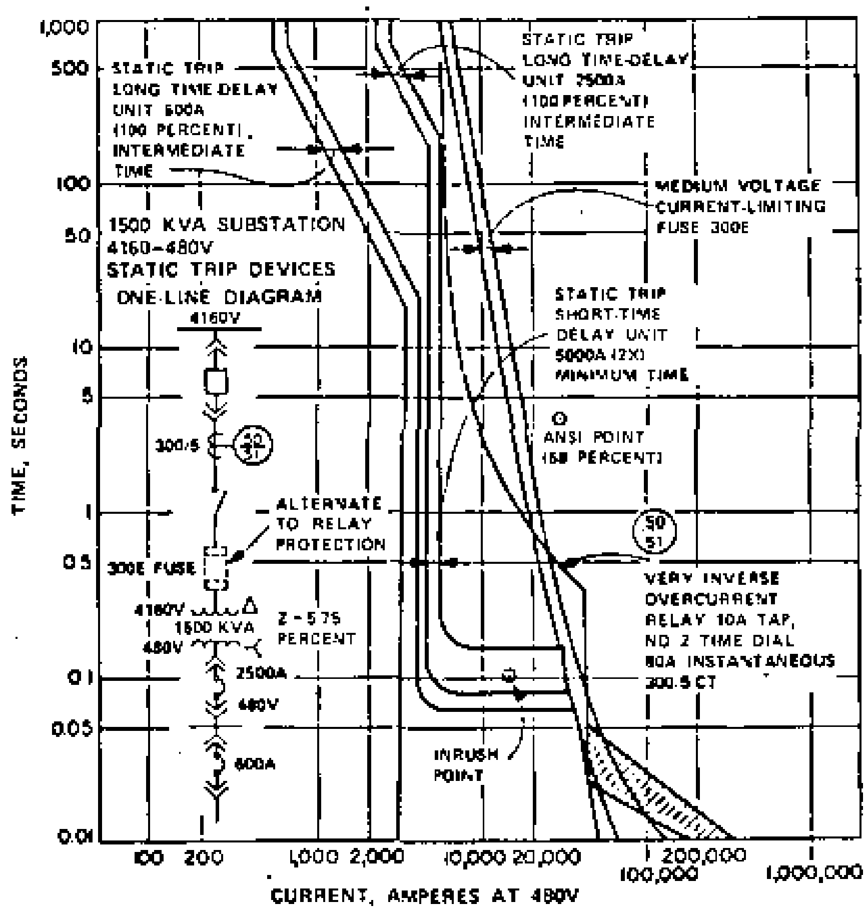


Fig. 4. Trip characteristic curves are plotted for 1500 kva substation (where low voltage breakers are equipped with static trip devices). Coordination criterion had been determined from table; results are verified by these curves.



LOAD CENTER PROTECTION COORDINATED SYSTEM
4,160V DELTA – 480V WYE(1)

Substation Size, kva	500	750	1000	1500	2000
Substation Impedance, Percent Z	4.5	5.75	5.75	5.75	5.75
Primary Voltage	4160	4160	4160	4160	4160
Secondary Voltage	430	480	480	480	480
Primary Maximum Rated Load Current, Amperes	69.3	104	139	208	278
Secondary Maximum Rated Load Current, Amperes	601	902	1203	1804	2406
ANSI Point (in 480V amps) = 0.58 × $\frac{1}{\text{impedance}}$ × FL for 3.7 Secs (5.75 Percent Z) or 2.5 Secs (4.5 Percent Z)	6062	9098	12,138	18,184	24,269
Inrush Point 8 × FL for 0.1 Sec (in 480V amps)	4308	7216	9624	14,432	19,248
Primary CT	100 5	150 5	200 5	300 5	400 5
Primary Relay(2)	IAC53	IAC53	IAC53	IAC53	IAC53
Primary Relay Pickup Amps (about 3 × FL)(3)	200	300	400	600	800
Primary Relay Tap (Amp)	10	10	10	10	10
Primary Relay Time Dial (No. 2–No. 5)	No. 2	No. 2	No. 2	No. 2	No. 2
Primary Relay Instantaneous (20 × FL Amp)	80	80	80	80	80
Primary Fuse	150E	200E	200E	300	375
Main Secondary LT Setting (125 Percent Max. Rated Current)	800	1200	1600	2500	3000
Main Secondary ST Setting (2 × Trip Device Rating)	1600	2400	3200	5000	6000
Largest Feeder LT Setting (1/3 Transf. FL)	200	300	400	600	800
Largest Feeder Inst. Setting (6×)	1200	1800	2400	3600	4800
Illustrative Curve			Fig 3	Fig 4	
Type of Trip Devices Shown			Magnetic	Static	

(1) For phase protection. Other considerations apply to ground fault protection schemes.
(2) IAC53 is General Electric relay type designation. (3) Use 2½ × for dry type transformers.

Ratings and trip device settings can be determined empirically from this table, minimizing trial and error plotting to determine device settings. Results should, however, be verified by trip characteristic plots after power system design has been completed. Note that similar tables can be developed for different primary and secondary voltages by adhering to this format and the principles outlined in this article.

The short-time delay element should be set at 2 to 3 times the trip device continuous rating in order to coordinate with primary phase overcurrent relay pickups. If an instantaneous element is used in addition to a short-time delay element, it should generally be set no higher than 10 times the continuous current rating of the breaker.

Feeder circuit breakers. To permit coordination with transformer main secondary breakers, feeder breakers rated ⅓ of transformer full load current or less should have instantaneous element settings no greater than 6 times the circuit breaker trip element rating. Feeder breakers rated at more than ⅓ of transformer rating should be equipped with long-time delay, short-time delay, and instantaneous trip elements. Short-time delay trip elements should be set at 2 to 3 times the trip device continuous current rating. Setting of the instantaneous trip element should be lower than 10 times the continuous rating of the trip device.

If an instantaneous trip element setting of more than 6 times is required on smaller feeder breakers, the incorporation of short-time delay elements in the trip device may be necessary to achieve coordination. To avoid specifying different types of trip devices on the same transaction, some engineers will specify long-time, short-time, and instantaneous trip elements for all sizes of feeder breakers.

Setting up the system. Empirical solutions can be applied to protective device settings, greatly simplifying coordination studies. The table gives ratings and settings for protective devices for several sizes of substations. The degree of coordination that can be achieved by applying data in this table will probably meet most of the coordination requirements for typical power systems.

Some feeders may be equipped with current transformers of different ratios than those shown, requiring that appropriate adjustments be made in trip device settings to achieve desired results. Tables for different primary and secondary voltages can easily be developed by utilizing the format and principles set forth in this article and the table. Note that pickups as high as 6 times rated full load current may still protect an individual transformer as well as, or better than, individual fuse protection.

Figures 3 and 4 provide graphical proof of the viability of this table. If criteria outlined in the table are adhered to, plotting of trip curves for a more refined coordination study can be an interesting, pleasant exercise instead of a frustrating chore.

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APPLICATION ENGINEERING INFORMATION

Some Fundamentals of Equipment Grounding Circuit Design

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GENERAL ELECTRIC

Some Fundamentals of Equipment-Grounding Circuit Design

R. H. KAUFMANN
FELLOW AIEE

Synopsis: An effective equipment-grounding system should, under conditions of maximum ground-fault current flow, accomplish the following objectives: 1. maintain a low potential difference, perhaps 50 volts maximum, between machine frames, equipment enclosures, conductor enclosures, building metallic structure, and metallic components contained therein to avoid electric shock hazard and unwanted circulating current, and 2. incorporate adequate conductance to carry this maximum ground short-circuit current without thermal distress and the attendant fire hazard. There is good reason to believe that current flow in the equipment-grounding system in a-c power systems will not stray far from the power cable over which the outgoing current flows. It follows that the installation of conductive material in an equipment ground system unless properly located can be ineffective and wasteful, and can create a false sense of security. This paper presents the results of a special series of full-scale tests dealing with this specific problem and a general analysis of the circuit behavior.

A MUCH better understanding of protective grounding systems is necessary to ensure freedom from hazard to life and property. The objective of this paper is to present the significant factors which control the behavior of protective grounding circuits in a-c industrial power distribution circuits during short-circuit conditions. It is hoped that this presentation may emphasize that improper application of material in equipment-grounding systems creates the wastefulness and unwarranted sense of security just mentioned.

Under a short-circuit to ground condition in an a-c distribution circuit, grounded or ungrounded systems alike, inductive reactance will exert a powerful influence in directing the return current flow in a path closely paralleling the going power conductor. The enclosing conduit or metallic raceway would constitute such a path. To attempt to relieve the conductor enclosure by installation of an external conductor is quite ineffective. Connections to near-by building structural members are equally ineffective. Only through the installation of an internal grounding conductor can the current which must be carried by the enclosure be noticeably reduced. Joints in conduits and raceways require special consideration to avoid a shower of sparks and attendant fire hazard during the short circuit's duration. Any thought of keeping the conduit or raceway insulated from ground except at one point seems totally impractical. Furthermore, such practice or a contemplated omission of the metallic enclosure may well lead to large induced voltages in near-by metallic structures which may appear either as dangerous shock hazards or unwanted circulating currents. Ungrounded distribution systems require equally careful treatment. Very often a second ground fault occurs before the previous one has been located and corrected. The problems discussed in this paragraph then appear simultaneously on each of the two circuits.

Test Procedure

A special installation of $2^1/_2$-inch conventional heavy-wall steel conduit and 4/0 copper cable conductors was made for this investigation. It was installed in a building previously used for short-circuit testing because this building contained a heavy steel column construction and all columns were tied to an extensive grounding mat composed of 250,000-circular-mil copper cables. The test installation is illustrated in Fig. 1. The conduit was supported on insulators throughout the 100-foot length. The conduit run was about 5 feet from a line of building columns. The external 4/0 cable was spaced about 1 foot from the conduit on the side opposite the building columns.

The particular arrangement of components makes possible the measurement of all currents and voltages at one location. This is especially valuable in that it avoids the running of lengthy voltage-measuring leads. The setup is intended to simulate an electric feeder circuit with power source at the left end and various simulated fault conditions at the right end. In all cases here reported the test current was caused to flow over the *A* cable to the far end. A variety of different possible return paths were examined, controlled by the connections made at the left end.

One series of tests was made at low current, 200 and 350 amperes, using an a-c welding transformer as a source of 60-cycle power. At these low-current magnitudes, the current flow could be maintained for extended periods. Voltage measurements were made with high quality indicating voltmeters. Current measurement was made with a clip-on ammeter.

A second series of tests was made at high current, around 10,000 amperes, using a 450-kva 3-phase 60-cycle transformer with a 600-volt secondary as a source of power. Switching was done at primary voltage, 13,800 volts, and an *IAC* induction relay was used to control the duration of current flow to an interval of about 1/4 second. An oscillograph was used for all measurement of current and voltage.

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The generous assistance of J. M. Schmidt and his staff in Facilities Engineering of the General Electric Company was invaluable to the test portion of this investigation. To him goes the credit for making the test installation, arranging for the loan of power supply transformers, together with switching and relaying equipment, and, in addition, authorizing the short-circuit tests from the 13,800-volt feeder lines serving the Schenectady plant. To L. J. Carpenter of Industrial Power Engineering goes credit for assistance in conducting the tests and the analysis of results.

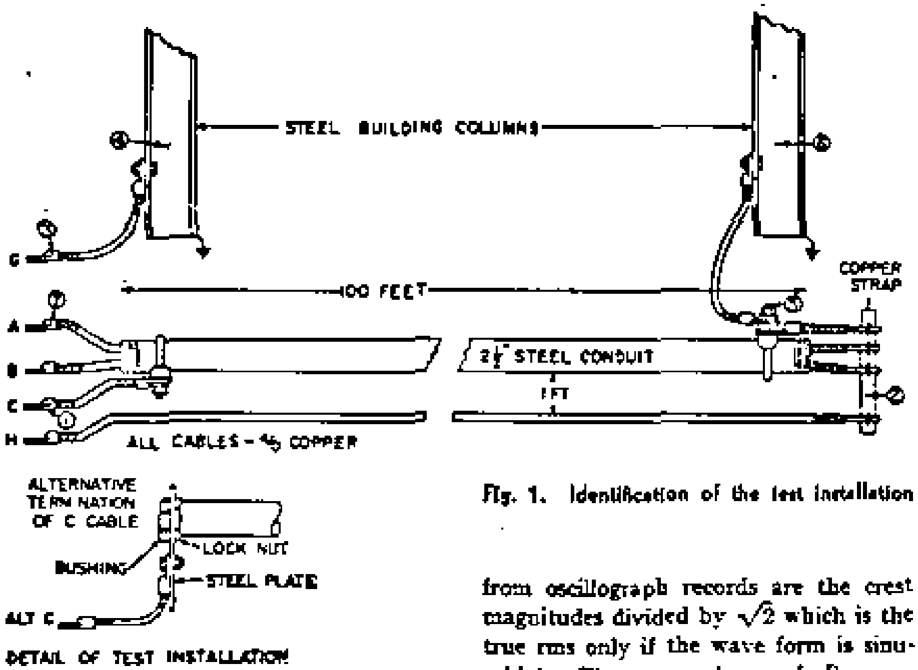


Fig. 1. Identification of the test installation

Results

The magnitudes of voltage and current obtained in the entire series of 60-cycle a-c tests are presented in organized form in Table I. The test number is an arbitrary assignment for reference purposes. The next two columns identify the connections used and indicate the possible paths of current flow. Next current values are tabulated: first, the total input current into the *A* conductor and, next, the return current in the conduit and its percentage of the total; and then the magnitudes of current in the other possible paths are given.

In all cases the tabulated values taken from oscillograph records are the crest magnitudes divided by $\sqrt{2}$ which is the true rms only if the wave form is sinusoidal. The wave shape of E_{CO} was commonly quite different from a sine wave, but in the extreme cases the magnitude also was small. See Fig. 3 pertaining to test B8.

Measurements of d-c resistance were made of the several return paths comprising the equipment-grounding system. See Table II. A controlled magnitude of direct current was caused to flow through the circuit and the d-c potential drop across the desired section was measured with an indicating millivoltmeter. The points of measurement refer to those indicated in Fig. 1.

No further analysis is needed to show conclusively that only by the use of an internal grounding conductor can any sizable fraction of the return current be diverted from the conduit or raceway. In spite of the extremely low resistance of the building structural frame, it was ineffective in reducing the magnitude of return current in the conduit. See tests A6, A7, B6, and B7. Further analysis is desirable to establish a better understanding of the nature of the circuits involved.

Some interesting secondary effects were observed in the course of the tests. The first high-current test produced a shower of sparks from about half the couplings in the conduit run. From one came a blowtorch stream of sparks which burned out many of the threads. Several small fires set in near-by combustible material would have been serious if not promptly extinguished. The conduit run had been installed by a crew regularly engaged in such work and they gave assurance that the joints had been pulled up to normal tightness and perhaps even a little more. A short 4/0 copper jumper was bridged around this joint but, even so, some sparks continued to be expelled from this coupling on subsequent tests. Other couplings threw no more sparks during subsequent tests. Apparently small tack welds had occurred on the first test.

In one high-current test the conduit termination was altered to simulate a connection to a steel cabinet or junction box. See bottom of Fig. 1. The bushing was applied finger-tight. On test with about 11,000 amperes flowing for about 1/4 second, a fan-shaped shower of sparks occurred parallel to the plate. In the process, a weld resulted and the parts were separated only with con-

Table I. Measured Electrical Quantities

Test No.	Current Flow: Out On	Current Flow: Return On	Current Magnitudes: I_A Total	I_C: Amperes	I_C: Per Cent of Total	I_B	I_H	I_G	Voltage Magnitudes: E_{AC}	E_{CO}	E_{AB}	E_{AH}	E_{AG}	E_{GH}
						Low-Current Tests								
A1	A	B	350	0		350	0	0	2.47		4.85			
A2	A	C	350	350	100	0	0	0	15.9	0.45	2.5			
A3	A	C	200	200	100	0	0	0	9.05	0.15	1.51			
A4	A	CH	350	340	97	0	12	0	16.0	0.05	2.55			
A5	A	CH	200	190	95	0	8	0	9.13	nil	1.55			
A6	A	CG	350	340	97	0	0	12	14.6		2.54	14.4		
A7	A	CG	200	180	90	0	0	8	9.5		1.50	9.4		
A8	A	CB	350	62	18	290	0	0	4.55	nil	4.55			
A9	A	CB	200	40	20	150	0	0	2.68	nil	2.68			
A10	A	GH	350	0	0	0	160	160	14.0	12.6	2.5	26.4	20.4	24.6
A11	A	GH	200	0	0	0	98	98	9.2	8.1	1.5	17.1	17.1	15.1
						High-Current Tests								
B2	A	C	11,200	11,200	100	0	0	0	168	36*				
B3	A	C	11,070	11,070	100	0	0	0	173	38*				
B4	A	CH	11,070	11,200	101	0	1,140	0	173	16*				
B5	A	CH	11,080	11,090	100	0	1,220	0	173	17*				
[illegible]	A	CG	10,930	10,770	99	0	0	1,080	168		71			
[illegible]	A	CG	10,910	10,730	99	0	0	1,145	173	9*				
[illegible]	A	CB	11,620	5,410	50	5,660	0	0		27*			135	
[illegible]	A	CB	11,380	6,070	53	5,620	0	0	146	25*				
B10	A	GH	8,710	0	0	0	4,300	4,500		146			268	

* Distorted wave shape. Tabulated values are crest/$\sqrt{2}$.

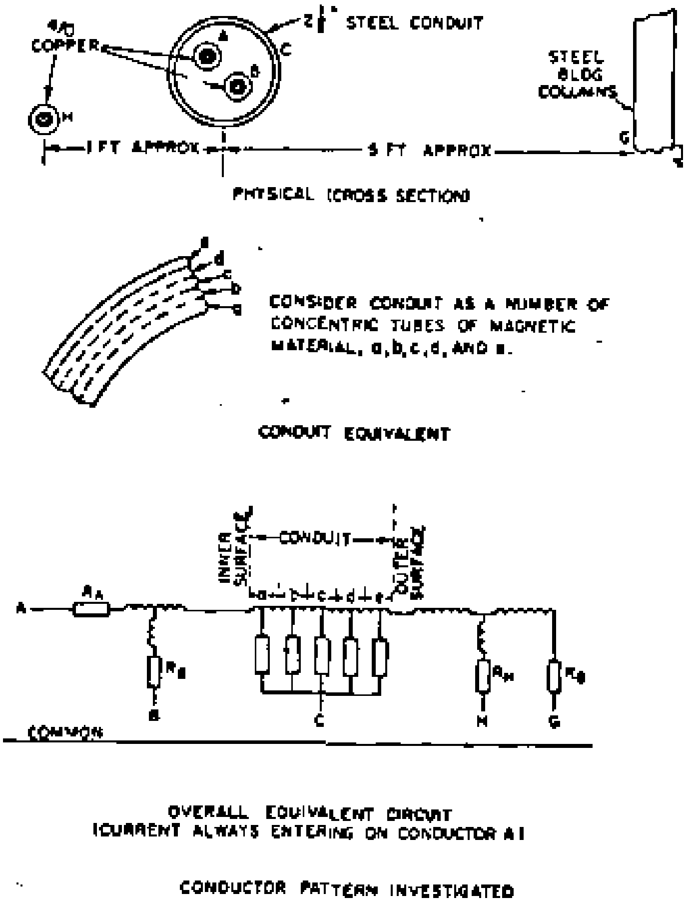


Fig. 2. Test circuit conductor geometry and equivalent electric circuit

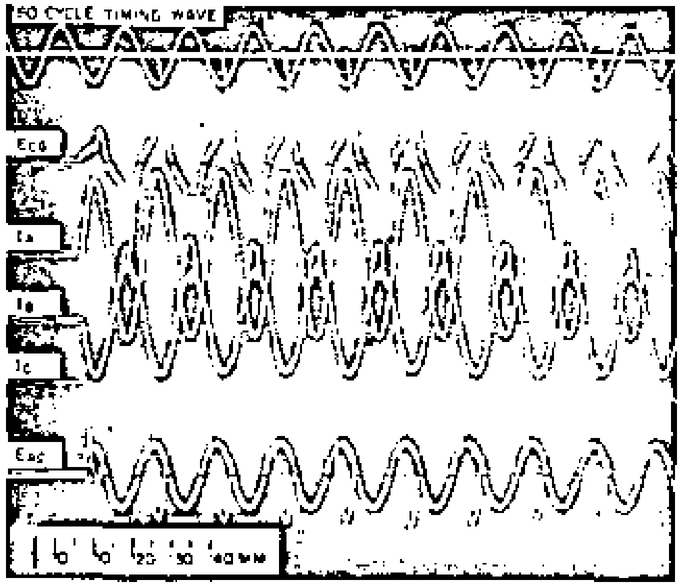


Fig. 3. Oscillogram of electrical quantities in test B8

E_{ca} conduit to ground volts, 1.26 volts per millimeter
I_a line current, 765 Angstrom units per millimeter
I_b ground cable current, 623 Angstrom units per millimeter
I_c conduit current, 947 Angstrom units per millimeter
E_{ac} input volts, 25.8 volts per millimeter

siderable difficulty, with the use of wrenches and a hammer. This suggested that a repeat shot would have produced no disturbance.

During high-current test B10 (conduit circuit open) a shower of sparks was observed at an intermediate building column. Careful inspection disclosed that the origin was at a spot at which a water pipe passed through an opening cut in the web of the steel beam involved. The pipe had been loosely in contact with the edges of the hole. Here is evidence of the objectionable effects of forcing the short-circuit current to seek return paths remote from the outgoing conductor. The large spacing between outgoing and returning current creates a powerful magnetic field which extends far out in space around the current-carrying conductors.

Circuit Analysis

The test installation as identified in Fig. 1 allows a study of a wide variety of equipment-grounding arrangements. The *A* conductor in all cases is used to represent the power conductor which has faulted to ground. One side of the test power was connected directly to the *A* conductor in all tests. The *B* conductor can be connected to act as an internal grounding conductor. The *H* conductor can represent an external grounding cable run parallel to the power cables with about 1 foot separation.

In addition to a resistance value associated with every conductor element is an inductive reactance value of a-c impedance. The reactance will increase as the spacing increases. Thus, for conditions in which the outgoing current will in all cases be carried by the *A* conductor, the reactances of the various elements will increase as their spacing from the *A* conductor increases.

The upper sketch in Fig. 2 defines the spacing characteristics of the circuit elements being studied. The steel conduit represents an annular area of high magnetic permeability. Until saturation occurs the magnetic flux produced in the steel pipe may be 500 or more times what it would have been in nonmagnetic material. The conduit may be considered as a series of thin-wall magnetic tubes, one within the other, such as that indicated in the center sketch in Fig. 2. The resulting equivalent circuit of the system under investigation takes the form indicated at the bottom of Fig. 2. The reactance of the circuit including the *B* conductor will be the lowest. Next will be the innermost tube of the conduit, followed by the others in successive order until finally the outer tube is reached. The inductance of these tubular elements of the steel conduit assumes unusual importance because of the high magnetic permeability. Next in spacing is the external grounding conductor (*H* cable) and, last, the structural members of the building frame and their interconnecting grounding cables buried below floor level. Any given circuit element is brought into use by connecting its terminal to the common bus.

Table II. Measured D-C Resistances

Element	Millivolt Drop Between	Ohms
100-foot length of 4/0 conductor	2-7	0.00515
100-foot length of 2½-inch steel conduit	1-5	0.00475
Steel building frame	4-6	0.00011
	3-5	0.0006

The effectiveness of the conduit in confining the flow of fault current within the conduit can be visualized with the aid of this equivalent circuit. Consider only the conduit (*C* terminal) connected to the common bus. This forces all the current to return on the conduit alone. The equivalent circuit shows that the current by returning on the inner surface of the conduit will avoid the reactance of the other annular sections. Furthermore, the conduit reactance will impede

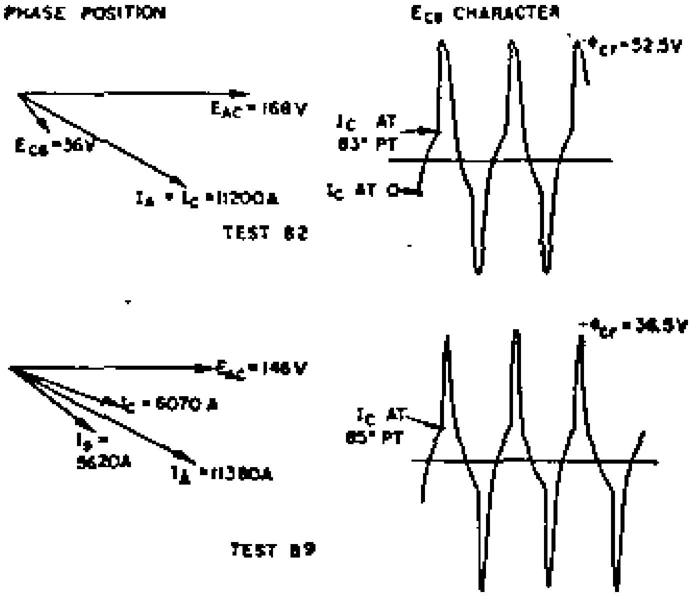
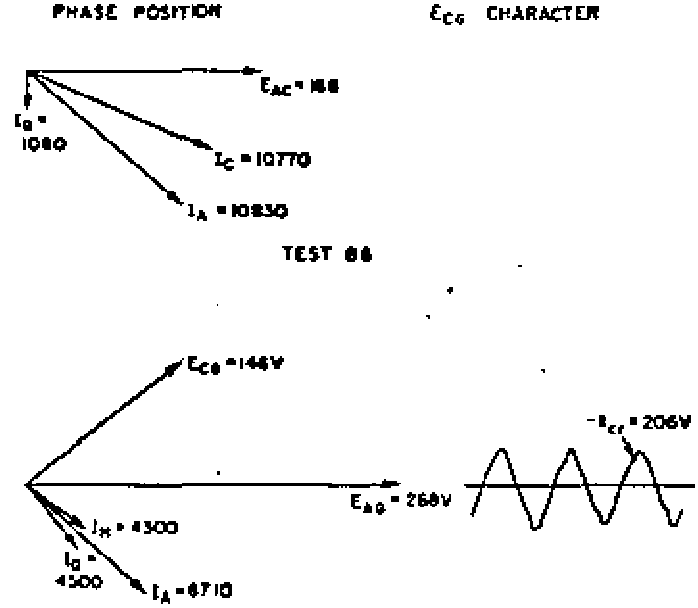


Fig. 4. Oscillogram analysis, tests B2 and B9



TEST B10

Fig. 5. Oscillogram analysis, tests B6 and B10

the diversion of current to the conduit outer surface. The voltage drop in a circuit path external to the conduit should be expected to be low until magnetic saturation occurs. Observe this effect in tests A2 and A3. The voltage E_{cg} is a voltage drop measured around a circuit external to the conduit. The value of 0.45 volt with 200 amperes flowing is less than the product of the current magnitude and the conduit d-c resistance. The same is true of the values obtained in tests B2 and B3 at high current. The oscillogram associated with test B8 is reproduced in Fig. 3. Notice the lag in the appearance of voltage in the circuit external to the conduit (E_{cg}) Magnetic saturation has been occurring in the steel conduit starting at the inner surface and progressing toward the outer wall. As complete saturation occurs the voltage appearing in the external circuit rises abruptly. Note that the current flow in the conduit had nearly reached crest value when this occurred.

Another interesting effect of the conduit is displayed when the conduit is not a part of the return electric circuit. Suppose that only the *H* cable is available as a return current path (all other terminals open). The current flowing out over the *A* conductor and returning over the *H* cable links the magnetic conduit as a transformer winding links its core. There tends to be reflected into the electric circuit a high magnetizing reactance modified only by the circulating current in the conduit metal. The conduit, not being laminated, allows a circulating current to flow much as a short-circuited secondary winding. This circulating current flows in a direction opposite to that in the *A* conductor on the conduit's inside surface and returns on the outside surface. In the equivalent circuit this circulating current is accounted for by a highly resistive circuit in parallel with the magnetizing reactance. The net impedance reflected into the electric circuit is much higher than would prevail if the conduit were part of the return electric circuit. These effects in iron conduits are described elsewhere.[4]

Figs. 4 and 5 give the phasor relationship of voltages and currents, together with the wave-form pattern of the voltage appearing along the exterior of the conduit as derived from several representative oscillograms.

In test B2, Fig. 4, the entire current was forced to return over the conduit alone. Note that the voltage E_{cg} appearing along the conduit exterior lags considerably behind the conduit current I_c, as was predicted. The wave shape of this voltage E_{cg} clearly shows the abrupt rise at the time of complete magnetic saturation.

In test B9, Fig. 4, the internal *B* cable was in parallel with the conduit and the return current divided nearly equally. The fact that the conduit current I_c leads the *B* cable current by a substantial angle is indicative that the conduit current is taking the highly resistive path along the inner conduit surface. The externally measured voltage E_{cg} exhibits the pattern found in test B2. After conduit saturation the external voltage closely approaches the current resistance drop computed from conduit d-c resistance.

In test B6, Fig. 5, the building structure was paralleled with the conduit. The large angle between the conduit current and the building frame current identifies the building structure as a highly inductive circuit while the conduit path appears as highly resistive. Although the current in the building frame was almost 1,100 amperes, it resulted in only a slight reduction in the conduit current because of the large phase displacement between the two current components. The voltage appearing along the conduit exterior in this test was impressed on the building structure and would appear as potential difference along beams and columns.

In test B10, Fig. 5, both the exterior grounding conductor (*H* cable) and the building frame (*G* terminal) were connected to provide parallel paths for the return current, but the conduit circuit was left open (*C* terminal not connected). The test results clearly evidence the powerful forces tending to maintain current flow in the conduit circuit. Note that across the open connection at the *C* terminal appeared a voltage of 146 volts (or, more significantly, over 50 per cent of the total impressed driving voltage), that required to force the current to return via the *H* cable and building frame in parallel. Such a voltage could be a serious shock hazard. Furthermore, unless the conduit were well insulated throughout the entire length, there would be a sufficient number of sparks at stray contact points to constitute a serious fire hazard. It was during this test that a shower of sparks observed between metallic members in the building system was caused simply by the strong magnetic field extending far out from the power conductors.

Conclusions

The significance of this investigation points unmistakably to the conclusions presented earlier in this paper. Effective use of the conduit or raceway in the equipment-grounding system is paramount. Additional work is needed to develop joints which will not throw fire during ground fault. To improve effectiveness requires greater conductivity in the conductor enclosure or the use of an internal grounding conductor. Grounding cables connecting building structure with ground electrodes (connection to earth) are needed to convey lightning currents or similar currents seeking a path to earth, but these conductors will play a negligible part in the performance of the equipment-grounding system. Of course, the importance of proper equipment-grounding becomes greater with the larger size feeder circuits and the availability of higher short-circuit currents.

Reference

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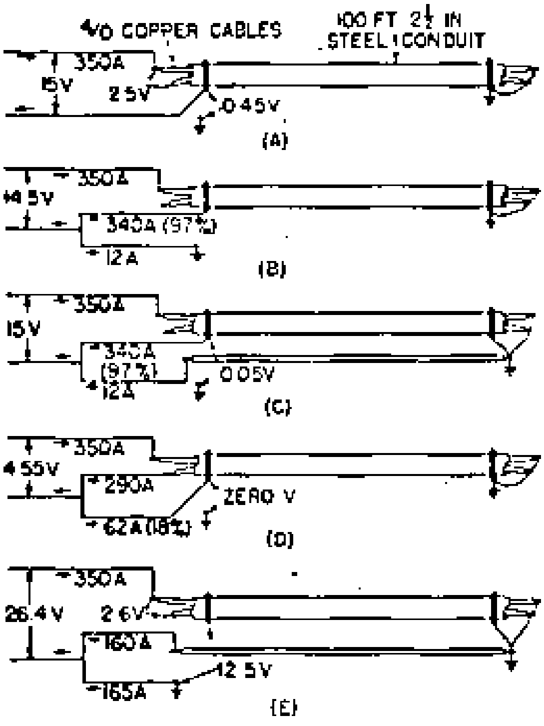
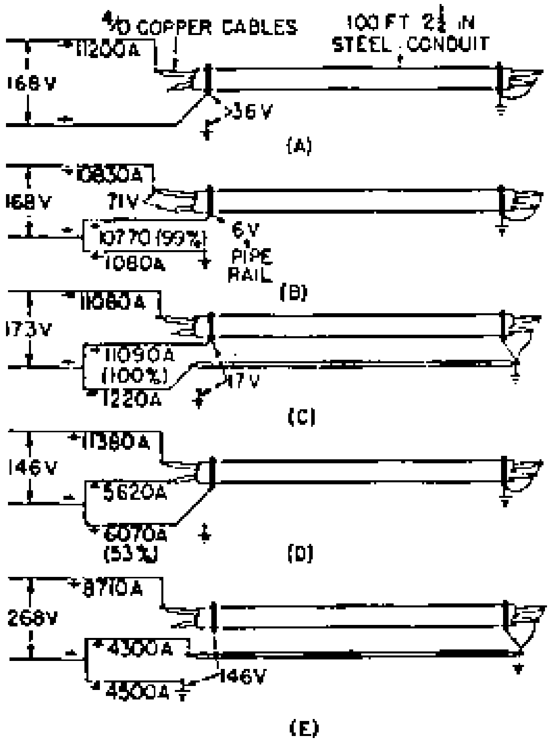
SUPPLEMENTAL INFORMATION NOT CONTAINED IN THE AIEE TECHNICAL PAPER





Summary of Significant Low-Current Tests Summary of Significant High-Current Tests

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A Review of Lightning Protection and Grounding Practices

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A Review of Lightning Protection and Grounding Practices

GEORGE W. WALSH

Abstract—Guides are presented to facilitate proper economic lightning protection of industrial power system component arrangements. Basic concepts of the traveling wave nature of lightning are included to enhance understanding of protective practices as they have developed and emphasize the need for careful adherence to approved practices in critical areas. The grounding treatment is very brief, being limited to the most salient considerations of equipment grounding in relation to the overall lightning protective system and the ground fault protective system. The paper is referenced throughout to current industry standards, application guides, and codes.

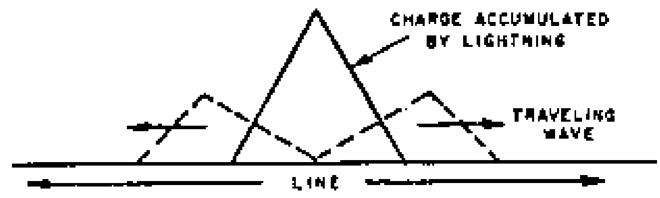

Fig. 1. Two "traveling" bodies of charge result when quantity of charge is deposited on conducting line by lightning.

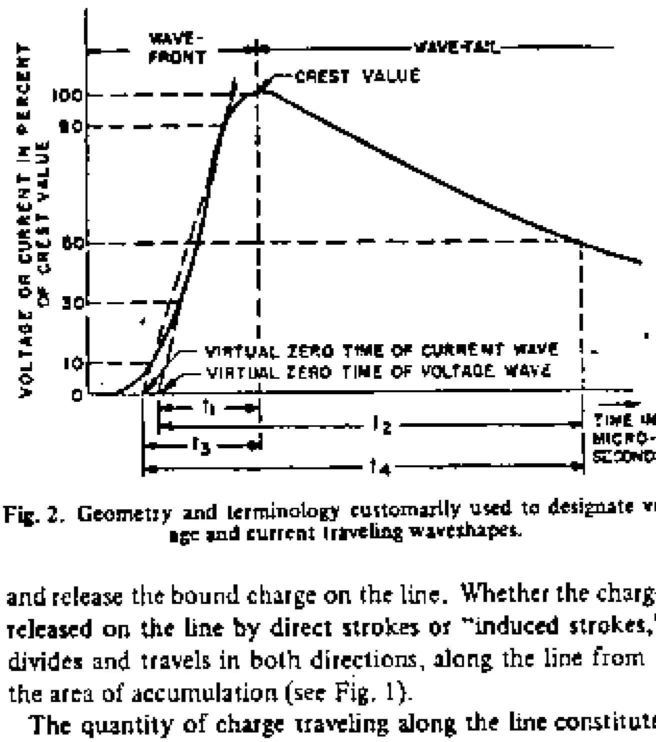

Fig. 2. Geometry and terminology customarily used to designate voltage and current traveling waveshapes.

Introduction

THE PROTECTION of power distribution systems against lightning involves first, the use of lightning protective equipment (arresters, surge capacitors, shielding, and ground systems) so applied as to limit the magnitude of lightning-produced overvoltages (and overcurrents) experienced by power circuits and apparatus to definite lower levels, and second, the provision of system apparatus insulation adequate to withstand these limited overvoltages during an economical life of the apparatus. This in turn requires a knowledge of the nature of lightning-produced overvoltages, characteristics of lightning protective equipment, and requirements of apparatus insulation.

Brief basic concepts and principles relating to these factors will be presented as an aid in developing a cognizance of the background of lightning protective practices. Much of the area of lightning protection practice enjoys relatively long-standing acceptance and usage; however, protection devices continually improve and "new" approaches to application practices evolve. The subject is very broad with numerous ramifications such that it is possible to treat only the most salient aspects of the associated concepts, principles, and practice elements in a single paper devoted to an overall review.

Nature of Lightning Protection Problem

Lightning-produced overvoltages on electric power systems are due to large quantities of charge placed upon the line by the action of lightning. In case of direct strokes to lines, the charge is placed directly on the line by the strokes. Charge is also accumulated on lines by electrostatic induction due to electric fields produced between earth and clouds during thunderstorms. Nearby lightning strokes to ground collapse this field and release the bound charge on the line. Whether the charge is released on the line by direct strokes or "induced strokes," it divides and travels in both directions, along the line from the the area of accumulation (see Fig. 1).

The quantity of charge traveling along the line constitutes a "traveling wave" of current and voltage, the zone of major influence or wavelength being of the order of a few thousand feet to a few miles. Excepting gradual attenuation, the magnitude and shape (voltage versus time, see Fig. 2) of the surge remain approximately the same at all points of a uniform line, but are displaced in time phase due to the traveling nature of the wave.

The distribution of charge and its rate of travel on the line are such that the rate of rise of voltage at a point can be extremely high. The complete lightning discharge may reach its crest in approximately 1-20 μs and produce conductor flashover voltages of 5-20 times normal in 1 μs or less. Direct-stroke overvoltages may be of the order of many millions of volts with discharge currents of many thousands of amperes, while the more frequent induced strokes produce only a few hundred thousand volts with discharge currents ranging from 50-2000 A.

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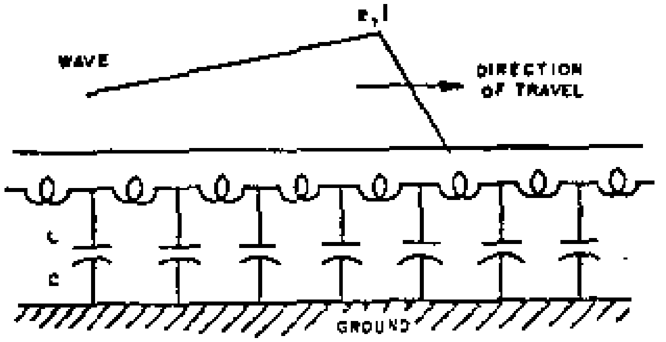

Fig. 3. Series of equivalent "T" or "π" sections to represent distributed constants of line. In practice, L is inductance in henries per foot or meter; similarly C is capacitance in farads.

TABLE I
SURGE IMPEDANCE AND TRAVELING WAVE VELOCITY

Power System Element	Typical Range of Surge Z	Typical Traveling Wave Velocity [illegible]
Open-Wire Line	250 to 500 ohms	[illegible]*
Cable	25 to 60	300 to 600
Large Gen	40 to 150	‡ 40 to 50
Small Gen	150 to 300	~ 50 to 100
Large Motors	150 to 3000	75 to 100
**Transformers	100 to 20,000	400 to 800

* 1000 normally used. 984 is theoretical maximum and is equal to velocity of light in free space.

** Transformer data from Reference [illegible].

† Data from Reference [illegible].

‡ 50 feet per microsecond commonly used.

Waveshape

Waveshape is customarily expressed by two time intervals associated with wave geometry. Referring to Fig. 2, the first time interval is between zero volts or amperes and crest on the wavefront; the second time interval is between zero volts or amperes and half-crest value on the wave tail. The wave is completely expressed if the crest value is added to the two time interval designations. For example, a 110 kV 1.2 X 50 μs wave rises from zero to a crest of 110 kV in 1.2 μs (front-time) and decays to 55 kV in 50 μs after zero. Current waves are similarly designated. Note that typically many kilovolts or kiloamperes are involved at crest, and the wavefronts vary from perhaps one to a few microseconds—the resulting gradients being exceedingly high.

[illegible]ge Impedance, Wave Velocity

When circuit geometry is short compared to wavelength, lumped circuit constants (L, R, C) often suffice for the particular analysis at hand. However, when wavefronts are short compared to the lengths of circuitry involved, then it may be necessary to use distributed constant representation. Such is the case with lightning-produced waves traveling on typical power lines, cables, and apparatus. Fig. 3 illustrates the distributed constant concept of a line. The equivalent distributed constant relationships exist in apparatus (transformers, rotating machines, etc.) but are somewhat more complex to analyze and visualize.

Note from Fig. 3 that each elementary inductance has a surge current magnitude and each elementary capacitance has a surge voltage impressed upon it by an assumed traveling wave. The associated electromagnetic energy ($\frac{1}{2} Li^2$) and electrostatic energy ($\frac{1}{2} Ce^2$) are expressed in joules (wattseconds) when units are as defined in Fig. 3. It is a profound property of traveling waves that the two forms of energy are of equal magnitudes and a surge voltage/current ratio will so result. Equating the two energy expressions and solving for e/i,

$$e/i = \sqrt{L/C} = \text{surge impedance} = Z. \qquad (1)$$

Again using basic concepts, but necessarily much more com[illegible] analysis, it may be shown that velocity of wave travel is

$$\frac{1}{\sqrt{LC}} = \text{unit lengths per second.} \qquad (2)$$

See Table I for typical surge impedances and traveling wave velocities in power system components.

In actual systems, voltage and current waves are gradually attenuated due to a relatively small amount of loss associated with the energy transfer along the circuit due to distributed resistances, corona, etc. These effects are neglected in these expressions for simplicity since the error is relatively minor, particularly in association with the short length of circuits encountered in the type of systems found in refineries, producing fields, and chemical complexes. Even in some of the much longer line utility applications, it is commonly assumed there is no loss involved.

Reflection of Traveling Waves

All types of traveling waves (such as sound, light, current, or voltage) exhibit marked changes when the travel medium is changed. This is due to a new traveling "reflected" wave that is created when the original traveling wave impinges on the change of travel medium. The reflected wave travels in each direction from this point of origin and is superimposed on the original wave (called the incident wave), adding to or subtracting from it.

Referring to Fig. 4, if at any instant E is the voltage of the incident wave at the junction, then $(E)(Z_2 - Z_1)/(Z_2 + Z_1)$ is the voltage of the reflected wave at the junction, where Z_1 is the surge impedance of the first conductor (over which the surge arrived) and Z_2 is the surge impedance of the second conductor. The voltage of the refracted wave at the junction is the sum of the voltages of the incident and reflected waves, that is, it equals $(E)(2Z_2)/(Z_2 + Z_1)$.

Fig. 5(a) is a frequently used simple dc equivalent circuit which may be derived from the foregoing to determine surge current and voltage at the junction of surge impedances Z_1 and Z_2. In this dc equivalent, E is a dc voltage equal to surge voltage magnitude and the surge impedances display the characteristics of resistance of the same ohmic magnitude. This latter property greatly simplifies surge analysis. Further generalization is valid to the extent Z_2 may also be a pure lumped inductance, capacitance, or combinations of these lumped circuit elements, providing the associated overall time constant is short compared to twice the surge travel time of the line, and E is a step function. See Fig. 5(b) and (c).

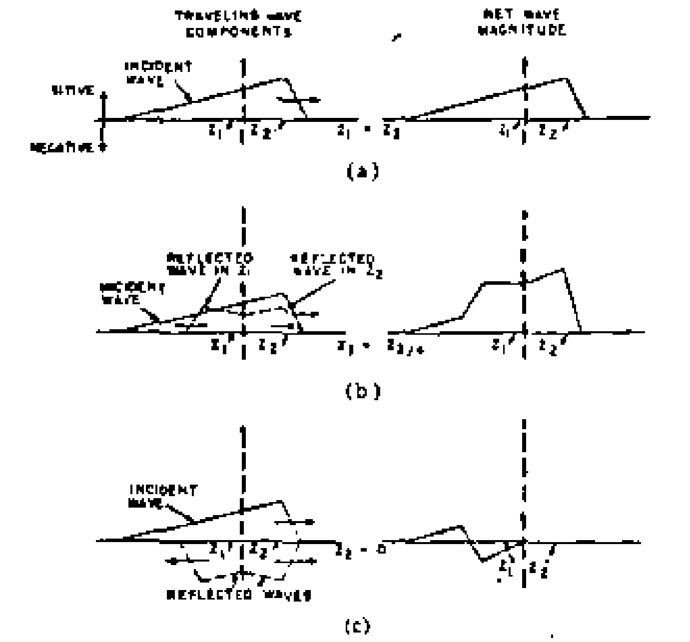

Fig. 4. Reflection of traveling wave at junction of two surge impedances (for a given instant of time). Total wave magnitude is algebraic sum of incident and reflected waves. (a) Wave traveling in medium of no change of surge impedance. Therefore no reflected wave is produced at junction between Z_1 and Z_2. (b) Case of Z_2 greater than Z_1 as Z_2 becomes very large compared to Z_1. Reflected wave magnitude approaches (as a limit) that of incident wave. (c) Limiting case Z_2 less than Z_1 where $Z_2 = 0$. Net wave magnitude in Z_2 (or refracted wave) is zero since incident wave and reflected wave components are equal in magnitude and opposite in polarity in Z_2 region.

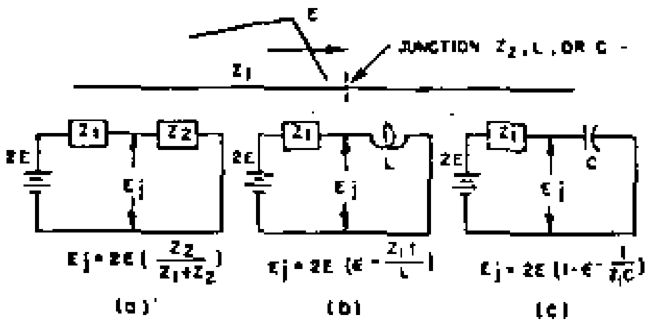

Fig. 5. Equivalent circuits for determining junction voltage (maximum) for different terminations of surge impedance (Z_1).

Thus it is seen that surge voltage (and current) at the junction may be determined by classical mathematical treatment of L, R, and C lumped constant elements depending on the manner in which the circuit surge impedance (Z_1) is terminated (i.e., in another surge impedance, R, L, or C).

Solving for the junction voltages (E_j) of arrangements of Fig. 5 for various terminations of Z_1 we obtain for surge impedance (Z_2) termination

$$E_j = 2E\left(\frac{Z_2}{Z_1 + Z_2}\right) \tag{3}$$

inductance (L henries) termination

$$E_j = 2E\left(\epsilon^{-\frac{Z_1 t}{L}}\right) \tag{4}$$

and for capacitance (C farads) termination

$$E_j = 2E\left(1 - \epsilon^{-\frac{t}{Z_1 C}}\right) \tag{5}$$

where E is the zero front-time step function.

The inductance termination responds initially like an open-circuited line but later behaves like a short-circuited line. This is important to the understanding of the detrimental effect of long interconnections to surge protective equipment. On the other hand the capacitance termination responds initially like a short circuited line, but later behaves like an open-circuited line.

As will be developed in the discussion of lightning arrester characteristics, the action of arresters is to make Z_2 relatively low. This produces a lowered surge voltage at the arrester, and in the immediate area of the arrester, thus providing surge protection for electrical apparatus in the area of the arrester. The extent of this "protected" zone is variable, being subject to many factors. Further treatment of this aspect of lightning protection is presented in the discussion of arrester location.

The foregoing has dealt with the simple case of a single incident wave as it impinges on a junction of two surge impedances. Obviously a practical system will experience on occasion a multitude of wave components traveling through its various surge impedances, producing a multitude of reflections and refractions at various junctions of surge impedances. Suffice it to state here, there are established methods and programs to evaluate these more complex cases if desired. However, as a practical procedure, the adequacy of surge protective measures is often judged on the basis of doubling at the junction (or protected apparatus terminal) of a single incident wave of established maximum probable value.

APPARATUS INSULATION CAPABILITY

An objective of surge protection is to achieve an optimum economic balance between investment in the surge protective system and investment in line, cable, and apparatus insulation required to withstand surges throughout reasonable life. Therefore, surge protection system properties and related apparatus insulation capabilities are fairly well standardized. Test levels for various configurations of waveshapes have been established as a basis for insulation capability and for lightning arrester protective ability.

The most important single waveshape test derived to establish the surge capabilities of insulation structures is the 1.2 × 50 μs wave. A given insulation structure assigned a given insulation class must be capable of withstanding, without flashover or apparent damage, a 1.2 × 50 μs wave of specified crest kV. This specified crest value is the basic impulse insulation level (BIL) of the equipment for the particular voltage or insulation class involved. The 1.2 × 50 μs wave is also referred to as "full wave." See Tables II-IV.

Tables II and IV covering transformers include not only impulse test levels which are of prime concern in lightning protection, but also low-frequency dielectric test levels (including hi-pot) and so-called "chopped wave" test levels. The chopped wave test is just as the name implies. Voltage is increased at a steady rate across the test specimen to a level indicated in the

TABLE II
IMPULSE TEST LEVELS FOR LIQUID-FILLED TRANSFORMERS*

Insulation Class and Nominal Bushing Rating	Windings				Bushing Withstand Voltages		
	Low-Frequency Tests	Chopped Wave Minimum Time to Flashover		BIL Full Wave (1.2×50)	60-Cycle 1-Minute Dry	60-Cycle 10-Second Wet	BIL Impulse Full Wave (1.2×50)
kV	kV	kV	Microseconds	kV	kV (rms)	kV (rms)	kV (crest)
1.2	10	54(36)	1.5(1.0)	45(30)	15(10)	13(10)	45(30)
2.5	15	69(54)	1.5(1.25)	60(45)	21(15)	20(13)	60(45)
5.0	19	88(69)	1.6(1.5)	75(60)	27(21)	24(20)	75(60)
8.7	26	110(88)	1.8(1.6)	95(75)	35(27)	30(24)	95(75)
15.0	34	130(110)	2.0(1.8)	110(95)	50(35)	45(30)	110(95)
25.0	50	175	3.0	150	70	70(60)	150
34.5	70	230	3.0	200	95	95	200
46.0	95	290	3.0	250	120	120	250
69.0	140	400	3.0	350	175	175	350
92.0	185	520	3.0	450	225	190	450
115.0	230	630	3.0	550	280	230	550
138.0	275	750	3.0	650	335	275	650
161.0	325	865	3.0	750	385	315	750

* Values in parentheses are for distribution transformers, instrument transformers, constant-current transformers, step and induction voltage regulators, and cable potheads for distribution cables. Data taken from industry standards.

TABLE III
BIL'S OF POWER CIRCUIT BREAKERS, SWITCHGEAR ASSEMBLIES, AND METAL-ENCLOSED BUSES

Voltage Rating kV	Basic Impulse Insulation Level kV	Voltage Rating kV	Basic Impulse Insulation Level kV	Voltage Rating kV	Basic Impulse Insulation Level kV
2.4	45	23	150	115	550
4.16	60	34.5	200	138	650
7.2	75**	46	250	161	750
13.8	95	69	350	230	900
14.4	110	92	450	345	1300

** 95 for outdoor-type switchgear with power circuit breakers.

TABLE IV
DRY-TYPE TRANSFORMER INSULATION DATA IN KV

Nominal System Insulation	Insulation Class	Low-Frequency Test	Standard BIL Values
1.2	1.2	4	10
2.4	2.5	10	20
4.8	5.0	12	25
8.32	8.7	19	35 *
14.4	15.0	31	50 *

* Some transformers may have higher BIL than this indicated standard level.

table for the particular insulation class of structure. The test specimen is required to hold this minimum voltage for a minimum time before flashover. The flashover produces or results in a very high negative gradient, thus chopping the wave. The chopped wave is applied to establish certain switching capabilities such as associated with sparkover of arresters and insulation breakdown and other flashovers (bushing, insulator) that may occur.

Tables II-IV provide a general picture of the standardized impulse capabilities of transformers and switchgear. Open wire lines vary somewhat in their impulse withstand depending upon construction, maintenance, weather, etc., but are generally considered well above associated transformers in this respect. An open wire 13.8-kV distribution circuit, for example, is typically considered to have a 400-kV BIL. While cables do not have assigned BIL's, they too have impulse capability significantly higher than associated liquid-filled transformers. The BIL of dry-type transformers is relatively low, being about one-half that listed for liquid-filled transformers. Rotating machines also have relatively low impulse strength as compared to liquid-filled transformers and have no established standardized BIL's.

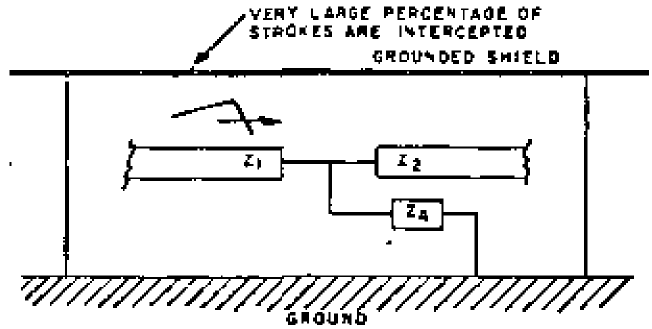

Fig. 6. Arrester low surge impedance insures low surge voltage at Z_1-Z_2 junction by producing reflections of opposite polarity to incident wave voltage permitted by shielding. This arrangement is basic to philosophy of lightning protection practice.

LIGHTNING PROTECTION PHILOSOPHY

In actual practice lightning protection is achieved by the processes of *interception* of lightning-produced surges, *diverting* them to ground, and by mollifying their associated waveshapes (see Fig. 6). Interception relates primarily to the prevention of direct strokes to lines and apparatus by shielding which also functions as an energy diversion path to ground. However, an extremely low percentage of strokes may penetrate overhead line static wire shielding in addition to induced surges that will occur on the line in presence of lightning in the area. Also, of course, some lines are not shielded. Therefore, lightning-produced surges do become impressed on power system components due to imperfect or nonexistent shielding. Strategically located arresters are applied to divert most of this surge energy around sensitive apparatus insulation and thus afford the necessary protection. In the most ideal and simplest applications the lightning arresters are connected in the closest practical shunt relationships with the insulation of the apparatus to be protected.

Continuing reference to Fig. 6 throughout this paragraph, the arrester may be considered a very low surge impedance in the presence of dangerous surge voltages but an extremely high impedance in the absence of surge voltages. In terms of traveling wave theory, whenever Z_A (arrester surge impedance) is much less than Z_1 (line or cable surge impedance, usually), then the surge voltage at the junction (terminals of protected equipment) will be much less than the incident wave voltage that arrives at the junction through Z_1. This is due to the reflected wave created at the junction that will approach the incident wave in magnitude but will be of opposite polarity. In the simple case illustrated, it is perhaps intuitively obvious that a low surge impedance arrester will divert a high percentage of the surge energy around the protected equipment to ground. However, actual applications present circumstances that are often somewhat more complex wherein, for example, economic protection requires that arresters be located at some remote distance from the protected equipment. In such cases, the traveling wave concept is very helpful in determining the gradients that may exist between the arrester and protected equipment and thus enhances the assessment of the associated depreciation in protection.

While most apparatus in the large majority of applications will tolerate the surge duties permitted by good shielding and proper arrester application, the associated gradients in particular may be damaging to rotating machines of multiturn coil construction. This includes virtually all motors and also smaller generators (up to approximately 35–40 MW at 13.8 kV). A following discussion of motor protection will cover this aspect of surge protection and associated application of surge capacitors.

SURGE ARRESTERS

Historically, various types of arresters have been used for power system protection; however, today the valve-type arrester is applied to the practical exclusion of other types, including expulsion. The basic elements of the valve-type arrester are the gap unit and the so-called valve unit. The gap unit is configured and augmented such as to achieve the most desirable sparkover protective characteristics and reseal capability consistent with cost. The valve unit consists of a nonlinear resistance

$$R_A = \alpha \frac{1}{E^K}$$

(where R_A equals the valve resistance, E equals the voltage across valve resistance, and K equals the constant for a particular design) which exhibits a relatively high resistance at low voltages (and current) and a much lower resistance at high (surge) voltage and current. This nonlinear property greatly enhances overall arrester design because it presents lowest resistance (surge impedance in effect) at the important high surge condition while its high resistance property at low surge levels assists the gap unit in resealing after surge discharge to prevent continued flow of power follow current.

Basis of Rating Valve-Type Arresters

It is imperative that the gap unit be capable of resealing itself (with assistance of the current throttling action of the valve unit) against power system frequency line-to-ground voltage after the surge has been discharged through the arrester. The lightning surge has a time duration that is very short compared to that of a half-cycle of fundamental frequency. The arrester is capable of diverting the short duration surge current to ground quite readily; however, the vast majority of arresters in service and most of those available today are not capable of carrying the relatively long duration half-cycles of power follow current (at least beyond a very limited number of such half-cycle periods). This aspect is crucial to the application of valve-type arresters and for this reason arresters are *rated* on the basis of the maximum power system frequency rms voltage which they may be expected to reseal against. Thus arresters are not rated directly on the basis of a particular surge protective specification. Special overvoltage arresters are available which are capable of sustaining a specified fundamental frequency overvoltage for a specified number of cycles.

Arrester Protective Characteristics

The surge protective characteristics of valve-type arresters are associated with the two basic units comprising the arrester: 1) sparkover voltage characteristics relating to gap unit performance, and 2) discharge voltage characteristics relating to valve unit performance. The sparkover characteristic, i.e., the surge voltage at which the gap unit conducts to engage the valve unit, varies with the waveshape of the surge. A perfect sphere gap will spark over at markedly higher values of voltage on steeper front waves and at lower values of voltage on "slower" waves, i.e., waves that take a longer time to reach a given crest value. Modern valve arrester gap units, however, are designed such as to produce a more uniform sparkover characteristic as a function of wavefront steepness.

Arrester standards [1] specify various waveshape tests whereby arrester sparkover performance is evaluated. Arrester manufacturers list performance characteristics based on these waveshapes. The two tests most frequently used for such listing are the front-of-wave and the $1.2 \times 50\ \mu s$ wave test. The front-of-wave sparkover is the voltage at which arrester-gap sparkover occurs on the front of a wave rising at the rate of 100 kV/μs for each 12 kV of arrester rating for arresters rated 3–144 kV, and 1200 kV/μs for arresters rated above 144 kV. For arresters rated less than 3 kV, the test wave rate-of-rise is 10 kV/μs. Also, all rotating-machine arresters have a specified front-of-wave test rate-of-rise of $10 \pm 3\ \mu s$ to gap sparkover. The $1.2 \times 50\ \mu s$ sparkover is the crest value of a $1.2 \times 50\ \mu s$ wave that causes arrester sparkover at the time crest value is reached.

So-called slow-front or switching-surge sparkover values are also sometimes listed. This is similar in nature to the $1.2 \times 50\ \mu s$ test wave except a series of waveshapes are used with fronts varying from 30–200 μs.

Table V lists sparkover characteristics based on the foregoing standard test waves. Also note the table includes so-called discharge voltage values. These are values of voltage that appear across the arrester when the indicated magnitude (crest) of a standardized [1] $8 \times 20\ \mu s$ current wave is conducted through the arrester. This voltage is also sometimes referred to as the "*IR*" voltage. Note that very large increases in discharge current result in relatively small increases in discharge voltage. This exhibits the nonlinear nature of the valve unit.

Arrester Class

Three classes of valve-type arresters are recognized by industry standards. In order of cost and overall protective quality and durability they are in order listed: 1) station class, 2) intermediate class, and 3) distribution class. Note from Table V that the station class, intermediate class, and special distribution class have comparable sparkover levels. The "standard" distribution class arrester has a sparkover level on front-of-wave of approximately one-third to two-thirds greater. The station class arrester can discharge approximately twice as much impulse current ($8 \times 20\ \mu s$ current wave) as the intermediate class arrester for a given discharge voltage. The intermediate class arrester similarly can discharge approximately one-half greater magnitude of impulse current for a given discharge voltage than the distribution class arrester. It should be noted that the values listed in Table V are based upon the offering of one manufacturer and may vary somewhat from other listings.

Arrester Discharge-Current Capability

To ensure arresters have an acceptable capability to discharge lightning currents and line and cable capacitance, an array of discharge-current withstand and duty cycle tests are specified

TABLE V
SURGE PROTECTIVE CHARACTERISTICS OF VALVE-TYPE SURGE ARRESTERS**

Arrester Rating kV rms	Maximum Impulse Sparkover Crest kV — ANSI Front-of-Wave — Sta.	Int.	Dist.*	1.2X50μ Sec. — Sta.	Int.	Maximum Switching Surge-Cr. kV Station	Maximum Discharge Crest kV at Indicated Impulse Current, 8 X 20μ Sec. Wave — 1.5 kA — Sta.	Int.	Dist.*	5 kA — Sta.	Int.	Dist.*	10 kA — Sta.	Int.	Dist.*	20 kA — Sta.	Int.	Dist.*	40 kA — Sta.	Arrester Rating kV rms
3	12	11	14.5/11	12	11	12	5.0	6.5	9.5/9	6.6	7.6	11/11	7.1	8.3	12/12	8.3	9.5	13.5/15	10.7	3
4.5	16	16	--/17	15	15	15	7.4	9.5	--/13	8.5	10.8	--/17	10.8	12.0	--/19	12.3	14.0	--/23	15.1	4.5
6	20	21	20/21	18	19	18	9.8	12.5	10/17	17.6	16.5	22/22	14.3	16.0	24/26	16.3	18.5	27/30	19.9	6
7.5	25	26	--/26.5	22	21.5	25	17.2	15.8	--/21	15.7	17.8	--/28	17.7	20.0	--/37	20.3	22.8	--/38	26.8	7.5
9	30	31	29/32	35	27.5	27	14.4	19.0	28/26	18.8	21.0	33/32	21.2	23.5	36/39	26.1	27.0	40/45	28.6	9
10	—	35	43/32	—	31	--	--	21.4	30/29	--	26.5	33/38	—	27.2	36/45	—	31.5	40/53	--	10
12	39	43	62/38.5	32	35.5	35	19.4	26.7	34/34	26.9	28.0	43/43	28.1	31.0	51/51	32.1	36.0	60/60	38.7	12
15	48	50	76/48	39	43.5	43	24.2	31.0	42/42	31.0	35.0	53/53	35.0	39.0	61/63	40.0	45.0	74/74	48.4	15
18	57		91/54.5	47		51	28.9		50/50	37.6		63/63	41.8		75/75	47.8		90/90	58.5	18
21	66	61	104/—	54	59	59	33.7	47.0	--/58	41.7	46.0	--/73	48.7	55.0	--/87	55.5	61.0	—/104	68.0	21
24	76	70		61	67	67	38.4	49.0		49.7	54.0		55.5	62.0		63.5	72.0		77.5	24
30	95	87		75	81	84	47.8	61.5		61.5	70.0		69.5	78.0		79.0	90.0		96.6	30
36	113	116		90	95	100	57.5	76.0		73.5	81.0		85.0	94.0		94.5	108		115.0	36
39	123	126		97	102	108	62.5	80.0		78.5	90.0		89.5	101		102.0	117		125.0	39
48	151	154		118	123	133	76.0	91.0		97.5	111		110	125		125.0	145		151	48
60	190	190		136	153	162	95.0	133		122.0	139		137	156		158	180		190	60
72	213	228		166	180	170	114	148		146	166		164	187		187	216		227	72
78	231	245		183	195	184	123	160		158	180		178	203		202	234		246	78
84	247	262		198	209	198	133	172		170	194		191	218		217	252		265	84
90	263	287		214	223	213	147	184		182	208		204	233		232	270		283	90
96	280	300		231	236	227	151	197		194	222		218	249		248	288		302	96
108	315	335		262	265	255	170	221		218	249		245	281		278	324		333	108
120	347	370		294	290	284	188	244		241	277		272	311		309	360		376	120
132	380			320		312	207			262			296			335			402	132
144	415			350		344	226			287			321			363			439	144
168	495			396		397	265			334			374			427			510	168
180	530			400		400	281			358			400			452			559	180
192	560			421		476	300			381			427			482			585	192
228	640			510		566	355			451			510			575			695	228

** This table is based upon the offering of one manufacturer and may vary somewhat from other listings.

* Standard and low-sparkover models data listed — Standard/Low-sparkover

• Arresters for rotating machine protection are available for ratings listed 3 kV to 24 kV inclusive, also arrester rated 650 V available for low-voltage apparatus protection.

by standards [1]. Two of the tests relate to high-current short-duration and to low-current long-duration duties. The high-current short-duration test consists of two discharges of a surge current (of 65-kA crest for intermediate and distribution class arersters, 100-kA crest for station calss) having a (4-8) X (10-20) μs waveshape. The low-current long-duration tests require station and intermediate class arresters to display capability to discharge capacitance equivalent to specified transmission line lengths (150-200 mi for station class, depending upon arrester rating, and 100 mi for intermediate class). Procedure for determining cable length equivalent is included in the same standard. Distribution arresters must exhibit (in a specified series of discharges) the capability of withstanding an approximate rectangular waveshape of 75 A minimum surge current of a minimum time duration of 1000 μs.

Some arresters have discharge capabilities well in excess of these indicated minimums. Where high discharge currents are of concern, consult arrester manufacturer data to determine adequacy of arrester discharge capability..

APPLICATION OF ARRESTERS

The application of surge arresters depends upon three basic considerations: 1) selection of arrester rating, 2) selection of arrester location, and 3) selection of arrester class. Whereas there is relatively little latitude in the selection of arrester ratings in most applications, there is somewhat more room for the exercise of judgment factors in the selection of arrester location and arrester class. These latter two basic considerations do provide for different degrees of risk that may be assumed by the owners and operators of a system.

Selection of Arrester Rating

As established in the foregoing discussion on valve-type surge arresters, they are rated on the basis of the maximum power system frequency rms voltage at which they may be expected to reseal against after having sparked over. The lower the arrester rating the better the protection afforded circuit and apparatus insulation—also, the lower the cost.. Therefore the selection of arrester rating is primarily one of determining the maximum *sustained* line-to-ground voltage that can occur at the arrester location and then choosing the closest arrester rating that is not exceeded by it. The circumstance of a line-to-ground fault on the system and the associated line-to-ground voltage on the unfaulted phases is the usual prime criterion for selection of arrester rating.

Line-to-ground faults tend to shift the system fundamental frequency phasor pattern from its normal position of symmetry with respect to ground. In the case of ungrounded systems, this shift is virtually complete, i.e., the unfaulted (sound) phase(s) arrester will be subjected to 100 percent of the line-to-line operating voltage, resulting in the so-called 100-percent arrester requirement. However, system "solid" grounding (depending upon degree) provides considerable restraint in voltage pattern shift and usually permits a considerable reduction in arrester rating requirement.

The prevailing IEEE standard for surge arresters [1] defines *coefficient of grounding* as "the ratio E_{LG}/E_{LL}, expressed as a percentage, of the highest rms line-to-ground power-frequency voltage E_{LG} on a sound phase, at a selected location, during a fault to ground affecting one or more phases to the line-to-line power frequency voltage E_{LL} which would be obtained, at the selected location, with the fault removed." Thus, *the minimum required arrester rating is the maximum operating voltage times coefficient of grounding*. In any case, various aids are available to facilitate the calculation and determination of coefficients of grounding [2]. Such aids are often presented in terms of symmetrical component parameters, and surge arrester rating practices have evolved to a certain extent around symmetrical component terminology. Further, systems have been categorized [2] as follows to aid in arrester rating selection: 1) effectively grounded—coefficient of grounding not exceeding 80 percent (X_0/X_1 is positive and less than three, and R_0/X_1 is positive and less than one); 2) noneffectively grounded or ungrounded when coefficient of grounding exceeds 80 percent.

The vast majority of medium-voltage (2.4-13.8 kV) industrial power systems including refinery power systems employ some form of resistance system grounding. For arrester application purposes these are noneffectively grounded systems having coefficients of grounding of 100 percent. The same is true for the very infrequently used ungrounded systems. This simply means that such systems require arrester ratings of at least 100 percent of the maximum operating voltage of the system.

Some chemical and petroleum complexes are served by medium-voltage systems which utilize "solid" system grounding only at (usually) the point of energy supply to the system. These so-called "uni-grounded" systems exhibit a wide range of coefficients of grounding (about 75 percent), depending upon the system or location in the system. Therefore these systems require individual study to ensure the most economical, secure, arrester rating selection.

Many high-voltage transmission systems may exhibit coefficients of grounding as low as 70 percent, and certain multigrounded four-wire distribution systems may be even slightly less. A recent IEEE Working Group [3] proposes open-wire four-wire multigrounded distribution systems use arresters with minimum rating of 1.25 times line-to-neutral (nominal) voltage, and similarly a 1.50 factor for same type systems utilizing spacer-cable construction. Based upon a 1.05 operating voltage regulation factor, this corresponds to coefficients of grounding of 69 and 84 percent, respectively. This working group emphasizes that the selection of arrester ratings for multigrounded distribution systems is usually based upon experience and not on system classification ratios as defined in recent industry standards [4].

A final note on arrester rating selection which is determined by maximum operating voltage and by coefficient of grounding. Maximum operating voltage may be escalated by such factors as generator overspeeds, load rejections, and resonant possibilities. Also, emergency operating modes may significantly alter system grounding such as to increase coefficient of grounding. Recognition of these factors will enhance their proper evaluation in a particular installation. See Table VI for the usually selected ratings of arresters.

Selection of Arrester Class

The vagaries of lightning with its wide range of surge duties that may be imposed at random system locations introduces such a degree of probability or uncertainty that considerable latitude is found in actual lightning protective practices. Understandably then, selection of arrester class is no exception since there are wide differences in some of the protective characteristics and in the durability characteristics among the three classes.

TABLE VI
VOLTAGE RATINGS OF ARRESTERS USUALLY SELECTED FOR THREE-PHASE SYSTEMS

Arrester Rating (Max. Value of Nominal Ratings) kV rms	Maximum System Voltage, kV rms: Ungrounded Neutral System (b)	Grounded Neutral System (a)
3	2.4	4.16
4.5	4.16	----
6	4.8	7.2
7.5	6.9	----
9	7.2	12.0
12	11.5	13.8
15	13.8	18
18	18	23
21	23	27.6
25	27.6	34.5
27	34.5	----
30	----	46
37	46.0	----
48	46	57.5
60	57.5	69
73	69	----
78	----	92
84	92	----
90	----	115
96	92	115
108	----	138
120	115	138
132	121	161
144	138	161
168	161	----
180	----	230
192	----	230
228	----	230
240	230	287

(a) Uni-grounded systems require individual study and may not qualify as grounded neutral.

(b) 0.5 microfarad surge capacitors standard for systems 2.4 to 6.9 kV. 0.25 microfarad surge capacitors standard for systems 11.5 to 13.8 kV. 0.125 microfarad surge capacitor for 24 kV systems. 1.0 microfarad surge capacitor for low voltage systems.

Arrester Class Versus System Component Size: As a general guide to arrester class usage versus equipment size, the following appears to prevail as typical practice:

station class	component protection of 7.5 MVA and above and large or essential rotating machines
intermediate class	component protection of 1-20 MVA substations and rotating machines
distribution class[1]	distribution class apparatus, small rotating machines, and dry-type transformers.

Considerable overlap of these categories prevails, tending to use of higher class arrester at higher voltages.

Effectively Shielded Installations (Discharge Current Versus Arrester Class): Since excessive discharge-currents are a prime cause of arrester failure, a knowledge of the discharge-current duties likely to prevail at a given location is necessary to a secure arrester application. Fig. 5(a) provides a ready approach to the approximation of maximum discharge current for effectively[2] shielded locations. The magnitude of surge voltage

[1] Use of special low sparkover models recommended, in fact necessary, in some cases.

[2] Reference [2, sec. 3.2.1] states: "Shielding is regarded as effective, if the probability of shielding failures, or back flashes from shield wires or grounded supporting structures to the conductors, or other live parts, is so small that the risk is considered acceptable for the specific application. Effectively shielded installations have shielding against direct strokes provided for the station and for all connected lines. The lines may be shielded the whole length but shielding for at least one-half mile from the station (line end protection) is regarded as necessary."

being delivered to an arrester location via a line surge impedance cannot exceed the actual impulse insulation strength of the line. Assuming this will not be more than 1.2 times the line BIL (1.2×50 μs wave, critical flashover), then the resulting maximum surge current through the arrester is

$$i_{\text{discharge}} = \frac{(2.4)\ (\text{line BIL})}{Z_L + Z_A} \tag{6}$$

where in Fig. 5(a) E is the line BIL (1.2), Z_1 is the line surge impedance Z_L, and Z_2 is the arrester surge impedance Z_A.

At the higher discharge currents of concern Z_A is generally small compared to Z_1 and is often neglected. For example, referring to Table V, the 15-kV rated intermediate class arrester listed displays a maximum of 2.25 Ω at 20 kA discharge, similarly 18 Ω for the 120 kV rated arrester. This is very small compared to typical line surge impedance of 400 Ω. Since line BIL increases with increasing operating voltage but surge impedance does not (in fact decreases modestly), it is to be expected that discharge currents will be greater at higher operating voltage levels. A 13.8-kV 400-BIL 400-Ω surge impedance line results in approximately 2400-A discharge current as derived by the foregoing expression. Similarly, a 138-kV line will result in 5000-A conservative maximum discharge current since its BIL will be at least twice as great.

Thus it is seen that for effectively shielded installations, the arrester discharge currents are rather modest. It is unlikely that arrester discharge voltage will exceed sparkover in such installations. Note from Table V that even the 15-kV low-sparkover distribution class arrester is listed with virtually equal sparkover and discharge voltages at 2500-A discharge current. Therefore, arrester sparkover is used as basis of lightning protection coordination in effectively shielded installations. In such installations, which encompass the majority of in-plant power systems and many refinery areas, discharge current has little bearing on selection of arrester class.

Noneffectively Shielded Installations (Discharge Current versus Arrester Class): It is in the noneffectively shielded installations where the aforementioned vagaries of lightning truly affect protective considerations and approaches. Obviously, nearby direct strokes to lines and apparatus subject them to extremely high surge currents and voltages. Voltage gradients in the order of 10^{12} V/s [2] may be involved. Severe gradients also result from flashover. Extensive field measurements accumulated over many years have established a "firm" probability of surge contents in various areas of system exposure. In badly exposed rural areas (greater than 40 thunderstorm days per year), distribution class arrester discharge currents in excess of 65 kA may be found in, say, 0.1 percent of arrester locations. However, in urban areas where a greater density of arrester population exists along with more inherent shielding of surroundings, this figure drops to about 20 kA.

Similarly, arrester discharge currents associated with noneffectively shielded installations up to 138 kV are greatly reduced compared to the surge currents for lightning at such stations. Statistics and experience are such that "standard" recommendations [2] are to use 20-kA arrester discharge current for conservative lightning protection coordination for these installations. Less conservative practice may be acceptable in some cases (say coordination with arrester discharge current as low as 10 kA). However, the conservative approach would appear prudent for power systems serving sensitive high-investment petroleum and chemical installations.

There is a preference on the part of many to keep the discharge voltage of arresters below the sparkover. This provides a more uniform margin of protection throughout the duration of a surge event. This, along with the added uncertainty entailed with nonshielded installations, gravitates practice toward use of higher class arresters. This would be particularly true in the higher isokeraunic levels in which many petroleum installations often reside. The result is to use station class and intermediate class arresters as a general practice in nonshielded installations where otherwise intermediate class and distribution class arresters, respectively, would be used. Note that while both station class and intermediate class arrester discharge voltage at 20 kA may exceed their sparkover (1.2×50 μs) the station class may do so only slightly while the intermediate class may do so significantly.

Frequently Switched Applications: Switching surges, being of relatively long duration, are of particular concern in systems experiencing frequent switching. Particularly when capacitors (power factor) are connected, switching transients may impose a more severe time-current duty on arresters. Such application should utilize station class arresters. Electric furnaces (submerged arc) serving certain segments of the chemical industry involve very frequent switching (and may also involve capacitors as well) and are classic applications of this type.

Location of Arresters

The ideal location for surge arresters, from the standpoint of protection, is directly at the terminals of equipment to be protected. However, as noted previously, practical system circumstances and sound economics dictate often that arresters be mounted remotely from equipment to be protected. Sometimes, for example, one set of arresters is applied necessarily to protect more than one piece of apparatus. Even so, it will be found that the low BIL apparatus (certain dry-type transformers and rotating machines) will often require surge protective devices in direct shunt with associated insulation. It is necessary, therefore, to estimate the depreciation in protection occasioned by separation distances between arresters and protected equipment.

The traveling wave mechanics developed previously (and illustrated by Figs. 4 and 5) establish that the total (refracted) surge voltage (E_j) appearing at a junction of surge impedances is a function of the incident wave voltage magnitude (E) and the surge impedances

$$E_j = E\left(\frac{2Z_2}{Z_1 + Z_2}\right) = E\left(\frac{2}{1 + Z_1/Z_2}\right) \tag{7}$$

Therefore, for a given connected pair of surge impedances, the total junction surge voltage is dependent directly on the magnitude of E, instant by instant, as it (E) impinges on the junction. An arrester, in order to influence (reduce) the surge voltage at the junction, therefore must have a protective char-

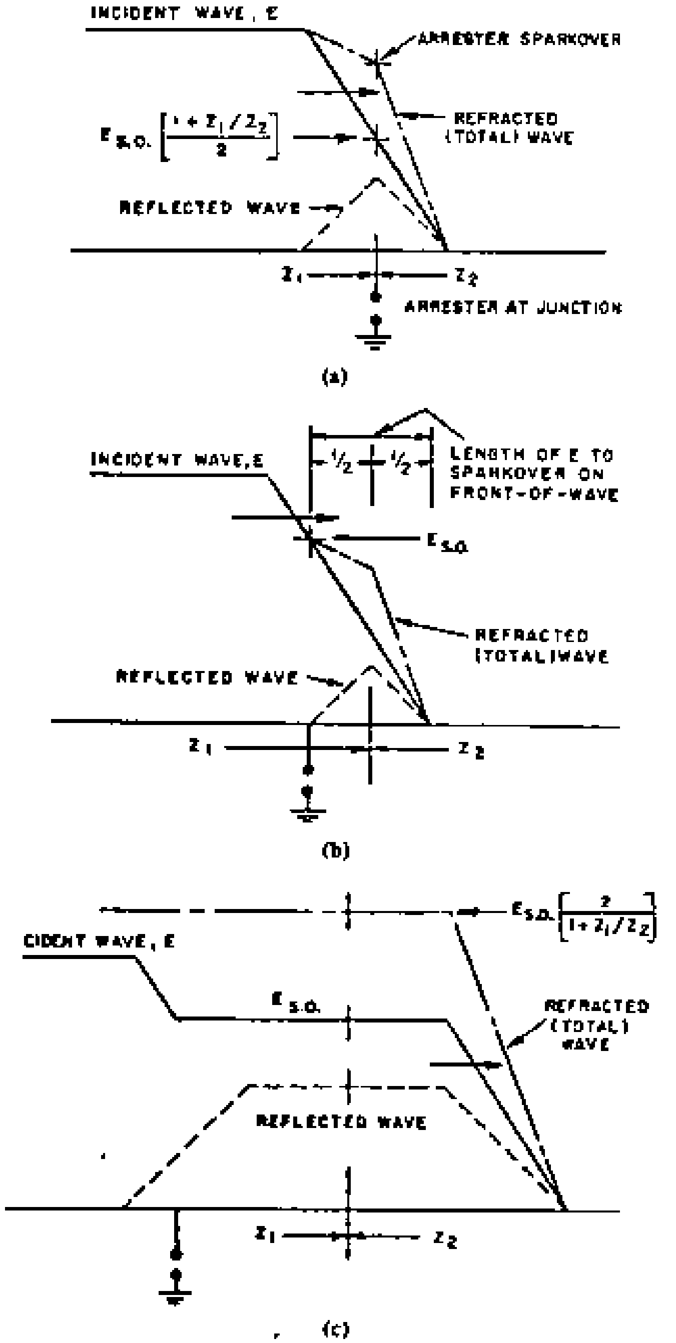

Fig. 7. (a) Junction arrester limits incident wave voltage at junction to less than arrester sparkover voltage ($E_{s.o.}$) depending upon ratio of surge impedances. This arrester location provides best protection for junction. (b) Arrester located remotely by a distance equal to length of front-of-incident wave at one-half sparkover. This is threshold location—up to this separation distance reflected wave returns in time to arrester to assist sparkover and thus reduce incident wave at junction to less than arrester sparkover. (c) Arrester is so remotely located from junction that reflected wave does not assist arrester sparkover. Wave incident to junction is permitted to reach arrester sparkover resulting in greater than arrester sparkover voltage at junction. In limiting case where Z_1/Z_2 is very small, then junction voltage will approach twice arrester sparkover.

acteristic and location such as to reduce the incident wave voltage E.

eferring to Fig. 7(a), the arrester is optimally located at the ..nction to hold its surge voltage to a minimum (of arrester sparkover). At every instant of time at this location the arrester experiences both the incident wave and reflected wave com-

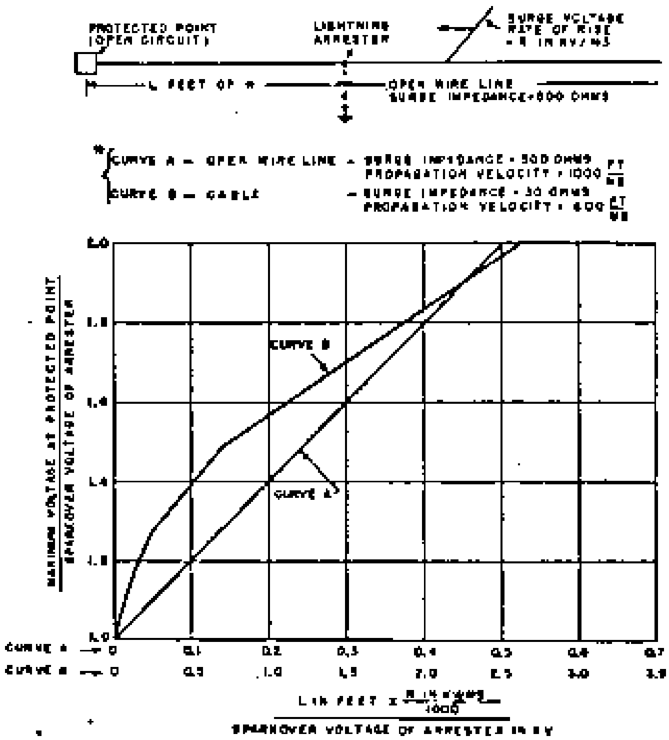

Fig. 8. Effect of separation distance between a lightning arrester and protected equipment on ratio of maximum voltage at equipment to arrester sparkover voltage.

ponents. Necessarily then, E must be held to less than arrester sparkover to accommodate this circumstance. Equating the preceding expression to arrester sparkover, E is seen to be limited by arrester sparkover to

$$E = \left(\frac{1 + Z_1/Z_2}{2}\right)(\text{arrester sparkover}) \qquad (8)$$

Z_2 (representing protected equipment surge impedance) is usually much greater than Z_1 (representing line surge impedance) therefore the incident wave is usually limited to approximately slightly more than one-half the arrester sparkover in this arrester location.

In order to hold the voltage of the wave incident to the protected junction to below arrester sparkover voltage, the arrester must be located sufficiently close to ensure that the reflected wave from the junction participates in the sparkover process. This will be found to be a distance ranging from zero up to the length commensurate with one-half sparkover on the front of the incident wave [see Fig. 7(b)]. This distance in turn depends upon the rate of rise of incident wave voltage and travel velocity. Fig. 8 illustrates the effect of separation distance between surge arrester and protected equipment for specific sets of surge impedances and wave travel velocities associated with line and cable circuits and may be used for estimating purposes.

Fig. 7(c) illustrates the case of an arrester remotely located from the protected junction. It is seen that the reflected wave is, in this case, delayed by travel time in getting to the arrester and does not contribute to arrester sparkover until the incident wave has reflected fully at the protected junction. The incident wave arriving at the junction cannot be reduced below sparkover voltage in the arrester remote location. As a limit the junction voltage will approach twice the arrester sparkover voltage since the arrester at its location will limit the incident wave voltage to its sparkover level.

More specific comments on recommended practices relating to arrester location is provided in the following discussion on protection of certain system components.

Specific System Component Protection

While actual lightning protective practices may necessarily vary from one type of installation to the next, the most basic categorical division relates to whether the installation is effectively shielded or noneffectively shielded. There are, of course, different degrees of jeopardy that may prevail in each of these two basic categories, indeed, such variation may occur with change in system arrangement or operating mode. In any case, common practice is to provide a safety factor of protective margin between established impulse capability of apparatus insulation and the protective level provided by arresters. This protective margin, expressed (as a percentage) is commonly defined as

$$\left(\frac{\text{apparatus insulation withstand}}{\text{surge arrester protective level}} - 1\right) 100.$$

The generally recommended protective margin to be observed is 20 percent for impulse coordination (front-of-wave, full wave) and 15 percent for switching surge coordination.

Effectively Shielded Substations

Reference [2] describes effectively shielded installations as having "...shielding against direct strokes provided for the station and for all connected lines. The lines may not be shielded the whole length but shielding for at least one-half mile from the station (line end protection) is regarded as necessary."

Shielding of immediate outdoor substation areas is usually provided by masts, or equivalent, which are designed to form a protective zone within which all vulnerable parts will lie. With a single mast the protective zone is usually considered to be a cone having its apex at the top of the mast and whose sides make an angle with the vertical of 30°–45°. With two or more masts the protective zone of each is increased somewhat in the area between them. This may be considered as an increase in the angle (made with the vertical) of the side of each protective cone which lies between two masts. With the usual spacings between masts, this angle may increase to 60°.

The incoming lines' shielding is provided by overhead ground wire that is grounded at each pole through as low a ground resistance as it is practicable to obtain, and it should be connected to the ground bus at the substation. Low ground resistance is particularly important for the ground connection at the first few poles adjacent to the substation.

In addition to proper shielding against direct strokes, substation equipment should be protected against voltage surges entering over the incoming lines by the proper application of lightning arresters. Typically, a set of arresters is required on each exposed overhead line as it enters the station to provide protection to disconnecting switches, buses, etc. Whether or not these arresters will also protect the transformer depends upon the system voltage, method of grounding, and circuit distance between the arresters and the transformer. It may prove necessary to install an additional set of arresters at the transformer. Assessment of such need may be made with the assistance of aids such as Fig. 8. It will be found that usually rather significant separation distances can be tolerated (say 75-200 ft—sometimes more) for station equipment 23 kV and above with full BIL insulation. For equipment in the 15-kV class and below, actual practice usually has been to avoid any appreciable separation distance. Low BIL dry-transformers and rotating machines require special attention, even in shielded environments.

Noneffectively Shielded Substations

Arresters should be applied at or very close to terminals of transformers in noneffectively shielded substations. Such substations are likely to be small, low-voltage (up to and including 34.5 kV primary) installations entailing relatively simple circuit arrangements—often only one incoming exposed line and/or one secondary exposed circuit. In such cases incoming line arresters may suffice to protect the transformer if a minimum of circuit length is devoted to associated overcurrent protection and switching equipment (breaker or fused switch, for example).

When a number of circuits are involved, the lightning-produced surge duties are divided among them in inverse proportion to their surge impedances and in general the hazard is reduced. Therefore, protective coordination should be established on the basis of the minimum number of circuits in service. Also, it is important to insure that sensitive apparatus is not left isolated (from its surge protection) as a result of sectionalizing to accommodate an unusual operating condition.

Since noneffectively shielded applications entail a much higher surge exposure, it is most important that the lowest practical ground resistance be obtained and that circuitous connections between arrester ground and terminal and protected equipment conducting frame be avoided. Short ground interconnections between these two points are often employed to place arrester in closest practical shunt with insulation to be protected.

Metal-Clad Switchgear

Metal-clad switchgear installed in substations should be protected in similar fashion to that implied in the foregoing for transformers as BIL's of the two types of equipment are somewhat comparable. Often metal-clad switchgear has a limited exposure, that of a length of cable intervening between the metal-clad and exposed line. Where the cable is of continuous metallic sheath, Fig. 9 illustrates this case and provides a guide as to the possible need for an arrester at the metal-clad switchgear. Note that an arrester is required at the line cable junction in any case to protect the cable. With arrester characteristics comparable to those listed in Table V, it will be found that arresters are not required at the switchgear for any length of continuous metallic sheath cable except in certain cases when standard distribution class arresters are used at the line cable

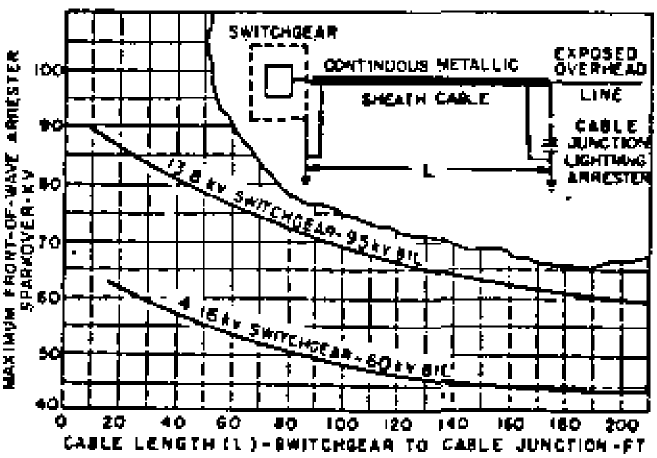

Fig. 9. Curves showing maximum permissible length of cable for which arresters are not required in metal-clad switchgear versus line-cable junction arrester sparkover voltage.

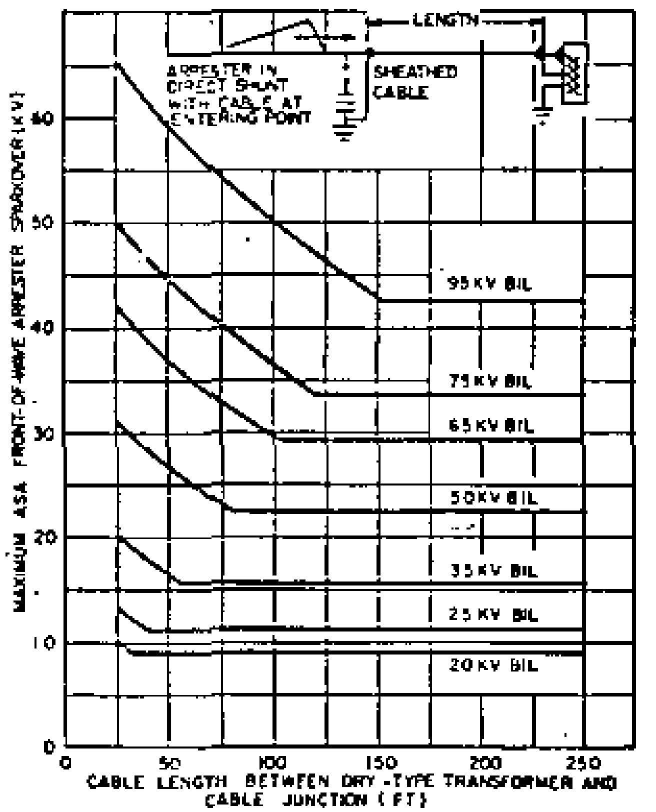

Fig. 10. Curves for determining maximum permissible length of cable for which arresters are not required at dry-type transformer versus line-cable junction arrester sparkover voltage.

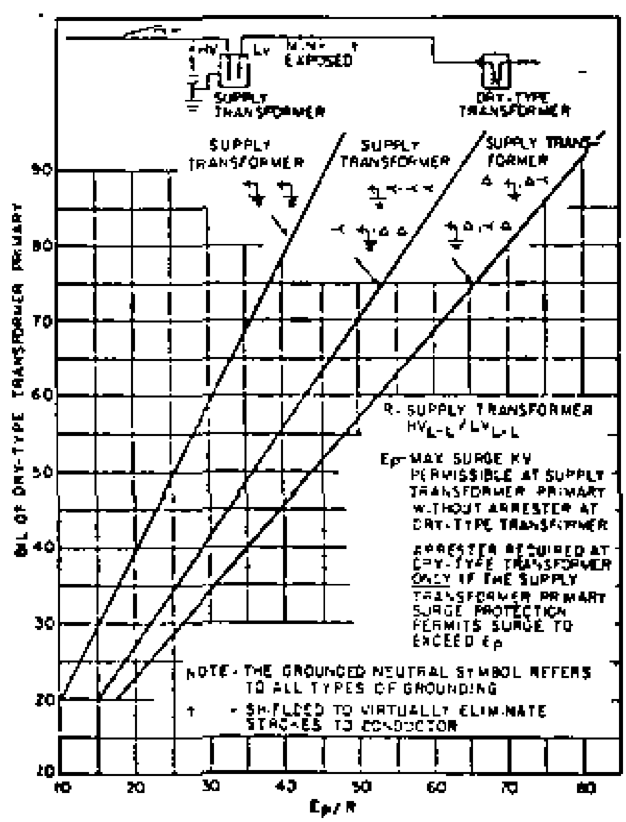

Fig. 11. Curves showing maximum surge permissible at supply transformer without requiring arrester at dry-type transformer.

junction. In these relatively few cases a distribution class arrester at the switchgear will suffice.

Nonmetallic-sheathed cables have higher surge impedances than metallic-sheathed cables and their use necessitates the use of arresters at the switchgear (distribution class will suffice). However, the installation of a neutral or ground wire in the duct with each three-phase nonmetallic-sheathed cable provides very nearly the same surge impedance as continuous-metallic-sheathed cable and may be so considered for surge protective purposes.

In many industrial installations the only exposure of the metal-clad switchgear to lightning may be through a power transformer. When the power transformer has adequate lightning protection on the exposed side opposite the switchgear, there is generally no necessity to provide arresters on the sheltered side of the transformer connected to the switchgear. Experience has shown that for the transformer sizes normally encountered in unit substations there is usually not enough surge transfer through the transformer to be harmful to the metal-clad switchgear.

Dry-Type Transformers

Dry-type transformers present relatively difficult lightning protective problems due to their usual low BIL's compared to liquid-filled transformers. When surge exposure is by direct-connected overhead lines, arresters are required in direct shunt of the dry-type transformer.

Regarding applications of surge exposure through cable, Fig. 10 applies for dry-type transformers in the identical fashion that Fig. 9 applies for metal-clad switchgear. With arresters comparable to those listed in Table V it will be found that in many practical applications, even in this relatively shielded environment, the line-cable junction arrester will not protect dry-type transformers against lightning-produced traveling waves. Where an arrester is required at the transformer, a special low-sparkover distribution class will suffice.

A somewhat less severe, though typical, surge exposure for dry-type transformers is through another (supply) transformer (see Fig. 11). Any surges impinging on the primary side of the supply transformer will be mollified somewhat as they are transferred through the transformer to appear on its (the supply transformer) secondary. For the most used wye-delta and delta-wye connected supply transformers, arresters are generally not required at the dry-type transformer.

Overhead Line Protection (4 kV–69 kV)

Historically, relatively little consideration has been given to the protection of open-wire overhead line insulation. This often results in line insulator flashover which must be cleared by a protective device, which in turn results in a momentary or extended circuit interruption. Both the high gradient associated with insulator flashover and service interruption are associated disadvantages of considerable significance to sensitive petroleum and chemical plant equipment and loads.

Analytical and test-model studies relating to overhead transmission and distribution circuits [5]–[7] have disclosed a so-called predischarge current effect in association with strokes to lines which in effect tends to suppress surge overvoltages at midspan and concentrate them at grounded poles. At grounded poles there is opportunity to install surge arresters on all phases so that voltages stresses are relieved by the arrester protective characteristics and thus prevent flashover of line insulators. A comprehensive coverage of the study techniques and results are embodied in the preceding referenced task force reports. Suffice to state here, study results and actual utility company experience show that arresters protecting each phase, at economically spaced intervals along the line, will often give improved protection and reliability of service over that of the overhead-wire-shield method. This new approach to line protection is also much less sensitive to footing resistance.

There is a growing practice among electric utility companies to use the foregoing approach in protecting overhead circuits in the range of 4–69 kV. This should certainly be a consideration toward improving protection on overhead circuits within the chemical and petroleum complex or on their utility supply lines.

Aerial Cable

Aerial cable is almost universally protected against direct lightning strokes by grounding the messenger and sheath at every pole through a low value of ground resistance. This is to allow a lightning stroke to the messenger to drain off by current flow to earth without causing the voltage of the messenger and sheath to rise excessively above the voltage of the cable conductors. If an aerial cable joins an open-wire line, lightning arresters should be installed at the junction to protect the cable insulation against lightning surges which arrive over the open line. The ground terminals of these arresters should be connected directly to the cable messenger and sheath as well as to ground.

Since the voltage and current surges produced in the messenger of aerial cable by lightning stroke to the messenger result in voltage and current surges in the cable conductors, it is generally recommended that aerial cable be considered the same as open-wire lines as far as the protection of terminal equipment is concerned.

Rotating Machine Protection

The basic winding design pattern of motors and generators involves rather large capacitance coupling between the conductor of the winding of each coil and the grounded core iron which surrounds it. A fast rising surge voltage at the motor terminal lifts the potential of the terminal turn, but the turns deeper in the winding are constrained (by this relatively large capacitance from coil to ground) and delayed in their response to the arriving voltage wave. The result is a greatly accentuated voltage gradient across the end-turns of the terminal coil which appears as severe voltage stress on the turn-to-turn insulation of the terminal coil. It is the protection of the turn insulation which becomes critical in avoiding failure in multiturn stator windings of ac motors and generators.

Machine Winding Impulse Strength: It has already been observed that there are no established impulse standards on the insulation structures for ac rotating machines. However, in the motor area there is evidence of unofficial endorsement of the acceptability of a voltage wave at the motor terminals which rises gradually to a maximum level at a rate not exceeding 1.25 times the crest value of the one minute hi-pot test voltage in 10 μs. It is not possible, practically, to devise a protective circuit which will result in a linear voltage rise from zero to crest at the motor terminals as indicated (by the dashed volt-time line) in Fig. 12. There are limiting inductance values present in the protective circuits which allow an initial steep-front step in terminal voltage followed by a moderate gradual rise from this initial shelf to the final crest value. Therefore, respectably sound motor coil insulation structures have a recognized capability to tolerate step voltage (zero time front) surges. There is a rather broadly based concensus that the motor coil structure should be capable of withstanding an initial step in voltage at least as great as crest of the normal line-to-neutral operating voltage. The character of the resulting time-voltage boundary is defined by the solid continuous volt-time lines in Fig. 12. It is on this basis that many motor surge protection recommendations have been made in recent years, in the absence of an industry standard definition of impulse capability.

Rotating Machine Surge Protection Practice: Much documentation exists relating to the surge protection of rotating machines. Recommendations are practically unanimous in requiring: 1) a strictly effectively shielded environment, 2) arresters at terminals of machine, 3) surge capacitors at terminals of machine, and 4) strict adherence to good grounding practices.

Effective shielding requirements for stations have been defined previously, and, in case of involvement with overhead line exposure, either direct or through intervening equipment (such as reactors, transformers, or cables), arresters are also applied out on the exposed lines a distance of 1000 to 2000 ft to further reduce surge magnitude duties on the more immediate surge protection equipment.

Refer to Table V for arrester ratings and characteristics. Station class, intermediate class, and special distribution class are suitable, depending on importance and size of machine. Station class arresters are used for the vast majority of appli-

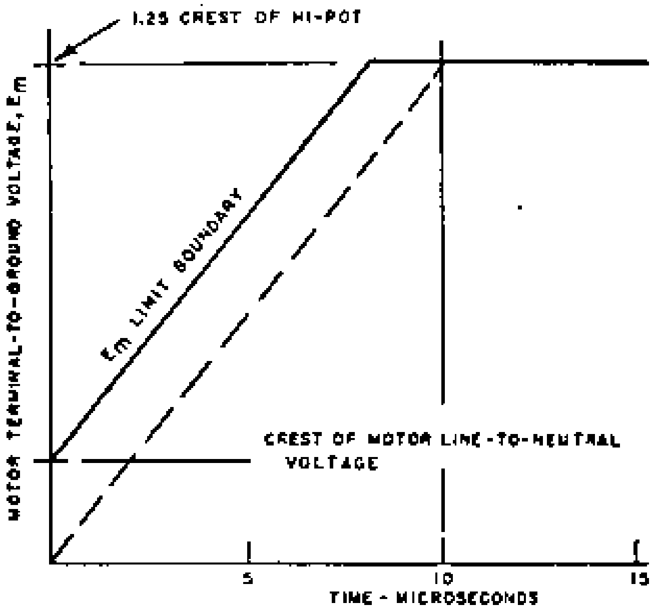

Fig. 12. Definition of motor impulse capability boundary used to assess adequacy of motor surge protection.

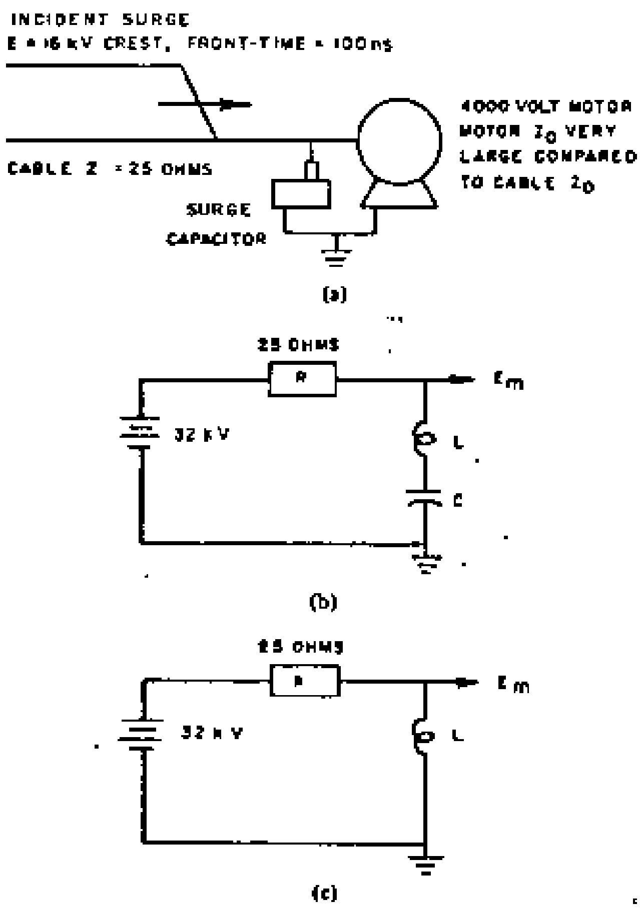

Fig. 13. Application of lumped constant equivalent to evaluate effect of inductive lead connections to surge capacitor on motor.

cations. Surge capacitors play a vital role in surge protection of rotating machines. They should be connected in the closest possible shunt relationship with the machine insulation (line to ground), as the following discussion will emphasize.

Actual practice indicates a very high percentage of motors above 4000 V are provided with arresters and surge capacitors. Similarly, at least half of the 4000-V motor installations are so equipped, while 2300-V are so equipped in only a minority of applications.

Special Care Required for Proper Installation of Surge Capacitors: Exploratory observations confirm the presence within "shielded" environments of voltage transients which approach arrester sparkover magnitudes and which have exceedingly steep fronts (0.1 μs front-time). Although lightning does not usually entail such steep fronts, certain switching events do; for example, insulation breakdown, capacitor switching problems, or discharge of high lightning current to ground. As established previously, separation distance between protective equipment and apparatus to be protected invokes (sometimes serious) depreciation of protection. This is particularly true when step wavefronts are involved.

Fig. 13 will illustrate a specific case of a surge occurring at a motor which has a surge capacitor connected to its terminals through lead inductance (L). Applying the principles of Fig. 5 and its related traveling wave dissertation, this physical arrangement may be represented as in Fig. 13(b). Here it is assumed 1) arrester sparkover is 16 kV, 2) motor surge impedance high enough to be considered an open circuit, 3) standard 0.5-μF surge capacitor with lead inductance of L henries, and 4) 100-ns wavefront. With these parameters it is evident from (5) that the capacitor cannot possibly charge to a significant voltage (only 260 V) in 100 ns even with a step function voltage. Therefore, during the initial critical 100 ns the capacitor may be considered removed, resulting in the equivalent of Fig. 13(c). This is a line terminated in inductance which, as developed previously (4), responds initially to a surge like an open-circuit and later like a short-circuit termination. Thus during the very critical short period of time associated with a very steep wavefront, the lead inductance may invoke a high degree of surge capacitor isolation, rendering it practically useless at the critical time of its need.

Quantitatively, the limits of lead inductance may be determined by judicious application of (4). Note that in this equation the incident wave voltage is a zero front-time wave. A finite-time wavefront may be analyzed by approximating its front by a series of incremental steps and processing them in their proper time sequence via (4) and adding. If this is done for the illustrated example of Fig. 13, it will be found that in order to abide by the motor protection prescribed by Fig. 12, it will be necessary to maintain a surge capacitor lead inductance of not more than one-fourth microhenry! This limits the lead length to approximately one foot or so.

While there will be variances from this typical example, it does illustrate that remote connection of surge capacitors (say at switchgear or motor starter) renders them helpless in the mitigation of gradients of very steep waves often prevailing in "sheltered" plant locations. The surge capacitor should be granted the most preferred location such that it may be connected in the closest possible shunt relation with the motor terminal-to-ground insulation.

Equipment Grounding

Definition – Objective

"Grounding" as related to electric power system protection may be considered to be comprised of two basic component practices—system grounding and equipment grounding. System grounding relates to the connection of the neutral or one of the normal current carrying conductors of the power system to ground for the purpose of enhancing overvoltage and fundamental frequency overcurrent (short circuit) protection. Such connections may be effected at various points and they may be connections of no intentional impedance (solid grounding), resistance (resistance grounding), or inductor (reactance grounding). A system that is provided with no such intentional connection to ground is said to be "ungrounded" but it is in fact capacitively grounded through the distributed capacitance to ground of the various system and load components.

Equipment grounding relates to the manner in which (normally) noncurrent-carrying conductive parts (apparatus frames and tanks, metal conduits, etc.) are interconnected and grounded. IEEE recommended practice [10] states that the basic objectives of equipment grounding are "1) to assure freedom from dangerous electric shock voltage exposure to persons in the area, 2) to provide adequate current-carrying capability, both in magnitude and duration, to accept the ground-fault current permitted by the overcurrent protection system without creating a fire or explosive hazard to building and contents, and 3) to contribute to superior performance of the electrical system."

Definition of Equipment Grounding Terms: National Electric Code (NEC) [11] defines a number of terms which relate to equipment grounding. Some of these definitions are restated here to facilitate the ensuing discussion. The following is from Article 100.

Ground: A ground is a conducting connection, whether intentional or accidental, between an electrical circuit or equipment and earth, or to some conducting body which serves in place of the earth.

Grounded: Grounded means connected to earth or to some conducting body which serves in place of the earth.

Grounded conductor: A system or circuit conductor which is intentionally grounded.

Grounding conductor: A conductor used to connect equipment or the grounded circuit of a wiring system to a grounding electrode or electrodes.

Grounding conductor, equipment: The conductor used to connect noncurrent-carrying metal parts of equipment, raceways, and other enclosures to the system grounded conductor at the service and/or the grounding electrode conductor.

Grounding electrode conductor: The conductor used to connect the grounding electrode to the equipment grounding conductor and/or to the grounded conductor of the circuit at the service.

The following discussions will use the term "equipment grounding network" or "grounding network" which will include all of these defined conductor types. Since many conductive components that find themselves in the equipment grounding network (either direct-connected or by magnetic coupling) exist for primarily nonelectrical reasons, they may be overlooked as possible current-carrying members. It is important that these equipment ground network components be connected such as to display the time-current capability required of a grounded conductor. Inadequacies in junction conductivity will not be manifested until a ground fault occurs.

Current Distribution in Equipment Grounding Network

Economical realization of the objectives of equipment grounding can be attained only by an understanding of the nature of current distribution in the equipment ground network. Historically, certain misconceptions prevailed which resulted in a false sense of achievement of these cited objectives. Inadequate provision of current-carrying ability in certain conductive grounded components resulted due to nonrecognition of the magnitude of current that may flow through them under fault conditions.

When a single line-to-ground fault occurs on a grounded power system the path of fault current flow is "out" via insulated phase conductor to the fault and "back" (return) through the equipment ground network to the (system) grounding conductor. The equipment ground network generally offers a number of paths for the return fault current, each with a specific (different) resistance and reactance. These circuits characteristically exhibit X/R ratios such that the reactance greatly predominates in its effect on current distribution as compared to resistance.

The reactance exhibited by an enclosed circuit (such as the fault loop) is a function of the magnetic flux enclosed by (or "linking") the loop. The smaller the area enclosed by the loop the less the flux enclosed and therefore the lower the reactance. Those paths in the equipment grounding network which are in closest proximity to the power conductors result in minimum fault loop area, therefore also least reactance and consequently carry most current. Thus there is good reason to believe that current flow in the equipment grounding network will adhere very closely to the power conductors over which the outgoing current flows. Accordingly, the equipment grounding paths closest to the power conductors must be sized to carry essentially the entire time-current duty permitted by the overcurrent protective devices without thermal or mechanical distress. Note that the mode of system grounding has little to do with this requirement. Equipment grounding paths installed remotely from power circuits are relatively ineffectual and may indeed be wasteful.

Conducting conduits and raceways are of prime importance and concern in the equipment grounding network. Because of their adjacency to the power cables they will carry a very high percentage of the ground fault current. Based upon a series of tests involving conventional heavy-wall steel conduit [12] it was found that the conduit returned between 90 and 100 percent of the fault current, the more remote "outside" paths carrying the small remainder. An internal grounding conductor in the conduit, however, being of slightly less reactance, very effectively shares the return current (generally 50 percent or more) with the conduit. Therefore if the conduit does not have the thermal capability to carry the anticipated maximum fault return current an internal grounding conductor is effective in reducing the current in the conduit wall. See NEC [11, article 250-95] for internal (to raceway) equipment grounding conductor requirements.

Control of Voltage Gradients in Equipment Ground Network

The flow of a given current through the various ground paths produces a voltage gradient in them that is proportional to their respective impedances. Thus minimizing the equipment grounding network impedance reduces the associated voltage gradients and therefore enhances attainment of one of the important equipment grounding objectives—that of eliminating dangerous electric shock voltage hazard to people. The requirement becomes one of maintaining sufficiently low grounding network impedance to accommodate full magnitude of ground fault current without producing dangerous impedance (IZ) voltages. The key factors in controlling the grounding network voltage gradients are impedance-related (grounded conductor size, length, and spacing with respect to the phase conductors) and current-related (magnitude of ground fault current). It is the double line-to-ground fault that imposes the most severe duty in resistance grounded and ungrounded systems.

Equipment Grounding Network Effect on Ground Fault Protective System

The equipment grounding network is a vital link in the ground-fault protective system. Its impedance must not be so high as to reduce ground-fault currents below protective device sensitivity (see NEC [11, article 110-10]). This is particularly pertinent to many solidly grounded low-voltage systems which utilize relatively insensitive ground-fault current detectors. Also, the grounding network impedance may become significant compared to the low-voltage system short-circuit impedance which makes ground-fault current magnitude quite sensitive to variations in equipment network impedance.

References to Equipment Grounding Techniques Versus Class of Area Use

The foregoing has sought to provide an insight into the objectives, and approaches to attaining these objectives, of equipment grounding. Various equipment grounding techniques have been developed and documented which represent "practice" to embrace the specific needs of various system areas. References [10] and [14] in particular provide detailed guidance on recommendations relating to equipment grounding in these various classes of area use.

Connection to Earth

Since certain ground fault currents and lightning currents (direct or through arresters) flow to earth through various of the equipment ground components, the connection to earth is a most important part of the equipment ground system. With the exceedingly high current magnitudes that must be accommodated safely, the earthing connection must be of minimal resistance if safe "IR" voltages are not to be exceeded. Larger substations and generating stations involve higher currents and the associated earth resistance should not exceed 1 Ω. Similarly, 5 Ω should not be exceeded for small substations and industrial plants. NEC [11] sets the maximum resistance to earth at 25 Ω.

Arrester grounds are secured by use of driven ground rods near the arrester to an arbitrary limit of 5 Ω. Additionally, the surge arrester ground should be connected to the common station ground bus (if in or near substation). NEC [10] requires arrester ground lead of not less than No. 6 AWG.

Concrete-Encased Electrodes: Resistance to earth may be calculated or measured [10], but in any case it may be exceedingly difficult to attain desirably low earth connection resistances. Sometimes existing metallic structures such as water systems, steel piling, etc., provide sufficiently low earthing resistance. However, so-called "made" electrodes are often necessary to establish a suitable ground. These take the form of counterpoises, plates, wells, driven rods, etc. Various design and application aids are available to facilitate their use and proper application [10].

Concrete-encased electrodes have recently been introduced [15] and have evoked much interest because of their effectiveness at generally promising cost advantage. While some constructors are "watchfully waiting" to ascertain the applicability of concrete-encased electrodes, some large users report favorable experience to date. Current IEEE recommended practice [10] calls for "electrical bonding between the metal tower base plate and the rebars in buried concrete footings. This can be accomplished readily in most instances via hold-down J bolts." This use of footings is the key to the economy of concrete-encased electrodes. Installation of concrete-encased electrodes for the sole function of achieving a required low-resistance connection to ground would not be justifiable economically.

NEC [11, article 250-83(a)] recognizes concrete footings as a bona fide made electrode provided there is ". . . not less than 20 ft of bare copper conductor not smaller than No. 4 encased by at least 2 inches of concrete and located within and near bottom of a concrete footing that is in direct contact with the earth."

Acknowledgment

The author gratefully acknowledges the assistance and counsel of F. J. Shields and R. H. Kaufmann.

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ENERGY SYSTEMS

APPLICATION ENGINEERING INFORMATION

Selection of Protective Devices for Paper Mill Power Distribution Systems

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Industry Sales & Engineering Operation

General Electric Company, Schenectady, N.Y.

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GENERAL ELECTRIC

Selection of Protective Devices for Paper Mill Power Distribution Systems

W. C. BLOOMQUIST

The secret to a reliable power system is planning—and on an overall system basis, and not just groups of components connected together. The bifurcation principle as applied to power circuit arrangements is a relatively new technique in paper mills and one which can offer good system protection economically. Several diagrams illustrate the application for paper mill power systems. The reliability of the system can often be materially improved by proper attention to the application of protective devices. The use of a ground-sensor type of relay and on both low-voltage and medium-voltage systems will greatly reduce equipment and component damage on system ground faults and arcing-ground faults. Knowledge of the National Electrical Code and USA Standards rules and especially their application relating to the 2½ and 6 times rules can result in good equipment and system protection.

Keywords: Electric power distribution · Protectors · Circuit protection · Equipment Economic factors · Circuit breakers · Electric relays · Electric fuses Substations · Transformers · Short circuits

NEED FOR AN OVERALL LOOK

Process continuity has become so important to paper mills on a plain dollar and cents basis that it should be obligatory to engineer and plan power systems to avoid unnecessary shut downs either for maintenance, expansion, or equipment failure. Personnel safety, of course, is always a matter of first importance. Our observations of many mill power systems have indicated a trend toward layouts consisting of groups of components tied together rather than as an engineered system. What is lacking is planning on an overall basis (*1*). Products, system and circuit arrangements, and technical material are available to aid in designing reliable power systems (*2-7*).

All types of protective devices may have their place in the system—the choice should be made on the requirements of the system at the particular point of application. Sound economics requires an evaluation of both the effect of the system on the device and the effect of the device on the system. It is not economically justifiable to specify circuit breakers for all locations, but neither is it justifiable to specify fuses for all locations based only on an examination of first costs. In some cases the judicious combination of current-limiting fuses with breakers or motor starters is the ideal and economical arrangement.

Here again, the key is overall planning. One should start with a *one-line diagram* and the *plot plan* of loads by process areas, determine the circuit arrangements, cable sizes, etc., and then the reliability requirements and degree of selectivity. Curves are available showing the characteristics of various protective devices and the exercise of some judicious engineering examination at this point should greatly simplify the decision as to which device is required for a given location. In most cases this should not be a matter of opinion, but should be a definite clean-cut decision based on the original planning requirements.

The decision made at this point in the system planning will be of vital importance to the ultimate system. If the maximum degree of coordination and protection is desired, it MUST be provided for in the original specifications. To revise a poorly designed system after it is installed can be prohibitively expensive. The bifurcation principle,[1] which unfortunately is not well known, is a helpful tool in economically obtaining circuit flexibility and system coordination and selectivity. Examples of the use of this bifurcation principle are included in the section on techniques for improving system protection.

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Report on
Electrical Engineering Committee
Assignment No. 4056

[1] Definition: To divide or fork into two branches; as used here it means the installation of two circuits from a feeder breaker, each with its own protective relaying.

COMPARISON OF PROTECTIVE AND SWITCHING DEVICES/EQUIPMENT

The following comparison lists some of the important application considerations of fuses and breakers. This is directed to medium-voltage systems (601 v to 15 kv), although some statements are also applicable to low-voltage systems (below 600 v). This guidance along with the following discussions can help in the selection of the appropriate device.

The application areas for breakers in paper mills is well established based on the functional needs, safety, flexibility, versatility, and operating practices. The larger the power system, the more important these factors become.

Fuses and Switches

1. Fuses have initial low cost but:
   (a) Do not have switching capability alone (required in most circuits).
   (b) They are a single-phase device.
   (c) They are limited in characteristic selection (coordination applicability is limited).
   (d) They have poor adaptability to system expansion.
   (e) They require spare fuses on hand and trained personnel for replacing fuses.
2. No maintenance or testing required.

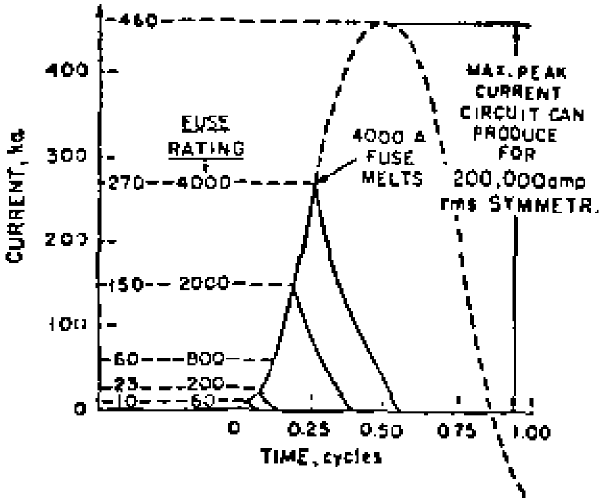


Fig. 1. Curve showing characteristic of a typical current-limiting fuse.

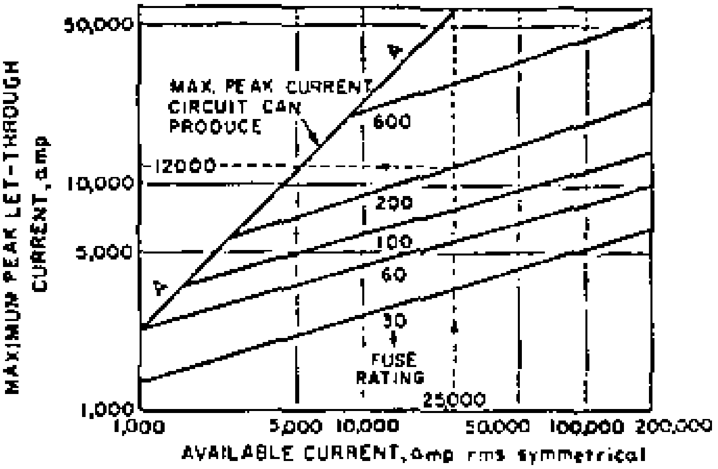


Fig. 2. Characteristic curves of maximum peak let-through current for (CLF) low-voltage fuses.

3. Fuses are fast on high short-circuit currents but:

(a) Are slow in operation on overcurrents (offers poor protection in this area).

(b) Fuses may be damaged when subjected to repeated operation at currents near their melting points (affects system coordination).

Circuit Breakers and Relays

Circuit breakers and relays:

1. Are designed and rated to be safely closed and operate at all levels of load and fault current within their rating.

2. Eliminate single-phase interruption and associated problems.

3. Protective coordination versatility is almost unlimited.

4. Repeated breaker operation will not affect its interrupting characteristics.

5. Automatic operation can be initiated by a variety of relay functions.

6. Provides flexibility in accommodating load changes. (They are designed for a variety of functions.)

7. Circuit breakers are not as fast in operation at high short-circuit currents as are most fuses but are faster than fuses at current levels of most faults.

8. Require periodic maintenance/testing.

CHARACTERISTICS OF FUSES

This discussion will pertain to current-limiting fuses since they offer so many advantages over the noncurrent-limiting type.

Figure 1 shows the outstanding characteristic of a typical current-limiting fuse; that is, it operates long before the current has reached the maximum current which a particular power system could produce under a short circuit.

The advantage of this current-limiting effect is obvious; less current means less damage which is especially important since the let-through energy is proportional to the integral of I^2t. It is this current-limiting characteristic which has permitted the marriage of current-limiting fuses with other apparatus to extend economically the rating of combinations of protective devices; typical applications are low-voltage and medium-voltage motor controllers, low-voltage molded-case and power circuit breakers, and fused switches.

Figure 2 is a plot of typical low-voltage current-limiting fuses. This clearly demonstrates the current-limiting action in terms of the fuse ampere rating. The straight line A-A is the limit where there is no current-limiting action (the "threshold" value): note that as the fuse rating increases, the fuse becomes less current-limiting; or stating it another way, the system available must increase before current-limiting action starts.

It is important to understand that a fuse in performing its current-limiting function does not simply convert one level of available short-circuit current to a lower level of basically the same type of current; instead it modifies the first major loop, as Fig. 1 shows, to a wave of current approximately triangular in shape. Also, the fuse does *not* reduce the system available duty.

The important point in this connection is: It simply is not enough to calculate the rms value of the waves and match the value to that of a breaker and then assign an interrupting value for the combination. This cannot be done for triangular waves because they have a higher peak current, a higher rate of rise and a different I^2t than a breaker in this combination. Therefore, performance data must be provided by *full-scale tests* for such electro-mechanical combinations. However, the I^2t let-through can be coordinated with such devices as switches or cables, for example.

These characteristics of current-limiting fuses suggest certain logical application areas such as:

1. Taking advantage of the current-limiting action to permit the marriage of fuses and apparatus with resulting economical equipment of high interrupting capacity. Typical of these are:

(a) Current-limiting fuses either in individual starters or in the incoming bus of motor-control centers. (The question of fuses versus breakers for operating reasons is another matter; if the operator does not want fuses and the system available is above the rating of the combination starter, other solutions such as a higher impedance transformer or a series reactor in the motor-control circuit can be used.)

(b) Extending the application range of breakers, such as power or molded-case breakers.

(c) Fused contactor motor starters on 2.4- to 4.8-kv systems of high short-circuit capacity.

(d) Extension of the rating of panelboards, for lighting systems.

2. Terminal or end loads where single-phasing may not affect other loads.

3. Small noncritical loads.

SELECTION OF FUSES FOR TRANSFORMER PROTECTION

System and circuit arrangements and protection features become closely associated with the peculiar requirements for protecting associated transformers in contrast with some other types of mill loads.

Most of this discussion will be directed toward secondary unit substation transformers although the same problems, principles, and requirements apply to higher voltage and larger power transformers. However, in medium-voltage and high-voltage power circuits, the protection problems are usually not so difficult because power switchgear equipment and relays are generally used for such main power loads. The use of relays offers considerable flexibility in simplifying system layout and protection problems.

It is important to realize that there are certain requirements needed for the application of fuses for transformer protection which generally result in oversized fuses and, therefore, poorer protection for the transformer.

Fuses on the primary of a transformer should:

1. Not blow on magnetizing current inrush, which is usually 8–12 times the full-load current, in less than 1/10 sec depending upon the transformer kva rating. For secondary unit substations, the inrush is usually taken at 8 times full-load current for 1/10 sec.

2. Protect the transformer within the USASI point (United States of America Standards Institute, which was formerly designated ASA for the American Standards Association) which prescribes that the transformer must be able to withstand without injury for specified time intervals a short-circuit on its windings. (For transformers connected delta-wye, which are so common in paper mills, use 58% of this value; this is because the primary delta-side fuse sees only 58% of the line-to-ground short-circuit current on the secondary wye-side.) Table I from USA Standard C57.12 indicates these values.

3. Meet the National Electrical Code (NEC) requirement which states the following in reference to primary- and secondary-side protection of a transformer (Article 450-3, 1965):

"A transformer having an over-current device in the secondary connection, rated or set at not more than 250 percent of the rated secondary current of the transformer, or a transformer equipped with a coordinated thermal overload protection by the manufacturer, is not required to have an individual over-current device in the primary connection, provided the primary feeder over-current device is rated or set to open at a current value not more than six times the rated current of the transformer for transformers having not more than six percent impedance, and not more than four times rated current of the transformer for transformers having more than six but not more than ten percent impedance."

Figure 3, the "necktie" curve, illustrates the zone of operation for transformer protection and illustrates how the requirements discussed previously are translated into a time-current plot. Thus, the problems of protection and coordination and associated system or circuit arrangements are interlinked, some solutions are discussed in the following sections.

To meet these protection requirements, the fuse current rating will have to be much larger than required for an equivalent nontransformer type and load, generally ranging from 200 to 300% for transformer ratings commonly used in paper mills.

Fuse standards prescribe certain time and current requirements. For example, a 100E and smaller fuse shall melt in 300 sec at a current of 2.0 to less than 2.4 of the fuse continuous current rating. Therefore, if the fuse rating is 2½ times the full-load current of the transformer and meets the fuse standard criterion of two times rated current for 300 sec, that means the fuse shall not melt in less than 300 sec (5 min) at five times rated transformer full-load current. In other words, the overall protection of a transformer by a fuse is not good, nor is it claimed to be: a fuse should be considered as primarily for short-circuit and not overcurrent protection. Manufacturers' selection tables indicate the ampere rating of fuses for various transformer kva ratings and are a handy time-saving reference.

Obviously because of the fixed time-current characteristics of a fuse, coordination of primary fuses with low-voltage feeder breakers and a main transformer-secondary breaker becomes difficult. In some cases this may limit the system selectivity because of the restrictions on feeder breaker current ratings in relation to the transformer full-load current.

SERIOUS PROBLEMS INTRODUCED BY SINGLE-PHASE OPERATION OF FUSED SUBSTATIONS

The discussion of single-phasing covered here is not the overload problem associated with an individual motor circuit, but the overall problem when for some reason a fuse on the primary of a load-center transformer or service-entrance supply opens. However, this is not to say that

Table I.* USASI Values

Percent Z	*rms symmetrical short-circuit current to be withstood*	*Time, sec*
4 or less	25 times rated current	2
5	20 times rated current	3
6	16.6 times rated current	4
7 or more	14.3 or less times rated current	5

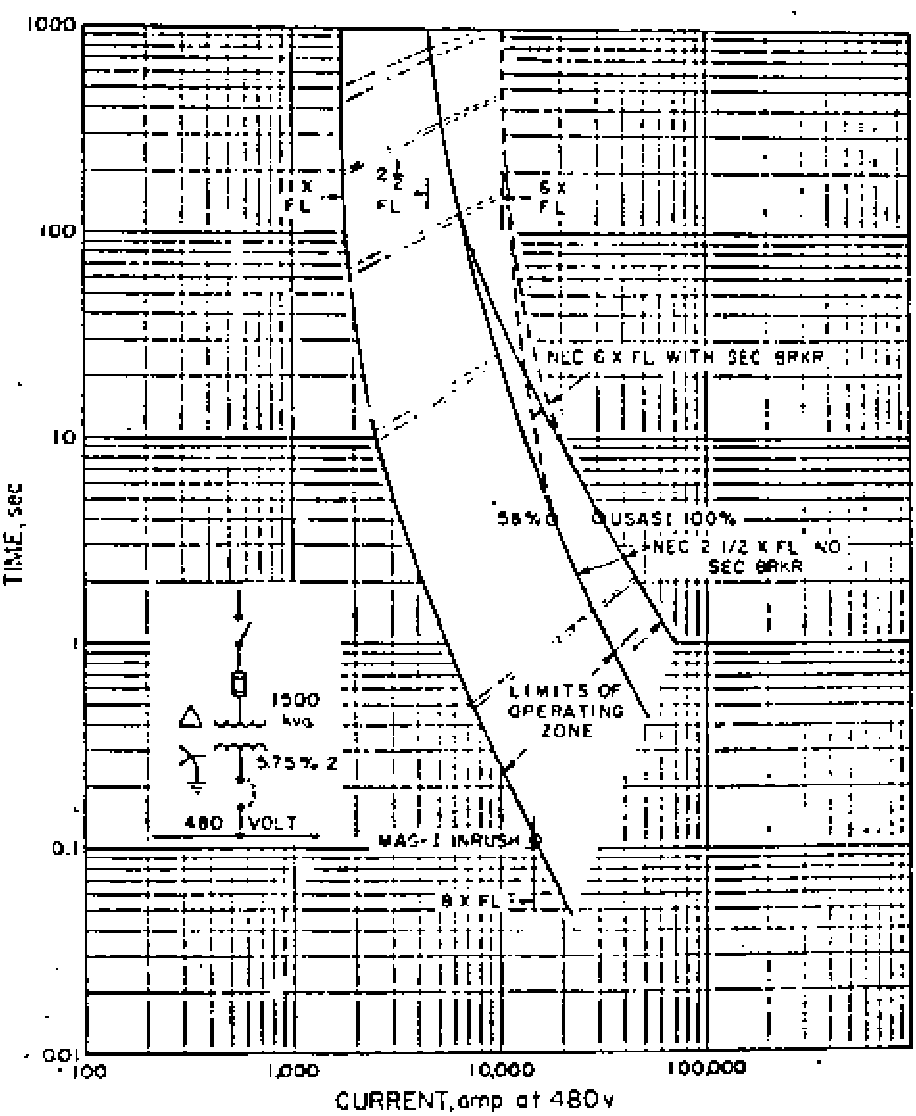


Fig. 3. Zone of protection for a transformer primary protective device. (Plotted in secondary current for convenience.)

Fig. 4. Transformer-secondary breaker destroyed by an arcing fault in a low-voltage switchgear section.

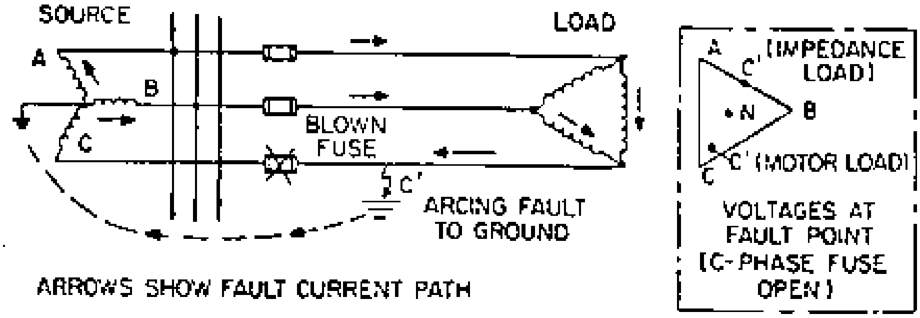


Fig. 5. Illustration of how reduced fault current may flow to an arcing fault after a fuse has blown.

there are not problems relating to motor operation and single-phasing. For example, a rather classic case was the loss of 1400 motors in a textile mill due to the single-phasing of the fused incoming service.

However, this is not to say that fuses do not have a place in power system work. The characteristics of current-limiting fuses suggest certain logical application areas: small or noncritical loads, terminal or end loads where single-phasing may not affect other loads, typically a motor application; or taking advantage of the current-limiting action of the fuse to permit the marriage of fuses and apparatus with resulting economical equipment of high interrupting capacity. Straightforward applications are *single-phase* 2- or 3-wire distribution for small loads in industrial or commercial buildings on single-phase branch circuits or 4-wire, 208Y/120 v or 480Y/277 v systems. The key here is that in single-phase circuits, a blown fuse automatically de-energizes the circuit.

Single-phasing of substations is a relatively recent problem. The question is, What is significant about the timing? In the early days of the introduction of the load-center principle of distribution, primary fuses were seldom used; in fact, power fuses were avoided in the planning stage whenever possible.

It was not until relatively recently when power fuses on the primary were being substituted in place of transformer-secondary breakers for overcurrent protection on secondary unit substations that troubles arose. It was the investigative analytical work of Kaufmann (*8*) that cleared up this area. Figure 4 is a photograph of a typical burndown of low-voltage equipment. These burndowns have been numerous with the destruction of unit substations, motor-control centers, busway, switchboards, and panelboards in equipments of all manufacturers, in clean and dirty atmospheres, and in commercial and industrial plants—in other words quite universal. These burndowns have occurred in low-voltage and medium-voltage systems, but have been more frequent on low-voltage systems because of the nature of the system circuit arrangement and type of equipment.

Usually the sequence in operation is something like this: An arcing fault starts in the equipment on the low-voltage side for one of a variety of reasons; since low-voltage equipment does not employ isolated phase construction with insulated buses, an arc flash will involve all phases rather promptly. The magnitude of this fault is large enough to open a fuse such as fuse *C* in Fig. 5, but note that this does not shut off the power. It does change the circuit characteristics so that much less current flows, according to Kaufmann and Page (*9*). In a 480-v system this may be reduced considerably and less than the full-load three-phase fault current and may be below the pickup value of the protective device. Note, too, that even if fuse *B* opens, the system is still "hot." The burndown or melting action is caused by the continued arcing at the point of the fault which releases a tremendous amount of energy in the faulted area. It is important to understand that burndowns can be much more damaging than the usual short circuits encountered in power system operation. The ordinary short circuit results in a shutdown of the circuit involved, but the damage is generally localized and the fault itself is promptly removed by the circuit protective device.

One obvious solution is a proper protection scheme. Since practically all faults on low-voltage systems quickly involve ground, a ground-fault sensor to trip the main transformer-secondary breaker or backup breaker can be used. Such ground-fault sensors are sensitive and operate quickly to open the power sources. Shields (*10*), Conrad and Dalasta (*11*), and Hoffman and Reifschneider (*12*) describe such protection which is now becoming common on low-voltage grounded systems.

The use of a three-phase interrupter would help reduce the amount of damage by opening all phases promptly. Various techniques for avoiding such single-phase problems are suggested in the section on techniques for improving system protection.

TRANSFORMER-SECONDARY BREAKERS—PRO AND CON

Paper mills vary in their use of transformer-secondary breakers—some do and some don't use them. The following may serve as a guide to the selection for a transformer-secondary breaker. Advantages are the following:

1. It offers greater latitude in providing overcurrent protection for transformers as required by the NEC (Art. 450-3); this in turn makes coordination of the primary and secondary protective devices much easier and allows the use of larger feeder circuit protective devices.
2. It provides fault protection for the main bus in conjunction with ground-sensor relaying.
3. It permits adoption of the secondary-selective arrangement which is especially useful (a) in providing power to critical or important loads and (b) in providing power and lighting during shutdowns for maintenance.
4. It provides backup protection in the event of failure of down-stream devices.
5. It provides a disconnecting means for maintenance purposes and safety.
6. The main secondary breaker provides the function of overcurrent protection for the transformer.
7. It provides fast removal of loads (NEC requires a single disconnecting means when there are more than six feeders per bus section).
8. It provides a simple method of key-interlocking low-voltage breakers with the transformer primary switch.

Some disadvantages are the following:

1. It usually results in higher cost, but this depends upon the skill in selecting the circuit arrangement. (This may be offset as described in the following section.)

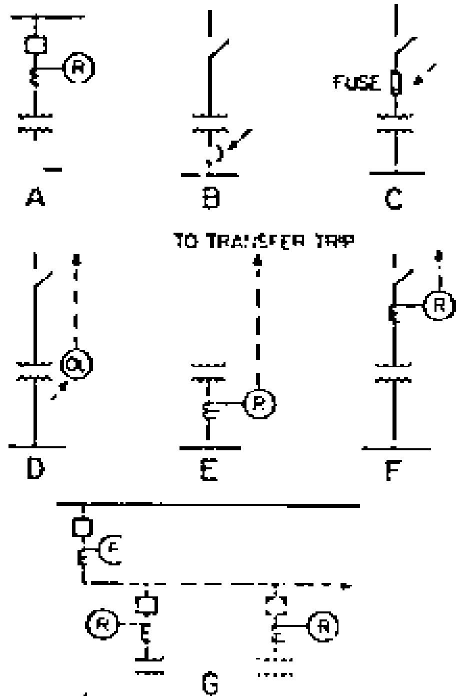


Fig. 6. Protection methods meeting the National Electrical Code requirements for overcurrent protection.

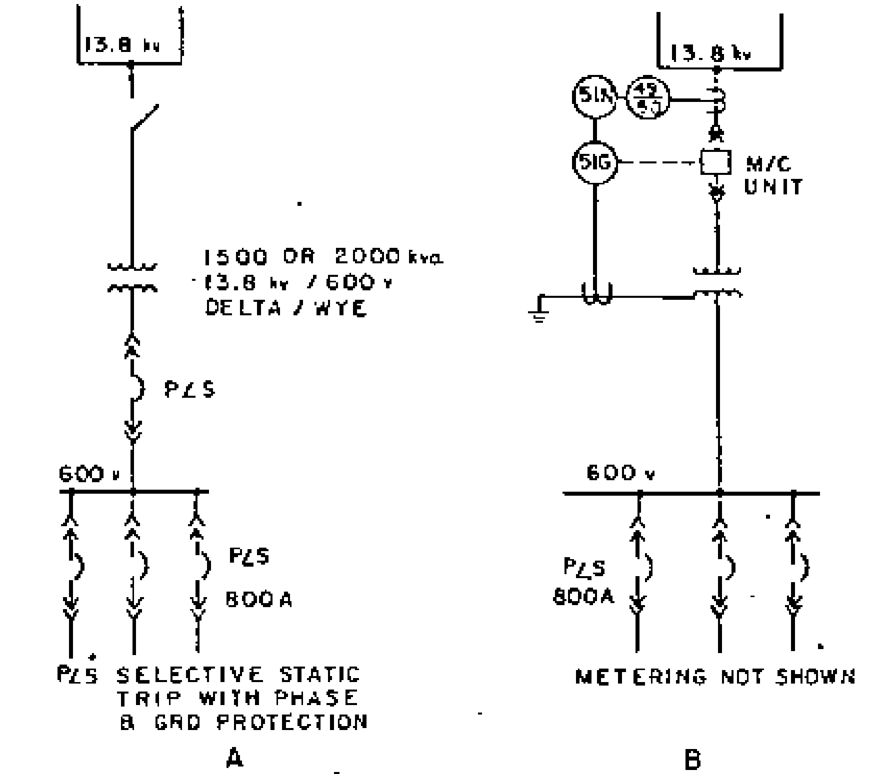


Fig. 7. Two arrangements for system protection (see Table II for cost comparison).

2. It results in greater space requirement of low-voltage switchgear equipment.

Table II. Price Comparison for 13.8- and 4.16-kv Service

Unit substation rating, kva	*Fig. 7A Prim. switch & trans.-sec. breaker, $*	*Fig. 7B Prim. M/C breaker, $*	*Cost difference, $*	*B vs. A, %*
		13.8-kv Service		
1500	25,715	26,535	+820	+3.1
2000	28,330	29,150	+820	+2.8
		4.16-kv Service		
1500	25,430	24,740	−690	−2.8
2000	28,046	27,355	−690	−2.5

...CHNIQUES FOR IMPROVING ...TEM PROTECTION

...lection and the 2½-Times Rule

According to the National Electrical Code wording in the section "Selection of Fuses for Transformer Protection"; the requirement of transformer overcurrent protection is met by any of the arrangements shown in Fig. 6.

The choice from an overall standpoint would probably favor methods A or B. Method C with its limitations has already been covered. Method D, a winding temperature or equivalent sensor, has not been used very often, except for alarm purposes, probably because of the transfer trip requirements. Method F would be preferred over E in that transformers of any size and number could be connected in a feeder circuit as each transformer is protected individually. Method A or G is ideal when individual breakers are used for power transformers, but is seldom economical for small secondary unit substations because of cost.

Method A or G becomes economically attractive for large secondary-unit substation transformers, say 1500 kva and larger. Figure 7 shows the switching arrangement of two methods investigated by a well-known consulting engineering ... to the paper industry. Table II gives the cost comparison of only the equipment for 13.8-kv service based on askarel-filled transformers and indoor fully rated switchgear. Also included, but not shown in these sketches in the interest of simplicity, were PT's, voltmeter and watt-hour meter, as well as CT's and ammeters on feeder circuits.

Since there was such a small price differential the consultant recommended and the client accepted the primary breakers method of Fig. 7B. (For a 4.16-kv system, the breaker method of Fig. 7B is favored by a few percent. It would be even more favorable on a "weak" system, which could use a 75 Mva breaker.)

A modification of Method A of Fig. 6 using the bifurcation principle as described later and shown in Fig. 8 makes the main primary breaker method attractive.

Methods D, E, and F require a transfer-trip circuit to the particular main feeder circuit breaker. This may or may not be an additional expense, trading the cost of a trip circuit for the savings in primary fuses or a secondary breaker. Paper mills can expect to incorporate more "control" circuits to central points: for example, sensors, process controllers, and data

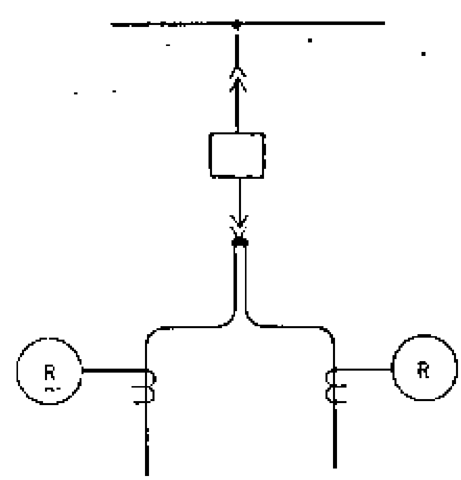


Fig. 8. Diagram illustrating the bifurcation principle.

channels associated with computer installations; remote control of many devices, remote measurements, and eventually all major power functions involving control

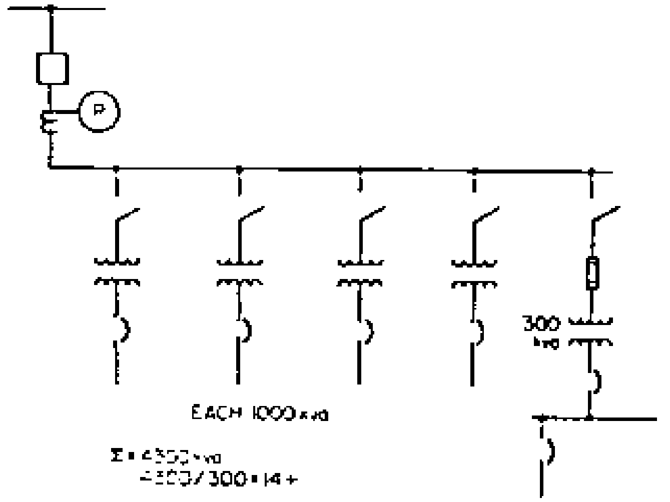


Fig. 9. A circuit illustrating a practical and economical application of fuses.

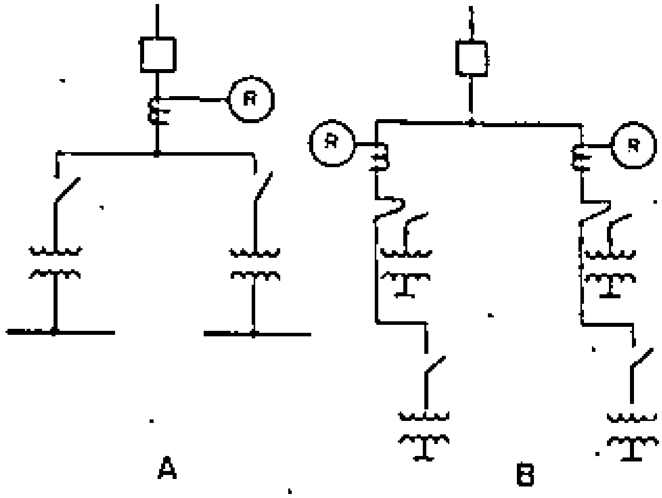


Fig. 10. Illustration of how easily a power system can be expanded via bifurcation.

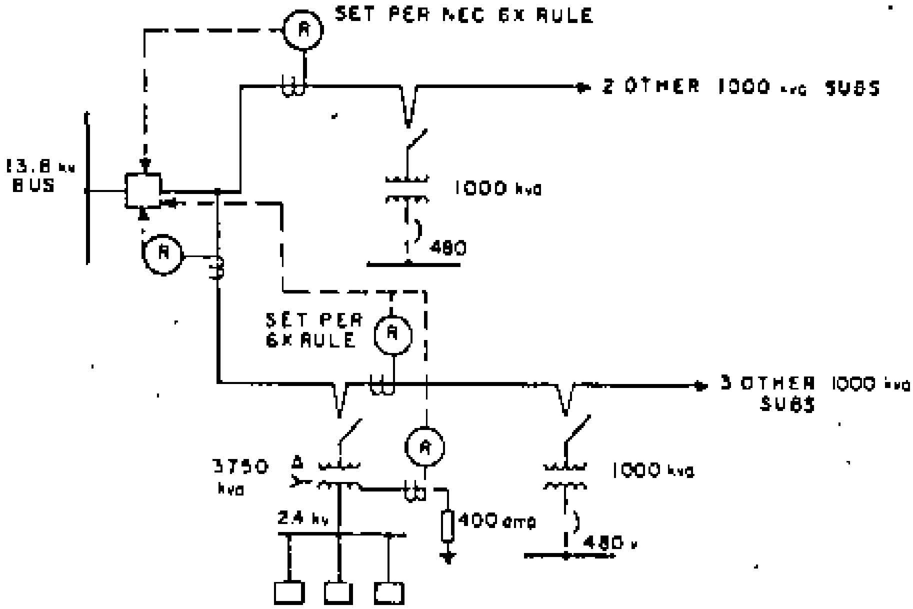


Fig. 11. Illustration of how one paper mill employed the bifurcation principle.

and information data will be fed into a centralized computer or operating point. Therefore, control circuits for such protective functions as in D, E, and F should be considered as current practice.

The remote trip circuit will be needed for arcing-ground fault protection and ground relaying. Obviously, in a given substation area several relay outputs can be fed into a single trip circuit to its common feeder breaker.

Primary Protection and the Six-Times Rule

Figure 9 shows a practical economical system arrangement for fuses when a transfer-trip circuit is impractical. Such applications are generally for noncritical loads. Note that the sum of the connected transformer kva is equal to 4300 while the smallest transformer is 300 kva, or the ratio of the total to the smallest transformer is equal to 14+, or considerably above the "six-times" rule; this, therefore, requires the use of an overcurrent device in that individual transformer.

Use of Bifurcation Principle of Circuitry

Bifurcation of circuits emanating from switchgear is relatively new; it offers real opportunities for reducing system breaker costs, often offers a substantial saving in cable costs, and offers better protection at lower cost than many other circuit arrangements.

Figure 8 shows this principle in elementary form. The bifurcation is made in the switchgear unit which includes both sets of CT's in the compartment and both sets of relays mounted in their usual location on the switchgear panel.

The circuit arrangement in Fig. 10A meets the Code's 2½-times rule without the need of a transformer secondary breaker, providing the transformer ratings are equal or approximately so. Note from Fig. 10B how easily this can be expanded with the bifurcation method—still offering good protection.

Figure 11 shows an economical use of this principle in one paper mill layout. Note the incorporation of transfer-tripping for protective functions.

Figure 12 shows another example of bifurcation in simplified form.

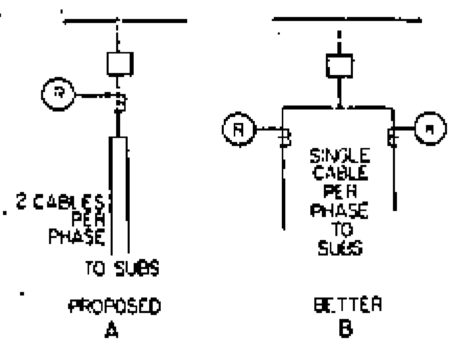
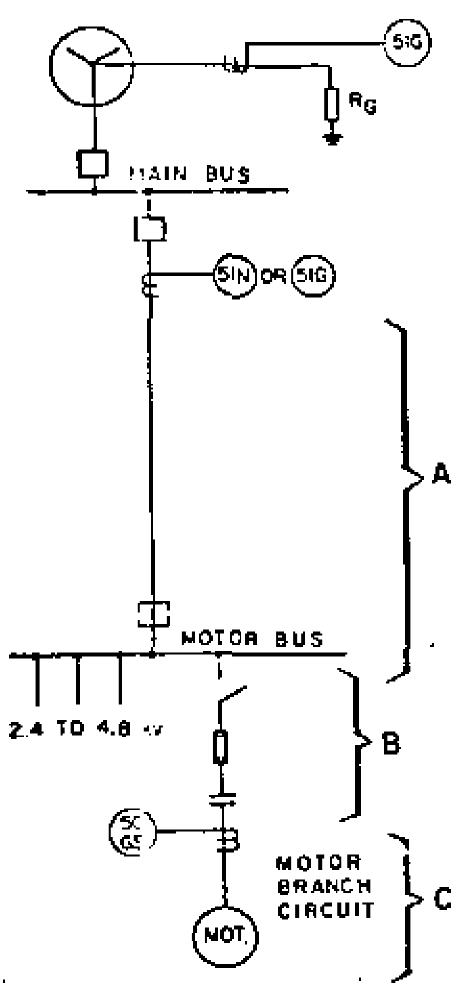


Fig. 12. A simple way to improve protection.

VALUE OF GOOD GROUND-FAULT PROTECTIVE RELAYING

Paper mills have used grounded power systems for many years *(13)*. As a matter of fact, they were among the early process-type industries to recognize the operating benefits of grounded power systems along with limiting the magnitude of the ground-fault current.

At the medium-voltage level, for example 2.4-13.8 kv, these power systems usually incorporate a resistor to limit the ground-fault current to a value about 400 amp on the newer systems using the ground-sensor relay and 1000-3000 amp on older systems having the residual-relay method of protection. In either case this permits sensitive relaying with low pick-up values of ground current. Since nearly all



rea A: Faults in this area usually start L-G. They are monitored by the system protective sensors and are not influenced by the fuses in the motor starter.

Area B: Faults in this area represent a motor starter failure and will inevitably involve ground.

Area C: Faults in this area almost always occur to ground, but those which are initiated L-L will involve ground with little delay.

Fig. 13. Elements of a typical system with a generator power source.

faults in these systems start as a ground fault, or will quickly involve ground, the main primary feeder will operate and "dump" the entire circuit for a ground fault. It is rare for the usual transformer primary fuse to "see" this low value of ground current, depending on its rating and its time-current characteristics. In a sense, therefore, it is the main feeder relaying that is doing most of the watch-dogging.

The use of a current-limiting fuse with high-voltage contactor-type motor starter is common. If a starter fuse blows, then only one motor is involved and it does not cause the same problems of single-phasing for transformer primary fuses as discussed earlier. However, a ground-sensor relay is recommended in each motor-branch circuit to open its own contactor, otherwise the entire motor bus would be de-energized for ground faults as shown in Fig. 13. Note that 51G is the final backup ground

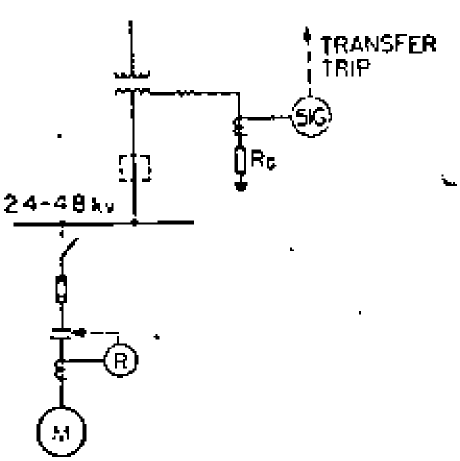


Fig. 14. Elements of a typical system with a transformer power source.

relay which also is set to protect the resistor.

Another version of this same protection method but with a transformer power source is shown in Fig. 14. Note here that a transfer-trip circuit is required for the ground relay 51G.

Physical compartmentation with isolation of key functions embodied in the equipment such as incoming line, main bus, breakers, instruments, and cable connections is used to prevent ionization of arcs from spreading within the enclosure. This type of isolation virtually eliminates one of the major causes of bus faults—the introduction of foreign objects, such as fish tapes, tools, rodents, etc., into the switchgear.

Several protection methods for low-voltage systems are available depending on the physical arrangement of the switchgear, but most manufacturers make use of the "donut"-type current transformer and a sensitive ground-sensor relay to detect low levels of ground-fault current. One manufacturer uses a linear-coupler type CT. Various tripping arrangements for ground faults on low-voltage systems are shown in Fig. 15.

Generally, in paper mills the low-voltage feeder circuits go to motor-control centers. Coordination is needed between substation breakers and downstream devices for ground-fault selectivity too. Sometimes this is obtained automatically by virtue of the relative current rating of the respective devices, i.e., power circuit breakers and molded-case breakers or fuses in motor starters. In many cases it is neither practical nor economical to obtain this ground-fault protection coordination on individual devices.

NEW LOW-VOLTAGE SWITCHGEAR AND PROTECTIVE DEVICES

Various switchgear manufacturers have improved their low-voltage protective devices, usually by employing solid-state technology. These new solid-state protec-

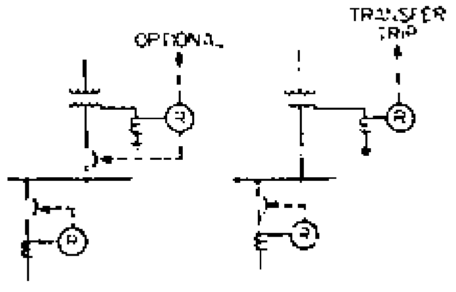


Fig. 15. Protection methods for ground faults on low-voltage systems.

tive devices offer many advantages, such as the following:

1. A different characteristic shape which permits better coordination and selectivity and faster operation.
2. Improved system selectivity and protection.
3. Much greater accuracy.
4. Economical ground-fault protection.
5. Freedom from mechanical wear.
6. Elimination of much pre-engineering and selection of tripping characteristics.
7. Simple field testing. (Small bench-type electronic equipment makes this simple. Only a few amperes are needed rather than thousands of amperes associated with the electromechanical breaker.)

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Providing Transformer Protection

. . . in accordance with American National Standards Institute and National Electrical Code guidelines

By ROBERT L. SMITH, JR., Application Engineer, Industrial Power Systems
General Electric Co., Schenectady, NY

THE FUNCTION OF transformer protection is to automatically disconnect a transformer from the power system for any of three reasons:

- To prevent higher than rated temperatures from developing in the transformer from excessive load current and, thereby, causing rapid deterioration of insulation or conductors. Protection provided to achieve this is known as overload protection.
- To prevent mechanical and thermal effects of large "through" currents from causing permanent deformation or other damage to the transformer. Such protection is known as short-circuit protection.
- To minimize the spread of damage inside a faulted transformer, and minimize power system disturbance resulting from a transformer fault.

Transformer Overload Capabilities—Capability of a transformer to withstand an overload for an extended period of time depends on its ability to dissipate the additional heat created by the overload. This capability is affected by ambient temperature, transformer loading prior to overload, duration of overload, and transformer construction.

Transformer capabilities have been estimated and transformer loading guidelines have been established based on consideration of these factors. Loading guides for dry-type and oil-immersed transformers are given in ANSI standard C57.96, titled "Guide for Loading Dry-Type Distribution & Power Transformers," and ANSI

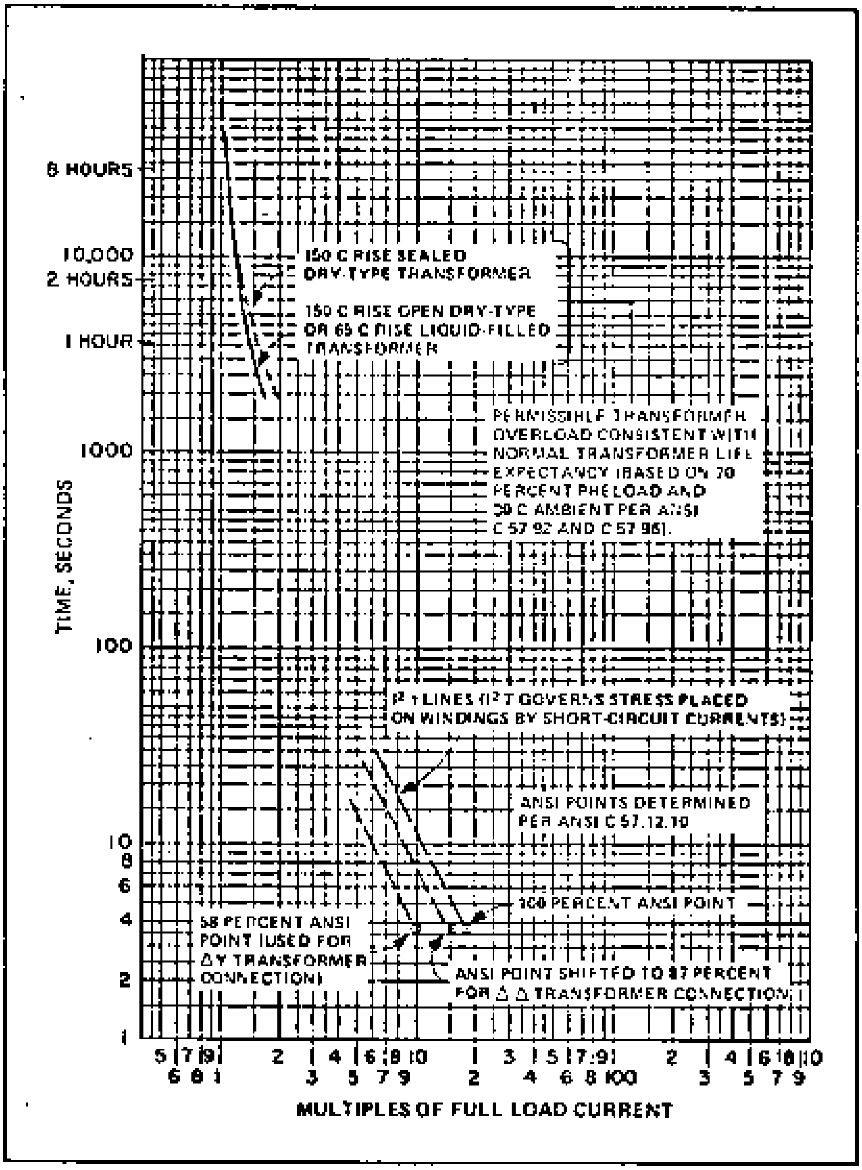

Fig. 1. Three ANSI transformer standards are important in determining protection to be applied to transformers. Loading curves shown are developed from criteria in ANSI C57.92 (Guide for Loading Oil-Immersed Power & Distribution Transformers) and ANSI C57.96 (Guide for Loading Dry-Type Distribution & Power Transformers). "ANSI Points" for specific transformers shown are developed from criteria in ANSI C57.12.10. The ANSI Point is the time-current point below which transformer protection must operate against through short-circuit currents. Note extended time scale used in this illustration when comparing Fig. 1 with Fig. 2, 3, and 4.

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standard C57.92, titled "Guide for Loading Oil-Immersed Power & Distribution Transformers."[1] Time-current curves, like those shown in Fig. 1, can be developed by applying the guidelines in these publications. Such curves define the general parameters required for operation of current-detecting protective devices.

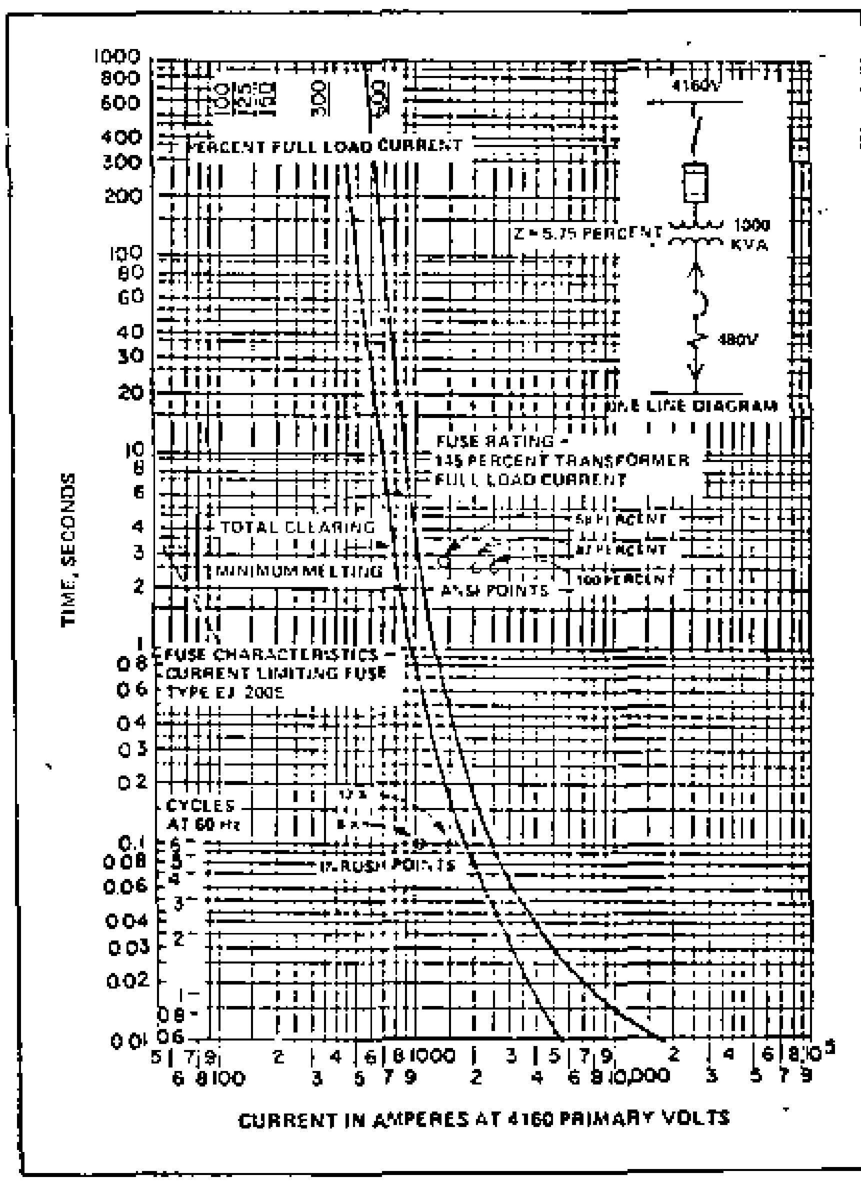
Transformer Short-Circuit Capabilities—The ability of a transformer to withstand through short-circuit currents (currents passing through the transformer and feeding into a fault downstream of the transformer) is defined in ANSI standard C57.12.10-1969, titled "Transformers, 138,000 Volts and Below." This standard specifies the magnitude and duration of maximum permissible through current that a transformer can withstand without sustaining damage. This "ANSI Point"[2] can be plotted for any specific transformer, Fig. 2.

Values of the ANSI Point vary from 25 times the rated full-load current for 2 seconds, for a transformer with 4-percent or less impedance, to 14.3 times the rated full-load current for 5 seconds, for a transformer with 7-percent impedance. If a primary protective device sensitive only to current magnitude is employed, the ANSI Point is shifted to reflect the difference between detected transformer primary current and winding current. Mechanical and thermal stress on windings in the short-circuit range below the maximum specified current vary as a function of time and the square of the current (I^2t). An I^2t plot is included in Fig. 1.

Transformer Inrush Current—Any device used in a transformer protection scheme must allow the transformer to be energized without actuating the protective device on the magnetizing inrush current. The precise magnitude and duration of inrush current vary from one transformer to another and, for any specific transformer, can only be determined by test. Commonly used estimates of magnetizing inrush currents for primary and secondary substation transformers range from an equivalent of 8 to 12 times full-load rms current, for a duration of 0.1 second.

Transformer Protection per the NEC and ANSI—Section 450-3 of the 1975 National Electrical Code—titled "Overcurrent Protection"—establishes certain criteria for determining the *maximum* transformer primary protective device rating or setting to provide the re-

Fig. 2. ANSI and inrush current points, and 200E Type EJ fuse characteristics are shown for 1000-kva, 5.75 percent impedance, 4160-480 volt transformer. Fuse must operate below ANSI Point, but be capable of carrying transformer energizing inrush current. Inrush current will vary from one transformer to another, and can only be verified for a specific transformer by actual test. It is customary to assume a value of inrush current of 8 to 12 times full load rms current for 0.1 second.



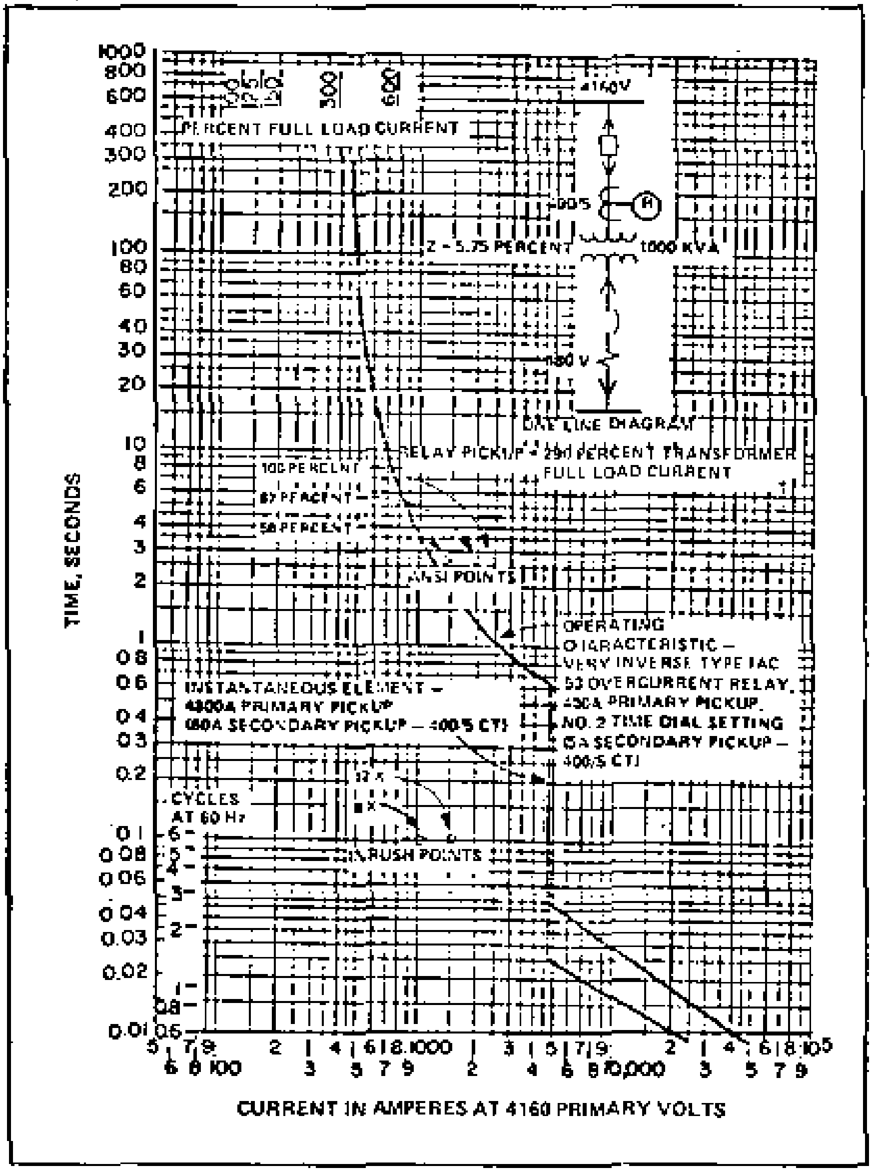
[1] *Available from American National Standards Institute, Inc., 1430 Broadway, New York, NY 10018. For a listing of other transformer standards, see "PLANT ENGINEERING's Exclusive Engineering Standards Digest," PE 1/23/75, p. 97.*

[2] *See Shortcuts to Selecting and Coordinating Electrical Trip Devices, PE 2/27/72, p. 55, and Backtalk, "What's an ANSI Point?" PE 10/5/72, p. 2.*

quired protection. The maximum permissible fuse rating is 300 percent of primary full-load current. Maximum permissible relay setting is prescribed at 600 percent of primary full-load current. These criteria apply to transformers with primaries over 600 volts and secondaries of 600 volts or less, protected by main secondary breakers or fuses or set at 250 percent (or less) of full-load current.

Electrical equipment manufacturers publish either recommended or minimum fuse ratings (or both) for fuses used as transformer protective devices. These published data consider both NEC compliance and ANSI Points. Ratings usually fall between 100 and 150 percent of transformer full-load current. If fuses of a lower rating than the minimum specified by the transformer manufacturer are used, they usually will operate on magnetizing inrush current.

Fig. 3. ANSI and inrush points, and typical protective relay characteristics and setting, are shown for 1000-kva, 5.75 percent impedance 4160-480 volt transformer. Because conventional relays with inverse, very inverse, and extremely inverse characteristics operate in considerably less time than permitted by ANSI transformer overload guidelines, relays are set to pick up at values greater than any anticipated overload.



Primary Overcurrent Protective Devices—Power or current limiting fuses that meet the ANSI fuse standard C37.46 are required to operate in 300 seconds at 200 to 240 percent of their rating if rated 100 amperes or less, and in 600 seconds at 220 to 264 percent of their rating if rated above 100 amperes. Protective-device operating times in the *overload* range of currents are not specified in ANSI standards. A recommended fuse characteristic for a 1000-kva transformer is shown in Fig. 2.

Conventional, standard, off-the-shelf relays usually operate in considerably less time than permitted by overload guideline criteria, and, therefore, are set to pick up at values greater than any anticipated overload. A typical primary relay setting is shown in Fig. 3.

Comparison of Fig. 2 and 3 with Fig. 1 shows that the time-current characteristics of conventional primary current detecting devices do not permit the selection of ratings or settings to match the overload capabilities and protection requirements of transformers. Any rating or setting selected in accordance with the maximum permitted by the NEC or ANSI will permit overloading a transformer in excess of the ANSI loading guides. Low settings of primary devices may not permit energizing a transformer because of magnetizing inrush currents. Low settings also compound system protective device coordination problems.

Secondary Overcurrent Protective Devices—Maximum rating or setting permitted by the NEC for main secondary breakers on transformers with primaries over 600 volts is 250 percent of transformer full-load current. Any secondary breaker rated or set at this maximum permissible value does not provide transformer overload protection. However, some degree of overload protection can be obtained by setting main secondary breakers at less than the maximum permitted by NEC Section 450-3. **A setting of approximately 125 percent of full-load current would provide reasonable overload protection, but would not necessarily permit taking full advantage of short-time overload capabilities greater than 125 percent of full-load rating.** A typical breaker-protection characteristic curve is shown in Fig. 4.

Obtaining the "Best" Protection —If a transformer is provided with a primary and a secondary breaker —each equipped with a reliable sensing device—good protection can be obtained for overload, for short-circuit through current, and for internal transformer fault conditions. Overload protection may utilize sensing devices that react to simulated winding temperature devices. **Such sensing devices can be used to either activate an alarm or operate a tripping device.**

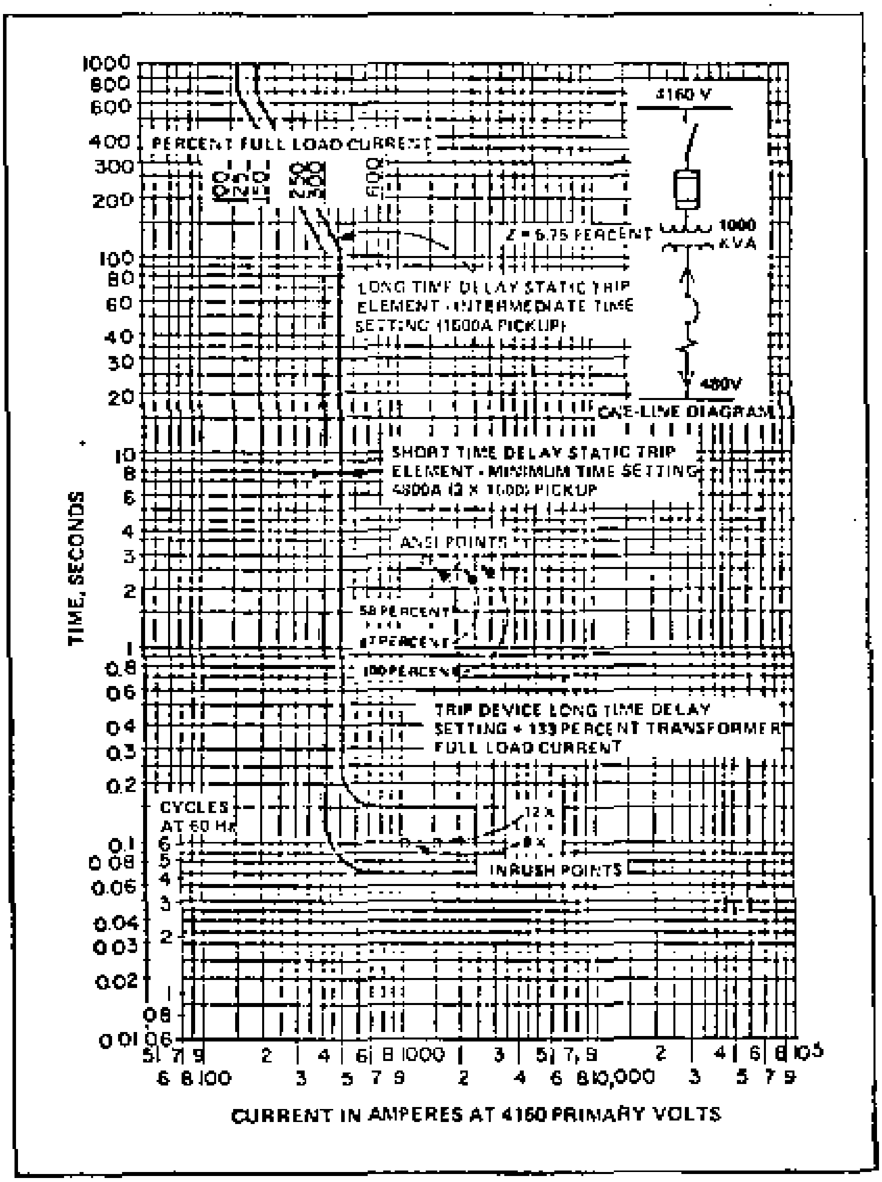
Through current short-circuit protection can be obtained by applying very inverse or extremely inverse relays. These should be set **at a high pickup value and low time dial setting, and should be used to trip the primary breaker.**

The best available protection for minimizing damage from an internal fault in the transformer is a differential relaying scheme,* or, in the case of liquid-filled transformers, a fault pressure relay. There is a trend toward preferred use of a fault pressure relay—rather than differential relay—in liquid-filled transformer applications.

The "Practical" Protection Solution—In many cases, the "best" possible protection cannot be economically justified, and the plant engineer must evaluate the degree of protection that can be provided with something less than a maximum protection package.

Because it is not practical to attempt to provide overload protection with either primary fuses or conventional primary overcurrent relays, these devices must be considered suitable for protecting against through short-circuit currents and internal transformer fault only. Overload protection can be obtained by the overcurrent device in the main secondary set at about 125 percent of transformer full-load current. Selecting the proper short-time trip device for the main secondary breaker can give selectivity with downstream feeder **breakers, as well as coordination with primary fuses or relays.**

Fig. 4. ANSI and inrush current points, and typical main secondary breaker trip characteristics and setting are shown for 1000 kva, 5.75 percent impedance 4160-480 volt transformer. Setting breaker overload trip element well below the 250 percent of full load current permitted by NEC gives reasonable transformer overload protection.



*Differential protection is explained in the article, "A-C Motor Protection," PE 5/7/74, p. 180.

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APPLICATION LIMITATIONS OF SINGLE-POLE INTERRUPTERS IN POLYPHASE INDUSTRIAL AND COMMERCIAL BUILDING POWER SYSTEMS

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APPLICATION LIMITATIONS OF SINGLE-POLE INTERRUPTERS IN POLYPHASE INDUSTRIAL AND COMMERCIAL BUILDING POWER SYSTEMS

R.H. Kaufmann*

Beginning some five to ten years ago, there appeared an increasing number of serious burndown experiences in industrial and commercial power systems, the reasons for which defied explanation. The low-voltage area, particularly 460 volts, was prominently involved. What was most disturbing was the fact that overcurrent protective equipment was found to be operative and in accordance with accepted protection standards. The results of intensive investigation of burndown experiences and concentrated analysis of the electric circuits involved, presented in this paper, show conclusively that single-pole interrupters, improperly used, can be a major contributing factor. It develops that the areas of adverse behavior can be catalogued into a few discrete patterns which simplifies the matter of recognition and understanding. Included in the paper are guide rules by which the troublesome areas can be avoided, or at least correctly understood.

There is ample evidence that the problem is chronic and widespread. Mr. Weddendorf in his paper (Ref. 1) describes and illustrates a number of typical cases in which only a pile of burned-out rubble remained. The electrical section of NFPA (National Fire Protection Association) found the problem sufficiently serious to create a special technical committee to deal with "overcurrent protection problems in high-capacity low-voltage networks."

The research time and effort expended in untangling this problem has been unbelievably great, largely because the single-pole interrupter (a frequent offender) was itself not distressed. In a great many of the early incidents, the accident report failed even to mention that a single-pole interrupter had been present or had operated. Here and there, a report would contain reference to an observed single-pole interrupter operation. From the accumulating reports, there began to unfold a repeating family of operating patterns in which the single-pole interrupter commonly played a villainous role.

A few basic facts will aid in understanding how the single-pole interrupter may act to deteriorate overcurrent protection in polyphase systems. Industrial and commercial power systems are generally three phase serving a large array of polyphase load apparatus and perhaps also substantial amounts of line-to-line connected single-phase load. Each polyphase circuit is in reality a single electric power transfer channel. All normal switching operations open all ungrounded phase conductors simultaneously.

All line-to-line connected load circuits constitute physical connections over which current can flow from one phase conductor to another at the load. Fault current to a particular circuit breakdown may thus approach the fault directly from the supply source on the phase conductor involved, or also via either or both of the other phase conductors by transferring to the faulted phase through the electric circuits in the load apparatus. To interrupt the flow of current to the fault will generally require that <u>all</u> phase conductors of the polyphase circuit which serves the faulty member be opened.

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To attempt to accomplish circuit protection by the use of independent phase-overcurrent interrupters alone may be next to impossible. The opening of the first single-pole device does not assure fault current interruption. What it does do is modify the circuit connection geometry which most likely will diminish the magnitude of fault current, perhaps seriously. The remaining phase overcurrent devices (whose operation must be accomplished if the fault is to be cleared) may, because of the reduced fault current magnitude, become inoperative, or perhaps operate only after a long time delay. Prolonged duration of even a rather modest fault current can produce catastrophic effects. A single-phase arcing fault of 600 amperes and an arc voltage of 200 represents heat liberation at the rate of 120 kw! A lot of copper (or aluminum) can be melted with 120 kw continued for 10 minutes.

Another serious effect may result from the prolonged operation of polyphase motors with badly unbalanced power supply. After the first phase interrupter opens, the power transfer to the polyphase system beyond the protector location will be predominantly single-phase. Sustained operation of motors with badly unbalanced power supply can be responsible for detrimental effects which can result in motor failure in spite of the presence of normal running overcurrent protection (Ref. 2). Included in the examples under Case I, is a case report in which about one-third of the connected polyphase motors failed incidental to a single pole interrupter operation.

Specific Patterns

Out of the dozens of reported serious burndown incidents which originally defied explanation, there developed several repeating specific patterns of misbehavior.

I. A line-to-ground fault on a medium-voltage polyphase feeder circuit serving line-to-line connected polyphase or single-phase loads, either directly or through step-down transformers, protected by single-pole, high-side interrupters.

II. A low voltage arcing fault at the secondary of a step-down polyphase transformer, with single-pole overcurrent protectors used as the sole high-side protection.

III. An arcing fault in a low-voltage grounded neutral polyphase service or main feeder with single-pole overcurrent interrupters constituting the sole fault protection.

The ability to catalogue most of the experiences into three distinct classes makes it possible: (1) to more easily describe the mechanisms involved and (2) to permit the identification of the fundamental weakness in a new burndown experience to be quickly made. There follows a detailed description and analysis of the three familiar patterns.

Case I - Single-Pole Interrupters Applied to Polyphase Medium Voltage Feeders Serving Line-to-Line Connected Loads

Both instances in which fuses are applied close to a step-down transformer (see Fig. 1) and those in which a substantial length of feeder is monitored by single-pole interrupters (see Fig. 2) present the same basic problem for a high-side fault beyond the protector. These two varieties differ tremendously, however, as to the degree of fault exposure. In the close coupled instance (Fig. 1), as the protector location approaches the transformer (with a transformer mounted protector representing the end limit), the degree of fault exposure diminishes to near zero at the end limit. In the remote-location instance (Fig. 2), the entire length of the primary feeder conductors represents potentially troublesome fault exposure.

In either instance, the initiating event is an insulation breakdown beyond the single-pole protectors location (1). This will most frequently be line-to-ground as illustrated, but involvement of a second phase conductor presents nearly the same situation. The supply system available ground fault current is normally pegged at a level which will produce prompt operation of the faulted-line overcurrent unit (2). If not, the fault is forced to sizzle and burn until it burns into a second phase before even the first protector could be operated. The opening of the first phase conductor (2) interrupts the flow of fault current in that particular phase conductor, but does not disturb the continuing current flow to the fault from the other two phases via the electric circuits comprising the load apparatus.

The electric potential which the faulted phase conductor tends to assume on the far side of the open protector will depend on the character of the load being served. Refer to the block explanation to the right of Fig. 1. The symmetrical triangle ABC represents the normal balanced voltage pattern. Point N, the system electrical neutral locates ground potential. All polyphase rotating machines, synchronous or induction, generators or motors, have the property of generating nearly normal voltages in all phases, if any are excited. Thus, the opening of one supply line, say Phase C, to a group of rotating machines would result in only a slight displacement of the "C" phase voltage at the load, for example, point C' on the diagram. On the other hand, had the load apparatus been of constant impedance (like lamps or resistance furnaces), the "C" phase voltage at the load would tend to assume a spot on the straight line between A and B such as C".

Both points C' and C" are substantially different than ground potential "N". On a 4160 volt system, the potentials to ground would be: for Point C 2400 V, for point C' perhaps 2000 V, and for point C" about 1200 V. Therefore, the line-to-ground fault at (1) would continue to have a voltage of this order impressed on it after opening of the "C" phase line conductor. It is at once evident that the magnitude of fault current will be greatly diminished since the load-apparatus impedance is in series with the fault current circuit. It is entirely possible that the fault current magnitude will be reduced to a value less than the normal full load current of the circuit. Phase-overcurrent protectors in the remaining two phase conductors are hopelessly handicapped and cannot function to interrupt the remaining fault current.

Modern medium voltage industrial power systems commonly are resistance grounded and equipped with sensitive, prompt acting ground current trips on feeder circuit breakers as illustrated on Fig. 1. An industrial power system of this design has the ability to provide prompt back-up protection for a Case I fault whether or not the first single-pole interrupter (2) opens. It is important, however, that the ground relaying be sensitive to the reduced fault current magnitude which will exist after opening of the first phase interrupter at (2).

Examples

During the course of this investigation, there were twenty-two reported experiences of unexplained back-up protector operation which fell in the Case I category. In one case, ground current responsive tripping directed the feeder breaker to open before any of the single pole branch overcurrent devices operated. In most of the experiences reported, feeder breaker opening in response to ground current flow occurred promptly after the first phase overcurrent protector had opened, thus effectively limiting arc damage. All these incidents were regarded as routine. The question was mainly, "Why did the overcurrent protection system operate as it did?" One reported experience clearly illustrates the severity of the problem if back-up protection is not present. Attention was first directed to the problem by growls and groans among the operating motors. Quick work by a central load dispatcher directed maintenance men, via a PA system, to shut down all motors in the area immediately. None the less, about one third of the motors had failed before being reached. (About one-third had already tripped off before being reached.)

Preventative Measures

Of course, it goes without saying that a polyphase interrupter, in its operation, avoids entirely the problem presented in Case I. There are a number of system design rules which can minimize the adverse performance described.

In systems represented by Fig. 1:

1. Locate fuses (if needed) directly at the transformer to minimize exposure.

2. Make sure that the primary circuit feeder breaker is equipped with sensitive ground responsive trips to back up the single-pole protectors.

3. Avoid the use of single-pole interrupters on polyphase transformer primaries where system design will permit.

In systems represented by Fig. 2:

1. Combine with fuse interrupters a power switching interrupter or other mechanism arranged to automatically open all phase conductors in response to the operation of any one fuse. (This, of course, could also be applied to the Fig. 1 pattern.)

Case II - A Low-Voltage-Side Arcing Fault on a Stepdown Transformer Using Single-Pole Interrupters for High-Side Overcurrent Protection

This family of misbehavior is associated with the circuit geometry displayed in Fig. 3. A major fraction of the reported burndowns have been of this class. The high side protectors are found generally to be rated or set at two to four times transformer rated current.

The burndown sequence begins with the creation of a low-side fault at the transformer, location (1). In many instances the origin of the fault is known; a workman left a wrench or other tool on the low-voltage buses, an inspection plate slipped as it was being removed and contacted energized buses, a metal fish tape upon entering the switching center enclosure made contact with an energized bus, etc. There are also many instances in which the exact origin is not known. There is no doubt about the fact that a fault arc was initiated.

Low voltage equipment does not employ isolated phase construction with insulated buses. Hence, an arc flash can readily ignite a polyphase arcing fault. (Arcing fault tests, at 480 and 600 volts, show that automatic involvement of all phases can occur within one millisecond - a small fraction of one cycle). The expected magnitude of arcing fault current (Ref. 3) would be judged ample to operate the high-side protector. And so it is - that is for the first interrupter.

One high-side protector (3) operates promptly (in the order of seconds). Its operation does not interrupt the fault, however. It merely changes the polyphase circuit character. With one hi-side line open, the power transfer at the protector location becomes 100% single phase. Except for some possible polyphase back feed from motors on the lines, all fault current arcs go out simultaneously. Following each current zero, the fault arcs must be re-ignited. This requires a higher recovery voltage than does the mere transfer of a fault arc from one phase to another. It is the delay in the re-ignition of the fault current after each current zero which in large measure accounts for the severe reduction in fault current which accompanies the first high-side protector opening. The character of the resulting delayed re-ignition current compared with what it would have been with immediate re-ignition is shown in Fig. 4. An analytical treatment of the degree to which current will be reduced by this mechanism is contained in reference (3). Theory confirmed by experience indicates unmistakably that the fault current on 460-volt systems can be diminished to a value too low to operate protectors rated or set at two to four times transformer rating.

In this behavior category (see Fig. 3), it is pertinent to note that no ground current flow will flow in the primary feeder whether the transformer be connected ΔΔ, ΔY, or YΔ. Hence, no back-up protection can be secured directly from the supply feeder breaker. It is possible, and perhaps sometimes feasible, to transfer trip the primary feeder circuit breaker from a dependable fault-sensing relay monitoring the low voltage equipment.

Examples

Dozens of catastrophic burndowns have been checked out and found to be in exact accord with the Case II pattern. Many varieties of low voltage equipment construction have been involved as should be expected. The majority of reported incidents have involved 460-volt systems. This should not be interpreted to absolve 575-volt systems, but merely be a reflection of the much greater aggregate amount of 480-volt equipment in the U.S. The 230- and 208Y/120-volt systems exhibit a rather strong, but not infallible, tendency toward automatic self-extinction of single phase arcing faults. This can readily explain the reason for a minor number of the burndowns in this voltage range.

After the clearcut repeating failure pattern began to appear, a few interesting incidents occurred in data collecting. In one of the later reported incidents, the report stated that no high-side interrupters had operated. In other respects, the burndown report fitted the regular pattern. A letter query brought a written reply confirming the initial report in this respect, but was countermanded by a telegram from a resident engineer stating that he had reliable information that one high-side fuse had in fact blown during the incident. In another incident report describing the typical burndown experience, a letter query asking for details brought a reply that the events conform exactly with Case II pattern, and no new knowledge could be generated by making a detail report of that last incident.

Preventative Measures

1. One of the most effective solutions in industrial power systems would entail the application of primary feeder system design which to as great an extent as possible eliminates the need for individual overcurrent protection at transformer stations.

2. The use of a multipole circuit breaker, of course, is a technically-correct solution, but it must justify the economic handicap of substantially greater cost.

3. Another solution could be achieved with a coordinated interrupter switch-fuse combination which contained provision for automatically opening all three phase conductors in response to excessive current sensed in any one phase.

4. Still other solutions could be achieved using a dependable low-side arcing fault sensor relay to:

   (a) Transfer trip a primary feeder circuit breaker.

   (b) Trip a high-side shorting switch which would in turn force a trip-out of the primary feeder breaker.

   (c) Trip a main low-voltage circuit breaker, the equipment construction of which so isolates and sectionalizes the supply-side run to the transformer that a fault in this zone is next to impossible.

5. In installations in which the size and character of the load block will allow, and the transformer with its associated switching equipment are installed apart from buildings or other apparatus, it may make reasonable economic sense to run the risk of an occasional burndown, since only the stepdown station and continuity of power supply to this load block are in jeopardy.

Case III - An Arcing Fault in a Large Rated Circuit from a 460Y/265 Volt Service System Protected by Single-Pole Interrupters

This particular family type is defined by the circuit geometry shown in Fig. 5. All of the cases which have been analyzed and catalogued by the author have been at the

460Y/265-volt level. There are known to have existed situations of prolonged arcing fault incidents on 208Y/120-volt systems, but it is not known whether this particular sequence pattern was involved. No cases of this type have been reported at the 575 volt operating level, but this doesn't mean that they are unlikely. (See comments under Case II.)

In common with the other cases, the initiating event is the occurrence of a short circuit beyond the single-pole interrupters (see Fig. 5). The most likely is a single-phase-to-ground fault, but other types of faults will trigger the same troubles. If bare conductors are used in a common enclosing housing, the fault can be expected to involve all phases quickly.

If the fault occurs and remains single line-to-ground, the single pole interrupter in that line opens promptly. The backfeed current via the load apparatus connected beyond the fault continues the arcing fault and the burning. The current magnitude may well be less than the rating of the line overcurrent protectors. Within a relatively short time (perhaps only a few seconds), the heat resulting from the released energy at the fault will have burned through any insulation on the other phase conductors, allowing them to be electrically connected to the arc plasma. (Had the conductors been bare, this involvement would have taken place without delay.)

The result is a double line-to-ground arcing fault on the supply system. The supply line currents can be expected to be increased, but still remain well below the three-phase arcing fault value. By now, the delivered voltage to motors beyond the fault has become so deteriorated that these motors have likely stalled and dropped off the line. Hence, a source of polyphase back-feed short-circuit current from motors is unlikely. The continuing line current to the fault alone (load current largely disappeared) may or may not be sufficient to operate a second pole interrupter. Records include both cases in which only a single pole opened and cases in which two pole interrupters opened.

Opening of the second line interrupter reduces the continuing fault current to pure single phase. All fault arcs go to zero current at the same instant. The great reduction in current which can attend the delay in re-ignition of the arc following each current zero has already been described. Furthermore, the magnitude of bolted fault single-line-to-ground current may be much lower than a casual guess might indicate. (See references 4 and 6.)

Examples

Several severe burndowns have been experienced in high-ampere-rated trunk circuits typically 4000 ampere, fed from large capacity service networks (typically 150,000 amperes IC, but at much lower levels also) protected by single-pole interrupters (typically 5,000 ampere fuses). In one case, several floors of vertical run were burned out. In another, a considerable length of horizontal run was burned out - and I mean burned out. Another actual case was unusual in that it involved cascading of faults (see Fig. 6). The fault was initiated (reason not known) at the line terminals of a fuse-breaker combination protective device (1). The fault promptly enveloped all three phases. Two of the coordinating fuses opened (2), but the third remained intact indicating that the fault current (single-line-to-ground) was probably less than 3,000 amperes. The continuing arcing developed lots of heat and ionized gases, which after a modest delay ignited a fault arc on the service equipment buses (3) which probably went three-phase at once. Two of the ıse protectors at (4) opened but the remaining one did not. The continuing arcing fault current, in addition to doing severe burning damage at location (3) damaged the transformers and network protectors at (5) to the extent that they required replacement. Some 10 to 15 minutes elapsed before the fault was cleared by manually tripping the high voltage service.

Preventative Measures

1. Combine with the high-speed, single-pole interrupters a coordinated multi-pole switching interrupter which will be signaled to open at once should any of the single-pole interrupters operate.

2. Design the equipment such that operation of any of the single-pole interrupters will signal automatic opening of the next adjacent polyphase interrupter on the supply side, i.e., operation of any single-pole interrupter at (2) arranged to produce automatic tripping of the circuit breaker (6).

3. Employ the "crowbar" principle of tripping a multi-pole shorting switch to apply a three-phase short circuit ahead of a set of single-pole interrupters in the event that a single-pole unit operates yet an appropriate sensor indicates that the fault condition still exists.

4. If the size of apparatus involved is modest and the load equipment will not be endangered by temporary application of badly unbalanced or single phase power supply, the divorcement of this apparatus from other equipment or buildings may justify the risk of an occasional burndown in which only the local portion of the electrical system is in jeopardy.

ADDITIONAL GUIDE RULES FOR SINGLE-POLE INTERRUPTERS APPLIED IN INDUSTRIAL POLYPHASE SYSTEMS

An interesting observation is the fact that the recognition of the protection deficiencies here described were brought to light through serious operating troubles in service. Present knowledge suggests that all these deficiencies could have been predicted by realistic analysis. The breadth of understanding of the general subject can be expanded by analytical techniques. The fruits of this work can provide additional guide rules.

Single-Phase, One-Side-Grounded Circuits

From the concepts already developed on fault clearing requirements, analytical methods lead to the conclusion that a single-pole interrupter, unassisted, can properly monitor a single-phase circuit operating with one conductor grounded. Whether existing alone as shown in Fig. 7A, in single-phase three wire configurations (Fig. 7B), or in three-phase, four-wire combinations (Fig. 7C) does not alter this fact.

Overcurrent in any single phase circuit of sufficient amount and duration to operate the overcurrent protector results in complete interruption of the abnormal circuit current. Power distribution using this principle of single phase protection will be found almost universal at 240/120-volt, single phase, three wire, very extensive at 208Y/120-volt, three phase, four wire, and to a large extent for fixed area lighting at 460Y/265-volt, three phase, four wire.

Note that control switches, or relay contacts should be wired in the hot line on the load side of the protector to avoid uncontrolled turn-on created by a ground fault and to insure that relay contacts are "dead" when the protector is in the "off" position.

POLYPHASE COMBINATION EQUIPMENTS

Fuse-Power Switching Combinations

Combination equipments are available in which fuse interrupters are wedded to power switching interrupters to accomplish a proper three-phase circuit monitor. (Fig. 8 illustrates one variety.)

At moderate overcurrents (within the capability of the switching device), the switching device alone is directed to open. An immediate opening of all phase conductors is accomplished without operation of any fuse interrupter.

At elevated currents (above the capability of the switching device unaided), the fuse unit functions to interrupt quickly the high current flow in the affected phase, having been matched with the switching device to prevent excess duty to its elements.

The acceptable combination also contains a dependable means of initiating an opening of the three-phase switching device in response to opening of any of the fuse interrupters. This combination incorporates the important feature that any overcurrent condition which opens a fuse unit will in turn result indirectly in the opening of all three phase conductors.

Fuse-Protected Motor Combination Starters

Combination fused switching devices are used extensively to control and monitor motor branch circuits (see Fig. 9). Although it is not customary to employ a direct means of opening the switching contactor in response to a fuse operation, there are a variety of means whereby this may be accomplished indirectly.

There are available a number of auxiliary sensors which can be counted on for dependable direction such as, (1) ground-fault-current responsive relays, (2) unbalanced-phase-current relays, and unbalanced-voltage relays. The normal undervoltage protection function can be made to assist in performing the desired end result.

An opening of one fuse would activate current unbalance relays and cause the switching contactor to be opened. The normal reason for a fuse operation is a motor branch circuit fault which almost always goes to ground either at once or with only little time delay. Grounded supply system operation would then insure operation of the ground relay with direct consequential opening of the switching contactor. Voltage unbalance relays would very likely respond to an open fuse. A motor branch circuit fault would tend to aggravate the voltage unbalance and insure relay operation, while normal load without a fault should create relay operation. A lightly loaded motor might remain blind but, of course, a lightly loaded motor with no circuit fault presents no single phase danger. About the same general comments apply to the operation of an undervoltage device. Of course, the sensitivity is not so good and its response depends on one specific line-to-line voltage. One line-to-line voltage may remain normal through a destructive burning fault.

There is this much to be said in defense of independently fused motor controllers. Only one single utilization machine is being monitored, rather than a main power channel serving many load machines. The severity of burning which can continue without automatic interruption is thus limited. Unless the danger of nearby combustible material or explosive atmospheres is present, the risk of extended burning on a single utilization branch circuit might be tolerable. Of course, if the motor branch circuit is run in duct or cableway adjacent to other cables, the damage exposure is expanded to include these other circuits.

CONCLUSIONS

Polyphase electric power circuits as incorporated in industrial and commercial power systems possess the ability to transfer current from one phase conductor to another by way of the line-to-line connected circuits in the load equipment. Thus, the flow of fault current in any such polyphase circuit cannot be assuredly interrupted unless all phase conductors are opened.

To attempt to secure polyphase circuit protection through the use of individual independent phase overcurrent protectors, unassisted by other means, can spell disaster. Each such single-pole protector, upon opening, modifies the electric circuit geometry and can adversely affect remaining protectors, even to the extent that they are rendered inoperative. No useful purpose is fulfilled by delaying their operation. The protection equipment should seek to accomplish immediate opening of all phase conductors in response to excess current sensed in any one phase.

Single-phase, one-side-grounded branch circuits may be properly monitored by a single overcurrent protector even if this circuit originates from a polyphase supply system.

A wide variety of application principles have been disclosed by which the single-pole interrupter may be properly embodied in polyphase circuit protective systems. The important point lies in recognition of the possible deficiencies and what measures can be taken to circumvent trouble. This paper is devoted primarily to presenting an understanding of the technical circuit problems created by the presence of single-pole overcurrent protectors in polyphase industrial power systems.

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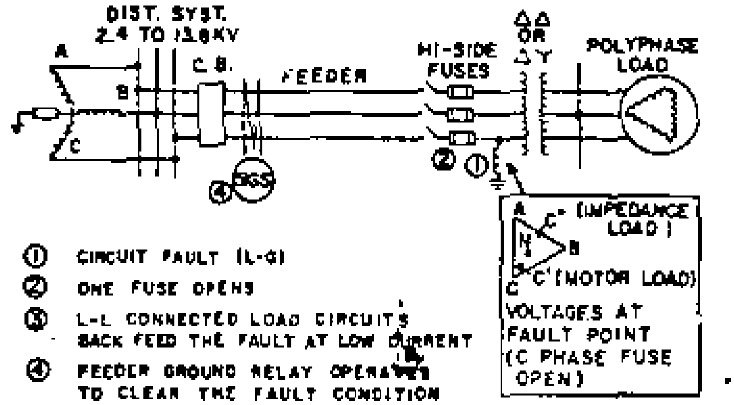


Fig. 1. Step-down transformer high-side fuses are vulnerable to a high-side ground fault between the fuses and transformer unless backed up by sensitive feeder-ground-responsive tripping.

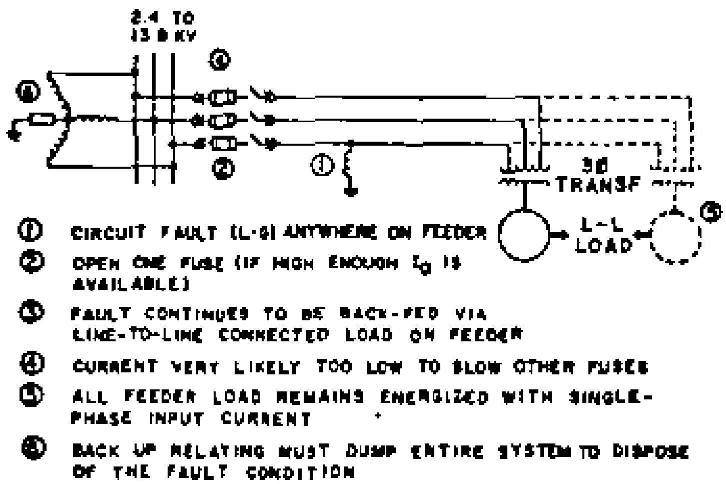
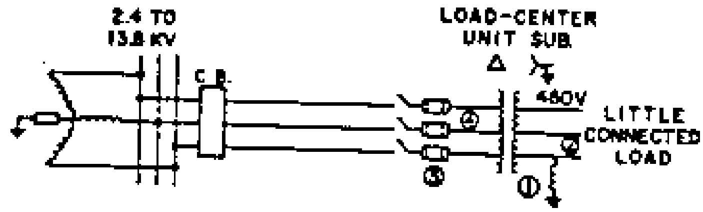


Fig. 2. Single-pole protective interrupters in polyphase medium-voltage feeders face troublesome limitations when confronted with a line-to-ground fault.



① CIRCUIT FAULT (L-G OR L-L)
② PROMPT SPREAD TO 3 φ ARC IN BARE BUSWORK
③ OPEN FIRST FUSE IN PERHAPS 1 TO 8 SECONDS
④ CURRENT FLOW TO FAULT ARC IS 100 % SINGLE PHASE
⑤ RESULTING LOW CURRENT IN ARC MAKES LONG DELAYED (OR IMPOSSIBLE) OPERATION OF OTHER FUSES

Fig. 3. Step-down transformer high-side fuses are of limited utility in coping with low-side faults.

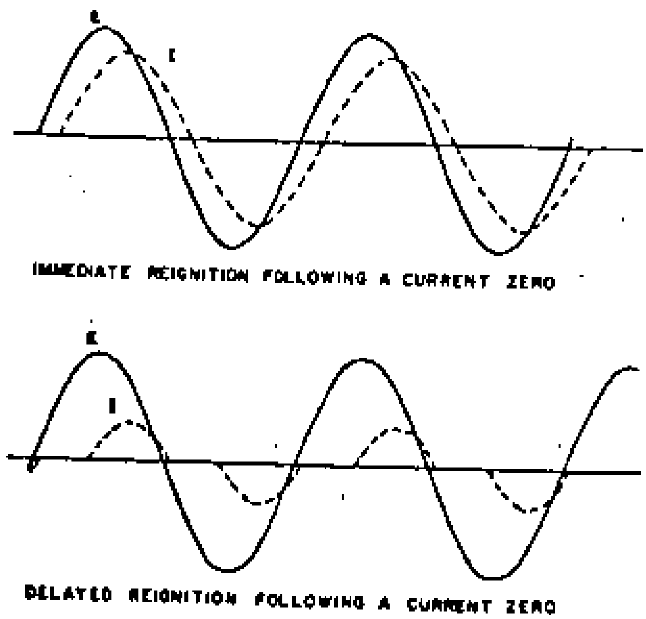
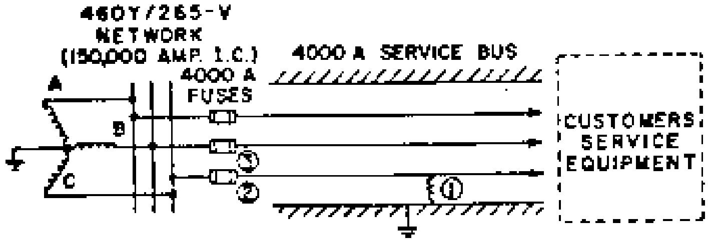
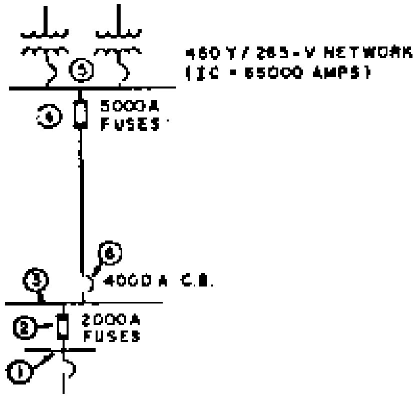


Fig. 4. The opening of one high-side phase overcurrent protector can seriously reduce the rms value created by a low-side arcing fault because of the delay in current re-ignition following each current zero.



1. CIRCUIT FAULT (PROBABLY, BUT NOT NECESSARILY, LINE TO GROUND)
2. ONE FUSE OPENS
3. PERHAPS A SECOND FUSE OPENS
4. A LOW-LEVEL FAULT CURRENT (LESS THAN 5000 AMP) CONTINUES TO FLOW

Fig. 5. This low-voltage circuit pattern which relies on single-pole overcurrent protectors alone has been observed to display protection limitations.



1. FAULT WAS INITIATED HERE - PROMPTLY WENT 3 PHASE
2. TWO FUSES OPENED - THE THIRD HELD
3. SUSTAINED ARCING IGNITED A NEW FAULT HERE WHICH PROMPTLY WENT 3 PHASE
4. TWO FUSES OPENED - THE THIRD HELD
5. THE CONTINUING MODERATE FAULT CURRENT (LESS THAN 5000 AMPS) DAMAGED NETWORK PROTECTORS AND TRANSFORMERS
6. A COORDINATION CHECK DISCLOSED THAT BETWEEN 6400 AND 70 000 AMP., FUSES AT 4 WOULD OPEN IN LESS TIME THAN 4000 A CIRCUIT BREAKER

Fig. 6. Low-voltage protection limitations of the type illustrated in Fig. 5 have been observed to occur in cascade sequence at two locations during a single short-circuit incident.

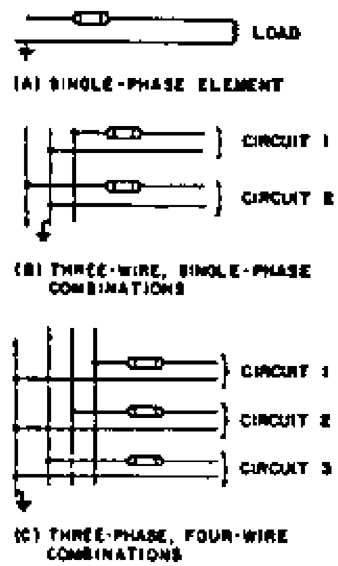


Fig. 7. Single-phase one-side-grounded circuits properly monitored by single-pole over-current protectors.

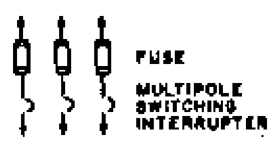


Fig. 8. A limited-capability multipole switching device co-ordinated with fuse interrupters.

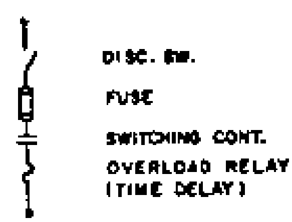


Fig. 9. A combination motor starter employing a limited capability multipole switching contactor co-ordinated with fuse interrupters.

6-65 (.5M)
5-66 (2M)
8-67 (1M)
12-71 (2M)

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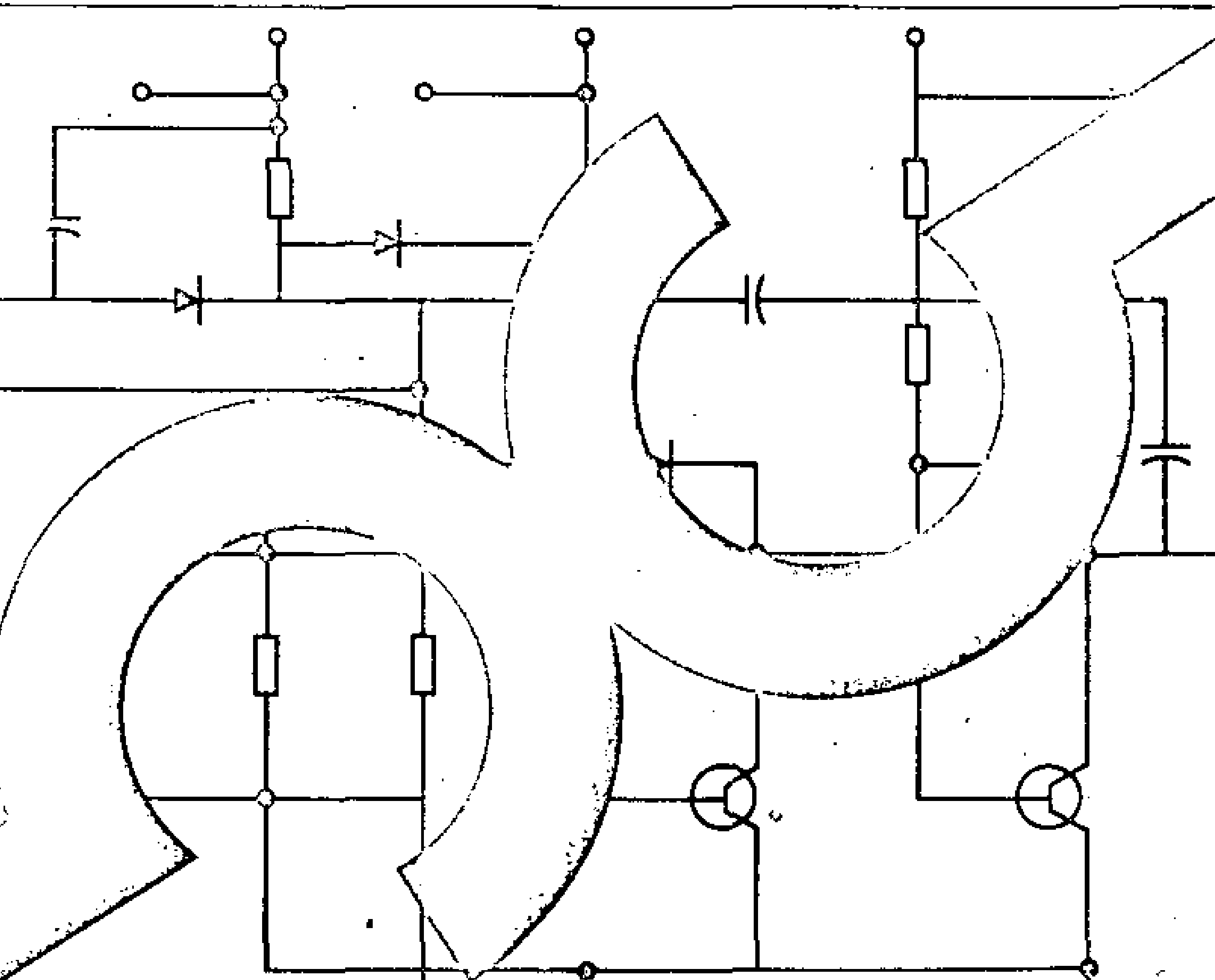

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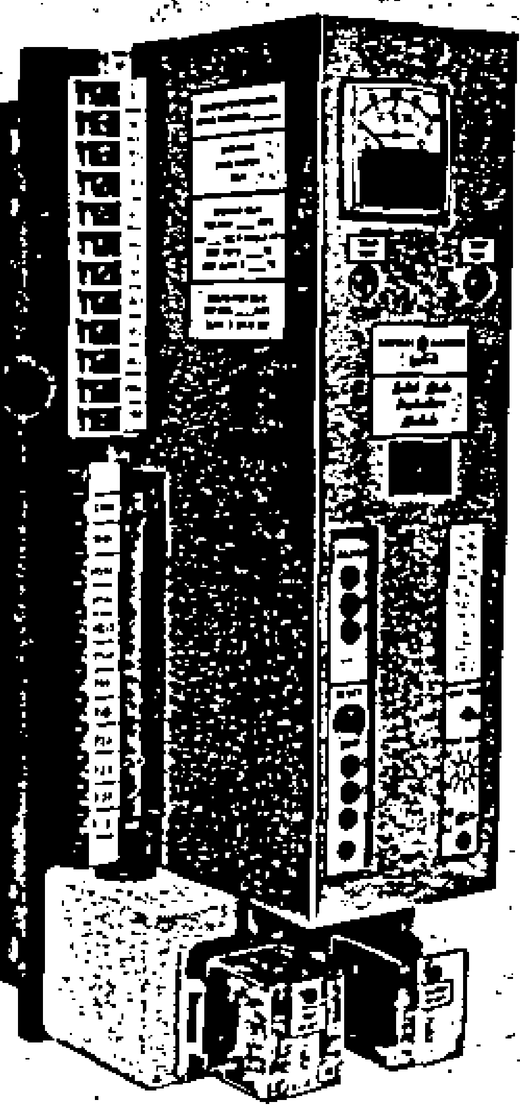

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Starting with five basic functions: overtemperature or overload, open-phase, phase-reversal or open-phase, phase-unbalance and ground fault, you can select the combination of functions to meet your application needs. Each function is contained on a replaceable plug-in printed circuit board that plugs into a prewired module which fits neatly into your present control equipment with a minimum of mounting and reconnection work. After installation, functions can easily be added or modified to meet your exact protection requirements.

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- Single base or door mounted unit containing up to three protective functions.
- Self-contained annunciation, common alarm and trip relays with visual indication and automatic or manual reset of alarm and trip.
- Field adjustment of variables.
- Plug-in electronics.

The LŌDTRAK multifunction package is an efficient means of combining up to three protective functions along with individual annunciation and common alarm and trip relays into one unit. This means that you can take one function from each of the three areas, over-temperature, phase protection and ground fault protection and package them into a self-contained base or door mounted unit. The functions are then coordinated to make an economical, efficient package replacing relays which may have previously performed some of these functions. As needs dictate, additional protective functions can be added either separately or in a second multifunction package.

With the LŌDTRAK multifunction package, you can select three of the following functions: *overtemperature, overload (time and current), bearing overtemperature, open-phase, phase-reversal, open-phase, phase-unbalance, ground fault.*

Overtemperature, Bearing Over-temperature and Overload Protection

- Dual-parameter type protection combining resistance temperature detection with load current readings.
- Direct temperature readout.
- Push-to-test capability.

The LŌDTRAK overtemperature protection system is a dual-parameter type system which combines analog resistance temperature detector readings with load current readings. This results in a highly accurate determination of heating at the motor windings. Separate overtemperature bearing protection can be accomplished with an additional relay module monitoring the motor bearing RTD's.

LŌDTRAK protection lets you use your motor to its full capacity and yet protects it under all possible operating situations. You get protection during stalls, hot start-up, high ambients, cooling failures, and running overloads. In fact, you get protection against any normal adverse condition to which your motor is likely to be exposed.

With LŌDTRAK dual-parameter type protection you can often increase the up-time of any process or production line. After shutdown, for example, you can attempt restart sooner than normal, knowing that your motor is fully protected during hot starts of any kind.

For motors without imbedded resistance temperature detectors, install LŌDTRAK single parameter overload protection which senses load currents alone for simulating motor heating. You will find that LŌDTRAK solid state reliability and repeatability gives you preferred protection.

Phase Protection

- Open-phase, phase-reversal protection
- Open-phase, phase-unbalance protection
- Adjustable trip levels
- Push-to-test capability

LŌDTRAK control adds an extra dimension to phase protection by operating from current signals rather than voltage levels. With an open phase condition, a three phase voltage can appear at the motor terminals which could prevent operation of a phase unbalance relay that senses voltage, but would not prevent operation of the LŌDTRAK relay. LŌDTRAK offers open phase protection when the possibility exists of a line opening upstream; phase reversal protection to prevent motor heating due to phase sequence changes; and unbalance protection to prevent motor heating due to an unbalance in line currents caused by high single phase loads.

Ground Fault Protection

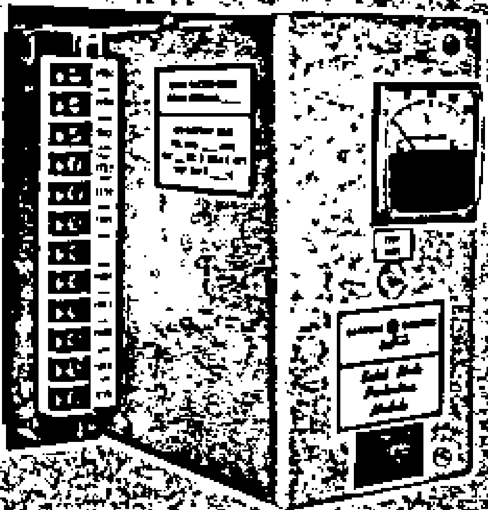
- Ground fault protection and diagnostic capability
- Manual or automatic reset
- Built-in test circuit
- Front panel calibration

LŌDTRAK control gives reliable solid state protection against ground faults and, at the same time, provides a convenient tool to facilitate the recognition of insulation deterioration. You can apply LŌDTRAK protection to either high or low resistance grounded systems. A built-in trip delay accommodates transient conditions and front panel calibration permits precise adjustment for trip out.

Single-function Units

You can specify single-function LŌDTRAK units for added flexibility in achieving the exact combinations of motor protection you require. Individual plug-in boards are mounted in a self-contained package with all inputs and outputs brought to a convenient side mounted terminal board. Each unit is designed for panel mounting, and contains visual trip and self-testing hardware.

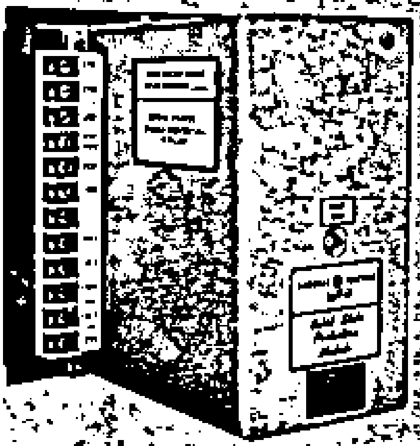
OVERTEMPERATURE PROTECTION



The LŌDTRAK overtemperature module combines RTD motor winding temperature readings with load current readings for accurate, dual parameter temperature protection. With an additional relay module, you can also measure bearing temperature. This means your motor is protected during stalls, hot start-up, high ambients, cooling failures, and running overloads.

Technical Data: GET 3163
GET 3158

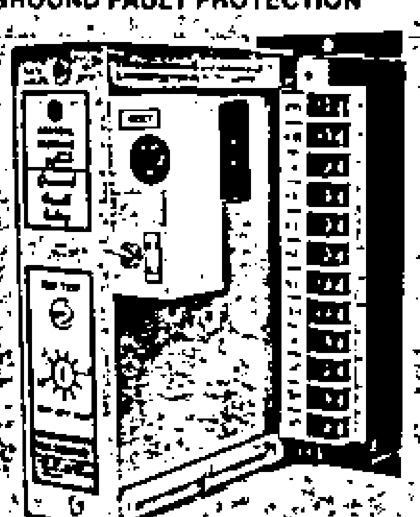
PHASE PROTECTION



The open-phase, phase-reversal and open-phase, phase-unbalance modules protect against open phase and incorrect rotation and open phase and phase unbalance respectively. Operating from current signals, open phase can always be detected, even if the motor is supplying a three phase potential to the relay.

Technical Data: GET 3161
GET 3159

GROUND FAULT PROTECTION



The LŌDTRAK ground fault protection module may be installed in both high and low resistance ground systems. The module features front panel calibration and trip delay for transients and may also be used in diagnosing insulation deterioration.

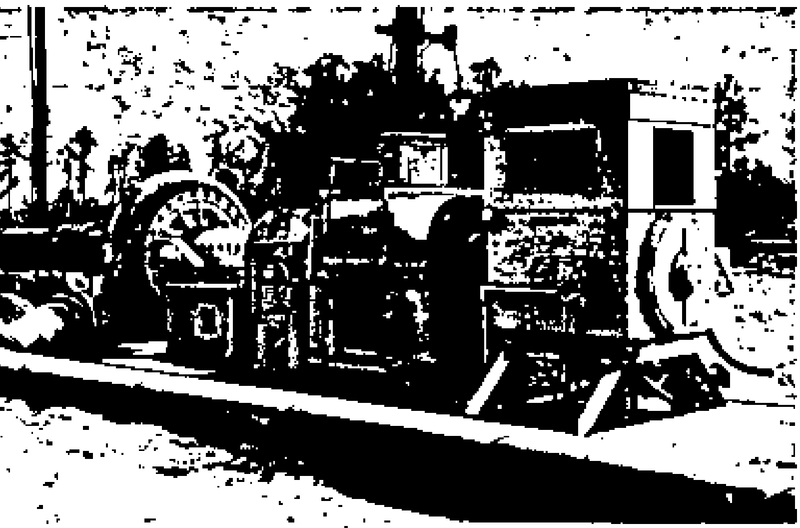
Technical Data: GET 3160

When Your Motor Needs LŌDTRAK Protection

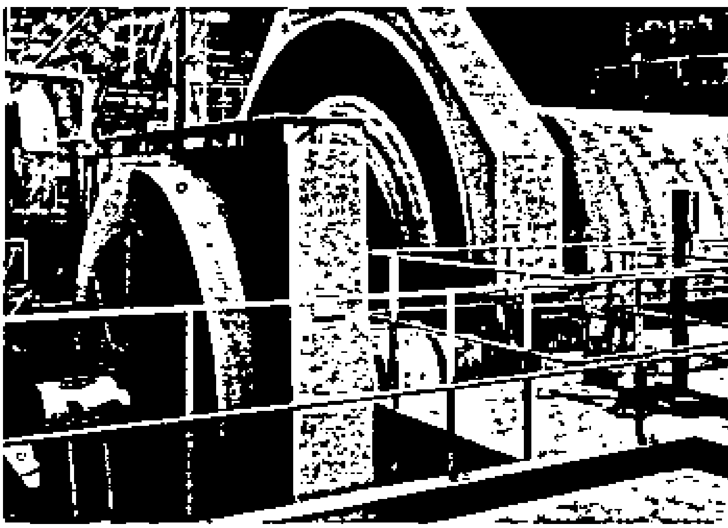
If you have a motor that must work at full capacity, a motor hit repeatedly with transient loads, a motor that must restart frequently, or any motor critical to plant or process drives, you have a motor that needs solid state LŌDTRAK protection.

For example, take a motor that must operate continuously, such as one driving main blowers on a catalytic cracker, one driving crude pumps for a distillation plant, one driving auxiliaries for a power station. Such a motor is critical to the process and its protection should be extra reliable to prevent loss of the motor altogether. In such a case it is also highly advantageous to receive a warning of impending shutdown so that the motor load can be reduced or other action taken. LŌDTRAK's computed temperature level signal (analog) can be made available for closed loop load control systems. Other applications include:

- Operating in an atmosphere that contains air filter clogging materials potentially destructive to your motor, such as in cement plants, textile mills, mining operations or chemical plants.
- When your motor is subject to severe transient loading such as found in chipper and crusher drives, positive displacement pumps and bulk material conveyors, LŌDTRAK allows output to the very limit of motor capacity without nuisance tripping.
- Drilling deep well irrigation pumps, unidirectional conveyors, compressors or any process where reverse phasing is destructive to the motor or other equipment.
- When it is imperative that continuous operation be maintained, such as main blowers on catalytic crackers, crude pumps on distillation processes or fuel pumps on high investment furnaces. Danger point alarms and indicators give you extra time to react to potential shutdown conditions.
- When you expect to obtain maximum available safe power from your motor, even at elevated ambient temperatures, you need LŌDTRAK protection.



Slurry portable booster pump where continuous operation is imperative and the motor must be protected against phase reversal, phase unbalance and operate over a wide temperature range.



Wet iron ore regrind ball mill where LŌDTRAK control protects during motor jogging, allowing the maximum number of safe starts per unit of time.

GENERAL ELECTRIC COMPANY
INDUSTRIAL CONTROL PRODUCTS DEPARTMENT
SALEM, VIRGINIA 24153

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(Reviewed and Accepted for Publication)

The Effects of Arcing Ground Faults on Low-voltage System Design

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The Effects of Arcing Ground Faults on Low-Voltage System Design

J. R. DUNKI-JACOBS, SENIOR MEMBER, IEEE

Abstract—Recurring reports of arcing ground fault burndowns have generated a considerable amount of interest in the subject on the part of those individuals who are responsible for the design of power systems. In fact the interest is so widespread that as one consequence, article 230-95 of the 1972 edition of the National Electrical Code requires that service entrance devices of specific types be equipped with additional ground fault protection.

This paper attempts to present a fundamental story on the subject of arcing ground faults to the extent that not only a greater appreciation can be gained from the elusive nature of this type of fault but also a better understanding of the requirements for applying protective devices. This knowledge is used to evaluate the degree of effectiveness of direct acting phase-overcurrent trip devices which leads into a discussion of the various ground fault protection modes. Subsequently the consequences of ground faults occurring on low-voltage systems protected by fuses are discussed to highlight the adverse consequences of single phasing.

Contributory Evolutionary Developments

THE FACT that arcing burndowns are a relatively recent development prompts the question as to what factors have adversely affected the operating record of low-voltage systems. It appears that the following three circumstances are the primary causes.

1) *A gradual change from ungrounded* delta-connected three-phase three-wire low-voltage systems to solidly grounded neutral systems serving both three-phase three-wire and three-phase four-wire *grounded systems.* This change was motivated by the realization that ungrounded delta-connected systems were susceptible to transient line-to-ground overvoltages which could be most effectively controlled by converting to a solidly grounded neutral system. This development encouraged the use of the neutral by line-to-neutral loading, such as in 480Y/277-V systems. As a consequence, however, a line-to-ground fault (the most predominant failure mode) resulted in a considerable fault current flow. Magnitudes as high as the three-phase fault value could be expected, compared to just a few amperes for a similar fault on an ungrounded system.

2) The early low-voltage systems were predominantly operated at 208Y/120 V. Due to increasing load density requirements, *an increase in voltage to 480Y/277 V* became an economical necessity but resulted in an increase in arcing fault burndowns because of inadequate ground fault protection. Research has shown that at the lower voltage, the arcing line-to-ground fault is essentially self-extinguishing, while at 277 V the arc can be sustained until an interrupting device disconnects all three phases of the faulted circuit from the source.

3) *A gradual change from lower interrupter current ratings, viz., 600 A, to extremely large ratings, up to 4000 A.* Economies further popularized the application of fused switches, which under certain circumstances may provide the barest arcing ground fault protection, if any at all.

The accumulated effects of the preceding developments set the stage for potential destructive arcing ground faults. When the number and extensive nature of the fault damage incidences became apparent, a gradual upgrading in system design practices emerged. The National Electrical Code recently accepted a proposal (230-95) to make the use of ground fault protection mandatory on all service entrance equipments rated 1000 A or more when operating at more than 150 V to ground.

Review of Fault Conditions

Historically, power system designers have generally concerned themselves with three-phase bolted fault current magnitudes because these quantities are used to select adequate interrupters, such as circuit breakers and fuses. Line-to-line fault magnitudes are of considerably lesser importance, but have been used by protective relay engineers to incorporate protection against line-to-line faults. The line-to-ground fault current magnitudes on low-voltage systems, however, were given hardly any consideration. A general understanding exists to the effect that a bolted line-to-ground fault could reach magnitudes as high as the bolted three-phase fault magnitudes. Such knowledge, however, was not really used since neither protective devices nor interrupters were selected on this basis.

In all these short-circuit calculations it was customary to assume that the fault was a *bolted* fault. It has become apparent that the *arcing* variety of faults has created severe problems, which up to about a decade ago were not clearly recognized. Not until repeated reports were made that equipments were severely damaged by some obscure type of fault, were thorough investigations initiated to determine the nature and cause of these faults and burndowns. These investigations revealed that *arcing* faults may have current magnitudes substantially less than bolted faults of the same type, with the result that phase-

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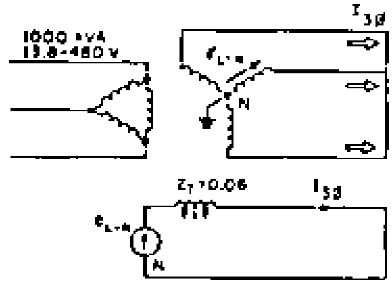
overcurrent protective devices may not be sensitive enough to detect these ground fault currents and initiate their removal.

Bolted Three-Phase Fault

Consider a 1000-kVA low-voltage substation with a conventional 6-percent short-circuit impedance transformer (Fig. 1). The calculation of the bolted three-phase fault current value basically involves only the driving voltage, which is the line-to-neutral voltage or 277 V and the transformer impedance. The bolted three-phase fault current magnitude in per unit will then be the per unit line-to-neutral voltage divided by the per unit transformer impedance, or one per unit divided by 0.06 which is about 16.6 per unit. Since, in the per unit system, one per unit A equals the full-load amperes of the transformer (1203 A), it follows that 16.6 per unit A is actually 16.6 × 1203 or about 20 000 A.



In per unit:

$1\ \text{p/u A} = \text{transformer FLA}$

$$= \frac{1000}{480\ \sqrt{3}} = 1203\ \text{A}$$

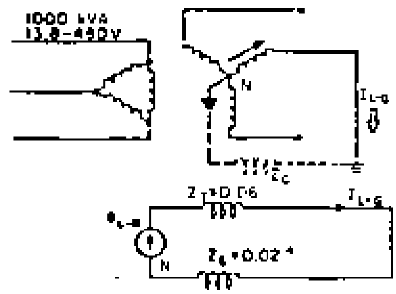
$$I_{3\phi} = \frac{e_{LN}}{Z_T} = \frac{1.0}{0.06} = 16.6\ \text{per unit}$$

$$= 16.6 \times 1200 = 20\,000\ \text{A}.$$

Fig. 1 Calculation of bolted three-phase short-circuit magnitude.

Bolted Line-to-Ground Fault

For a bolted line-to-ground fault, the line-to-neutral driving voltage will not only be required to drive the ground fault current through the appropriate transformer winding impedance but also through the impedance of a ground return path back to the neutral of the transformer (Fig. 2). Therefore, two impedance elements restrict the flow of current. The transformer impedance is the same impedance used and discussed previously. The new element, the ground return impedance or Z_G, is a variable quantity and is controlled primarily by the type of ground return path available to the ground fault current. A ground return path physically close to outgoing power conductors usually exhibits only a very small reactance and impedance. If the ground fault current path is through remote water pipes, building steel and other metallic or nonmetallic elements, the ground return impedance will be considerably higher. The sample calculation in Fig. 2 assumes that the ground return impedance is two percent, and the outgoing phase circuit impedance is negligible. The ground fault current is again the line-to-neutral per unit voltage divided by the total per unit impedance of the transformer and the ground return circuit, or one per unit divided by 0.08 or about 12.5 per unit. In terms of actual amperes, this represents 12.5 times 1203, or approximately 15 000 A.



In per unit:

$1\ \text{p/u A} = \text{transformer FLA} = 1203\ \text{A at 480 V}$

$$I_{L-G} = \frac{e_{L-N}}{Z_T + Z_G} = \frac{1.0}{0.06 + 0.02}$$

$$= \frac{1.0}{0.08} = 12.5\ \text{per unit}$$

$$I_{L-G} = 12.5 \times 1203 = 15\,000\ \text{A}.$$

If $Z_G = 0$, then $I_{L-G} = I_{3\phi} = 20\,000$ A.

Fig. 2 Calculation of bolted line-to-ground short-circuit current magnitude. *Ground path impedance (Z_G) can vary considerably. For minimum Z_G provide ground return circuit in close proximity to outgoing power conductors.

Nature of Arcing Faults

The assumption of bolted faults is quite hypothetical since these faults are not usually encountered in actual situations. More realistically, faults are of the arcing type, meaning that energized conductors may come in accidental erratic contact with each other or ground. To better understand the phenomenon and the calculations associated with an arcing fault, it is helpful to introduce at this point a spark gap as a mathematical facsimile of an arcing fault. Considerable research done in this area indicates that the spark gap on a 480-V system would have

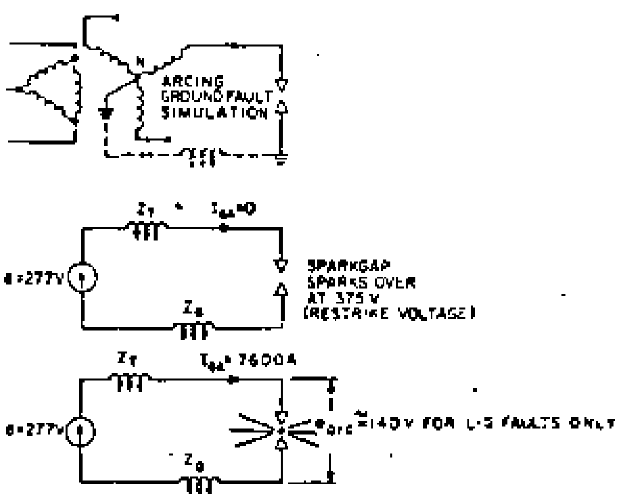


Fig. 3. Simulation of arcing fault by spark gap.

a "spark-over" voltage or a "restrike" voltage of about 375 V (Fig. 3). In other words, it takes an instantaneous value of 375 V before the spark gap begins to conduct. It further develops that once the spark gap conducts, the voltage across the gap reduces to approximately 140 V. *It is the energy of this arc which releases a tremendous amount of heat in an extremely short time*. The surrounding air heats up, building up pressures which blow open doors and cause copper or aluminum buses to be melted away in a matter of seconds or less. Most surprisingly, this large amount of energy is released at fairly low current levels. The usual phase-overcurrent direct-acting trips may not always sense these low level arcing faults within a reasonably short time. It is therefore appropriate to gain an understanding of the current limiting effects of arcing faults.

Comparing Bolted and Arcing Line-to-Ground Fault

Going back to the *bolted* line-to-ground fault example [Fig. 4(a)], the dotted sine wave represents the 277-V rms line-to-neutral voltage. Note that the instantaneous peak voltage of this wave is 390 V. The solid sine wave represents the bolted line-to-ground fault which was previously calculated at 15 000 A. Note that this current is a continuous sinusoidal current with an rms value of 15 000 A.

Plotting the same 277-V rms line-to-neutral voltage on another time base, it is essential to first identify the spark-over voltage of 375 V, [Fig. 4(b)]. Up to the point in time that the instantaneous voltage is less than 375 V, the spark gap does not conduct, and therefore the arcing current is zero. When the voltage increases to a value of 375 V, the gap begins to conduct. At that instant an arcing current begins to build up, while the voltage across the gap remains relatively constant at about 140 V. (This suggests that the arc resistance is inversely proportional to the arc current.) The arc current reaches its peak when the line-to-neutral driving voltage equals the arc voltage e_{arc}; thereafter the arc current diminishes. The arc extinguishes when the line-to-neutral voltage reverses polarity to reach a value at which the volt-time areas A and B are equal, [Fig. 4(b)]. This process is repeated every half-cycle and results in an arcing ground current of a discontinuous nonsinusoidal character.

Overcurrent devices generally respond to rms currents; this value of the arcing ground fault current is as indicated in Fig. 4(b). Although the determination of this rms value is quite complex, researchers were able to relate this value to the bolted fault current value. In the case of the *arcing ground* fault, the probable minimum rms value is only 38 percent of the *bolted* three-phase fault value. Applied to the calculated value in the example, this would be about $0.38 \times 20\,000 = 7600$ A.

With a basic understanding of this phenomenon as it applies to line-to-ground faults, it suffices to say that line-to-line and three-phase arcing faults can be similarly

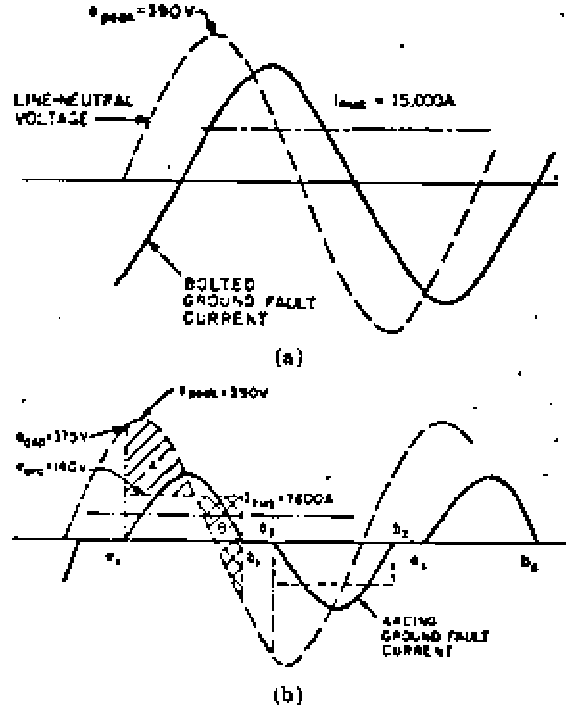


Fig. 4. (a) Bolted line-to-ground fault current is essentially a sine wave. (b) Arcing line-to-ground fault is a discontinuous nonsinusoidal wave.

explained. The higher driving voltage (line-to-line rather than line-to-neutral voltage) causes the gap to conduct for a considerably longer time. Although the arc voltage builds up to 275 V (as compared to 140 V) the resultant probable arcing current values are considerably higher.

The importance of the system voltage can now also be visualized. On 208-V systems, neither the peak line-to-neutral voltage ($1.41 \times 120 = 170$ V) nor the peak line-to-line voltage ($1.41 \times 208 = 295$ V) exceeds the 375-V restrike voltage. On this theoretical basis, an arcing line-to-ground fault could not be sustained. In practice however, not all 208-V arcing ground faults are known to have been self-extinguishing.

In summary, it should be remembered that arcing ground faults are limited not only by the ground return path impedance, but also by the arc voltage value. It is also important to remember that the probable minimum arcing line-to-ground fault current value is only about 38 percent of the bolted three-phase fault magnitude calculated at 480 V*. As a matter of interest, the minimum line-to-line arcing fault is 74 percent of the bolted three-phase value, while the minimum three-phase arcing fault value is about 89 percent of the bolted three-phase fault value contributed by the transformer only. Any motor contribution should not be considered part of the calculated three-phase bolted value.

The knowledge gained in the discussion will prove to be extremely useful in determining why circuit interrupters have in the past failed to provide the protection against low level arcing ground faults.

* See author's note on page 10.

't protection feature can no longer be justified eco- ically. This development will consequently require that *ground fault* protectors on the larger upstream interrupters may have to be coordinated with downstream *phase-overcurrent* direct-acting trips. The anticipation of the proper compatibility between such devices in the early specification phase of the design activities requires an increasing intelligence and experience level on the part of the design engineer. As a result, selectivity studies on low-voltage systems are expected to become the rule rather than the exception.

In preparation for a reevaluation of the ground fault protection options, it is essential to identify four distinct modes of ground fault detection.

1) *Ground Sensor Protection:* It is based on a combination of a donut-type current transformer (CT) which surrounds all three or four outgoing conductors *and a specific* overcurrent relay with either instantaneous or time-delay operating characteristics. The current transformer produces an output proportional to the ground fault component of the total *outgoing* current (Fig. 7).

In the case of balanced three-phase operation, the total current will always equal zero, and consequently the ground sensor relay will not sense any current. Even in the presence of line-to-neutral loads, the relay current will be ·o for the reason that the phase current passing through window will return through the neutral conductor which is also located inside the window. Therefore, the total current "out" equals the total current "in" which results in a cancellation of fluxes. In the presence of a ground fault, however, the ground fault current will pass through the donut only once and will return through some ground fault path outside the donut CT.

The ground sensing principle has been used for many years in medium-voltage systems and is capable of detecting currents as low as 10 A. In low-voltage systems, it is used in conjunction with molded case breakers or power circuit breakers equipped with direct-acting trips. Physically, the CT can be easily applied on cable circuits, but busway circuits represent real problems in that the donut CT will become extremely large and expensive. In these instances, the use of solid-state current relays are particularly advantageous since these relays require only a small iron core cross section.

2) *Broken Delta Ground Fault Protection:* The second ground fault protection principle senses a broken-delta voltage. This principle has been applied in the GE static overcurrent trip (Power Sensor). The ground fault option Power Sensor ground (PSG) available on the Power Sensor trips operates in conjunction with three current sensors (CT) which are connected in series or delta. ;. 8). Under *balanced* load conditions, the *outgoing* currents in phases A, B, and C will induce a secondary voltage signal proportional to the primary current. Because of the delta connections, the three individual secondary voltages will appear in delta to form a closed delta with the result that the voltage signal $V_{\Delta 1}$ to the PSG will be zero.

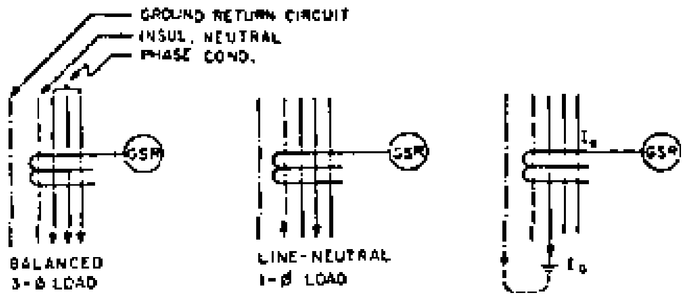


Fig. 7. Operation of ground sensor relay protection principle.

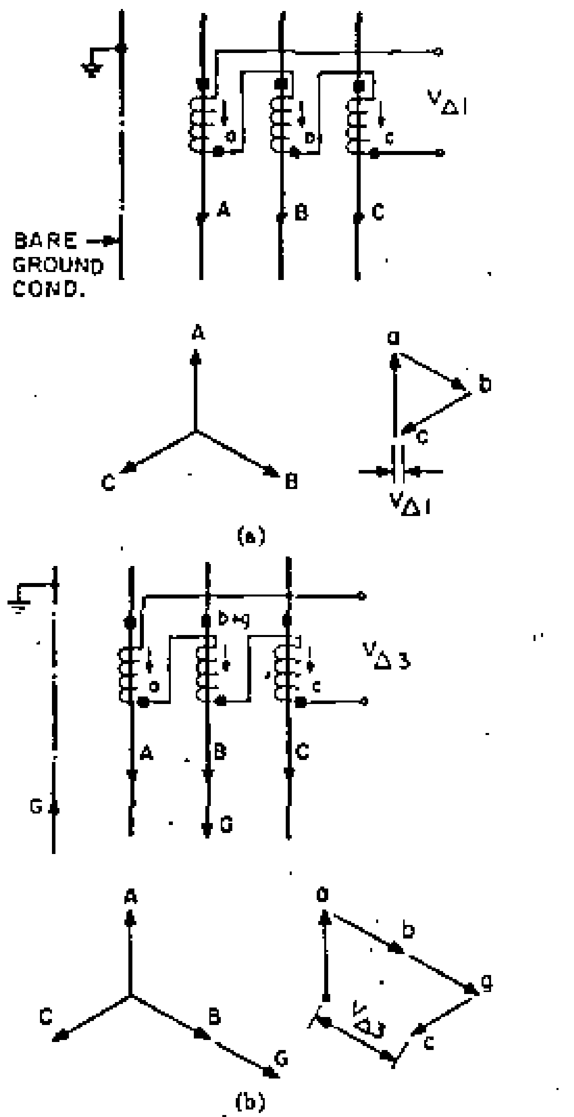


Fig. 8. Operation of broken delta protection principle.

Occurrence of a ground fault will add another vector (G) in phase with vector (B). On the secondary of the current sensors, a corresponding vector (g) will be introduced which tends to open one corner of the delta. A secondary voltage, $V_{\Delta 3}$ will appear, and the PSG will respond properly.

Note that the PSG scheme relies on three individual current sensors and can therefore be easily used on busway

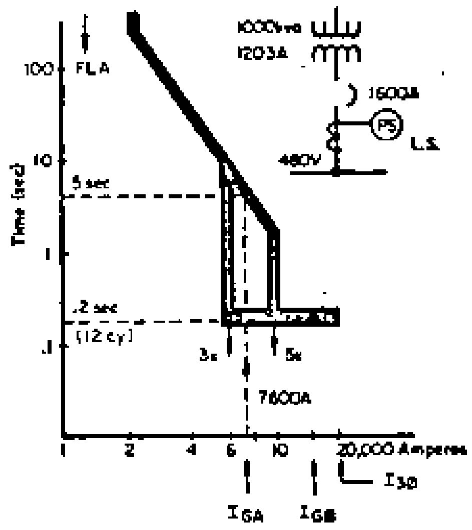


Fig. 5. Illustration of effectiveness of low-set short-time trips in presence of arcing ground fault.

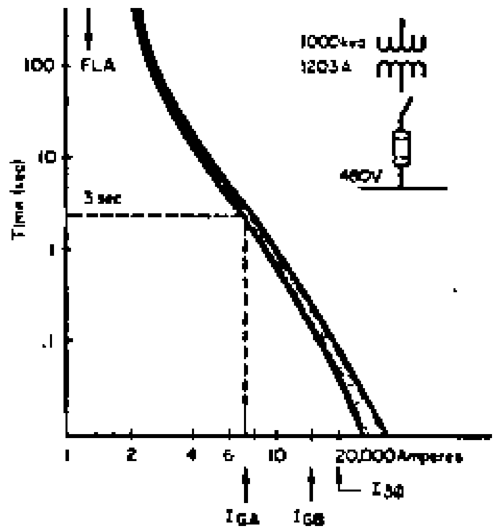


Fig. 6. Illustration of expected operation of fuse in presence of arcing ground fault.

Phase Overcurrent Trips as Arcing Ground Fault Protectors

To be effective, phase-overcurrent protectors should be equipped with short-time trips or instantaneous trips set low enough to quickly sense the anticipated minimum arcing line-to-ground fault. In Fig. 4(b) this magnitude was identified as 7600 A. It is customary to set protective devices at about 70 percent of the anticipated minimum fault current to help assure that, in the presence of this minimum current, the overcurrent protective device will cause positive tripping.

On the time-current plot shown in Fig. 5, the *Power Sensor** (GE solid-state direct-acting trip) selective trip characteristic is shown, consisting of long-time and the short-time elements. It is assumed that this trip represents the 1600-A transformer main secondary breaker usually applied with a 1000-kVA unit substation. Two settings of the short-time trip have been shown; one at three times and one at five times the 1600-A coil rating of the Power Sensor trip.

As previously derived, the bolted *three-phase fault* value is 20 000 A, while the bolted *ground fault* value was calculated to be about 15 000 A. The *arcing* ground fault magnitude is shown to be roughly 7600 A which is 38 percent of 20 000 A.

First assume that the short-time trip was set at five times. The arcing ground fault of 7600 A will not cause this short-time trip to pick up. Consequently, the long-time trip will, after some 5 s, time out and trip the main breaker. This is an extremely long time for an arcing ground fault to persist in a bus structure. Lowering the short-time trip setting to three times, it becomes immediately evident that the same 7600-A arcing ground fault will be removed in 12 cycles. This short fault clearing time is within the desired fault clearing time for arcing faults which is generally considered to be between 6 and 30 cycles. This examination shows that *it is extremely important to keep the short-time trip pick-up levels as low as possible.* Ideally, arcing ground faults should be cleared in less than 12 cycles.

* Registered professional trademark of the General Electric Company.

Fuses as Arcing Ground Fault Protectors

Under the same circumstances, fuses will perform rather poorly (Fig. 6). Again assuming a 1000-kVA substation using a 1600 A "*L*" fuse, the average melting curve indicates that one fuse will blow on a 7600-A arcing fault in about 3 s. This is considerably longer than the desired 12-cycle fault clearing time. Inasmuch as the fuse characteristic is fixed, very little can be done to improve the ground fault sensitivity of the fuse. The only solution appears to be the addition of a separate ground fault relay. A later discussion will bring to light that, even *if one fuse* properly senses a ground fault, the subsequent *fuse blowing will not remove the ground fault.*

Fuses in the primary of a delta-wye connected transformer are less effective in that the low-voltage *arcing ground fault* current (I_G) appears to the primary fuses as a *phase overcurrent* of a magnitude equal to only 58 percent of I_G. (This is shown later in Fig. 11.)

Review of Ground Fault Protection Modes

The continuing emphasis on arcing fault protection will be accompanied by increasing demands for electrical equipments designed to minimize the initiation as well as communication of arcing faults within switchgear and switchboards. In spite of such equipment features and improvements, the probability of arcing faults cannot be ignored. Back-up protection in the form of sensitive ground fault protection is expected to find acceptance.

The additional ground responsive relays and trips are likely to increase the cost of interrupters appreciably. The percentage increase is especially significant on smaller and lower priced equipments. The function-cost tradeoff will establish a price level below which the ground

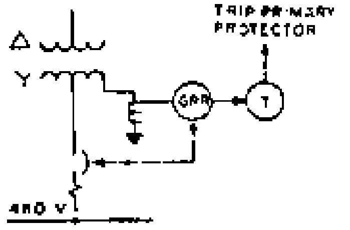


Fig. 9. Ground return protection applied to transformer neutral ground protection.

feeders. A fourth current sensor will be required on three-phase four-wire systems.

3) *Residual Ground Fault Protection:* Although frequently applied in medium-voltage systems, this scheme is seldom used at low-voltage levels because of the need for three current transformers in case of three-phase three-wire systems, or four current transformers for three-phase four-wire systems. Only for special applications will residual ground fault protection be practical. For this reason, no further reference will be made to this mode of ground fault protection.

The options so far described rely on the detection of *ground fault* current as it flows *from the power source to the ground fault.* These options are the most reliable since they respond to the *total* ground fault current.

4) *Ground Return Current Protection:* The fourth ground fault protection principle attempts to sense the ground fault current as it returns to the transformer neutral. This option should be used only in very limited applications for the reason that it is susceptible to operating falsely due to the fact that ground return currents may flow through more than one path. A very effective application of this scheme is in the transformer neutral connection to ground (Fig. 9). It should be obvious that all ground fault current will have to return to this connection.

The ground return relay (GRR) has to be set selective with the downstream phase and ground fault protective devices to achieve selectivity. Operation of the GRR should cause the main secondary breaker to trip and a timing relay to start timing. If after a preset time delay, the fault has not been removed by the main secondary breaker, the timing relay should transfer-trip the transformer primary protector. Thus the GRR not only backs up the main breaker protection, but also provides protection against ground faults in the transformer secondary winding and its connection to the breaker.

Ground Fault Protection Considerations

The application of ground fault protection on solidly grounded systems is relatively simple if a complete and separate set of ground fault relays is available with each interrupter. The main reason for the absence of these ground responsive devices is the cost of the additional ground fault protectors; sometimes as high as 25–40 percent of the basic interrupter price. As a result, system designers are expected to place a greater emphasis on system design practices which tend to produce conditions whereby the phase-overcurrent protector has sufficient sensitivity and speed to provide arcing ground fault protection as well.

The usefulness and limitation of phase-overcurrent trips to function as arcing ground fault protection are to a great extent determined by the relative characteristics and ratings of the interrupters operating in series as well as the available short-circuit current. No attempt will be made here to pursue this subject for the reason that its complexities have not been resolved so that a simple procedure can be suggested. Instead, to assist the design engineer in selecting the proper ground fault protective function, a broader discussion on the more subtle peripheral considerations will be presented which is believed to be of greater significance in the overall context.

Effect on Combination Motor Starters

By definition, a combination starter consists of a contactor and another interrupter, either a fuse or circuit breaker, usually a molded case circuit breaker.

The majority of combination starters utilizes breakers with a range of ratings which inherently provide arcing ground fault protection. Increasing motor horsepower ratings, however, require circuit breaker ratings which may be insensitive to arcing ground faults. When additional ground fault protection is required, these breakers need to be equipped with shunt trips and an appropriate control power supply.

Another solution would be to allow the ground fault protector to de-energize the starter holding coil. The probability that the contactor will be called upon to interrupt a current in excess of its contact interrupting rating, however, prohibits this apparent solution. Mindful of this limitation, the fused combination starter should be avoided whenever additional ground fault protection is mandatory.

Effect on Fused Switches

Fused switches rely on fuses to interrupt phase overcurrents in excess of about six to seven and a half times the switch rating. The switch is usually operated by a manual or electrical mechanism initiated by operating personnel.

Ground fault relays require that fused switches be equipped with an electrical trip to remove a ground fault of a predetermined magnitude either instantaneously or after a set time delay [Fig. 10(a)]. Under these circumstances the switch cannot be permitted to await the operation of the fuse because, especially on larger fuses, the arcing ground fault will persist too long. The devastating results of prolonged arcing ground faults have been previously explained.

Furthermore, it should be recognized that an arcing fault may be initiated as an *arcing line-to-ground* fault with a magnitude below the switch interrupting rating [Fig. 10(b)]. Assume that, either instantaneously or

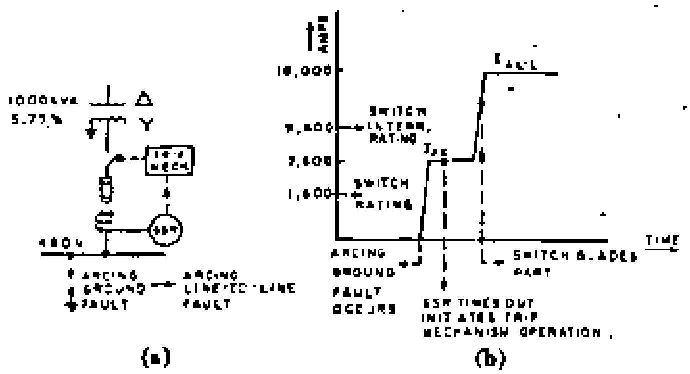


Fig. 10. Potential problem created by operation of fused switch in presence of dynamic arcing fault.

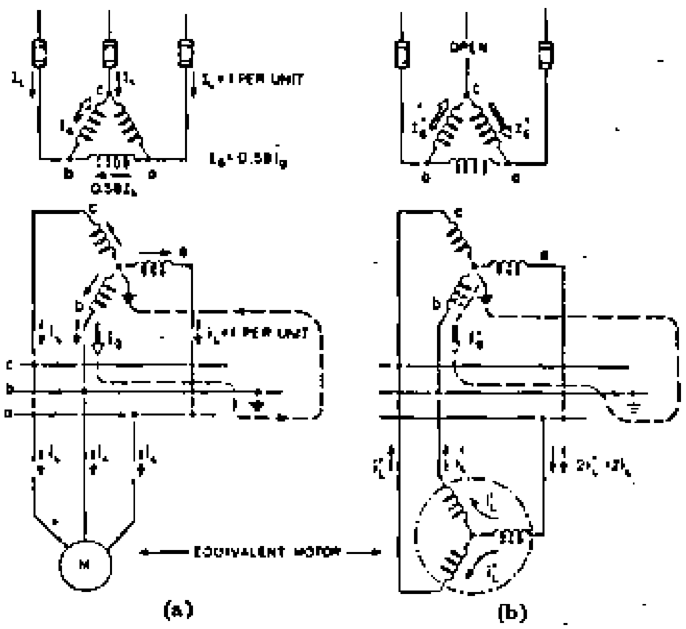


Fig. 11. Diagrams illustrating that ground fault persists after blowing one transformer primary fuse.

after some time delay, the switch receives the signal to open. Because of its turbulent nature the fault could, in bare bus equipments, easily escalate into an *arcing line-to-line* fault. The fault current magnitude would then increase rapidly above the switch interrupting ability just as the switch attempts to open the short circuit.

It should be recognized that the fused switch protection coordination philosophy is based on a steady-state fault current. In the case of an arcing ground fault, however, the fault current is transitory, imposing an unpredictable interrupting duty on the switch mechanism. For this reason, the use of fused switches with inadequate load break ratings should be avoided.

Transformer Primary Circuit Single Phasing

In the absence of a main secondary breaker, an arcing ground fault in the main bus structure can be extremely devastating in that only transformer primary protectors are available to detect such a ground fault. It will be shown that such protection may be inherently inadequate to prevent a burndown.

In Fig. 11, an arcing ground fault is assumed on the "b" bus. The resultant ground current (i_g) in the low-voltage "b" phase winding causes a corresponding current (I_G) in the high-voltage "b" phase winding. Observing that the primary delta current must be 58 percent of the corresponding secondary wye current to satisfy the transformer energy equation, it follows that $I_G = 0.58\, i_g$.

It is appropriate to point out at this time, the difference in the nature of the primary I_G and secondary i_g currents. The low-voltage i_g current is truly a ground fault in that this current returns to the neutral of the low-voltage winding through a ground return circuit. Observe that the primary I_G current is not a ground current since it flows only in the phase conductors. As a result: *ground fault relays in the transformer primary supply circuit will not respond to low-voltage ground fault currents.* Only phase-overcurrent relays in the transformer primary supply circuit will sense the I_G currents but are likely to operate only after some time delay, since they are set to pass relatively high steady-state load currents.

If the transformer primary protector is in fact a fuse, the arcing fault currents of reduced magnitudes are likely to blow a primary fuse only after a considerable time delay. Of course, the fuse melting time will be measurably shortened when the transformer approaches full-load conditions. In the meantime, however, a low-voltage arcing fault causes considerable burning damage to equipments.

In the event only one primary fuse does blow, [Fig. 11(b)], the problem is compounded since not only the ground fault persists at low current levels, but also the motor load is operated from a single-phased power supply. The single-phasing aspect forces a current distribution in the motor branch circuits in a two-one-one proportion [Fig. 11(b)]. As a result, only one phase will sense an overcurrent, which dictates the need for three overload relays.

SUMMARY

The occurrence of arcing ground faults and associated damage can be effectively reduced by the use of compartmentation in equipments such as available in GE AKD-5 switchgear. This feature must be complemented with suitable arcing ground fault protection to help assure that any developing arcing ground fault will be quickly sensed and properly removed. To do this, the most economical approach involves the use of lower ampere rated three-phase protectors, such as the power circuit breakers. The use of devices with long-time and short-time trips rather than those with just long-time and instantaneous trips should be seriously considered in an effort to sense ground faults and remove such faults within the desired 6 to 12 cycle fault removal time. To accomplish this, short-time trips and also, where possible, instantaneous trips should be set as low as possible. Additional selectivity will also be gained. Where this combination of requirements cannot inherently provide ground fault protection, it will be necessary to add one of the four suggested methods of arcing ground fault protection.

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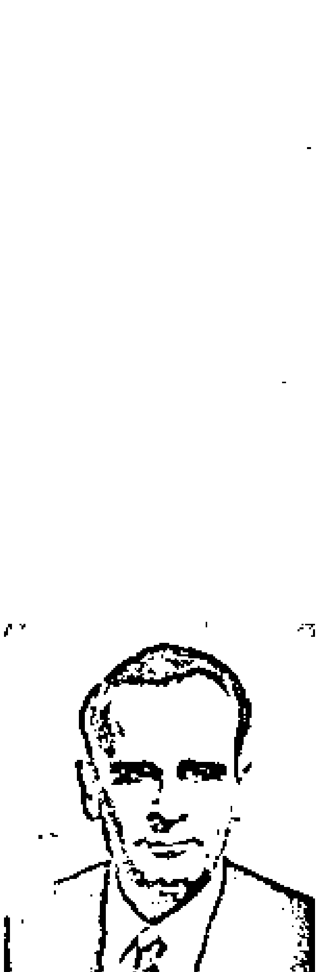
Author's note (Dec. 1975)

In the example, comparing bolted and arcing ground-fault magnitudes, the fault was assumed at the transformer secondary terminals on the load-center unit substation bus. For this fault location the ground return path impedance is negligable, hence the bolted three-phase fault magnitude equals the bolted line-ground fault magnitude ($x_1 = x_2 = x_0$).

The statement that the arcing ground fault value equals 38 percent of the bolted three-phase fault is only true in the example; viz. a fault at the load-center bus.

More generally, the statement should read that the arcing fault value equals 38 percent of the bolted line-ground value as calculated for a particular fault location.

For example, to evaluate the arcing ground fault current value at a motor control center, first calculate the bolted three-phase fault current. Using the ground return impedance magnitude, calculate the bolted line-ground fault current. Multiply this magnitude by 0.38 to determine the probable minimum arcing ground fault current value.



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Power Systems Protection

INTRODUCTION

The Art of Protective Relaying

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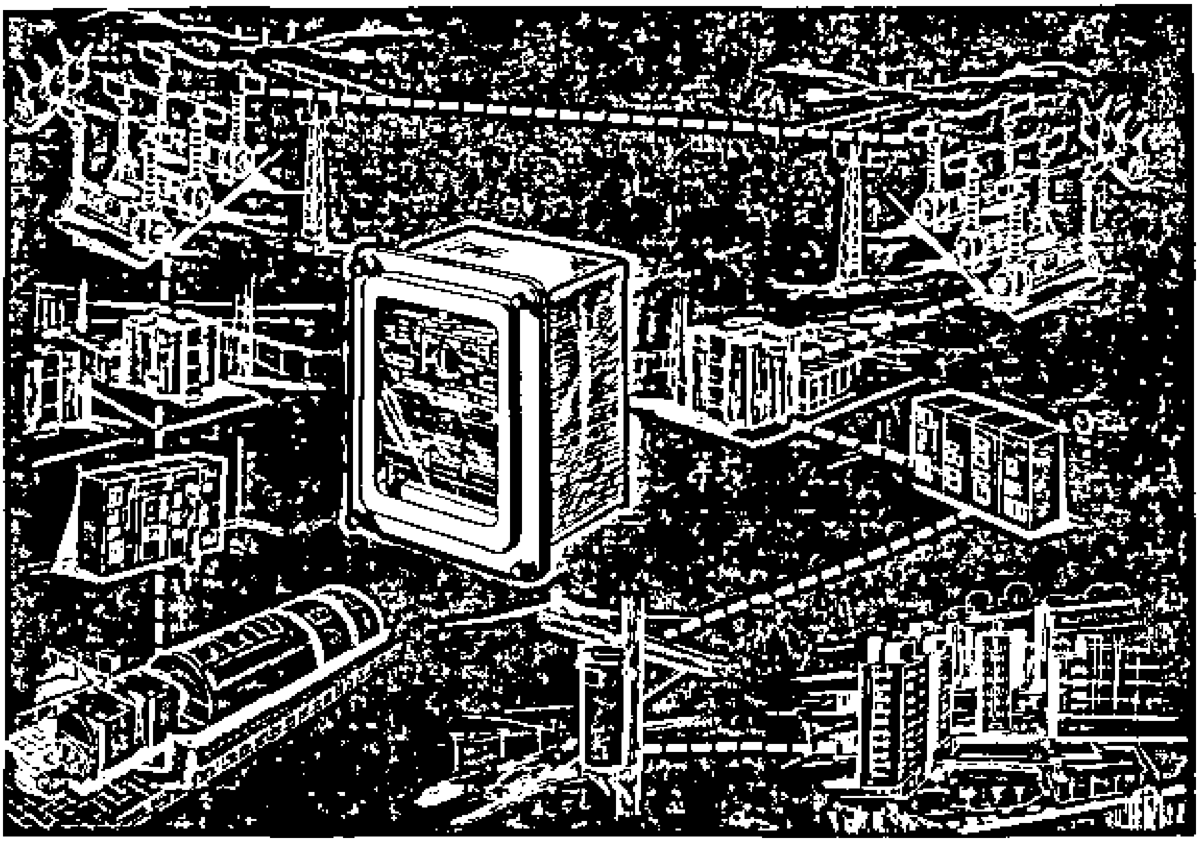


An Introduction to Protective Relaying

Modern electric power systems are remarkably dependable, standing ready night and day to deliver their energy without interruption. Protective relays have an important part in assuring this continuous service. Always on guard, they react instantly to protect the system from damage and to minimize any service interruption.

THE POWER SYSTEM

To understand better how protective relays fit into the modern power system, let us first review the makeup of that system. A power system is designed to generate electric power of sufficient quantity to meet present and estimated future demands of the users in some particular area, to transmit it to the area where it will be used, and then to distribute it within the area. For normal operation, these are minimum requirements.

To insure the maximum return on the large investment in equipment which goes to make up the power system, and to keep the users satisfied with reliable service, the whole system should be kept in operation. This may be accomplished in two ways. The first way is by design and maintenance of each component to prevent any failures which would destroy the component's usefulness in the power system. Since the economic considerations of design and maintenance procedures allow this course to proceed only so far, a second course must be followed: to control and minimize the effects of any failures that do occur. This is where the protective relay fits into the power system. The protective relay is the device which operates to disconnect a faulty part of the power system, thereby protecting that part and the remainder of the system from damage.

There are a number of causes for the failure or breakdown of the various components of the power system. Faults or short circuits can occur between individual phase wires or coils and between a phase wire or coil to ground as a result of a breakdown of the insulation protecting them. The resulting electric arc, usually containing considerable power, can wreak terrific damage in a very short time, not only putting that component of the system out of immediate service but also making it inoperable for a long time. These faults or short circuits are caused basically by insulation failure, but the failure may be induced by such things as voltage surges, overloading with subsequent overheating of apparatus, abrasion due to expansion and contraction, or foreign matter in the apparatus. Transmission lines develop faults from such causes as wind, ice and sleet, large birds bridging the insulators, lightning, swinging tree limbs, crane booms, and many other causes. Some of the other abnormal conditions which impair a component's function in the power system are overheating of bearings, over or under speed, reversed phase sequence, and single-phase supply where three-phase power should be present.

A power system can be thought of as a chain, the links of which are the generators, the power transformers, the switchgear, the transmission lines, the distribution circuits, and the utilization apparatus. The arrangement of these links may be seen in Fig. 1. The failure of any link destroys the capacity of the

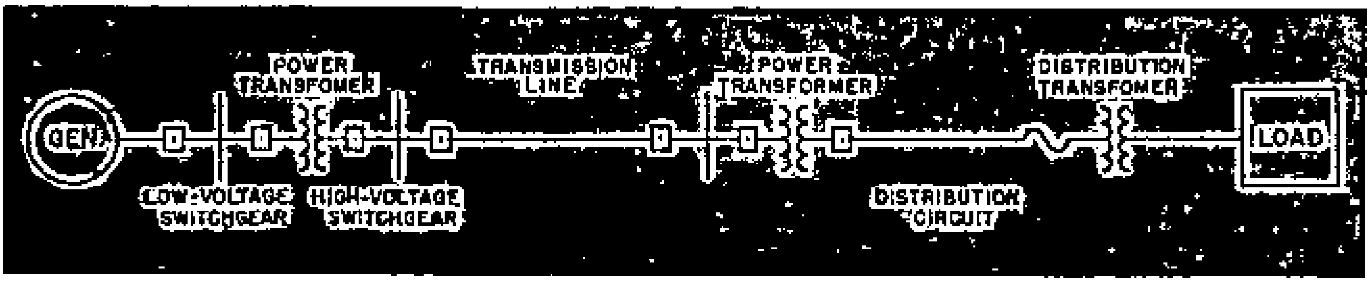


FIGURE 1. Arrangement of power system links

chain to do the work for which it was intended.

One way in which the continuity of the chain can be preserved is to provide alternate links. For example, the transmission lines, being exposed to the natural elements, are much more vulnerable to short circuit faults than the power transformers and switchgear. Hence, alternate transmission lines may be economically justified, whereas alternates for the power transformers and the switchgear would not. The networks of power systems now blanketing the United States are often interconnected at various points to accomplish this. Since each link in the chain involves a large investment in equipment, alternates are frequently prohibitively expensive.

THE FUNCTION OF RELAYS

Protective relays are placed on the system to reduce the number of alternate links to a minimum. They do so by avoiding equipment damage or by limiting it to the single unit that may be in trouble. Quickly the relays locate the fault and trip circuit breakers which will interrupt the flow of current into the defective apparatus, thereby isolating it. The effect of this quick isolation is twofold. First, it minimizes, or prevents altogether, damage to faulted apparatus, thus reducing the time and expense of repairs and permitting quicker restoration to service. Secondly, it minimizes the seriousness and duration of the fault's interference with normal operation of the unfaulted parts of the system, allowing them to continue to supply their normal power. In many cases, the unfaulted parts of the power system can supply the additional power to replace what was normally supplied through the faulted apparatus.

The protective relay gains the information it needs to locate a fault in the form of currents and voltages from instrument transformers located on the specific portion of the power system being protected. This information is then relayed in the form of a tripping impulse to the circuit breakers, which isolate the defective apparatus by interrupting the flow of current from all sources.

Of course, the source of the relaying information, the instrument transformers, and the particular circuit breakers which are to be tripped by the protective relay when it operates must be preselected. This is done when the relay is applied to the power system. For example, the instrument transformers would be selected so as to indicate the flow of current into the protected portion of the system and the voltage drop across that portion of the system. The circuit breakers selected to be tripped would interrupt all sources of current flow into the protected portion of the system.

This is an example of *primary relaying*, the first line of defense. When the primary relaying operates to trip its associated circuit breakers, only the faulty element or the minimum portion of the power system is disconnected.

Back-up Relaying

If a primary relay should malfunction or a circuit breaker fail to operate when needed, damage will result. Often, some elements of the power system are so important and the extent of the possible damage so great that supplementary relaying known as "back-up relaying" is provided. Back-up relaying can be located on another element of the power system, perhaps the next adjacent station. This will tend to prevent the same cause from inducing simultaneous failure of both the primary and back-up relaying. When so located, this type of relaying is called "remote back-up." Back-up relaying usually disconnects more of the power system than just the part with the faulty element, but this is necessary in order to remove the abnormal condition and to minimize the effect on the remainder of the power system.

Ever-increasing system growth, heavier line loadings, higher fault currents, and increased numbers of generating stations have all tended to make remote back-up relaying ineffective. Remote back-up is inherently slow, and when it does operate it often disconnects more of the power system than is necessary to clear the fault. These conditions introduce problems of fault damage and system disturbance and indicate that faster back-up relaying is necessary. This can be accomplished by placing the back-up relaying in the same location as the primary relaying. Such protection is called "local back-up." Local back-up relaying should be as completely separated from the primary relaying as is possible. This would include control circuits as well as instrument transformers. Local back-up protection is often applied to protect against failure of the primary relaying and also to protect against the failure of the associated circuit breaker. It is arranged for faster back-up tripping and also to clear the fault by tripping the minimum number of circuit breakers.

DEFINITION AND BASIC TYPE OF PROTECTIVE RELAYS

To define a protective relay, we say that *it is a device which, when energized by suitable currents, voltages, or both, responds to the magnitudes and relationships of those currents and voltages to indicate or isolate an abnormal operating condition*. Basically, the protective relay consists of an operating element and a set of contacts. The operating element takes the information from the instrument transformers in the form of currents and voltages, performs a measuring operation, and translates the result into motion of the contacts. When they close, the contacts either actuate a warning signal or complete the trip circuit of a cir-

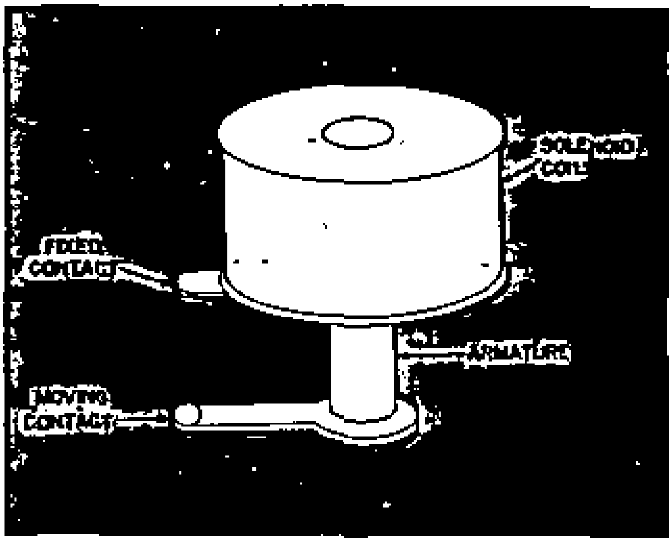


FIGURE 2. Plunger construction

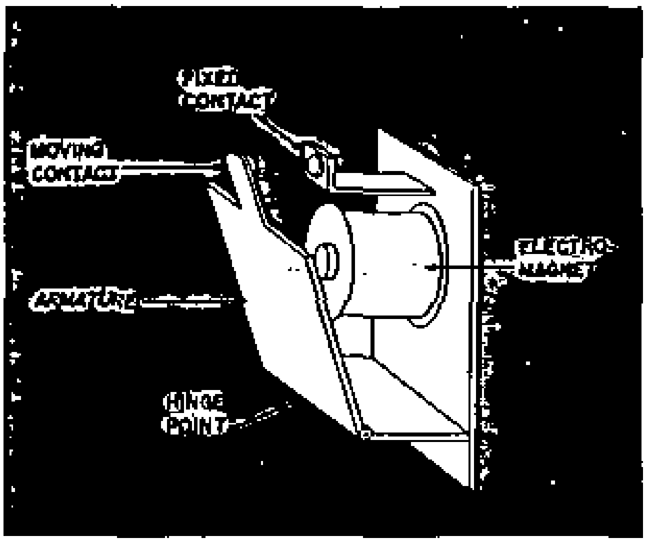


FIGURE 3. Hinged armature construction

cuit breaker, which in turn completes the isolation of the faulty element by interrupting the flow of current into that element. The relay usually includes some form of visual indicator to show that it has operated.

Electromagnetic

The operating elements for electromagnetic protective relays can be classified according to their construction into four basic types. These are *plunger*, *hinged armature*, *induction disk*, and *induction cup*.

The first two basic types, plunger and hinged armature, are magnetic attraction types. In this type, the armature is attracted into a coil or to the pole face of an electromagnet. This principle may be applied with either alternating- or direct-current quantities. The other two basic types, induction disk and induction cup, are magnetic induction types wherein torque is developed in a movable rotor in the same way that it is produced in an induction motor. Of course, this principle may only be applied with alternating-current quantities.

The plunger type of construction consists of a bar or cylinder armature which is attracted axially into a solenoid coil. The armature carries the moving portion of the contact which meets a fixed contact when the armature is picked up. A sketch of this type of construction is shown in Fig. 2.

The hinged armature construction, which also includes cantilever and beam types of construction, consists of a flat plate or bar type of armature which pivots at a fixed point when attracted to the pole face of an electromagnet. The armature again carries the moving portion of the contact which meets a fixed contact when the armature is picked up. A sketch of this construction is shown in Fig. 3.

The induction disk element consists of a metallic disk of copper or aluminum which rotates between the pole faces of an electromagnet. There are two general methods for actuating the induction disk type of relay. One is the shaded pole method, in which a portion of the electromagnet pole face is short circuited by a copper ring or a coil to cause the flux in the section to lag the flux in the unshaded portion. A sketch of this type of construction is shown in Fig. 4. The other operating method, known as the wattmetric type, uses one set of coils above the disk and another set of coils below

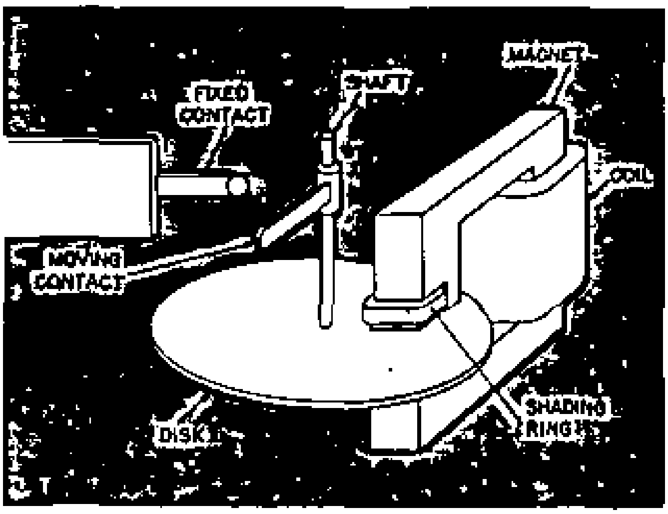


FIGURE 4. Shaded pole induction disk

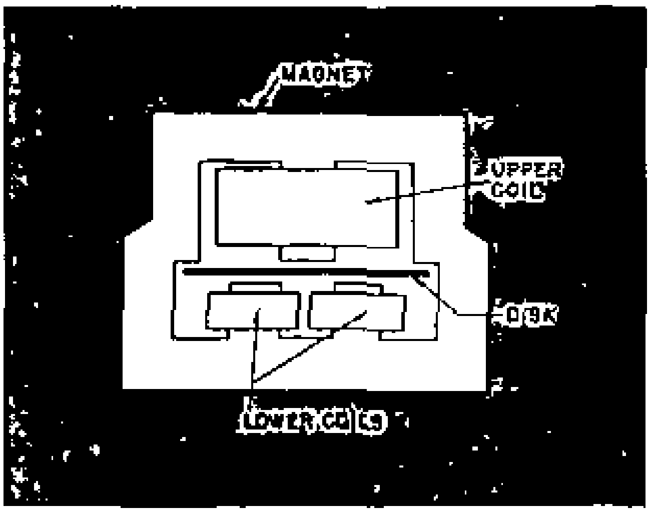


FIGURE 5. Wattmetric induction disk

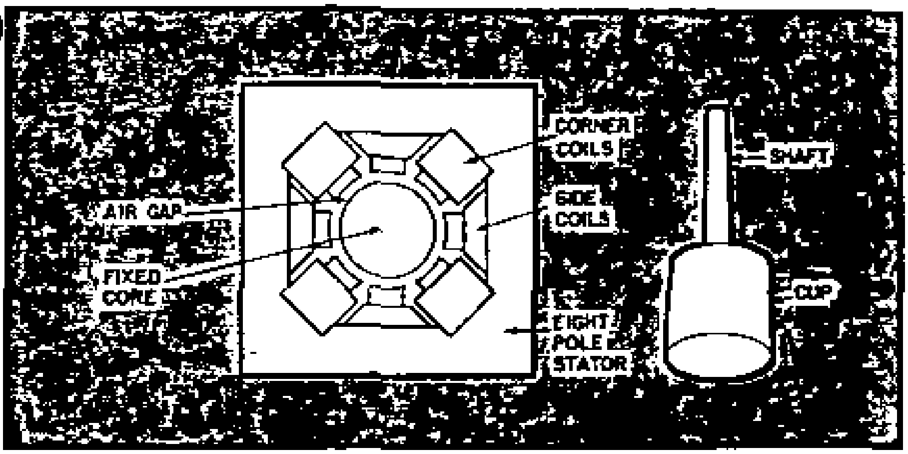


FIGURE 6. Induction cup construction

the disk. A sketch of this type of construction is shown in Fig. 5. In either case, the moving contact is carried on the rotating shaft of the disk element as shown in Fig. 4.

The induction cup element consists of a metallic cylinder with one end closed like a cup, which rotates in an annular air gap between the pole faces of electromagnets and a central core. In its present form the induction cup unit uses four or eight poles spaced symmetrically about the circumference of the cup. A sketch of the induction cup type of construction is shown in Fig. 6.

The plunger and hinged armature types of construction have no inherent time delay; hence they are used for functions which require instantaneous operation. The hinged armature type of construction, since it changes the length of its magnetic air gap as it operates, inherently produces a spread between the force necessary to just pick up the armature and the reduced force necessary to just allow the armature to drop out again. Therefore, its measuring qualities are somewhat impaired. This is also true of the plunger type of construction, but to a lesser degree. The induction disk element is always used as a time delay element because of the inertia of the moving disk. The time delay feature is added by means of a permanent magnet. The disk rotates between the poles of this magnet causing an induction drag. Since the rotating parts of the induction cup unit are of low inertia, this unit is capable of high speed operation; hence it is used for functions requiring instantaneous operation. The multiplicity of poles also permits measurement of more than one electrical quantity.

Static Elements

The development of static semiconductor devices with a high degree of reliability such as transistors have led to the design of protective relays which utilize these components to produce the required responses. Static relays are extremely fast in their operation because they have no moving parts, and they have response times as low as one-quarter cycle. Circuits are designed to provide the various functions of level detection, phase angle measurement, amplification, pulsing, squaring, timing and others. These circuits react instantaneously to the inputs of current and voltage so as to supply the proper outputs for the required characteristics.

As an example of how a static relay could measure the phase angle between a voltage and a current, refer to Fig. 7. The voltage and current sine waves at the top are supplied to separate squaring amplifiers whose function is to convert the sine wave to a square wave which is zero during the negative half cycle and provides a constant signal during the positive half cycle. These square waves are commonly called blocks, and can be supplied to a comparer circuit in such a way that an output is obtained only when both signals are present. The duration of their overlap or the duration of the comparer output is then a measure of the complement of the phase angle between the current and the voltage. In actual practice it is usually the complement of the angle that is measured.

RELAY SYSTEM REQUIREMENTS

There are three characteristics required by any protective relay to perform its function properly. These are sensitivity, selectivity, and speed. The relay must be sensitive enough so that it will operate under the minimum conditions expected. In any power system at various times of the day and during various seasons of the year, the load supplied varies over rather wide limits. To meet these changing requirements, various combinations of generating sources are switched in and out of the system to provide the most efficient mode of operation. The condition which provides the minimum of generation is often the criterion in deciding how sensitive the relay must be. Under these conditions, a short circuit fault would draw the minimum current through the relay for which it must be sensitive enough to operate to effect removal of the fault.

The selectivity of a protective relay is its ability to recognize a fault and trip a minimum number of circuit breakers to clear the fault. The relays must select between faults in their own protected equipment for which they should trip, and faults in adjoining equipment for which they should not trip. Some relaying schemes are inherently selective; that is, they are unaffected by faults outside of their own protected apparatus. An example of an inherently selective scheme is differential relaying. Other types of relaying, which operate with time delay for faults outside of the protected apparatus, are said to be relatively selective. Their selectivity is obtained by adjustment of operating times and characteristics relative to the relays with which they are intended to be selective. If the relays are of different types of characteristics, it is especially important that selectivity be established over the full range of short circuit current magnitude.

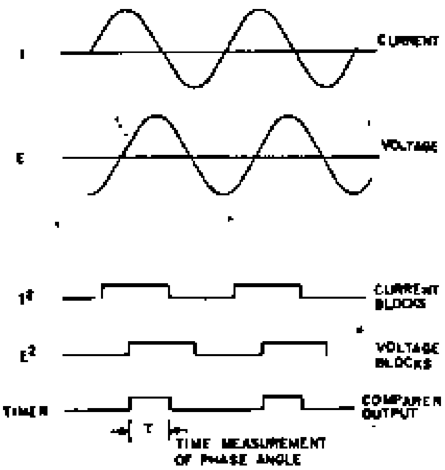


FIGURE 7. Typical waveforms used in static relay measuring operations

The relay must also operate with the proper speed. Of course, speed is essential in clearing a damaged element of a power system since it has a direct bearing on the damage done by a short circuit and, consequently, the cost and the delay in making repairs. The speed of operation also has a direct effect on the general stability of the power system. During a short circuit fault, the rest of the power system can transmit less power because the various sources of generation tend to go out of synchronism. The less time that a fault is allowed to persist, the smaller the effect on the synchronism or stability of the system.

For a relay system to perform properly it must have reliability. This is a measure of the degree of certainty that the relay system will perform correctly. It must have the dependability to operate correctly under those conditions when it should operate, and it must have security which is freedom from incorrect operations due to extraneous causes. The reliability of a relay system depends on the inherent reliability of the relays themselves and on their application, installation, and maintenance as a part of the system.

RELAY CHARACTERISTICS

A relay may be actuated by a single quantity, such as a current, or by two quantities, such as a current and a voltage. In the latter case the relay may be made to respond to the phase angle between the two quantities, or to the relative magnitudes of the two quantities, or to a combination of the magnitudes and the phase angle. The relation between the quantities that will cause the relay to operate may be shown graphically by what is called the "operating characteristic." When the relay is actuated by a single quantity, its response is purely a function of time, as in Fig. 8. When the relay is actuated by two quantities, the characteristics may be shown in terms of the magnitude of one quantity and the phase angle between the two quantities as in Fig. 9; in terms of the relative magnitudes of the two quantities as in Fig. 10; or in terms of the combination of relative magnitudes and phase angles of the two quantities as in Fig. 11. In addition, the speed of response may be shown by the time curves. The characteristic curves are useful for determining the relay settings that will provide the necessary speed, selectivity, and sensitivity to protect the power system and to coordinate with other protective devices.

Overcurrent Relays

It is necessary to trip a circuit breaker when more than a certain amount of current flows into a particular portion of a power system. This requirement points out the need for the overcurrent relay characteristic. For an instantaneous overcurrent characteristic, either the plunger type, the hinged-armature type, or the induction-cup type of operating elements could be used. Although these elements are inherently fast, they do require some short time to operate, as illustrated by the "instantaneous" time curve of Fig. 12.

Where it is desired to have more time delay in closing the contacts for purposes of co-ordination with other protective relays, the induction disk construction may be used. The time delay is controlled by a permanent magnet arranged to produce an induction drag on the disk. The time of contact closing varies inversely as the current. Such characteristics are shown graphically by a family of time current curves for various multiples of the pickup current and for various contact gap or time dial settings. There are three most commonly used shapes for the time-overcurrent characteristics which differ by the rate at which the time of operation of the relay decreases as the current increases. These curve shapes, shown in Fig. 12, are called "inverse," "very inverse," and "extremely inverse."

Obviously, overvoltage relays having similar characteristics may be produced by using voltage as the actuating quantity in the operating element. Similarly, an undercurrent or an undervoltage relay is produced by adding a set of contacts which are closed when the operating element resets in response to the decrease of the actuating quantity below a predetermined value.

Directional Relays

Directional relays are required for applications where it is desirable to allow tripping for current flow in only one direction. The directional relay can be produced in either the induction cup or the wattmetric induction disk construction. One winding may be energized by the

FIGURE 8. Quantity vs time

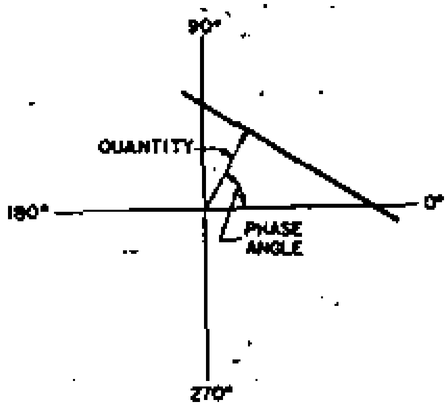


FIGURE 9. Quantity vs phase angle

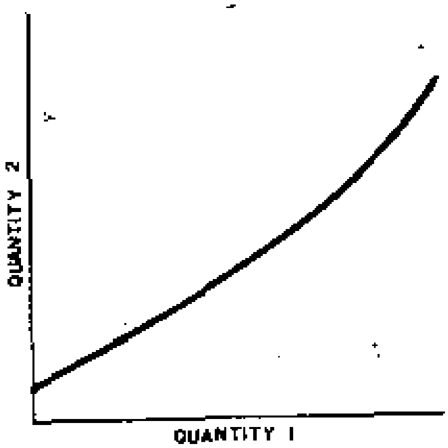


FIGURE 10. Quantity vs quantity

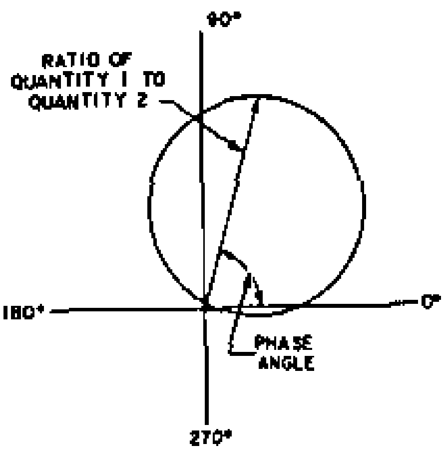


FIGURE 11. Quantity vs quantity and phase angle

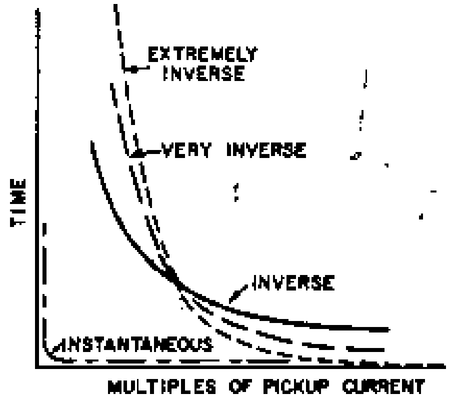


FIGURE 12. Time-current characteristics

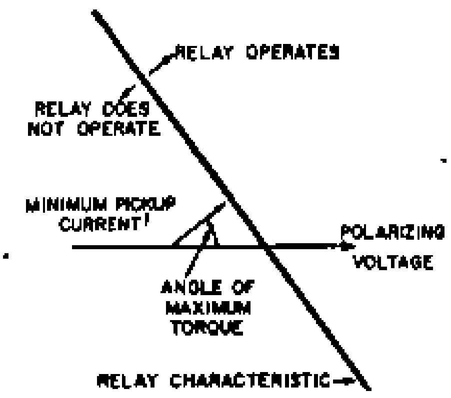


FIGURE 13. Directional characteristic polar diagram

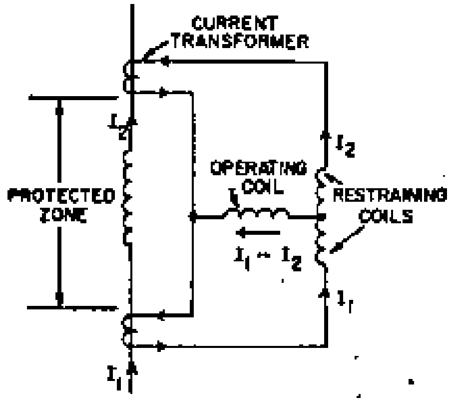


FIGURE 14. Differential circuit connections

circuit voltage to "polarize" the unit—that is, to predetermine the direction of current flow for which the unit is to operate by providing a reference quantity. The other winding may then be energized by the desired current. Current flow in the operating direction will produce a torque to close the contacts, but current flow in the reverse direction will produce a torque to restrain the unit or to hold the contacts open.

Since voltage is used to polarize the directional unit, its pick-up current is dependent on the magnitude of the voltage and the phase angle between the current and the voltage. The particular phase angle at which the pick-up current is a minimum is called the "angle of maximum torque." This is shown in Fig. 13. Any condition of current at a particular phase angle, as represented by a vector on the diagram, will indicate how the directional unit will react. Current vectors ending on one side of the characteristic indicate conditions which will produce a net operating torque, while vectors ending on the other side of the characteristic indicate conditions which will produce a net restraining torque. The characteristic will be displaced from the origin of the diagram by the amount equivalent to the pickup of the unit at the angle of maximum torque.

A sensitive directional unit will operate for a very small value of the actuating quantity when the polarizing quantity is the normal rated value; its function is only to recognize the proper direction. With the addition of restraint, the directional unit can perform a measuring function. An example of this type of unit is the directional overpower relay. Both the sensitive type and the measuring type can be made to operate instantaneously, or with some purposely-introduced time delay.

On occasion, a directional unit may be polarized by some reference current instead of a voltage. An example of this type is a directional overcurrent unit for protection against short circuits involving ground. In this case, the reference current can be obtained from a current transformer connected in the neutral of a grounded transformer bank.

Current-balance Relays

In situations where it is desirable to trip a breaker whenever there is an abnormal change in the division of current between two circuits, a current balance relay may be applied. A current balance relay may use the hinged armature, induction disk, or the induction cup construction. Such a relay has two torque-producing elements actuated by currents obtained from the two circuits. One element produces operating torque tending to close the contacts, while the other element produces restraining torque tending to open the contacts. The ratio in percent of the operating current to the restraining current to cause the relay to operate is called the percent "slope" of the operating characteristic. The relay also requires a minimum current to operate when the current in the restraining element is zero.

Differential Relays

Differential relaying is the most selective relaying principle. It is achieved by a certain connection of current transformers, and almost any type of relay may be used. Current transformers are put in all of the connections to the system element to be protected, and their secondaries are connected in parallel to a relay operating coil. So long as current flows normally through the protected system element, the current transformer secondary currents merely circulate between the current transformers, and no current flows through the relay coil. But should a short circuit occur in the protected system element, a difference current will flow in the relay coil and cause the relay to trip all of the breakers in the circuits connected to the faulty element.

Figure 14 shows the differential principle applied to one phase winding of a generator. Here, a current balance relay is used to provide what is called "percentage differential" relaying. The two sets of current transformers are connected in parallel to the operating coil, as previously described. In addition, the current from each current transformer is made to flow through a restraining coil. The purpose of the restraining coils is to prevent undesired relay operation, should current flow in the operating coil as a result of current transformer errors. As shown in Fig. 15, the operating coil current (I_1—I_2) must exceed a certain percentage of the "through" current (I_t) for the relay to operate.

Wire-pilot Differential Relays

Since the differential interconnection of current transformer secondaries involves a large number of wire connections, the application of differential relays is necessarily limited to equipment terminating at points relatively close together. A modified form of differential relaying employing a wire-pilot channel is applicable for the protection of line or

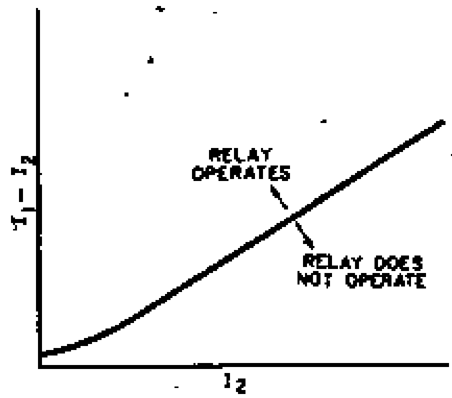


FIGURE 15. Percentage differential characteristic

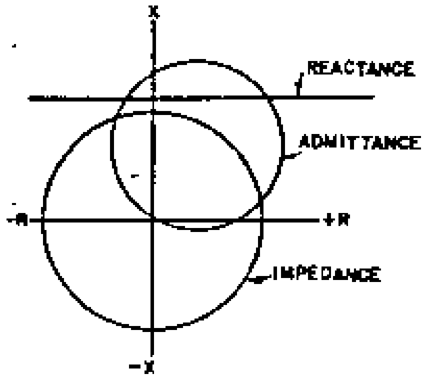


FIGURE 16. R and X diagram of distance relay characteristics

cable sections with more widely separated terminals. The wire-pilot channel is a two wire metallic circuit joining the two points between which it is desired to provide the differential relaying.

The wire-pilot circuit is used for the interchange of relaying information in the form of currents or voltages between the relays at the two line terminals. These relays have a current balance characteristic arranged to cause relay operation if the current entering the protected line section is not balanced by the current leaving the line section. Under external fault or load conditions, these currents are in balance and, hence, the relays will not trip. However, for internal faults, the currents will no longer be in balance and the relays will trip the breakers at the line terminals.

Distance Relays

The term "distance" is applied to a family of relays that respond to a ratio of voltage to current and therefore to impedance or a component of impedance. Impedance is a measure of distance along a transmission line for whose protection such relays are used, which explains the choice of the term "distance."

There are three different basic types of distance relays: (1) impedance, (2) admittance or "mho," and (3) reactance. All of these types, like the current balance type, comprise a balance between two torque-producing elements. When the operating element torque exceeds the restraining element torque the relay will close its contacts.

A graphical representation of the impedance, reactance and admittance characteristics may be made on an R and X diagram as shown in Fig. 16. This diagram, as its name implies, is the plot of impedance on the basis of its resistive and reactive components and is a very useful adaptation of the "two quantities vs. phase angle" representation of relay characteristics as previously shown in Fig. 11. The relay unit will operate on any impedance vector which terminates inside the circular characteristics of the mho admittance unit, or the impedance unit, or below the straight line characteristic of the reactance unit.

Carrier-pilot Relaying

Just as a wire-pilot channel is used to provide relaying over longer distances than is feasible for the direct form of differential relaying, so a carrier-pilot channel is used to provide protection over even greater distances than the wire-pilot channel. There are two general types of carrier-pilot relaying: phase comparison and directional comparison. Phase comparison carrier-pilot relaying compares the phase angle of the currents entering and leaving the protected line section. The relays operate when an internal fault causes a sufficient difference in phase angle between these currents. This comparison is made directly over the carrier channel.

Directional comparison carrier-pilot relaying compares the response of directional relays at the ends of the protected line. The operation is such that for external faults, a carrier signal is initiated by the directional relay at the line terminal where the current is flowing out of the line to block tripping at the other line terminal. During internal faults, this carrier blocking signal is shut off by the directional units and simultaneous tripping of both line terminal breakers is effected.

Combination Characteristics

The basic types of characteristics that have been described may be produced by using a combination of operating units or elements in a protective relay. They may be combined so that one characteristic exercises electrical control of another, or they may be combined mechanically so that actuating torques are applied to the same shaft or moving member of the operating element. An example of the combination employing electrical control is the directional overcurrent relay. The directional unit, which may be of the induction cup construction, only permits torque to be developed in the overcurrent unit (an induction disk element or an induction cup element) when the directional unit contacts are closed indicating current flow in the proper direction for tripping. The contacts of the directional unit are in a series circuit with either wound shading coils of the induction disk element magnet or phase shifting coils of the induction cup element; closing of the directional unit contacts permits torque to be developed.

One form of the impedance relay is an example of a mechanical combination. An induction cup unit contains current coils which act on the cup rotor to produce operating torque. Acting on the same shaft through a form of hinged armature construction is a set of potential restraint coils. The net torque in the shaft, which is the difference between the current operating torque and voltage restraining torque, produces the impedance characteristic.

APPLICATION

As noted previously, protective relaying equipment should be chosen and applied to a power system on the basis of its speed, selectivity, and sensitivity. The proper application of the protective relays can contribute a high degree of reliability to the power system. Associated system apparatus that affects the relay operation must also be considered. For example, instrument transformers of adequate relaying quality are a definite contribution towards the over-all reliability of the system.

The best application approach is an over-all standard plan of system protection requiring a minimum of effort in selecting the proper equipment. Such a plan should be adaptable to the growth of the power system. For protection against short circuits, the basic element of this standardized plan concept is differential type relaying with its inherent selectivity.

e Basic Approach

he various types of relays available to protect power system elements have known characteristics, and their range or zone of operation can be predicted. The primary relaying equipment is arranged with overlapping zones of protection as illustrated in Fig. 17. Thus, no matter what the location of the fault, there will always be at least one protective relay to provide the necessary isolation of that fault. It can be seen that a fault could conceivably occur within the overlap of two protected zones, which would cause the operation of more than the minimum number of circuit breakers to clear the fault. However, this type of operation is much preferred over that of a non-overlapping system in which faults could occur for which no primary relaying would respond, and only the back-up relaying would clear the fault. Fig. 17 shows all the zones of protection overlapping around circuit breakers. This is the preferred method of providing the overlap. Thus, it is evident that while each relay protects the service of a part of the power system, each part is so closely associated with the next part that the protective relaying must be a rdinated system and not just a ction of single items of equipment.

It is not always the size or importance of a system element that determines the quality of protective relaying to be applied. For example, if a failure in a small or unimportant element of the system is not promptly removed from the system, it could jeopardize the service equally as much as a failure in some other larger element. The criterion is how a fault on any one part of the system could affect the rest of the system. Each relay indirectly protects much more than just the immediate equipment.

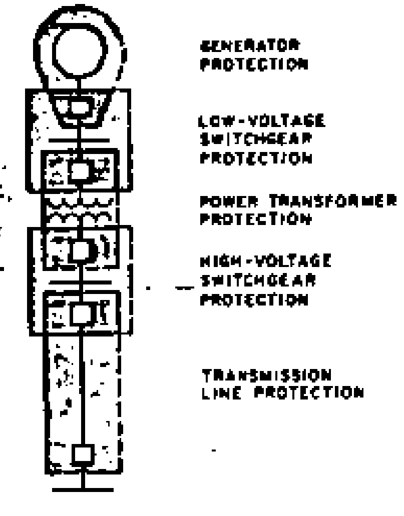


FIGURE 17. Overlapping zones of protection

The relay protection recommended for generators, transformers, and switchgear is a standard package of relay equipments that are considered necessary for the over-all primary protection of these power-system components. This recommended relay protection is as follows:

1. Each generator protected by product-restraint percentage-differential relays
2. Each power transformer protected by harmonic-restraint percentage-differential relays
3. Each high- and low-voltage bus section differentially protected by voltage relays

This standard relay protection package can be duplicated when similar components are added at any place in the power system, thereby providing complete protection for the system components with a minimum of application effort. This is not to imply that this is the only form of primary relaying protection that can be applied to these power system components. Other relays are frequently applied, and they are discussed below.

Generators

Generators are subject to various types of faults in both the alternating-current stator and the direct-current rotor. Some of these are phase to phase or phase to ground short circuits, overcurrent, overheating, motoring, and loss of excitation.

It is particularly important to provide high speed relay protection for generator short circuits because of the possibility of excessive damage if the short circuit is not promptly isolated. The most effective protection against both phase and ground short circuits in the stator is percentage-differential relaying. A percentage-differential relay with an increasing slope characteristic is best for this protection. The significance of the increasing slope characteristic, shown in Fig. 18, is that in order to operate the relay, the ratio of difference current to through current must increase as the through current increases. This permits a larger difference current resulting from current transformer inaccuracies at the higher currents without causing incorrect relay operation on external faults, and at the same time assures tripping for internal faults.

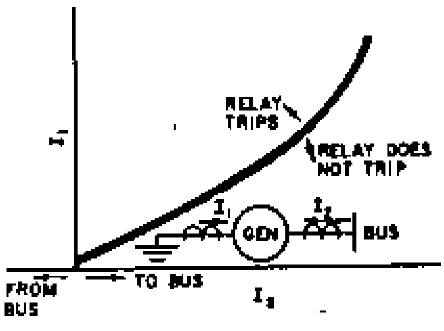


FIGURE 18. Percentage differential characteristic with increasing slope

The differential protection should be arranged to trip all circuit breakers to which the generator is connected so that outside sources will not supply current to the short circuit. The field circuit of the machine should also be opened so that the generator will not supply current to its own fault. The neutral breaker, if used, should be tripped, and the prime mover should be shut down.

With a unit generator transformer arrangement, shown in Fig. 19, it is the practice to ground the generator neutral through a distribution transformer whose secondary is loaded with a resistor. In effect, this is high resistance grounding, the current to a ground fault being limited to approximately 10 amperes. An overvoltage relay energized from the secondary of the distribution transformer is arranged to sound an alarm or, more usually, to trip the generator main and field breakers when a ground fault occurs in the generator, its leads, or the power transformer windings directly connected to the generator. This type of ground protection can be made very sensitive and still provide selectivity for ground faults elsewhere.

Protection against overheating may be provided by the use of a resistance temperature detector embedded in the machine windings. As an alternative to the temperature detector method, a replica type temperature relay using the current at the machine terminals may be used to detect overheating. Bearing overheating may be detected by means of a thermo-sensitive, bulb-actuated relay with the bulb in direct contact with either the bearing metal or the lubricating oil.

Motoring of a generator upon loss of prime mover power may be harmful to the prime mover, or at least it may be objectionable to the system. A steam turbine may overheat under such circumstances, and protection should be provided by thermal relays located

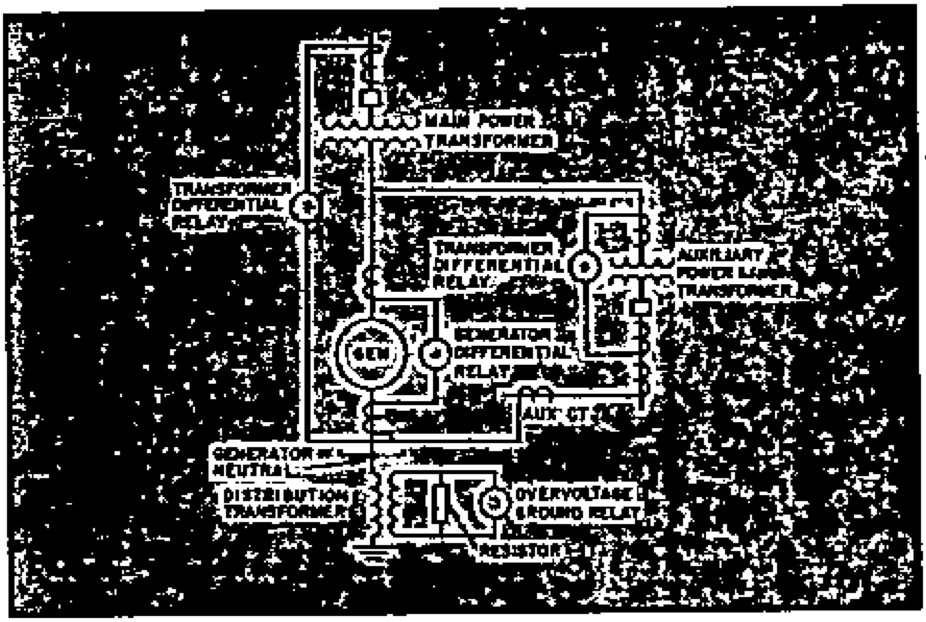


FIGURE 19. Unit generator-transformer protection

where the turbine temperature will be the highest. Other types of prime movers may impose objectionably high loads on the system. In such cases, generator reverse power relays with suitable sensitivity will provide the necessary protection. Such relays should have time delay to avoid undesired operation on momentary reverse power synchronizing surges.

Loss of excitation in a generator may bring about a severe voltage disturbance on the rest of the power system, thereby causing instability and impairing system operation. It may also cause overheating in the rotor due to currents induced in the rotor when the generator loses synchronism with other machines. Protection is afforded by means of a loss of excitation relay with an admittance characteristic. The admittance characteristic, Fig. 20, is arranged to trip the relay when the generator begins to draw reactive power from the system upon

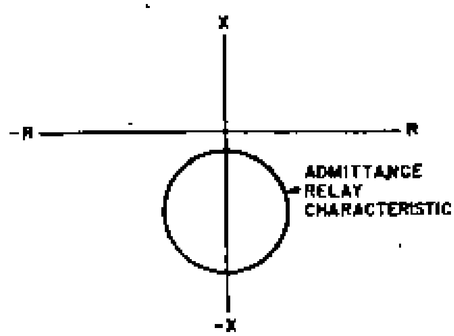


FIGURE 20. Loss-of-excitation characteristic

losing its excitation. The characteristic setting is such that operation of the unit on power swings or momentary loss of synchronism is avoided.

Open circuit or single phase operation of a generator may be detected by the application of a current balance relay of the induction disk construction. In this application, each phase current is balanced against each of the other two phase currents in a three-phase machine. Negative phase sequence overcurrent relays are available for protecting the generator rotor against overheating in the event that unbalanced external faults are not promptly removed from the system. The negative phase sequence overcurrent relay responds only to negative phase sequence currents and provides better protection for the generator against localized heating that results from unbalanced faults.

External fault back-up protection, using a voltage-restrained, inverse time overcurrent relay or a distance type relay with a timer, is provided to disconnect a generator from a bus or feeder fault that is not properly cleared otherwise.

Transformers

Power transformers may be subjected to short circuits or overloads. The effect of prolonged short circuits on system stability, as well as the possibility of considerable damage to an expensive piece of power equipment, make high-speed relaying essential in most cases.

For short circuit protection, induction disk percentage differential relays have been widely used where moderate speed of operation is satisfactory and where more expensive equipment could not be justified. Frequently, additional equipment must be employed to desensitize the relays to prevent improper operation during the magnetizing current inrush to a power transformer. Such desensitizing may affect the degree of protection should a transformer fault occur during the inrush period, which is just the time when a fault is likely to occur. Also, the desensitizing equipment is not effective when inrush occurs because of voltage recovery following the removal of an external fault. High speed percentage differential relays with harmonic restraint are used whenever they can be justified economically. Such relays are made to be inherently immune to magnetizing current inrush under any circumstances, and yet they are faster and more sensitive than the induction disk type. Consequently, their use is recommended, particularly whenever stability is a factor.

A schematic diagram of transformer differential protection applied to a three-winding transformer is shown in Fig. 21. Restraint coils are provided for the current entering or leaving each of the three transformer windings, and the net difference current passes through the relay operating winding.

Fault pressure relays are used to detect sudden changes in the transformer oil such as would be caused even by incipient or low level faults. They are capable of detecting faults even below the sensitivity level of modern differential relays and thus provide excellent protection by tripping off the transformer immediately. Also, since even incipient faults will produce gaseous by-products from the oil, fault detection can be accomplished by a measure of the amount of accumulated gas or by an analysis of the gas to determine the amount of combustible gas present. Using either of these latter two methods, early detection of incipient faults is possible, and in many instances the damage can be repaired quickly, at minimum cost and with a minimum outage time.

Unit Generator—Transformer

The one line diagram of Fig. 19 shows how transformer and generator differential relaying are applied with a unit generator-transformer arrangement. These connections have the advantage

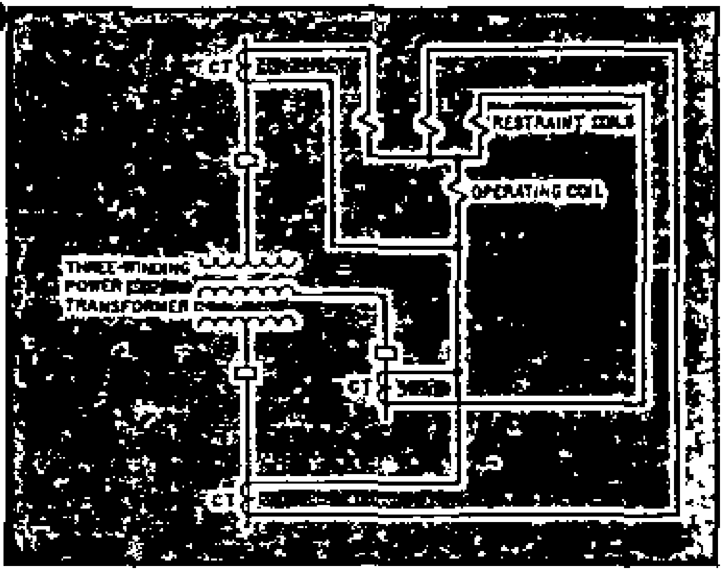


FIGURE 21. Three-winding transformer protection

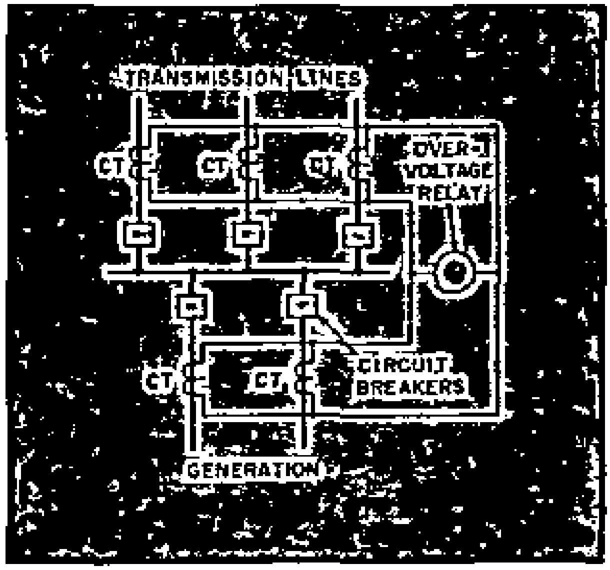


FIGURE 22. Switchgear differential protection

of using one set of current transformers in common. With the transformer differential zone arranged to include the the generator, additional protection for the generator is provided. The usual unit generator-transformer arrangement applies power to an auxiliary station-service power transformer which is solidly connected to the generator bus. The main power transformer differential zone should also include the station service transformer in order to avoid any blind spots in the protection scheme where faults could occur and not be promptly isolated. However, this does not provide adequate primary protection for the station-service-transformer but should be considered only as additional protection. The station service transformer should be protected separately with high speed percentage differential relays that are immune to magnetizing inrush current.

When differential relaying is not applied for the primary protection of transformers, overcurrent or directional overcurrent relaying of the induction disk type may be used. Sufficient time delay is necessary to maintain selectivity with the relaying on adjoining system elements. In some cases, directional overcurrent relaying may offer faster selective tripping than non-directional relaying. Overcurrent relaying of the induction disk type may also be applied in conjunction with differential relaying as back-up protection against transformer overheating because of external faults that are not promptly cleared.

Apart from the overcurrent relaying used for external fault back-up protection, it is not the practice to provide overload protection to remove a power transformer from service.

Bus Protection

Switchgear is the power station equipment that is used to direct the flow of power and to isolate power apparatus or circuits. It includes circuit breakers, disconnect switches, buses, connections, and the structures on which they are mounted. To isolate faults in buses, all source circuits connected to the buses must be opened. Since this disconnection may include generating sources as well as transmission lines, thus affecting a large portion of the system, it is very important to have correct operation for faults on the bus only and to avoid incorrect tripping during external faults. Differential relaying is essential because of its inherent selectivity.

Overvoltage differential relaying is particularly applicable to bus protection because it distinguishes between internal and external faults on the basis of voltage rather than time, thus permitting more accurate performance and faster clearing time without the danger of incorrect tripping. This equipment, connected as shown schematically in Fig. 22, uses standard bushing type or specific window type current transformers. It derives its selectivity from the fact that the internal secondary impedance of the current transformers is very low when compared to their magnetizing impedance. When an external fault occurs, there is considerably less voltage produced across the relay circuit because the secondary current is only opposed, at the most, by the CT lead resistance and the internal secondary impedance of the current transformer in the faulted circuit when it is completely saturated. When internal faults occur, however, the secondary current is opposed by the magnetizing impedance of the transformers and by the high impedance of the relay circuit, thus producing a large operating voltage on the relay and insuring its operation. All that is necessary to prevent false operation is to adjust the minimum pickup of the relay well above the maximum voltage obtained on an external fault. In fact, a 2 to 1 setting can usually be made while still retaining good sensitivity for internal fault protection.

For switchgear installations that do not have current transformers with characteristics suited to the application of overvoltage differential relays, time overcurrent relays with a differential connection may be applied. However, because of possible current transformer errors under high current external fault conditions, the relays must have a time delay long enough to provide the necessary selectivity; otherwise, false tripping would result. Percentage differential relays are applicable with certain arrangements of the switchgear sections. For example, a bus section having only three circuit connections could be protected by a percentage differential relay having three restraining coils, one for each circuit. Differential relays for this form of protection are available with a maximum of six restraint coils, thus providing for restraint on six separate bus circuit connections. This arrangement may be extended to buses having more than six connections if certain groupings of the circuits can be made so that restraining action will be obtained for any external fault.

Under some conditions, partial differential protection may be applied. This protection is connected to the current transformers in all the source circuits of the bus, omitting the connections to feeder and distribution circuits which have no source. Partial differential relaying is less sensitive because the relay pickup setting must be higher than the total normal load current, and selectivity with the feeder-circuit relaying must be maintained on a time-current basis to avoid isolating all of the bus for a feeder fault.

Short-circuit faults in generators, power transformers, and buses are not generally transient in nature. Even if the original cause was transient, the possibility of permanent damage being done to the equipment is so great that a reapplication of voltage immediately after clearing a fault is usually prohibited. However, since this equipment is relatively well protected from the natural elements and from human error, the incidence of faults is rather low when compared to other parts of the power system such as transmission lines.

Transmission Lines

Transmission lines are the high voltage circuits interconnecting parts of the power system separated by a considerable distance. Since they must carry large amounts of power between parts of the system, they are very important to the operation of that system. These lines are exposed to the natural elements as well as to human error; hence, they are much more vulnerable to short circuit faults than are the generators, transformers, and buses. Also, many faults occurring on transmission lines are transient in nature and do little or no damage to the equipment if they are quickly isolated. Therefore, once faults are cleared, it is often expedient to reapply the voltage to the circuit immediately.

Since the terminals of transmission lines are usually rather far apart, true differential relaying is not applicable; therefore, distance relaying and pilot relaying are particularly applicable to transmission line protection. Distance relaying is so called because it is responsive to the impedance of a faulted section of transmission line, and this impedance is proportional to the distance from the relay to the fault. Distance relays having the reactance and admittance type characteristic can be produced in the induction cup construction. Since such relays operate on the ratio of voltage to current, their speed of operation is relatively unaffected by the short circuit current magnitude. They provide good selectivity and good sensitivity, often operating on less than normal load currents, as well as operating at high speed. Their primary zone of protection is usually arranged for high speed operation over 80 to 90 per cent of the line length, with a short time delay in operation for the remaining 20 or 10 percent, and with a longer time delay in operation for adjoining elements of the power system. This back-up protection is provided by a separate reactance or admittance unit controlling a timer. When distance relays are used for phase-fault protection, directional overcurrent relays are usually used for ground fault protection. However, there are applications for more complex systems where ground distance relaying would provide a distinct improvement in protection against single phase to ground faults.

Pilot Relaying

Pilot relaying, being a modified form of differential relaying, is the best protection that can be applied to transmission lines. It is inherently selective, suitable for high speed operation, and capable of good sensitivity. Back-up relaying usually must be provided by other supplementary equipment.

Pilot relaying is classified according to the type of pilot channel that is used to coordinate the relays at opposite ends of the transmission line with one another. The "wire-pilot" channel requires a metallic connection between the two terminals, such as a telephone wire pair. Due to the expense of leasing or constructing such a wire connection, this type of pilot channel is limited to short line applications. The "carrier-pilot" channel uses a carrier-current signal transmitted over the line conductors. The length of line that can be protected by this type of pilot channel is only limited by the power of the carrier equipment and the signal attenuation or loss of strength occurring during transmission.

Wire-pilot Relaying

The relay equipment used with the wire-pilot channel may be so arranged that a through current, due to either a normal load or an external fault, produces opposing voltages at the two ends of the pilot wire circuit, and no operating current will flow. At the same time, current in a restraint circuit of the relay will prevent false tripping of the relay. On an internal line fault, either phase or ground, the voltages at the two ends of the pilot wires will be additive, causing a relatively large operating current to flow. The operating torque thus produced will overcome the restraining torque, causing the relay unit to close its tripping contacts.

Carrier-pilot Relaying

The relay equipment used with the carrier-pilot channel may be of either the phase comparison type or the directional comparison type.

The phase comparison type of relaying equipment compares the phase angle of the currents at each end of the line over the carrier channel. If the two currents are nearly in phase, as they would be for normal load or for external fault conditions, tripping is blocked. On internal line faults these currents are nearly 180 degrees out of phase; therefore tripping is permitted.

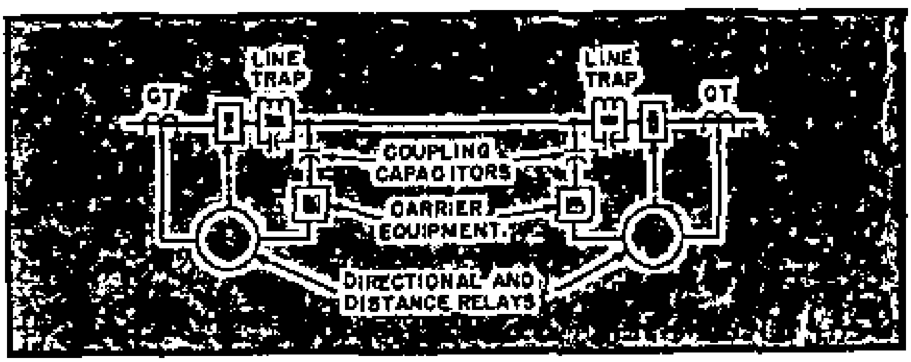


FIGURE 23. Carrier-pilot transmission-line protection

The directional comparison type of relaying equipment schematically shown in Figure 23 uses directional relays and distance relays to start the transmission of a carrier signal to block tripping at both line terminals during external faults. On an internal line fault, other directional and distance relays stop the transmission of the carrier signal, permitting both line terminals to trip instantaneously.

With either the phase comparison or the directional comparison type of relaying equipment, the carrier channel is used only to prevent tripping on external faults. If the protected line section is faulted, no carrier signal is transmitted for blocking, and both terminals will trip instantaneously. Conventional directional comparison equipments include back-up relaying for both phase and ground faults.

Pilot relaying equipments, because of their high degree of selectivity and high speed operation, are capable of isolating a faulted transmission line section instantaneously at both line terminals. This rapid clearing of the fault often permits the immediate reclosing of the circuit breakers at both terminals of the line by means of reclosing relays. Thus, the transmission line is interrupted for the shortest possible time. Of course, if the fault conditions persist on the line, the protective relays must re-trip the line breakers.

Transferred Tripping

Another form of pilot relaying for transmission line protection employs transferred tripping, a scheme where a communication channel is used to transmit a trip signal from the relay location to a remote location. Line transferred trip schemes are also functionally differential in nature since the zone of protection is precisely defined and high speed tripping of all line terminals is obtained for a fault anywhere on the protected line.

Three basic line transferred tripping schemes are used: direct underreaching, permissive underreaching, and permissive overreaching. The communication channels commonly employed can be frequency shift audio tone signals over pilot wires or over a microwave channel; or narrow band, frequency shift, carrier current equipment can be used over the power line conductors. All of these schemes require two-way communication between each pair of line terminals. Each terminal, in addition to the communication channel, requires fault detector relays which are directional. These are usually of the distance type for phase faults and of the overcurrent or distance type for ground faults.

The direct underreaching transferred tripping scheme, Figure 24, uses fault detectors set to reach 80 to 90 percent of the line section. When an underreaching fault detector at one end of the line operates, indicating a fault, it trips its local breaker directly and sends a transfer trip signal to trip the remote breaker directly.

The permissive underreaching scheme adds an additional set of fault detectors which are set to reach beyond the remote line terminal or overreach. Again the underreaching fault detector trips its local breaker directly and sends a transfer trip signal to the remote line breaker. The remote line breaker is permitted to trip only if its overreaching fault detector has operated on this same fault.

The permissive overreaching scheme uses only overreaching fault detectors which, when they operate on a fault, send a transfer trip signal to the remote terminal. At the remote terminal, its overreaching fault detector will also see the fault and will send a transfer trip signal to the local terminal. Each terminal breaker will be tripped when both a transfer trip signal is received and its overreaching fault detector has operated.

Another use for the transferred tripping channel is to trip the remote breaker of a transmission line that terminates in a power transformer with no circuit breaker between the transformer and the line, as shown in Fig. 25. When a transformer fault occurs, the transfer trip channel is used for the transmission of a tripping signal to the remote line breaker, thus completing the isolation of the transformer from all power sources.

The carrier current channels provided for relaying are sometimes used jointly for other functions, such as communication, supervisory or remote control, and telemetering. When so used, the circuit must be arranged to give the relays preference during fault conditions so that correct blocking or correct tripping may be accomplished.

Multi-terminal Lines

The ideal transmission line from a protective relaying point of view is one without any taps and with a line circuit breaker at each end. For sound economic reasons, many transmission lines are tapped, and this produces a multi-

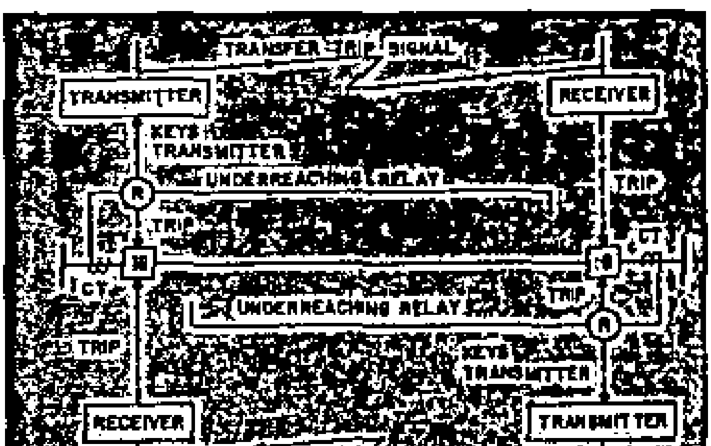


FIGURE 24. Direct underreach transfer trip

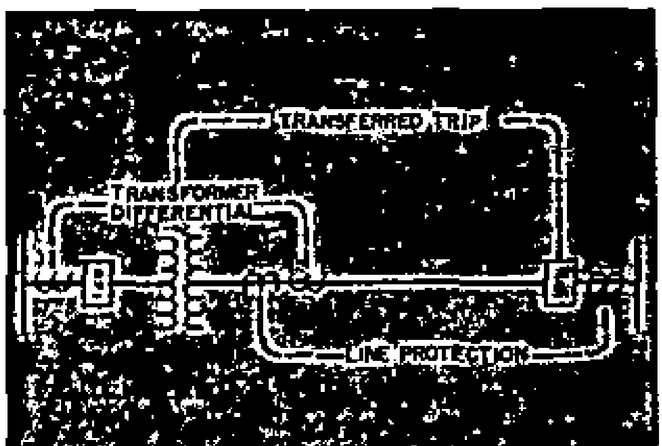


FIGURE 25. Transferred tripping protection

terminal line with three or more terminals. This line configuration presents problems in applying protective relaying to obtain adequate line protection.

In studying the relay application to these lines, the fault current distribution at each line terminal for both internal and external faults must be determined. Changes in system conditions, such as maximum or minimum generation, maximum or minimum grounding, and other lines open or closed, must also be factored into this study. The reach of distance relays in particular is affected by fault current infeed. For example, in order for a distance relay located at line terminal 1, Fig. 26, to operate for a fault located near line terminal 2 it would have to have its reach or setting increased because of fault current infeed from line terminal 3. This fault current infeed makes the apparent impedance seen by the relay to be larger than the true line impedance from the relay to the fault as shown.

EHV Systems

The use of extra high voltage (EHV) systems of high capacity has been stimulated by the economic advantages of system interconnections, power pooling, and the use of larger unit generator sizes. Because of the extreme importance of these systems it is imperative that the protective relaying have a high degree of reliability, be capable of high speed operation, and provide coverage for more contingencies than might be justified at lower voltage levels. Transformers at EHV levels are important and costly, and complete protection is recommended, including harmonic-restrained differential relays, fault pressure relays, and gas detection and analysis. For EHV switchgear and buses, overvoltage differential relaying is recommended. Where system stability is a problem it may be necessary to duplicate the primary relaying as back-up protection for transformers and buses. It is advisable that as complete a separation as possible be made between the primary and back-up relays, including control circuits as well as instrument transformers.

Transmission line protection is best applied using static relay units for phase and ground protection in a directional comparison or phase comparison carrier relaying scheme. The ultra high speed of the static units (one-quarter to one and one-quarter cycles) provides for greater system stability and minimum line damage. Further, this operating time is practically independent of the level of fault current. Because of the ground relaying problems which can occur on EHV systems, some form of ground distance relaying or zero sequence phase comparison relaying is recommended. Operating experience with static relay units indicates that they are highly reliable and that their characteristics are very stable.

The various static relay circuits are so arranged and combined as to provide the same characteristics as electromechanical relays. These are overcurrent, directional, impedance, mho admittance, reactance, and phase comparison. By providing the proper inputs of current and voltage from instrument transformers, these characteristics are made suitable for transmission line protection for all types of faults, both phase or ground.

Series capacitors are being used for EHV transmission line compensation to improve system stability limits, to improve voltage regulation, and to provide the maximum load carrying capability of the system. Series capacitors introduce special problems for line protective relays since, under fault conditions, their protective gaps may or may not flash over. However, a widely applicable form of protection for these lines will be phase comparison relaying "supervised" by "mho" admittance units. This is specifically designed for such applications.

Breaker Back-up

Protection against relay failure is provided by local back-up relays, an entirely separate group of relays from those used for primary protection. Even though the protective relays operate correctly, their associated circuit breakers could fail to clear the fault because of some malfunction in a breaker or its control circuits. In such a case, the fault would remain on the system, and some other means must be provided to clear it. It is recommended that the operation of the primary or back-up relays, in addition to attempting to trip the breaker, should also energize a timer to start the breaker back-up function. If the line breaker fails to clear, the relays will remain picked up, and when the timer times out, all remaining breakers on the bus are tripped to remove the fault. The breaker back-up scheme is arranged to trip the minimum number of breakers necessary to clear the fault. Its timing must be fast enough and so coordinated as to meet the system requirements for stability, service continuity, and minimum damage.

Subtransmission Lines and Distribution Circuits

Subtransmission lines are lower voltage transmission lines that connect the transmission system to the distribution system. The distribution circuits connect the subtransmission system to the utilization apparatus. Except for lines where distance or pilot relaying might be used, the protection problems of subtransmission and distribution systems are very similar. For circuits operated at the lower voltages, distance or pilot relaying is usually not economically justified; therefore, the various forms of time overcurrent and directional relays are usually used for both phase and ground fault protection.

Time overcurrent relays of the induction disk type are made with three general shapes of time-current curves: inverse, very inverse, and extremely inverse. These names refer to the rate at which the relay operating time decreases with an increase of current, as shown in Fig. 12. The various characteristics are applicable to the protection of subtransmission and

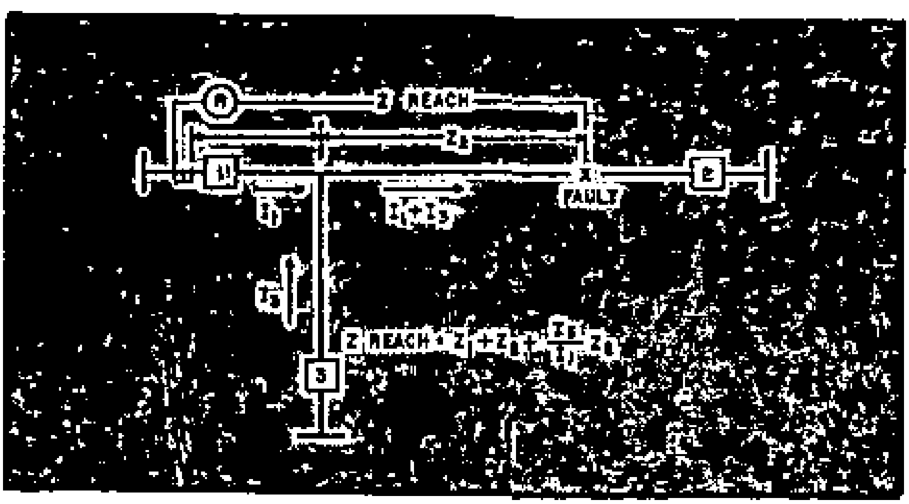


FIGURE 26. Three-terminal line

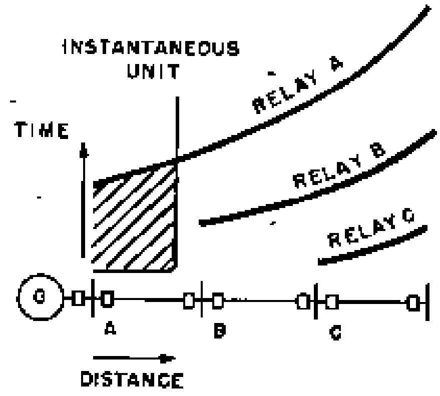


FIGURE 27. Co-ordination for time-overcurrent relays and instantaneous unit

distribution circuits under various conditions of selectivity with other protective equipment. For example, the extremely inverse characteristic is most suitable for coordination with distribution circuit fuses. It is also the least likely to trip undesirably when picking up a feeder and a large accumulated load after a prolonged service outage.

The application of overcurrent relays requires a system short-circuit study to determine the fault currents on which the relays are expected to operate and be selective with the rest of the protective system. For example, in setting the pick-up or sensitivity of a relay, the minimum fault current expected is calculated. The relay pickup is then set so as to insure its operation on that current. The time setting of the relay is made using the maximum fault current expected so that the relay will co-ordinate in time with the protective relays on adjoining parts of the system.

The setting of a series of time overcurrent relays on a feeder or distribution circuit is begun at the point farthest removed from the generating sources. As the relaying is set and co-ordinated back toward the generating sources, the time required to clear a fault becomes longer as the source is approached (see Fig. 27). In order to overcome this disadvantage, instantaneous overcurrent relays are often used to provide high speed primary protection. These relays must be set to pick up under maximum fault current conditions for three phase faults somewhat short of the end of the line, as illustrated in Fig. 27. The shaded area of the figure illustrates the improvement in tripping time obtained with instantaneous relays.

Directional overcurrent relays are used many places on subtransmission and distribution circuits. The purpose of the directional characteristic is to prevent tripping of the protected line section unless the fault current flow is into the section. This simplifies the selectivity problem between adjoining system elements, especially on loop systems where interconnected circuits return to the same starting point. It is important that directional overcurrent relays be of the type in which torque is not developed in the time or instantaneous overcurrent units until the fault current is flowing in the tripping direction. This feature is called "directional torque control." It prevents any false operation that might result from the power reversal occurring after the clearing of an external fault. Directional overcurrent relaying used for phase protection requires a voltage source for polarization in order to establish the directional reference.

Ground relaying of subtransmission and distribution circuits is accomplished by means of instantaneous, time overcurrent, and directional overcurrent relays. These relays can generally be made to operate faster and with more sensitivity for ground faults and still maintain selectivity because their connections render them immune to load currents. The directional relays require a source of polarization that is obtained either from a current transformer in the neutral of a power or grounding transformer or from the broken delta of a grounded-neutral wye-delta potential transformer bank.

A power directional unit with induction cup construction may be used in conjunction with time overcurrent units to provide power directional protection for lines and distribution circuits. Other types of power directional units may be used to trip a line on reverse power conditions where that line was intended only as an incoming feeder.

Utilization Apparatus

Depending upon the importance of certain types of utilization apparatus, various forms of protective relaying that have already been discussed may be applied, such as over and under frequency and over and under voltage. Protection against single and reversed phase starting may be applied to certain types of alternating current motor installations where direction of rotation is important. Overcurrent relaying is the basic form of protection against short circuits. Differential relaying may be applied where the size of the apparatus justifies it.

Miscellaneous Applications

There are other types of protective relays that are not principally concerned with the removal of a faulted element from the power system. A synchronism check relay will permit closing of a circuit breaker if the two parts of the system that are to be joined are already joined by parallel circuits or have not been allowed to get out of synchronism with each other. An automatic synchronizing relay can be used to join two parts of a power system that are not in synchronism but are operating at nearly the same frequency.

In connection with the protection of transmission lines, subtransmission lines, and feeder or distribution circuits, it was mentioned that a large proportion of the faults are transient in nature, doing little or no physical damage if they are quickly isolated. It is therefore possible to reapply the voltage to those circuits immediately. This operation may be performed with an automatic reclosing relay, which will automatically reclose a circuit breaker upon tripout with as many as one immediate and three delayed reclosures.

It is sometimes necessary to limit the amount of power sent over a line in a particular direction, or to remove a particular generator from the system when the power being delivered falls below a certain amount. For these applications, over power and under power relays of the induction disk type are used, operating with some time delay to avoid unnecessary tripping on temporary power surges. These over and under power relays are most sensitive under normal power conditions when the current is in phase with the voltage. They should not be confused with the directional relays used for fault protection, which are most sensitive to short circuit conditions when the current is usually highly lagging the voltage.

There are also a number of auxiliary relays used in conjunction with protective relays for such functions as timing, interlocking, contact multiplying, contact or circuit duty relieving, and electrical separation.

The vastly expanded electric power systems predicted for the future will require much in the way of relay protection. The best approach to this tremendous job is the use of the standardized relaying that has been discussed, which can bring about better electric service with a minimum of application effort and expense.

Power Systems Protection

RELAYING FOR
INDUSTRIAL ELECTRICAL
POWER SYSTEMS AND
EQUIPMENT

POWER SYSTEMS
PROTECTIVE RELAYS

The Art of Protective Relaying

GENERAL ELECTRIC

Contents

Relaying for Industrial Electrical Power Systems and Equipment

Past developments and continuing innovations in the art of generating, distributing, and converting electrical energy have made power the backbone of our present-day industrial manufacturing and processing plants. The continuous supply of this energy at a reasonable cost is vital to the operation of these facilities. Essential to the achievement of these goals is the servicing of these plants by a properly designed power system with adequate and coordinated protective equipment.

The greatest hazard to the continuous supply of electrical energy to its utilization equipment is a short circuit caused by insulation failure. When this occurs, it is necessary to quickly interrupt the flow of short-circuit current. A properly designed electric system has sufficient flexibility so that service can be maintained even with the defective portion disconnected. Adequate and coordinated protective equipment will enhance system operation and minimize damage (down time) by quickly and automatically disconnecting only that part of the system which is defective.

THE SYSTEM

In the design and layout of a new industrial power system, one of the first problems confronting the industrial power system engineer is the source of energy. Where the economics are favorable, this energy may be completely or partially supplied by in-plant generation. Where in-plant generation is the sole source of energy, multiple generating units are usually provided as a means of securing greater reliability.

Utilities are noted for their very reliable and economical service and, as a result, the majority of industrial power systems are either completely or partially serviced by them. The utility thus becomes an important part of the industrial power system and the two must be properly integrated to achieve acceptable system design and performance. The industrial power systems engineer should be aware that one of the aims of the utility is to provide reliable service to all customers. To this end, the utility must be sure that should a fault occur in a user's circuit, it will be automatically disconnected without jeopardizing service to other customers. It is therefore not uncommon for the utility to have established relaying requirements for its customer service circuits. These requirements are quite often very specific, embracing not only the type of relaying but also the particular characteristics, ratings, and settings to be used. These are important to the industrial power system designer since they must be coordinated with the downstream devices in his system. Therefore, much can be gained by early contact and close cooperation with the utility.

The reliability of an electric power system can generally be improved by providing multiple sources of energy. It is therefore quite common for a utility-fed industrial system to have two or more incoming circuits. These preferably should be located on separate right-of-ways and originate at different sections in the utility system. Further, where it is feasible, improved continuity of service can be obtained and system disturbances minimized by operating the circuits in parallel and providing relays and circuit breakers to automatically and quickly disconnect a defective circuit.

Where it is not possible to parallel the incoming circuits due to sources being non-synchronous, or the interrupting rating of the circuit breakers being exceeded, etc., service can be improved by providing automatic throw-over equipment. With such an arrangement, should the normal source fail, the industrial system would be automatically switched to the stand-by circuit.

DISCONNECTION OF DEFECTIVE SYSTEM ELEMENTS

The complete industrial system comprises many elements, such as generators, transformers, converting apparatus, switchgear, distribution circuits, and utilization equipment. In order to maintain service reliability, the industrial power system designer should endeavor to so interconnect these elements, preferably through circuit breakers, such that a defective element may be isolated from the system by opening one or more breakers. Further, the protective relays which control the tripping of the breakers should be coordinated with respect to each other so as to trip only the minimum number of breakers directly supplying the defective element. This type of coordination is called "selectivity".

METHODS OF OBTAINING SELECTIVITY

The most positive selective relaying system is the differential type, wherein relay operation is obtained when there is a difference between current entering and leaving a protected element. This system of relaying requires a "pilot channel" or interconnecting circuitry between the terminals of the protected element which can be used in making the current comparisons.

Where a pilot channel is not available, selectivity can be obtained by a graded time-overcurrent relay system. Briefly described, this system uses current and time settings so that the relays intended for protecting the faulted element operate before the relays located upstream or closer to the source operate. Directional relays may be used in combination with the overcurrent relays to prevent operation except in one predetermined direction of power flow. Where the maximum current that can be fed over a sound element is exceeded by the current which will flow into that element when it is (itself) short circuited, instantaneous overcurrent relays can be used to supplement the time-overcurrent relays, thus minimizing tripping time. The instantaneous relays should be set above the maximum through-fault current.

Where an element embraces appreciable impedance such as open line wires, distance relays may be used to obtain selectivity. The characteristic of these relays is such that they respond to an indicated impedance or component of the impedance such as reactance. This ohmic indication can be used to permit relay operation only when a fault occurs in the element which the relay is protecting.

INCOMING-LINE RELAYING
Single Line Operation

Many industrial systems are fed from utilities through a single incoming line. Further, it is not uncommon for the utility to supply power at a voltage level which is suitable for either direct use or distribution by the industrial. Minimum relaying for these single incoming circuits consists of three time-overcurrent relays. Usually, two of the relays are arranged to monitor the phase currents, with the third relay monitoring ground currents. In addition, the phase units may also include high-set instantaneous elements. Figure 1a shows such an arrangement. Operation of the relays, Devices 50/51 and 51GS, should trip circuit breaker, Device 52. (For switchgear device function number see reference No. 1.)

Where the voltage of the utility supply is at a level that is unsuitable for the industrial system, a transformer must be included in the utility interconnection. Figures 1b and 1c show two such typical arrangements.

In Figure 1b, transformer protection is provided by the primary fuses. The overcurrent relays, Devices 50/51, provide system backup protection for phase faults and should trip the circuit breaker, Device 52. System back-up ground relaying is provided by Device 51G-1. This device should trip the circuit breaker. In addition, since it will operate for ground faults in the transformer secondary, it should also operate an upstream device to cause the transformer to be de-energized. When it is important that the upstream device be tripped as a last resort, a second ground-overcurrent relay, Device 51G-2, may be added. This relay would be set with a longer operating time than 51G-1. 51G-1 would trip Device 52 only, and 51G-2 would trip the primary breaker. Ground faults out in the industrial system would be cleared by the operation of Devices 51G-1 and 52. The primary breaker would be tripped for ground faults in the transformer secondary and its connections to Device 52. Where it is desired to provide protection against single phasing due to blowing of a single fuse on the primary, a voltage-unbalance relay, Device 60, should be included. Since this relay is of the instantaneous type, it will respond to transient unbalances caused by switching, etc. Therefore, to prevent unwanted operations under these conditions, a time-delay relay, Device 62, which will override the transients, should also be included. The output of the Device 60, 62 combination is usually used to trip breaker, Device 52, or, if this is not desired, it can be used to sound an alarm.

Figure 1c covers the arrangement where circuit breakers are provided for the primary and secondary windings of the transformer. Overcurrent relaying connected to the transformer secondary circuit would be the same as that already discussed under Figure 1b. Protection for the transformer would be obtained by instantaneous and time-overcurrent phase relays, Device 50/51P, and the time-overcurrent residually connected ground relay, Device 51N. Operation of these devices should trip Device 52P. Although only two phase-overcurrent elements are shown, more

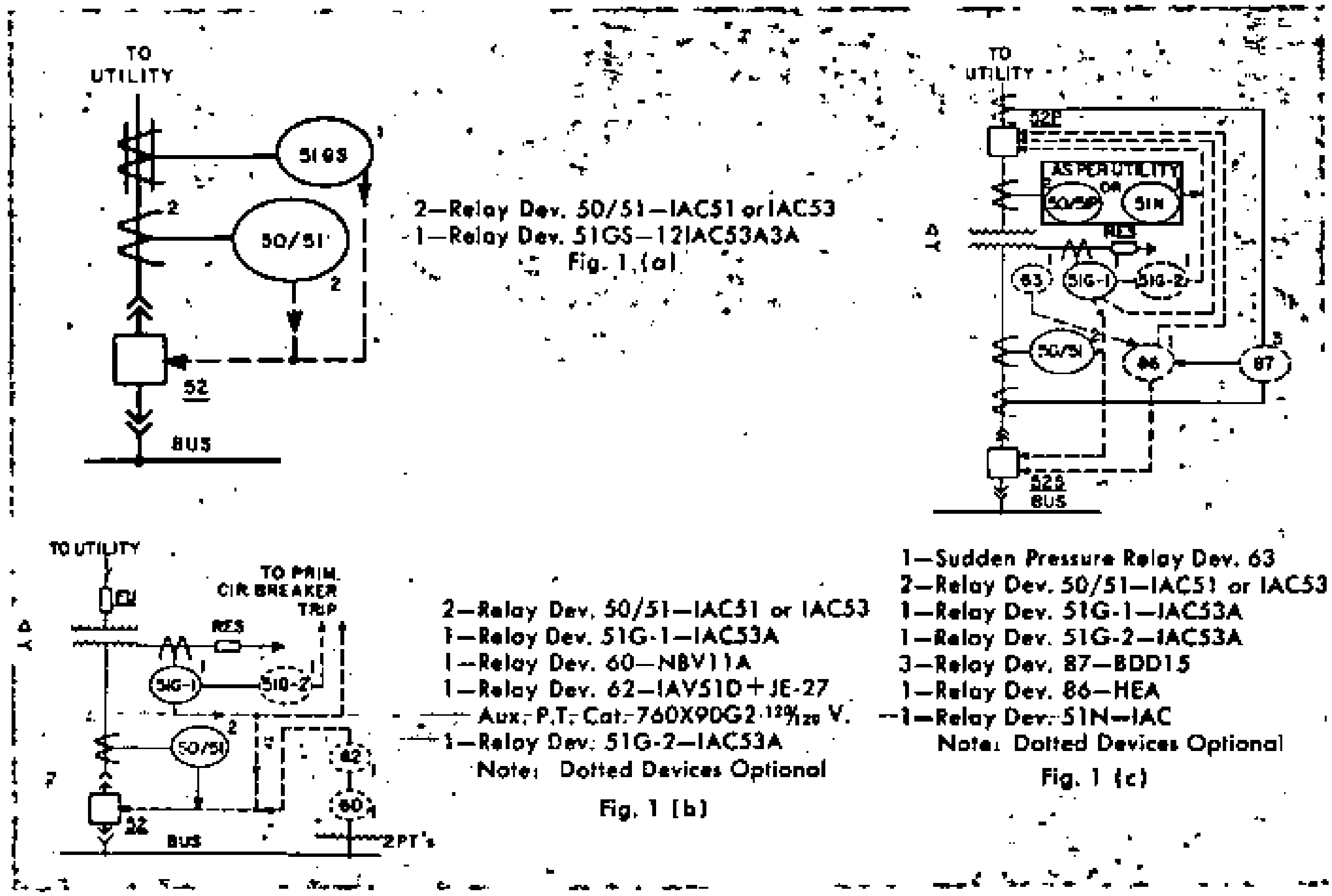


Figure 1. Recommended minimum protection for single incoming lines — no local generator

sensitive protection for single-phase fault in the secondary circuit can be assured by providing three such phase elements. Where the transformer rating is 5000 kva and above, the improved protection provided by transformer-differential relays, Device 87, is desirable. These relays operate through a hand-reset lockout device to trip and lock out both the primary and secondary breakers, Devices 52P and 52S. In some instances, a sudden-pressure relay, Device 63, may be furnished as an accessory for the transformer. It can be used in lieu of, or to supplement, the transformer differential relays.

Parallel Line Operation

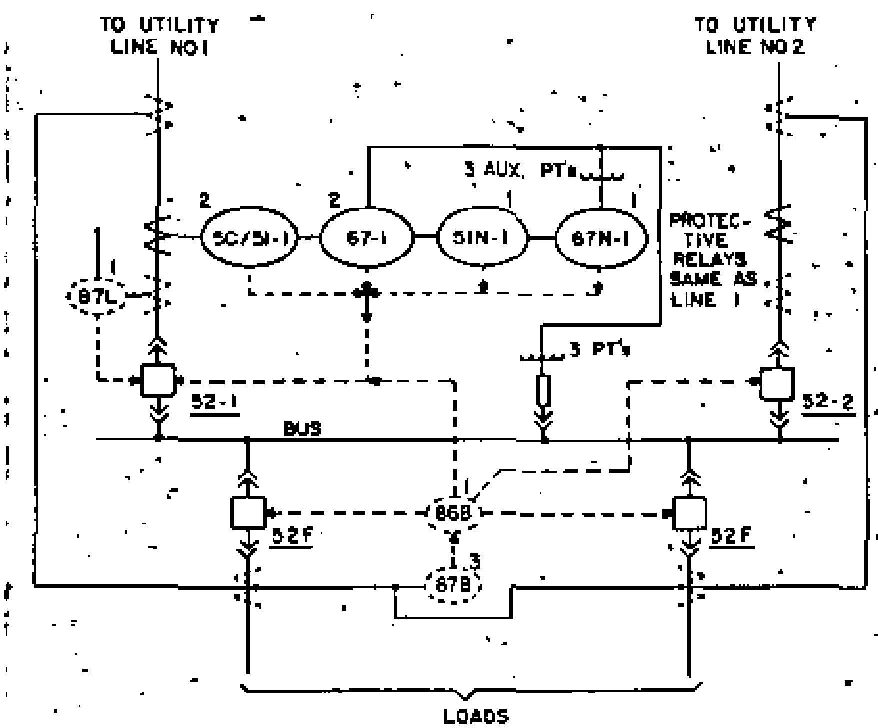
As noted previously, multiple incoming lines are used to improve continuity of service. Figures 2, 3, and 4 cover three such arrangements where the lines are operated in parallel. Referring to Figure 2, the various relay protective functions are as follows:

DEVICES 50/51 and 51N — These relays provide "backup" protection for the bus and feeder circuits. As such, should a fault occur on one of the feeder or load circuits, the feeder relays and circuit breaker should normally operate to disconnect the defective circuit; however, should they fail to do so, the incoming line relays, Devices 50/51 or 51N, would open the incoming line breakers to clear the fault. The operating time of the Devices 50/51 and 51N should be set longer than the corresponding feeder circuit relays. Generally, the Devices 50 (instantaneous overcurrent) portion of the phase relays would be disconnected on the incoming line circuits. They would be included only when it is desired to make these relays duplicates of (interchangeable with) corresponding relays on the feeder circuits.

DEVICES 67 and 67N—These directional overcurrent relays provide protection for faults that occur on the incoming line circuits and the utility system. As such, they are arranged to operate for current flowing away from the bus. In order to secure complete coordination, their operating time should be less than the nondirectional overcurrent relays on these circuits.

DEVICE 87L—This relay, being of the differential type, provides a means of clearing a fault on the incoming line circuits much faster than can be done with the directional overcurrent relays. It should be used to supplement, not replace, the directional-overcurrent relays since it operates only for faults which embrace the incoming lines. The directional-overcurrent relays on the other hand will operate not only for faults on the incoming circuit should Device 87L fail to operate, but also for faults further out on the utility system which might be fed through these incoming circuits. The Device 87L scheme requires the installation of a relay at each end of the protected line, with an interconnecting pair of leads (pilot channel) between the two.

DEVICE 87B—These relays provide high-speed, sensitive protection for faults which occur on the bus. They are of the differential type and would be arranged to operate the high-speed, hand-reset auxiliary relay, Device 86B. This relay, in turn, trips all the circuit



Each Line
2—Relay Dev. 50/51—IAC51 or IAC53
1—Relay Dev. 51N—IAC51 or IAC53
2—Relay Dev. 67—IBC51 or IBC53
1—Relay Dev. 67N—IBCG51 or IBCG53 + 3 Aux. P.T.'s JE-27*
1—Relay Dev. 87L—CPD11 + Insulating Transformer, Test Switch & Voltmeter
*One set of aux. PT's may be common to both lines
Each Bus Section
3—Relay Dev. 87B—PVD11
1—Relay Dev. 86B—HEA
Note: Dotted Equipment Optional

Figure 2. Recommended minimum protection for incoming lines, operated in parallel

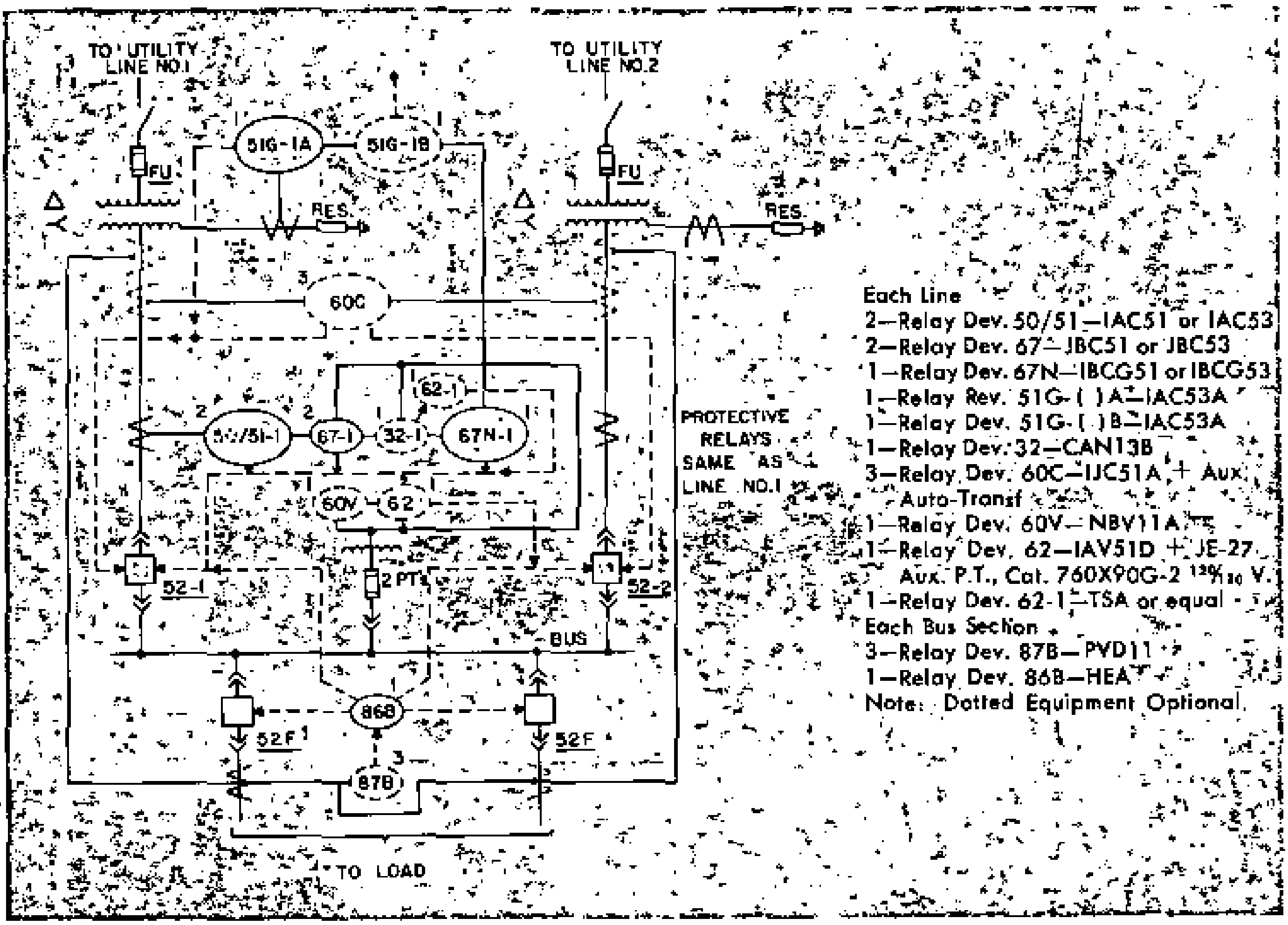


Figure 3. Recommended minimum protection for incoming lines operated in parallel with local transformers having fused primary

breakers connected to the bus and prevents the reclosing of those breakers which can feed power to the bus. Bus differential relaying is especially desirable where a bus tie circuit breaker, as described later, has been provided.

Figure 3 shows a typical arrangement where transformers with fused primaries are provided between the industrial and utility systems. Devices 50/51, 67, and 67N provide protection as outlined in connection with Figure 2. The inclusion of directional instantaneous overcurrent as a part of Device 67 improves transformer protection. By setting these relays to operate on bus-feed transformer fault currents which are above the currents that can flow for faults out on the utility system, high-speed tripping for the more serious transformer failures can be secured without sacrificing coordination. Devices 51G( )A and 51G( )B provide ground back-up protection as described previously under Figure 1b. Where it is desired to provide protection against single phasing due to the loss of a fuse on the primary side of either or both of the transformers, a protective scheme which includes Devices 60C, 60V, and 62 may be used. In this scheme, Device 60C is arranged to compare the magnitude of each individual phase current of one transformer with the corresponding phase currents of the other. Should a fuse on one of the transformers blow, the phase currents between the units would become abnormally unbalanced causing Device 60C to operate and trip the secondary breaker of the faulted unit. Depending upon current-transformer ratings, etc., Device 60C may be set to respond to a minimum unbalance of 10 percent of the transformer rating. When the banks are not operating in parallel, Device 60C is made inoperative. The voltage unbalance relay, Device 60V, and its timer, Device 62, operate as described previously. Its function is to detect a blown fuse under the following conditions:

1. When the transformers are not operating in parallel.

2. When the transformers are operating in parallel and fuse failure occurs in the same phase of both transformers. Such a condition would not be detected by Device 60C.

Where the utility system is grounded and the transformer primaries are delta connected, line-to-ground faults on the lines feeding the transformers will not be detected by the fuses and overcurrent relays shown. A sensitive power directional relay, Device 32, which operates on power flow from the industrial system may be used to disconnect such faulted lines from the industrial system bus. Device 32 is set to operate on the no-load losses of the transformer and, as such, will be sensitive to momentary power reversals which result from switching operations. Timing relay, Device 62-1, is provided to prevent unnecessary operation under these transient conditions. Where high speed bus protection is desired, Devices 87B and 86B should be included.

Figure 4 shows an arrangement where circuit breakers replace the fuse and switch shown connected to the transformer primaries under Figure 3. The basic minimum relaying and many of the optional protective devices will be the same for the two conditions. In Figure 4, it will be noted that the optional single-phase protection (Devices 60C, 60V and 62) included under Figure 3 has been omitted. Since the fuses and switches on the primary side of the transformers have been replaced with circuit breakers, the possibility of single-phase operation is materially reduced and single-phase protection is seldom considered necessary. The addition of the primary circuit breakers provides a means of readily isolating either transformer from both the utility and industrial system. The use of transformer differential protection (Devices 87T and 86T) should therefore seriously be considered for transformers rated 5000 kva and above. As discussed previously in connection with Figure 1c, Device 87L provides high-speed tripping for faults on utility lines.

Single Line Operation With Stand-by

Under some conditions such as insufficient breaker interrupting capability system operating procedures, non-synchronous sources, etc., it is not possible to operate the incoming lines in parallel. Where these conditions exist, it is usual practice to feed the bus from a single line; the remaining line providing an alternate or stand-by source. Service continuity at the bus is improved by providing control which will automatically switch the bus from a failed source to the stand-by circuit. Such control is called automatic throwover equipment and may be of the preferential or non-preferential and synchronous or non-synchronous types. Referring to Figure 5, these are defined as follows:

PREFERENTIAL

This type of control would be arranged such that the bus would always be connected to the preferred

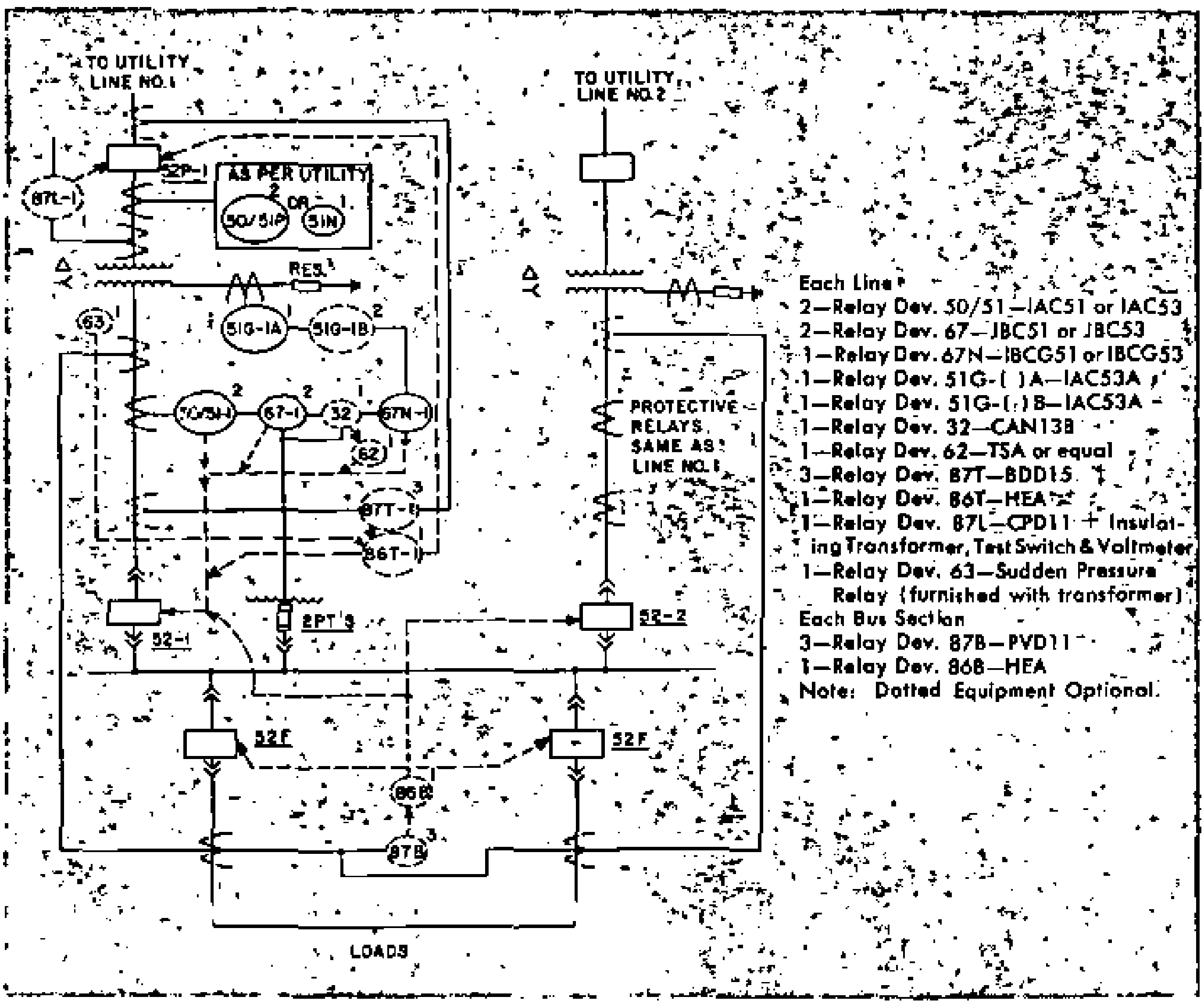


Figure 4. Recommended minimum protection for incoming lines operated in parallel with local transformers having primary breakers

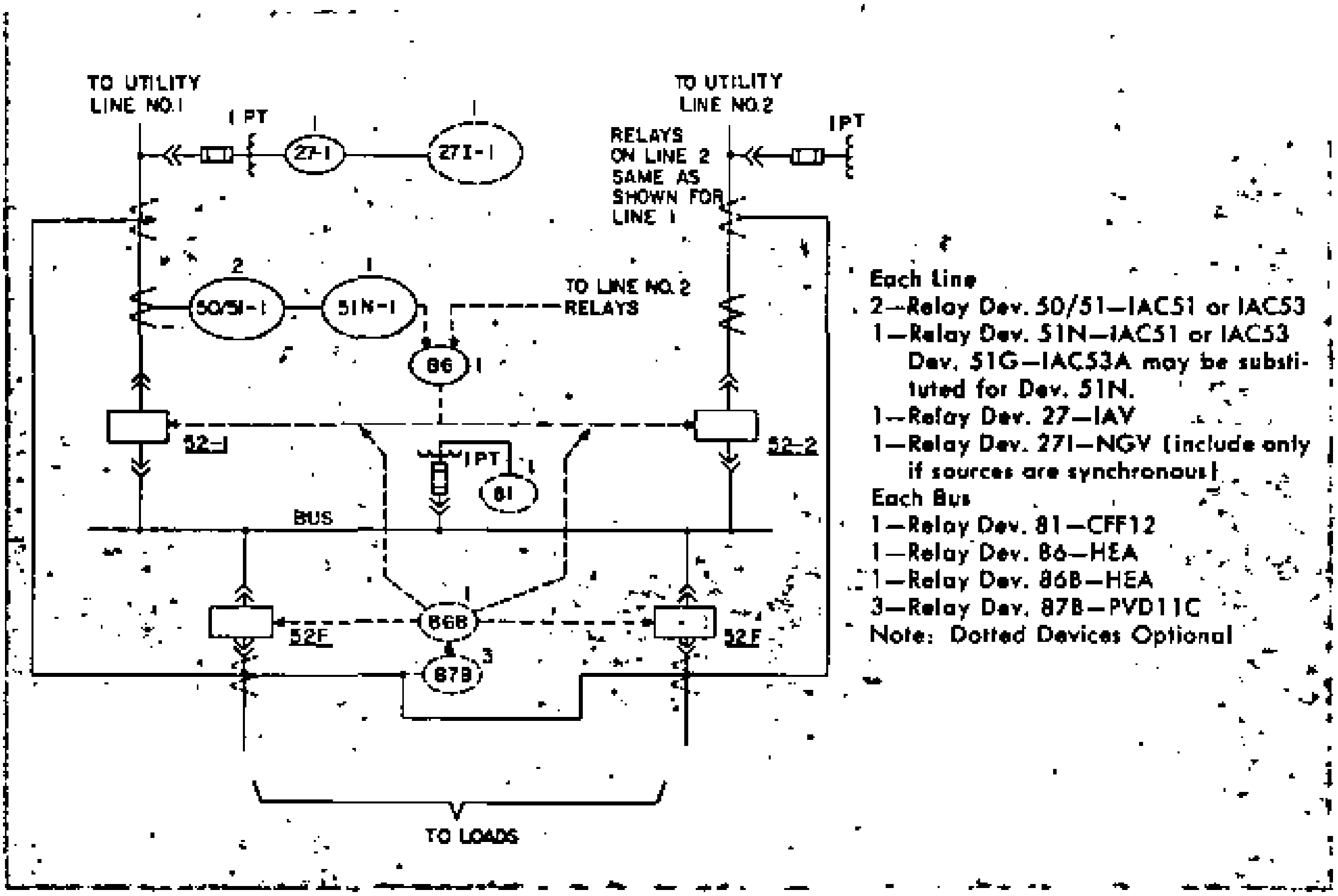


Figure 5. Recommended minimum protection for two incoming lines with throwover equipment

source whenever it is available, and would connect to the stand-by source only when the preferred source failed. Assuming line No. 1 had been selected as the preferred source, then, under normal conditions, circuit breaker 52-1 would be closed and circuit breaker 52-2 would be open. Should line No. 1 fail and energy be available over line No. 2, the control would automatically trip circuit breaker 52-1 and then close circuit breaker 52-2. Should line No. 1 subsequently be re-energized, the control would automatically switch the bus back to line No. 1 even though line No. 2 should be energized. With the preferential type of control, a unit sequence selector switch, Device 10, is provided so that the operator may select either line as the preferred source.

NON-PREFERENTIAL

This type of control is arranged such that the bus would remain connected to one of the lines until such time as it should fail. Referring to Figure 5, assume circuit breaker 52-1 was closed and the bus was energized from line No. 1. Should line No. 1 fail and voltage was available at line No. 2, circuit breaker 52-1 would open and circuit breaker 52-2 would close. The bus would then continue to be fed from line 2 until such a time as it should fail.

SYNCHRONOUS

This type of control would be used when the two lines are always in synchronism. With synchronous sources and preferential-type throwover, the control would be arranged such that with both lines energized, a transfer from the stand-by source to the preferred source would be made with overlap. That is, the breaker connecting the preferred line would be closed before the stand-by source is opened.

NON-SYNCHRONOUS

This type of control would be used when the two lines are not in synchronism. With non-synchronous and preferential-type throwover, the control would be arranged to prevent overlap when transferring from the stand-by source to the preferred line. In other words, the breaker connecting the stand-by line to the bus would be opened before the preferred line breaker is closed.

Voltage relays are generally used in all schemes to initiate throwover. They should be of the time-delay type to prevent unnecessary operation of the equipment due to momentary voltage disturbances on the systems. Other features which would be included are a manual-automatic transfer switch and a hand-reset lockout relay, Device 86. The manual-automatic switch provides a means of rendering the automatic equipment inoperative and placing the control of the circuit breakers under the supervision of an operator. The lockout relay is necessary to prevent continued operation of the throwover equipment in the event a fault should occur in the industrial system which requires the opening of the incoming-line breakers to clear it.

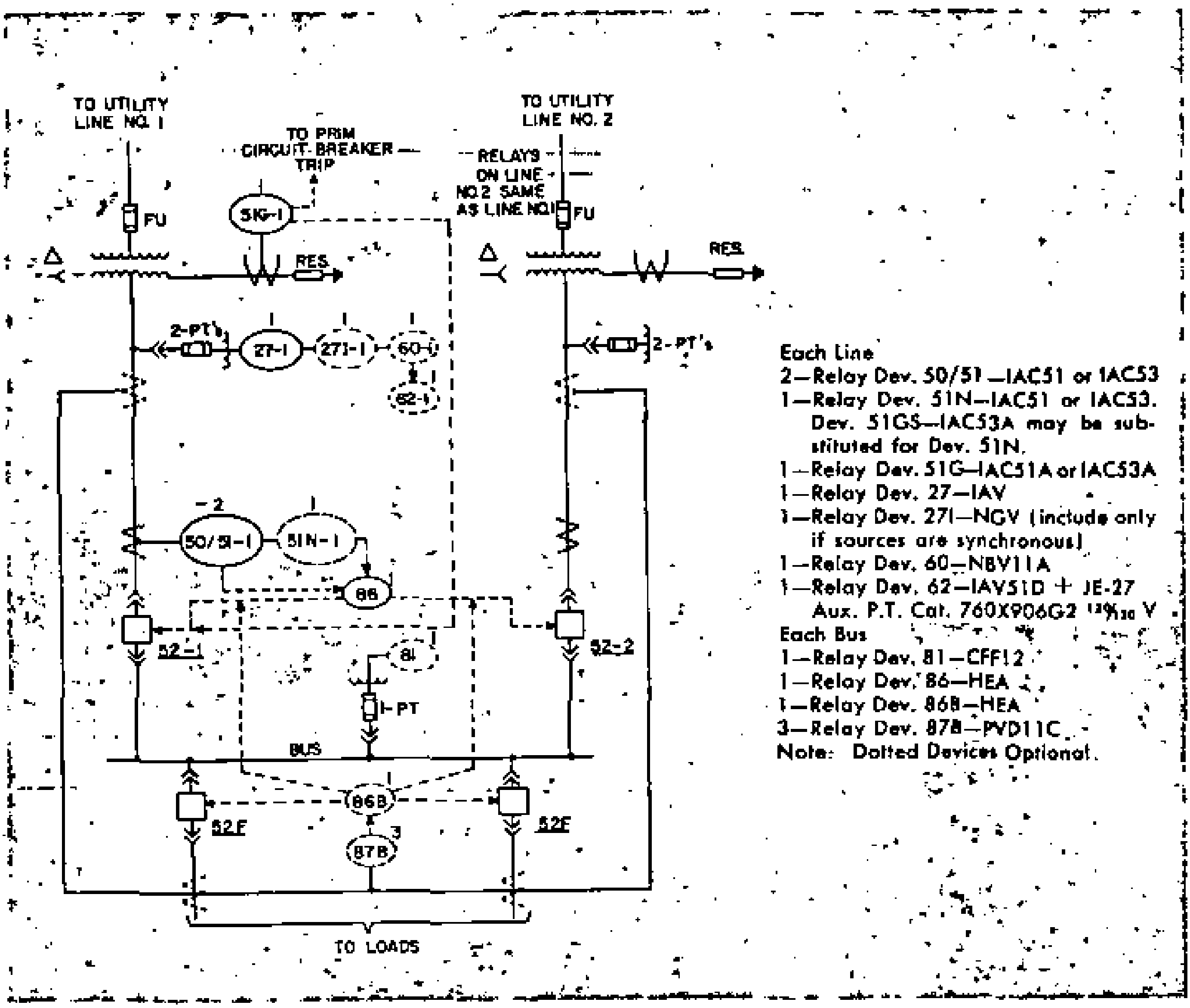


Figure 6. Recommended minimum protection for two incoming lines including fused transformers and with throwover equipment

Referring to Figure 5, the overcurrent relays, Devices 51 and 51N or 51G, provide bus protection and back-up protection for the feeder circuits. These relays operate Device 86 which trips the incoming line breakers 52-1 and 52-2 and renders the automatic throwover equipment inoperative. Devices 27-1 and 27-2 sense the presence or absence of voltage on their respective lines to initiate operation of the automatic throwover equipment. Device 271 would be included only if the sources are synchronous to prevent operation of the throwover equipment due to momentary voltage dips which might occur simultaneously on both lines. Device 87B would provide high-speed protection for the bus. It would operate Device 86B which, in turn, trips all circuit breakers connected to the bus. Where synchronous motors are fed from the bus, operation of the throwover equipment would be delayed since these machines would act as generators to maintain voltage on Device 27 when the incoming service fails. When this is the case, Device 81 would be included to speed up the transfer by detecting a decline in frequency and removing field from the motors.

Figure 6 covers an arrangement similar to Figure 5, except that transformers with primary fuses are included between the utility and the industrial system bus. The relaying is essentially the same as that covered under Figure 5, with the following exceptions. Where 51N (or 51GS) is not included, Device 51G should be arranged not only to trip a circuit breaker on the primary of the transformer but also operate the lockout Device 86 and thus render the automatic throwover equipment inoperative. It should be noted that 51G not only provides ground-fault back-up protection for the feeder circuits and protection for the bus, but it will also operate for faults in the transformer secondary

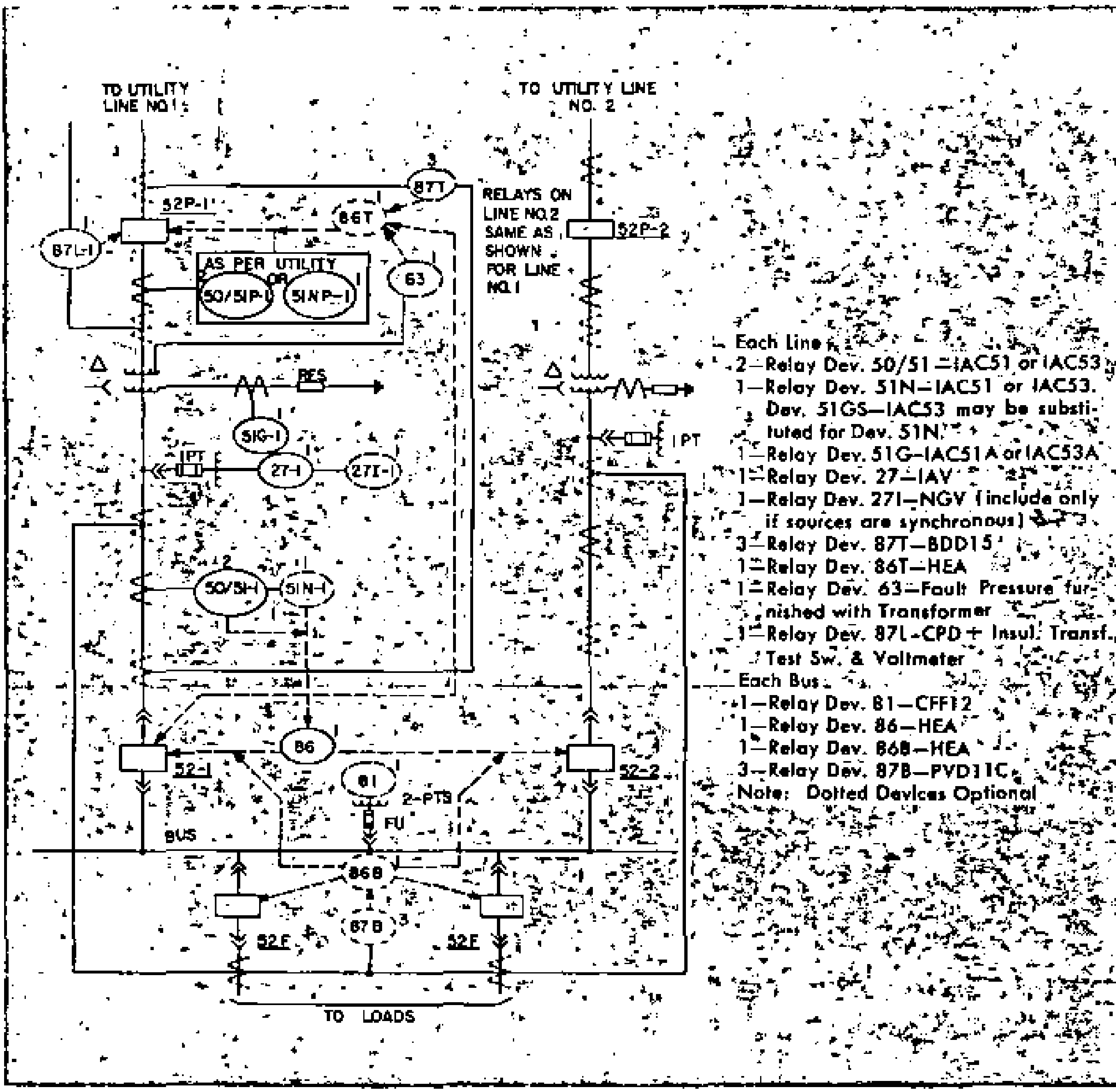


Figure 7. Recommended minimum protection for two incoming lines including transformers with primary breakers and with throwover equipment

winding and the connections to the transformer secondary breaker. The throwover equipment will therefore be unnecessarily blocked for these latter faults. With the addition of Device 51N (or 51GS) and arranging it to operate Device 86 and block the automatic throwover equipment, service continuity at the bus is improved. In this instance, operation of Device 51G would trip the transformer primary and secondary breakers and initiate automatic throwover. Where it is desired to initiate throwover upon loss of a transformer primary fuse, Devices 60 and 62 would be included.

Figure 7 is the same as Figure 6, except circuit breakers have been substituted for the fuses on the transformer primaries. Devices 50/51, 51N, 51GS, 51G, 27, 27I, 81, 86, 86B, and 87B operate as described for Figure 6. The addition of Devices 63, 86T, 87L, and 87T will provide improved and faster protection for the utility lines and transformers. In addition to tripping breakers 52 and 52P, these should also be arranged to initiate throwover, thus avoiding the time delay which would otherwise be necessitated in waiting for the time-delay undervoltage relay, Device 27, to operate.

Bus Tie Circuits

Figure 8 covers the bus tie circuit arrangement wherein all tie connections are in the switchgear assembly or are bus duct. Devices 50/51 and 51N provide overcurrent protection for their respective bus and back-up protection for the feeders. It should be noted a single set of relays operated from current transformers in the incoming and tie circuits has been provided for each bus section. This type of relaying is sometimes called "partial differential or summation relaying." With this scheme, the current transformers are so interconnected that through currents, *i.e.*, currents that flow in the incoming circuit and out the tie circuit or vice versa, do not appear in the relays Device 50/51 or 51N. The relays thus would operate only on those faults which involve their particular bus section and feeder circuits. Partial differential or summation relaying provides a faster over-all relay system than is possible with the conventional arrangement using an individual set of overcurrent relays for each incoming circuit and the tie breakers, since one relay step is eliminated.

The use of cables should be avoided in making bus tie connections since the integrity of the bus section to which the cables are connected will be no better than that of the cables. Where it is necessary to use cables, consideration should be given to providing a tie circuit breaker for each bus section and providing the necessary relays to open these breakers in case of cable fault. Continuity of service at the buses would thus be maintained. The recommended relaying for the cables would be of the differential types, typically the IJD, CFD or PVD. Where it is desired to operate with the tie circuit normally open, operating procedure should be to keep the cables energized from one end. This will ensure detecting cables faults should they occur when the tie circuit is not in use.

Generator Circuits

Protection for generator circuits is covered by Figure 9. The voltage-restrained overcurrent relays, Device 51V, provide system back-up protection. Where the generator is operated in parallel with other sources, they also provide protection for the generator. Ground protection is provided by either Device 51G or 50GS. If the system is grounded at some point other than the generator-neutral instantaneous-ground relay, Device 50GS should be included. It will provide sensitive high-speed ground-fault protection for the generator. In the event the system is grounded at the generator neutral, relay Device 51G should be furnished. This relay is of the time-delay type and will provide system back-up as well as generator ground-fault protection. Device 51G will be slower operating than 50GS.

Anti-motoring protection, Device 32, should be provided for all machines except hydro-generators and those steam-turbine generators which are provided

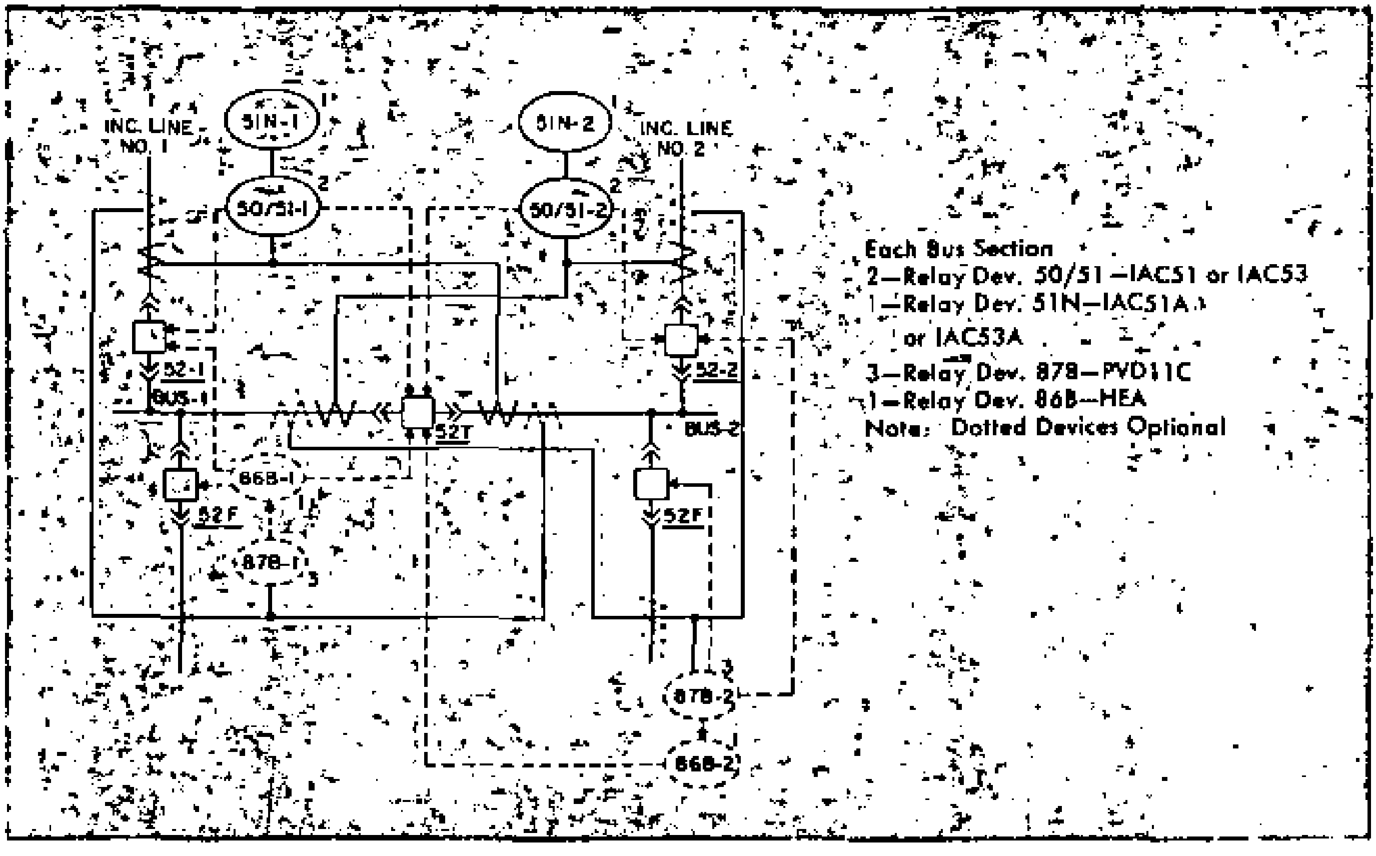
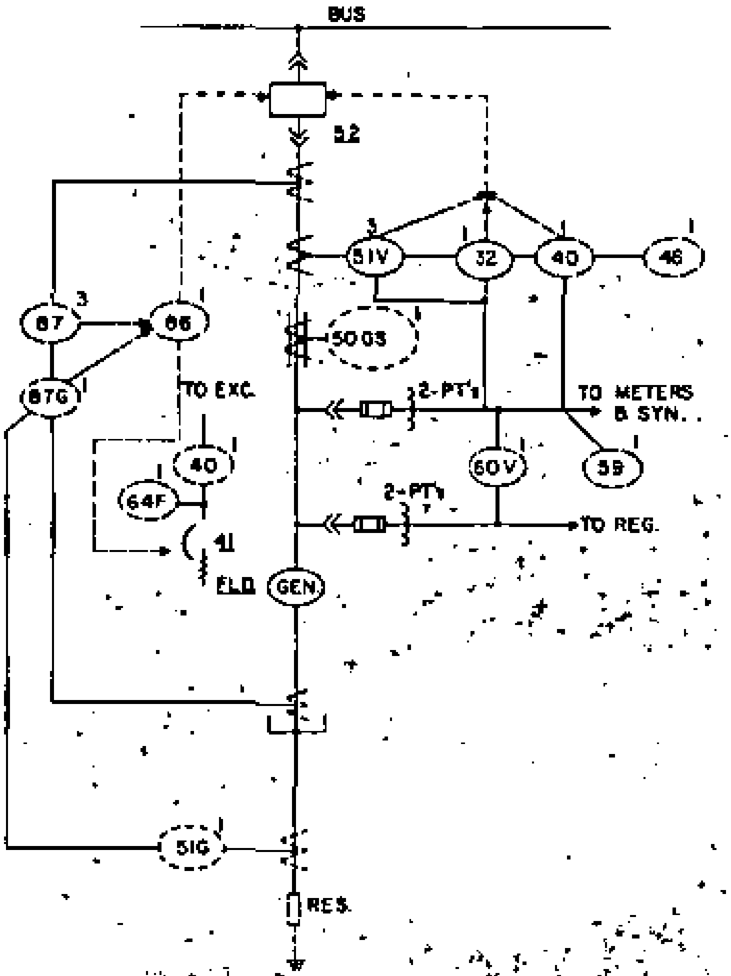


Figure 8. Recommended minimum protection for bus tie circuit breaker (tie connections are in switchgear assembly or are bus duct)



3—Relay Dev. 51V—IJCV
1—Relay Dev. 51G—IAC51 or IAC53 (use if generator neutral is grounded)
1—Relay Dev. 50GS—PJC (use if generator neutral is ungrounded)
1—Relay Dev. 32—GGP (Steam Turbine Drive) or ICW (Gas Turbine or Diesel Drive) may be omitted if protective function is included with steam turbine.
1—Relay Dev. 40—CEH (Stator Impedance Type) or IC2820-A100 (Loss of Field Current Type)
1—Relay Dev. 46—INC
1—Relay Dev. 64F—PJG
1—Relay Dev. 60V—CFVB
1—Relay Dev. 59—IAV71B (Include with hydro only)
1—Relay Dev. 86—HEA
3—Relay Dev. 87—CFD or IJD
1—Relay Dev. 87G—ICC
Note: Dotted Devices Optional

Figure 9. Recommended minimum protection for generators

with built-in blade temperature protection. Where the motoring losses are above 5 percent of the machine rating, the Type ICW relay should be used. Motoring losses below 5 percent would require the Type GGP relay. Two types of relays are available for use as Device 40 to detect loss of excitation. The simplest type is the IC2820A100 undercurrent relay. It would be connected in series with the generator field and would operate wherever current ceases to flow. The relay should be provided with a short time delay to ride through momentary interruptions of current flow which sometimes occur due to short circuits on the system. The relay would not detect loss of excitation due to short circuits in the field circuit. Where more complete protection is required, the Type CEH relay should be used. This relay operates on the change in impedance of the generator stator which occurs upon loss of excitation and, thus, would operate for conditions which the simpler field undercurrent scheme would fail to detect. Device 40 is normally arranged to automatically take the machine out of service.

Where it is desired to provide protection against generator rotor overheating due to unbalanced phase currents, Device 46 should be furnished. The negative phase-sequence, overcurrent relay, Type INC, recommended for use as Device 46, is provided with two contacts, each of which operate at a different level of negative phase-sequence current. The more-sensitive operating contact is generally used to sound an alarm, while the other contact is used to take the machine out of service.

It is usual practice to operate generator field circuits ungrounded, so that a single ground will not result in damage to the machine. However, since a second ground may cause damage, the use of a Type PJG, generator-field ground relay, Device 64F, is desirable. This relay incorporates a separate low-voltage grounded source and a potential relay. The ungrounded side of the source is connected in series with the relay coil and to one side of the field circuit in such a manner that any ground occurring in the circuit will operate the relay. The usual procedure is to arrange the relay to sound an alarm when it operates. Satisfactory operation of the relay requires that the generator rotor be grounded. To accomplish this, means should be provided to bypass the bearing oil film. In some machine designs, the bearing seals provide the necessary bypass, while other designs may require the addition of a brush on the rotor shaft to secure effective grounding of the rotor.

Satisfactory operation of the voltage regulator and certain relays, *i.e.*, Devices 51V, 40, etc., requires proper output from their associated potential transformers. Failure of these circuits due to fuse blowing, etc., would, in the case of the regulator, cause the generator excitation voltage to go to its ceiling level. In the case of Device 51V, loss of restraint voltage may result in unnecessary tripping and shutdown of the generator. The Type CFVB relay, Device 60V, provides a means of monitoring these potential circuits. As long as the outputs from the two sets of potential transformers are alike, the relay will not operate. However, should there be a deviation between the outputs, the relay will operate. In case the relay potential transformer output was lower than the output from the regulator transformers, Device 60V would close a set of contacts which usually would be arranged to sound an alarm and block tripping by Devices 51V, 40, etc. On the other hand should the output from the regulator transformers be lower, Device 60V closes another set of contacts which would usually be arranged to sound an alarm and switch the regulator to the manual mode of operation with "fixed" excitation.

Where hydro-generators are used, overspeed accompanied by overvoltage may occur due to loss of load. Overvoltage relay, Device 59, should be used to protect against this condition. The relay should have a time delay and instantaneous unit and have a non-frequency sensitive characteristic. The Type IAV-71B relay will fill the above requirements. Generally, the time unit is set to pick-up at 110 percent, and the instantaneous is set to pick-up at 130 percent of normal.

Differential protection for generators, Device 87, provides a means whereby a faulted machine may quickly be removed from service. The following is a guide to indicate when serious consideration should be given to its use.

1. Any voltage, 1000 kva and larger.
2. Any kva, 5000 volts and higher.
3. 2200 volts and higher, 501 kva and larger.

The types of relays available for use as Device 87 are the Type IJD and CFD relays. The Type IJD relay is relatively slow in operating and requires a fairly good match of the overcurrent characteristics of the current transformers connected to each end of the machine windings. The Type CFD relay, on the other hand, is fast in operating and is less sensitive to current transformer mismatch. When the generator is grounded through an impedance which limits the maximum ground fault current to less than the generator full-load current, the ground-differential relay, Type ICC, Device 87G, should be provided. The differential relays should be arranged to operate the lockout relay, Device 86, which trips and locks out the main generator breaker, Device 52, and the generator field breaker, Device 41. Where automatic CO_2 fire-extinguishing equipment is present, consideration should also be given to initiating its operation by the differential relays. The use of differential relays requires that both ends of the generator windings be brought to terminals.

MEDIUM-VOLTAGE MOTOR PROTECTION

In the typical industrial plant, the sizes of medium-voltage motors may range from several-hundred horsepower to several-thousand horsepower. It is logical that more extensive protection be considered for the larger motors than for the small motors, since they represent more capital investment. Hence, for each type of motor, the minimum recommended protective relaying is divided into two groups; one for motors rated below 1500 hp, and the other for those rated 1500 hp and above.

Induction Motors

Referring to Figure 10a for motors rated below 1500 hp, protection against loss of voltage or low voltage is generally provided by the single-phase time-delay undervoltage relay, Device 27. Where it is desired to secure three-phase undervoltage protection, such as when the motor is fed through fuses or from an overhead open line wire, Device 47 would be used in place of Device 27. In addition, the Type ICR relay, Device 47, would provide protection against phase sequence reversal should it occur between the source and the motor's associated switchgear. The Type TMC relay, Device 49/50, provides short-circuit, stalled-rotor, and running overload protection. The Type TMC relay has a thermally operated time-overcurrent device. It is therefore generally to be preferred for this application over an inverse time-overcurrent relay such as the Type IAC relay, since its time-overcurrent characteristic more closely matches that of a motor. The instantaneous device on the Type TMC relay is normally set at 1.6 to 2 times locked-rotor current. Sensitive and fast ground-fault protection is provided by the instantaneous ground sensor equipment, Device 50GS. Device 48, the incomplete sequence timer, would be included where the control package is of the reduced-voltage type. It provides protection for the motor and control package against continued operation at reduced voltage which could result from a control sequence failure. For wound-rotor motors where the starting inrush current is limited, more sensitive short-circuit protection can be provided with the addition of the Type IAC time-overcurrent relays, Device 51. With the motor inrush current limited, these relays can generally be set to operate at full-voltage locked-rotor current with all secondary resistance shorted.

Figure 10b covers protection for the larger motors rated 1500 hp and above. A current-balance relay, Type IJC, Device 46, is included to provide protection against single-phase operation. Running overload protection, Device 49, is provided by a Type IRT relay which operates from a resistance-temperature detector imbedded in the machine stator winding. This type of running overload protection is to be preferred over the stator-current-operated device included under Figure 10a, since it responds to actual motor temperature. The Type IAC66K relay, Device 49S, provides protection against stalled rotor conditions. This device is necessary since the resistance-temperature detector used with Device 49 will not respond immediately to fast changes in the stator conductor temperature as would be the case under stalled conditions. The Type IAC66K relay includes a special high-drop-out instantaneous-overcurrent unit which is arranged to prevent its time-overcurrent unit from tripping except when the magnitude of current is approximately equal to that occurring during stalled conditions. Differential protection, Device 87, provides sensitive and fast protection

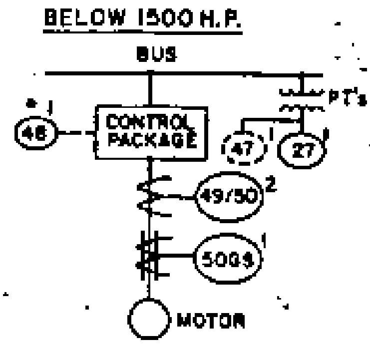


Fig. 10 (a)

Dev. Fig. 10 (a)
27△—Undervoltage—IAV
*49/50—Thermal & Inst. Short Circuit—TMC
50GS—Instantaneous Ground Sensor
48—Incomplete Sequence—Timer
47△—3Ø Undervoltage & Reverse Phase Rotation—ICR
For Wound Rotor Motors Add 2—Dev. 51—IAC
*Include if Control Package is Reduced Volt. Start
△Omit Dev. 27 when Dev. 47 is included.

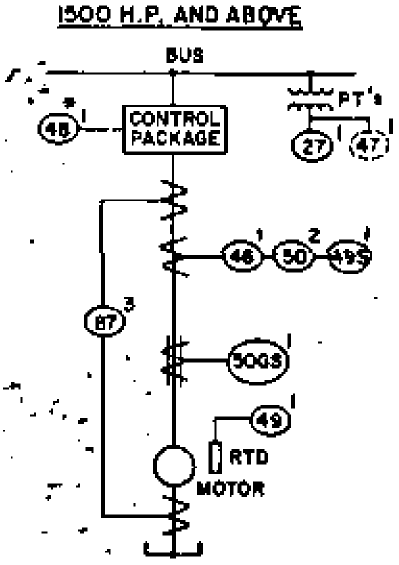


Fig. 10 (b)

Dev. Fig. 10 (b)
27△—Undervoltage—IAV
46—Current Balance—IJC
49—Thermal—IRT
49S—Thermal (Stalled)—IAC66K
50—Inst. Short Circuit—PJC
50GS—Instantaneous Ground Sensor
87—Differential—IJD (below 3000 hp), CFD
47△—3Ø Undervoltage & Reverse Phase Rotation—ICR
48—Incomplete Sequence—Timer
For Wound Rotor Motors Add 2—Dev. 51—IAC
If 87 is Self-balancing Primary Current Add 2—Dev. 51
*Include if Control Package is Reduced Volt. Start
△Omit Dev. 27 when Dev. 47 is included.

Figure 10. Recommended minimum protection for induction motors

phase-to-phase and phase-to-ground faults. Protection provided by Devices 27, 50, 50GS, 47, and 48 is as described under Figure 10a.

Synchronous Motor Driving M-G Set

Referring to Figures 11a and 11b, it will be noted that the devices specified are essentially the same as those recommended for induction motors, with additions as noted hereinafter. Field-undercurrent relay, Device 40, provides protection against out-of-step operation due to loss of field. The relay is provided with a short time delay to ride through momentary interruptions in the flow of field current which sometimes occurs during system disturbances. Under Figure 11b, the overcurrent relay, Device 51R, provides protection against continuous operation at high levels of stator current. The Type IAC relay used as Device 51R is provided with a wound-shading coil which is so connected to prevent its operation until after the motor has been synchronized.

Synchronous Motor for Power-Utilization Equipment

Synchronous motors used with power utilization equipment are subjected to somewhat different conditions than those forming a part of motor-generator sets. During starting, they usually must accelerate and synchronize while carrying relatively heavy loads. Also, while operating, the overloads to which they may be subjected cannot be as readily controlled as they are with M-G sets where the generators have breakers with overcurrent trip devices. The additional

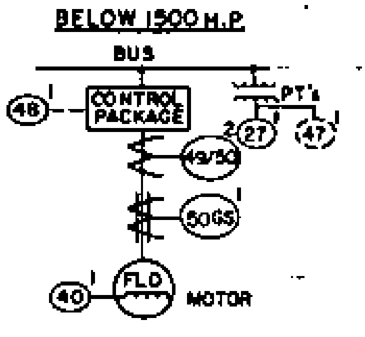


Fig. 11 (a)

Dev. Fig. 11 (a)
27^{Δ}—Undervoltage—IAV
40—Field Undercurrent—IC2820-A100
47^{Δ}—3Ø Undervoltage & Reverse Phase Rotation—ICR
48—Incomplete Sequence—Timer
49/50—Thermal & Inst. Short Circuit—TMC
50GS—Instantaneous Ground Sensor
$^{\Delta}$Omit Dev. 27 when Dev. 47 is included

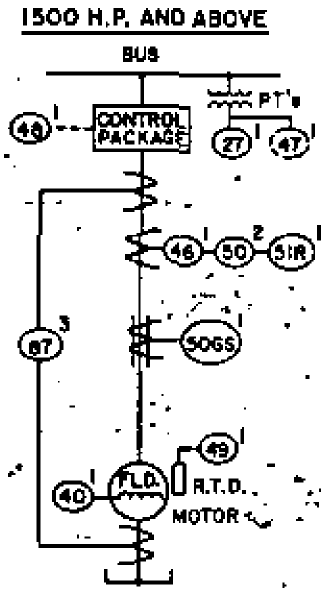


Fig. 11 (b)

Dev. Fig. 11 (b)
27^{Δ}—Undervoltage—IAV
40—Field Undercurrent—IC2820-A100
46—Current Balance—IJC
47^{Δ}—3Ø Undervoltage & Reverse Phase Rotation—ICR
48—Incomplete Sequence—Timer
49—Thermal—IRT
50—Instantaneous Short Circuit—PJC
50GS—Instantaneous Ground Sensor
51R—Running Overcurrent—IAC
87—Differential—IJD (below 3000 hp), CFD
If 87 is Self-balancing Current Add 2—Dev. 51—IAC
$^{\Delta}$Omit Dev. 27 when Dev. 47 is included

Figure 11. Recommended minimum protection for medium-voltage synchronous motors driving M-G sets

protection over and above that recommended for induction motors is therefore somewhat different than for M-G set synchronous motors. Referring to Figures 12a and 12b, it will be noted that apparatus thermal device, Device 26, has been included. The device provides protection for the motors' short-time-rated squirrel-cage winding during starting. The IC2820F102 is a frequency-sensitive, inverse-time-current, thermal-type relay. Its characteristic is such that, for a given current, the operating time decreases as the frequency increases. The relay is connected to the field circuit in such a manner as to monitor the induced currents which flow during starting. When the motor is at standstill, the frequency of these induced currents is system frequency and the tripping time of the relay is short. As the motor rotates and comes up to speed, the frequency drops, increasing the tripping time. Such an arrangement automatically compensates for the additional motor operating time which is permissible as a result of the cooling effect produced by rotation of the rotor. Operation of Device 26 should be arranged to shut down the motor.

The power-factor relay, Device 55, has also been included to protect the motor from operating at sub-synchronous speed with its field applied. This so-called out-of-step operation will produce oscillations in the motor stator current, causing them to pass through the "lagging" quadrature. The power-factor relay is connected to sense this current and will operate when it becomes abnormally lagging. Upon operation, excitation is immediately removed from motor allowing it to run as an induction machine. After excitation has been removed, the control is arranged

BELOW 1500 H.P.

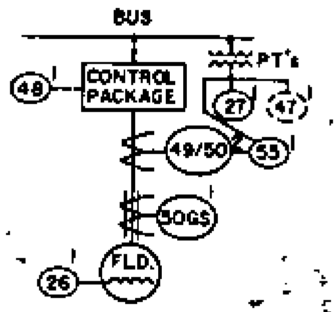


Fig. 12 (a)

Dev. Fig. 12 (a)
26—Apparatus Thermal Device—IC2820–F102
27^{Δ}—Undervoltage/IAV
47^{Δ}—3ϕ Undervoltage & Reverse Phase Rotation—ICR
48—Incomplete Sequence—Timer
49/50—Thermal & Inst. Short Circuit—TMC
50GS—Instantaneous Ground Sensor
55—Power Factor Relay—IC2820–1751A
$^{\Delta}$Omit Dev. 27 when Dev. 47 is included

1500 H.P. AND ABOVE

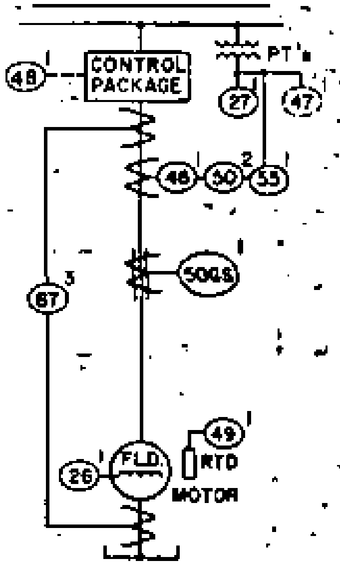


Fig. 12 (b)

Dev. Fig. 12 (b)
26—Apparatus Thermal Dev.—IC2820–F102
27—Undervoltage—IAV
46—Current Balance—IJC
47^{Δ}—3ϕ Undervoltage & Reverse Phase Rotation—ICR
48—Incomplete Sequence—Timer
49—Thermal—IRT
50—Instantaneous Short Circuit—PJC
50GS—Instantaneous Ground Sensor
55—Power Factor Relay—IC2820–1751A
87—Differential—IJD (below 3000 hp), CFD
If Dev. 87 is Self-balancing Primary Current Add 2—Dev. 51—IAC
$^{\Delta}$Omit Dev. 27 when Dev. 47 is included

Figure 12. Recommended minimum protection for medium-voltage synchronous motors with power utilization equipment

to either shut the motor down, or, if the drive is equipped with an automatic unloader, unload the machine and allow it to accelerate and resynchronize.

Brushless Synchronous Motors

Figures 13a and 13b cover the recommended minimum protection for brushless synchronous motors. The protection is essentially the same as that recommended for power utilization drives under Figures 12a and 12b. The type of relay used for Device 26 however has been changed. This is necessary since the motor field circuit to which the IC2820F102 relay is normally connected is not brought off the machine rotor. Stalled-rotor protection, Device 26, for brushless machines is a stator-current operated Type IAC relay. The characteristic and rating of this relay is picked at the factory to closely coordinate with the starting and operating characteristics of the individual machine being protected.

CONCLUSION

It should be noted that the protection covered in this bulletin will provide adequate protection for the majority of applications. There will however be some requiring specialized relaying or more complete protection. These should be referred to the Power Systems Management Department of the General Electric Co., Philadelphia, Pa. 19142. In general, the relaying described meets the requirements of USA Std. C-37.2-1962 Table I.

REFERENCES

1. "Switchgear Device Function Numbers," General Electric Company Bulletin GEA-163.

BELOW 1500 H.P.

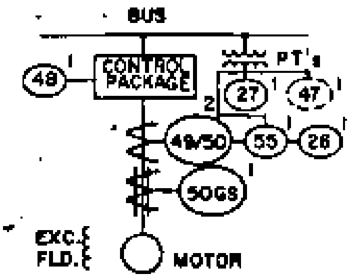


Fig. 13 (a)

Dev. Fig. 13 (a)

26—Apparatus Thermal Device—IAC (Operating characteristics carefully coordinated with motor)
27$^{\Delta}$—Undervoltage—IAV
47$^{\Delta}$—3Ø Undervoltage & Reverse Phase Rotation—ICR
48—Incomplete Sequence-Timer
49/50—Thermal & Inst. Short Circuit—TMC
50GS—Instantaneous Ground Sensor
55—Power Factor Relay—IC2820-1751A
$^{\Delta}$Omit Dev. 27 when Dev. 47 is included

1500 H.P. AND ABOVE

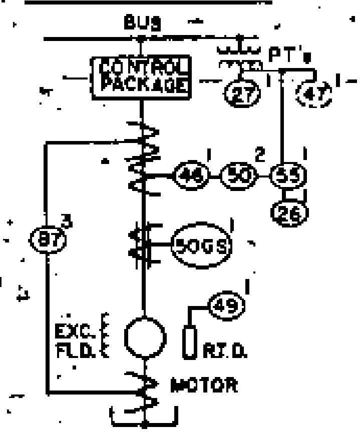


Fig. 13 (b)

Dev. Fig. 13 (b)

26—Apparatus Thermal Device—IAC (see above)
27$^{\Delta}$—Undervoltage—IAV
46—Current Balance—IJC
47$^{\Delta}$—3Ø-Undervoltage & Reverse Phase Rotation—ICR
48—Incomplete Sequence-Timer
49—Thermal—IRT
50—Instantaneous Short Circuit—PJC
50GS—Instantaneous Ground Sensor
55—Power Factor Relay—IC2820-1751A
87—Differential—IJD (below 3000 hp), CFD
If 87 is Self-balancing Primary Current Add 2—Dev. 51—IAC
$^{\Delta}$Omit Dev. 27 when Dev. 47 is included

Figure 13. Recommended minimum protection for medium-voltage, brushless, synchronous motors

GENERAL ELECTRIC PUBLICATION REFERENCES

RELAY TYPE	PUBLICATION NO.	RELAY TYPE	PUBLICATION NO.
BDD	GET-7278	ICR	GET-7270
CAN	GEI-44082	ICW	GEH-2056
CEH	GEI-31017	IJC	GEH-1789
CFD	GET-7277	IJCV	GES-7010
CPF	GET-7233	IJD	GET-7275
CFVB	GEI-31030	IRT	GEI-44244
CPD	GEH-1811	JBC	GET-7262
GGP	GEI-33891	NBV	GEI-5261
HEA	GET-7293	NGV	GET-7228
IAC	GET-7215	PJC	GEH-1790
IAV	GET-7225	PJG	GET-7306
IBC	GEH-1817	PVD	GEH-1770
IBCG	GEK-1271	TMC	GEI-44203
ICC	GEH-1779		

GENERAL ELECTRIC

Electric Power Distribution

for

Industrial Plants

FOURTH EDITION

Published by

THE INSTITUTE OF ELECTRICAL AND ELECTRONICS ENGINEERS, INC.

345 East 47th Street, New York, N. Y. 10017

PREFACE

The purpose of this publication is to promote the use of sound engineering principles in the design of electric systems for industrial plants. It explains what is good electrical practice today, but is not a handbook of design data. Because there are a great number of different types of industrial plants, it is impractical to cover in detail all the varied electric systems required. This publication treats those features of the electric distribution system which are applicable to most types and sizes of industrial plants.

The first edition of Electric Power Distribution for Industrial Plants was published in 1945 by the American Institute of Electrical Engineers. It was widely accepted by the engineering profession. The second edition was published in 1956, and represented substantial additions and revisions. The third edition brought up to date the practice resulting from technical developments since publication of the second edition. The present edition, the fourth, incorporates minor modifications.

It is anticipated that in addition to its usefulness to electrical engineers this publication will be informative to others involved in the design of industrial plants; the process engineers, architects and managers who are responsible for decisions affecting the electric system.

Comments, corrections and suggestions for future revision of this publication are welcome. They should be submitted to the Industrial and Commercial Power Systems Committee of The Institute of Electrical and Electronics Engineers, 345 East 47th Street, New York, N. Y. 10017.

Industrial Plants Power Systems Subcommittee
of the Industrial and Commercial Power Systems Committee
of the IEEE Industry and General Applications Group

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THE FOURTH EDITION

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CONTENTS

ELECTRIC POWER DISTRIBUTION FOR INDUSTRIAL PLANTS

CHAPTER I

SYSTEM PLANNING

An industrial plant is only as good as its electric distribution system. For this reason, careful system planning for an industrial power system is very important. This chapter outlines the procedures of system planning and presents a guide which will make the details of succeeding chapters more useful and understandable. As has been often quoted, "If you can see the problem in your 'mind's eye', the rest is A, B, C."

A standard electric distribution system is not adaptable to all industrial plants because no two plants have identical requirements. Methods must be used to analyze the specific requirements of the industrial plant qualitatively and quantitatively, and design the system which will most adequately meet the electrical requirements of the particular plant, with consideration given to both present and future operating conditions.

Basic Design Considerations

Any approach to the problems must include several basic considerations which will affect the overall design. They are:

1. Safety—Safety takes two forms; safety to personnel and safety to materials, buildings and electric equipments.

   Safety to personnel involves no compromise; only the safest system can be considered.

   Safety to materials, buildings and electric equipments may involve some compromise where safety of personnel is not jeopardized.

2. Reliability—The continuity of service required is dependent on the type of manufacturing or process operation of the plant. Some plants can easily tolerate momentary outages while others require a very high degree of service continuity. In view of this, the system should be designed to isolate faults with a minimum disturbance to the system and should have features to give the maximum dependability consistent with the plant requirements.

3. First Cost—While first cost is important, it is often minimized if the system is reliable and its operation satisfactory. It should not be the determining factor in the design of the plant since distribution cost represents only 2 to 10 percent of the plant investment.

4. Simplicity of Operation—Simplicity of operation is a big factor in the safe and reliable operation of a plant. Avoid complicated and dangerous switching operations under emergency conditions.

5. Voltage Regulation—For some plant power systems, voltage spread may be the determining factor of the distribution design. Poor regulation is detrimental to the life and operation of electric equipment.

6. Maintenance—A well designed distribution system, with properly chosen equipment, will reduce emergency maintenance. In planning the system, the accessibility and availability for inspection and repairs should be given careful consideration.

7. Plant Expansion—Plant loads generally increase. Consideration of the plant voltages, ratings of equipment, space for additional equipment and capacity for increased load must be given serious study.

Planning Guide for Distribution Design

With the above factors in mind, the following procedure is given to guide the engineer in the design of an electric distribution system for any industrial plant.

1. Obtain a general layout and mark it with the major loads at various locations and determine the approximate total plant load in horsepower, kilowatts, and kilovolt-amperes.

2. Estimate the lighting, air-conditioning, and other loads from known data and the system load survey information given on pages 10 and 11.

3. Determine the total connected load and calculate the maximum demand by using demand and diversity factors.

4. Investigate unusual loads, such as the starting of large motors, operation of arc furnaces or welders, and operating conditions such as boiler auxiliary motors, loads that must be kept in operation under all conditions, and loads that have a special duty cycle.

5. Investigate the various types of distribution systems and select the system or systems best suited to the requirements of the plant. Make a preliminary one-line diagram of the power system.

6. If power is to be purchased from the utility, obtain such information concerning the supply system or systems as: performance data, voltage available, voltage spread, type of systems available, method of system neutral grounding, and other data such as relaying, metering and the physical requirements of the equipment. The interrupting rating and momentary ratings of power circuit breakers should be obtained as well as the present and future short-circuit capabilities of the utility system at the point of service to the plant. Investigate the utility's power contract to determine if off-peak power at lower rates is available, and any other requirements, such as power factor and demand clauses, that can influence power cost.

7. If considering a generating station for an industrial plant, such items should be determined as: generating kva required including standby loads, generating voltage, and such features as relaying, metering, voltage regulating equipment, synchronizing equipment and grounding equipment. If parallel operation is contemplated, be sure to review this with the utility and obtain its requirements.

8. A cost analysis may be required of the different voltage levels and various arrangements of equipment to justify and properly determine the voltage and equipment selected. The study should be made on the basis of installed cost including all the components in that section of the system.

9. Check the calculations of short-circuit requirements to be sure that all breakers are of the correct rating. Review the selectivity of various protective devices to assure selectivity during load or fault disturbances.

10. Calculate the voltage spread and voltage drop at various critical points.

11. Determine the requirements of the various components of the electric distribution system with special attention given to special operating and equipment conditions.

12. Review all applicable national and local Codes for requirements and restrictions.

13. Check to see that the maximum safety features are incorporated in all parts of the system.

14. Write specifications on the equipment and include a one-line diagram as a part of the specifications.

15. Obtain typical dimensions of equipment and make drawings of the entire system.

16. Determine if the existing equipment is adequate to meet additional load requirements. Check such ratings as voltage, interrupting capacity, and current-carrying capacity.

17. Determine the best method of connecting the new part of the power system with the existing system so as to have a minimum outage at minimum cost.

Naturally the above procedure will not automatically design the electric power system in itself; it must be used with good, sound, basic engineering judgment.

General Layout

A general layout of the plant should be available before the engineer can begin his study. This layout usually gives the location and the size of the proposed building or buildings in the initial particular project. The extent of the available layout gives the engineer an idea of the possible expansion of the plant in the future, and must be considered by the engineer in planning the electric distribution system.

Types of Circuit Arrangements

Most modern industrial plants make use of the load-center system. This system generally consists of several small substations receiving power from a medium- or high-voltage system and stepping down at the substation to utilization voltages at the various load areas. The use of many small substations introduces the possibility of many different circuit arrangements. Since the type of circuit arrangement selected will have an important effect on power system performance, cost, and reliability, it is a factor which must be considered in the system planning stage.

The basic types of circuit arrangements together with their respective characteristics are discussed in detail under Selection of Circuit Arrangements on page 18.

Plans for Future Expansion and Modernization

When plant facilities have to be expanded or modernized, the engineer is afforded an opportunity to design his ideal electric system. First, a one-line diagram should be prepared showing the type of system which would be used for a new plant of similar design. Having made the plan, he should let it guide the future modernization and expansion. Existing equipment obviously cannot be retired at once, but as additions and replacements of equipment are required, they should be made on the basis of being integrated in the ideal plan and not as replacements for the old system.

Flexibility

Plants change manufacturing processes from time to time. Where castings are used today, welding may be used tomorrow. Both process and product may change as demands and styles change. The electric distribution system for any plant should be flexible enough so that complete new process layouts can be made without requiring major changes in the distribution system.

Flexibility for expansion should be considered. In line with this, the engineer should strive for a system design that will permit reasonable expansion with minimum investment and minimum downtime to existing production.

Two great contributions toward flexibility are: (1) the load-center system with small substations which may be added in small blocks as required and (2) plug-in busway which permits the installation of flexible permanent power distribution systems on which machine tools and other devices are merely plugged in where necessary.

System Reliability

Service reliability in any plant is important. Most manufacturing processes are on a production-line basis so that a line shut-down may hold up an entire plant. Also some processes in themselves require a very high order of service reliability. Many factors influence the reliability of electric supply in the plant. Among the most important factors are the following: (1) Reliability of bulk power supply from utility and/or local generation; voltage fluctuations usually occur more frequently than momentary or sustained interruptions. Faults on the supply system can cause momentary voltage depressions in the supply voltage which may adversely affect industrial equipment; (2) Plant distribution system arrangement; (3) Simplicity of system arrangement; (4) Simplicity of system operation and maintenance; (5) Reliability of equipment and installation. All of these factors should be considered in designing a system to meet the service reliability requirements of a given system. A study of equipment reliability is reported in Reference 5.

Selection of Equipment

The fundamental consideration in selecting equipment is to choose the optimum equipment consistent with the requirements of the plant. Frequently it costs no more in the long run to use the best equipment available as it pays dividends in service continuity and lower maintenance. Some widely accepted principles are:

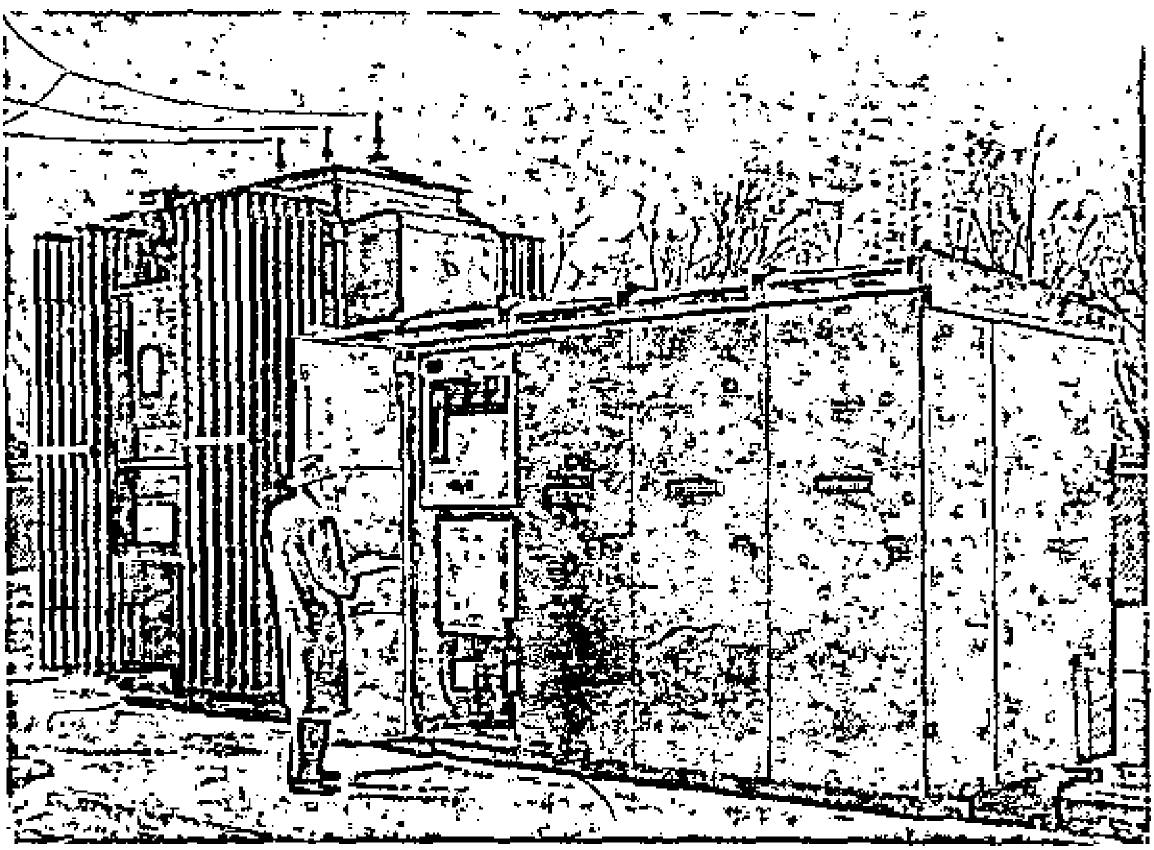

Figure 1.1
Industrial unit substation installation of 7500 kVA with load-tap-changing equipment and outdoor metal-clad switchgear

1. Use of metal-clad and metal-enclosed equipment.
2. Choose nonflammable or dry type transformers for indoor installations.
3. Use factory-assembled equipment for easier field installation and better coordination.
4. Be sure equipment ratings are adequate in every respect, such as voltage, current, momentary, and interrupting rating.

Figure 1.1 shows a typical industrial unit substation incorporating these features.

Economics

Economics is a very important part of power system engineering. The engineer must compare systems on the basis of cost as well as other features. In making economic comparisons, it is important to include all parts of the system from the power source down to and including the utilization equipment.

Economic comparisons should also include installation as well as equipment and operating costs. As an example: system A may require less transformer kVA than system B, but the connections of system A and other factors may require far more expensive switchgear and more cable than system B. The increased cost of switchgear and cable may more than offset savings in transformer equipment. A comparison on the basis of transformers only would give the wrong answer. (Reference 6)

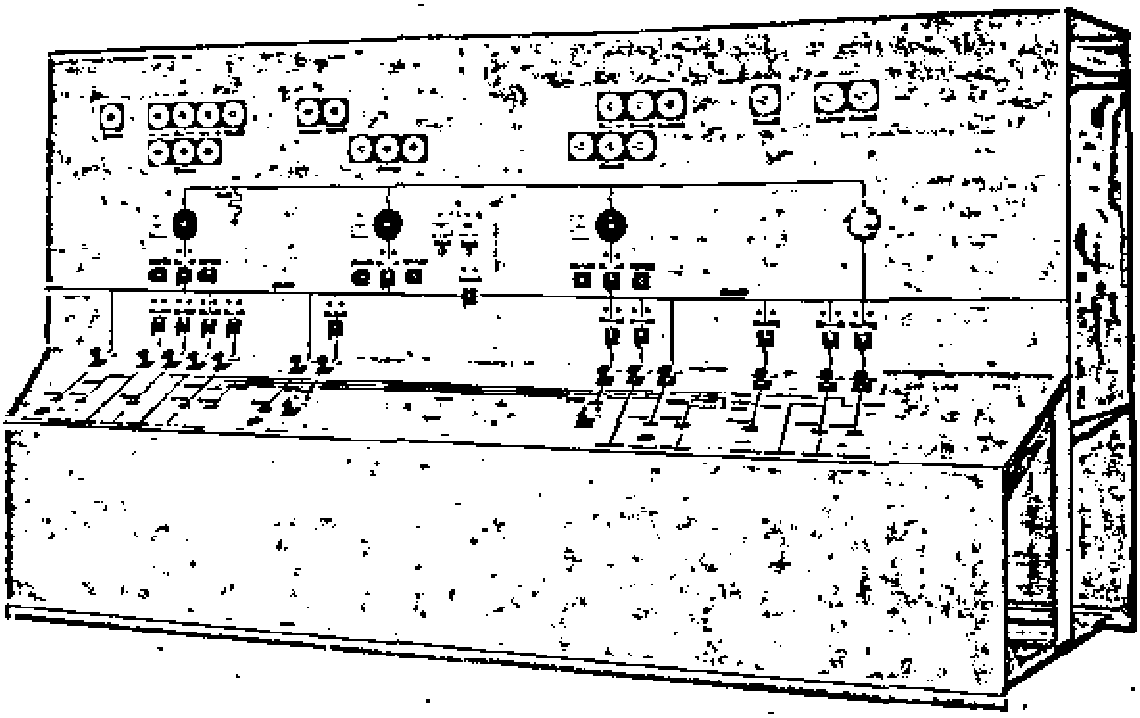

Figure 1.2
A central control benchboard for the main 13.8-kV power distribution system of an industrial plant

Operation and Maintenance

Proper maintenance is as important to successful performance of the system as selection of the system and its components. Long after the first cost is forgotten the maintenance cost will continue and, if foresight has not been used, this cost may be considerable.

Figure 1.2 shows a centralized controlboard. The mimic bus and organized arrangement of components can be a real aid in avoiding operating errors.

Although maintenance is largely in the hands of the operators, the system designer can aid in the problem by designing systems that can be maintained economically with a minimum of downtime or provide alternate power circuits.

One circuit can then be taken out for maintenance without dropping essential load. Also, drawout equipment should be used wherever possible to enable maintenance on breaker elements to be done in a service shop.

Another important factor to consider is that maintenance costs often can be reduced by care in locating equipment and by providing convenient auxiliary services. As an example, adequate aisles should be provided and spares of vulnerable parts should be accessible. Provisions should be made for auxiliary power and light so that vital services can be continued during periodic maintenance work.

Other important considerations are location and routine operation and setting of devices. Switchboards, circuit breakers, panelboards, and similar equipment, should not be located where they are subjected to accumulations of dirt, dust and other foreign materials or where they may be damaged by cranes or factory trucks. Operation and settings of relays should be checked regularly. The design engineer can help by including suggested maintenance schedules in the data given to the operator.

Utility Service

In designing the power distribution system, thought must also be given to the utility service. This service must be reviewed from the standpoint of voltage level and also voltage spread, as discussed in Chapter II.

If the supply voltage is 15 kV or less, it is frequently used without transformation. Voltages above 15 kV are generally considered too high for use within buildings and, hence, transformation is required in these cases. When transformation is necessary, there is a problem of selecting the proper primary voltage—i.e., 2.4, 4.16, 6.9 or 13.8 kV. The choice is usually based on economics and will greatly affect both the first cost and also the cost of future expansion of the distribution and utilization equipment. In general, 4.16 kV is chosen for loads less than 10,000 kVA; 13.8 kV is chosen for loads above 20,000 kVA; and either might be selected for loads between 10,000 and 20,000 kVA, depending upon the possibility of expansion and concentration of the load. This subject is covered later under Selection of System Voltage on page 17.

Voltage spread in the utility system may be troublesome depending upon the type of utilization equipment involved. If the primary voltage variation is excessive, then feeder or bus voltage regulators may be required. These may be load-tap-changing transformers, individual regulators, switched capacitors or secondary feeder regulators. The choice is based upon both economic and engineering considerations.

Determination of Loads
General

Determination of the load is the electrical engineer's first problem and may be difficult to solve. The size and number of primary and secondary substations, the size, number and arrangement of primary feeders, and the type of secondary distribution, are largely dependent on the amount and nature of the load and its distribution.

The plant distribution system usually must be designed before all loads are known. This is at a time when the equipment layout itself is only in the formative stage. Equipment may be bought piecemeal during which time changes in machines are taking place either in number or size. Ideas are changed by the impact of what is commercially available, or by manufacturers' recommendations for improved models, better ways of securing a given result, or by competitive conditions. Processes themselves are being changed as available equipment is fitted into the prospective production schedule.

Many plants are built to manufacture new products, which adds to the difficulty of establishing power requirements. Plant layouts are subject to considerable modification of the original scheme. Entire plant rearrangement may be necessary in the middle of a job; air and refrigerating compressors, fans, blowers and pumps may come into the picture or shift position rapidly; oil-fired annealing furnaces may become electrically heated as a result of laboratory tests that prove a controlled atmosphere necessary, thus adding hundreds if not thousands of kilowatts to the plant load.

Even after a plant is in operation, loads may change in size and location. New models, new products and production methods call for continual change in the distribution system, but these changes can be minimized by careful planning.

Preliminary Load Survey

How to make preliminary estimates of loads is a problem deserving the closest study. These estimates may have to be used as the basis for major decisions. At this stage in the plant design, the electrical engineer often has available only a few building layout drawings or perhaps a plant map. The general locations of the major pieces of equipment will usually be roughly indicated and their power requirements may or may not be known. Starting with this information the electrical engineer must call on all his knowledge and experience as well as on that of other plant engineers and designers to enable him to arrive at an estimate which will stand up as the loads become better defined. In most cases, it is better to consider the lighting and power loads separately and combine them later to determine the demand in any one area, since present practice is usually to supply these loads from a load-center substation.

Factors most frequently used in determining distribution system loads are as follows:

Demand Factor: The ratio of the maximum demand on a system to the total connected load of the system. (The maximum demand is usually the integrated maximum kilowatt demand over a 15 or 30 minute interval, rather than the instantaneous or peak demand.

Diversity Factor: The ratio of the sum of the individual maximum demands of the various parts of a system to the maximum demand of the whole system.

Load Factor: The ratio of the average load over a designated period of time to the peak load occurring in that period.

Information as to the demand and the diversity factors for the various loads and groups of loads is needed to design the system. For example, the sum of the connected loads on a branch load circuit, multiplied by the demand factor of these loads, will give the maximum demand which the branch circuit must carry. The sum of the maximum demands of the branch circuits associated with a sub-load center or panelboard divided by the diversity factor of those branch circuits will give the maximum demand at the sub-load center and on the circuit supplying it. The sum of the maximum demands of the circuits radiating from a load center, divided by the diversity factor of those circuits, will give the maximum demand on the transformer at the load center. The sum of the maximum demands of the load-center transformers divided by the diversity factor of the transformer loads will give the maximum demand on their primary feeder. By the use of the proper demand and diversity factors as outlined above, the maximum demands on the various parts of the system from the branch load circuits to the power source, inclusive, can be determined.

Lighting Loads

Estimating the lighting is usually not difficult. For rough estimates, only the area of the building and the illumination level desired need be known. For more accurate estimating, the general type of construction must be known as well as mounting height and spacing and location of roof trusses and columns, so that the optimum arrangement can be checked against physical requirements. The intensity of illumination and the type of lighting (mercury, fluorescent, or incandescent) desired together with general construction features will make possible computation of load using formulas in lighting handbooks or data from fixture manufacturers.

For quick estimates of lighting with the most efficient fluorescent units, approximately three watts per square foot will provide 50-footcandle illumination. If incandescents are used, the wattage will be approximately twice as much.

Information on outdoor lighting is readily available. Fence lighting can be estimated at 200 watts per 100 feet. "Yard lighting" is often adequate if a 200-watt lamp is placed every 100 feet along the exterior walls of buildings. The total outdoor lighting will seldom exceed 25 percent of all lighting and it may be as little as 5 percent; hence, a rather nominal allowance in primary substation and feeder capacity will provide for considerable leeway for changes in the outdoor lighting which may develop late in the construction period.

Table 1.1 gives lighting requirements in various industries.

Table 1.1
Lighting Requirements in Various Industries

Industry	*Lighting in Percent of Total Connected Load*
	Percent
Steel Foundries	1 to 3
Steel Rolling Mills, Oil Refining	3 to 5
Heavy Electric Equipment, Wire Drawing	5 to 8
Auto Equipment, Baking	8 to 10
Machine Parts	10 to 15
Auto Assembly and Parts	15 to 25

The diversity factor of the lighting load will be low and the demand factor of the lighting connected to any load center should be considered as 100 percent.

Power Loads

Estimating the power load is considerably more difficult than estimating the lighting load. Table 1.2 gives estimated load densities in representative industries.

Table 1.2
Estimated Load Densities in Various Industries

Type of Plant	*Voltampere Demand Light and Power*	
Airplane Factories	15 to 25 VA/sq ft	
Beet Sugar Factory and Refinery	19	"
Paper Mills	14	"
Textile Mills, Engine Builders	12	"
Cigarette Manufacturing	11	"
General Manufacturing, Chemicals, Electronic Equipment	10	"
Small Appliance Manufacturing, Machine Repair Shop	7½	"
Lamp Manufacturing	5	"
Small Device Manufacturing	3½	"

Table 1.2 should be used for preliminary estimating only since the size of the plant and its processes will vary considerably within a given industry category.

When the loads of individual machines or areas are known, it is necessary to combine them to obtain the maximum demand. The maximum demand determines the system capacity which must be provided to supply it as well as optimum system voltage. It is determined by applying demand and diversity factors to the connected load. The selection of demand and diversity factors, like load density, is based on known conditions, experience, and similar operations in existing plants. Table 1.3 gives the factors for the more common types of manufacturing loads and is the factor by which the connected load must be multiplied to obtain total plant demand assuming diversity factor of one. If the diversity factor is known, the demand thus obtained should be divided by the diversity factor to obtain the actual demand.

Table 1.3
Demand Factors

Load	*Estimating Demand Factor—Percent*
Arc Furnaces	100
Arc Welders	30
Induction Furnaces	80
Lighting	100
Motors	
1. General Purpose, Machine Tool, Crane Elevators, Ventilation, Compressors, Pumps, Rolling Mills, etc.	30
2. Semi-continuous Processes, Paper Mills, Refineries, Rubber Mills, etc.	60
3. Continuous Operations, Textile Mills, Chemical Plants, etc.	90
Resistance Ovens, Heaters and Furnaces	80
Resistance Welders	20

As the table shows, the demand factor will vary considerably with different types of loads. For example, the demand factor of a group of motors driving a conveyor belt will approach 100 percent, while the demand factor of a group of hand tools in a small furniture factory or machine shop might be only 10 percent A diversity factor of unity is often used to provide ample system capacity, since the margin provided in this way is soon used by load growth. Although a diversity factor of unity represents the sum of the maximum demands of the individual load centers and of the equipment applied at the distribution voltage on the distribution system, the usual practice is to provide a system adequate for a maximum demand obtained with a diversity factor of unity or to provide even more than 100 percent capacity in the main system to take care of load centers which would be added in the future.

Any of a wide variety of plants may come under consideration in making a load survey. A knowledge of approximate kva load necessary to produce unit weights of the material being made is a great help. This knowledge may come from past experience or available published material. It would be impossible to list all types of industries here, but requirements for some of the more important industries follow:

Table 1.4
Bulk Product Industries

Product	Kilowatthours Per Pound of Product
Gasoline	0.0015
Liquid Sulphur Dioxide	0.002
Glycerine (from soap)	0.005
Ammonium Phosphate	0.007
Sulphuric Acid	0.016
Formaldehyde	0.030
Tri-Sodium Phosphate	0.038
Portland Cement	0.050
Ethylene Oxide	0.070
Alumina Ex Bauxite	0.090
Nitric Acid	0.180
Synthetic Ethyl Alcohol	0.300
Electric Steel	0.330
Carbon Disulphide	0.450
Benzene Hexachloride	0.600

Ammonia, Chlorine & Caustic (salt electrolysis)	0.750
Phosphoric Acid (electric furnace)	1.80
Rayon	2.50
Sodium	4.70
Hydrogen Peroxide / Electrolytic Magnesium	8.0
Aluminum	9.0

Table 1.5
Unit Product Industries

Kilowatthours Per Unit of Product

	kWh	*Unit*
Automobiles	1050	each
Carpets & rugs (wool)	1480	1000 sq yd
Cement	22	bbl.
Paper		
Wood Pulp	384	ton
Paper & Board	575	ton
Pig Iron	25	ton
Shoes	472	1000 pairs
Steel	227	tons
Sugar		
Beet	154	ton of refined sugar
Cane	220	ton of raw sugar
Tobacco		
Cigarettes	200	million
Cigars	8100	million

Electronic Data Processing Machines

Large computers require that special consideration be given to the electric distribution system supplying them. Special requirements are usually stipulated by the computer manufacturer, and requirements vary with computer design.

A typical computer will require 3-phase, 4-wire, 60-hertz supply at 208, 230 or 240 volts. Permissible voltage variation ranges from ± 3 to ± 10 percent, depending on computer design. Frequency variations permitted are in the order of ± ½ to ± 1 hertz. Computers in general are likely to be damaged by system transients which may otherwise go undetected. The degree of susceptibility varies with the computer design. It is usually advisable to feed the computer from a separate transformer, and in some cases it is necessary to isolate it further by the use of a motor-generator set.

Power requirements of typical large computer systems range from about 200 to 500 kVA, with air-conditioning requirements of from 25 to 75 kVA.

Trends in Design of Industrial Power Systems

Trends Affecting Power System Arrangements

Three important trends in the design of industrial power systems which affect power system arrangement are: (1) the increased use of load-center systems, (2) the grounding of the system neutral at all voltage levels, and (3) the increased use of higher voltages (generally 480Y/277 volts) for lighting in industrial and commercial buildings. These three trends are reviewed below:

Load-Center Systems

A load-center system may be defined as one in which power is transmitted at voltages above 600 volts to unit substations located close to the centers of electric load. At these substations the voltage is stepped down to the utilization level and distributed by short secondary feeders to the points of use. The trend to this type of system as opposed to older types of systems has become very marked in recent years. An examination of the advantages listed below for the load-center system when compared to older systems will indicate why such a trend has come about.

1. Lower first cost.
2. Reduced power losses.
3. Improved voltage regulation.
4. Increased flexibility.
5. Better continuity of service.
6. Simplified engineering, planning, and purchasing.
7. Lower field installation expense.
8. Higher salvage value.

Load-center systems may employ any of the basic system arrangements for primary power supply. The five combinations most generally used are radial, secondary selective, primary selective, looped primary and secondary network. What system to use should be determined by a study of the requirements for each job. Various other types of system arrangements, such as primary network, have been used as well as combinations of the basic system arrangements, such as primary selective—secondary selective. It should also be pointed out that a contributing factor to the increased use of load center systems has been the development of air circuit breakers, metal-clad and metal-enclosed switchgear, and especially askarel-filled and dry type transformers. These equipments have permitted the installation of the unit substations in buildings and close to the centers of loads without requiring expensive vaults to minimize fire hazards and danger to personnel. Another factor has been use of the transformer and large motor scheme, switched and protected as a unit.

System Neutral Grounding

Grounding of system neutrals at primary voltages has been almost universally practiced. However, there have always been two schools of thought regarding grounding of system neutrals at utilization voltages. There are many systems in operation with ungrounded neutrals, but few such systems are being installed today. There is therefore, a trend toward neutral grounding at the lower voltages, and it is probable that most of the new systems from now on will be of the grounded-neutral type. The advantages claimed for system neutral grounding are:

1. Reduced operating expense.
2. Improved service reliability.
3. Greater safety.
4. Better system and equipment overcurrent protection.
5. Improved lightning protection.

The use of grounded-neutral systems affects power system design by requiring, through study and careful selection, a means of grounding. Selection of transformers of proper characteristics for the unit substations will usually be involved. In some cases lower rated lightning arresters may be used resulting in better surge protection. Ground relays are usually employed on high- and medium-voltage systems for faster relaying of faults.

Higher-Voltage Lighting

The use of higher-voltage lighting, such as 480Y/277 volts, is gaining favor for large industrial and commercial buildings. Fluorescent and mercury-vapor lamps which require ballasts or transformers regardless of supply voltage are well adapted to operation on the higher voltages. Reduction of the total installed cost is the principal objective. The savings to be made are a function of the size of the building and the percentage of the total load connected to the higher voltage.

Higher-voltage lighting will affect the design of the power system by reducing the number and size of low-voltage feeders operating at 120 volts, although it will not be practicable to eliminate such circuits entirely due to the need for convenience outlets for appliances. Likewise, step-down transformers from 480 to 120 volts will also be reduced in number and size. Where the lighting is of the incandescent type and more than half the load it may not be economical to use higher-voltage lighting, since incandescent lamps require transformers to permit their operation on lower voltages.

Trends Affecting Power System Equipment Application

The principal trends that affect equipment in the industrial power system include:

Metal-Enclosed Switchgear Assemblies

The high cost of construction labor in recent years has emphasized the need for purchasing factory-assembled equipment if maximum economy is to be achieved. This need plus the many unquestionable advantages of metal-enclosed switchgear has accelerated the trend toward its use in plants recently built or in the process of building.

Three types of metal-enclosed switchgear have evolved over a span of 40 years since this type of equipment was first introduced to the industry. The distinction between types is based on construction features and voltage classification. Metal-enclosed switchgear is available in either indoor or outdoor construction.

Metal-clad switchgear consists of completely metal-enclosed, grounded stationary structures in which the secondary control devices, main power bus and outgoing circuits are each isolated by means of grounded metal barriers to provide maximum reliability. The circuit interrupting devices are of the removable type and the buses, connections and joints are insulated throughout. Interlocks are provided to insure proper sequence and safe operation. Metal-clad switchgear is available for medium-voltage-class systems. Refer to Figure 1.3.

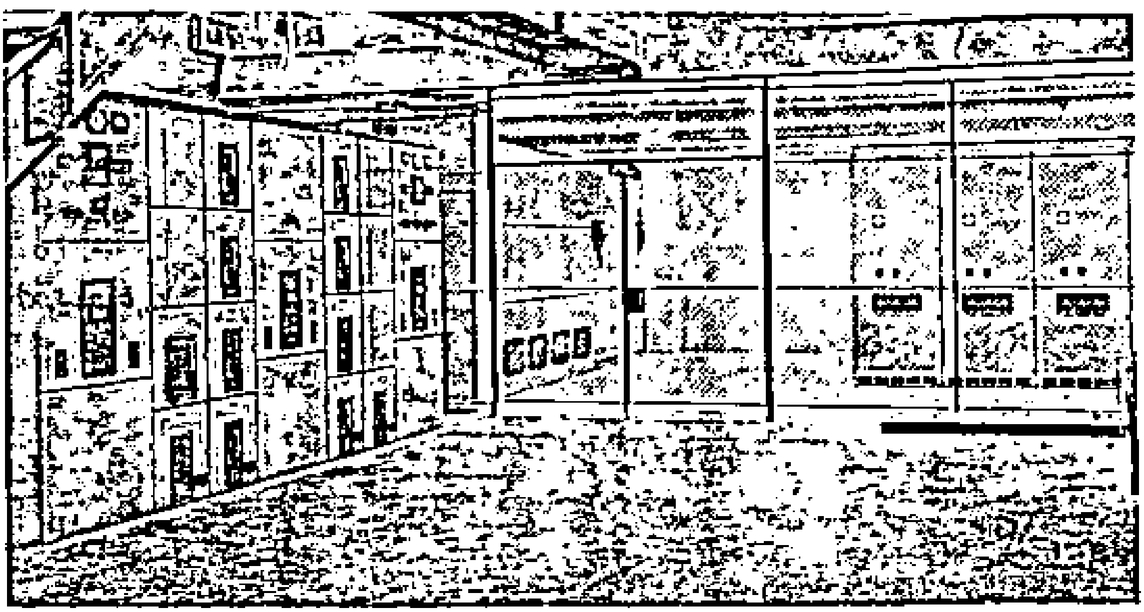

Figure 1.3
Indoor metal-clad switchgear with primary, transforming and secondary sections of a 3000-kVA unit substation.

Metal-enclosed load-interrupter switchgear consists of completely metal-enclosed, grounded structures with fixed or removable fused (or non-fused) load-interrupter switches. No metal barriers are used to isolate separate parts of the primary circuit. Buses, joints and connectors are non-insulated copper or aluminum mounted on suitable supports. The fused load-interrupter switch is designed to interrupt load current, and should be capable of safely closing against high fault currents. The fault-interrupting capacity and the high-current closing capability of the equipment are dependent on the characteristics of the associated fuses. Suitable interlocks can be provided to insure safe and proper operation. Metal-enclosed load-interrupter switchgear is also available for low- and medium-voltage-class systems.

Metal-enclosed, low-voltage switchgear consists of free standing metal-enclosed, grounded switchboard structures with low-voltage power circuit breakers contained in individual compartments. The circuit breakers are either stationary or drawout mounted and may be controlled remotely (electrically operated) or from the front of the switchgear. The buses are normally non-insulated and incoming and outgoing circuits are not normally barriered. Suitable interlocks are provided to insure safe and proper operation. As the name of this equipment implies, it is available for applications to low-voltage class systems.

A few of the advantages of metal-enclosed switchgear are:

1. Safety to personnel.
2. Ease of maintenance.
3. Ease of installation.
4. Compactness.
5. Lower installed cost.
6. Flexibility.
7. Ease of ordering.
8. Uniformity of appearance.

Power Circuit Breakers

Air circuit breakers are now almost universally used as opposed to oil circuit breakers for a wide variety of voltages, current-carrying and interrupting capacities to cover almost every requirement in an industrial plant or commercial building. They have established a good record for reliability, safety, and low maintenance costs.

Askarel and Dry-Type Transformers

The use of load-center systems has been facilitated by the development of transformers which can be installed in buildings close to centers of load without requiring expensive vaults. The askarel-insulated transformer is the most commonly used type in the industrial field and has the broadest range of application. It has the advantages over the ventilated dry type of about twice the impulse strength, a lower audio sound level, lower maintenance, and can be located outdoors or almost anywhere in the plant. This type transformer has one property superior to oil-immersed transformers, in that the insulating liquid is non-flammable. Askarel is a non-oxidizing insulating fluid and when decomposed by an electric current evolves only non-explosive gaseous mixtures. These gases are toxic and rooms in which askarel transformers are located should be ventilated.

The developments in ventilated and sealed dry type transformers in the larger sizes have contributed to their increased use for unit substations. At the present time dry type transformers are readily available in ratings to 2000 kVA at 15 kV and below. The cost of ventilated dry type transformers is about 10 to 15 percent above that of conventional oil-insulated self-cooled transformers and is less than the cost of the askarel type. They are well adapted for use in clean locations.

Hermetically sealed dry type transformers filled with inert gas are available for use in less favorable locations. The cost is 35 to 40 percent more than the conventional oil-insulated self-cooled transformers but only 10 to 15 percent more than the askarel type. The hermetically sealed, Class H transformers, can be placed almost anywhere in a building provided adequate ventilation is available.

Cables

Rubber and rubber-like synthetic compounds used as insulation and cable coverings suitable for direct exposure to the elements and for direct burial in the ground are in common use at voltages up to 15 kV.

Synthetic compounds of the thermoplastic type, such as poly-vinyl-chloride and polyethylene, are being used at an increasing rate for low-voltage power and control cable insulations because of the excellent electrical and moisture-resistant properties as well as their relatively low cost. Such insulations have made possible the use of these cables in trays.

Medium-voltage insulations require, in addition, high dielectric strength and corona and ozone resistance. Thermosetting synthetic compounds such as butyl, silicone, and rubber compounds are being used to meet these requirements.

To protect insulating compounds which exhibit excellent electrical properties but lack the desired environmental resistance, polychloroprene compounds are being widely used for jacket material. Polychloroprene, a tough thermosetting synthetic compound, has a high resistance to chemicals likely to be encountered in service.

On medium-voltage cables, shielding is normally used for voltages in excess of 4 kV except for portable cables where shielding is normally used on cables above 2 kV.

The availability of the synthetic materials has created a trend away from underground duct systems and open wire on cross arms. Aerial cable, which is gradually replacing the duct and open-wire systems, is becoming quite popular for long outdoor circuits. Aerial cable is factory or field assembled from three or more properly insulated and jacketed conductors and a supporting messenger wire, which is effectively banded to the conductors. They are commonly made for voltages up to 15 kV grounded neutral and sizes up to 500 MCM. Advantages over the open-wire system are fewer service interruptions, good appearance, ease of installation, less congestion on poles or towers, improved voltage regulation because of lower and balanced reactance, and reduced clearance requirements.

For indoor and short outdoor circuits, interlocked armor cables have found wide application at all voltage levels up to 15 kV. This cable eliminates the need for conduit, raceways, or duct and is frequently installed in troughs, baskets or racks. To help insure a low ground return circuit impedance, an interstitial equipment ground wire is recommended and sometimes required by local Codes. It has been found that the interlocked armor exhibits an appreciable impedance which causes stray currents to flow through building members and may result in sparking and thus create a safety hazard, unless internal grounding conductors or other effective grounding circuit is provided.

For a more complete discussion of cable practices, see Chapter IX.

Plug-In Busway

The use of plug-in busway is quite common for industrial buildings where changing loads must be accommodated. Factories, within which machines are likely to be moved around or changed frequently, provide excellent applications for the plug-in busways. Although the first cost of such an installation may be higher, future changes can be made at much lower cost and in less time.

Capacitors

Shunt capacitors are used to advantage in many industrial installations. Electric power contracts frequently contain power-factor clauses which benefit the plant if reasonably high power factor is maintained. The savings realized will often pay for the installation cost of the capacitors within a short time. In addition, reduced voltage drop is realized, particularly if the capacitors are located near the loads. Likewise the power losses in feeders and branch circuits may be reduced because of lower currents flowing through them when the power factor is improved. This in turn achieves another benefit: the ability to carry additional connected load on the same feeder circuit.

Voltage Regulators

The spread in voltages supplied by the utilities, together with the voltage drops occurring in transformers, feeders, and branch circuits under load conditions, may result in a wide variation in voltage at the utilization devices between light load and heavy load conditions. The trend is to reduce such voltage variations to a minimum in order to obtain more satisfactory operation of the power utilization devices. Some of the larger industrial plants install voltage regulators on buses or feeders to maintain relatively constant voltages at the load. Transformers with load tap changing, have been used and are being increasingly applied when the incoming supply voltage is above 15 kV. While the trend is in the direction mentioned above, each case must be carefully studied to determine whether or not voltage correcting equipment can be economically justified.

Motor Control Centers

A strong trend has been established toward centralized motor control equipment. The advantages of grouping all motor controls at a central point are often present even when individual motor control units are used. Motor control centers have a number of advantages over the individually mounted controllers. The most important advantages are:

1. Reduced installation costs. Complete units assembled and wired at factory.

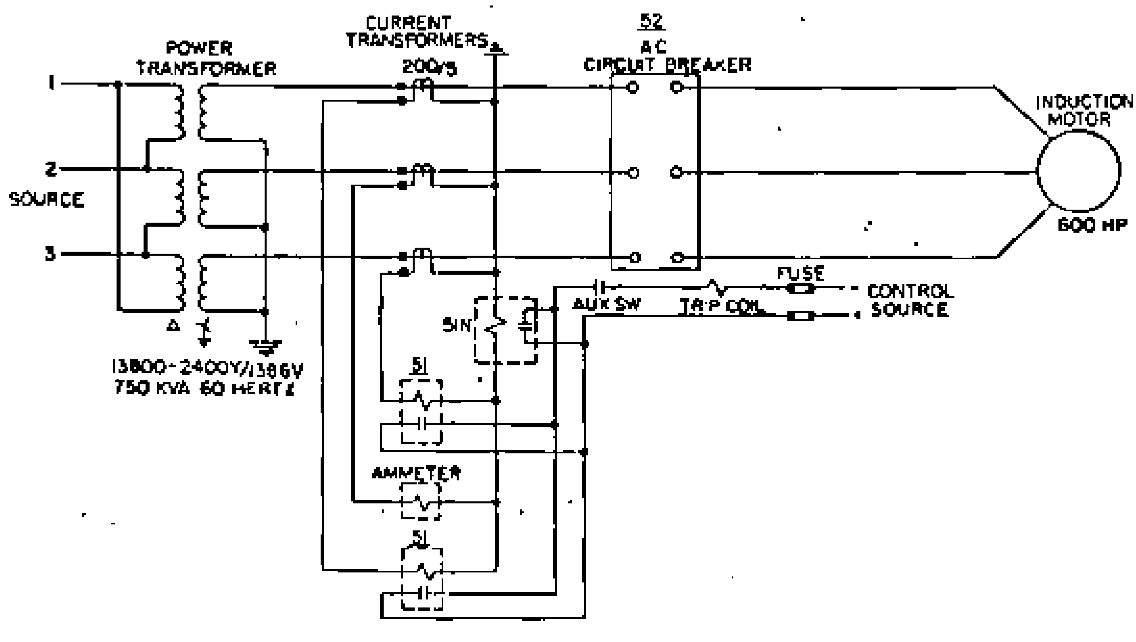

Figure 1.4
Three-line diagram

2. Flexibility. Because of modular type of construction, starters of various sizes can be readily interchanged on job.

3. Ease of maintenance. Starters may be removed for maintenance.

4. Increased safety. All units dead-front with interlocked doors.

5. Compactness.

6. Reduced engineering and purchasing costs.

7. Better protection against moisture, dirt, and mechanical injury.

8. Better appearance.

Prospective users of motor control centers should carefully study manufacturers' specifications to make sure that the equipment offered will be adequate for the duty involved. Preference should be given to standard construction. The economic advantage of motor control centers may be lost when special features are desired.

One-Line Diagrams

A one-line diagram is one which indicates, by means of single lines and simplified symbols, the course and component devices or parts of an electric circuit or system of circuits.

To illustrate, consider the simple circuit shown in Figure 1.4. This is a three-line diagram. It shows the details of an entire circuit. The complete paths of all currents can be traced through all the conductors and apparatus in the circuit.

However, in a general consideration of such a circuit wherein we are concerned mainly with the path of energy transfer (but not current paths) and the identification of circuit components with their ratings, the one-line diagram, Figure 1.5 serves the purpose better.

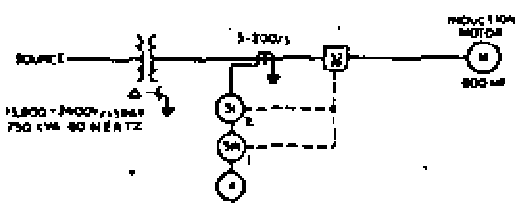

Figure 1.5
Simplified one-line diagram

In the preparation of preliminary plans for a system or specifications, it is not necessary to show all details in complete form on a one-line diagram.

Some of the more important items to be included as follows:

1. The available short-circuit and ground currents of power company's system.

2. The size, type, and number of incoming and outgoing cables.

3. The ratings, reactances, and connections of the transformers.

4. The points at which power is to be metered and the type of metering desired.

5. The amount and character of the load on all feeders.

6. Authentic information as to the exact geographical location of the installation.

Figure 1.6 illustrates a preliminary one-line diagram of a typical industrial power system.

The following items, if given special attention during preparation, insure complete, accurate, and lucid diagrams.

1. Keep the Diagram Simple

The one-line diagram should show the major electric circuits and components in the most simple form for ease of understanding. Equipment should be arranged to minimize the number of crossing lines without regard to the actual geometry of the plant. The geometry of the plant is of course important to keep in mind when making the one-line diagram. This geometry should be shown on a map, and a wiring diagram should be made later showing the actual location and routing of the circuits.

2. Avoid Duplication

The one-line diagram is a sort of "diagram shorthand," and for this reason every line, symbol, figure, and letter has a definite meaning and is made to serve some definite purpose in conveying significant information. Therefore, duplication should be carefully avoided. For example, when giving the rating of a current transformer, the abbreviation "CT" should not be used because the symbol itself conveys this information. It is sufficient to state merely the type and rating, thus "800/5." Even the abbreviation "AMP" after the rating is unnecessary, because current transformers obviously can be rated only in amperes.

3. Use Standard Symbols

The use of standard symbols and conventions is desirable. If special features occur which cannot be accurately covered by standard symbols and conventions, care should be exercised to make entirely clear the meaning of any nonstandard symbol or convention devised to cover such features.

4. Show All Known Facts

Details of circuits and devices known to the author of a diagram may seem to be unimportant or even irrelevant to him at the time. To someone else, however, or even to the author at a later date, these details may assume major importance, and their omission may be the cause of much extra work and loss of time, or even errors and misunderstandings. No detail within the scope of the diagram, therefore, should be considered as "unimportant," and the rule, "when in doubt, show it," should be followed.

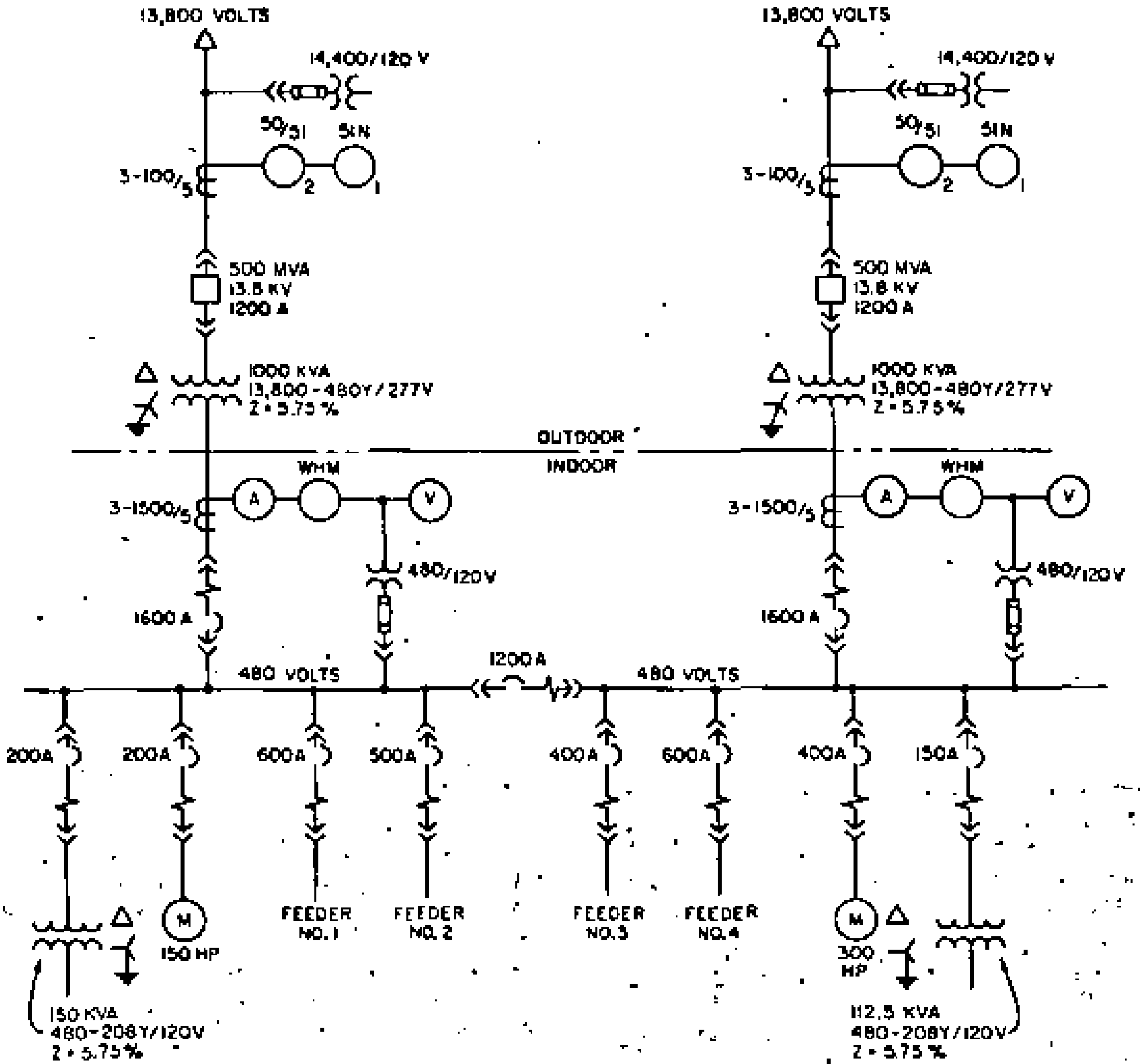

Figure 1.6
Typical one-line diagram

By checking the following list before releasing a diagram, the omission of some of the more important details can be avoided.

1. Manufacturer's type designations and ratings of devices.
2. Ratios of current and potential transformers, taps to be used in multi-ratio current transformers and potential transformers, connection of double-ratio current transformers.
3. Connections of power-transformer windings (i.e., wye, delta, etc.).
4. Circuit-breaker ratings in volts and amperes and (if not indicated by the manufacturer's type designation) the interrupting rating, type and number of trip coils on circuit breakers.
5. Switch and fuse ratings in volts and amperes.
6. Functions of relays.
7. Ratings of machines and power transformers.
8. Size and type of cables.
9. Voltage, phase, and frequency of all incoming circuits. A statement should accompany this information stating whether or not the neutral of any apparatus connected to the source is grounded. If grounded, the statement should specify whether the ground is solid or through an impedance. If the latter, the value of the impedance should be given.

5. Show Future Plans

Frequently, special features are devised which have no purpose in connection with the system being drawn at the time but which are included in equipment in order that it may fit into some plan for future changes or extensions. Such future plans should be set forth on the diagram either in diagrammatic form or by explanatory notes. For example, an outdoor station structure is often built with two disconnecting switches in series in a given circuit with the intention of using them ultimately as isolating switches for a circuit breaker to be installed later. If shown without comment or the indication of the future breaker, the purpose of the second switch is entirely obscured.

6. Include Correct Title Data

Care should be exercised in the assignment of titles to one-line diagrams to the end that they may accurately identify the installation.

To all who contribute to the preparation of one-line diagrams this admonition is given:— "Tell what you know on the one-line sketch but nothing which you do not know. Other engineers are likely to mistake your guesses for your knowledge, often with disastrous results."

Selection of System Voltage

The selection of utilization, distribution and sub-transmission voltage levels is one of the most important considerations in power system design. System voltages usually affect the economics of equipment selection and plant expansion more than any other single factor. It behooves the power system engineer to consider carefully the problem when designing the distribution system.

Voltage Classes

The various voltage levels may be broadly classified as follows:

1) 600 volts and less (low voltage)

2) 601 to 15,000 volts (medium voltage)

3) above 15,000 volts (high voltage)

The low-voltage class is normally restricted to supplying utilization equipment directly. The medium-voltage class (commonly 2.4, 4.16, 6.9, and 13.8 kV) is used most frequently for distribution purposes but occasionally is employed as a utilization voltage, particularly for motors rated 2.3, 4.0, 6.6 or 13.2 kV. The high-voltage class, above 15,000 volts, may occasionally be encountered as the utility supply voltage. In a large plant, with widely dispersed load areas, voltages above 15,000 volts may be used to distribute power.

Factors Affecting Voltage Selection

The factors affecting system voltage selection are:

1. Service voltages available from utility
2. Load magnitude
3. Distance power is to be carried
4. Rating of utilization devices
5. Safety
6. Codes and standards

The relative effect of these factors varies widely depending upon the particular plant involved. In general, however, the following will apply:

Service Voltages Available From Utility—The best distribution voltage to use within a plant may not be one of the service voltages available from the utility at the plant site. When this situation arises, the system design engineer must determine the relative costs of using the service voltage, for distribution or providing sufficient substation transformer capacity to obtain the desired distribution voltage. In some cases, the necessary substation investment will prove uneconomical and one of the available service voltages will be used.

Load Magnitude—Load magnitude has little if any bearing on selection of voltages in the 600-volt class but is an important factor in selecting distribution voltages. It is usually the determining factor for selecting distribution voltages when the plant is compact and where the load is concentrated in one area. The utilization equipment voltage ratings and voltage limitations are almost the entire governing factor.

Distance Power Is to Be Carried—Distance does not usually affect selection of voltages in the 600-volt class but is an important consideration in the selection of distribution and sub-transmission voltages. It is particularly important when sizable loads are located at quite a distance from the main plant.

Rating of Utilization Devices—Utilization devices have a major effect on the selection of voltages in industrial plants. Incandescent lamps, small fractional horsepower motors, hand tools, business machines, appliances, etc. are generally available with 110-, 115-, or 120-volt ratings. Where this type of equipment is used, 120-volts single-phase must be available.

Three-phase motors are readily available for voltages from 208 to 13,200 volts. However, the most desirable voltage for a given motor from both a design and system cost standpoint varies with the horsepower rating. The horsepower ratings of three-phase motors definitely affect system voltage selection in both the low-voltage and medium-voltage classes. Other types of utilization equipment affect the selection of system voltages. For example, approximately 75 percent of furnaces using resistance elements are designed for 240 volts, with 480 volts generally maximum. Large arc-furnace transformers are generally limited to a maximum of 23 to 34.5 kV because of switching equipment limitations. This illustrates how utilization equipment other than lighting and rotating machinery can affect system voltage selection.

Safety—Safety is a major factor in selecting system voltage in the area of 120 volts, or below, where appliances and portable tools are used. For example, where there is a possibility of contact with energized parts such as in ungrounded frame portable tools, voltages of the order of 32 volts have been selected because it has been shown that voltages above 50 volts to ground can be lethal. This practice, in general, conforms to National Electrical Code. The grounding of all portable tools is recommended when permitted.

On circuits above 120 volts to ground there seems to be little concrete evidence that voltage selection from a safety standpoint is a major consideration. While the chances of electrocution do, to a certain extent, increase with an increase in voltage, these higher ratings can all electrocute a person if he contacts a live part under proper conditions. For the highest order of safety on circuits 50 volts and higher, work on current-carrying parts should be done only with the circuit de-energized.

Codes and Standards—The National Electrical Code places limitations on the voltage ratings of equipment and distribution circuits within buildings and should be consulted to assure conformance.

Selection of Circuit Arrangements

General

The power systems engineer has a choice of many different circuit arrangements. Although the various arrangements may be compared on several bases, the choice usually resolves itself into the selection of an arrangement which will provide the required degree of service reliability at the minimum cost. In arriving at a satisfactory compromise between cost and service reliability, the following fundamental considerations should be kept in mind:

The cost of providing electric power to a particular area in an industrial plant includes fixed investment charges and capitalized losses in addition to the cost of the power itself. A great deal more can be done to control investment charges and losses than can be done to control the power cost. Thus, the principal concern when attempting to reduce over-all costs is with the initial investment.

In controlling initial investment, far more can be accomplished by proper selection of circuit arrangement than by economizing on equipment details. When cost reductions are necessary, they should never be made at the sacrifice of safety and performance by using inferior apparatus. Reductions should be obtained by using a less expensive distribution system with some sacrifice in reserve capacity and reliability.

The degree to which extra expenditures should be added to the plant distribution system to increase its service reliability depends upon (1) characteristics of the manufacturing process, and (2) reliability of the power source. Both of these factors must be considered in arriving at a solution to this problem.

Characteristics of Manufacturing Process—In many manufacturing plants, a short outage of power can be tolerated. In other plants, short outages of power result in the spoiling of considerable material in process or cause shutdowns over a large area. In the former cases, where short shutdowns can be tolerated, it is questionable if anything but the simplest system can be justified on an economic basis. In the latter cases, it might be possible to justify considerable expense for increasing the reliability of the distribution system.

Power Source Reliability—Service reliability at the point of utilization depends upon the reliability of the power source. Therefore, every effort should be made to obtain a power source having a degree of reliability commensurate with plant requirements.

If the source circuits are cable, and particularly underground cable, the probability of faults in them will be much less than in overhead, open-wire circuits. However, while the frequency of occurrence is low, as much as 24 hours may be required to locate and repair the fault.

Faults on overhead open-wire circuits may be either transient or permanent in nature. In the case of transient faults, service is generally restored immediately by reclosing of the line breaker. Outages due to permanent faults may require about 8 hours to locate and repair.

It is important to keep in mind that service reliability figures are highly variable on various parts of a system and on various systems. Historical records of similar installations under similar conditions will provide a resonable guide as to what to expect. (Reference 5.)

Types of Circuit Arrangements

There are many types of circuit arrangements possible, although the most commonly used power system arrangements can usually be classified as one of the following basic types:

1. Radial
2. Secondary-Selective
3. Primary-Selective
4. Looped-Primary
5. Secondary-Network

A brief discussion of each of these basic circuit arrangements follows:

Radial

In the radial arrangement, there is only one primary feeder and one transformer through which a given secondary bus is served. Earlier types of radial systems usually consisted of an outdoor transformer supplying the load through several low-voltage secondary feeders. A system of this type is shown in Figure 1.7.

Recently, however, there has been an increasing trend toward the load-center distribution type of radial system shown in Figure 1.8.

The load-center system differs from the earlier type in that power is distributed at primary voltages of 2.4 to 13.8 kV to substations located close to the centers of electric load. Here, the power is stepped down to utilization voltage (600 volts or less) and delivered by short secondary feeders to points of use. The load-center system offers several important advantages over the earlier type of radial systems and is usually the preferred arrangement except in small plants where floor space may be at a premium.

The radial-type circuit arrangement of the load-center system will be the least expensive in the majority of installations since there is no duplication of equipment.

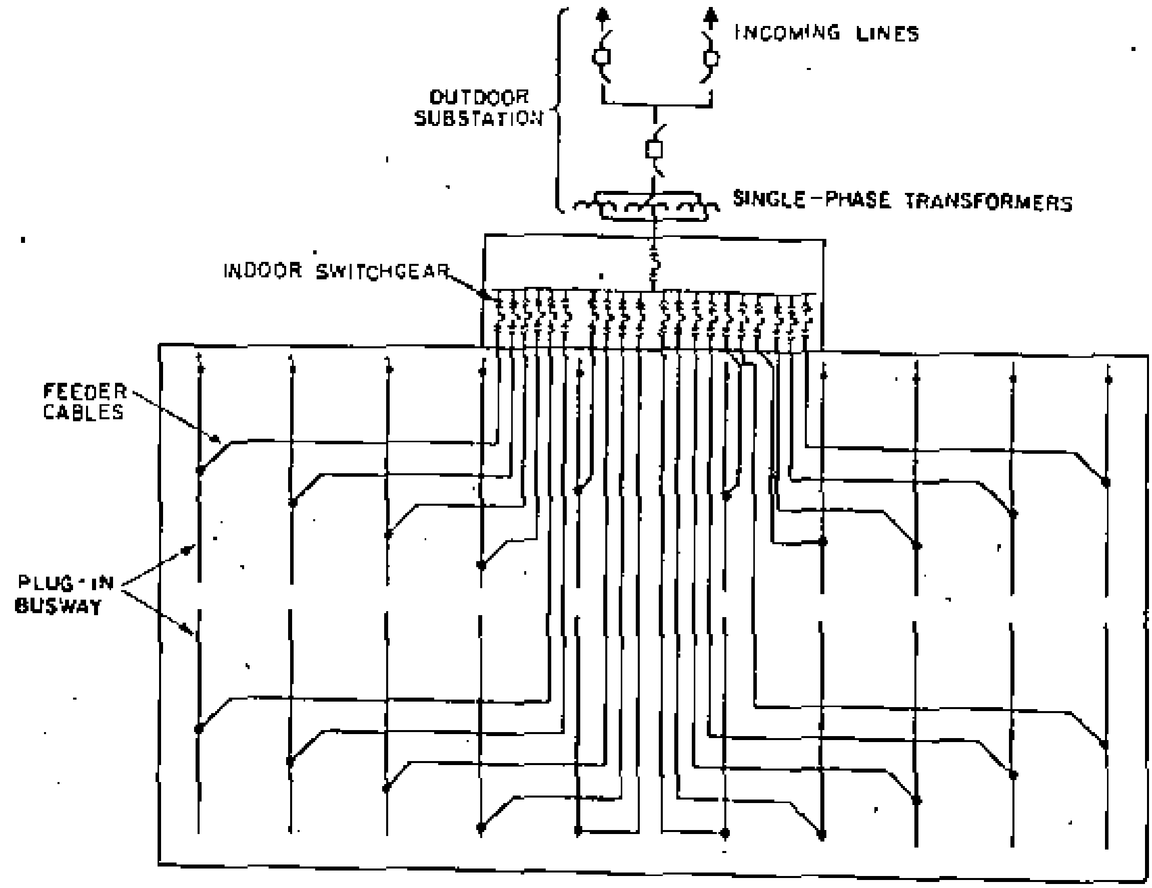

Figure 1.7
Old style distribution system for a medium size plant using one large substation and long secondary feeders

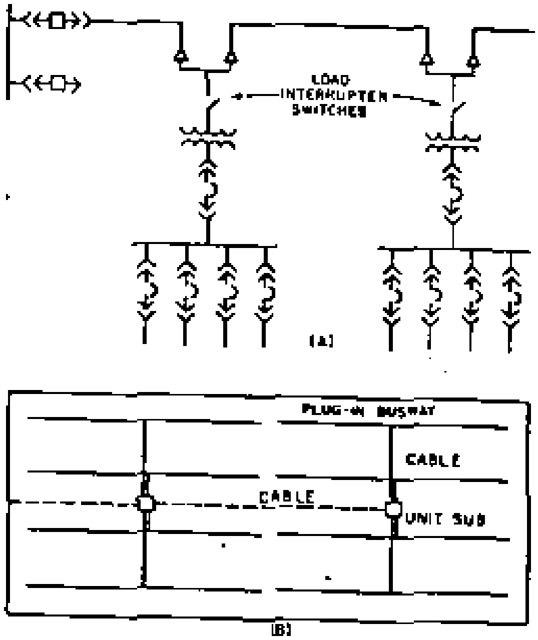

Figure 1.8
Typical radial circuit arrangement load-center distribution system
(A) one-line diagram (B) layout in plant

If sufficient substation capacity is used, the radial arrangement will adequately care for practically any diversity that will be encountered due to shifting of load. With adequate, properly installed equipment, the system is safe, simple, easy to operate and easy to expand by merely extending a medium voltage feeder, or adding a new feeder and substation. Good voltage regulation is provided because of the short secondary feeders.

It must be recognized that should a primary cable or transformer fail, service is lost to the area supplied by the faulty equipment until it is repaired. Furthermore, maintenance on primary feeders or transformers requires the complete de-energization of the area served by the equipment being maintained. Many engineers feel that the de-energization during maintenance is far more of a handicap than forced outages. Forced outages are so rare that temporary connections can be resorted to, if necessary, in order to keep essential loads in operation.

Secondary Selective

Two of the several possible arrangements of the secondary-selective system are shown in Figure 1.9. This system utilizes two primary feeder circuits and two transformers to supply each load-center area. This arrangement

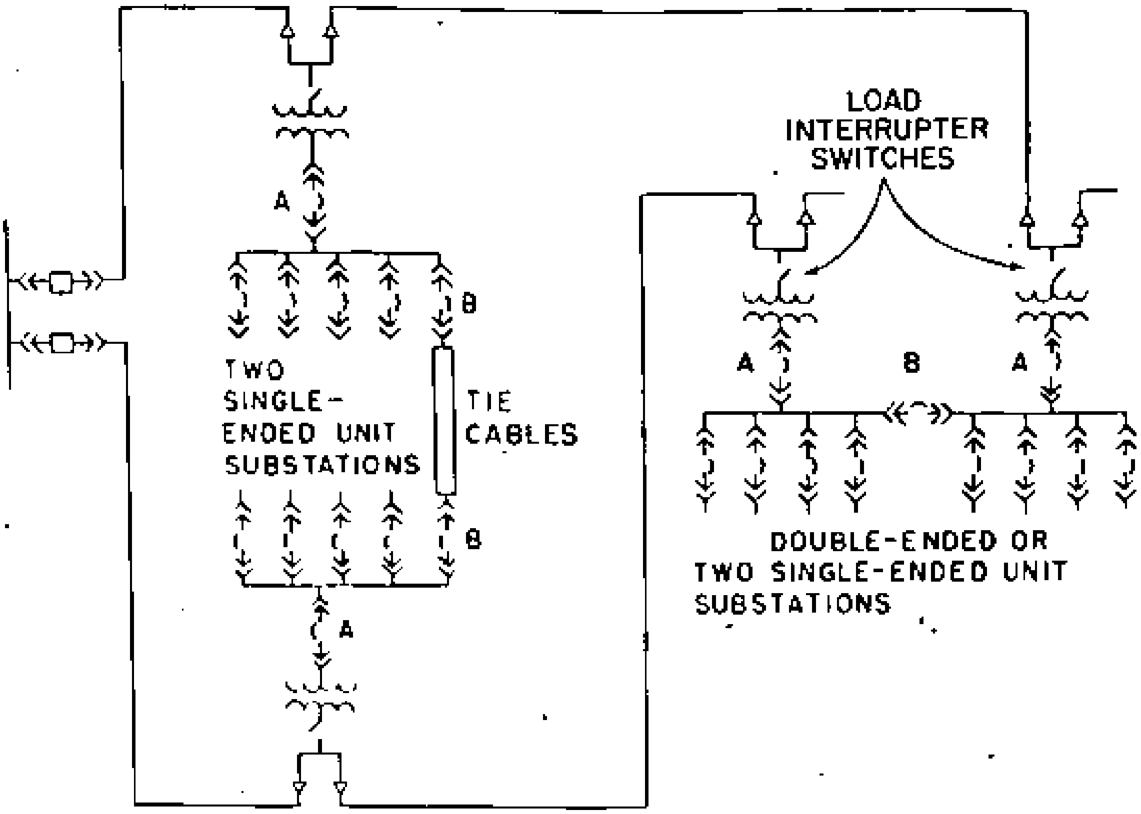

Figure 1.9
Typical secondary-selective arrangement of the load-center distribution system

provides duplicate paths of supply from the source to each secondary bus and makes it posible to provide power at all secondary buses when a transformer or primary feeder circuit is out of service.

The secondary-selective arrangement may be achieved through a tie between two single-transformer substations or through the use of double-ended substations. The tie breaker is normally open and the system operates as two parallel radial systems entirely independent of each other beyond the power supply point. The tie breaker is normally interlocked with the two transformer breakers so that it cannot be closed unless one of the transformer breakers is open. This practice minimizes the short-circuit duty imposed on the low-voltage feeder circuit breakers.

Since the load is normally divided equally between the two bus sections, half of the load in the area is dropped in the case of a primary feeder fault. Service can be quickly restored to the interrupted loads by opening the transformer breakers associated with the faulted feeder and closing the bus-tie breakers at all load centers. If the system is to carry the entire plant load with one primary feeder circuit out of service, each primary feeder must be capable of carrying the entire load and sufficient reserve transformer capacity must be provided. The reserve transformer capacity installed will usually be based on the magnitude of essential loads.

Primary Selective

The primary-selective arrangement differs from the radial and secondary-selective systems in that two primary feeders are brought to each substation transformer as shown in Figure 1.10. Half of the transformers are normally connected to each of the two feeders. The system is designed so that when one primary feeder is out of service, the remaining feeder has sufficient capacity to carry the entire load.

With this arrangement, as with the secondary-selective arrangement, service to half of the load is interrupted when a fault occurs on a primary-feeder circuit. To restore service quickly to all loads following the loss of one feeder, the transformers normally supplied from the faulted feeder can be switched to the good feeder. In cases where the fault may be in a transformer, preferred operating procedure would be to open the circuit breaker on the energized feeder and switch one transformer from the other feeder to the good feeder. When this switching has been accomplished, the good feeder would be energized. This procedure would be followed until all transformers had been switched or until the feeder breaker tripped because the last transformer connected to it was faulted.

If switching is to be done while one primary feeder circuit is energized, the safest way to make the transfer from one feeder to the other is with adequate power circuit breakers. However, the cost of such an arrange-

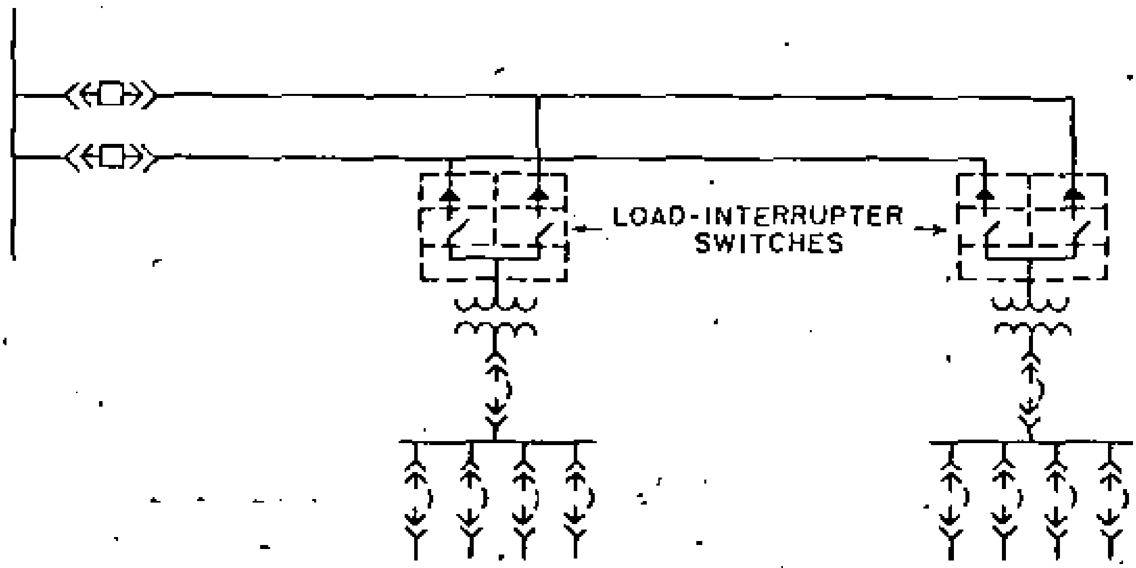

Figure 1.10
Primary-selective load-center system with two single-throw interlocked primary interrupter switches

ment is relatively high and normally is not used unless an automatic transfer scheme is desired. Usual practice is to use two load-interrupter switches properly interlocked, to accomplish the transfer from one feeder to the other.

The primary-selective system provides a higher degree of service reliability than the radial system and about the same as the secondary-selective system, depending on the amount of reserve transformer capacity installed in the secondary-selective system. The flexibility of this arrangement to handle shifting or growing loads is the same as the radial system assuming the same reserve transformer capacity in both system.

Looped Primary

The systems considered thus far have radial primary feeders. In cases where the centers of load are relatively far apart, the use of looped-primary feeders may offer some advantages. Figure 1.11 shows two forms of the looped-primary arrangement.

The looped-primary arrangement at the top of Figure 1.11 utilizes a single primary-feeder breaker and has one sectionalizing load-interrupter switch at each transformer while the lower loop arrangement utilizes two primary-feeder breakers and has two sectionalizing switches at each transformer. When a transformer or primary-feeder fault occurs in either loop arrangement, the primary-feeder breaker or breakers will open and interrupt service to all loads served from that loop. The fault can be located by opening all load-interrupter switches and closing them one at a time in sequence. It is strongly recommended that the primary-feeder breaker or breakers be open before operating any switch. This practice will eliminate the possibility of closing the switch on a fault. Although modern load-interrupter switches have fault closing ratings deliberate closure on faults as with any switching device should be avoided.

When the fault has been located, it can be isolated from the system by leaving the appropriate load-interrupter switch or switches in the open position. In the upper loop arrangement, of Figure 1.11, one transformer and its loads must be out of service for a transformer fault or a fault in the loop between transformers until the fault is eliminated. In the lower loop arrangement, the only time that loads are subjected to an extended outage is in the case of a transformer fault. The two switches at each transformer make it possible to isolate any fault location on the loop and still provide service to all transformers.

The upper loop arrangement will cost little more than the radial arrangement and offers the advantage of providing service to all loads except those served from one transformer when either a transformer or primary-feeder fault exists on the system. The lower arrangement will have a lower cost than the primary-selective arrangement and will provide service to all loads when a primary-feeder fault has been isolated similar to the primary-selective arrangement. A transformer fault will cause an extended outage to the associated loads in either the looped-primary or primary-selective arrangement.

The main disadvantage of the looped-primary arrangement is that a primary-feeder or transformer fault will cause an interruption of service to all loads.

Secondary Network

The secondary-network system may take the form of either a distributed network or a spot network and either form may utilize a primary-selective feeder arrangement.

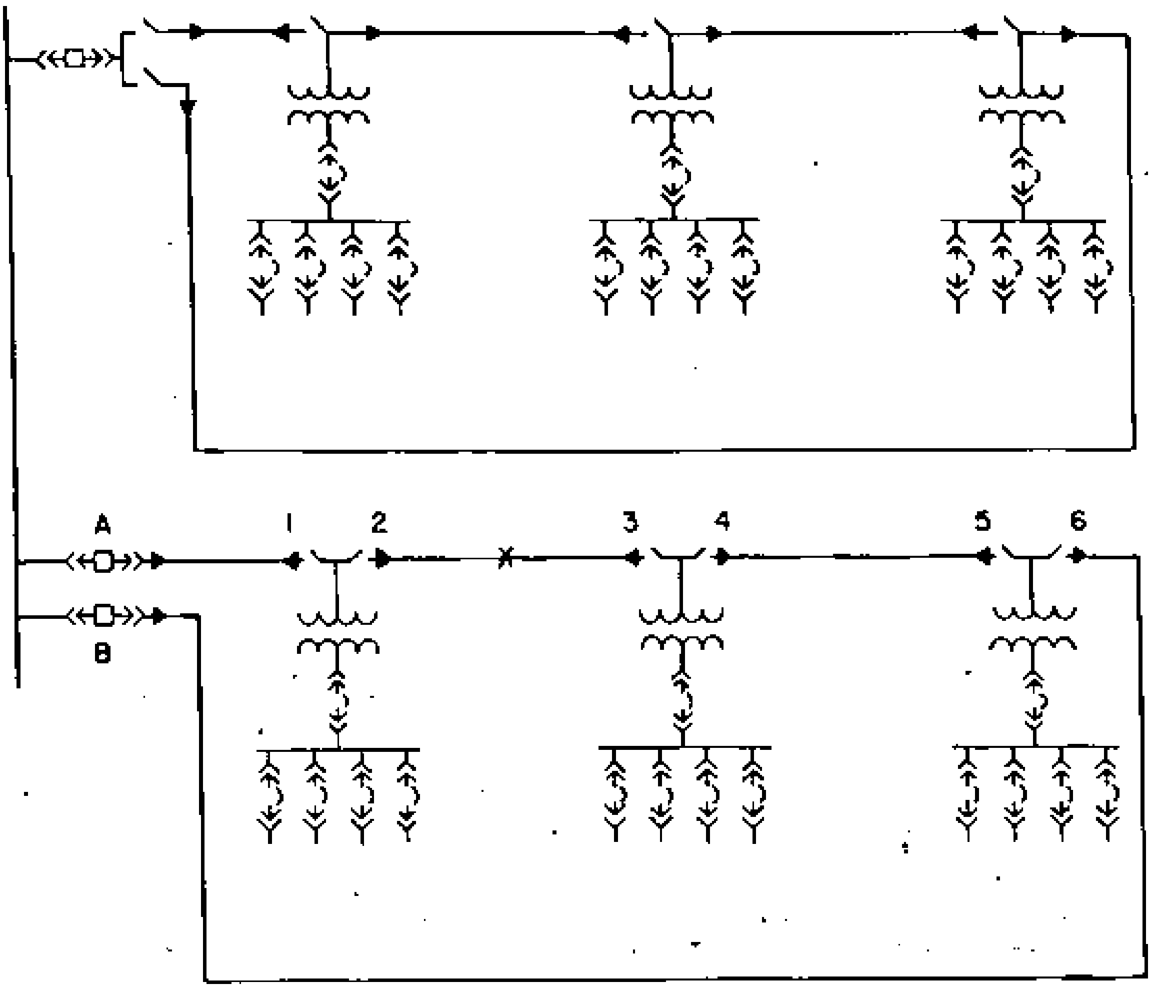

Figure 1.11
Looped primary load-center systems with sectionalizing switches for supplying load-center unit substations

The primary-selective secondary-network arrangement shown in Figure 1.12 is the form of the network system used most frequently in industrial plants.

This system differs from the radial, secondary-selective, primary-selective and looped-primary system arrangements in several important aspects. The major difference is that a primary feeder or transformer fault will not cause even a momentary interruption of power to any of the loads. The transformer secondaries are interconnected and operated in parallel and two or more primary-feeder circuits are used to supply the system. In effect, there are several parallel paths of power supply from any load on the secondary back to the power source. In many industrial secondary network systems plug-in busway is used for the tie circuits between transformer buses.

If two primary feeders are used to supply the primary-selective network system, half of the transformers would normally be connected to each feeder with adjacent transformers on different feeders. In the event of a primary-feeder fault, the fault is isolated from the system by the automatic tripping of the primary-feeder circuit breaker and all of the network protectors associated with the faulted circuit. Following these tripping operations, the entire load is supplied over the remaining feeder and half of the network transformers. All transformers can be restored to service by manually switching the de-energized units to the remaining feeder. When the faulted circuit is repaired and the appropriate transformers have been reconnected to the feeder, the network protectors associated with those transformers will close automatically when the feeder breaker is closed.

The network protector is the device that makes it possible to operate the two primary feeder circuits in parallel. The network protector consists basically of an electrically-operated air circuit breaker that is controlled by a directional-power relay and by a phasing-voltage relay. When a primary-feeder fault occurs, there is a flow of power from the secondary to the fault through all of the network protectors associated with the faulted feeder. The directional-power relay in each of these network protectors operates and trips the appropriate network protectors to isolate the fault from the secondary. In the meantime, the primary-feeder breaker has tripped to completely isolate the fault from the rest of the system. When the fault is eliminated, and voltage is restored on the feeder by closing

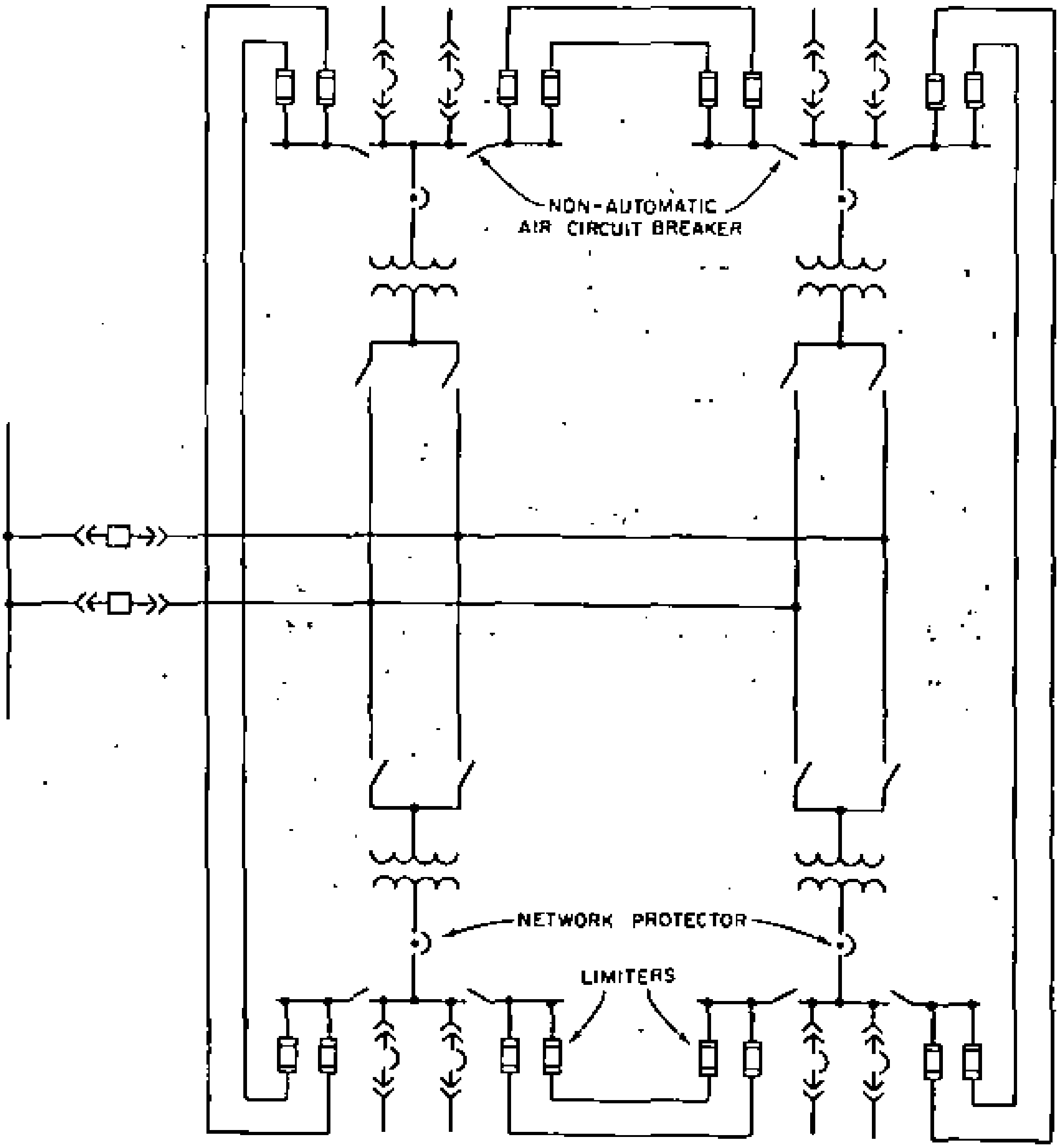

Figure 1.12
Typical primary-selective secondary network arrangement of load-center distribution system

the feeder breaker, the network relays on all associated network protectors will cause the protectors to close automatically if conditions are such that power will flow from the primary to the secondary.

In addition to providing a high degree of continuity of service to the loads, the network system with its interconnected secondaries inherently offers flexibility to meet shifting or growing loads. In the radial, secondary-selective, primary-selective, and looped-primary arrangements, the magnitude and characteristics of the loads to be supplied from a given transformer secondary bus are governed by the rating of the particular transformer. In the network system, the tie-circuits between transformers make it possible for adjacent transformers to share load and thereby permit loads on some buses that are in excess of the kva rating of the transformer at that bus. The amount of power that can be transferred between transformer buses will be determined by the tie-circuit impedance, the transformer impedance, and the characteristics of the load.

Spot Network

The secondary-network arrangement described above is designed to serve loads that are reasonably distributed within an area. However, if there are concentrations of critical loads that are widely separated and there is very little load in the areas between them, the spot-network arrangement will be more economical than the conventional network arrangement. The spot-network arrangement operates on the same principle as the conventional network, the main difference is that the transformers are all connected to the same bus.

Figure 1.13 shows two forms of the spot-network arrangement.

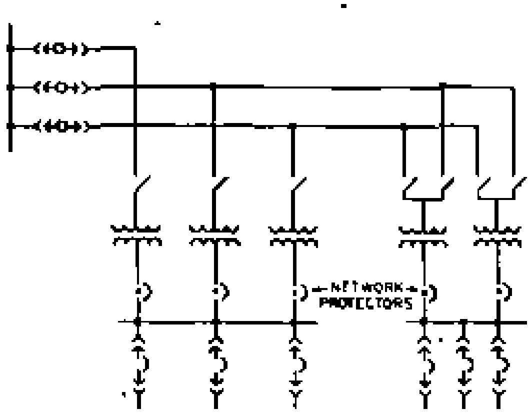

Figure 1.13
Two forms of the spot-network arrangement of the load-center distribution system

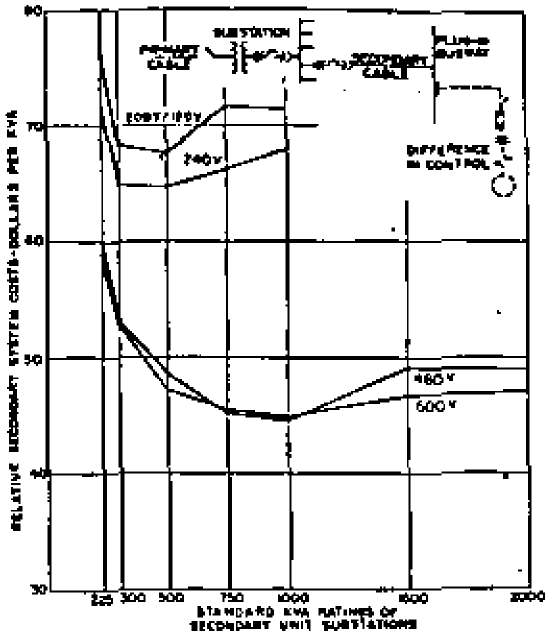

Figure 1.14
Curve showing the approximate installed costs of 208-, 240-, 480-, and 600-volt radial secondary systems

Selection of Substation Ratings

This discussion assumes that the system circuit arrangement and substation voltage ratings have been decided. The selection of the kva rating of the substation is then largely a matter of economics with the lowest over-all system cost as an objective.

Three major system components affect the over-all system cost. These are primary cable, substations and secondary cable. These factors work contrary to one another so the most economical system as affected by substation kva rating can only be obtained by looking at all three at once.

As the number of substations increases in a given area, the length of primary feeder cable required to serve these substations increases. Conversely, as the number of substations in a given area increases, the amount of secondary feeder cable required decreases. The substation cost per kva varies depending upon the kva rating of the substation. If these factors are combined in their proper proportions for a typical industrial plant, the results will be as shown in Figure 1.14.

The curves in Figure 1.14 indicate that there is a very definite minimum system cost as a function of substation size for different voltage levels. There are also other factors which have an influence on substation rating. The most important of these are:

1. Higher primary voltages may require substations with larger kVA ratings so that a greater kVA per primary feeder can be handled without unduly complicating the substation overcurrent protection problem. For example, when the primary voltage is 13.8 kV, it is desirable to have a loading of 4000 to 7500 kVA per primary feeder. With total primary feeder loadings of this magnitude and using standard 500-kVA substations with typical diversity factors, individual primary overcurrent protection would be required. (National Electrical Code, 1968 edition, article 450-3.) If 750-, 1000- or 1500-kVA substations were selected, then primary feeder loadings of this same order of magnitude could be obtained without individual overcurrent protection. This point is of particular importance in systems with primary voltages of 15 kV and above.
2. Large spot loads can sometimes justify larger unit substations. For example, a single furnace, a single large oven, or a single large welder may justify substations of the order of 2000 to 2500 kVA at 480 volts secondary since there is no secondary distribution. Therefore, there is nothing to be saved in that part of the system to offset the lower cost per kVA of the larger substation with a very few secondary breakers attached to it. Where these larger spot loads are encountered, it is well to consider using two smaller substations rather than one larger substation, particularly if the number of feeder breakers for the secondary exceeds three or four. For general factory areas, two 1000-kVA unit substations will nearly always provide a lower over-all system cost than one 2000-kVA substation. Many times a system using two 750-kVA substations will be less expensive for over-all than a system using one 1500-kVA substation per load area.
3. Space available for unit substations sometimes dictates larger substation kVA ratings. For example, one 1500-kVA substation instead of two 750-kVA substations may be necessary because the space can be found for the one larger unit whereas it could not be found for the two smaller units. Conversely, other areas may allow space for the two smaller units, but not for the larger one.

There are other local factors which may affect the kVA size of substations in a particular plant. In general, however, the points listed on the preceding pages are the major factors involved in the selection of substation sizes for most industrial plants.

Lighting Distribution Methods

During the past few years, adequate lighting for factory floor areas has been recognized as necessary for better production and safety. At the present time, illumination levels of 50 lumens per square foot are considered good practice and levels as high as 100 lumens per square foot are not out of the ordinary. Thus, the lighting load in an industrial plant has become an appreciable part of the total load. Load intensities of two to four volt-amperes per square foot for lighting and eight to ten volt-amperes per square foot for power are about normal.

Until the advent of the fluorescent lamp, most distribution of power for lighting loads was at 120 volts for the most efficient operation of incandescent lamps. Higher-voltage incandescent lamps are fragile and generally not very satisfactory. Modern lighting practice, however, includes more and more the use of fluorescent lamps either alone or in combination with other types. Since the fluorescent lamp has a ballast in series with it, the 120-volt limitation no longer applies. The required voltage for starting is always above 120 volts and is supplied by a transformer built into the ballast. The use of fluorescent lamps, therefore, has opened new possibilities for the use of higher voltage circuits to reduce the cost of the power system. And, the trend toward locating the substation at the utilization point has made possible the use of 480Y/277-volt combined light and power systems.

Two points which should be mentioned in connection with using higher voltage fluorescent lighting are as follows. First of all, many plants have high bay areas where mercury and incandescent lamps are often used in combination. The mercury lamps have ballasts like the fluorescent lamps and are, therefore, suitable to higher voltage. The 120-volt incandescent lamps can be operated through small step-down transformers connected to the 480-volt system.

The second point concerns factory office lighting. Frequently, industrial plants are designed with a sizable office area at one end of the factory area. A 480Y/277-volt system can be used for general area fluorescent lighting within the office area. One or more feeders would be run into the office area for general lighting. Whereas, controllers might be used as switching devices in the factory area, either 24-volt remote control relays or 277-volt wall switches may be used in the office area. The relay contacts operate in the 480Y/277-volt system, but the relay coil is supplied with 24 volts from the small transformer. Thus, only 24 volts is within reach of an operator. The 277-volt wall switch can be used in place of the remote control system providing this type of switch can be applied to meet local Codes.

Overcurrent Protection

Overcurrent protection assists in preventing or limiting equipment damage, loss of production, building damage from fire, and injury to personnel. Current is a practical circuit characteristic for actuating a protective system, and overcurrent protection is used in all distribution systems. There are various additional kinds of protection used, such as frequency, differential, under or over voltage or power, but overcurrent protection will normally be employed as back-up protection even where it is not the primary circuit or equipment protection.

It is desirable for the overcurrent protective device to be actuated by moderate abnormal current, as well as higher short-circuit current. Protection is then afforded against equipment damage from overloading, such as for motors or conductors where there has been no dielectric breakdown. However, there are exceptions and a good example where such thermal equipment protection is not obtained is the usual overcurrent protection applied to transformers at levels of about 1.5 to perhaps 6 times rated current.

The kinds of devices used for overcurrent protection are fuses, circuit breakers with direct-acting trips, and circuit breakers or contactors with relays. Fuses must be selected in ratings that will achieve protection objectives; some direct-acting trips are similarly not adjustable. Most relays are adjustable over a wide range and particular protection requirements may be met by adjustment and selection of appropriate current transformer ratings. The protection afforded may be further adapted to special requirements because there will often be a choice in the time-current characteristics of the protective devices available.

In order to maintain maximum electric service reliability, only those circuit protective devices directly associated with a failure or abnormal conditions should function to open the circuit; this is called "selectivity." Selectivity is accomplished by coordination of the various circuit protective devices, commonly on a time-current basis. The type of power system and the characteristics of the various protective devices are both important in achieving selectivity. In general, the simpler the protective system the greater the system reliability.

It is good engineering practice to provide "back-up" overcurrent protection as a safeguard against failure of the primary protection to operate. It may simply provide a second chance to correct an abnormal current condition in a given part of a system or it may supplement the primary protection in another part of the system further removed from the source.

Proper circuit protection should be included during the planning stage of the electric system. Generally, in large industrial plants this is done by the engineering staff. In small plants or simple power systems adequate protection may be achieved by compliance with the National Electrical Code.

It is important to recognize that changes in the electric system, such as increased power or additional loads, may require the resetting of protective devices to assure proper protection and selectivity.

Some types of loads or circuits may have specific requirements. Many of these, including motors, conductors, or transformers, are covered by general rules in the National Electrical Code. Chapter III, on System Protection, covers many specific suggestions concerning selection, application, and setting of relays.

Special Systems

In addition to the problems of general power distribution, the modern industrial plant also has the need for some special types of power. These are high-frequency power, direct-current power, electronic equipment power, and critical load power requirements.

General

The general rule to follow when special power supplies are involved is to use the basic principles of load-center distribution. Locate the device supplying the special service as near the center of the load as possible. Many machine tools, requiring high-frequency power for instance, have the converting equipment built right into the machine itself. The direct-current power can be supplied in the form of motor-generators and controls "packaged" in one unit and included with the equipment itself.

A central power supply may prove to be more economical where a number of special loads can be located within a certain area. The cost of the individual power supply units will be higher than the cost of a larger unit to supply all the loads. The cost of maintaining several units is generally higher than maintaining one unit, especially rotating equipment.

One possible disadvantage of a central power supply is the inability to relocate the utilization equipment conveniently. Today, the emphasis in production is for flexibility. In the modern industrial plant very few machines are fixed. Changes in processes and plant layout to take advantage of the latest manufacturing techniques are everyday occurrences in many plant engineering departments. Limiting such moves due to lack of power supply or requesting additional funds to permit such moves to be made in order to provide the necessary power will show lack of planning on the part of the electrical engineer.

High-Frequency Circuits

High-frequency power in industrial plants should be distinguished from the term as used in electronics and communication fields. Frequencies of 120, 180, 360, 420 and 900 hertz (cycles per second) are most commonly used for higher-speed motors. These motors supply the drive for grinding and polishing machines, woodworking and spinning operations and in small portable hand tools.

The trend is for higher and higher speeds in machine tools. New metal discoveries and new metal alloys not only have permitted these higher speeds but actually demand that these speeds be used in order to get the best efficiencies and tool life. Hence the need for higher frequencies than the conventional 60 hertz.

One of the plus values of the use of high-frequency power is that the motors and transformers are smaller in size and lighter in weight. These two factors make the use of 120 and 180 hertz ideal for the operation of small power tools found on assembly lines in the automobile and aircraft industries.

The source of high-frequency power has generally been from frequency converters of the rotating type. Nonrotating types of converters that incorporate electron tubes, transistors, and controlled rectifiers are now generally available.

Where several frequencies are required, various rotary converters can be mounted on a common base and driven by a standard 60-hertz motor. Circuits are then brought to the machine tool and terminated in a plug board. By plugging in the motor in the various receptacles, speed ranges up to 100,000 r/min are obtainable in one motor alone.

High frequency is also used for induction and dielectric heating. The conversion equipment for these is usually built as part of the unit itself. It is necesary, due to the high impedance, to give special consideration to the circuits between the high-frequency converter and the load it is supplying.

A new use of high-frequency power is for lighting where fluorescent lamps are used. Such lighting will offer many attractive benefits. Fixtures will be lighter in weight, no ballasts will be needed, heat losses from the ballast will be eliminated, more light output per lamp and controllable lumen output of the whole system by varying the frequency are but a few of the benefits that this new system will offer. High-frequency lighting is already being used successfully in subway cars, trolley buses, aircraft and commercial buildings.

Electronic Equipment

The greater use of electronics in industrial plants has brought up a new problem in power distribution voltage control. The problem has always been troublesome in plant operation, but it is becoming more critical due to the increased load of electronic devices.

The major role of electronics in the industrial plant is for specific applications. Some of these applications are: control to operate with the speed of light, control that is super-sensitive, control for quality or inspection, control for remote installations, and control for extreme accuracy. All of these services call for closely regulated performance which in turn call for a system with a low voltage regulation. The foe of such a voltage supply in plants works in two fields. The first is in the field of voltage spread between maximum and minimum voltages caused by the plant loads on transformers, feeders and incoming power supply from the public utility or plant generating units. The second is the disturbances to the voltage supply due to the starting of large motors, arc furnaces, welding and similar large loads of power. The effects of excessive voltage regulation are discussed in Chapter II titled Voltage Considerations.

Direct-Current Power Systems

The use of direct current as power in industrial plants has been increasing. In the early days, plant power was generated by direct-current generators at 250 volts. With the coming of alternating-current power and its many advantages of transmission, most plant equipment was converted to alternating current. However, one of the most attractive features of direct-current motors was lost in this conversion; this was speed control. Many attempts have been made to obtain this feature with alternating-current motors, but to date it has not been possible to develop an alternating-current adjustable-speed drive which is comparable in cost and performance with a direct-current drive.

Recently, the ability to control speed accurately has been emphasized, especially with machine tools, conveyors, and process equipment. Machine tools have to cover wide ranges of speeds, accurately adjustable to a given speed in order to take advantage of new processes and the discovery of new materials with which to work. The one type of motor that could meet these specifications was the direct-current motor. The big problem was where to get the direct-current power to drive the motors.

There are three practical sources of direct-current power: (1) generation by prime movers, (2) motor-generator sets, and (3) rectifiers. Methods (2) and (3) are the most commonly used today. There are still engine- or turbine-driven direct-current generators in old plants, but the most economical way is to buy or generate alternating-current power, transmit it to the point of use and then convert it either by generation or rectification at that point.

The use of power rectifiers has increased as the modern way of obtaining direct-current power. These rectifiers range from small control units to large rectifier equipments rated in thousands of kilowatts capacity. Rectifiers may be of the electron tube, mercury pools in tanks, silicon cell, selenium cell, germanium cell, or copper-oxide plate type. All these devices take in alternating-current power at all ranges of voltages from the plant distribution systems and convert it to direct-current power in voltages from 6 to 12 volts for plating, 125 volts for lighting, 250 volts for general motor work, 600 to 750 volts for steel mill drives and up to 850 volts for the electrochemical processes.

Rectifiers are attractive from the standpoint of maintenance. They have few moving parts to wear out and the units can be located directly in the manufacturing areas.

Other sources of direct-current power are the "packaged drives." These drives are in one enclosure containing: motor-generator sets, magnetic control, and possibly signal generators and electronic controls. The units are compact and usually can be mounted close to the machine. A number of manufacturers make these units, and they cover all ranges of applications.

Safety and Plant Protection

General

Protection of personnel and equipment must always be a primary thought in the mind of the electrical engineer when designing any equipment or installation. He must be aware of the many hazards that are present and take adequate precaution to protect against them. It is only by the recognition of these hazards and careful planning to control them that the use of electricity has become the safe and effective means of power transmission that we know today.

Plant protection rests to a large extent upon the shoulders of the electrical engineer for it is he who must provide the plans for adequate alarm systems, communications, emergency lighting and other essential emergency services as well as the general distribution system for normal plant operation.

Personnel Safety

There are listed below items which should be considered in order to provide safe working conditions for the personnel.

1. Interrupting devices should be able to function safely and properly under the most severe duty to which they may be exposed.

2. Protection should be provided against accidental contact with energized conductors by elevation, barriers, enclosures, and other similar equipment.

3. Disconnecting switches should not be operated while they are carrying current, unless designed to do so. Suitable barriers should be provided between phases to confine accidental arcs unless adequate space separation is provided.

4. In many instances interlocks between the disconnecting switch and the power circuit breaker are desirable, so that the breaker in series must be opened first before the disconnects can be operated, thus preventing accidental opening of the disconnects under load.

5. Sufficient unobstructed room in any area containing electric apparatus must be provided for the operator to perform all necesary operations safely.

6. A sufficient number of exits with "panic-type" door features should be provided from any room containing electric apparatus such as a substation, control room or motor room so that escape from this area can be easily effected in the event of failure of apparatus in the room.

7. A protective tagging procedure should be set up to give positive protection to men working on equipment. Such a procedure should be coordinated with the local utility for the common equipment.

8. Industrial plant electric systems should generally be designed so that all necessary work on circuits and equipment can be accomplished with the particular circuits and equipment de-energized. The system design should provide for locking out circuits or equipment for maintenance. Lockout switches should accept three or more padlocks and should be located near the driven equipment convenient for mechanical maintenance personnel so that non-electrical personnel need not enter motor and control rooms. The lockout device should be carefully identified with its associated driven equipment. In very special situations where it is necessary to work on energized circuits, specially trained crews with adequate safety equipment should be used.

9. Rubber gloves deteriorate and consequently should be checked regularly, otherwise they may become more of a hazard than a safeguard because they give the operator a false sense of security. In general, they should not be used without leather protectors if the work is such that the glove may be snagged or torn.

10. All circuits should be marked in the switching station so as to be readily identified. Cables should be identified with suitable tags at both ends and in all manholes for the protection of men working on them.

11. Consider the fire and explosion hazard of oil-filled apparatus and whether such equipment is permitted by Codes. Wherever possible, substitute apparatus such as air circuit breakers, air load-interrupter switches, and askarel-insulated or dry type transformers.

12. A fire brigade should be formed of local employees who are familiar with the equipment and the hazards involved. This group should be trained in the proper procedures to follow in the event of fire in the electric apparatus, the proper use of the various types of extinguishers and methods of fire fighting.

Medium-Voltage Installations

The use of load-center distribution systems in industrial plants involves the installation of wiring and equipment operated between 2.4-kV and 14.4-kV. The design and installation of these systems must take into account the qualifications of the personnel who will be called upon to operate and maintain them. Plant personnel assigned to operate and maintain equipment energized at voltages above 600 volts must be trained in proper operating procedures and impressed with the hazards involved.

Equipment installed in areas that are accessible to other than qualified personnel should be completely enclosed so that no live parts are exposed or readily accessible. Where live parts are exposed or where safe practice dictates, equipment should be installed in locked equipment rooms or fenced enclosures and the distribution of access keys should be limited to qualified persons. Appropriate signs should be used to identify the equipment and provide operating instructions.

Wiring diagrams of the system must be available to operating and maintenance personnel together with the type, make, and ratings of equipment and relay settings. When fuses are used in a system, a stock of spare fuses of the appropriate ratings should be maintained. These practices are particularly important in cases where contract electricians who are not familiar with the system or equipment are called in to perform maintenance or repair work.

Plant Communication and Alarm Systems

Any plan for the protection of a plant must include an adequate and reliable system of communication, both within the plant and to the associated utilities and emergency services which may be called upon in case of need. This can be accomplished in several ways; a principal one is by a completely self-contained and self-maintained inter-plant system of telephones, alarms, etc., and may include modern radio equipment. Another plan consists of a joint system tied in to the existing communication services.

Fire alarm circuits, whether self-contained or tied into city alarm systems, should be installed in a manner that will guarantee the least interruption from faults and changes in buildings or plant operations. Lines should be arranged to provide easy means of testing and of isolating portions of the system, in case of fault or changes, without interference with the balance of the system.

Watchman circuits are used in many plants for the purpose of providing a ready means for the individual watchman to report unusual circumstances to his supervisor without delay. Such systems are frequently combined with loudspeaker paging systems and/or other alarm methods. The use of annunciators in groups located at central points provides a means of recording calls and actuating other devices. Their use is proving to be a great aid to the engineer charged with a plant communication system installation.

In the larger plants of the country today, there are to be found many installations of short-wave radio communications which offer many advantages, especially instant communication with mobile units. Others have installed systems which are connected to existing plant distribution systems and by impressing a modulated high-frequency carrier wave are able to transmit voice over the existing power circuits.

No matter what type of system is used, care must be taken to see that it is effectively laid out to give the coverage required, that it is installed in a practical safe manner, free of external faults, and that it is supplied with power at all times.

Protective Lighting

No plant protection system is complete unless it has ample provision for lighting vulnerable areas, where employees enter and leave the plant, fences and boundaries and other particularly important points. Lighting of these areas is usually arranged to be independent of normal lighting circuits and may be used either continuously during the night hours or may be controlled for intermittent use automatically or by the plant protection personnel. Critical areas may be protected by providing ample lights to illuminate the area either by local fixtures or by floodlighting from more distant points, but sufficient units must be used to provide complete coverage.

Boundary lighting is often found to provide more useful illumination when asymmetrical fixtures are used and arranged so that the greater portion of the light output is spread along the boundary.

The general aspects and much detailed information on industrial wiring methods may be found in the IEEE Standards Publication No. 241, "Electric Systems for Commercial Buildings", and the reader is referred to that book for more details of lighting problems.

Emergency Power

Emergency lights should be provided where necesary to protect personnel against a sudden failure of lighting. Areas to be especially considered are those where people congregate and where controls for processes are located, particularly when the controlled functions are supplied from different sources of power than that supplying the lighting.

The National Electrical Code requires that any building or part of a building designed or intended or used for dramatic, operatic, motion picture or other shows shall be provided with an emergency lighting system if the seating capacity of the auditorium exceeds 100 persons. The National Fire Protection Association's Building Exits Code also outlines the requirements for emergency lighting of exits in various classes of buildings used for public assembly, including factories. It requires that the electric power used for emergency lighting purposes shall be supplied from a source independent of that for the general lighting or shall be controlled by an automatic device which will operate reliably to switch the circuit to an independent secondary source in the event of failure of the primary source of power.

Emergency power systems may also be desirable to insure continuity of service in certain processes or occupancies where loss of power may introduce a fire or explosion hazard or result in extensive damage to materials being processed. These emergency systems should be installed in accordance with the rules and regulations of the National Electrical Code and may have as a source a separate service connection with the utility power system, a storage battery, or an engine-driven generator.

Codes

General

Safety to life and the protection of property from electric arcing, fire and explosions which may result from the installation and use of electric equipment should be carefully considered during the design stages of a proposed electric installation. State and municipal regulations will vary to some extent and fire and casualty insurance carriers usually have definite requirements for the safeguarding of specific hazards associated with the use of electric apparatus. Details of the proposed installation should be reviewed with representatives of these various groups before construction is started. In some cases there are no local regulations or ordinances and the only authorities having any jurisdiction are the insurance carriers.

In general all electrical construction should conform to the latest requirements of the National Electrical Code and the National Electrical Safety Code. Both of these publications are USA Standards and approved by the United States of America Standards Institute. The National Electrical Code is published by the National Fire Protection Association (NFPA). They are generally accepted by most state, municipal and insurance authorities as the minimum requirements considered necessary for safety, although careful check should always be made with any municipal authorities who may have jurisdiction as these standards are sometimes modified or amplified by them to conform with local conditions.

In Canada the counterpart of the National Electrical Code is the Canadian Electrical Code Part I published by the Canadian Standards Association.

Codes as Applied to Property Protection

A potential fire or explosion hazard is inherent with the use of nearly all electric apparatus and proper arrangement and protection of the equipment at the start will minimize if not eliminate serious property damage or interruption to production when insulation failures or breakdowns occur.

The fire and explosion hazard of oil-insulated and compound-filled equipment is one of the most common hazards to safeguard against. Fires or explosions in oil insulated transformers occur infrequently, but where they do the results may be disastrous depending upon the arrangement of the equipment and the safeguards provided. The old practice of locating oil-filled transformers in the same room with an important switchboard or switchgear or other valuable apparatus should be avoided because a fire in the transformer will usually involve the other equipment increasing the damage and prolonging the interruption to production.

The National Electrical Code clearly outlines the installation requirements for transformers of all types. Oil-insulated transformers installed indoors must be installed in a vault of fire-resistant construction if the total capacity exceeds 75 kVA. Where a vault is required, adequate ventilation and drainage facilities are necessary to prevent overheating of the transformer and to drain away, to a safe place, any oil that may be released or expelled.

The cost of a vault may be eliminated, and a saving in space effected, by substituting askarel-insulated or dry type transformers in place of the oil-insulated type. Dry-type sealed-tank nitrogen-filled transformers are considered fire and explosion resistant and need no special safeguards from this standpoint.

Where oil-insulated transformers are installed outdoors they should be located at least 25 feet away from combustible buildings or structures. They should not be located under important bridges, conveyors, tanks or similar structures where heat from a fire in the transformer may cause collapse of or serious damage to the structure. Facilities such as crushed stone-filled basins or drained concrete basins should be provided under the transformers to drain away any oil that may be expelled from them in time of trouble. Where a fire in one outdoor oil-insulated transformer is likely to involve other transformers in the same bank, a non-combustible barrier or wall is sometimes provided between adjacent transformers to confine the fire to the unit in which it started.

Permanently piped fire extinguishing systems may also be installed over large oil-insulated transformers or other oil-insulated apparatus where the value or importance of the apparatus and nearby equipment justifies this expense. These systems may be arranged to discharge either manually or automatically. One system employs water spray nozzles connected to a reliable and strong water supply arranged to completely envelop the transformer with a dense fine spray if fire occurs. The effectiveness of this system depends upon many factors such as the size of nozzles, nozzle spacing, elevation, direction and angle of discharge, water pressure, wind velocity and temperature of the oil. Carbon dioxide is also available as an extinguishing medium in these fixed fire extinguishing systems for both indoor and outdoor installations.

Electric arc furnace transformers are frequently installed in the same vault with the oil circuit breaker controlling the transformer and the control panel for raising and lowering the electrodes. This is not considered a good arrangement as failure of either the transformer (which is usually the oil-insulated type) or the circuit breaker will sometimes involve the other equipment in the vault resulting in increased property damage and an extended interruption to production. A preferred arrangement is to place the transformer, the circuit breaker and the control panels, each in its own vault. The circuit breaker, which is subjected to severe duty, should be very carefully maintained. Air circuit breakers are generally used for arc-furnace duty.

The oil used in the lubricating and governor systems of steam-turbine driven generators is a potential hazard where the steam temperatures are 700°F or higher. Turbine oil will ignite if it contacts hot steam lines of this temperature. It is important, therefore, to arrange the oil lines so that if leaks should develop the oil will not drip or be sprayed on hot metal parts. Thermometers and other similar accessories on these systems should be protected against breakage.

Large enclosed generators, excepting the hydrogen-cooled type, should be provided with a built-in type of fire-extinguishing system. Failures do occur in these machines from both electrical and mechanical causes, as well as lightning, and considerable additional damage often results from the ensuing fire. In enclosed machines such fires are inaccessible and the built-in fire protection is the only possible way of extinguishing a fire, if it occurs, and keeping the damage to a minimum. The two common means of extinguishing fires in such machines which are now employed are:

1. The perforated spray rings installed in the end bells at each end of the machine, arranged to discharge water over the end turns upon manual operation of a conveniently located control valve, and;

2. The use of carbon dioxide arranged to discharge automatically or manually from a battery of cylinders into the interior of the generator. These systems are designed to maintain a sufficient concentration of gas during the decelerating period to completely extinguish any fire in the machine.

Hydrogen-cooled generators need no built-in extinguishing equipment since a purity of about 97 percent of hydrogen is normally maintained in the machine and ignition cannot take place under these conditions.

Large, enclosed, valuable motors, such as the reversing mill motors in steel mills, should also be provided with a built-in fire extinguishing system to help minimize the damage if fire occurs. On smaller enclosed motors under 3000 horsepower, the expense of a built-in fire extinguishing system may not be justified, but in any case covered openings should be provided in the enclosure to permit the easy application of extinguishing agents to the windings in case of fire.

The grouping together of a number of valuable or important cables or wires in trenches, cable boxes, junction boxes and manholes should be avoided, particularly if they have combustible insulation. This applies to both low, medium, and high-voltage installations, and lead-sheathed cables as well. A failure in one cable or conductor can cause an arc that ignites the insulation on one cable and fire may destroy the entire group, or the arc can do extensive damage in the event of sustained arcing. Where it is necessary to group such cables together, they should be protected with a fireproof covering. The control circuits in power houses and substations should be arranged so that they will not be exposed to damage by arcing or fire. When possible, these wires should have asbestos or similar fire-resistive coverings.

An adequate supply of fire extinguishers should be provided on the premises, particularly in the vicinity of large quantities of electric apparatus. Extinguishers suitable for use on live electric apparatus are the vaporizing liquid, carbon dioxide, and dry chemical types. Where insulating oil or compound is present in large quantities in power houses, substations, and motor rooms where there are many large motors present, small hose (1½ inch) protection with portable spray nozzles should be provided as back-up protection in the event that the hand extinguishers are inadequate.

Soda acid and foam type extinguishers are dangerous to use on live electric apparatus because the materials used are conducting. Care should also be exercised when using carbon tetrachloride extinguishers on a fire in a confined space as the fumes are toxic.

GROUNDING

The subject of grounding may be divided into two main parts. That is, the grounding of the system for electrical operating reasons and the grounding of non-current-carrying metal parts for safety to personnel.

The principal reasons for grounding an electric system are:

1. Reduce operating and maintenance expense.
2. Keep transient overvoltages that may appear on a system at a minimum.
3. Improve service reliability.
4. Limit the displacement of the neutral for greater safety.
5. Better system and equipment overcurrent protection.
6. Readily locate and isolate circuits which have become accidentally grounded.
7. Improve lightning protection.

The grounding of electric systems and equipment has been a National Electrical Code requirement for many years. This Code states specifically that "Circuits are grounded for the purpose of limiting the voltages upon the circuit which might otherwise occur through exposure to lightning or other voltages higher than that for which the circuit is designed; or to limit the maximum potential to ground due to normal voltage." The latest requirements for grounding low-voltage systems may be found in Article 250 of the 1968 Edition of the National Electrical Code.

Failure to provide proper grounding for electric equipment may be considered as the primary cause of many accidents which have resulted in the death of personnel and no system is complete unless adequate grounding connections have been made. This subject has been covered in Chapter V of this book in detail, but because it is such an important phase of the electric installation, it must not be passed over too lightly. This is particularly important when we realize that high voltages are not necessary to cause death from electric shock. Many deaths are recorded annually resulting from shock received from the usual 115-120 volt lighting and appliance circuits and many of these could and should have been avoided by proper grounding procedures.

Maintenance

The design of equipment and the design of equipment installations should provide for adequate protection to the electric parts from oils, greases and dirt, all of which are generally very harmful to the windings and insulation. As heat is a common enemy of most electric equipment, a proper ventilating method must be provided both in the equipment design and in the installation.

Dirt is probably the greatest enemy of all electric equipment because the accumulation of dirt and dust affects the equipment's internal and external ventilation. This results in greater heating of parts with the resulting lowered efficiency and therefore progressively increased heating. At the same time this shortens the life of the insulation because most insulating materials have a life expectancy which decreases rapidly when the temperature rises.

Rotating equipment requires lubrication and where lubrication is needed, wear usually is found. Bearings must be checked to maintain proper clearances between the stationary and rotating parts.

Insulation of equipment usually depreciates with age. Careful checks on the decrease of insulation resistance prevents many failures. A sudden drop in insulation resistance of any unit is indicative of developing trouble and this can frequently be forestalled by immediate corrective measures.

Protective devices will function properly only if regularly examined and checked. An overload relay which does not open a circuit at the designed level of operation is poor insurance against preventing serious electrical failure. Systems have even been reported where overload relays were actually blocked out of service to prevent their tripping. Details of system relaying are given in Chapter III.

The essence of good maintenance can be summarized as follows:

1. Cleanliness. Keep equipment clean and well ventilated.
2. Regular inspections. Note variations from normal conditions.
3. Lubrication. Apply proper lubricants when needed. Develop lubrication schedules and adhere to them.
4. Repairs and adjustments. Remember that small repairs or adjustments that are neglected or postponed too long frequently lead to more extensive repair jobs.
5. Records. Develop a system of record keeping which will show the repairs required by the equipment over a long period.

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CHAPTER II

VOLTAGE CONSIDERATIONS

Nominal System Voltages and Equipment Voltage Ratings

Before starting a discussion on system voltage problems, it is necessary to have an understanding of the system voltage nomenclature and the preferred voltage ratings of various apparatus used in the system so that the proper voltage identification can be used throughout. It is also necessary to know why the voltage designations are applied to help in understanding the system voltage discussion in the following sections.

Progress with System Voltage Nomenclature

The IEEE Industrial and Commercial Power Systems Committee has had a long interest in the nomenclature for alternating-current power systems as applied in industrial plants and commercial buildings. A very comprehensive and significant paper, the "Report on Industrial Voltage Requirements,"[1] was presented at the 1947 AIEE Summer General Meeting by the then Subcommittee on Industrial Voltage Requirements. (The "Report on Industrial Voltage Requirements," Transactions Paper 47-157, was published in the April 1948 issue of *Electrical Engineering*.)[1] In 1958 a System Voltage Nomenclature Working Group of the Codes and Standards Subcommittee of the AIEE Industrial and Commercial Power Systems Committee was formed and later produced the paper, "A-C System Voltage Nomenclature for Industrial and Commercial Power Systems,"[2] presented in October at the 1960 Fall General Meeting. Upon the recommendation of the Industrial and Commercial Power Systems Committee, it was submitted to the Standards Committee of the Institute with the result that it became Standards Publication No. 92, published in December 1962.

The formal acceptance of IEEE No. 92 (formerly AIEE No. 92) documented a comprehensive approach to the areas needed to change the national standard on this subject. In fact, the closing paragraph states that "it is a further recommendation of this Committee that the proposed voltage ratings and practices included in the paper be submitted to the American Standards Association to be adopted in their Standard on 'Preferred Voltage Ratings for A-C Systems and Equipment'."[2]

The System Voltage Nomenclature Working Group had a specific motivation in wanting to develop a consistent and workable voltage Standard. That desire concerned the work then underway by the Committee to develop consistent voltage terminology in the Committee's present publications. During this time the third edition of *Electric Power Distribution for Industrial Plants*[4] (known as the Red Book) and *Electric Systems for Commercial Buildings*[5] (known as the Gray Book) were in preparation. Chapter II of the Red Book, titled "Voltage Considerations," and Chapter III of the Gray Book, titled "Voltage Selection," are both based on the system voltage nomenclature practices developed in the Working Group paper.

A Look at C84

The present Standard for the rating of all alternating-current systems and equipment in the United States is *Preferred Voltage Ratings for AC Systems and Equipment*, USAS C84.1. (The American Standards Association became the United States of America Standards Institute in September 1966.) This Standard is based on the report of a joint committee of the Edison Electric Institute (EEI Publication R-6) and the National Electrical Manufacturers Association (NEMA Publication 117) published in May 1954; this revised the Standard issued in 1930.

The present Standard C84 detailed the voltage zones into the categories of *favorable zone* and *tolerable zone*. The present voltage-band limits for these zones are given in Table 2.1, which is a copy of C84. To develop an understanding of the meaning of these zones, the definitions of both the favorable and tolerable zones from C84 are as follows.

Favorable Zone

"This zone will contain the greater part of the existing voltages. Systems will ordinarily be designed with the intention that most of their operation voltages lie within this zone. Equipment will ordinarily be designed and rated so as to give fully adequate and efficient operation throughout this zone, although not necessarily with normal characteristics at all voltages."

Tolerable Zone

"This zone will contain voltages which lie above and below the Favorable Zone. These necessarily result from practical operation under field conditions. They must be recognized as a normal part of the existing range of voltages, although not those most desirable. Systems will ordinarily be designed so that the frequency of occurrence of such voltages, both as to location and as to time, will be minimized. Equipment should, in general, be able to give fairly satisfactory operation throughout this zone, although not necessarily with as good characteristics as are given through the Favorable Zone. For some types of equipment, modification of loading or even alternate designs may be required for satisfactory operation in the upper and lower parts of the Tolerable Zone."

Table 2.1

System Voltages

System Designation in Terms of Base Voltage (BV)	Preferred Base Voltage	Preferred Nominal System Voltage(a)(g)	Voltage Zones: Favorable Zone Minimum	Favorable Zone Maximum	Tolerable Zone (d) Minimum	Tolerable Zone (d) Maximum
VOLTAGES AT POINT OF UTILIZATION BY EQUIPMENT						
1 BV	120	120	110	125	107	127
1/2 BV	120	120/240	110/220	125/250	107/214	127/254(c)
1/1.73Y BV	120	120/208Y	114/197Y	125/216Y	111/193Y(c)	127/220Y
2 BV	120	240	210	240	200	250
4 BV	120	480	420	480	400	500
5 BV	120	600	525	600	500	625
20 BV	120	2400	2200	2450	2100	2540
20/34.6Y BV	120	2400/4160Y	2200/3810Y	2450/4240Y	2100/3630Y	2540/4400Y
40 BV	120	4800	4400	4900	4200	5080
60 BV	115(b)	6900(b)	6300	6900	6000	7200
	120(b)	7200(b)				
PRIMARY VOLTAGES AT DISTRIBUTION TRANSFORMERS						
20 BV	120	2400	2300	2500	2200	2600
20/34.6Y BV	120	2400/4160Y	2300/4000Y	2500/4330Y	2200/3810Y	2600/4500Y
40 BV	120	4800	4600	5000	4400	5200
60 BV	120	7200	6900	7500	6600	7800
40/69.3Y BV	120	4800/8320Y	4600/8000Y	5000/8660Y	4400/7620Y	5200/9000Y
100 BV	120	12000	11000	12500	10500	13000
60/103.9Y BV	120	7200/12470Y	6900/12000Y	7500/13000Y	6600/11450Y	7800/13500Y
63.5/110Y BV	120	7620/13200Y	7270/12600Y	7960/13800Y	7000/12100Y	8250/14300Y
110 BV	120	13200	12600	13800	12100	14300
120 BV	120	14400	13000	14500	12600	15000
VOLTAGES AT SUBSTATIONS AND ON TRANSMISSION SYSTEMS						
20 BV	120	2400	2300	2600	2200	2750
20/34.6Y BV	120	2400/4160Y	2300/4000Y	2600/4500Y	2200/3810Y	2750/4760Y
40 BV	120	4800	4600	5200	4400	5500
60 BV	120	7200	6900	7800	6600	8250
40/69.3Y BV	120	4800/8320Y	4600/8000Y	5200/9000Y	4400/7620Y	5500/9520Y
VOLTAGES AT SUBSTATIONS AND ON TRANSMISSION SYSTEMS						
100 BV	120	12000	11000	13000	10500	13200
60/101.9Y BV	120	7200/12470Y	6900/12000Y	7800/13500Y	6600/11450Y	7920/13700Y
63.5/110Y BV	120	7620/13200Y	7270/12600Y	8250/14300Y	7000/12100Y	8320/14500Y
110 BV	120	13200	12600	14300	12100	14500
120 BV	120	14400	13000	15000	12600	15500
200 BV	115	23000	(e)	(e)	20400	25800
240 BV	115	27600	(e)	(e)	24500	31000
300 BV	115	34500	(e)	(e)	30600	38000
400 BV	115	46000	(e)	(e)	40000	48300
600 BV	115	69000	(e)	(e)	60000	72500
1000 BV	115	115000	(e)	(e)	100000	121000
1200 BV	115	138000	(e)	(e)	120000	145000
1400 BV	115	161000	(e)	(e)	140000	169000
2000 BV	115	230000	(e)	(e)	200000	242000
(See Note (f))						

NOTES:

(a) Except for the first and second lines, which indicate the usual single-phase two- or three-wire systems, the figures in the third column refer to three-phase systems.

(b) Since utilization at this level is confined principally to 6600-volt motors in large steel mills, mines, etc., a nominal designation of 6900 volts is commonly used and is included herewith, even though it is not consistent with other nominal voltages in the utilization group. The voltage zones for this level are likewise related to 6900 volts rather than to 7200 volts.

(c) Equipment to be used on both the 120/208Y and the 240-volt systems must recognize the minimum voltage of the former and the maximum voltage of the latter.

(d) Equipment designed for the Favorable Zone will in general give fairly satisfactory operation throughout the Tolerable Zone, except that modification of loading or alternate designs may be required for certain types of equipment.

(e) For systems with nominal voltages above 14400 volts, designation of a "Favorable Zone" has been omitted as being somewhat less necessary than for the lower voltages. It should be considered, however, that the relationships and definitions pertaining to the lower voltages apply equally well to the higher voltages.

(f) Preferred system voltages above 230 kV are not included in this table. A study of these higher voltages is still under way in conjunction with the International Electrotechnical Commission.

(g) In order that other numerical designations for system voltages which are sometimes used may be interpreted in terms of the "Preferred Nominal System Voltages" values shown in Table 2.1, the following* tabulation has been prepared. It should be emphasized that all of the different values on any one line refer to the same system as defined by its zone values in Table 2.1. Apparatus ratings indicated in other tables in this report in connection with the "Preferred Nominal System Voltages" apply, therefore, equally well where these other designations are used.

* *See next page for continuation of Note (g)*

Note (g) of Table 2.1 continued

Preferred Nominal System Voltage	*Other Designations for Identical Systems*
120	110, 115 or 125
120/240	110/220 or 115/230
120/208Y	115/199Y
240	220 or 230
480	440 or 460
600	550 or 575
2400	2200, 2300 or 2500
2400/4160Y	3810 or 4000
4800	4400, 4600 or 5000
7200	6600, 6900 or 7500
4800/8320Y	8000
12000	11000 or 11500
7200/12470Y	11450, 11950 or 12000
7620/13200Y	—
13200	13500 or 13800
14400	13200, 13800 or 14000
23000	22000 or 24000
27600	26400
34500	33000 or 36000
46000	44000 or 45000
69000	66000 or 72000
115000	110000 or 120000
138000	132000
161000	154000
230000	220000

The current activity of the present USA Standards Committee C84 has re-examined the definitions of the two voltage zones and, because of the difficulty of finding a clear and succinct title for the zones, has presently labeled them Range A and Range B. It should be observed that the scope of the proposed definitions needfully differ from the present C84. The current definitions are as follows.

Range A: Service Voltage

"Electric supply systems shall be so designed and operated that most service voltages are within the limits specified for this range. The occurrence of service voltages outside of these limits is to be infrequent with respect to time and place."

Range A: Utilization Voltage

"User systems shall be so designed and operated that, with service voltages within Range A limits, most utilization voltages are within the limits specified for this range.

"Utilization equipment shall be designed and rated to give fully satisfactory performance throughout this range."

Range B: Service and Utilization Voltages

"This range includes voltages above and below Range A limits that necessarily result from practical operating conditions on supply and/or user systems. Although such conditions are a part of practical operations, they shall be limited in extent, frequency and duration. When they occur, corrective measures shall be undertaken within a reasonable period of time to improve voltage to within Range A limits.

"Insofar as practicable, utilization equipment shall be designed to give acceptable performance in the extremes of this range of utilization voltage, although not necessarily as good performance as in Range A.

"It must be recognized that, because of conditions beyond the control of the supplier and/or user, there will be infrequent and limited periods when sustained voltages outside of Range B limits will occur. Utilization equipment may not operate satisfactorily under these conditions, and protective devices may operate to protect the equipment. When voltages occur outside the limits of Range B, prompt corrective action is recommended. The urgency for such action will depend upon many factors, such as location and nature of load or circuits involved, and magnitude and duration of the deviation beyond Range B limits."

Low-Voltage Systems

To correlate the different system voltage levels, the starting point in the industrial field is with low-voltage systems.

Change in Motor Voltage Rating

After ASA C84.1 was issued in 1954, problems continued to appear with the 220- and 440-volt ratings of electric motors. Table 2.2 shows an extract from the Standard listing the maximum and minimum voltages in the *favorable zone* for the 120-, 240-, and 480-volt systems. As quoted earlier, the *favorable zone* is defined as that in which most operating voltages will fall. It should be noted that the 120-volt system allows a 5-volt rise above nominal voltage, but *no* plus tolerance is allowed for the 240- and 480-volt systems.

IEEE Standards Publication No. 92 recognized the disadvantage of retaining the nine percent difference between the 480-volt transformer and 440-volt motor. Actual operating practice indicates that the system voltages were about five percent above the motor voltage. This reduced system-voltage drop was due to the general adoption of the *load-center* principle of distribution. Accordingly, it recommended that the standard NEMA transformer be operated on the plus two and one-half percent tap to give a secondary voltage of 468 volts with rated primary voltage. This approach would eventually lead to the adoption of a line of transformers rated at 460 volts, in place of 480 volts, to be more closely in harmony with the 440-volt motor. This approach was not acceptable to the electric utility industry which has made a long and continuous effort to standardize on transformers based on multiples of 120 volts. Thus, the alternative was to retain the 120-volt based transformer and investigate the possibility of going to a three-phase motor based on multiples of 115 volts as presently exists for low-voltage single-phase systems so as to accomplish the same end result of harmony between the system and motor voltages. Careful study was given to this subject by a joint committee of the NEMA Motor and Generator Committee and the NEMA Industrial Control Committee. A result has been publication of *Suggested Standard for Future Design*.[8] There has been wide acceptance of the proposal to line up the three-phase motors on the 115-volt base, which has been the basis for single-phase motors for many years.

Problems of Standard Usage

Because of discrepancies in tolerances between utilization equipment and power system voltages, there have been a number of unfair complaints that the utilities were raising the voltage.

Table 2.3 shows an extract from the tabulation of *primary voltages at distribution transformers* for the 12000-volt (not usually an industrial voltage but easy to use by way of comparison) system showing a maximum voltage of 12500 volts and a minimum voltage of 11000 volts for the *favorable zone*. Table 2.4 shows that if the maximum voltage of 12500 volts is applied to the primary of a standard 12000-volt distribution transformer, the secondary voltage will be 125 volts for a 120-volt transformer, 250 volts for a 240-volt transformer, and 500 volts for a 480-volt transformer. Table 2.2 shows that 125 volts is within the *favorable zone* for the 120-volt system but exceeds the *favorable zone* for the 240- and 480-volt systems. Table 2.5 shows that 125 volts is within the tolerance of the 115-volt motor but 250 volts exceeds the tolerance of the 220-volt motor and 500 volts exceeds the tolerance of the 440-volt motor. As a result there were numerous complaints that the utilities were raising the voltage when the actual cause was the requirements of the Standard and the ratios of the standard transformers built to meet them.

Table 2.2

System Nominal Voltage	*Favorable Zone Voltage*	
	Minimum	*Maximum*
120	110	125
240	210	240
480	420	480

Table 2.3

System Nominal Voltage	*Favorable Zone Voltage*	
	Minimum	*Maximum*
12000	11000	12500

Table 2.4

Primary Voltage	*Secondary Voltages*		
12000	120	240	480
12500	125	250	500

Table 2.5

Motor Rating Voltage	*115*	*220*	*440*
10 percent plus	126.5	242	484

Table 2.6

Primary Voltage	*Secondary Voltage*
12000	208
11000	191

Another problem concerns the use of the 220-volt motor on 208Y/120-volt systems. Originally the 208-volt system was developed to provide an economical and highly reliable system for light and power services in the commercial buildings of large cities. Since the operation of a 220-volt motor with a minimum voltage limit of 198 volts was marginal, the voltage of the standard network transformer was standardized at 216Y/125 volts to provide 208 volts at the customer service. Since network system voltages are relatively stable due to the relatively short primary feeders, satisfactory service is generally secured, especially since most power equipment is installed in the basement close to the power source.

The recent development of commercial installations such as shopping centers, high-rise apartments, motels, and offices brought an increased demand for 208-volt service to supply the large lighting and air-conditioning loads. Standard 208-volt transformers (not the 216-volt network type) were used and supplied from relatively long suburban feeders. The 208-220/440-volt conventional open motor might be in difficulty from low voltage. This is due to the application of standard 208Y/120-volt unit substation transformers (not the 216Y/125-volt network type) and these transformers may be supplied from relatively long suburban feeders. (It should be noted that motors particularly designed for 208 volts or the hermetically sealed type designed for a larger voltage range should still be satisfactory.) As low-voltage problems materially increase, motors develop lower torque and larger losses and may overheat. Table 2.6 contains an extract from the Standard showing that when the voltage of a 12000-volt system drops to 11000 volts, the minimum limit of the *favorable zone*, the secondary voltage will drop to 191 volts, well below the minimum limit of 198 volts for a 220-volt motor.

Industry and Commercial Power Systems Proposal for 230-, 460-, and 575-Volt Systems

In the late 1950s, the System Voltage Nomenclature Working Group reached the conclusion that the 240- and 480-volt systems produced voltages too high for the 220- and 440-volt motors; the solution was to lower the voltages in the low-voltage system to a 115-volt base from the present 120-volt base to produce a low-voltage system in the series 115, 230, and 460 volts.

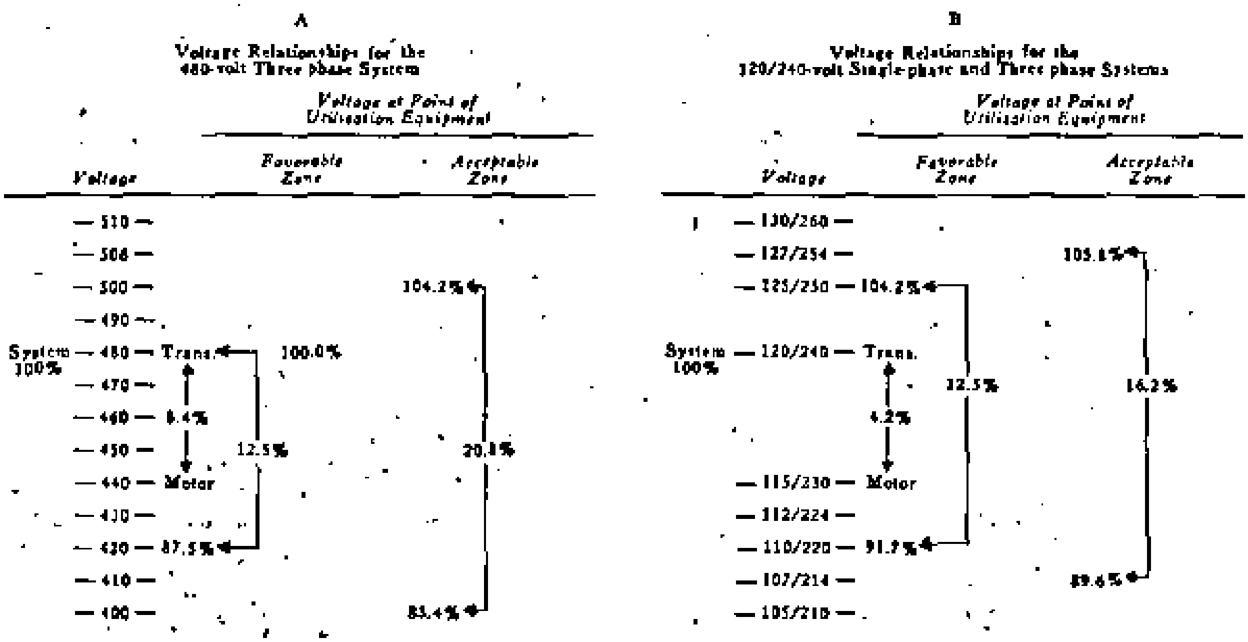
However, objections were raised to this proposal because of the problems of lowering existing supply voltages, the need for changing the distribution transformer Standards, and the incompatibility of this Standard with the 208-volt system. Yet the need to review the present Standard was quite apparent, so early in 1962 the American Standards Association (now the United States of America Standards Institute) Sectional Committee C84.1 was reactivated with representatives from all sectors of the electrical industry to revise the 1954 Standard.

Voltage Survey

The first major task of the new C84 Committee was to undertake a comprehensive voltage survey of the electric utility industry in the United States to determine the voltages in use, their relative importance, the trend in importance, the design policies for distribution systems and voltage control, and actual readings of voltages in the field. This report was completed and submitted to the committee in 1965. In general, the report showed that the average operating voltages for the various systems were very close to the nominal values in the existing Standard (120, 208, 240 and 480 volts for low-voltage systems) and the variations from nominal approximated the limits specified in the Standard. A portion of the results of the survey was published in the January 1966 issue of the *EEI Bulletin* (in an article, "65000 Service Voltage Tests Across the USA," by J. W. Anderson, Chairman of the Voltage Survey Subcommittee of USA Standards Committee C84).[7]

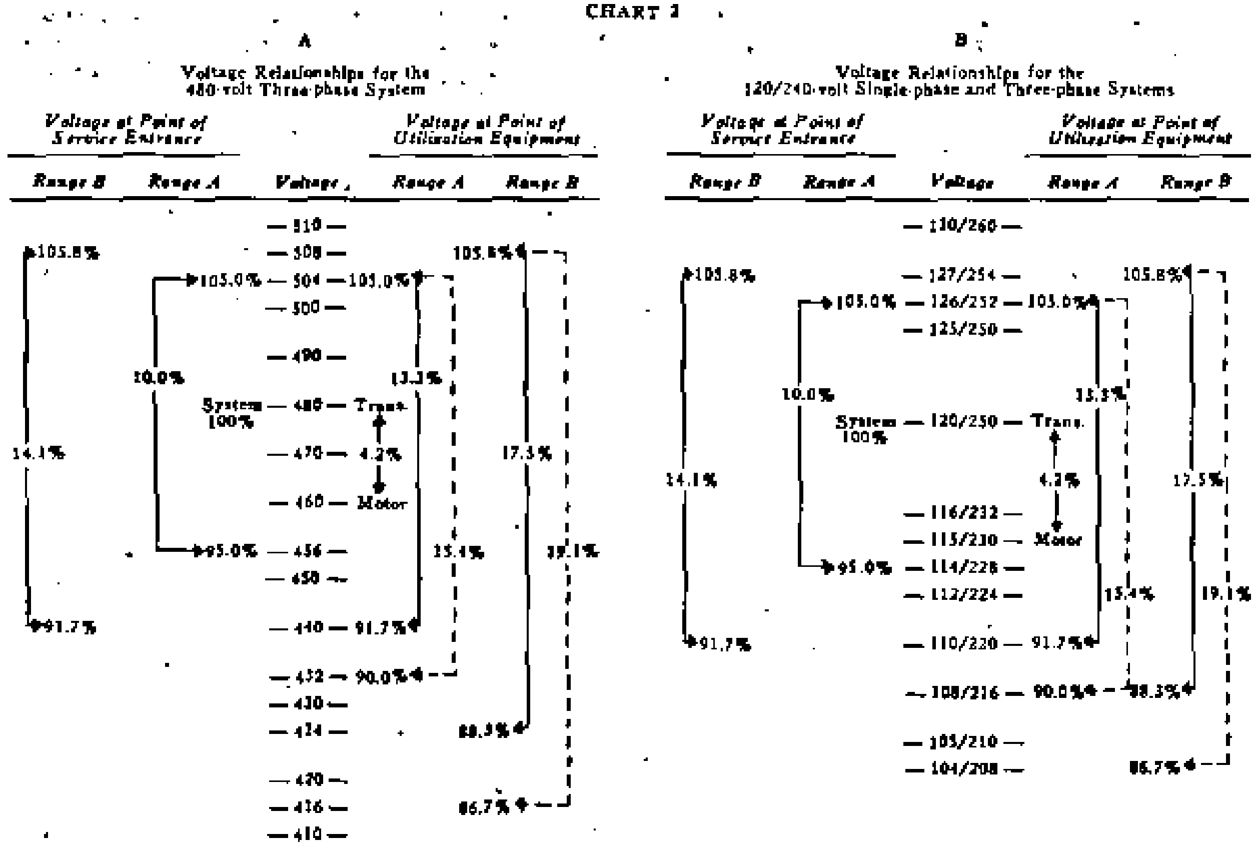
Voltage Relationships from 1954 ASA C84

CHART 1



Voltage Relationships from Proposed 1969 USAS C84

CHART 2



——— Lighting or Combination Lighting and Power Circuits
– – – Power Circuits

System to 240, 480, and 600 Volts—Motors to 230, 460, and 575 Volts

While this survey was being made, the motor manufacturers in NEMA reached the conclusion that a rerating program[8, 9] was possible because of improved materials, particularly at higher temperatures, and the improved art of design. In their design studies it was important that not only the voltage supplied to the motors be maintained within plus-or-minus ten percent of the utilization voltage, but also that the right voltage be established. Many users were pressing for higher design voltages and the C84 survey confirmed a definite need. A survey of voltages by NEMA motor manufacturers (indicating that the average voltage at the motor terminals of a 440-volt motor was 450 to 460 volts) added to the evidence. Also, many problems in the field indicated a great number of overvoltage problems. Thus the NEMA Motor and Generator Section established a Standard for future design in 1965, raising the voltage rating of motors to 230, 460, and 575 volts for 240-, 480-, and 600-volt systems.

A separate line of standard motors will be required for 208-volt systems; the increase in motor voltage operating range from 208-220 volts to 208-230 volts would handicap the 230×460-volt design. The preference is for 200 volts since this rating puts *all* low-voltage motors on a consistent 115-volt base.

This change places most low-voltage motors on a 115-volt base which is 4.2 percent below the system nominal voltage on a 120-volt base. Chart 1 shows the voltage relationships for the present 480-volt three-phase system and illustrates the disharmony with the 120/240-volt single-phase systems (or 240/120-volt three-phase system shown in Table 2.7) found in C84. Chart 2 shows the change to the proposed new Range A and Range B voltage based on the motor now being on a 115-volt base. (Chart 2 applies equally well to the 230- and 575-volt motors and their 240- and 600-volt systems, respectively.)

The plus-and-minus ten percent tolerance of the 115-volt motor permits the voltage applied to the motor terminals to vary from a maximum of 126.5 to a minimum of 103.5 volts. In terms of the system voltage this is a voltage variation from plus 5.42 percent to minus 13.75 percent, for a total swing of 19.17 percent. The problem now is to determine how much of this system voltage swing should be allotted to provide an adequate and workable allowance for variations in the supply voltage and how much should be allotted to provide for an adequate and workable allowance for the voltage drop in the wiring between the supply connection and the motor.

These charts show the extreme limits of the voltage swing. It is expected that the new Standard will provide for a limited voltage spread which will cover the majority of the voltages in service and limit the maximum spread to unusual conditions.

Influence on Power Distribution System Design

The problem of designing an electric power distribution system which will maintain the supply voltage to all customers within acceptable limits is illustrated in Figure 2.1, which shows the voltage profile of an electric distribution

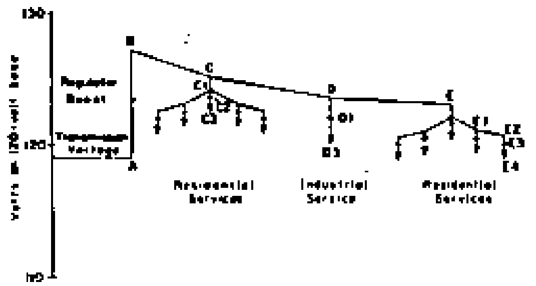


Figure 2.1
Voltage profile of a distribution system 120-volt base average conditions

system on a 120-volt base. (This figure is similar to Figure 2 of Appendix A, "Discussion of the Background for the Report," as a part of ASA C84.) A transmission line supplies a distribution substation with some voltage represented by point *A*. This is the voltage that would be supplied to a large industrial plant taking service directly from a subtransmission line at 69000 to 138000 volts. Transformers in the substation step the subtransmission voltage down to a distribution voltage; the most popular for an industrial plant is 4160 or 13800 volts. (Of course, the supplying electric utility may have other system voltages in this class based on its total system economics.) This is also represented by point *A* since the use of the 120-volt base cancels out the transformation. Automatic voltage regulators, either built into the transformer or installed separately, maintain the distribution voltage represented by point *B* regardless of changes in the transmission voltage. The regulators also raise and lower the distribution voltage slightly to compensate for the changes in the voltage drop along the feeder as the feeder load increases and decreases, as represented by the declining voltages at points *C*, *D*, and *E*.

Transformers are installed along the feeder to step the distribution voltage down to utilization voltages under 600 volts. The first transformer from the substation is shown at *C*. There will be a voltage drop through the transformer represented by *C*-*C1*. Under average conditions the maximum voltage will be received by the customer connected closest to the transformer *C* since his voltage will be reduced from the value at the transformer terminals by the voltage drop in the service represented by *C1*-*C2* and the voltage drop in the building wiring represented by *C2*-*C3*. In low load-density areas secondary wiring may be run from the transformer to adjacent poles to serve additional customers, in which case the voltage received by these customers will be further reduced by the voltage drop in the secondary as shown by the diagram.

The minimum voltage under average conditions will be received by the farthest customer from the last transformer on the feeder shown at *E*. The voltage he receives will be reduced below that received by the customer at *C3* by the voltage drop along the feeder represented by the declining values from *C* to *E* plus the voltage drop in the secondary represented by the declining values from *E1* to *E2*.

A service is shown at point D to an industrial plant having its own transformers. In this case there are no secondary and service voltage drops but the transformers are usually of larger rating with a higher impedance and hence a higher voltage drop than the usual distribution transformer; also, industrial plant wiring is usually much longer and more heavily loaded, so the wiring voltage drop is much higher than in a residence.

It should be pointed out that this diagram illustrates a continuously varying situation. Voltage drops change as loads are switched on and off. Cooking load comes on at mealtime. Lighting load comes on at night. Industrial and commercial load is generally turned off at night and on Sundays. Heating load comes on in the winter time and cooling load in the summer. New electric equipment is purchased. So, the voltage delivered to the terminals of a piece of electric equipment varies not only from minute to minute but also from hour to hour, day to day, and year to year.

The ends of utility feeders are usually equipped with switches to permit a feeder to be tied to an adjacent feeder in cases of emergency when the supply equipment has failed or the feeder conductor or supporting poles have been damaged. In such cases the length and load on a feeder is increased so the voltage drop is increased during the emergency. Under these conditions the voltage supplied to a motor may drop below the limits of the *favorable zone* but will still be within the minimum ten percent tolerance of the motor.

Engineering Approach to Voltage Zones

Based on the concepts given in Appendix A of ASA C84 (and illustrated by Figure 1), a proposed standard voltage profile for low-voltage systems can now be developed. This is shown in Table 2.7.

Medium-Voltage Systems

Medium-voltage systems are presently defined as those systems whose nominal values of voltage fall between 601 and 15000 volts.[2] Unlike low-voltage systems, medium-voltage systems are predominately used to supply secondary unit substations and distribution transformers, which in turn step the medium voltage down to a utilization voltage in the low-voltage range. Therefore, the voltage limits for medium-voltage systems must be established by determining the voltage limits which, when applied to the primary terminals of a supply transformer, will allow for the voltage drop in the transformer and secondary connections, and still provide a proper secondary service voltage.

The present USA Standard for system voltages[3] is reproduced in Table 2.1. The 7200-volt three-phase system is obsolete and should be dropped from Table 2.1 and the 13800-volt system is now an accepted Standard. With these changes, Table 2.8 shows the voltage limits for medium-voltage systems.

The extrapolation of the base voltage values to produce the limits for medium-voltage systems in Table 2.8 requires that the ratios of the supply transformers used to make the transformation from the medium voltage to the low voltage as shown on the transformer nameplates be identical to the nominal values of the two voltages. The use of transformers with nameplate ratings other than identical to the nominal system voltage values (which occurs in the case of: 1) transformers with primary nameplate ratings over 13800 volts, or 2) old transformers with secondary voltage ratings on other than a 120-volt base, or 3) the use of taps to change the transformer ratio for purposes other than to make the actual ratio agree with the nominal system voltage ratio) will change the voltage relationships given in Table 2.8.

Comparison with the Present Standard

The voltage limits for medium-voltage systems corresponding to the calculated limits for primary service voltages in Table 2.8 are given in the section of the present Standard in Table 2.1 headed *Primary Voltages at Distribution Transformers*. A comparison between the values given in these two tables shows that the voltage limits for the *tolerable zone* in the present Standard exceed both the maximum and minimum values given in Table 2.8, indicating that severe overvoltages and undervoltages could occur on the low-voltage utilization equipment if the medium voltages approached the maximum and minimum limits indicated. Even in the *favorable zone*, the minimum voltage limits are exceeded in the case of the 12000-volt and 14400-volt systems.

In Table 2.1 in IEEE Recommended Practice No. 92[2] the voltage limits for medium-voltage systems were based on the present Standard in Table II headed *Voltages at Point of Utilization by Equipment*. The information is given as Table 2.9. In this case a comparison between the values in these two tables shows that the voltage limits for the *tolerable zone* in the present Standard are the same for the maximum values but still lower for the minimum values. For the *favorable zone* the maximum and minimum values are both less than Table 2.8.

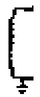
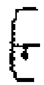
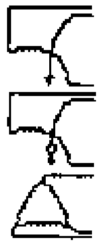
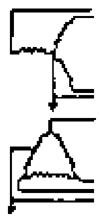
Medium-Voltage Utilization Equipment

The direct connection of utilization equipment to medium-voltage systems is recognized in the present Standard as shown in Table 2.1 by the extension of the section of the Standard headed *Voltages at Point of Utilization by Equipment* to include medium voltages up to 7200 volts. Table 2.10 shows the five standard medium voltages currently used in industrial plants for medium-voltage distribution, the nameplate rating of the standard motor for use on each system, and the plus and minus ten percent tolerance limits of the motors.

A comparison between *tolerable zone* limits for the *voltages at point of utilization by equipment* and the plus and minus ten percent limits for the motors shows very close agreement indicating that values listed in the present Standard are based on the voltage tolerances of the medium-voltage motors. However, a comparison of the tolerance limits for medium-voltage motors in Table 2.10 and the tolerance limits for Range B for primary service voltages from Table 2.8 shows that the maximum limits agree very closely but the minimum limits for *primary service voltages* are much higher due to the voltage drop allowance for the transformer and secondary system. However, the limits for *primary service voltages* in all cases are within the tolerance limits of the motors so that if the voltage is satisfactory to supply a transformer, it will be satisfactory for the motor.

Table 2.7

Proposed Standard System Voltages for Low-voltage Systems

Nominal System Voltage (Note a) Bold type—Preferred voltage Light type—In use but not preferred				*Voltage Range A*						*Voltage Range B*					
Single-phase Systems		*Three-phase Systems*		*Minimum*				*Maximum*		*Minimum*				*Maximum*	
 *Two-wire*	 *Three-wire*	 *Three-wire Wye or Delta*	 *Four-wire Wye or Delta*	*Utilization Voltage (Note c)*		*Service Voltage*		*Utilization and Service Voltage (Note e)*		*Utilization Voltage (Note c)*		*Service Voltage*		*Utilization and Service Voltage*	
				LOW-VOLTAGE SYSTEMS											
120				110	91.7%	114	95.0%	126	105.0%	106	88.3%	110	91.7%	127c	105.8%
	120/240			110/220	91.7%	114/228	95.0%	126/252	105.0%	106/212	88.3%	110/220	91.7%	127/254c	105.8%
			208Y/120	191Y/110	91.7%	197Y/114	95.0%	218Y/126	105.0%	184Y/106 (Note d)	88.3%	191Y/110 (Note d)	91.7%	220Y/127c	105.8%
		240		220	91.7%	228	95.0%	252	105.0%	212	88.3%	220	91.7%	254c	105.8%
			240/120b	220/110	91.7%	228/114	95.0%	252/126	105.0%	212/106	88.3%	220/110	91.7%	254/127c	105.8%
		480		440	91.7%	456	95.0%	504	105.0%	424	88.3%	440	91.7%	508c	105.4%
			480Y/277	440Y/254	91.7%	456Y/263	95.0%	504Y/291	105.0%	424Y/245	88.3%	440Y/254	91.7%	508Y/293c	105.4%

EXPLANATION OF TERMS

Nominal Voltage

The nominal voltage of a circuit or system is a nominal value assigned to the circuit or system for the purpose of conveniently designating its voltage class.

Service Voltage

Service voltage is the voltage at the point where the electric systems of the supplier and the user are connected.

Utilization Voltage

Utilization voltage is the voltage at the line terminals of utilization equipment.

NOTES:

(a) Three-phase three-wire systems are systems in which only the three phase conductors are carried out from the source for connection of loads. The source may be derived from any type of three-phase transformer connection, grounded or ungrounded. Three-phase four-wire systems are systems in which a grounded neutral conductor is also carried out from the source for connection of loads. Four-wire systems in Table 2.7 are designated by the phase-to-phase voltage, followed by the letter Y (except for the 240/120-volt delta system), a slant line, and the phase-to-neutral voltage. The principal transformer connections that are used to supply single-phase and three-phase systems are illustrated in Appendix A.

(b) The 600-volt system was omitted at this time in that the limits have not been resolved.

(c) Minimum utilization voltages for 120-600-volt circuits not supplying lighting loads are as follows:

Nominal System Voltage	*Range A*	*Range B*
120	108	104
208	187	180 (Note d)
240	216	208
480	432	416
600	540	520

(d) Many 220-volt motors were applied on existing 208-volt systems on the assumption that the utilization voltage would not be less than 187 volts. Caution should be exercised in applying the Range B minimum voltages of Table 2.7 and Note (c) to existing 208-volt systems supplying such motors.

(e) For 120-600 volt nominal systems, voltages in this column are maximum service voltages. Maximum utilization voltages would not be expected to exceed 125 volts for the nominal system voltage of 120, nor appropriate multiples thereof for other nominal system voltages through 600 volts.

(f) Low-voltage relationship of industrial transformers, and motor and control:

Three-phase Transformer	*Three-phase Motor and Control*	*Single-phase Motor and Control*
600Y/346V	575V	
480Y/277V	460V	460V
240Y/139V	230V	230V
208Y/120V	200V	115V

Table 2.8

Nominal System Voltage	Range A Minimum 97.5 Percent	Range A Maximum 105.0 Percent	Range B Minimum 95.0 Percent	Range B Maximum 105.83 Percent
2400*	2340	2520	2280	2540
4160*	4050	4370	3950	4400
4800*	4680	5040	4560	5080
6900	6730	7260	6550	7300
8320	8100	8740	7900	8800
12000	11700	12600	11400	12700
12470	12160	13090	11850	13200
13200	12870	13860	12540	13970
13800*	13460	14490	13110	14600
14400†	14041	15120	13680	15240

* Standard voltages used in industrial plants as well as utility systems.

† Requires 13800-volt transformer with taps set on 14400 volts.

Table 2.9

	Voltage	Percent of System Voltage	Voltage Spread, Percent	
Favorable zone: maximum voltage	2450	102.1	+2.1	
System nominal voltage and transformer voltage rating	2400	100.0		10.4
Motor voltage rating	2300	95.9		
Favorable zone: minimum voltage	2200	91.7	−8.3	
Favorable zone: maximum voltage	4240	102.1	+2.1	
System nominal voltage and transformer voltage rating	4160	100.0		10.4
Motor voltage rating	4000	96.1		
Favorable zone: minimum voltage	3810	91.7	−8.3	
Favorable zone: maximum voltage	4900	102.1	+2.1	
System nominal voltage and transformer voltage rating	4800	100.0		10.4
Motor voltage rating	4600	95.9		
Favorable zone: minimum voltage	4400	91.7	−8.3	
Favorable zone: maximum voltage	7050	102.1	+2.1	
System nominal voltage and transformer voltage rating	6900	100.0		10.4
Motor voltage rating	6600	95.7		
Favorable zone: minimum voltage	6320	91.7	−8.3	
Favorable zone: maximum voltage	14100	102.1	+2.1	
System nominal voltage and transformer voltage rating	13800	100.0		10.4
Motor voltage rating	13200	95.7		
Favorable zone: minimum voltage	12630	91.7	−8.3	

Table 2.10

Nominal System Voltage	Rated Voltage of Motor	110 Percent of Motor Rating	90 Percent of Motor Rating
2400	2300	2530	2070
4160	4000	4400	3600
4800	4600	5060	4140
6900	6600	7260	5940
13800	13200	14520	11880

Table 2.11

Transformer Primary Nameplate Voltage	Nominal System Voltage	Range A Minimum 97.5 Percent	Range A Maximum 105.0 Percent	Range B Minimum 95.0 Percent	Range B Maximum 105.83 Percent
22900	20780Y/12000	20260	21820	19740	21990
	22860Y/13200	21290	24000	21720	24190
	23000	22330	24050	21860	24240
	23900Y/13800	23300	25100	22700	25290
	24900Y/14400	24280	26150	23650	26350
34400	34500 and 34500Y/19920	33540	36120	32680	36410
43800	46000	45050	48510	43890	48690
67000	69000	67080	72240	65360	72810

Since a medium-voltage distribution system supplying only medium-voltage motors would be unusual, the voltage limits for medium-voltage systems must be based on the requirements to supply transformers (and not on the requirements of medium-voltage motors). The only purpose for allowing a lower voltage at the utilization equipment would be to provide for an additional drop in the building wiring as done for the low-voltage system. However, voltage drop is rarely a factor in medium-voltage systems. For example, the 210-volt difference between the minimum voltage limit of the 2300-volt motor and the minimum voltage required to supply a 2400-volt transformer represents one and one-half miles of fully loaded cable while the 1230-volt difference between the minimum-voltage limit of the 13200-volt motor and the minimum voltage required to supply a 13800-volt transformer represents approximately eight miles of fully-loaded cable.

Feeders anywhere near this length would require special consideration and should not be the subject of a Standard. Since the voltage limits required to supply transformers as given in Table 2.8 will provide satisfactory service to the motors, there is no reason to consider voltage limits for utilization equipment on medium-voltage systems. If necessary, the actual voltage tolerance of equipment can be obtained by reference to the equipment Standards.

High-Voltage Systems

Until the National Electrical Code was changed in 1959, the maximum voltage which could be brought into a building for primary distribution was 15000 volts, except with special construction features. (This same limit also applied, for the most part, to the regulated voltages used by utilities to supply distribution transformers.) Thus, when the present Standard was being prepared, a clear distinction existed between medium voltages and the unregulated transmission and subtransmission voltages used by utilities to supply substations.

The increase in load densities in recent years and the movement of industrial plants and commercial buildings into the suburban and rural areas outside the cities have created problems in providing adequate distribution capacity at a reasonable cost. One solution has been to convert subtransmission lines in the range from 15000 to 35000 volts to distribution systems by connecting distribution transformers to them. Another solution has been to convert three-wire systems in the upper medium-voltage range to 4-wire by changing the phase-to-phase voltage to a phase-to-neutral voltage in the same way that the 2400-volt system has been largely converted by utilities to 4160Y/2400 volts. As a result, the demarcation between distribution voltages under 15000 volts and subtransmission voltages over 15000 volts has largely disappeared. The present Standard for distribution transformers[10] provides for primary voltages up to 69000 volts.

This development requires that Table 2.8 listing the voltage limits for primary services should be extended up to 34500 volts (and up to 69000 volts if correlation with the distribution transformer Standard is desired). This extension is given in Table 2.11 which is based on the percentage values for primary service voltages as were used in Table 2.8. (This is also shown in Table 2.12.)

Voltage Ratings for 60-Hertz Electric Power Systems

Explanation of Terms

Nominal Voltage

The nominal voltage of a circuit or system is a nominal value assigned to the circuit or system for the purpose of conveniently designating its voltage class.

Service Voltage

Service voltage is the voltage at the point where the electric systems of the supplier and the user are connected.

Utilization Voltage

Utilization voltage is the voltage at the line terminals of utilization equipment.

Selection of Nominal System Voltages

When a new system is to be built or a new voltage level introduced in an existing system, it is recommended that one (or more) of the nominal system voltages shown in bold face type in Table 2.1 be selected. The logical and economical choice for a particular system among the voltages thus distinguished will depend upon a number of factors, such as the character and the size of the system.

Other system voltages that are in substantial use in existing systems are shown in light face type. Economic considerations will require that these voltages continue in use and in some cases may require extension of their use; but they are not generally recommended for new systems or new voltage levels in existing systems.

The 4160-, 6900-, and 13800-volt three-wire systems are particularly suited for industrial systems that supply predominantly polyphase loads including large motors, because these system voltages correspond to the standard motor ratings of 4000, 6600, and 13200 volts. Two of these systems are shown in bold face type to indicate that their use for this purpose is recommended. It is not intended to recommend the use of these systems for utility primary distribution, for which four-wire systems of 12470Y/7200 volts or higher are recommended.

Explanation of Voltage Ranges

For any specific nominal voltage, the voltages actually existing at various points at various times on any power system, or on any group of systems, or in the industry as a whole, will be distributed by percentage in some such manner as indicated by Figure 2.2. This distribution is characteristic of voltages at any designated class of points, such as points of service delivery and points of utilization. It is important that the design and operation of power systems and the design of equipment to be supplied from such systems be coordinated with respect to these voltage variations so that, insofar as practicable, the equipment will perform satisfactorily throughout the range of actual utilization voltages that will be encountered on the systems. In order to further this objective, this Standard establishes for each nominal system voltage, two ranges for service and utilization voltage variations, designated as Range A and Range B, the limits of which are given in Table 2.1. These limits apply to sustained voltage levels and not to momentary voltage excursions that may result from such causes as switching operations, motor starting currents, etc.

Application of Voltage Ranges

Range A: Service Voltage

Electric supply systems shall be so designed and operated that most service voltages are within the limits specified for this range. The occurrence of service voltages outside of these limits is to be infrequent with respect to time and place.

Range A: Utilization Voltage

User systems shall be so designed and operated that, with service voltages within Range A limits, most utilization voltages are within the limits specified for this range.

Utilization equipment shall be designed and rated to give fully satisfactory performance throughout this range.

Range B: Service and Utilization Voltages

This range includes voltages above and below Range A limits that necessarily result from practical operating conditions on supply and/or user systems. Although such conditions are a part of practical operations, they shall be limited in extent, frequency and duration. When they occur, corrective measures shall be undertaken within a reasonable period of time to improve voltage to within Range A limits.

Insofar as practicable, utilization equipment shall be designed to give acceptable performance in the extremes of this range of utilization voltage, although not necessarily as good performance as in Range A.

It must be recognized that, because of conditions beyond the control of the supplier and/or user, there will be infrequent and limited periods when sustained voltages outside of Range B limits will occur. Utilization equipment may not operate satisfactorily under these conditions, and protective devices may operate to protect the equipment. When voltages occur outside the limits of Range B, prompt corrective action is recommended. The urgency for such action will depend upon many factors, such as location and nature of load or circuits involved, and magnitude and duration of the deviation beyond Range B limits.

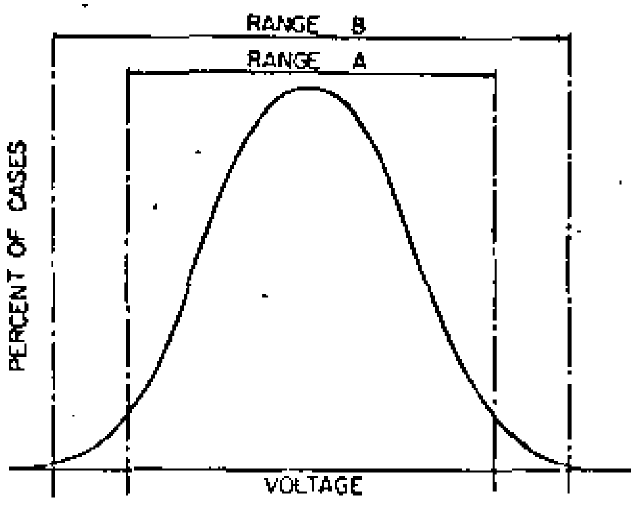


Figure 2.2
Distribution Characteristics of System Voltages

Table 2.12

Standard System Voltages

NOMINAL SYSTEM VOLTAGE (Note a)			VOLTAGE RANGE A (Note b)			VOLTAGE RANGE B (Note b)		
			Minimum		*Maximum*	*Minimum*		*Maximum*
Two-wire	*Three-wire*	*Four-wire*	*Utilization Voltage (Note c)*	*Service Voltage*	*Utilization and Service Voltage (Note e)*	*Utilization Voltage (Note c)*	*Service Voltage*	*Utilization and Service Voltage*
Single-phase Systems								
120			110	114	126	106	110	127
	120/240		110/220	114/228	126/252	106/212	110/220	127/254
Three-phase Systems								
		208Y/120	191Y/110	197Y/114	218Y/126	184Y/106 (Note d)	191Y/110 (Note d)	220Y/127
		240/120	220/110	228/114	252/126	212/106	220/110	254/127
	240		220	228	252	212	220	254
		480Y/277	440Y/254	456Y/263	504Y/291	424Y/245	440Y/254	508Y/293
	480		440	456	504	424	440	508
	2400		2160	2340	2520	2080	2280	2540
		4160Y/2400	3740Y/2160	4050Y/2340	4370Y/2520	3600Y/2080	3950Y/2280	4400Y/2540
	4160		3740	4050	4370	3600	3950	4400
	4800		4320	4680	5040	4160	4560	5080
	6900		6210	6730	7240	5940	6560	7260
		8320Y/4800	(Note f)	8110Y/4680	8730Y/5040	(Note f)	7900Y/4560	8800Y/5080
		12000Y/6930		11700Y/6760	12600Y/7270		11400Y/6580	12700Y/7330
		12470Y/7200		12160Y/7020	13090Y/7560		11850Y/6840	13200Y/7620
		13200Y/7620		12870Y/7430	13860Y/8000		12540Y/7240	13970Y/8070
		13800Y/7970		13460Y/7770	14490Y/8370		13110Y/7570	14520Y/8380
	13800		12420	13460	14490	11880	13110	14520
		20780Y/12000	(Note f)	20260Y/11700	21820Y/12600	(Note f)	19740Y/11400	22000Y/12700
		22860Y/13200		22290Y/12870	24000Y/13860		21720Y/12540	24200Y/13970
	23000			22430	24150		21850	24340
		24940Y/14400		24320Y/14040	26190Y/15120		23690Y/13680	26400Y/15240
		34500Y/19920		33640Y/19420	36230Y/20920		32780Y/18930	36510Y/21080
	34500			33640	36230		32780	36510

Higher Voltage
Three-phase Systems in kV

Nominal System Voltage	*Maximum Voltage*
46	48.3
69	72.5
115	121
138	145
161	169
230	242

For these systems Range A and Range B limits are not shown because, where they are used as service voltages, the operating voltage level on the user's system is normally adjusted by means of voltage regulation to suit his requirements.

Extra High Voltage
Three-phase Systems in kV

Preferred Nominal System Voltage	*Preferred Maximum Voltage*
345	362
500	550
700	765

Information from USA Standard C92.2—1967.

NOTES:

(a) Three-phase three-wire systems are systems in which only the three phase conductors are carried out from the source for connection of loads. The source may be derived from any type of three-phase transformer connection, grounded or ungrounded. Three-phase four-wire systems are systems in which a grounded neutral conductor is also carried out from the source for connection of loads. Four-wire systems in Table 2.12 are designated by the phase-to-phase voltage, followed by the letter Y (except for the 240/120-volt delta system), a slant line, and the phase-to-neutral voltage. The principal transformer connections that are used to supply single-phase and three-phase systems are illustrated in Appendix A.

(b) The 600-volt system was omitted at this time in that the limits have not been resolved.

(c) Minimum utilization voltages for 120-600 volt circuits not supplying lighting loads are as follows:

Nominal System Voltage	*Range A*	*Range B*
120	108	104
208	187	180 (Note d)
240	216	208
480	432	416
600	540	520

(d) Many 220-volt motors were applied on existing 208-volt systems on the assumption that the utilization voltage would not be less than 187 volts. Caution should be exercised in applying the Range B minimum voltages of Table 2.12 and Note (c) to existing 208-volt systems supplying such motors.

(e) For 120-600 volt nominal systems, voltages in this column are maximum service voltages. Maximum utilization voltages would not be expected to exceed 125 volts for the nominal system voltage of 120, nor appropriate multiples thereof for other nominal system voltages through 600 volts.

(f) Utilization equipment does not generally operate directly at these voltages. For equipment supplied through transformers refer to limits for nominal system voltage of transformer output.

In preparing Table 2.11, a column was added to list the primary nameplate voltage of the transformer because above 13800 volts, the transformer primary nameplate voltage and the system nominal voltage are not identical. The voltage limits should be based on the actual transformer ratio and not the system nominal voltage. This is an area that needs additional study to determine the values of having the system nominal voltage and transformer voltage the same, as with the present low-voltage and medium-voltage systems.

Voltages at Substations and on Transmission Systems

The present Standard provides voltage limits for medium voltages at *substations and on transmission systems* and this now falls in the medium-voltage system classification. The values given for minimum voltages are the same as those given for *primary voltages at distribution transformers*, but the maximum values are higher.

These figures do not seem to serve any useful purpose. The values are far beyond the limits provided in Table 2.8 to serve distribution and other supply transformers. The only other purpose would be to establish maximum and minimum limits for voltages applied to substation and transmission line equipment, but these requirements could be covered much better by a reference to the appropriate equipment Standard.

Need for Improved System Voltage Nomenclature

The approach developed for low-voltage[11] systems and extended to medium-voltage[12] systems results in the development of a table of Standard System Voltages, Table 2.12. This table represents major progress from the approach found in Table 2.1 representing the present Standard, and provides a sound, workable basis for integrating the customers' requirements with the utility supply system.[13]

Transformer Voltage Representations

Transformer voltage designations become rather complex. For instance, windings may have series-parallel connections; or they may be designed for connection line-to-neutral on higher rated voltage systems, such as 2400-volt transformers which are suitable for line-to-neutral operation on 4160-volt systems. These and other complex arrangements make exact identification desirable.

These variables in transformer voltage ratings have long been expressed by various symbolic methods. Such methods are essential because to describe fully the windings of transformers often would require a fairly lengthy paragraph. However, to be of any value, a transformer rating so expressed should mean the same to everyone. To further a consistent use of symbols, both NEMA and USA Standards have been established to recommend a standard transformer "shorthand."

Four symbols are used: the dash (—), the slant (/), the X and the Y. In general terms, their uses are as follows:

Dash (—) Used to separate the voltage ratings of separate windings in a specific transformer.

Slant (/) Used to separate voltages to be applied to or obtained from the same winding. The slant may be used to designate voltages derived by taps or by line-to-neutral connections.

X—Used to designate separate voltages obtainable by reconnection of the coils of a winding in series or multiple combinations, but not for three-wire operation.

Y—Used to designate a winding that is wye-connected. The absence of this symbol in a three-phase transformer rating indicates that the winding is delta-connected.

Selection of Proper Plant Voltage Levels

The selection of system voltages in an industrial plant is, broadly speaking, an economic problem. However, a determination based on strict economic analysis may, in practice, be modified by plant or industry standardization, availability of equipment and construction materials and other factors. The economic analysis will take into consideration:

(a) Class of service available from supplier.

(b) Total size of the installation.

(c) Planning for future growth.

(d) Characteristics of the equipment supplied.

(e) Density of the load.

(f) Safety considerations and qualifications of personnel available for operation and maintenance.

(g) Whether the installation is an extension or reconstruction of an existing plant, or whether it is a completely new, isolated installation.

For an extension to an existing plant, the principal decision to be made will be whether existing voltages can be used satisfactorily in the enlarged plant or whether in the interest of long-range economy, a different (usually higher) voltage should be boldly selected for the new equipment. In the latter case, there will be the temporary disadvantage of operating two different systems, either superimposed in the same building or separated in different buildings, the latter being the least objectionable. The superseded system may, in the future, become a small part of the total and ultimately disappear as processes change, as machines are moved about, and as motors are rewound.

There are several factors having a tremendous influence on the over-all cost and selection of system voltage; these are: the feeder circuits, switchgear, system fault duty, circuit arrangements, total motor horsepower, and motor horsepower ratings. It is beyond the scope of this chapter to cover these. However, refer to Chapters I and X. Since, in various voltage classes, different factors have the most pronounced effect on voltage selection, the discussion of selection of voltage is divided into:

(1) Selection of voltages 600 volts or less (low voltage)

(2) Selection of voltages 601 to 34,500 volts (medium voltage)

(3) Selection of voltages above 34,500 volts (high voltage)

Selection of Voltages 600 Volts or Less

In most industrial plants, the majority of loads are integral horsepower polyphase motors and welders which are most suitable for operation on systems 600 volts or less. The choice of nominal system voltages in this class for serving these loads is 208, 240, 480 (or 480Y/277), or 600 volts. These are compared in Figure 2.3.

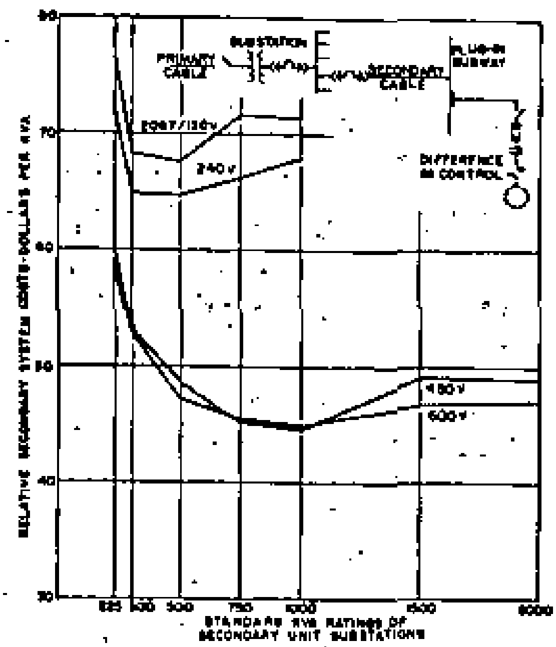


Figure 2.3
Curve showing the approximate installed costs of 208-, 240-, 480- and 600-volt radial secondary systems

A brief comparison of these low-voltage systems follows:

480 versus 600-Volt Systems

Although 600-volt load-center systems cost about two to seven percent less (See Figure 2.3) than 480-volt load-center systems, they have decreased in popularity primarily due to the lack of availability of standard 550 and 575-volt utilization equipment from manufacturers' and distributors' stocks in the United States. This was brought out forcibly during World War II when the percentage of standard 550-volt induction motors decreased from 11 to 4 percent of the total standard induction motors made.

When ordering machine tools or other utilization equipment with considerable electric control circuits, it is often difficult to obtain 575 (or 550)-volt equipment, particularly on short shipment. Pumps and other equipment which are stocked by the manufacturers with motors already mounted are generally stocked 230 (or 220) or 460 (or 440)-volt ratings and not with 575 (or 550)-volt ratings.

Availability of utilization equipment is the only major problem when choosing between 600-volt and 480-volt systems. Today, 600-volt systems are limited primarily to expansion of those plants which already operate at 600 volts or to some textile plants where most motors are of special design and, thus, are not widely available from manufacturers' stocks.

Another advantage of the 480-volt over the 600-volt system is the possibility of using 480Y/277-volt distribution with 277-volt fluorescent lighting.

480 versus 240-Volt Systems

Economically speaking, there is seldom any reason for selecting 240 volts instead of 480 volts. Load-center systems at 240 volts cost from 25 to 50 percent more (See Figure 2.3) than 480-volt load-center systems. Lower-voltage systems cost more because there is more current per kVA to be carried, thereby increasing the size of the circuit breakers and conductors required.

Generally 240-volt systems have higher losses and higher percentage voltage drop than 480-volt systems. If enough copper is used in the 240-volt feeders, the losses and percentage voltage drop can be more comparable to those in 480-volt systems, but in practice this is seldom done.

Some industries, where there is considerable dampness such as in dairies and slaughterhouses, have often selected 240 volts because it is felt to be safer than 480 volts. Operating records show that the biggest factor in safety is to properly and securely ground all non-current-carrying parts so that insulation breakdowns cannot place dangerous potentials on the non-current-carrying parts. When working on circuit conductors while energized, there is a greater chance for injury from electric shock with higher potentials to ground or phase-to-phase. However, any voltage above 50 volts can be lethal and, therefore, the only safe way to handle these circuits in damp or other locations is to enclose the carrying conductors in securely and properly grounded metal enclosures and to work on current-carrying parts only when they are deenergized.

In areas with the load predominantly electric furnaces, 240 volts may be most advantageous. This is due to the limitation of voltage which may be applied to these furnaces. In general, furnaces are large spot loads and cover only a small portion of the area of the plant. These furnaces, therefore, may be supplied by a separate load-center substation stepping down to 240 volts for the furnace only and the rest of the load supplied at 480 volts. It is seldom economical to use 240 volts for general distribution in a plant even though a sizeable portion of the total kW load may be 240-volt furnaces.

Where 208Y/120-Volt Systems Are Applicable

There are certain areas where 208Y/120-volt systems are more economical than 480-volt systems because the types of utilization equipment involved must be operated at 120 volts. When such utilization equipment constitutes a major portion of the load (more than about 50 to 65 percent of the total load), 208Y/120-volt systems may be more economical than 480-volt systems.

Typical of such loads is that of a clothing manufacturing establishment where practically all of the power is utilized by motor-operated hand shears. Other areas in which 208Y/120 volts may be desirable are on assembly benches where small components are assembled and small portable tools such as soldering irons, electric hand drills, electric nut tighteners, etc., are used. A typical case would be a small electronic equipment assembly line. Again, the choice of the lower voltage is primarily based on the desire to limit the voltage in the hand tools to 120 volts. In these assembly areas, most of the power is utilized at this low voltage.

General Practice—Systems of 600 Volts and Less

As general practice, 480 volts is most widely used and recommended by engineers as a general secondary distribution voltage in industrial plants. Where a lower secondary system voltage is required 208Y/120 volts may be used, since it provides 120 volts for incandescent lamps, hand tools, etc. These two voltages should cover practically all requirements for secondary voltages for the modern industrial plant except for electric furnaces.

In factories where at least one-third to one-half the load can operate on 480-volt systems and the remainder of the load must operate at a lower voltage or where distances are greater than about 200 feet, 480-volt main distribution and small step-down transformer to 120 or 240 volts may be most economical.

One additional point which should be mentioned in connection with low-voltage distribution is the trend toward the 480Y/277-volt system. Such a system with the neutral readily available takes advantage of the savings inherent in the 480-volt system and, in addition, provides an economical method for supplying the lighting load. By extending the neutral circuit in the lighting feeders only, 277-volt fluorescent lighting can be distributed between the three phase conductors and neutral. The power load would be supplied at 480 volts from three-conductor, three-wire circuits. It is not necessary to extend the neutral circuit in the feeders supplying only power load.

Selection of Voltages for Systems of 601 Volts to 15 Kilovolts

Voltages in this class are used mainly for primary power distribution in industrial plants. All plants using a primary voltage employ voltages of this class except some of the very large chemical plants, steel mills, etc. The latter may employ subtransmission voltages above 15,000 volts.

When the utility voltage is below 15,000 volts, there is no problem of selecting the primary voltage.

Since the National Electrical Code permits 15,000 volts inside buildings, without special restrictions, there is generally no reason for transforming voltages of the order of 13,800 volts to, say, 2400 volts or 4160 volts for distribution through the building. The higher voltage can be carried to the load-center substations and there transformed to utilization voltage.

Above 15,000 volts, the National Electrical Code, Section 230-101 (h), states that service entrance conductors brought into a building must directly enter metal-enclosed switchgear or a transformer vault. Therefore, when the utility supply voltage is above 15,000 volts, transformation to some lower voltage is desirable both economically and technically for distributing the power through the plant to the load-center substations where it is stepped down to utilization voltage. (An exception to this is large steel mills, chemical plants, etc., having large widely-scattered loads.) The trend in the past few years has been toward selection of higher voltages to obtain greater economy and flexibility for expansion. Many studies have shown that either of two voltages will suffice in the majority of cases.

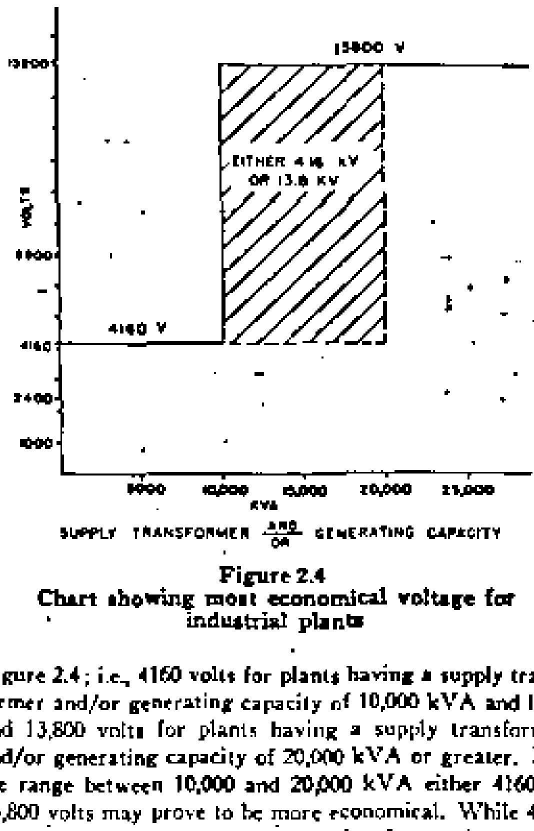


Figure 2.4
Chart showing most economical voltage for industrial plants

Figure 2.4; i.e., 4160 volts for plants having a supply transformer and/or generating capacity of 10,000 kVA and less, and 13,800 volts for plants having a supply transformer and/or generating capacity of 20,000 kVA or greater. For the range between 10,000 and 20,000 kVA either 4160 or 13,800 volts may prove to be more economical. While 4160 volts might be slightly less expensive for a 15,000 kVA plant, if the plant should happen to grow, then 13,800 volts would be more economical.

Where 2400 Volts is Particularly Applicable

In plants which are served at 2400 volts directly from the utility system, then, of course, it would be more economical to use 2400 volts directly and to place all motors rated 200 horsepower and above directly on the primary feeders. However, in these cases, most motors rated less than 200 horsepower should be operated on a 480-volt system, stepping down from the 2400-volt primary system. In some cases, there are existing 2400-volt systems in industrial plants, and it is often more economical to extend these at 2400 volts rather than changing to 4160 volts. However, it may be more desirable to extend it at some higher voltage like 13,800 volts rather than to extend the system at 2400 volts.

Where the primary voltage is above 5000 volts, 2400 volts is applicable to concentrated loads which supply motors rated 200 horsepower and above. In these cases, it is preferable to step down from the higher voltage to 2400 volts rather than to 4160 volts, if the capacity per 2400-volt bus is limited to less than about 7500 kVA and nearly all of this load is utilized at this bus directly by motors rated above 200 horsepower. For single loads larger than 7500 kVA per bus with motors above about 250 horsepower, it is often necessary to go to 4160 volts to enable the switchgear to handle the short-circuit currents available from such large buses. A typical application where 2400 volts would be most economical is a pumping station, in which the control may be of the fused combination type to give fast short-circuit protection or of the circuit-breaker type where the frequency of starting is not too great. If this preference is followed, it will be necessary to make a transformation for these large motors. The cost of the transformation is substantially the same whether it is made to 2400 volts or to 4160 volts. Thus, the power system cost is not a significant factor as all of the load is concentrated in one place. The 2300-volt motors and their starters are less expensive than 4000-volt motors and their starters in most cases.

The influence of motors on choice between 2400 and 4160 volts as the primary system voltage is shown in Figure 2.5.

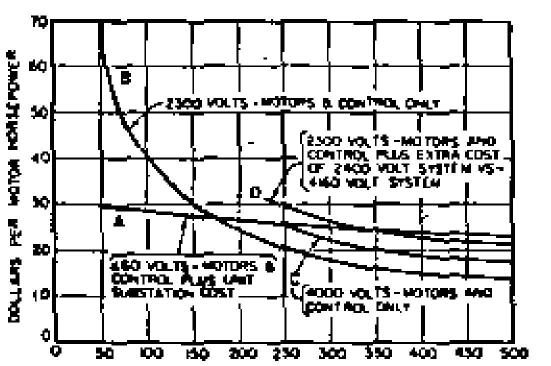


Figure 2.5
Approximate cost of induction motors and control and appropriate system costs as a function of motor horsepower

System Voltage Variation

An ideal electric power system is one which will supply constant frequency and voltage at rated nameplate value to every piece of apparatus in the system. In modern power systems, frequency is a minor problem. It is impractical to design a power system which will deliver absolutely constant rated nameplate voltage to every piece of apparatus. Since this cannot be attained, what are the proper limits of voltage variations in an industrial plant? This should be determined by the characteristics of the utilization apparatus.

Definitions

Voltage drop in a distribution system is the difference at any instant between the voltages at the source and utilization ends of a feeder, branch circuit, or transformer.

Voltage spread is the difference between the maximum and minimum voltages existing in any one voltage-class system under specified steady-state conditions.

Voltage regulation is a measure of the change in voltage between no load and full load in terms of the full-load voltage.

Percent Regulation =

$$\frac{(\text{no-load volts})-(\text{full-load volts})}{\text{full-load volts}} \times 100$$

Causes of Voltage Regulation

Voltage drop is caused by current flowing through an impedance such as a transformer, cable, reactor, or bus. The voltage regulation at the terminals of the utilization apparatus is caused by the regulation of the incoming supply voltage and the voltage drop in the power system within the industrial plant.

Let us examine a typical industrial plant. Figure 2.6 shows a simplified one-line diagram. Figure 2.7 shows the voltage profile for a particular set of conditions. Note that the no-load voltage is 490 volts. There is a 10-volt drop due to the spread in the primary system, in addition to the voltage drops in the various portions of the system. Note that the total spread is 30 volts, 20 of which is due to the regulation within the plant, so the normal operating voltage will be around 460 volts.

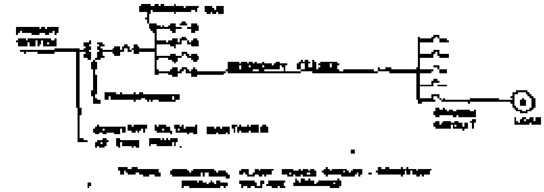


Figure 2.6
Simplified power system for studying voltage regulation

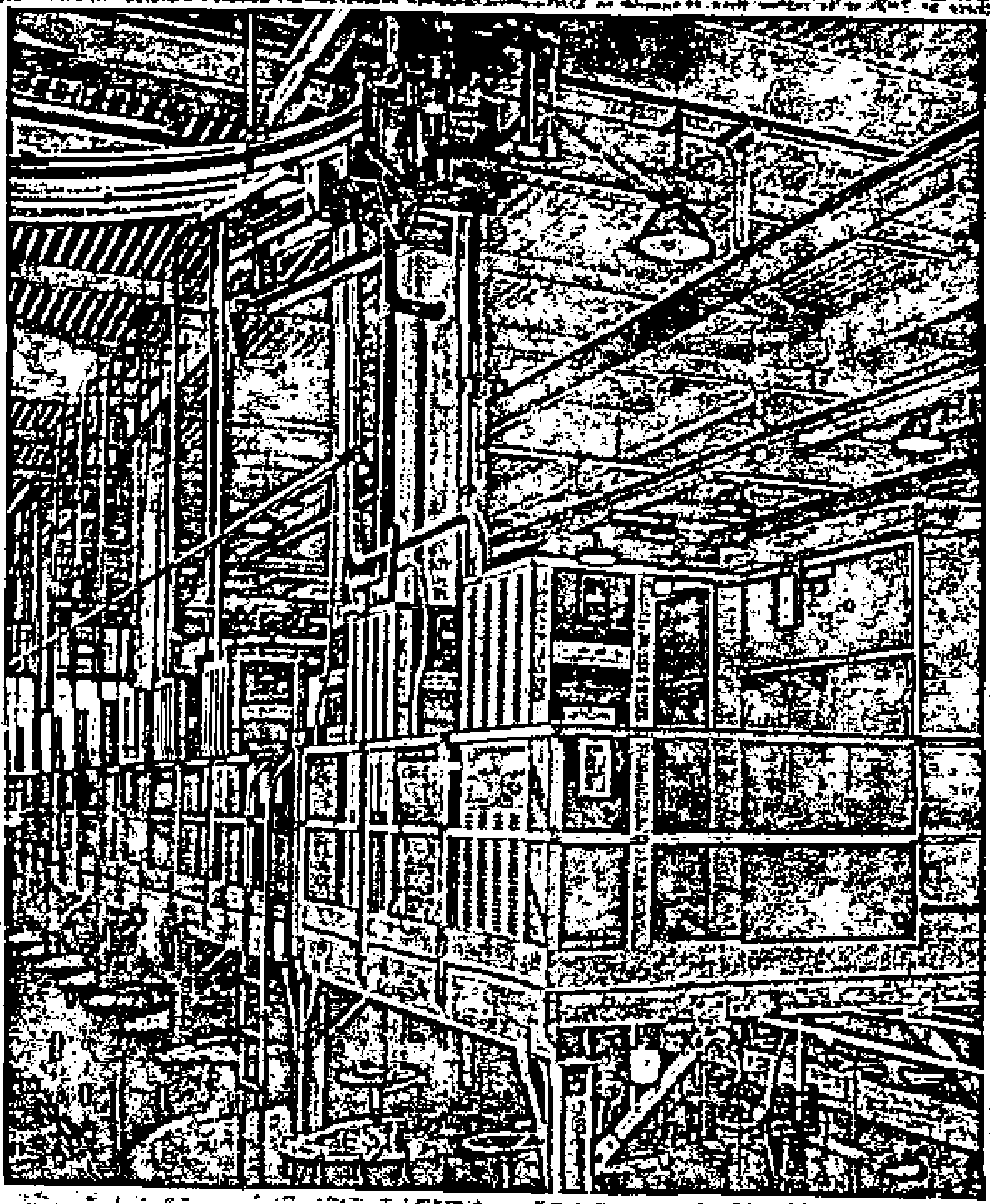


Figure 2.6a
A line-up of automatic induction voltage regulators to maintain precise voltage on critical plating lines

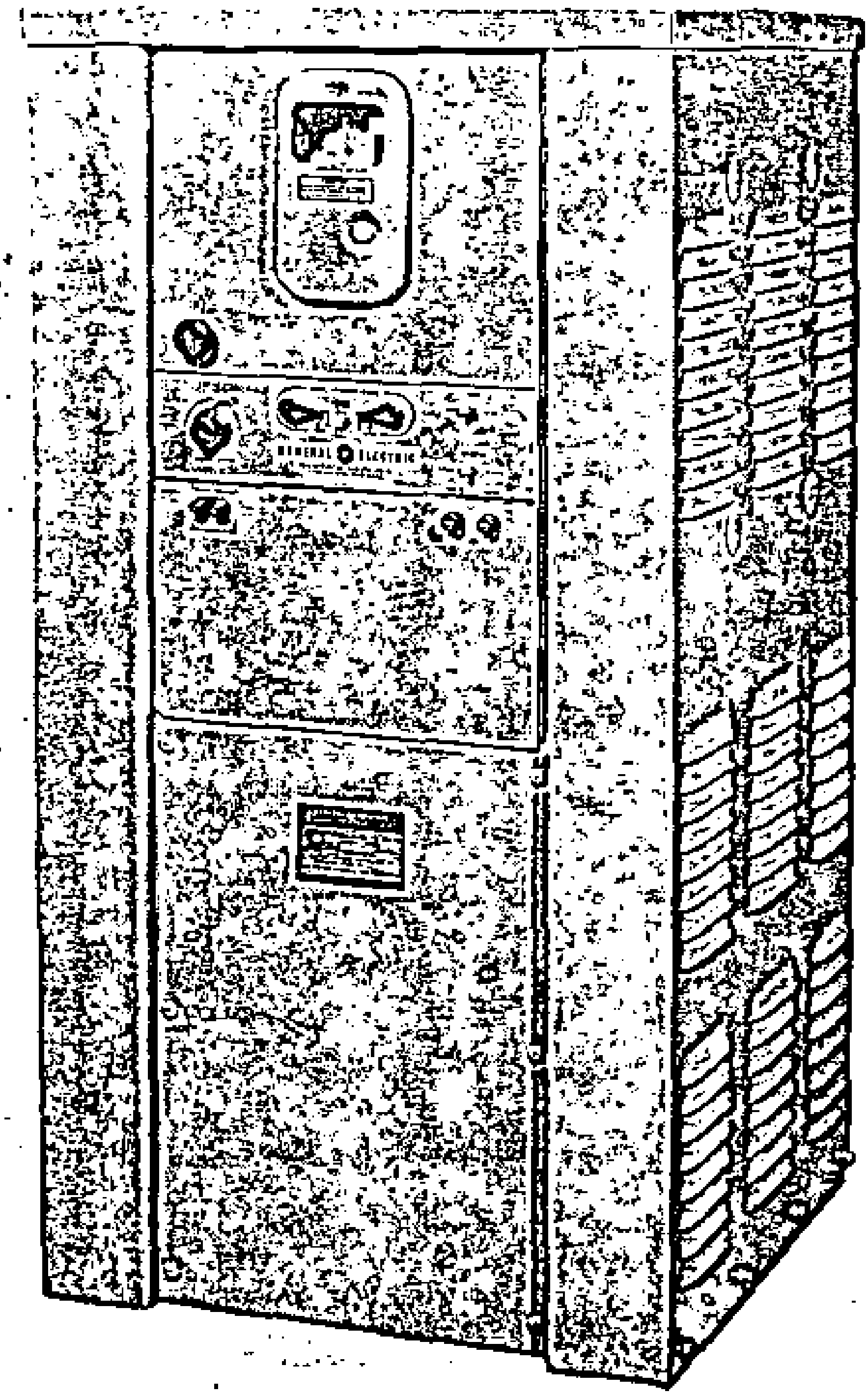


Figure 2.6b
A closeup view of one regulator of the type shown in Figure 2.6a

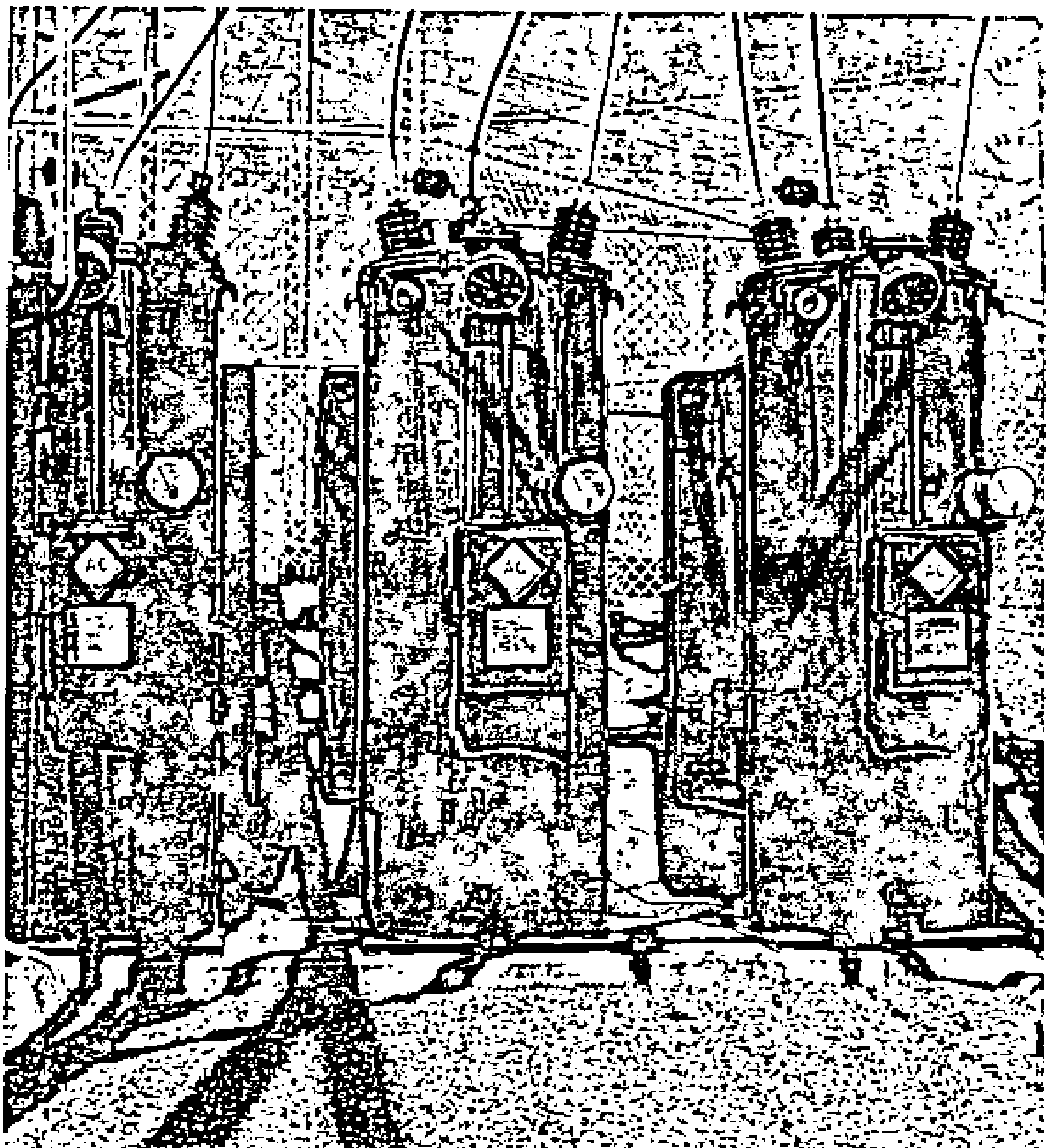


Figure 2.6c
Bank of outdoor voltage regulators for primary regulation

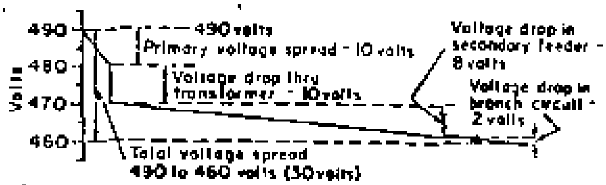


Figure 2.7
Voltage profile for a particular load condition for system of Figure 2.6

A primary system whose load cycle does not coincide with the load pattern in a plant may cause an excessive voltage spread. In such cases, automatic voltage regulation may be required.

Voltage profile charts, similar to Figure 2.7 are useful for studying voltage patterns and to locate causes or reasons for abnormal voltage conditions.

Effect of Voltage Spread on Utilization Equipment

General Effects—Whenever the voltage at the terminals of a utilization equipment varies from nameplate rating of the equipment, something is sacrificed either in life or performance of the equipment. The effect may be minor or serious, depending upon the characteristics of the equipment—how it is applied and the amount the voltage deviates from the equipment rating. NEMA Standards provide for certain tolerances which may be taken advantage of without seriously affecting the performance of the apparatus. However, with usage of electric power for precise operations, there is often a major sacrifice in production for voltage variations of considerably less than given in the NEMA Standards.

Induction Motors—The most common utilization equipments in industrial plants. The variation in characteristics as a function of voltage for the widely used induction motors are given in Table 2.13.

Table 2.13

General Effect of Voltage Variation on Induction Motor Characteristics

		Voltage Variation	
Characteristic	*Function of Voltage*	*90 Percent Voltage*	*110 Percent Voltage*
Starting and maximum running torque	$(\text{Voltage})^2$	Decreases 19%	Increase 21%
Synchronous Speed	Constant	No Change	No Change
Percent Slip	$1/(\text{Voltage})^2$	Increase 23%	Decrease 17%
Full-Load Speed	(Synchronous Speed-Slip)	Decrease 1½%	Increase 1%
*Efficiency**			
Full Load	—	Decrease 2%	Increase ½-1%
¾ Load	—	Practically No Change	Practically No Change
½ Load	—	Increase 1-2%	Decrease 1-2%
Power Factor			
Full Load	—	Increase 1%	Decrease 3%
¾ Load	—	Increase 2-3%	Decrease 4%
½ Load	—	Increase 4-5%	Decrease 5-6%
Full-Load Current	—	Increase 11%	Decrease 7%
Starting Current	Voltage	Decrease 10-12%	Increase 10-12%
Temperature Rise,* Full Load	—	Increase 6-7C	Decrease 1-2C
Maximum Overload Capacity	$(\text{Voltage})^2$	Decrease 19%	Increase 21%
Magnetic Noise—No Load in particular	—	Decrease Slightly	Increase Slightly

* This data applies to motors of over 25 horsepower.

The most significant effects of low voltage are reduction in starting torque and increased full-load temperature rise. The most significant effects of high voltage are increased torque, increased starting current, and decreased power factor. The increased torque may cause couplings to shear off or damage driven equipment. Increased starting current causes greater voltage drop and increases light flicker.

Synchronous Motors—The effect of voltage variation on the performance of synchronous motors is similar to that on induction motors. However, while the starting torque varies as the square of the line voltage, the maximum or pull-out torque varies directly with the line voltage. However, if a static direct-current source is used for field voltage, and this source is connected to the same line as the alternating-current motor terminals, then the pull-out torque varies as the square of the line voltage.

Incandescent Lamps—The light output and life of incandescent filament lamps are critically affected by the impressed voltage. A 10 percent reduction in lamp voltage results in a 30 percent reduction in light output. In other words, when the voltage is 10 percent low, the investment in the lighting system is working only at 70 percent efficiency—thus, 30 percent of the investment is lost. With an overvoltage of 10 percent, the lamp life is reduced to less than 1/3—thus, lamp replacement costs are three times as great as at normal voltage.

Fluorescent Lamps—Fluorescent lamps, unlike the incandescent lamp, operate satisfactorily over a rather wide voltage spread. In general 1 percent variation in line voltage will change the lumen output only about 1 percent. The life of fluorescent lamps is affected less by circuit voltage variation than incandescent lamps.

Mercury Lamps—In general, the lamp light output will decrease about 30 percent for every 10 percent decrease in terminal voltage. The mercury lamps require between 4 and 8 minutes to come up to full brilliancy due to vaporization of the mercury. Upon excessive low voltage (about 20 percent under voltage), the mercury arc will be extinguished and the lamp cannot be restarted until the mercury cools. This time interval is again between 4 and 8 minutes. This is true of all lamps which do not have special cooling controls. The lamp life is interrelated with the number of lamp starts. If low voltage conditions require repeated starting, then lamp life will be affected accordingly. Excessive high voltage raises the arc temperature which could damage the glass enclosure when the temperature approaches the glass softening point.

Infrared Heating Processes—Although the filaments in the lamps used in these installations are of the resistance type, the energy output does not vary with the square of the voltage because the resistance varies at the same time. The energy output does vary roughly as some power of the voltage slightly less than the square, however. Voltage variations can produce unwanted changes in the process heat available unless thermostatic control or other regulating means is used.

Resistance Heating Devices—The energy input and, therefore, the heat output of resistance heaters varies, in general, with the square of the impressed voltage. Thus, a 10 percent drop in voltage will cause a drop of 19 percent in heat output. This, however, holds true only for an operating range over which the resistance remains constant.

Electronic Equipment—The current-carrying ability or emission of all electron tubes is affected seriously by voltage deviation from rating. The cathode life curve indicates that the life is reduced by half for each 5 percent increase in cathode voltage. This is due to the reduced life of the heater element and to the higher rate of evaporation of the active material from the surface of the cathode. It is extremely important that the cathode voltage be kept up near rating on electron tubes for satisfactory service. In many cases, this will necessitate a regulated power source. This may be located at or within the equipment, and often consists of a regulating transformer having constant output voltage.

Capacitors—The kilovar output of capacitors varies with the square of the impressed voltage. A drop of 10 percent in the supply voltage, therefore, reduces the kilovars by 19 percent and where the user has made a sizeable investment in capacitors for power factor improvement, he loses the benefit of almost 20 percent of this investment.

Solenoid-Operated Devices—The pull of alternating-current solenoids varies approximately as the square of the voltage. In general, solenoids are designed liberally and are designed to operate satisfactorily on 10 percent overvoltage and 15 percent undervoltage.

Improvement of Voltage Conditions

If voltage conditions must be improved, the following are suggested lines of consideration.

Changing System Layout or Circuit Constants

Since the percent voltage drop varies as the square of the voltage, higher system voltage will reduce the drop. In other words, use the load-center principle of power distribution.

Since voltage drop is affected by current and impedance, a reduction of these will reduce the drop. Some suggestions are:

1. Use closely-spaced conductors, use cable instead of widely separated conductors often used for open wiring.
2. Use low-voltage drop busway of multibar interleaved construction. Interleaved construction makes busway exhibit low-voltage-drop properties.
3. In some cases, two smaller cables in parallel may have lower impedance than one large cable.
4. Use lower impedance transformers. High impedance transformers reduce short-circuit currents, but increase voltage drop.
5. Keep low-voltage feeder lengths as short as possible.
6. Improve the operating power factor of a circuit.

Changing the Transformer Taps

Maintaining the voltage at an average desirable level requires the judicious use of transformer ratios and taps. Most modern transformers have taps in the windings to change the turn ratio. The taps do not materially affect the voltage drop through the transformer; they merely change the turn ratio, hence the no-load voltage ratio and, therefore, the voltage level. For example, a standard transformer rated 2400-480 volts may have four 2½ percent taps in the 2400-volt winding. The standard for these taps in transformers used in industrial systems is to have two 2½ percent taps above 2400 volts and two 2½ percent taps below 2400 volts. The no-load ratios of such a transformer would be:

2520—480 volts	5 percent above tap
2460—480 volts	2½ percent above tap
2400—480 volts	Normal rating tap
2340—480 volts	2½ percent below tap
2280—480 volts	5 percent below tap

These taps do not improve voltage regulation, but are only for changing the general voltage level in the plant. For example, if a 2400 to 480-volt transformer is connected to a system whose maximum voltage is 2520 volts, then the 2520 to 480-volt tap could be used which would provide a maximum of 480 volts at no load on the system. The tap selected in the transformer should be based upon maximum voltage conditions. *It should be selected so that the maximum voltage never goes above 480 volts.*

Use of Regulating Equipment

Even where the plant power system uses a load-center system to carry the power the greatest practical distance at high voltage, where impedances and currents have been kept to a minimum and low-voltage feeders are as short as possible, it may not be possible to achieve the required voltage spread due to too great a voltage variation in the primary supply system. In such cases, or where special conditions require unusually close voltage spread, voltage regulating equipment may be necessary.

If the power supply to a plant is subject to a voltage spread greater than 5 percent, it may be difficult to maintain the desired voltage even with the best designed power system. If the supply is at high voltage and must be stepped down to below 15 kV for distribution, regulation can be built into the transformer. This is accomplished by load tap changing. Usually, there are 32 (⅝ percent) steps for close voltage control over a range of plus or minus 10 percent. The control circuit for the load tap changing can be set to hold the bus voltage constant, or it may be compensated to raise the bus voltage slightly under load.

If power is supplied at less than 15 kV, and regulation of voltage is required, transformers with load-tap changing may be used for loads of 5000 kVA or more. For loads less than 5000 kVA, step or induction voltage regulators should be installed ahead of the plant primary bus to hold the bus voltage constant. Their standard range of voltage regulation is also plus or minus 10 percent.

In some cases, there is often reason to install regulating equipment at medium voltage for the entire plant load (for example, incoming power transformers provided with load-tap changing). In other cases, there are applications where feeder regulators should be based on individual low-voltage circuits. For example, the voltage spread may be satisfactory for most utilization equipment such as motors, but not good enough for incandescent lamps, electronic equipment, resistance heaters, etc. In such cases, the secondary feeder or individual loads at 600 volts or less may require regulation of voltage to obtain the desired performance. Air-cooled induction regulators may be used for this purpose.

Determination of Voltage Drops

Two kinds of voltage drops will be considered:

1. Steady-state voltage drops.
2. Short-time voltage drops due to motor starting.

Determination of Steady-State Voltage Drops

To determine the steady-state voltage drop the circuit impedance, circuit current and power factor of the current relative to some voltage must be known. In this discussion, the power factor will be that of the load. Two methods of determining voltage drops are described. The first is by calculation using either the sending or the receiving end voltage, the magnitude and power factor of the load current, and the total impedance of the circuit. The second method employs charts of voltage drop versus load for various circuit components.

For the purpose of ordinary use in industrial plant problems, the voltage drop calculated from the following approximate formula is sufficiently accurate where the slide rule is used.

$$E = E_s - E_r \quad (2.1)$$

$$E = E_s - I\,(R\cos\theta + X\sin\theta) \quad (2.2)$$

Nomenclature for formula

- E — Voltage drop or change in volts, line-to-neutral
- E_r — Line-to-neutral voltage at load end
- E_s — Line-to-neutral voltage at source end
- I — Line current
- R — Resistance of the circuit in ohms per phase
- X — Reactance of the circuit in ohms per phase
- θ — Angle whose cosine is the load power factor
- $\cos\theta$ — Load power factor in decimals
- $\sin\theta$ — Load reactive factor in decimals. By convention, $\sin\theta$ is positive for lagging power factor and negative for leading power factor.)

(The values of E, R, and X are on a line-to-neutral basis in accordance with accepted practice.)

The line-to-line drop of a three-phase system is $\sqrt{3}\,E$ and for a single-phase system $2E$.

There are available all sorts of charts, curves and other such data for obtaining voltage drops quickly; such references are especially handy when many checks must be made.

Some data with examples are included here:

Cable Voltage-Drop Charts

Voltage-drop curves, Figures 2.8 through 2.15 may be applied with reasonable accuracy to all types of copper conductor, paper-insulated, rubber-insulated, and varnish-cambric-insulated cable insulated for 600, 5000 and 15,000 volts. The voltage drop charts for single-conductor 600- and 5000-volt cables are plotted on the same chart because their associated voltage drops are practically equal. There are four sets of charts which combine the two voltage classes. The same type charts are plotted for 5kV and 15 kV cables with two voltage classes on a chart. Voltage drop for loads between 0.7 power factor lagging and unity is shown for this range of cable sizes for three-conductor and three single-conductor cables in either magnetic or non-magnetic conduit.

The charts are prepared for three-phase circuits. For single-phase circuits consisting of a two-conductor or two single cables in a conduit, the voltage drop measured line-to-line will be 15.5 percent higher than indicated in the charts.

Example: Assume that a 500-foot, three-conductor (non-shielded) interlocked armored, size 1/0 cable is the feeder for a three-phase, 440-volt, 60-cycle, 150-ampere, 0.8 power factor inductive load. Find voltage drop.

Solution: Enter chart, Figure 2.8, at 0.8 power factor and move upward to the 1/0 AWG cable curve. From the point of intersection, move to the left and read voltage drop as 2.4 volts per 10,000 ampere feet.

Ampere-feet in cable = 500 x 150 = 75,000

Actual voltage drop = (75,000/10,000) x 2.4 = 18.0

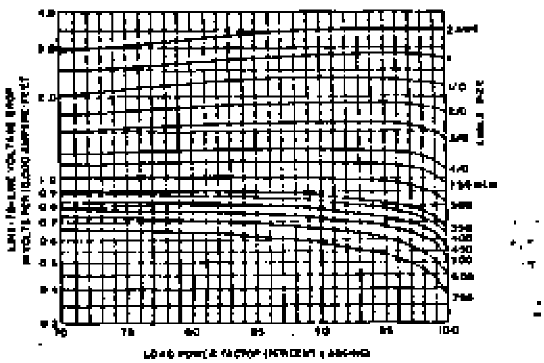


Figure 2.8
Voltage-drop curves for 3/c 600-volt and 5-kV cable (nonshielded) in magnetic duct or steel interlocked-armor cable

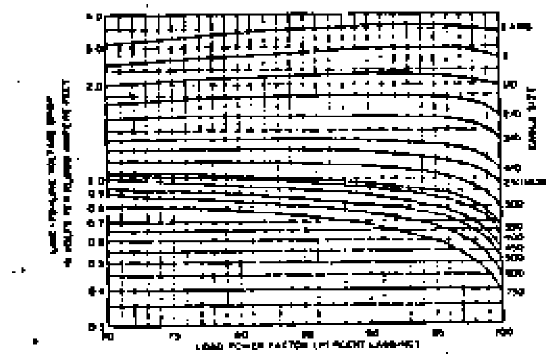


Figure 2.10
Voltage-drop curves for three 1/c 600-volt and 5-kV cables (nonshielded) in magnetic duct

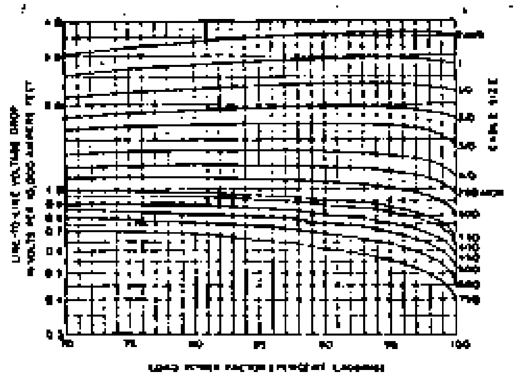


Figure 2.9
Voltage-drop curves for 3/c 5-kV and 15-kV cable (shielded) in magnetic duct or steel interlocked-armor cable

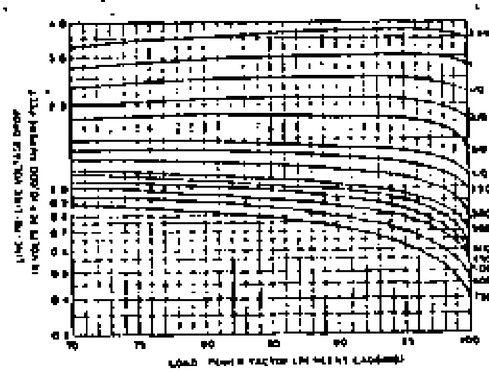


Figure 2.11
Voltage-drop curves for three 1/c 5-kV and 15-kV cables (shielded) in magnetic duct

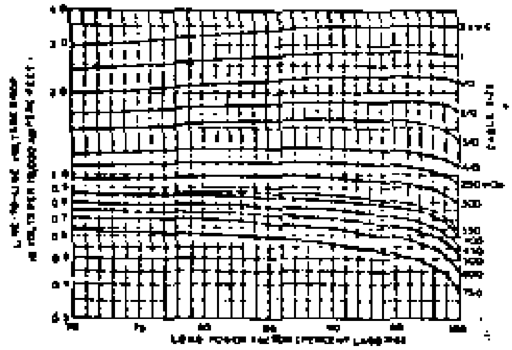


Figure 2.12
Voltage-drop curves for 3/c 600-volt and 5-kV cable (nonshielded) in nonmagnetic duct or aluminum interlocked armor

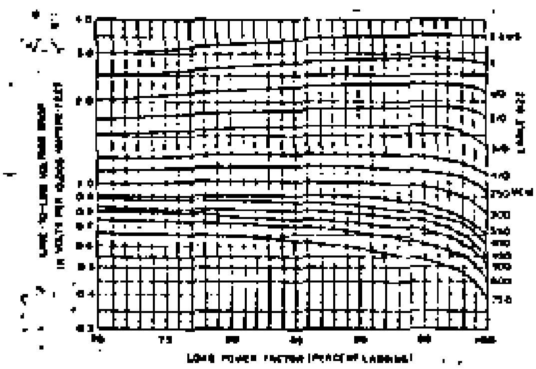


Figure 2.13
Voltage-drop curves for 3/c 5-kV and 15-kV cable (shielded) in nonmagnetic duct and aluminum interlocked armor

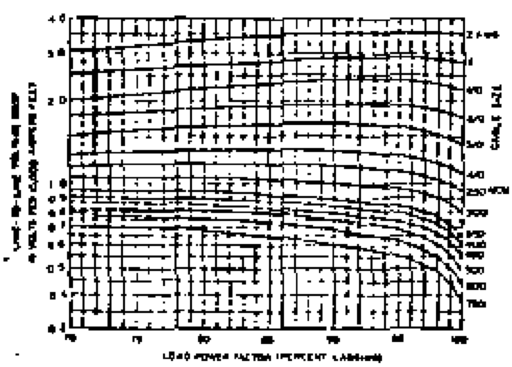


Figure 2.14
Voltage-drop curves for three 1/c 600-volt and 5-kV cables (nonshielded) in nonmagnetic duct

Busway Voltage-Drop Tables

Tables 2.14 and 2.15 are prepared for use in determining the voltage drop in busways. Although these are for a particular manufacturer, they are representative and may be used for approximate calculations.

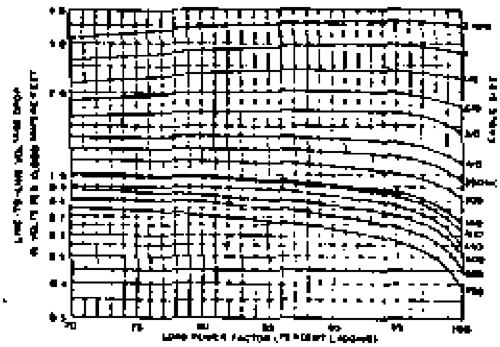


Figure 2.15
Voltage-drop curves for three 1/c 5-kV and 15-kV cables (shielded) in nonmagnetic duct

Transformer Voltage-Drop Charts

Voltage-drop curves for three 1/c 5-kV and 15-kV may be used to determine the approximate voltage drop in single-phase and three-phase, 60-hertz, liquid-filled, self-cooled transformers. The voltage drop through a single-phase transformer is found by entering the chart at a

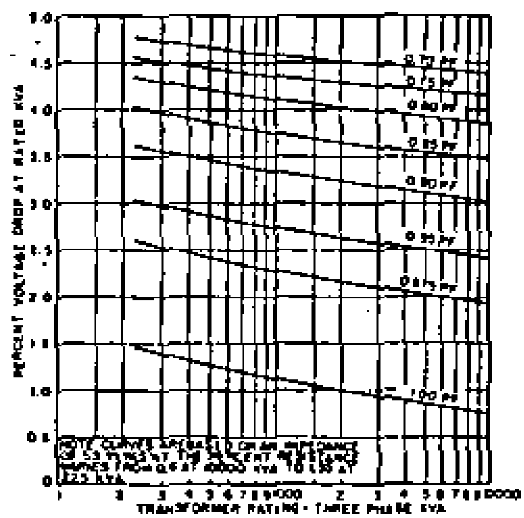


Figure 2.16
Transformer voltage drop curves for three-phase transformers, 225 to 10,000 kVA, 5 to 25 kV

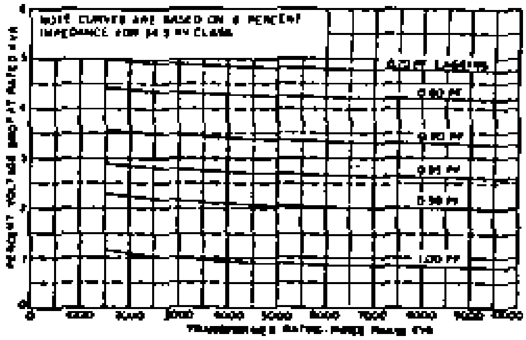


Figure 2.17
Transformer voltage drop curves or three-phase kVA ratings 1500 to 10,000 kVA, 34½-kV voltage class

Table 2.14

One Manufacturer's Voltage-Drop Values for Three-Phase Busways with Copper Bus Bars in Volts Per 100 Feet Line-to-Line at Rated Current with Entire Load at End. Divide Values by Two for Distributed Loading

Ampere Rating	*Power Factors* 20	30	40	50	60	70	80	90	95	100
Low-Voltage Drop Ventilated Feeder										
800	3.66	3.88	4.04	4.14	4.20	4.20	4.16	3.92	3.60	2.72
1000	1.84	2.06	2.22	2.40	2.54	2.64	2.72	2.70	2.62	2.30
1350	2.24	2.44	2.62	2.74	2.86	2.94	2.96	2.90	2.78	2.30
1600	1.88	2.10	2.30	2.46	2.62	2.74	2.82	2.84	2.76	2.42
2000	2.16	2.34	2.52	2.66	2.78	2.84	2.90	2.80	2.68	2.30
2500	2.04	2.18	2.38	2.48	2.62	2.68	2.72	2.62	2.50	2.14
3000	1.96	2.12	2.28	2.40	2.52	2.58	2.60	2.52	2.40	2.06
4000	2.18	2.36	2.54	2.68	2.80	2.80	2.90	2.80	2.68	2.28
5000	2.00	2.16	2.30	2.40	2.50	2.60	2.68	2.60	2.40	2.10
Low-Voltage Drop Ventilated Plug-in										
800	6.80	6.86	6.92	6.86	6.72	6.52	6.04	5.26	4.64	2.76
1000	2.26	2.56	2.70	2.86	2.96	3.00	3.00	2.92	2.80	2.28
1350	2.98	3.16	3.32	3.38	3.44	3.46	3.40	3.22	3.00	2.32
1600	2.28	2.44	2.62	2.78	2.90	3.00	2.96	2.94	2.88	2.44
2000	2.58	2.78	2.92	3.02	3.10	3.16	3.08	3.00	2.82	2.28
2500	2.32	2.50	2.66	2.76	2.86	2.90	2.86	2.78	2.66	2.18
3000	2.18	2.34	2.48	2.60	2.70	2.74	2.72	2.66	2.58	2.10
4000	2.42	2.56	2.76	2.88	3.00	3.02	3.00	2.96	2.84	2.36
5000	2.22	2.30	2.48	2.60	2.70	2.76	2.74	2.68	2.60	2.16
Plug-in										
225	2.82	2.94	3.04	3.12	3.18	3.18	3.10	2.86	2.70	2.04
400	4.94	5.08	5.16	5.18	5.16	5.02	4.98	4.30	3.94	2.64
600	5.24	5.34	5.40	5.40	5.36	5.00	4.50	2.10	3.62	2.92
800	5.06	5.12	5.16	5.06	5.00	4.74	4.50	3.84	3.32	1.94
1000	5.80	5.88	5.84	5.76	5.56	5.30	4.82	4.12	3.52	1.94
Trolley Busway										
100	1.2	1.38	1.58	1.74	1.80	2.06	2.20	2.30	2.30	2.18
Current-Limiting Ventilated										
1000	12.3	12.5	12.3	12.2	11.8	11.1	10.1	8.65	7.45	3.8
1350	15.5	15.6	15.4	15.3	14.7	13.9	12.6	10.7	9.2	4.7
1600	18.2	18.2	18.0	17.5	16.6	15.6	14.1	11.5	9.5	4.0
2000	20.4	20.3	20.0	19.4	18.4	17.0	13.9	12.1	10.1	3.8
2500	23.8	23.6	23.0	22.2	21.0	19.2	17.2	13.5	10.7	3.8
3000	26.0	26.2	25.8	24.8	23.4	21.5	19.1	15.1	12.0	4.0
4000	29.1	28.8	28.2	27.2	25.6	25.2	21.0	16.6	13.0	4.1

Table 2.15

One Manufacturer's Voltage-Drop Values for Three-Phase Busways with Aluminum Bus Bars in Volts Per 100 Feet Line-to-Line at Rated Current with Entire Load at End. Divide Values by Two for Distributed Loading

Ampere Rating	*Power Factors* 20	30	40	50	60	70	80	90	95	100
Low-Voltage Drop Ventilated Feeder										
800	1.68	1.96	2.20	2.46	2.68	2.88	3.04	3.12	3.14	2.90
1000	1.90	2.16	2.38	2.60	2.80	2.96	3.06	3.14	3.12	2.82
1350	1.88	2.20	2.48	2.74	3.02	3.24	3.44	3.56	3.58	2.38
1600	1.66	1.92	2.18	2.42	2.64	2.84	3.02	3.12	3.16	2.94
2000	1.82	2.06	2.30	2.50	2.70	2.88	3.02	3.10	3.04	2.80
2500	1.86	2.10	2.34	2.56	2.74	2.90	3.04	3.10	3.08	2.78
3000	1.76	2.06	2.26	2.52	2.68	2.86	2.98	3.06	3.04	2.78
4000	1.74	1.98	2.24	2.48	2.70	2.88	3.04	3.08	3.12	2.88
5000	1.72	1.98	2.20	2.42	2.62	2.80	2.92	3.02	3.02	2.80
Low-Voltage Drop Ventilated Plug-in										
800	2.12	2.38	2.58	2.80	3.00	3.16	3.26	3.30	3.24	2.90
1000	2.44	2.66	2.86	3.06	3.22	3.36	3.42	3.38	3.28	2.84
1350	2.22	2.48	2.78	3.00	3.24	3.46	3.60	3.68	3.64	3.30
1600	1.82	2.12	2.38	2.62	2.80	2.96	3.08	3.16	3.14	2.88
2000	2.00	2.30	2.50	2.76	2.92	3.06	3.12	3.18	3.12	2.80
2500	2.00	2.28	2.50	2.70	2.92	3.02	3.12	3.16	3.08	1.78
3000	1.98	2.26	2.44	2.66	2.86	3.00	3.10	3.18	3.14	2.82
4000	1.94	2.20	2.48	2.64	2.86	3.00	3.12	3.18	3.16	2.88
5000	1.90	2.16	2.38	2.58	2.76	2.92	3.06	3.10	3.08	2.52
Plug-in										
100	1.58	2.10	2.62	3.14	3.56	4.00	4.46	4.94	5.10	5.20
225	2.30	2.54	2.76	3.68	3.12	3.26	3.32	3.32	3.26	2.86
400	3.38	3.64	3.90	4.12	4.22	4.34	4.38	4.28	4.12	3.42
600	3.46	3.68	3.84	3.96	4.00	4.04	3.96	3.74	3.52	2.48
800	3.88	4.02	4.08	4.20	4.20	4.14	4.00	3.66	3.40	2.40
1000	3.30	3.48	3.62	3.72	3.78	3.80	3.72	3.50	3.30	2.50
Small Plug-in										
50	2.2	2.6	3.0	3.5	3.8	4.1	4.5	4.7	4.8	4.6
Current-Limiting Ventilated										
1000	12.3	12.3	12.1	11.8	11.2	10.9	9.5	8.0	6.6	3.1
1350	16.3	16.3	16.1	15.6	14.7	13.7	12.1	8.1	8.0	3.1
1600	18.0	17.9	17.7	17.0	16.1	14.9	13.4	10.7	8.6	3.3
2000	22.5	22.4	21.8	21.2	19.9	18.2	16.0	12.7	9.9	3.1
2500	25.0	24.6	23.9	23.1	21.7	19.9	17.5	13.7	10.8	3.0
3000	26.2	25.8	25.1	24.1	22.7	20.8	18.2	14.2	10.9	2.9
4000	31.4	31.0	30.2	28.8	27.4	24.8	21.5	16.5	12.7	2.9

Table 2.16
Comparison of Motor-Starting Methods*

Type of Starter (Settings given are he more common for each type)	$\left(\dfrac{\textit{Motor Terminal Voltage}}{\text{Line Voltage}}\right)$	$\left(\dfrac{\textit{Starting Torque}}{\text{Full-Voltage Starting Torque}}\right)$	$\left(\dfrac{\textit{Line Current}}{\text{Full-Voltage Starting Current}}\right)$
Full-voltage starter	1.0	1.0	1.0
Autotransformer			
80 percent tap	0.80	0.64	0.68
65 percent tap	0.65	0.42	0.46
50 percent tap	0.50	0.25	0.30
Resistor starter, single step (adjusted for motor voltage to be 80 percent of line voltage)	0.80	0.64	0.80
Reactor			
50 percent tap	0.50	0.25	0.50
45 percent tap	0.45	0.20	0.45
37.5 percent tap	0.375	0.14	0.375
Part-winding starter (low-speed motors only)			
75 percent winding	1.0	0.75	0.75
50 percent winding	1.0	0.50	0.50

*For a line voltage not equal to the motor rated voltage multiply all values in the first column by the ratio:

$$\frac{\text{Actual voltage}}{\text{Motor rated voltage}}$$

Multiply all values in the second column by the ratio:

$$\left(\frac{\text{Actual voltage}}{\text{Motor rated voltage}}\right)^2$$

and multiply all values in the last column by the ratio:

$$\frac{\text{Actual voltage}}{\text{Motor rated voltage}}$$

kva three times the rating of the single-phase transformer. Figure 2.16 covers transformers in the following ranges:

Single-phase

250—500 kVA, 8.6—15 kV Insulation Classes.
833—1250 kVA, 5—25 kV Insulation Classes.

Three-phase

225—750 kVA, 8.6—15 kV Insulation Classes.
1000—10,000 kVA, 5—25 kV Insulation Classes.

An example of the use of the chart is given below:

Example: Find voltage drop in a 2000 kVA, three-phase, 60-hertz transformer rated 4160—480 volts. The load is 1500 kVA at 0.85 power factor.

Solution: Enter the chart on the horizontal scale at 2000 kVA, extend a line vertically to its intersection with the 0.85 power-factor curve. Extend a line horizontally from this point to the left to its intersection with the vertical scale. This point on the vertical scale gives the percent voltage drop for rated load. Multiply this value by the ratio of actual load to rated load.

Percent drop at rated load = 3.67

$$\text{Percent drop at 1500 kVA} = 3.67 \times \frac{1500}{2000} = 2.75.$$

Actual voltage drop = 2.75 percent × 480 = 13.2 volts

Figure 2.21 applies to the 34.5-kV insulation class power transformer in ratings from 1500 kVA to 10,000 kVA. These curves can be used to determine voltage drop for transformers in the 46-kV and 69-kV insulation classes by using appropriate multipliers at all power factors except unity.

To correct for 46 kV, multiply the percent voltage drop obtained from the chart by 1.065 and for 69 kV, multiply by 1.15.

Effect of Motor Starting on Generators—Figure 2.18 shows the behavior of the voltage of a generator when an induction motor is started. Starting a synchronous motor has a similar effect up to the time of pull-in torque. The case used for this illustration utilizes a full-voltage starting device and the full-voltage motor starting kva is about 100 percent of the generator rating. It is assumed for curves A and B that the generator is provided with an automatic voltage regulator.

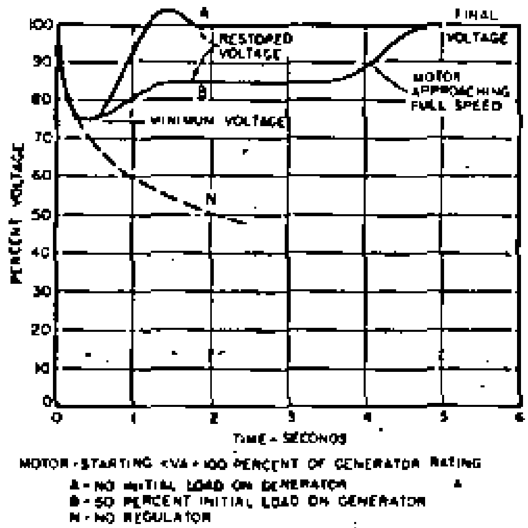
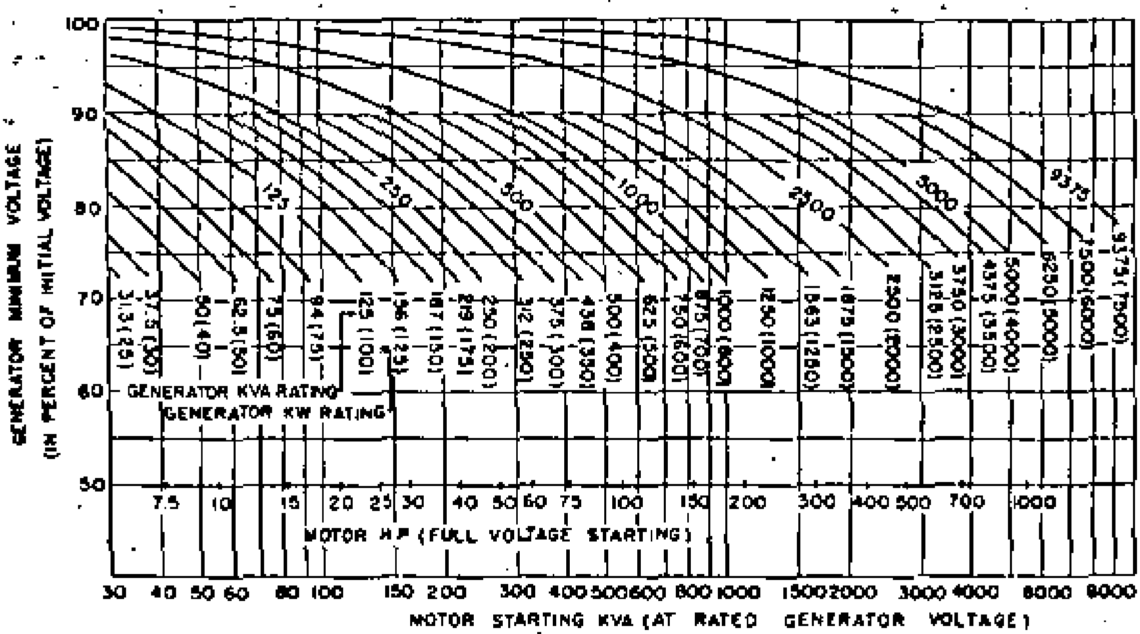


Figure 2.18
Typical generator voltage behavior due to starting a motor

The minimum voltage of the generator as shown in Figure 2.18 is an important quantity because it is a determining factor affecting undervoltage devices and contactors connected to the system and the stalling of motors running on the system. The curves of Figure 2.19 can be used for estimating the minimum voltage occurring at the terminals of a generator supply power to a motor being started.

Motor Starting Voltage Drop

It is characteristic of most alternating-current motors that the current which they draw on starting is much higher than their normal running current. Synchronous and squirrel-cage induction motors started on full voltage may draw a current as high as seven or eight times their full load running current. This sudden increase in the current drawn from the power system may result in excessive drop in voltage unless it is considered in the design of the system. The motor-starting kVA, imposed on the power-supply system, and the available motor torque are greatly affected by the method of starting used. Table 2.16 gives a comparison of several common methods.



NOTES:

(1) SCALE OF MOTOR-HP IS BASED ON STARTING CURRENT BEING EQUAL TO APPROXIMATELY 5.5 TIMES NORMAL

(2) IF THERE IS NO INITAL LOAD, VOLTAGE REGULATOR WILL RESTORE VOLTAGE TO 100 PER CENT AFTER DIP TO VALUES GIVEN BY CURVES

(3) INITIAL LOAD, IF ANY, IS ASSUMED TO BE CONSTANT-CURRENT TYPE

(4) GENERATOR CHARACTERISTICS ASSUMED AS FOLLOWS:

GENERATORS RATED 1000 KVA OR LESS

PERFORMANCE FACTOR, K = 1.0
TRANSIENT REACTANCE, X'd = 25 PERCENT
SYNCHRONOUS REACTANCE, Xd = 120 PER CENT

Figure 2.19
Minimum voltage of a generator due to starting a motor
(for estimating purposes only)

Effect of motor starting on distribution system—Frequently, in the case of purchased power, there are transformers and/or cables between the starting motor and the generator. Most of the drop in this case is within the distribution equipment. When all of the voltage drop is in this equipment the voltage falls immediately (because it is not influenced by a regulator as in the generator case) and does not recover until the motor approaches full speed. Since the transformer is usually the largest single impedance in the distribution system, and therefore takes almost all of the total drop. Figure 2.21 has been plotted in terms of motor starting kva which is drawn if rated transformer secondary voltage were maintained.

Reactor Voltage Drop

The approximate circuit-voltage drop introduced by a current-limiting reactor can be obtained from the curves plotted in Figure 2.20 when the load power factor and percent reactance are known. The percent reactance is normally given as part of the reactor rating.

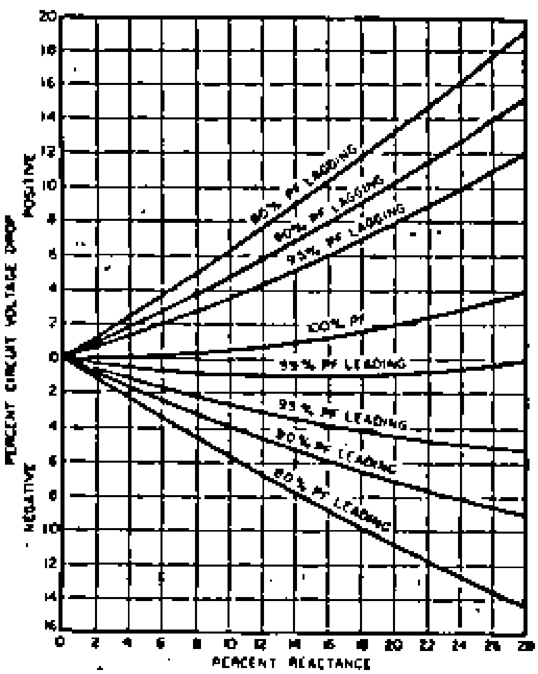


Figure 2.20
Voltage drop introduced by reactors

Light Flicker Problems

Although a change in voltage changes the output of lamps, slow changes in voltage such as due to normal load variations, generally do not affect the output enough to be noticeable or irritating. The effect of sudden changes in voltage repeated at short intervals is termed "light flicker", and flicker may become an annoying problem. In industrial plants, flicker is caused primarily by the following types of load: resistance welders, arc furnaces, fluctuating motor loads such as compressors, and punch presses, etc. The irritation caused by light flicker is a function of the amount of change in the light output, the frequency of change, the rate of change, the duration, and the acuity of the individual observer. The dip-limit curves of Figure 2.22 are a composite of several studies.

Fluorescent and mercury lamps are less subject to flicker during voltage changes than are incandescent lamps, provided that the lower limit of voltage remains above that value at which the fluorescent and mercury lamps will be extinguished.

The system should be designed to eliminate objectionable light flicker so as to adhere to the limits of Figure 2.22. Wider limits may be used under certain conditions without complaint from the personnel occupying the affected area.

Figure 2.23 has been included because it represents some up-to-date thinking on the part of electric utilities with regard to flicker limits.

One way to reduce light flicker is to separate electrically, the flicker-producing load from the lights. Details of methods for reducing flicker are beyond the scope of this publication.

Harmonics

Nature of Harmonics

Harmonic voltages and currents are becoming of increasing importance in industrial power systems, particularly with regard to their effect on fluorescent lighting, communication systems, capacitor installations, and, more recently, electronic process control systems. They are, for the most part, caused by nonlinear loads such as electric welders, arc furnaces, and rectifiers, transformer-magnetizing current, and, to a lesser extent, by synchronous and induction machines.

The harmonic content and magnitude existing in any power system is largely unpredictable and will have a wide variation at different parts of the same system. Consideration of the effects of harmonics in the design of an industrial power system is seldom practicable or necessary except where the following are involved:

(a) Mercury-arc or mechanical rectifiers

(b) Arc furnaces

(c) Large arc welders

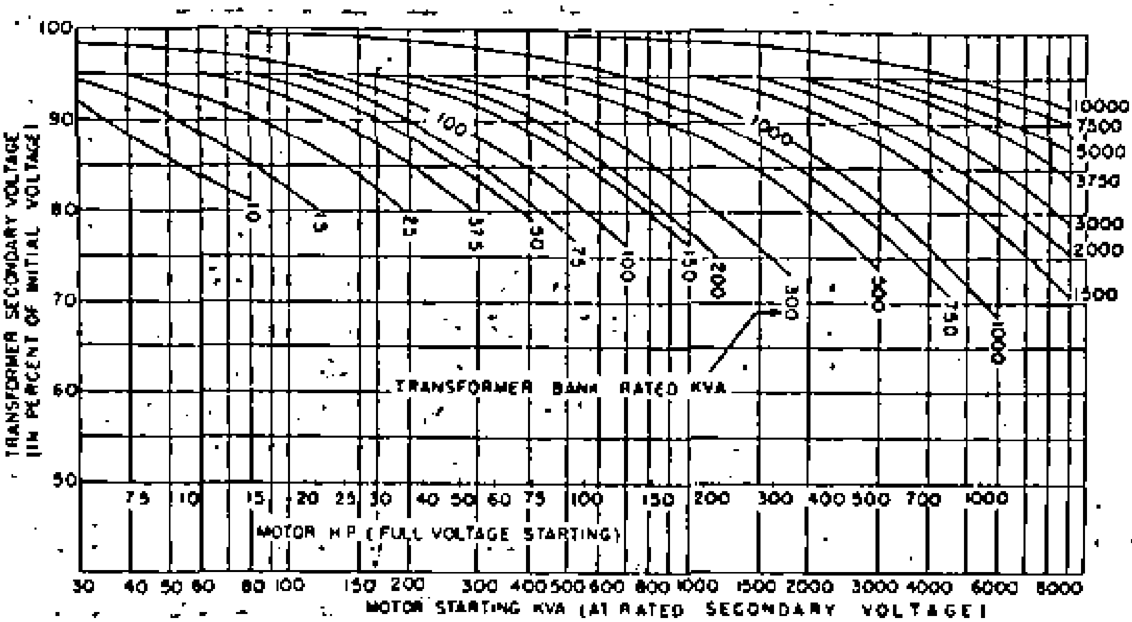
(d) Large fluorescent or mercury-vapor lighting systems

(e) Local generation, particularly if directly connected to an overhead utility distribution system at generator voltage

(f) Voltage stabilizers.

Arc Loads

Rectifiers, furnaces and welders are seldom troublesome except where capacitors are installed or where there is the possibility of inductive coupling to telephone circuits, either within the plant, or more likely, on the utility system. (Capacitors do not generate harmonics, but they may *reduce or increase* harmonics, depending upon the particular circumstances.)



NOTES

1. SCALE OF MOTOR HP BASED ON STARTING CURRENT BEING EQUAL TO APPROXIMATELY 5.5 TIMES NORMAL

2. SHORT-CIRCUIT KVA OF PRIMARY SUPPLY IS ASSUMED TO BE AS FOLLOWS:

BANK KVA	PRIMARAY SHORT-CIRCUIT KVA
10-300	25,000
500-1000	50,000
1500-3000	100,000
3750-10000	250,000

3. TRANSFORMER IMPEDANCES ARE ASSUMED TO BE AS FOLLOWS

BANK KVA	BANK IMPEDANCE
10-50	3%
75-150	4%
200-500	5%
750-2000	5.5%
3000-10000	6.0%

4. REPRESENTATIVE VALUES OF PRIMARY SYSTEM VOLTAGE DROP AS A FRACTION OF TOTAL DROP ARE AS FOLLOWS, FOR THE ASSUMED CONDITIONS

BANK KVA	SYSTEM DROP/TOTAL DROP
100	0.09
1000	.25
10000	.44

Figure 2.21
Voltage drop in a transformer due to starting a motor (for estimating purposes only)

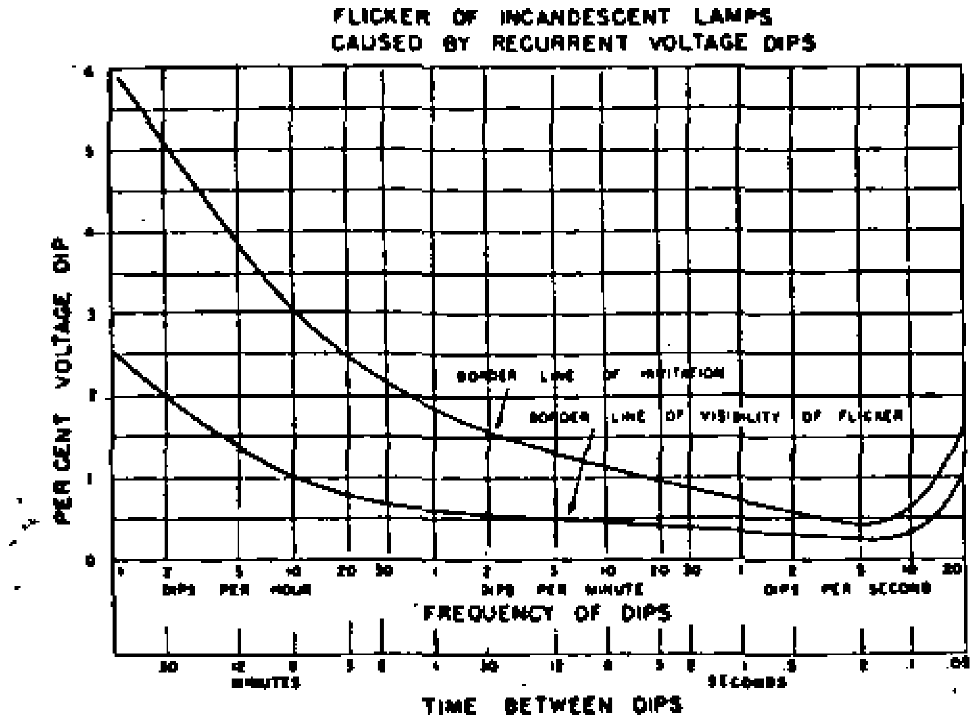


Figure 2.22 Flicker curve

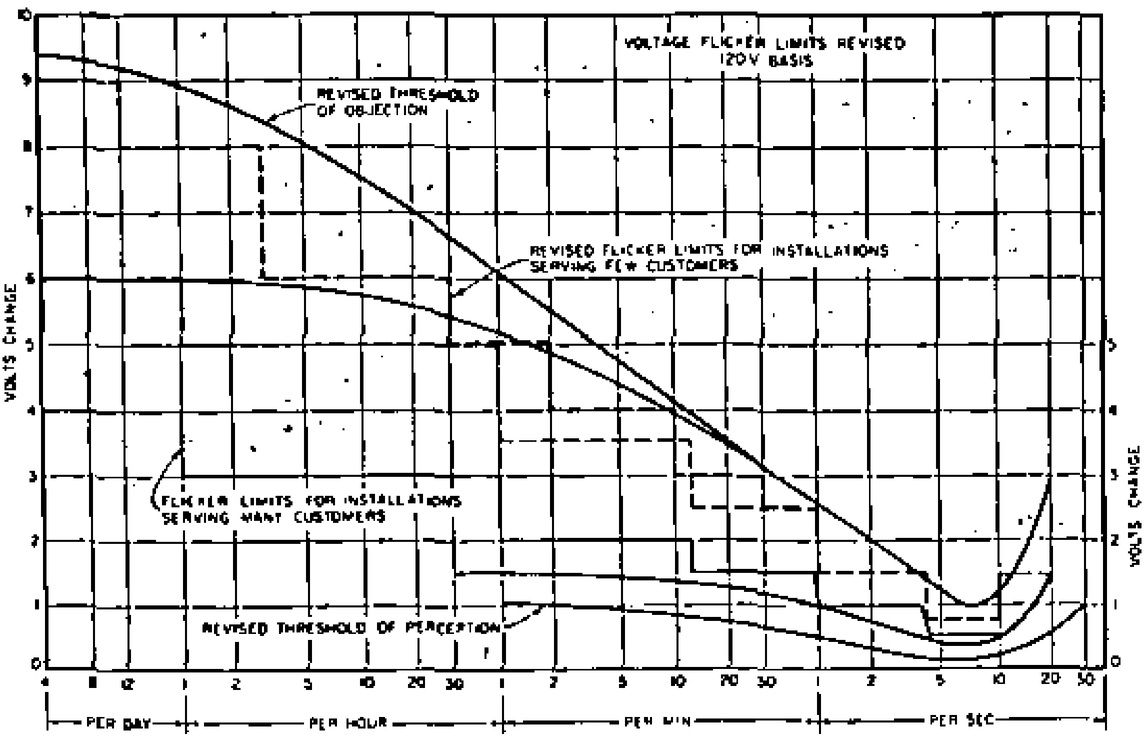


Figure 2.23 Flicker curves

NOTES:

1. These limits are for normal operation, except for services supplied by closely associated transformers (three or more banks), where these limits apply for first contingency only. For first contingency elsewhere, within the network area, allow 1½ times the above limits.

2. *GROUP I Limits* apply to residences, small apartment houses, stores and industrial establishments in general, as follows:

   (A) A 6-volt flicker is permissible for infrequently started appliances if the service supplies more than one customer.

   (B) An 8-volt flicker is permissible during the starting of air-conditioners or other infrequently started appliances, provided the service supplies only one customer.

   (C) A 9-volt flicker is permissible for fire pumps and other occasionally started equipment, and also for apparatus started not oftener than once in two hours if little or no lighting is involved.

3. *GROUP II Limits* apply to services supplying extensive amount of lighting and affecting relatively large groups of people, such as office buildings, hotels, theaters, large stores, large apartment buildings, etc. *GROUP II Limits* should also be used for equivalent 120-volt flicker in 2.4 and 4 kV primary feeders.

Where capacitors are installed for power-factor improvement on a power system with arc-producing loads and the system reactance happens to equal the capacitor reactance at one of the harmonic frequencies generated, the harmonic currents in the capacitors and the interconnecting circuits will be substantially higher than the harmonic current normally generated and may damage the capacitors through overheating. The resultant harmonic voltages on the distribution system may also cause local telephone interference. Possible remedial measures include the use of tuning inductances or changing the total kva of connected capacitors.

Lighting Systems

The arc discharge of fluorescent or mercury vapor lamps, combined with their associated capacitors and ballasts, are a source of harmonics, particularly the third. Experience shows that the third harmonic current may be as high as 30 percent of the fundamental in the phase conductors and 90 to 95 percent in the neutrals. Therefore, feeder circuits serving such lighting predominately should have the neutral conductor rated 100 percent of the lighting load.

Rotating Machines

It is commercially impracticable to build synchronous machines that generate a pure sine wave. Also, unbalanced supply voltages to induction machines will result in the generation of harmonics. While well designed generators and motors seldom cause harmonic problems in the average industrial power distribution system, it is well to consider the possibility when specifying generators, particularly where unbalanced loading or possible telephone interference from exposed transmission lines or cables is anticipated.

Direct-Current System Voltages

There has been no specific industry standardization of direct voltages. In modern plants where direct current is required for special purposes, 250 is the most common voltage. Representative manufacturers list 125-, 250-, 600- and 750-volt equipment as being available.

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CHAPTER III

SYSTEM PROTECTION

Purpose

This chapter discusses the importance of adequate system protection in industrial plants through the use of relays, breakers and fuses. The type of relays available and their particular characteristics, the basic principles of applying relays and relaying systems, and the minimum requirements of testing and maintaining relays to assure proper operation are included. Fuses and fuse applications are discussed in a later section of the chapter.

Industrial plants vary greatly in the complexity of their electric systems; the smallest having only a small radial system with fuse protection, and the largest having an intricate combination of buses, lines, and breakers requiring very complete relay protection. While most industrial users purchase all of their electric energy, there are many who generate part or all of their requirements, sometimes operating in parallel with local utility generation. Invariably the local utility requires fault protection at the service entrance to the industrial plant, and in all cases at an early stage of design, the engineer should consult with the utility regarding fault protection requirements.

The primary objective of an industrial plant is to produce consistently and economically. The ability to produce is dependent on the adequacy and continuity of the electrical service, and service interruptions can be evaluated directly in terms of lost production. Usually, the cost of lost production exceeds the cost of physical damage to equipment involved in a fault. Therefore, it is important to the industrial operation that the electric system be properly designed so that protective equipment can be applied in such a manner as to isolate faults quickly and with a minimum of service interruption.

In addition to production loss, system faults can result in injury to personnel and extensive property damage either directly or as a result of a fire or explosion. Also, a serious uncleared fault in a plant can jeopardize the utility operation and result in an area outage that would affect numerous other customers. These basic factors including production loss, personnel injury, property damage, and consideration for other users of the service should be included together with the engineering requirements in determining the fault protection that is required.

The losses associated with a service interruption vary widely in different types of industries. For example, a service interruption in a machining operation may mean only a delay in production, while a similar interruption in a chemical reduction plant can cause loss of material and production, costly cleanup operations and possible damage to production equipment. Other industries such as refineries, paper mills, textile mills, steel mills, and processing plants are affected similarly, but in varying degrees.

For some types of loads, such as paper, film, and textile fibre processes, and others involving complex automation, a momentary voltage dip can be as serious as a complete interruption. Others can tolerate a momentary interruption, but not a sustained one. Thus, the type of industrial operation has a major influence on the type of fault protection applied to the electric system.

Some industrial plants, because of their size or the nature of their operations, are able to maintain electrical engineering staffs capable of the design, installation and maintenance of an efficient protective system; while others will probably find it more economical to engage competent engineering advice and services from consultants. This work is specialized and often very complex, and it is neither safe nor fair to the operating engineer to expect him to do it as a sideline. Neither is it feasible for the equipment manufacturer or the local utility to maintain a sufficient force to provide this service.

Protection in an electric system is a form of insurance. It pays nothing as long as there is no fault or other emergency, but when a fault occurs it can be credited with reducing the extent and duration of the interruption, the hazards of property damage and personnel injury. Economically, the premium paid for this insurance must be balanced against the cost of repairs and lost production. The fact should not be overlooked that protection well integrated with the class of service desired may reduce capital investment by eliminating the need for equipment reserves in the industrial plant or source utility system.

Nature of the Problem

It would be neither practical nor economical to build a faultproof power system. Consequently, modern systems are designed with reasonable precautions to provide sufficient insulation, clearances, etc. but a certain number of faults must be tolerated during the life of the system. Even with the best design possible, materials tend to deteriorate, and the likelihood of faults increases with age. Every system is subject to short circuits and grounds that should be removed quickly, and a knowledge of the effect of faults on system voltages and currents is necessary to design suitable relay protection, since these quantities are used to actuate the relays.

The ordinary types of faults that protective relays must detect are three-phase, phase-to-phase, two-phase-to-ground, and single-phase-to-ground short circuits. There are two general classifications of three-phase alternate-current systems; first, isolated neutral or ungrounded systems, and second, grounded systems where the neutral is grounded either solidly or through a neutral impedance. Both classifications of systems are subject to the four types of faults, but the severity of those faults involving ground depends to a large extent on the method of grounding the system neutral and the magnitude of the neutral impedance.

Grounded and Ungrounded Systems

The general subject of system grounding is treated from the viewpoint of System Design in Chapter V, and it is necessary to observe here only the effect on basic relaying methods of the choice between a grounded and an ungrounded system.

In grounded systems, phase-to-ground faults produce currents of sufficient magnitude to be useful in the operation of neutral overcurrent relays, which automatically detect the fault, determine which feeder has faulted, and initiate the tripping of the correct circuit breakers to de-energize the faulted portion of the system without interruption of service to unfaulted portions. Moreover, if the system neutral is grounded through a well-chosen impedance, the value of the fault current can be made sufficient for dependable relaying, yet insufficient for extensive damage at the point of the fault.

In ungrounded systems, phase-to-ground faults produce relatively insignificant values of fault current. In a small isolated-neutral industrial installation, the ground fault current may be well under one ampere; while the largest plant, containing miles of cable to provide electrostatic capacitance to ground, may produce not more than 20 amperes of ground-fault current. These currents are not useful for the operation of overcurrent relaying to locate and remove such faults, not only because of the extreme sensitivity of the relays that would be required, but also because of the complexity of the flow pattern resulting from the fact that the "source" of the ground current is the distributed capacitance to ground of the unfaulted conductors. (See Figure 3.1.) It is possible, however, to provide a neutral voltage relay which will operate an alarm on the occurrence of a ground but which cannot provide any indication of its exact location.

The one advantage of an ungrounded system lies in the possibility of maintaining service on the entire system, including the faulted section, until the fault can be located and the equipment shut down for repair. Against this advantage must be balanced such disadvantages as the impossibility of relaying the fault automatically, the difficulty of locating the fault, the long-continued overstressing of the insulation of the unfaulted phases (1.73 times operating voltage in the case of solid grounds and perhaps much more in the case of arcing grounds), and the hazard of multiple ground faults and transient overvoltages.

Distortion of Phases During Faults

Balanced three-phase faults do not cause voltage distortion or current unbalance. The balanced relationships of voltages and currents are shown in Figure 3.2. Other

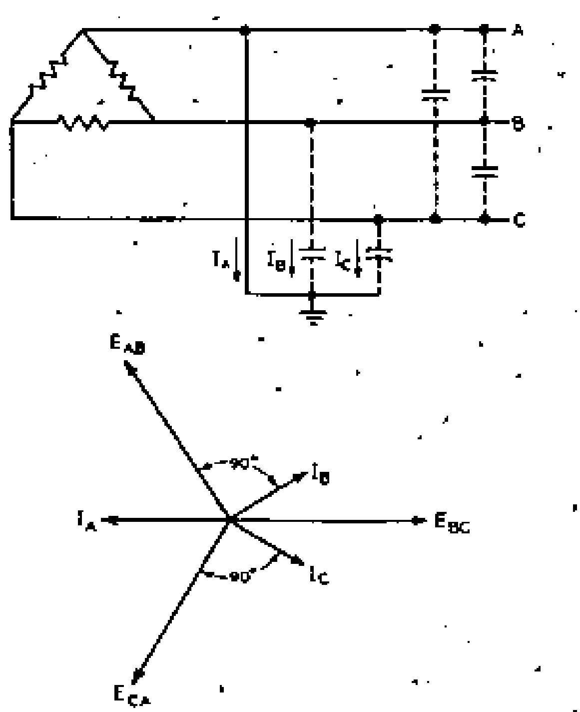


Figure 3.1

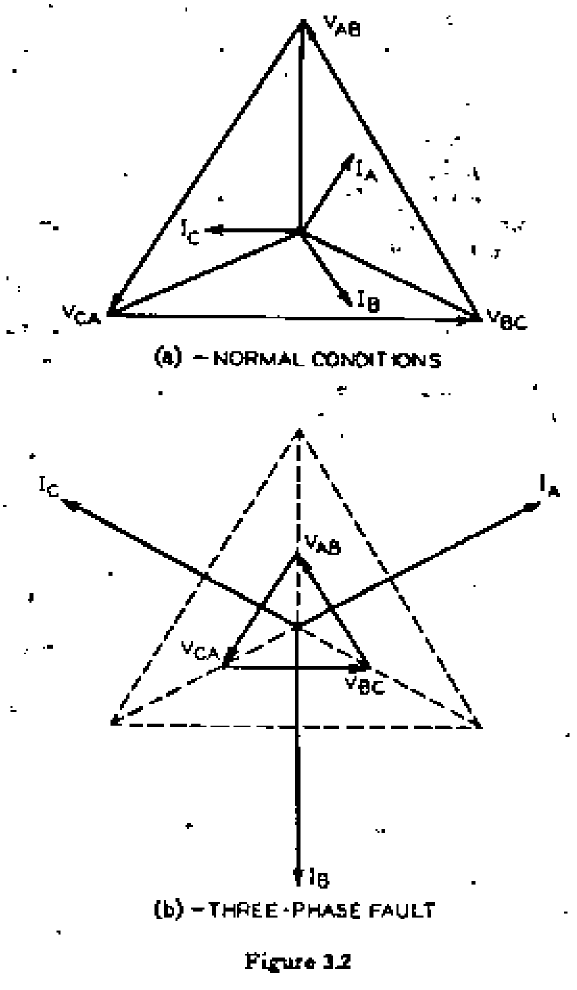
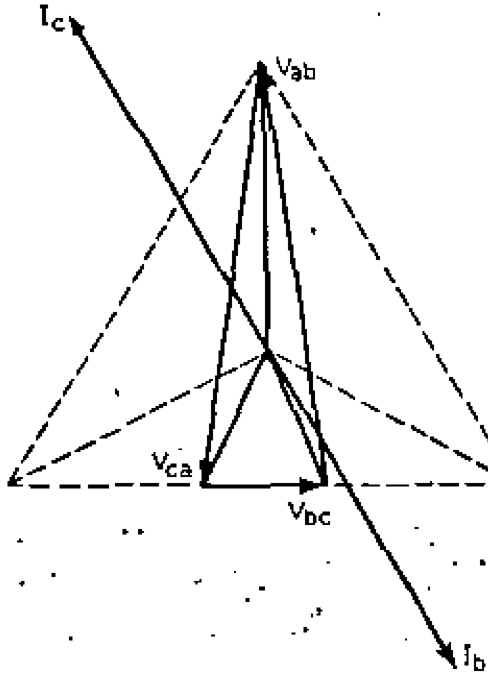
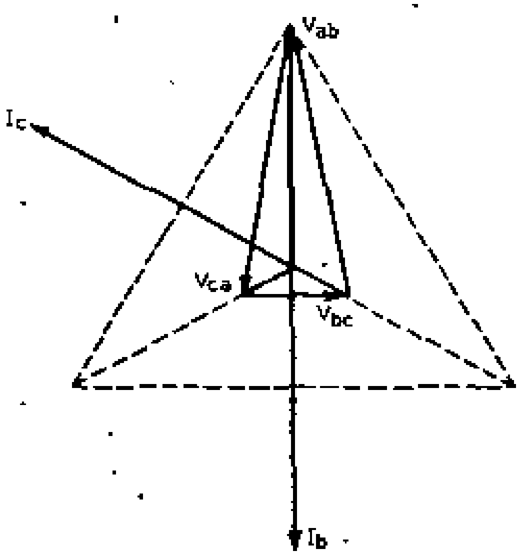


Figure 3.2



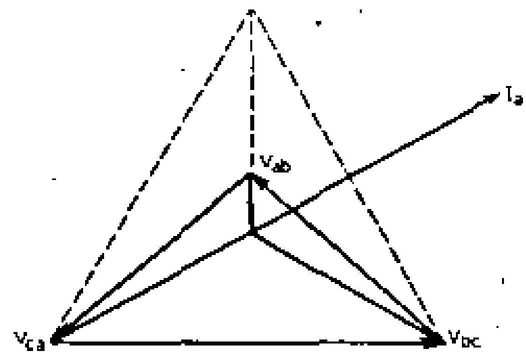
(a) – PHASE-TO-PHASE FAULT BETWEEN PHASES b AND c.

Figure 3.3a



(b) – TWO PHASE-TO-GROUND FAULT BETWEEN PHASES b AND c AND GROUND.

Figure 3.3b



(c) – PHASE-TO-GROUND FAULT BETWEEN PHASE a AND GROUND.

Figure 3.3c

types of faults, phase-to-phase, single-phase-to-ground, and two phase-to-ground, cause distorted voltages and unbalanced currents. The voltage distortion is greatest at the fault and minimum at the generator or source.

Currents and voltages which exist during a fault vary widely for different systems. They vary on a given system depending on type and location of the fault and the degree of system grounding. The vector diagrams of Figure 3.3 show voltage and current relations which exist for different types of faults on a solidly-grounded system in which the currents lag the voltages by 60 degrees. Load currents are not included.

These diagrams are typical of the fault conditions which cause relays to operate. The distortion can be greater or less than that shown, depending on the severity of the fault and its distance from the relay.

Practical Limits of Protection

When the industrial power system is in normal operation, all parts should have some form of automatic relay protection; however, some fault possibilities may be deliberately set aside as too improbable to justify the cost of specific protection. Before accepting a risk on this basis, however, the magnitude of the probable damage should be seriously considered; otherwise, too much protection might be provided for troubles which occurred frequently but caused only minor difficulties, while rare but serious causes of trouble might be neglected. For example, internal transformer failures rarely occur, but the consequences may be very serious since such faults can cause oil fires and endanger personnel.

Most systems have some flexibility in the manner in which circuits are connected together. The various possible arrangements should be considered in planning the relay system, so that some emergency operating condition is not left without protection. Some types of systems have so many possible operating combinations that relay protection cannot be applied to operate correctly for all combinations. In such cases, the operating connections for which the protection is inadequate should be avoided if possible.

Types and Characteristics of Protective Relays

General

Following is a brief description of the types and characteristics of relays most commonly used in industrial plant power systems for short-circuit protection.*

Overcurrent Relays

The most common relay for short-circuit protection of the industrial power system is the overcurrent relay. The overcurrent relays used in the industry are largely of the electromagnetic attraction, induction and solid state types. Relays with bimetallic elements are used for thermal overload protection which is outside the scope of this chapter. The simplest overcurrent relay using the electromagnetic attraction principle is the solenoid type. The basic elements of this relay are a solenoid wound around an iron core and steel plunger or armature which moves inside the solenoid and supports the contacts. Other electromagnetic attraction-type relays have hinged armatures or clappers of different shapes (Figure 3.4).

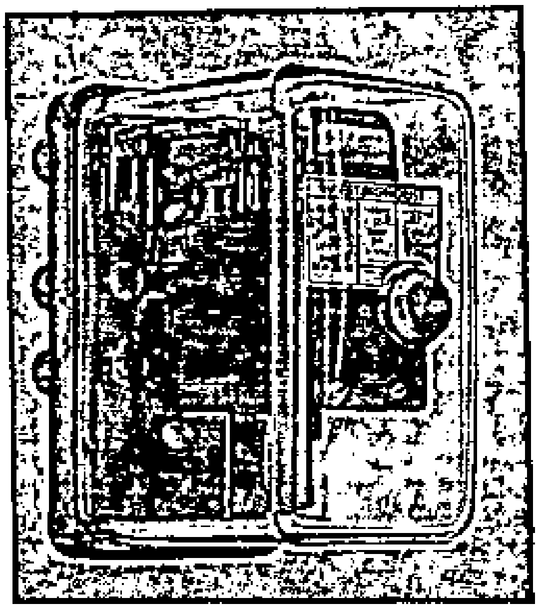


Figure 3.4

The construction of the induction-type overcurrent relay is similar to a watthour meter as it consists of an electromagnet and a movable armature which is usually a metal disc on a vertical shaft. The relay contacts are operated by the movable armature (Figure 3.5).

A recent addition to the relay family is the solid state type. These have the advantage of no moving parts.

All of the different types of overcurrent relays have in common adjustable current settings; and when the current through the relay coil exceeds a given setting the relay contacts close and initiate the breaker tripping operation. The relay usually receives current from the secondary of current transformers. In some cases, particularly at low voltages (600 volts and below) the relay coil may be a part of the conductor itself.

Overcurrent relays have provision for adjustment of current pickup. If this current operates the relay without intentional time delay the protection is called instantaneous overcurrent protection. When the overcurrent is of a transient nature such as may be caused by the starting of a motor or some sudden overload of brief duration, it is undesirable to open the breaker. For this reason most of the relays are equipped with a time delay which permits a current several times in excess of the relay setting to persist for a limited period of time. If a relay operates faster as current increases it is said to have an inverse-time characteristic. Overcurrent relays are available with inverse, very inverse, and extremely inverse time characteristics to fit the requirements of the particular application. There are also relays whose operating time after a certain current value is reached, is practically independent of the magnitude of current. These are definite minimum-time overcurrent relays with time-current characteristics as shown in Figure 3.6. Induction overcurrent relays have provision for variation of the time adjustment and permit change of operating time for a given current. This adjustment is called a time lever or time dial setting of the relay.

Figure 3.6 shows a family of time-current curves of a typical definite minimum-time overcurrent relay. It can be seen that, with increasing current values, the relay operating time will decrease in an inverse manner down to a certain minimum value. Figure 3.7 shows the characteristic curves of inverse, very inverse, and extremely inverse time relays when set on their minimum and maximum time-dial positions. It also shows the characteristic of the instantaneous element that is usually supplied in these relays.

Overcurrent Relays with Voltage Restraint or Voltage Control

A short circuit on an electric system is always accompanied by a sudden collapse of the voltage, whereas an overload will cause only a moderate voltage drop. Therefore a voltage-restrained or voltage-controlled overcurrent relay is able to distinguish between overload and fault conditions. A voltage-restrained overcurrent relay is subject to two opposing torques, an operating torque due to current and a restraining torque due to voltage. As such, the overcurrent required to operate the relay is higher at normal voltage than it is at reduced voltages. A voltage-controlled overcurrent relay operates by virtue of current torque only, the application of which is controlled by a voltage relay set to operate at some predetermined value of voltage. Such relays are useful etc, when it is desirable to be able to set the relay close to load current and still be sure that it will not operate incorrectly on load current.

Ground Relays

Where the industrial power system neutral is grounded and ground-fault current can flow in the conductors a

* Specific definitions of relay types and terms may be found in USA Standard C37.1.

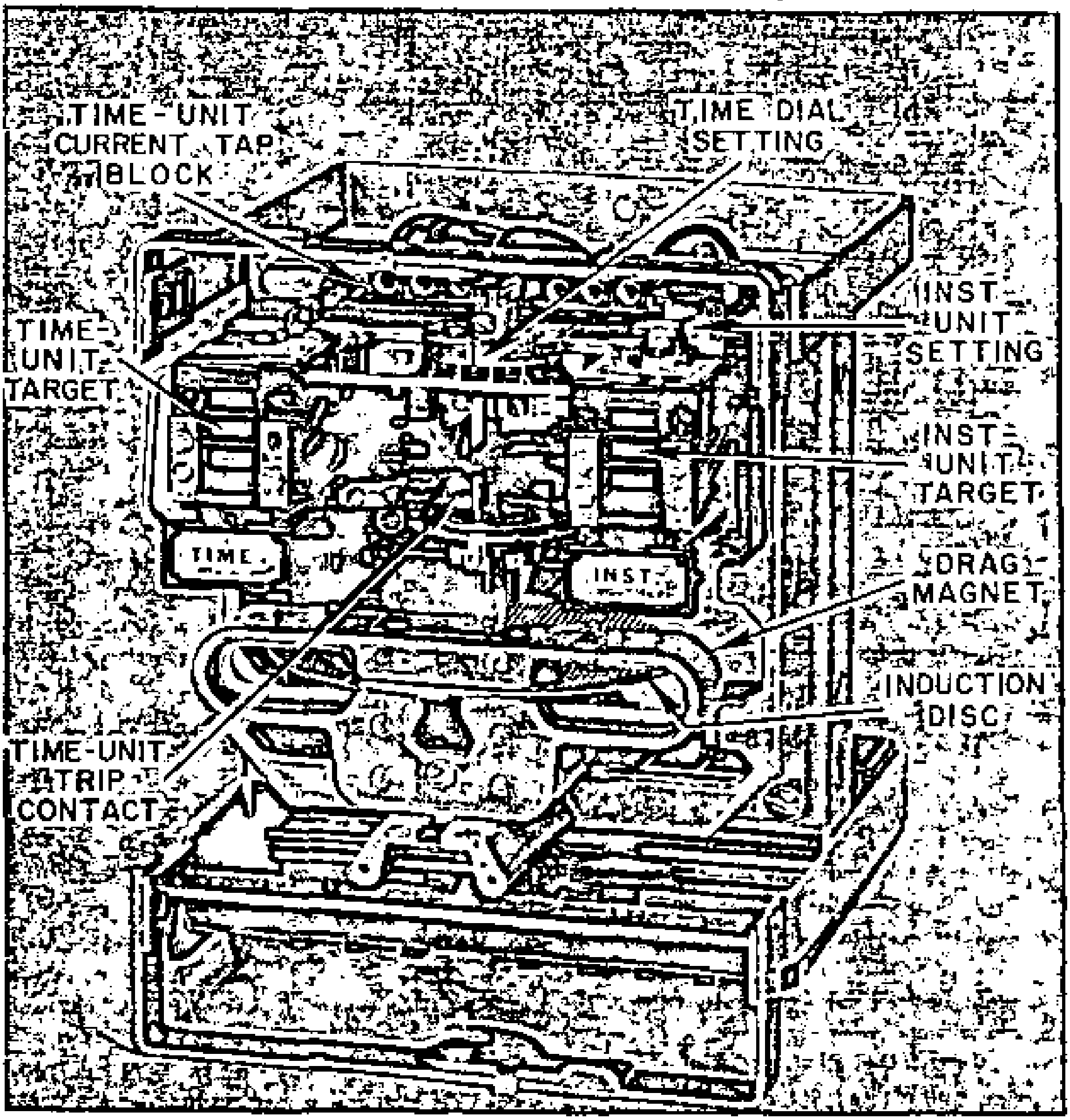


Figure 3.5
Typical time-overcurrent relay as used to monitor industrial plant power circuits

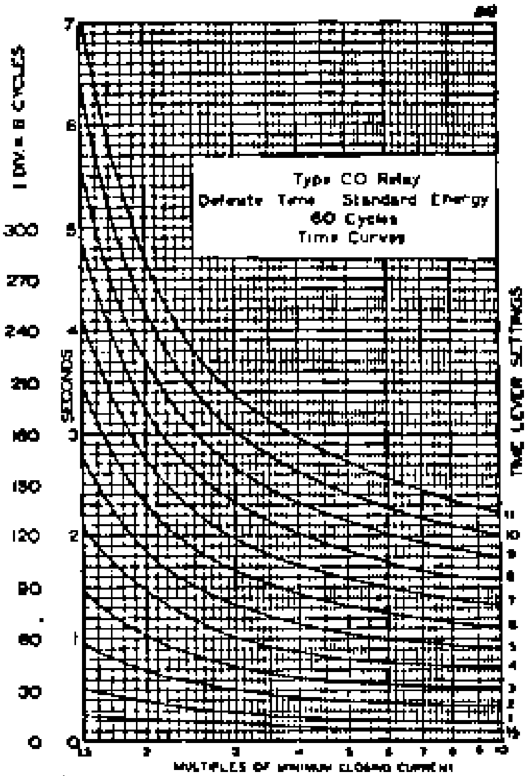


Figure 3.6
Time versus current characteristic of a typical definite minimum time overcurrent relay

ground relay may be used to advantage. This is ordinarily an overcurrent relay connected in the common lead of the wye-connected secondaries of the three line current transformers. It can be set to pick up at much lower current values than the phase relays because it does not see normal balanced load current.'

The types of overcurrent relays used for ground protection are generally the same as those used in phase leads, except that for ground relays a more sensitive range of minimum operating current values is likely to be required. Relays with inverse, very inverse, and extremely inverse time characteristics, as well as instantaneous relays, are all applicable for ground relays.

Use of cable current transformer with low ratio (10 to 1) and instantaneous overcurrent relay (set 1.0 ampere) widely used for sensitive ground protection—especially on large motors where inrush can saturate current transformers and produce false residual current.

Directional Relays

Overcurrent Relay

Directional overcurrent relays consist of a typical overcurrent unit and a directional unit which are combined to operate jointly for a predetermined phase-angle position and magnitude of current. In the directional unit the current in one coil is compared in phase angle position with a voltage or current in another coil of that unit. The reference current or voltage is called the polarization. Such a relay, therefore, operates only for current flow to a fault in one direction and will be insensitive to current flow in the opposite direction. The overcurrent unit of the directional overcurrent relay is practically the same as for the plain overcurrent relay and has similar definite-minimum-time, inverse, very inverse, time-current characteristics. The directional overcurrent relays can be supplied with voltage restraint on the overcurrent element.

The newer type directional relays are usually "directionally controlled", that is, the overcurrent unit is inert until the directional unit detects the current in the tripping direction and releases or activates the overcurrent unit.

Directional Ground Relay

The neutral-grounded industrial power system consisting of parallel lines or loops may use directional ground relays which in general are constructed in the same manner as the directional overcurrent relays used in the phase leads. They require a polarizing source which may be either potential or current as the situation demands.

Directional Power Relay

The directional power relay is in principle a contact-making wattmeter, either single-phase or three-phase, and operates at a predetermined value of power. It is often used as a directional overpower relay set to operate if excess energy flows out of an industrial plant power system into the utility power system to which it is connected. However care should be used in the application of single-phase watt relays as at certain power factors their torque is negative. Under certain conditions it may also be useful as an underpower relay to separate the two systems if the power flow drops below a certain value.'

Voltage Relay

A voltage relay is one that functions at predetermined values of voltage. It may be an overvoltage or undervoltage relay, or a combination of both. Generally it is a plunger-type or induction-type relay. Both types are provided with different settings to permit the voltage pickup or drop-out to be adjusted. The plunger-type relays are usually instantaneous in operation although they can be furnished with bellows, dash pots, or other delay devices. The induction-type relay is always equipped with adjustable time delay and it is inverse in characteristic, that is, the greater the deviation of the voltage from the setting of the relay, the faster it will operate. Relays are sometimes required to tolerate transient voltage disturbances and for this reason long-time relays are available.

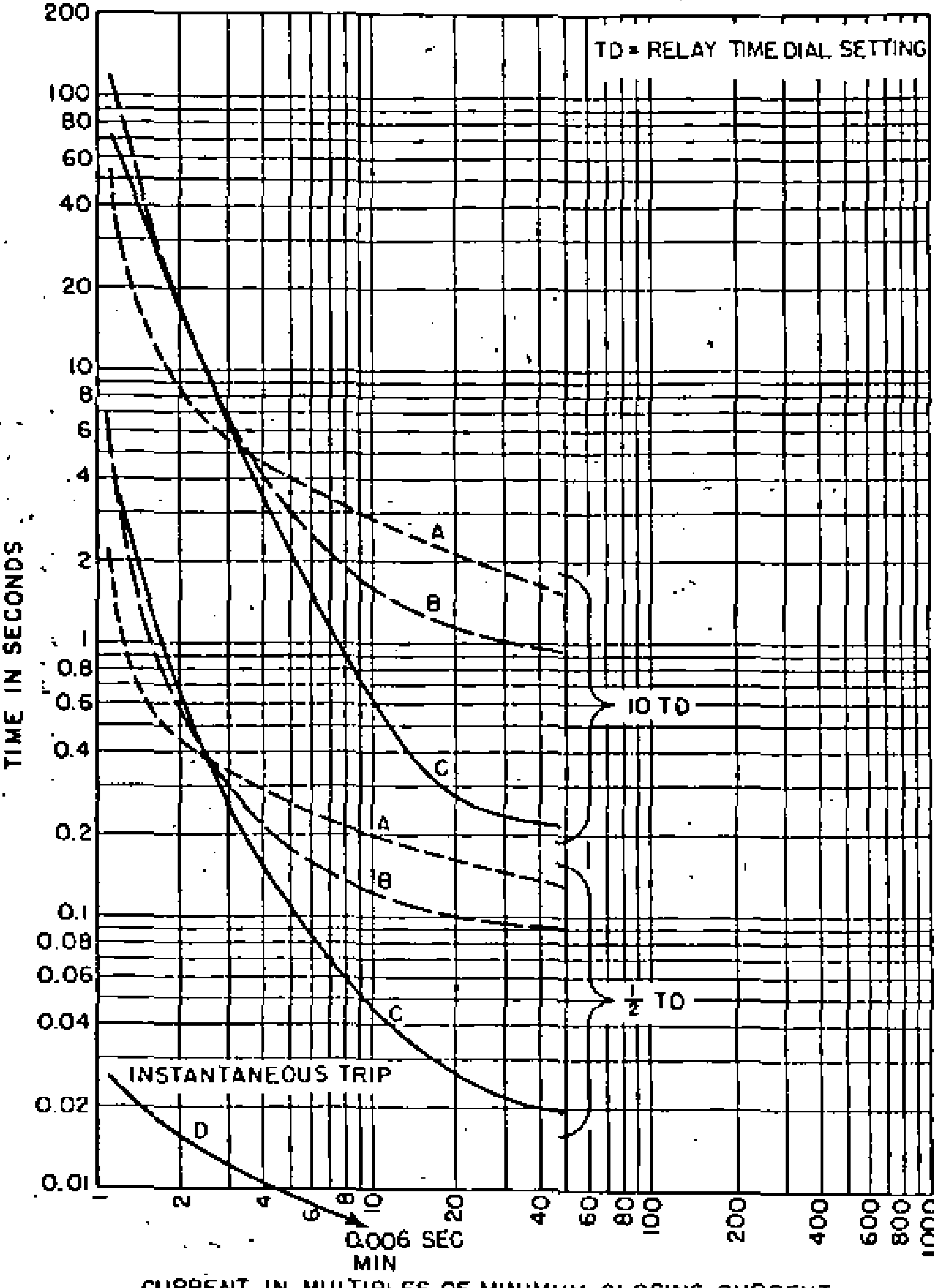


Figure 3.7
Relay time versus current characteristics

Frequency Relay

The overfrequency relay operates when the system frequency exceeds the value for which the relay is set, whereas the underfrequency relay operates when the frequency drops below this value. An appreciable frequency deviation indicates serious system trouble. Frequency relays, particularly underfrequency, are used to restore a balance automatically between load and generation. The commonly used frequency relays have provision for adjustment of operating frequency and voltage. The speed of operation depends on the deviation of the actual frequency from the setting of the relay. There are types of frequency relays which operate instantaneously if the frequency deviates from the set value. There are also types which are actuated by the rate at which the frequency is changing.

Differential Relays

All the previously described relays have the common characteristic of adjustable settings to operate at a given value of some electrical quantity such as current, voltage, frequency, power or a combination of current and voltage or current and phase angle. There are other fault-protection relays which function by virtue of continually comparing two or more currents. It is assumed that the fault conditions will cause a change of these compared values with reference to each other and this change can be used to operate the relay. The simplest form of differential protection for transformers, generators, or motors, is an overcurrent relay connected to measure the difference of current value as obtained from current transformers on opposite sides of transformers or in the two ends of each phase of the machine windings. The preferred modern devices are the percentage differential relays, which permit more sensitive protection without risking false operation due to small differences in the current output from the current transformers. These relays are available for differential percentage characteristics ranging from 10 percent to 50 percent. Most differential relays are essentially instantaneous in operation. Preferred differential for large power transformers is the harmonic restraint type.

Current Balance Relay

The principle of a differential relay as applied to rotating equipment protection requires that the current transformers be available at both ends of the phase windings to permit the comparison between the current magnitudes at these ends. In some instances, particularly in smaller units, it may not be possible to justify the cost of installing these current transformers or of bringing out the extra winding terminals to make their installation possible. In such cases, phase-balance, current comparison relays provide a very acceptable substitute for differential protection. In applying these relays it is assumed that under normal conditions the phase currents in the multiple phase supply to the equipment are balanced. Should the fault occur in the motor or generator involving one or two phases or should an open circuit develop in any of the phases, the currents will become unbalanced and the relay will operate. In addition to this protection against winding faults, the phase-balance, current relay affords protection against damage to the motor or generator due to single-phase operation. This type of protection is not provided for by the usual differential relays. This application requires extended time delay for high inertia motors and loads to prevent misoperation.

Phase Sequence or Reverse Phase Relay

Reversal of the phase rotation of a motor may result in costly damage to machines, long shutdown, and reduced production. Thus, important motors are frequently equipped with phase sequence or reverse phase relay protection. If this relay is connected to a proper potential source it can be made to close its contacts whenever the phase rotation is in the desired direction and open its contacts whenever it is in the opposite direction. It also can be made sensitive to unbalanced voltage or undervoltage conditions.

Bus Protection Relays

Large industrial power system buses often have sectionalizing breakers so that faults in one of the bus sections can be isolated without involving the remaining sections. Each of the bus sections or in some cases the whole bus (if not sectionalized) can be provided with differential relay protection, which in case of an internal fault isolates the bus section. Several types of bus protective relays are used, including the percentage differential relay, linear coupler, and the differential voltage relay.

a. *Percentage Differential Relay*

Where the number of circuits connected to the bus is relatively small, relays using the percentage differential principle similar to the transformer differential relay may be used. The problem of application of percentage differential relays for bus protection, however, increases with the number of circuits connected to the bus. It requires that all current transformers supplying the relays should have the same ratio and have identical characteristics. Variation in the characteristics of the current transformers, particularly the saturation phenomena under short-circuit conditions, presents the greatest problem to this type of protection and often limits it to applications where only a limited number of feeders are present.

To avoid operation from the inrush of magnetizing current when switching transformers, various relay desensitizing schemes are used. The harmonic restraint type has features which distinguish between magnetizing inrush current and internal fault current. Another type utilizes external timing relays and shunting resistors during the switching interval.

b. *Linear Coupler*

The so-called linear coupler bus-protection scheme eliminates the difficulty due to differences in the characteristics of iron-core current transformers by using air-core mutual inductances without any iron in its magnetic circuit. Since it does not contain any iron in its magnetic circuit the linear coupler is free of any direct-current or alternating-current saturation. The linear couplers of the different breakers are connected in series and produce voltages that are directly proportional to the currents going through the feeders. For normal conditions, or for external faults, the sum of the voltages produced by linear couplers, equals zero. During internal (bus) faults, however, this voltage is no longer zero and is measured by a sensitive relay which operates to trip breakers and clear the bus fault.

c. *Differential Voltage Relay*

Another method of bus protection is the use of differential voltage relays. This scheme uses through-type iron-core current transformers. It overcomes the problem of current-transformer saturation by using a voltage-responsive (high-impedance) operating coil in the relay.

Bus protection using linear couplers or differential voltage relays is not limited as to number of source and load feeders, and is in general faster in operation than protection using the percentage differential principle. It should be noted that linear couplers or current transformers used for differential voltage relays cannot be used for other purposes. Separate current transformers are required for line relaying and metering.

Pilot-Wire Relays

The relaying of tie lines, either between the industrial system and the utility system or between major load centers within the industrial system, often presents a special problem. It is essential that such lines be capable of carrying maximum emergency load currents for any length of time, and equally essential that they be removed from service very quickly should a fault occur. A modified form of differential protection known as pilot-wire relaying is used for this purpose. Pilot-wire relaying responds very quickly to faults in the protected line, clearing the fault promptly and minimizing line damage and disturbance to the system; yet it is totally unresponsive to load currents and to currents flowing to faults in other lines and equipment. The various types of pilot-wire relaying schemes all operate on the principle of comparing the conditions at the terminals of the protected line, the relays being connected to operate if the comparison indicates a fault in the line. The information necessary to this comparison is transmitted between terminals over a pilot-wire circuit, hence the designation of this type of relaying. Because, like all differential schemes, it is completely and inherently balanced within itself and completely selective, the pilot-wire relay scheme does not provide protection for faults at the adjacent station bus or beyond it.

Distance Relays

In recent years the use of distance relays has become widespread in transmission systems. These relays measure line impedance between the fault location and the relay location; and since these quantities are proportional to line length the relays are frequently referred to as distance relays. The measuring element is usually instantaneous in action, any desired time delay being provided by a timer element, so that the delay after operation of a given measuring element is constant. In a typical application, three measuring elements are provided. The first, which operates only for faults within the "primary-protection" zone of the line, trips the breaker without intentional time delay. The second element, which operates on faults not only in the primary-protection zone but also in one adjacent or "back-up-protection" zone, trips after a short time delay; while the third element is, set to include a still more remote zone and to trip after a longer time delay. These relays have their greatest usefulness in applications where selective instantaneous operation of breakers in series is essential (see instantaneous overcurrent relays), where changes in operating conditions cause wide variations in magnitudes of fault current, and where load currents may be great enough, in comparison with fault currents, to make overcurrent relaying undersirable.

Principles of Protective Relay Application

Fault-protection relaying can be classified into two groups, one the primary relaying, or that group of protective gear that should function first in removing faulted equipment from the system, the other "back-up" relaying which functions only when primary relaying fails.

To better illustrate the "areas of protection" associated with primary relaying we have shown in Figure 3.8 the various areas, together with the circuit breakers which feed each electric element of the system. It will be noted that it is possible to disconnect any piece of faulted equipment by causing one or more breakers to operate. For example, let it be asumed that a fault occurs in the high-voltage transmission line (L1) in Figure 3.8. This fault is within a specific area of protection and should be cleared by the primary relays which operate Breaker 1.

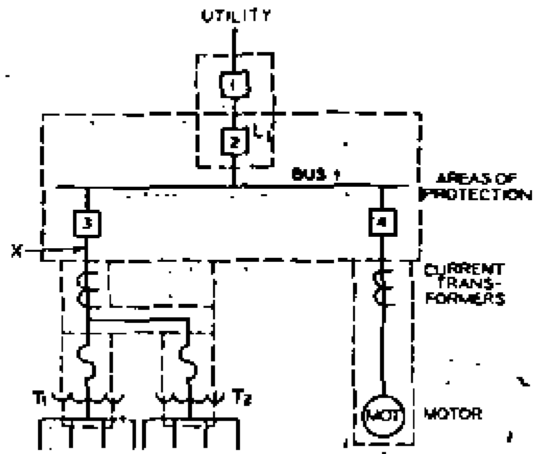


Figure 3.8

Likewise a fault on Bus 1 is within a specific area of protection and should be cleared by the primary relaying actuating Breaker 2.

If for some reason Breaker 2 fails to open and as a result the faulted equipment remains connected to the system, it is necessary to depend on back-up protection, which in this case is provided by Breaker 1 and its relays.

Figure 3.8 illustrates the basic principles of primary relaying, with separate areas of protection established around each system element. The significance of this is that any equipment failure occurring within a given area will cause tripping of all breakers supplying power to that area.

To assure that all faults with a given zone will operate the relays of that zone, it is desirable that the current transformers associated with that zone be placed on the far side of each breaker, so that the breaker itself is a part of two adjacent zones. This is known as overlapping. For economic reasons, however, it is often necessary to locate both sets of current transformers on the same side of the breaker. This is the case in metalclad switchgear, in which the physical construction necessitates locating the current transformers on the line side. In radial circuits, the consequences of this lack of overlap are not usually very serious. For example, a fault at X on the load line side of Breaker 3 in Figure 3.8 could be cleared by the opening of Breaker 3, if there were any way to cause it to open Breaker 3. However, since the fault is between the breaker and the current transformers, the relays of Breaker 3 will not see it, and Breaker 2 will have to open and interrupt the other load of the bus. The consequences of lack of overlap become more serious in the case of tie breakers between differently-protected buses, and bus feeds protected by differential or pilot-wire relaying.

In applying relays to industrial systems, many factors must be considered. A few of the most important are: (1) simplicity, (2) reliability, (3) maintenance, (4) tripping power source, (5) degree of selectivity required, (6) system loading, (7) cable ratings.

Before attempting to set up a protective relaying plan for a system, it is advisable to examine the various elements that make up the distribution system together with the operating requirements. Let it be assumed that, (1) all circuit breakers are capable of interrupting the maximum fault currents, (2) all lines will withstand fault currents, without damage, for a long enough time to allow the protective relays to clear the faulted equipment, (3) breaker control is to be direct-current supplied from a battery source, (4) the system voltage is 4160 volts and the neutral is grounded.

Typical Small Plant Relay Systems

One of the simplest types of industrial power systems might consist of a single incoming line circuit breaker, a single feeder and one transformer bank stepping the utility's voltage down to utilization voltage. There would undoubtedly be several circuits on the secondary side of the transformers, protected by either fuses or circuit breakers. Such a system is shown in Figure 3.9.

Protection for the circuit between the incoming line and the breakers on the transformer secondary would normally consist of phase and residually-connected overcurrent relays. Preferably the relays should have the same time-current characteristics as those of the relays on the utility system, in order to facilitate relay coordination. If they are induction type, the phase relays

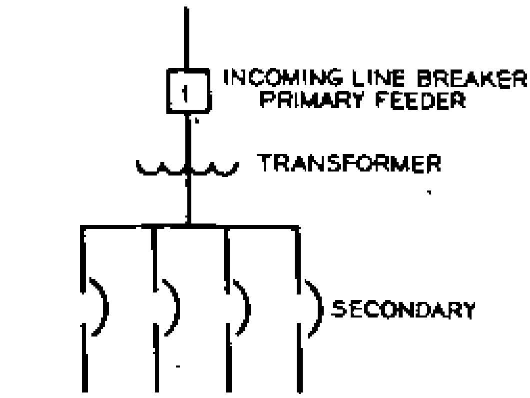


Figure 3.9

should have instantaneous elements for use on high-current faults.

The electrical engineer should furnish the utility curves of the various low-voltage protective devices being used together with other pertinent information such as the rating and starting current of large motors, etc., so that the primary relays can be set for best overall protection and coordination.

It can be seen from even this simple system that both primary and back-up relay protection is provided. For instance, a fault on a secondary feeder should be cleared by the secondary protective device; however if this device should fail to trip, the primary relays on Breaker 1 will open it and clear the fault.

This simple industrial system can be expanded by tapping the primary feeder and providing fuse protection on the primary of each transformer bank. This type of system is shown in Figure 3.10.

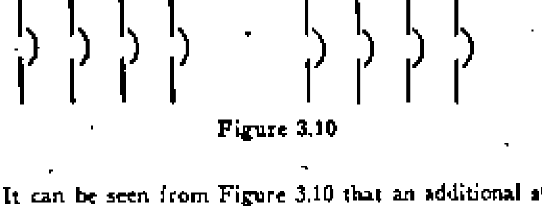


Figure 3.10

It can be seen from Figure 3.10 that an additional step or area of protection is included over the simpler system shown in Figure 3.9. All secondary feeder faults should be cleared by the secondary breakers as before, while faults within the transformer should now be cleared by the transformer primary fuses. The fuses will also act as back-up protection for the faults which are not cleared by the secondary feeder protective devices. The primary feeder faults will, as before, be cleared by Breaker 1. This breaker will in turn act as back-up for the transformer primary fuses.

Fuse Protection of Transformers

The simplest form of protective device is a fuse connected between the transformer and the incoming line as shown in Figure 3.11a. With the simple layout shown, the application of the proper fuse is relatively easy. In

Fuses can be applied, to advantage, in many instances. If, for example, it is found necessary to install a small transformer on a heavily loaded feeder as shown in Figure 3.11b, secondary fault protection for this transformer cannot be obtained using the overcurrent relays on the feeder breaker whose pickup is determined by the load requirements. The protection problem is solved by the installation of properly selected fuses on the primary side of the 200-kVA transformer.

Fuses should be installed on the primary side of each

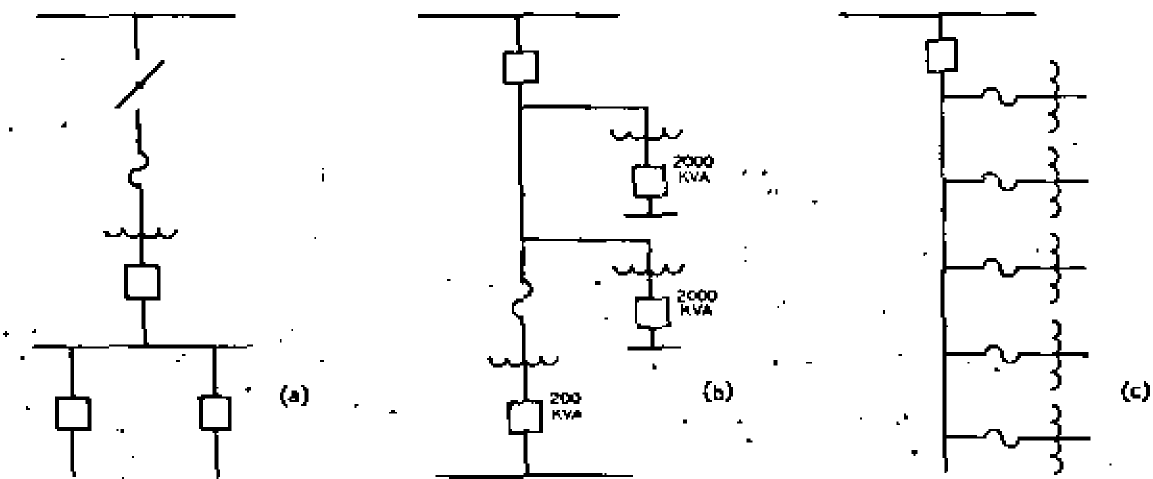


Figure 3.11

fuse applications the following items need to be considered:

1. The voltage rating of the system.
2. Rated load current of the transformer.
3. The type of load, whether steady, fluctuating or subject to heavy motor or furnace starting surges.
4. Coordination with other protective devices.
5. Short-circuit kVA of the supply system.

A fuse as a protective device is responsive only to the current which passes through it. Each type of fuse has its own melting time characteristic curve, some of which are fast, others slow, depending on the alloy used. Unlike an overcurrent relay, once a fuse has been installed the melting time characteristic curve becomes a non-adjustable step in the overall protective system. The amount of protection afforded depends on the size of the fuse compared to that of the electric equipment it is required to protect.

It should be noted that the clearing of a fault by blowing fuses may leave one or two of the three-phase leads energized. On lighting circuits, this is often desirable, but motors may be damaged. This deficiency can be overcome by single-phase protection. Most manufacturers supply this as an optional feature and some make "do it yourself" kits available for installation on existing equipment. In contrast, relay-breaker installations usually open all phases. (Code requirement)

transformer where there are several transformers fed from the same feeder as shown in Figure 3.11c.

In general, fuses should be used where there is doubt as to whether or not a piece of apparatus is adequately protected when connected to multiple-load feeders. It must be kept in mind however that too close a coordination between fuses or fuses and circuit breakers should not be attempted. The tolerance band, the differently shaped characteristic curves and the deterioration occurring over the years in fuses make their selective functioning doubtful when it is called upon.

Plant with High-Voltage Bus

With the foregoing knowledge it is now possible to establish the areas of protection and assign the protective relays to a more complicated system such as that of Figure 3.12.

Inquiries to the utility indicate that the relays on Breaker 1 will be very-inverse-time overcurrent relays without instantaneous elements. This will permit a selective relay system, assuming instantaneous tripping for major 4160 volt feeder faults. Breaker 2 might be similar to Breaker 1 except with a lower time lever or current tap setting. The current transformers will usually be the same ratio for both Breakers 1 and 2.

To protect the power transformers supplied through Breakers 3, 4 and 5, relays similar to those of Breaker 2 except with instantaneous elements could be used. Be-

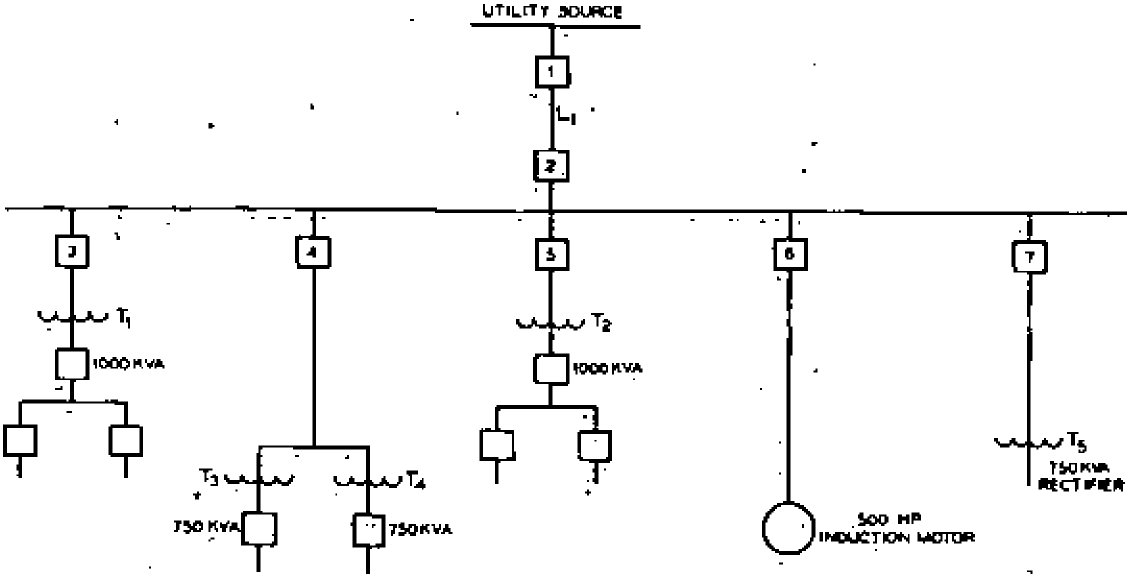


Figure 3.12

cause of the low system impedance between Breaker 2 and Breakers 3, 4 and 5, selective tripping may be accomplished by the use of lower ratio current transformers or lower time settings which will permit better current discrimination at Breakers 1 and 2.

The reason for suggesting that the relays in the plant have the same time-current characteristics as those on incoming lines is to facilitate their coordination. It is difficult to coordinate relays with differently shaped characteristic curves, and the result is generally inferior either in the selectivity afforded or in the total time required to clear faults.

Protection of the 500-horsepower motor against fault currents can be provided by the use of instantaneous relays in two phases and one inverse-time ground overcurrent relay. A long time delay induction overcurrent relay in the third phase, set about 150 percent of full-load current, may be used to protect against overload and locked rotor currents. Because of variations in motor starting characteristics, the time lever setting of this relay may advantageously be determined by trial. The remaining transformer, Position 7, has a six-phase secondary supplying a rectifier; since there are no heavy starting surges, the rectifier may be given maximum protection through the use of short-time overcurrent relays with instantaneous units.

To approximate how the various protective relays will function, asumed faults can be placed on the system. For transformer secondary faults, the very inverse time element of the overcurrent relay will give adequate back-up protection and in addition time-selectivity with the fuses and secondary breakers. Major faults in the transformer primary windings and 4160-volt cables will be cleared by the instantaneous elements of the overcurrent relays. Relays applied on the incoming breakers will give adequate back-up protection to the individual load breakers for primary transformer and cable trouble.

Protective Relay System for Large Industrial Plant Power System

As an electric system becomes larger the number of sequential steps of relaying also increases, giving rise to the need of a protective relaying scheme which is inherently selective within each zone of protection. Figure 3.13 shows the main connections of such a system.

In this case the relay selectivity problem is of great concern to the utility's protection engineers, because their main feeders are paralleled through the industrial plant's synchronizing bus. The public utility will provide the necessary relays for selective operation of Breaker A in case of trouble in Cable 1 and Transformer 1. Due to the synchronizing bus tie in the plant it is obvious that for a fault in either Cable 1 or Transformer 1 the opening of Breaker A alone will not clear the faulted equipment from the system. To do so it is also necesary to open Breaker 1 on Bus 1. It is recommended that three directionally controlled overcurrent relays be installed for Breaker 1 connected to trip for current flow toward the main transformer. Directionally controlled overcurrent relays are suggested because they are not directly affected by the load demands of the various buses. Each of the Breakers 1, 21, and 31 on the secondaries of the main transformers will be relayed identically. Three overcurrent relays having very-inverse-time characteristics should be installed in these breaker positions as back-up protection for faults that may occur immediately adjacent to the main buses. The next zone of protection are Buses 1, 2 and 3. Fault currents are relatively high in magnitude for any equipment failure on or near the main buses. For this reason a differential protective relay scheme is recommended for each bus. Differential relaying is rapid in operation and is inherently selective within itself. Without such relaying, high-current bus faults must be cleared by proper operation of overcurrent devices on the several sources. This usually results in long time clearing since the overcurrent devices have pickup and time settings

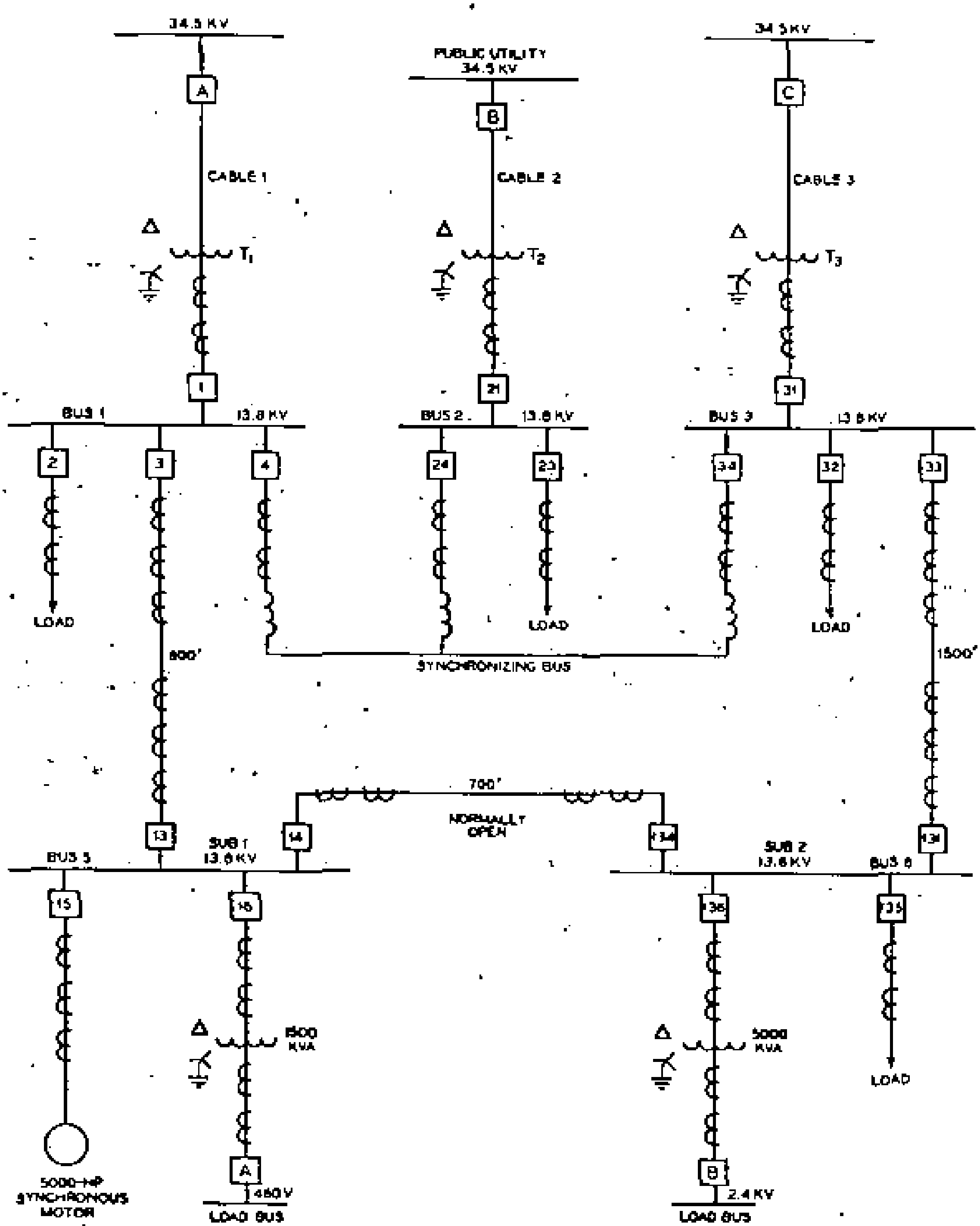

34.5 KV
PUBLIC UTILITY
34.5 KV
34.5 KV
A
B
C
CABLE 1
CABLE 2
CABLE 3
T1
T2
T3
BUS 1
13.8 KV
BUS 2
13.8 KV
BUS 3
13.8 KV
LOAD
LOAD
LOAD
800'
1500'
SYNCHRONIZING BUS
700'
NORMALLY
OPEN
BUS 5
SUB 1
13.8 KV
SUB 2
13.8 KV
BUS 6
1500
KVA
5000
KVA
LOAD
5000-HP
SYNCHRONOUS
MOTOR
460 V
LOAD BUS
2.4 KV
LOAD BUS

Figure 3.13

determined by other than bus fault considerations. It is general practice to use separate current transformers for the differential relay scheme all of which must have the same ratio and output characteristics. The operating characteristics of the various differential relays are explained in the section on "relay charactertistics". A multi-contact auxiliary relay is used with the differential relays as it is necessary to trip all of the breakers connecting to the bus whenever bus trouble occurs.

Breakers 4, 24, and 34, which are the ties to the synchronizing bus make up the next zone of protection. A bus differential scheme is also recommended to cover this zone of protection. In addition to the differential relaying, overcurrent relays with very-inverse-time characteristics should be installed at each breaker position for back-up protection against breaker failures on either of the three main buses. For example, if Breaker 3 failed to clear a fault in the cable to Substation 1, the overcurrent relays on Breakers 1 and 4 must operate to clear the faulted equipment. Likewise, should the directional overcurrent relays on Breaker 1 fail to function properly, the overcurrent relays on Breaker 4 would have to clear the faulted equipment. Each zone of protection must overlap the other.

Good protection for the cable ties between Bus 1 and Substation 1, and Bus 3 and Substation 2 would be wire-pilot differential. Pilot wire schemes usually are instantaneous in operation, inherently selective within themselves, and require only two pilot wires, if the proper relays are used. This form of relaying requires the addition of suitable back-up relaying. For this reason overcurrent relays should be installed at the source end on Breakers 3 and 33, but if desired, for fault detection purposes, additional overcurrent relays could also be installed at the load end on Breakers 13 and 131. The overcurrent relays on all four breaker positions should have very inverse-time charactertistics to match those on the incoming transformer secondaries. Bus 5 in Substation 1, and Bus 6 in Substation 2 should be protected the same as Buses 1, 2 and 3 with bus differential relaying. The tie cable between Substations 1 and 2 could be relayed the same as the other cable ties with pilot-wire differential and overcurrent back-up relays in each tie position. Separate current transformers should be used for the pilot wire differential to provide reliability and flexibility in the application of other protective devices.

The basic relaying usually supplied for the 5000 horsepower motor connected to Substation 1 would be, (1) percentage differential relays for protection against internal faults, (2) phase sequence and undervoltage relay, used to stop the motor if undervoltage occurs and to prevent attempted starting if open-phase or reverse-phase conditions exist, (3) phase-balance current relay, which affords protection against single-phase operation not protected by the motor differential or phase sequence undervoltage relays; a time delay is required to prevent misoperation on external unbalanced faults, (4) instantaneous overcurrent relays in 2 phases, plus an inverse-time residually connected ground overcurrent relay, to insure tripping in the event of failure of the above, (5) thermal overload relays are connected to either give an alarm (audible or visible) or trip when excessive overloads occur for a definite length of time.

Connected to Breaker 136 is a 5000 kVA power transformer. It is good practice for transformers of this size, where a breaker is used on both the primary and secondary side, to install transformer percentage differential relays with inverse charactertistic overcurrent relays for back-up protection. To prevent operation of these relays on magnetizing inrush current when the transformer is switched on, it is desirable to choose differential relays which are restrained or desensitized during the period of the initial excitation transient. The transient contains a large proportion of currents at harmonic multiples of the line frequency; these are separated from the line-freqeuncy currents by filters, and passed through the restraint winding. Thus the current unbalance required to trip can be made much greater during the excitation transient than during normal operation.

Relaying for an Industrial Plant with Local Generation

Some industrial plants generate all or a portion of their electric power requirements. When additional power is required in a plant that has been generating all of its power and a parallel-operated tie with a utility system is decided on, the entire fault-protection problem should be reviewed together with circuit breaker interrupting capacity. In this case, Figure 3.14, which is entirely hypothetical, it will be assumed that:

1. All circuit breakers in the industrial plant are capable of interrupting the increased short-circuit current.
2. Each industrial plant feeder breaker position is equipped with inverse-time or very inverse-time overcurrent relays with instantaneous units.
3. Each of the industrial generators is protected by differential relays, and also has external fault back-

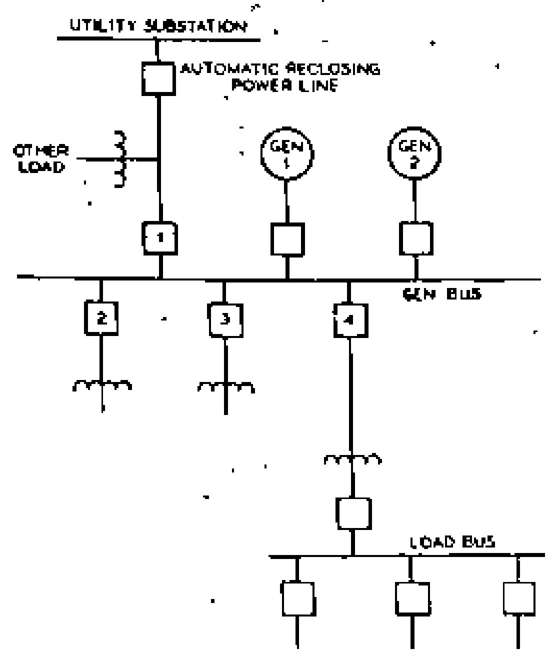


Figure 3.14

up protection in the form of generator overcurrent relays with voltage-restraint or voltage-controlled overcurrent relays.

4. The utility company end of the tie line will be automatically reclosed, through synchronizing relays, following a trip-out.
5. The utility system neutral is grounded and the neutrals of one or both of the industrial plant generators will be grounded through a resistor.
6. The industrial plant generators are of insufficient capacity to handle the plant load and no power is to be fed back into the utility system under any condition.

Protection for the utility end of the tie line might consist of three distance relays or time overcurrent relays without instantaneous units. If the distance relays were used, they would be set to operate instantaneously for faults in the tie line up to 10 percent of the distance from the industrial plant and time delay for faults beyond that point in order to allow one step of instantaneous relaying in the industrial plant on heavy faults. If time overcurrent relays are used, they would be set to coordinate with instantaneous relays at the industrial plant.

At the industrial plant end of the tie, there should be a set of directional overcurrent relays of some type for phase and ground-fault protection. Reverse power or underfrequency relays should also be provided to prevent overloading of the industrial plant generators in case the utility breaker is opened leaving the generators with their own load, which is in excess of their capacity, plus possibly some external utility-customer load.

Since there will be no sustained feedback of power into the utility system, the directional overcurrent relays for protection against faults in the tie line can be set quite low without running the risk of false operation. This is desirable because they might have to have some time-delay to coordinate with the relays in the utility system, in which case maximum sensitivity is helpful to insure positive tripping because the magnitude of the fault current supplied by the industrial generators decreases very rapidly due to generator decrement.

Three-phase power directional relays are instantaneous; so if they are used to keep the industrial plant generators from feeding power into the utility system, it is necessary to supplement them with time-delay relays to avoid false operation on power swings during synchronizing.

The reverse power relay would be connected to trip the industrial plant's incoming line utility breaker together with breakers supplying non-essential loads in the plant, in order to reduce the total load to the capacity of the generators.

If underfrequency relays are used as a means of preventing generator overloading, they are used in the same manner to trip the incoming line breaker and non-essential load feeder breakers. Sometimes, two or more underfrequency relays are used and set to operate at successively lower frequencies, so that the non-essential load circuits can be tripped in succession depending on the load demand on the system.

Generator external-fault protective relays usually of the voltage-restraint or voltage-controlled type, assumed to be already on the existing system, are to provide primary protection in case of bus faults and backup protection for feeder or tie line faults that are not cleared by their own relays. These generator relays will also operate as backup protection to the differential relays in the event of internal generator faults, provided there are other sources of power to feed fault current into the generator.

The relays used to open the industrial plant incoming line breaker should be fast enough to insure that the breaker is open before the utility breaker is reclosed automatically. Preferably, the utility end of the tie line should have relays that will check to make sure that the line is dead before re-energizing it so as to avoid any possibility of tieing in with the industrial plant generators out of phase. In many cases, and incidentally, the safest method, the utility operator checks with the industrial plant operator to be sure that the industrial plant tie breaker is open before re-energizing the line. In some cases, however, particularly where there are other customers on the same line, advance notice of reclosure cannot be provided. The use of a synchrocheck relay will permit automatic restoration of service only if the industrial generators are in phase with the supply.

In all cases, the proposed relay protection for a tie line between a utility system and an industrial plant with local generation should be thoroughly discussed by the engineers of the utility, the user, and the manufacturer to be sure that the equipment supplied will accomplish the desired result.

COORDINATION

Proper coordination of circuit interrupting devices is an essential but frequently overlooked phase of industrial power system design. On all but the simplest systems there will usually be at least two such devices in series between any fault or overload and the power source. To minimize the effects of a fault on the system, these devices should be selective in operation so that the one nearest the fault on the source side will operate first and, if any device should fail to function, the next closest device on the source side should open the circuit.

In a properly coordinated power system the protective devices should be either preselected (as in the case of fuses and non-adjustable trip elements), or be capable of adjustment over the required range:

1. To operate on the minimum current that will permit them to distinguish between fault and load current.
2. To function in the minimum time to permit selectivity with other devices in series with them.

Since the coordination requirements differ for each power system, all adjustable protective devices must be set in the field to achieve the desired coordination. There is no mystery involved, rather it is a case of perseverance in trying various combinations of characteristic curves to insure correct operation on both maximum and minimum fault currents. The basic procedure is as follows:

1. Secure the information needed and make the necessary short-circuit calculations to determine the different values of minimum and maximum fault current required to permit selection of coordinated time-current curves for the various devices involved.

2. Using the proper values of fault current from (1), select time and current settings for the adjustable devices, and check the performance of the non-adjustable devices with the objective of securing a combination that will operate in the sequence necessary to isolate a fault with minimum disturbance to unfaulted portions of the system.
3. Plot time-current curves for those devices that are to operate selectively in series to be sure that there are no potential trouble spots due to unexpected overlapping of time-current curves, or unnecessarily long operating time intervals between devices in series.

Actual plotting of the curves is desirable, because rarely do all of the fault protective devices involved have the same shape of time-current curves, and it is difficult to visualize the relationship of the many different shapes of curves. They should be plotted on a single sheet of graph paper using a common current scale. It seems to work out best to use a scale corresponding to the currents expected at the lowest voltage level, e.g. for fault current protective devices on both sides of a 2400-480 volt transformer plot everything on a 480 volt-current scale. To plot 2400-volt device time-current curves on the 480 volt scale, first determine the desired time and current settings in the usual manner on the basis of current expected in the 2400-volt circuit. Then plot time directly since that scale is unchanged, but multiply the 2400 volt currents by 5 (ratio of voltages) before plotting on the 480 volt scale.

Short-circuit currents are reflected through delta-delta or wye-wye transformers inversely as the voltage ratio for all types of faults. The same is true for three-phase fault currents passing through wye-delta or delta-wye transformers but not for line-to-line fault currents. When the latter occurs, the relays on the faulted side see only 86.6 percent as much current as for a three-phase fault at the same location, whereas the relays on the source side of the transformer see 100 percent of three-phase fault current in one conductor and 50 percent of three-phase fault current in each of the other conductors. Therefore one of the relays on the source side of the transformer will see 16 percent more current (neglecting the ratio) than any of the relays on the faulted side; and the relays will not coordinate correctly unless proper allowance is made for this unbalance.

Preferably the curves should be plotted progressively as each circuit is studied starting with the device at the end of the chain (farthest from the source). This procedure will show whether or not the proposed time-current characteristic of each successive device coordinates with the one on its load side. The maximum allowable time at the power company source may be limiting.

Time-Delay Relays in Series

The time-current curves of direct-acting, time-delay trips, fuses and time-delay thermal devices include the necessary allowance for over-travel, manufacturing tolerances, etc. The time-current characteristics of relays, on the other hand, are represented by families of single-line curves to which tolerance-bands must be added. Most relay time-current curves begin at 1.5 multiples of minimum closing current or pickup setting, because their performance cannot be predicted too accurately below that value. However, curves showing expected time-current performance down to 1.1 times pickup can usually be obtained if required.

This time-margin or tolerance-band is based on the fact that the second relay in a chain continues to see fault-current until the breaker associated with the first relay has opened and the arc has been extinguished. This is nominally 8 cycles for the breakers commonly used in industrial systems, although actually the opening time will be 4-5 cycles. Then after the first breaker has opened the circuit and de-energized the second relay, the latter's contacts will continue to coast for 0.1 second (standard inverse-time relay) due to the inertia in the induction disk of the relay to which the movable contact is attached.

A minimum total time margin of 0.4 second with maximum fault current flowing should be sufficient to afford satisfactory selectivity between inverse-time relays. This margin allows for the 0.13 second breaker opening time (8 cycles), 0.1 second overtravel, and a safety factor of 0.17 second to cover manufacturing variations and inaccuracies in positioning of the time dial or lever when setting the relay.

When selecting current-tap and time-dial settings for induction relays, it should be borne in mind that when two relays in series are set to coordinate properly under the maximum value of fault current expected, they will always be satisfactorily selective on lower values of current, if they have the same shape time-current curves, and the current setting of the slower relay is higher than that of the faster relay. If the current setting is lower, the operating-time curves of the two relays will cross each other at some low value of fault current, and the "slow" relay will beat the "fast" one for all currents below that value.

The value of plotting the time-current curves on a single graph with a common current for all the relays and other devices in series is illustrated in Figure 3.15 which reveals two conflicts which might otherwise have escaped notice. In the case illustrated, it was assumed that the power supply was sufficient to maintain a 250,000 kVA short-circuit level without appreciable decrement, and that there was no pump-back fault current from synchronous equipment on the 2400-volt system. On this basis, the maximum symmetrical fault current would be 20,000 amperes on the 2400-volt system, and 10,250 amperes on the 13.8 kV system (60,000 amp on a 2400-volt base). It was also assumed that the end relay in the chain (D) must be set at a minimum of 0.5 second.

The three sets of 2400-volt relays were coordinated by selecting time-current settings that would make their operating time 0.4 second apart at the maximum current of 20,000 amperes. Then, the single set of relays on the 13.8 kv system was coordinated with those on the 2400-volt system on the same value of fault current (3480 amp at 13.8 kV), because that is all that the relays at "A" would see during a fault on the 2400-volt side of the transformer. This was accomplished by selecting time-current settings that would give 0.4 second between relays

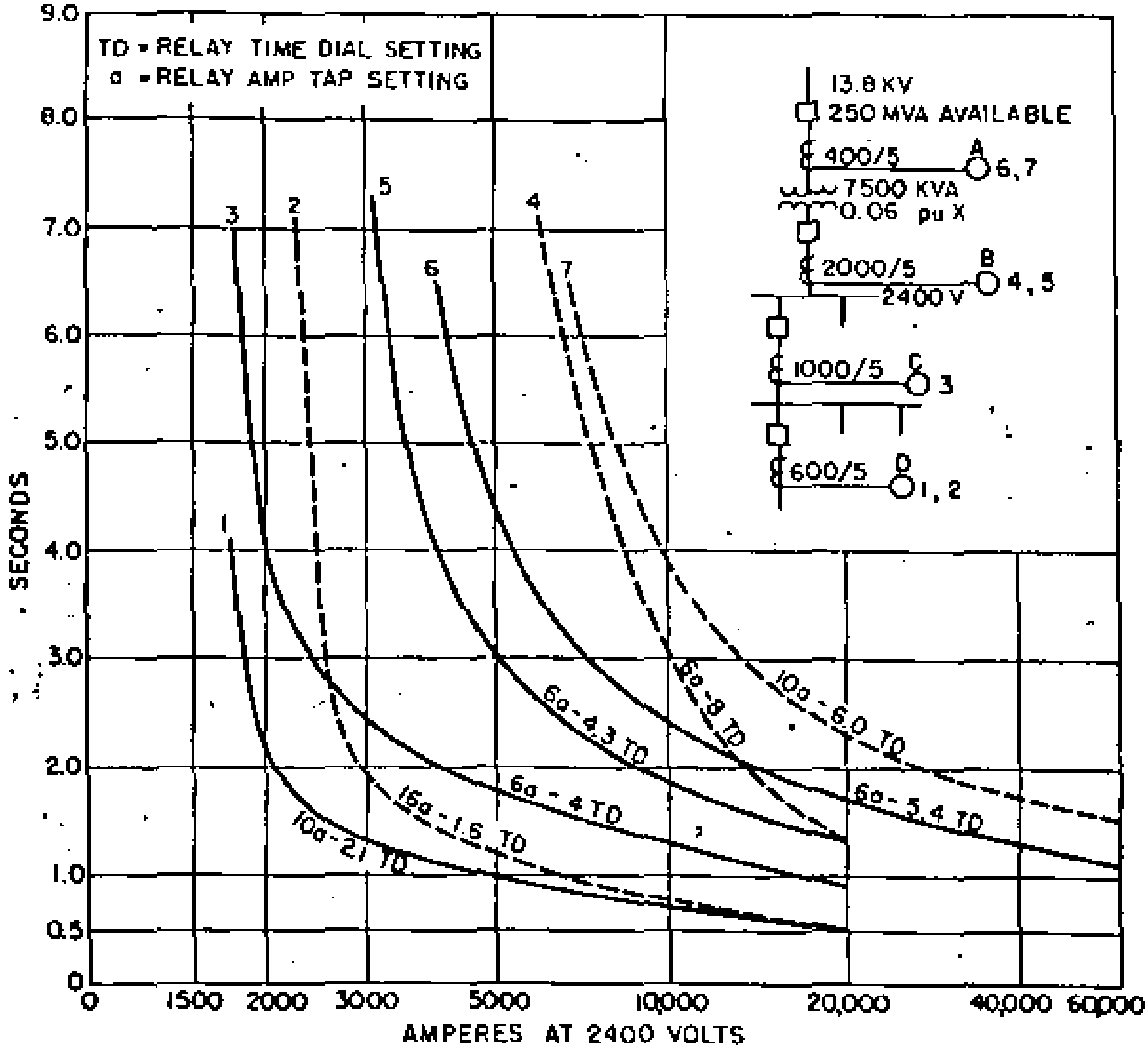


Figure 3.15

"A" and "B" for a 20,000 ampere fault on the 2400-volt system.

The foregoing procedure would give satisfactory results without plotting the curves, if the basic rules for coordinating relays were observed. (1) Use relays with the same shape curves in series with each other and (2) make sure that the relays farthest from the source of power always have current settings below that of the relays ahead of them. Unfortunately, however, it is easy to overlook one, or both, of these basic rules, and that is when the effort required to plot the curves proves worthwhile.

As shown in Figure 3.15 time-current settings on relay "D" that would give either Curve 1 or Curve 2 would satisfy the requirement that it take a minimum of 0.5 second at 20,000 amperes. Curve 2 setting, however, is slower and less sensitive than that represented by Curve 1 throughout most of its range. Furthermore, Curve 2 crosses Curve 3 representing the desired setting for Relay C, thereby compelling desensitization of C to make it selective with D. Thus Curve 2 setting on Relay D would mean that much poorer short-circuit protection could be provided by either C or D.

Curves 4, 5, 6 and 7 of Figure 3.15 illustrate what would happen if Relay B had a very-inverse-time characteristic instead of an inverse-time curve, as the others do. Curve 4 meets the requirement that it be 0.4 second slower than Curve 3 representing Relay C, when both are operating on 20,000 amperes. Also Curve 6 satisfies the requirement that Relay A be 0.4 second slower than B when A is operating on the equivalent of the 20,000-ampere 2400-volt system short-circuit current. If the curves had not been plotted, there would be reason to believe that the contemplated settings for A and B as represented by Curves 6 and 4 would be satisfactory. Actually, however, the very-inverse characteristic of Relay B causes its curve to cross that of A at a high level of fault current, which would mean that the tripping sequence of the breakers would be reversed. For this particular circuit, that would not be too serious, since tripping either breaker would shut down the whole circuit, but it would still nullify the effectiveness of the relays in giving indication as to where the trouble was. If it was necessary to retain the very-inverse-time relay at B, Relay A's setting would have to be desensitized and increased in time (Curve 7) to be selective with B. This would presumably result in greater damage during a short circuit, so it would be better to substitute an inverse-time relay for the very-inverse-time relay at B, making it possible to set B to give performance as shown by Curve 5. This would mean that A and B could both be more sensitive and faster, and consequently would give better protection to the system.

It should also be noted that if the very-inverse-time relay was used at B, the backup protection that it could provide would be very poor indeed, due to the big "gap" in the pickup currents (sensitivity) of Relays B and C, as shown by Curves 3 and 4.

Another factor to be considered, when choosing between two combinations of current-tap and time-dial settings, either of which will give a desired operating time with maximum fault current flowing is that the combination with the lower current and higher time-dial setting is usually preferable. The reason is that the relay with such a setting will be more sensitive and faster on low values of fault current. For example, suppose an operating time of 0.5 second is desired with a relay connected to 1000/5 ampere current transformers in a circuit with maximum symmetrical fault current of 20,000 amperes. Relays with 6 ampere tap and 2.1 time-dial, or 10 ampere tap and 1.7 time-dial settings will both give the desired time. But in case of a fault involving only 3000 amperes, the relay with the 6 ampere setting would operate in 1.25 second compared with 2 seconds for the 10 ampere combination. If the current is still further reduced to 2000 amperes, the first relay will still operate in 2.1 seconds, but the second one will be very, very slow, since the current is only 1.0 times relay pickup at which point operation is uncertain.

Instantaneous Relays

When two breakers in series both have instantaneous overcurrent relays, the selectivity of these relays is dependent solely on their current settings. Therefore they must be set so that the relay nearest the source will not trip its breaker on the maximum asymmetrical fault current that can flow through the other breaker. This can be accomplished only if there is sufficient impedance in the circuit between the two breakers in series to cause faults beyond both breakers to receive a considerably smaller current than faults near the source breaker, so that the relays of the source breaker can discriminate between them. If this differential between fault currents at the two locations is insufficient it is impossible to provide selective operation with instantaneous overcurrent relays; and it will be necessary either to tolerate the opening of both breakers on through faults, or to make the relays of the breaker farthest from the source inoperative.

Usually the impedance of a transformer is sufficient to permit coordinating an instantaneous relay on a high-voltage feeder panel with the instantaneous trip-coil of a low-voltage secondary breaker. Also the reactance of open transmission lines may be sufficient to provide the necessary differential in short-circuit current magnitude to permit the use of instantaneous relays at both ends.

Instantaneous relays cannot be coordinated on ordinary-length cable systems because the circuit impedance is too low to cause the necesary current differential. In such cases, the relay at the bus end of the feeder should be utilized and the other one made inoperative, in order to afford fast protection to the cable as well as the load.

The fact that a relay-setting study reveals that some of the instantaneous relays must be made inoperative should not be interpreted as a sign of a poorly-designed protective system. This is so because it is quite common practice to include instantaneous attachments on all of the time-delay overcurrent relays on switchgear equipment so that they will be interchangeable.

Low-Voltage Breakers with Direct-Acting-Trip Devices — 600 Volts and Below

Direct-acting-trip devices on low-voltage breakers are usually electromagnetic, plunger or hinged-armature operated, and may be either instantaneous or have a combination of instantaneous and time delay tripping. Three tripping devices are provided on each three-phase breaker.

Tripping-device operating coils are available in a wide range of current ratings up to and including the maximum continuous-current-carrying capacity of the circuit breakers. The current rating of a circuit-breaker is determined by its trip coil rating rather than its maximum-continuous-current-carrying capacity, or so called "frame size". However, the interrupting capacity is governed by the frame size or maximum current-carrying capacity of the breaker and must always be considered when applying direct-acting trip device breakers.

In a selective trip system, the main secondary breaker should be of the selective type; that is, equipped with series overcurrent tripping devices having long and short time delay characteristics. The devices should be selected and set to meet the following requirements.

1. Furnish overload protection for the transformer.
2. Furnish short-circuit protection for the bus and feeder breakers.
3. The transformer main secondary breaker should be selective with the feeder or group breakers; that is, the time-current characteristics of their respective series overcurrent devices should not overlap.
4. The secondary main breaker should give the best possible coordination with the primary protective device. To insure ample selectivity tripping between the primary protective device and main secondary breakers, the total-clearing time of the breaker should lie below the minimum operating curve of the primary protective device for all values of current equal to and less than the maximum value of symmetrical fault current that can flow through the transformer to a secondary fault.
5. Where the transformer protection is by a primary circuit breaker, both the time and instantaneous de-

vices of the breaker relays should be set above the transformer inrush current. When fuses are used for primary protection they should be rated approximately 200 percent of the transformer rated current, to withstand the transformer magnetizing inrush current and provide adequate fault protection.

Feeder breakers off the main bus should be selected and set to give complete selectivity with the transformer secondary breaker. (Figure 3.15A). When fuses of the damageable type are used, it may be that some overlap of the breaker and fuse damageability or short time curve cannot be avoided, then it is desirable to set the breaker such that the breaker will always trip even though the fuse may blow or be damaged thermally. This can be accomplished by keeping the total clearing time of the transformer-breaker below the minimum melting time curve of the fuse.

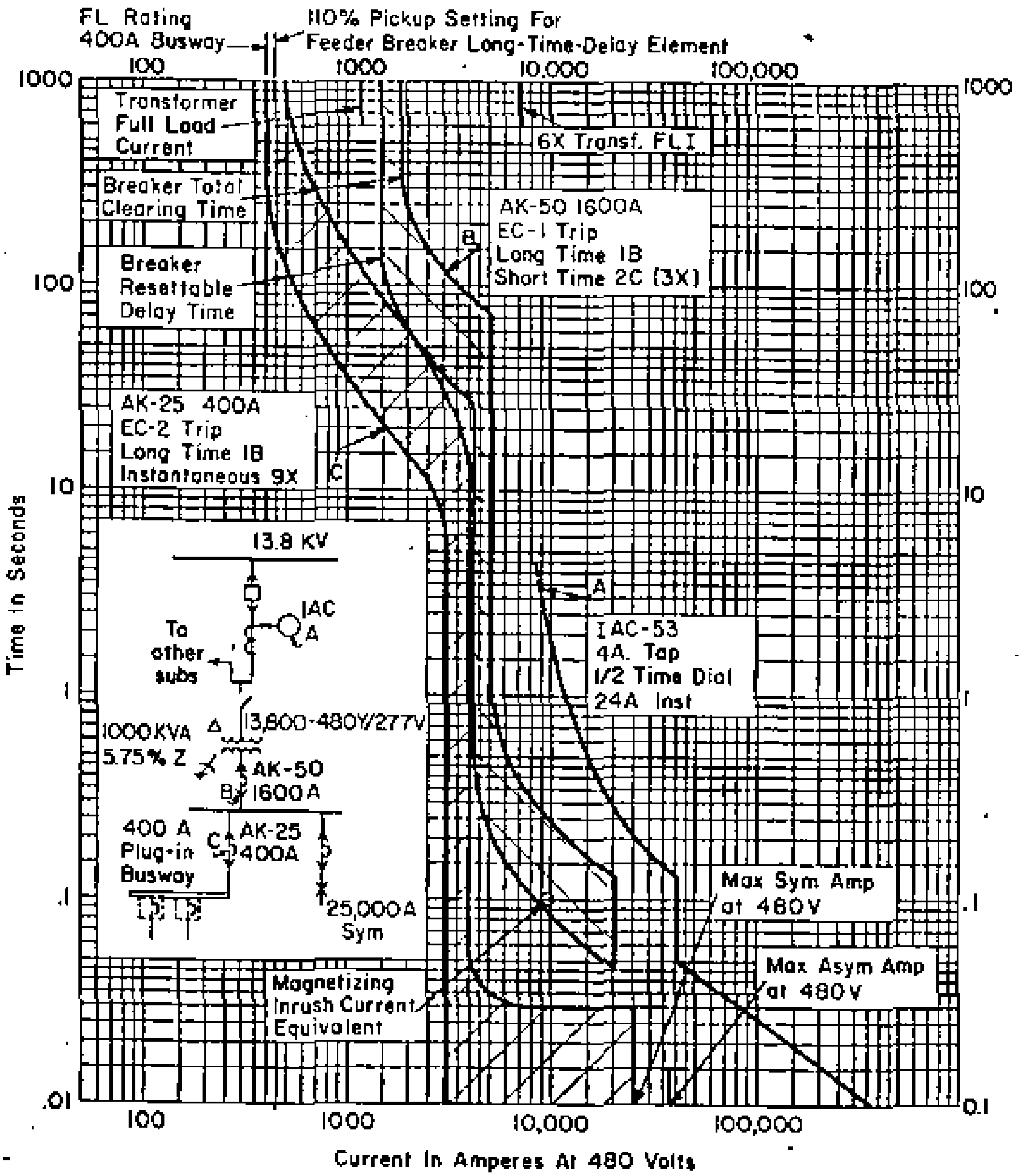


Figure 3.15A
Selective tripping time-current characteristic curves for the low-voltage transformer installation with primary fuses.

Complete selectivity, that is, no overlapping of the characteristic curves, between the primary protective device and the secondary breaker is desirable. In the application of fuses it is sometimes difficult to obtain because of the extreme differences in their characteristic curves. The current rating of the fuse should not be increased to give complete selectivity at the expense of sacrificing adequate protection. Partial overlapping of the primary fuse and secondary main breaker characteristic curves should not be objectionable when it is realized that there would be concurrent operation of the fuses and breaker only for bus faults, which are rare.

On applications where some overlapping cannot be avoided it is recommended that the primary fuses be replaced as a matter of operating procedure whenever the secondary main breaker trips for a bus fault. In some cases the use of a non-damaging type of fuse may minimize the overlap problem.

Installation and Testing of Protective Equipment

In order to secure the full benefit which a properly designed protective installation is capable of providing it is necessary to make certain that it has been properly installed and tested. The tests which must be performed are always exacting and often quite complex; and they must be performed very carefully to avoid endangering persons and equipment. Where it is at all possible, it is wise for industrialists to hire these services from specialists; but where this is impossible the following guide may be of assistance.

The checking which must be done on a new installation to ascertain that it has been correctly installed, connected and adjusted is of course much more comprehensive than the testing which should be done periodically to assure against deterioration, gradual loss of adjustment, or tampering. The subject of installation checking will therefore be discussed in detail, after which there will be some consideration as to which tests shoud be repeated periodically and which can safely be omitted.

Installation Checking

This work is discussed under four main heads as follows:

I. General survey and diagramming.

II. Preliminary checking of equipment.

III. Calibration and setting of installed equipment.

IV. Final checking of equipment going into service.

I. GENERAL SURVEY AND DIAGRAMMING

a. Study the intended function of each device, and the manner in which all of the devices are intended to be coordinated.

b. Check the wiring diagrams to be sure that each device is so connected as to be able to perform its intended function. If no diagrams have been provided, either make them or insist on getting them for it will be almost impossible to do a safe or intelligent job of testing without them. Preserve the diagrams for future reference, and see that they are kept up-to-date when changes or additions are made.

c. Compare the diagrams with the actual connections; and when differences are found, determine whether the error is in the diagram or in the wiring, and correct it.

II. PRELIMINARY CHECKING OF EQUIPMENT

a. Inspect equipment for damage or maladjustment caused by shipment or installation.

b. Verify that all protective relays, auxiliary relays, trip coils, trip circuit seal-in and target coils, fuses and instrument transformers are of the proper type and range.

c. Remove wedges, ties and blocks installed by the manufacturer to prevent damage in shipment.

d. Make electrical continuity checks of all current, potential and control circuits, referring constantly to the diagrams.

e. Remove short-circuiting links from current transformers, after checking that secondary circuits are complete.

f. Make ratio and polarity checks of current and potential transformers.

g. Make tests of the insulation of all relays, wiring, instrument transformer secondaries, and instruments.

h. See that provision is made for future testing of the equipment in conveniently small units. The installation of a relatively small number of test switches, test terminals and test links before the equipment goes into service may make it possible to test the various elements of the protective installation one by one after they are in service, with a minimum of disturbance to production; whereas the omission of such devices will likely require that major parts of the plant must be shut down periodically for testing. Where current transformers or wiring are shared between the relays of a single position and differential or other relays which are common to groups of positions, see that safe means are provided for separating each position's relays, current transformers and wiring from the group relaying for testing.

III. CALIBRATION AND SETTING OF INSTALLED EQUIPMENT

a. Direct trip breakers. Low-voltage air circuit breakers are often tripped directly by the current through them without the interposition of current transformers and relays. They are usually set at the factory; and to check them in the field requires a test source capable of supplying very heavy currents. If they cannot be tested, at least verify that the marked instantaneous and time-delay settings are as required for coordination with other breakers and fuses.

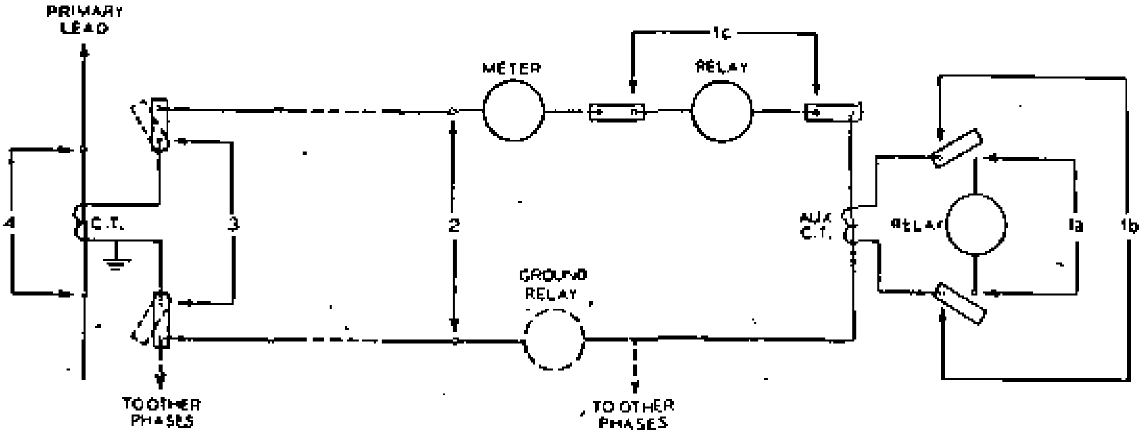


Figure 3.16

b. Relay operated breakers. The relays themselves as instruments can be checked in accordance with the manufacturer's instructions, and with the general guide below in which initial and maintenance checks are compared. However, the actual performance of the relays in service is influenced by the behavior of the instrument transformers which supply them with current and potential; and these in turn are influenced by the magnitude of their secondary burdens. It is therefore advisable to plan the testing in such a way as to obtain information about the performance of the relays, wiring and transformer together as a unit, as well as separately.

Figure 3.16 shows a single phase of a typical current-transformer circuit, indicating four different positions at which test current may be applied. In the first three of these positions it is possible to cause current to flow either toward the relay only, toward the current transformer only, or toward both in parallel. The test from Position 2 or 3 toward the current transformer only is a secondary impedance or excitation test, and should include at least three points on the current-transformer saturation curve, with one at or slightly above the knee. One three-phase set of current transformers may differ widely in impedance from another set, yet each be satisfactory for its own function if the values are consistent within the set.

Position 1. Test Current Applied at the Individual Relay Location

At this point it is possible to make three measurements, each of which is useful under certain conditions. (In order to enable Position 1 to be shown in all three of its variations, an auxiliary current transformer has been shown in Figure 3.16. These are often useful in multiple differentials and other complex schemes but are not generally employed in simple circuits like that of Figure 3.16. In testing they may be treated the same as any other current transformers.)

1a. The relay is disconnected, checked, and calibrated separately as an instrument.

Relays should be checked with current and an accurate timing device when they are placed in service to make sure that they have not been damaged in shipment and that they will operate in the desired time shown by the coordination study curves. If a relay does not give the desired operating time for a given current on the predetermined time dial setting, the desired time can usually be obtained by adjustment of the time dial. Other adjustments should not be attempted unless the adjuster is quite familiar with relay design and performance, or has specific manufacturer's instructions.

1b. With the relay disconnected and the main current-transformer primary effectively open, the test current is applied to the remainder of the secondary circuit. The current drawn should be quite low until the voltage is raised to the point where a main or auxiliary current transformer begins to saturate. This test checks for defects in the secondary circuit, except in the disconnected relay, but including current transformer excitation current, open and short circuits, certain cross connections to other phases, etc.

If this test discloses appreciable differences in the test voltage required to produce a given value of current in the various phases, find out why. The cause may be an open or short circuit in the secondary wiring, or a defective current transformer, or a legitimate unbalance of secondary burden, caused, for example, by single-phase metering or by the omission of a relay on one phase. It is not unusual to find that in the current-transformer common return lead of the three phases the burden, including relays, is much greater than in the phase leads. If it appears to be excessive the tests should be extended at least to Position 2.

1c. The test current is applied to the relay current terminals, with the secondary wiring to the current transformers and other equipment normally connected. The relay is subjected to the same tests as in Position 1a, including timing, any difference in the results obtained being of course due to the fraction of current used in the excitation of current transformers.

This test is of particular value, not only because it provides a measure of the extent to which current-transformer performance affects relay pickup and timing, but also because it is the basis of much maintenance testing. If, on later maintenance tests, the values obtained in this position are substantially the same as in the installation tests, the entire layout may be asumed unchanged. As a rule, only if the tests in Positions 1c and 1b show unexplained unbalances, definitely noticeable saturation or questionable residual burdens will more extended tests be necessary.

Position 2. Test Current Applied at Switchboard Terminals of Current-Transformer Leads

In this position the test current is applied to an entire phase group of relays, meters, auxiliary current transformers, etc. Since the main current transformers remain in shunt with the burden, their effect on relay performance is included. This is a convenient and fairly effective means of determining whether special relay calibrations are required.

In testing ground relays from Position 2, both phase and ground-relay burdens will be included, which is the condition that will obtain in actual operation to clear a ground fault. The phase relays will sometimes be called upon to operate on phase-to-phase faults (test current applied between two current-transformer phase leads) and sometimes on three-phase faults (test current applied between one current-transformer phase lead at a time and the neutral current lead, with the neutral burden jumpered out). If there is any significant difference in readings, data should be recorded for both connections.

It is possible to open the connections at Position 2, so as to test the current transformers without burden other than their leads to the panel. This is particularly advantageous in metalclad installations, where Positions 3 and 4 are apt to be inaccessible or nearly so.

Position 3. Test Current Applied at Current-Transformer Secondary Terminals

In this position the test current is applied across the secondary terminals of the current transformer, or across the secondary leads in the proximity of the current transformer, with all meters, relays and other burden normally connected, and of course with the primary open. The testing is the same as Position 2, and the results are the same except for the added advantages that the secondary leads are included with the burden in the same manner as in normal service and that all devices can be readily identified with their respective current transformers. If leads were not positively identified in other ways, this is very important. It is of course possible also to test the current transformer alone from this position.

Position 4. Primary Current Check

This is the most reliable and satisfactory method of checking the performance of current transformers and relays together, since all burdens are included, together with their normal effect on the saturation characteristics of the current transformer. Unfortunately it is usually difficult to make the necessary high-current connections to the primary copper; and the equipment required for the high-current test source is somewhat unwieldy. For these reasons the primary current check tends to be limited to special applications. When a primary current check is made, both ratio and polarity of current transformers should be determined.

IV. FINAL CHECKING OF EQUIPMENT GOING INTO SERVICE

It is asumed that the usual high-potential and phasing checks have been completed, and that the equipment is energized at normal potential for final check. It is assumed also that the instrument-transformer cases have been grounded with conductors of adequate size, and that the secondary wiring has been grounded either solidly or if necessary through well-designed spark gaps. See the IEEE Application Guide for Grounding of Instrument Transformer Secondary Circuits and Cases, Standards Publication No. 52. With proper grounds in place, with suitable test switches, jacks, links, etc. installed, and with the use of adequately insulated test leads it is customary with many users to manipulate connections and make tests with the equipment energized. It is important, however, to make certain that all of the necessary auxiliary testing devices are present, and that every step of the testing procedure has been planned and closely examined in advance, to guard against unforeseen hazards.

A. *Current-Transformer Secondary-Circuit Checks.* It is absolutely vital to safety to make sure that all changes of connection, insertion and removal of meters, etc., be made in such a manner that the secondary circuits of energized current transformers are not opened even momentarily.

1. *Null Checks.* If current is found where there should be none, a defect is indicated. However, a satisfactory null check is inconclusive and must be supplemented by some kind of positive or activity check, to prevent deception by a false null caused by open or short circuit.

   For differential circuits in which the operating coil normally has no current, check that there is none. This, in conjunction with check 2 or 3, verifies that the current-transformer ratios are correctly balanced and the polarities and phases correctly related.

   Similarly a zero or negligible current reading in the neutral or common return lead of a three-phase set of current transformers under balanced-load conditions indicates ratio balance and like polarity of the three secondaries.

2. *Inspection of Active Relay Circuits.* By use of ammeter, voltmeter and wattmeter of phase-angle meter, it is possible to check that the expected values and polarities of voltage and current are present in the various relay circuits. Check the contact positions of directional elements and voltage relays, and compare with those expected in view of load conditions.

3. *Relay Operation Checks with Diverted Load Currents.* Whenever any relay in service is tested in such a manner as to cause it to operate, the consequences of breaker tripping should be considered.

In some cases arrangements can be made with operating authorities so that tripping can be permitted during a specified period; while in other cases it may be necessary to open the trip circuit of the relay being checked.

Differential Relays

After it has been established that there is current in the individual current-transformer circuits but none in the operating coil circuit, a current may be caused to flow in the operating coil by temporarily short-circuiting and disconnecting all but one of the current-transformer branches. The current from the remaining current-transformer will afford a check not only of the operating coil circuit, but also of the current transformer and its leads. This should be done with each current transformer circuit in turn if they have not been completely verified by other tests.

Neutral or Residual Current Relays

Short-circuit and disconnect the current transformer leads of all but one phase. The remaining phase will supply current to the relay.

B. *Potential Transformer Secondary Circuit Checks.* Measure the potentials applied to all relay potential coils. If any are inadequate, investigate. Look for blown fuses, short circuits, excessive burdens, and improperly adjusted potential devices.

Check the potential transformer and phase to which each relay potential terminal is connected by removing one potential fuse at a time (at the potential-transformer secondary terminals), and noting the effect on the voltage applied to the relay.

Ground-Fault Potential Relays and Elements

Voltage relays, or relay elements, that are connected in one corner of a potential transformer secondary delta have no voltage across them in the absence of a ground fault. Such a fault can be simulated in the following manner:

a. De-energize the equipment, and make it safe to work on.

b. Disconnect the phase lead from one potential-transformer primary terminal, and fasten this lead where it can safely be re-energized.

c. Short-circuit the vacated primary terminal to its neutral terminal.

d. Re-energize the equipment, read voltages and observe relay operation.

e. De-energize the equipment and return connection to normal.

Ground-Fault Directional Relays

These have their potential windings energized from one corner of a broken-delta-connected set of potential transformers, the same as the preceding type, and their current windings from the common (neutral or residual) connection of a set of current transformers. To check them with diverted load currents:

a. Determine the direction of power flow.

b. Alter one phase of the potential transformer primary as above.

c. Short-circuit and disconnect the current-transformer leads of this same phase. This should cause the ground-fault directional relay to indicate a direction of power flow the reverse of that actually obtaining in the line. That is, if power flow is toward the bus, the relay contacts should close to trip.

d. Restore the current-transformer leads removed above, remove their short circuit, and then short-circuit and remove the current-transformer leads of the other phases. This should cause the relay to indicate a direction of power flow the same as that actually in the line.

e. Restore all connections to normal.

C. *Staged System Tests at Normal or Reduced System Voltage.* This method offers no difficulties in the case of automatic throw-over devices, and is therefore the best method of testing them. Nearly all other system tests require setting up staged faults, which are the last resort in testing. The faults are applied to the system at carefully chosen times and places, under controlled and back-up-protected conditions; and the action of relays and other equipment is recorded and analyzed. Such tests are seldom used, and can only be justified if (a) the scheme is intricate, new or unfamiliar, or (b) the wiring is complicated or inaccessible, or (c) the relay response characteristics are believed to be so critical that the use of normal or diverted load currents would introduce intolerable phase-angle errors, or (d) the scheme has shown otherwise unexplainable misbehavior.

Before any staged fault test should be approved, it should be established that no other method of testing will suffice, the plan should be scrutinized from every conceivable safety angle, and all parties who could possibly be affected by it should be notified.

Periodic Testing

Protective equipment should be checked periodically to assure that its operation and coordination have not been impaired by exposure to dusty, smoky, oily or corrosive atmospheres, by mechanical vibration or shock, by excesive temperature, by tampering, or in any other manner. The consequences of neglecting proper testing may at first seem slight; but they are cumulative and such neglect can lead to an increasing loss of protection.

Responsibility for Periodic Testing

If a plant is interconnected with a utility, that utility will probably own or control the protective equipment adjacent to one or both sides of the tie point, and will itself make the initial and periodic tests deemed necessary to protect its own equipment and the service to its other customers. The acceptance of responsibility for the proper maintenance of other equipment is sometimes covered by contracts and correspondence between the utility and the industrial power user; but more frequently it is left to be defined by custom and practice. It is desirable to have these matters more clearly defined; for both parties profit if each recognizes its responsibilities to the other in view of the fact that fault currents do not respect an arbitrary boundary line.

It is never safe for the industrial user to assume that the burden of protective equipment periodic checking is automatically placed on the utility by its need to protect its own equipment and service. This may indeed be almost true in the case of incoming lines and the equipment directly connected thereto; but there are many points in most industrial plants where faults could occur that if uncontrolled would be very costly to the plant but hardly noticeable to the utility. A particular utility may, as a matter of customer relations, provide services for positions of the latter class as well as of the former; but the necessities of its own operation do not require it to do so.

Frequency of Testing

The time interval that may safely be allowed to pass between tests of protective equipment is a variable, depending upon such factors as cleanliness of atmosphere and surroundings, average operating temperatures, freedom from vibration and shock, quality of operating personnel, etc. The best interval in any given type of installation must be determined by experience, but will in all cases lie somewhere between a minimum of six months and a maximum (with supplementary operating checks at intermediate periods) of three years. It may be taken as a guide that if no deterioration is found on several successive checks, the testing is probably too frequent; while if equipment is found in a completely inoperative condition the testing has been delayed too long. The ideal is to test frequently enough to detect and repair incipient trouble.

Regularly scheduled testing should be supplemented with special tests made at any time that there is reason for suspecting that the protective equipment may have been damaged. One of the plus values of an intelligent and loyal operating force is the assistance it can give in noting and reporting signs of abnormal performance; and where such assistance is reliable, the periodic tests may be scheduled less frequently. Standard test values should, of course, be on file, and whether all tests are recorded or not, details of any defects found should be recorded. The records should include all protective gear, not relays only, and should include special as well as periodic tests.

Scope of Testing

Testing of protective equipment is generaly thought of in terms of relay testing; but its value goes far beyond mere verification of the relay's calibration. In fact, the greater number of irregularities found do not involve the relays as instruments. The testing should be so planned as to check, as far as possible, the entire scheme from instrument transformers to circuit breaker operation.

Instrument Transformers and Wiring

Equipment should be inspected visually for obvious defects such as broken studs, loosened nuts, damaged insulation and the like.

Ordinarily the indication of normal potential at the relay by lamp or voltmeter is considered adequate verification for potential transformers and circuits. If the combined relay and current-transformer check made at installation can be repeated, the repetition of substantially the same results will be sufficient proof that there is no short circuit in the current transformer or its leads. A check under load with a low-burden ammeter in series or shunt with the relay will establish proof of continuity. More elaborate checking as outlined under installation, is required if there has been any change in the equipment or wiring, if a change in setting materially alters the current or potential transformer burdens, or if there is evidence of improper performance. In this latter case, it is desirable also to test the insulation of the current, potential and control wiring; this requires that the equipment be completely de-energized and the protective grounds removed.

Relays in General

The relays should be inspected for loosened terminals, lock screws and other parts, for fillings or other foreign material in magnet gaps, for burned or dirty contacts, for sticky contact back-stops, for dirty, worn or broken bearings or any other causes of sluggish operation, for damaged coils, resistors or wiring, and for damaged or maladjusted indicator targets or holding devices.

Performance tests of the relays will vary somewhat with the type. The following list compares initial and periodic tests for some of the more common types of relays:

Differential Relays

a. Initial. Verify the published differential characteristics by checking at minimum operating current and at several other values.

b. Periodic. Check minimum operating current with current in each restraint coil. Check operation and time at a higher value with one restraint coil.

Undervoltage Relays

a. Initial. Check and adjust pick-up and drop-out values. Record time, at least on drop from normal to zero volts.

b. Periodic. Check drop-out voltage and time.

Overvoltage Relays

a. Initial. Check and adjust pick-up and drop-out values Check time characteristics, if specified, and operational functions.

b. Periodic. Check pick-up Check operation according to desired functions, which are quite different in various installations.

Directional Elements

a. Initial. On energizing the current winding or the potential winding alone, there should be no more than a slow drift toward closing. Using high current and low voltage, determine the minimum volt-amperes required for effective closing. Set test-feed for high (60 amperes or more) current and no voltage, and apply momentarily; the contacts should not close. In applying time settings to a directional overcurrent relay, arrange the test to include the time of both the directional and the overcurrent elements. *Note:* On current-polarized directional units and on current-product type of directional relays, the current coils can usually be connected in series for ease in testing and calibrating.

b. Periodic. Test for action of current or voltage alone as above. Check overall time, including the associated element. Check directional element time separately only if the selectivity margins are so close as to require it.

Instantaneous Overcurrent Relays and Elements

In checking pick-up current of these relays, it is advisable to raise the current gradually in order to avoid transient effects. Also, some plunger-type relays exhibit a marked increase of burden impedance when the gap of the magnetic circuit closes in operating, so that it may be difficult to obtain certain values of current on test. This effect can be made less troublesome by the use of relatively high values of test voltage, including a resistance in series with the test source. If a relay heats excessively during current adjustment, make a preliminary adjustment of the current with the relay by-passed.

a. Initial. Check pick-up current and adjust if required. Drop-out is important in a few applications. If a plunger-type relay has trip coils or other protective devices in series with the relay coil, check from Position 2, 3 or 4, to be sure that the pick-up relay does not make the total current-transformer burden too great for the operation of these other devices.

b. Periodic. Check minimum pick-up current and functional response.

Induction Time-Overcurrent Relays and Elements

These are particularly susceptible to variation in both pick-up current and timing if the waveform of the current used for testing is distored. Such distortion can arise from non-linear magnetic effects either in the relay itself or in a test transformer. It can be minimized by using a relatively high-voltage test source (several times the voltage required across the relay winding itself), absorbing the excess in a rheostat connected in series with the relay. Some relays also change characteristics with heating, which may arise from ambient temperatures, load currents or test currents.

a. Initial. Check pick-up current, and operating time at the specified current values. These may be anywhere from 1.5 to ten times the minimum pick-up current depending upon the nature of the selectivity margins with other protective equipment. Make all of these tests both with the relay isolated and with the current transformers and other burden included, and if there is any significant difference record both sets of data for future use.

b. Periodic. Check pick-up current and timing, preferably in a combined test.

Control Wiring and Operation

An important step in periodic testing of protective equipment is to make certain that the operation of any tripping relay will result in the breaker being tripped. After a visual check of all terminals and exposed portions of the trip circuit wiring and of the condition and adjustment of any circuit-breaker auxiliary switches in the trip circuit, make at least one check of an actual trip operation from the relay contacts. Where there are a number of relays and it is not desired to trip the breaker from each, it is usually possible to devise other means of testing the trip circuit through the other relays to a common point on the opening control wire; or a record may be kept of the relay from which the breaker was tripped, so that all may be covered in successive periods.

Summary: Requisites for Protective Equipment Testing

1. Adequate test sources.

2. Adequate test switches or similar means of isolating equipment for test, both individually and also in functional groups.

3. Control and metering equipment for the applied currents and voltages. Some types of relays require special equipment, which is specified in the manufacturer's instruction books.

4. Adequate means of detecting and timing trip circuit closures and openings. This device will also be found useful for timing circuit breaker closing and opening times, etc.

5. Adequate records of all connections, electrical constants, settings, test values, operating performance, and failures or weaknesses found on test.

6. Trained personnel.

FUSES

MEDIUM-VOLTAGE AND HIGH-VOLTAGE FUSES:

A fuse is defined by NEMA SG2-1.01 as "An overcurrent protective device with a circuit-opening member heated and destroyed by the current passing through it."

From this definition it can be seen that a fuse is primarily responsive to current and does not selectively respond to any other system occurrence.

Medium-voltage and high-voltage fuses vary widely in their design and construction, however, they can be divided into several general classifications as follows:

1. Distribution cutouts.

2. Non-current-limiting with renewable fuse elements.

3. Non-current-limiting with non-renewable fuse elements.

4. Current-limiting fuses.

The designs of the various fuses vary widely, therefore they can only be described in a general way.

Distribution Cutouts:

The cutout is a medium-capacity fuse intended for use in a distribution system up to 15 kV. It consists of a fuse mounting, fuse holder, and fuse link. The fuse holder has a medium interrupting rating and is designed to use the universal type cable link at its maximum rating for five interruptions with only the universal link being replaced. The cutout is used at small substations for protection against line faults, isolating faulted distribution transformers, at capacitor installations and in small industrial plants. When applying fuse cutouts, system short-circuit currents must be known, in order not be exceed the manufacturer's rating. Modern cutouts have interrupting ratings in the magnitude of 8000 amperes at 7.2 kV (symmetrical) and 6700 amperes at 14.4 kV (symmetrical). Cutouts should not be used in confined or enclosed areas.

Non-Current-Limiting Power Fuse with Renewable Element

This type fuse is a medium-capacity fuse intended for use in industrial and central station systems up to 34.5 kV. It consists of a mounting, fuse holder and fuse refill unit. The fuse is available in continuous ratings of 200 amperes maximum, 400 amperes maximum, and (for two fuses in parallel) 720 amperes maximum for voltage ratings up through 15 kV. Continuous ratings up to 300 amperes are available at 23 and 34.5 kV. A variety of short-circuit interrupting ratings are available, up through 60,000 amperes asymmetrical at 2.4 and 4.16 kV, 40,000 amperes at 13.8 kV, 32,000 amperes at 23 kV, and 28,000 amperes at 34.5 kV. These ratings can be expressed as three-phase symmetrical short-circuit interrupting ratings as follows.

Nominal Rating kV	Short-Circuit Interrupting Rating, MVA
2.4	150
4.16Y/2.4 Grounded Y	250
13.8	500
23.	750
34.5	1000

This fuse has many applications in a distribution system of an industrial plant.

Non-Current-Limiting Power Fuse with Non-Renewable Element

This type fuse is a high-capacity fuse intended for use on industrial and central station systems up to 138 kV. It consists of a mounting, fuse end fittings, and fuse unit. The fuse is available in current ratings up through 300 amperes, and voltage ratings through 138 kV, and is available in various interrupting ratings up through 1,500,000 kVA (three-phase symmetrical) at 34.5 kV, 1,750,000 kVA at 46 kV and 2,000,000 kVA at 69 through 138 kV.

Current-Limiting Fuse

This type fuse is a medium-capacity fuse primarily developed for use with a contactor, to obtain a high-interrupting-capacity high-voltage starter. It can also be used as a distribution-type fuse. It consists of a mounting, fuse fittings and a fuse unit. The fuse is available in ratings up to 200 amperes at 5 kV and 100 amperes at 15 kV with interrupting capacities in the order of 50,000 to 60,000 amperes.

The fuse is so designed that the melting of the fuse element introduces a high arc resistance in the circuit in advance of the possible peak current of the first half cycle. This restricts the short-circuit current to a lower value than would be present without the current limiting effect of the fuse.

This fuse is widely used on industrial systems wherever it is necessary to limit short-circuit current on high-capacity systems. It is used to protect potential transformers, small loads on high-capacity circuits, and on high-voltage motor starters.

NEMA FUSE RATING

All power fuses manufactured at the present time are the NEMA "E" rating fuse which meet the following standards:

1. All fuses must carry their current rating continuously.

2. Fuses rated 100 amperes or less shall melt in 300 seconds at an rms current within the range of 200 to 240 percent of the continuous rating of the fuse element.

3. Fuses rated above 100 amperes shall melt in 600 seconds at an rms current within the range of 220 to 264 percent of the continuous rating of the fuse element.

Application of Fuses

In the application of a fuse it must be selected for voltage, current-carrying capacity and interrupting capacity. When fuses must be coordinated with other fuses or breakers the characteristic curves must be used.

The voltage rating of a fuse should be selected as the next higher standard voltage rating above the service voltage.

The current rating of a fuse should be selected so that it blows only on faulted condition or long time overload and not on current inrush. Ambient temperatures and types of enclosures affect fuse performance and should not be overlooked. When fuses are applied to motor feeder circuits they must be selected by the motor manufacturer, or full details of the motor charactertistics must be supplied to the fuse manufacturer.

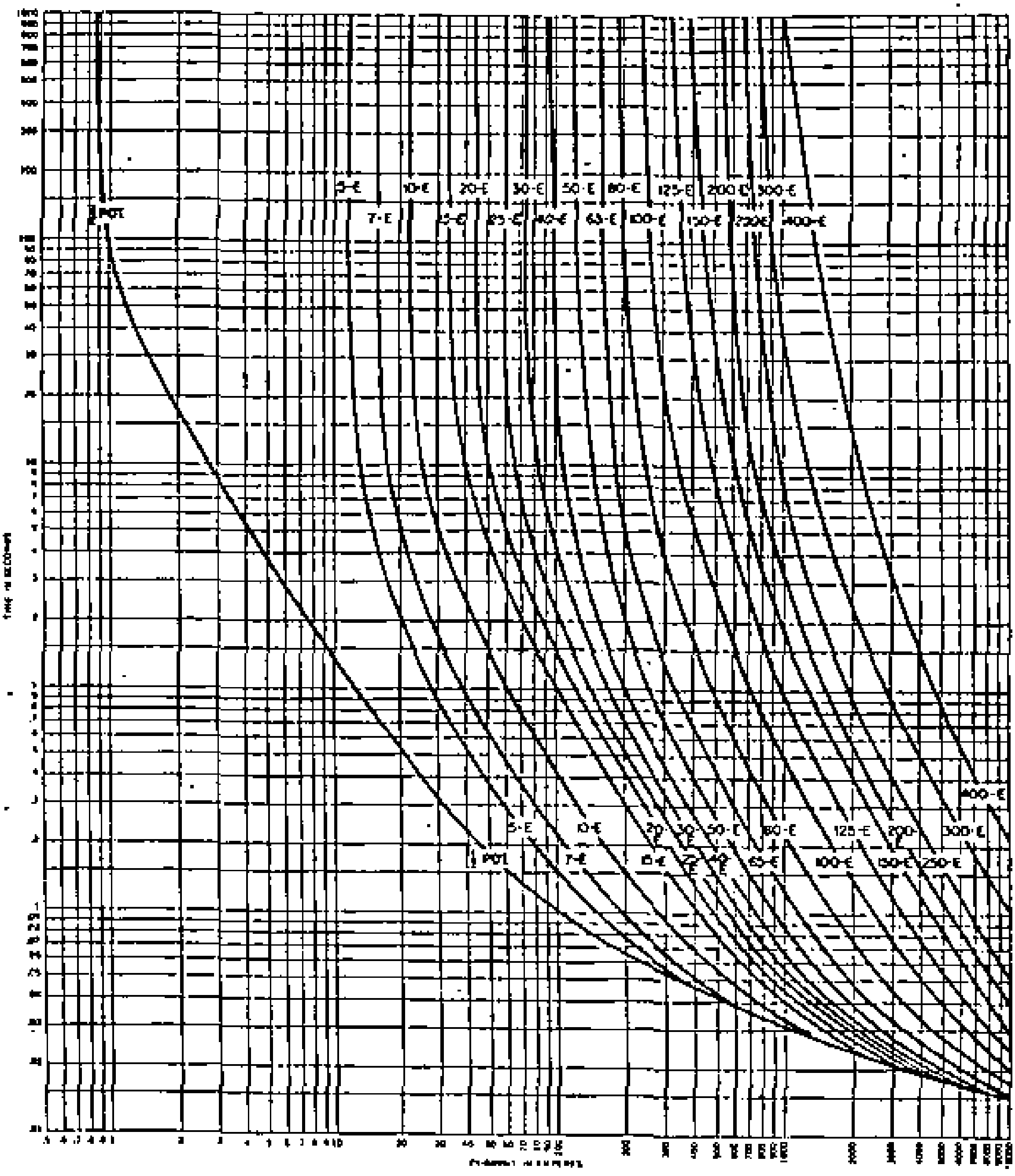


Figure 3.19
Total Clearing Time-Current Characteristics—Standard Refills—No Previous Loading · At a Temperature of 25 C

These curves are based on maximum test points so all variations are negative. They should be used for all coordination problems where the fuse is the PROTECTING device. Where the fuse is the PROTECTED device, refer to Figure 3.17.

A dual-element fuse has current-responsive elements of two different fusing characteristics in series in a single cartridge. The fuse is one-time in operation, and the fast-acting element protects against short circuits in much the same way as an ordinary fuse. The long-delay element permits short-duration overloads, but melts if these overloads are sustained. The most important application of these fuses is for motor circuits. They do not blow on motor inrush current, but protect the motor and branch circuits from damage by sustained overloads. Another advantage of dual-element fuses is that they operate cooler than the typical one-time fuse. Further, the overload element acts as a temperature protector for the fuse, causing the fuse to blow before its structure is damaged by some abnormal condition such as an overheated fuseholder. Dual-element fuses in which the short-circuit element is current-limiting are available.

Current-limiting fuses are intended for application to circuits where available short-circuit current is beyond the interrupting rating of ordinary fuse (or standard circuit breakers). According to NEMA (Standard 8-13-1959), "An ac current-limiting fuse is a fuse which safely interrupts all available currents within its interrupting rating and, within its current-limiting range, limits the clearing time at rated voltage to an interval equal to or less than the first major or symmetrical current loop duration and limits peak let-through current to a value less than the peak current that would be possible with the fuse replaced with a solid conductor of the same impedance". The current-limiting fuse, therefore, places a definite ceiling on the peak let-through current. It differs in this respect from a high-interrupting capacity fuse which simply interrupts short circuits up to its maximum rating but does not influence the current which flows in the circuit.

A discussion of power equipment incorporating fuses, and of the general advantages and disadvantages of fuse relative to circuit breakers, will be found in Chapter VII, Power Equipment.

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CHAPTER IV

FAULT CALCULATIONS

Protection of industrial power systems against failures in circuits and equipment has become of increased importance with the expanded utilization of electric power in industry. Even the best designed electric systems will occasionally experience short circuits resulting in abnormally high currents. Overcurrent protective devices must operate to isolate such faults safely with a minimum of damage to circuits and equipment and with a minimum amount of shutdown of plant operation. The circuit breakers and fuses ordinarily used to perform this protection job must be selected to handle and interrupt safely the largest currents to which they may be subjected. Other parts of the system such as cables, bus duct, and disconnect switches must be capable of withstanding the mechanical and thermal stresses resulting from maximum flow of fault current through them.

The current flow during a fault at any point in a system is limited by the impedance of circuits and equipment from the source or sources to the point of fault and is not directly related to the load on the system. However, additions to the system, made to handle a growing load, while not affecting the normal load being carried in some existing parts of the system, may well cause protective devices in those parts to be subjected to drastically increased fault currents. Expansion of an existing system as well as installation of a new system should include an accurate knowledge of available fault currents for proper application of overcurrent protective devices. The purpose of this chapter is to present a relatively simple method for calculating fault currents and to furnish typical data which can be used in making such calculations.

The size and complexity of many modern industrial systems may well make long-hand fault calculations so time consuming as to be impractical. Analog and digital computer facilities are available in many locations and the cost of using these facilities may be justified where a major fault study is planned. Whether or not these facilities are used, a knowledge of the nature of fault currents and calculating procedures is essential to such a study.

Sources of Fault Current

Current which flows during a fault comes from two basic sources, synchronous and induction rotating machines. These may be operating as generators, motors or synchronous condensers. The current which each of these delivers to a fault on its own terminals is limited by the impedance of the machine. Each of these rotating machines produces fault current which decreases with time after the initiation of a fault. In other words, these sources exhibit a variable reactance to the flow of fault current.

Generators

Fault current from a generator decreases exponentially from a relatively high initial value to a lower steady-state value some time after the initiation of the fault. Since a generator continues to be driven by its prime mover and to have its field energized from its separate exciter, the steady-state value of fault current will persist unless interrupted by some switching means.

For purposes of fault current calculation, the variable reactance of a generator can be represented by three reactance values.

X''_d = Subtransient Reactance — Determines current during first cycle after fault occurs. In about 0.1 second this value increases to the value:

X'_d = Transient Reactance — This value increases in about ½ to 2 seconds to the value:

X_d = Synchronous Reactance — This is the value that determines the current flow after a steady-state condition is reached.

As most fault protective devices, such as circuit breakers or fuses, operate before steady-state conditions are reached, generator synchronous reactance is seldom used in calculating fault currents for application of these devices.

Synchronous Motors

Synchronous motors supply current to a fault in much the same manner as do synchronous generators. Upon the drop in system voltage due to a fault, the synchronous motor receives less power from the system for rotating its load. At the same time the internal voltage will cause current to flow to the system fault. The inertia of the motor and its load acts as a prime mover and with field excitation maintained, the motor acts as a generator in supplying fault current. This fault current diminishes as the motor slows down.

The same designation is used to express, in useful terms, the variable reactance of a synchronous motor as previously described for a generator. However, numerical values of the three reactances X''_d, X'_d and X_d will often be different for motors than for generators.

Induction Motors

The fault current contribution of an induction motor results from generator action produced by inertia driving the motor after the fault occurs. In contrast to the synchronous motor the field flux of the induction motor is produced by induction from the stator rather than from a direct-current field winding. Since this flux decays on removal of source voltage resulting from a fault, the contribution of an induction motor drops off, disappearing completely after a few cycles. As field excitation is not maintained there is no steady-state value of fault current as for synchronous machines. As a consequence of these factors, induction motors are assigned only a subtransient value of reactance (X''_d). This value will be about equal to the locked-rotor reactance hence the fault current contribution will be about equal to the full-voltage starting current of the machine.

Wound-rotor induction motors normally operate with their rotor rings shorted. In this circumstance they will contribute fault current in the same manner as a squirrel-cage induction motor. Occasionally, however, large wound-rotor motors are operated with some external resistance maintained in their rotor circuits. These machines may then have sufficiently low short-circuit time constants that their fault contribution is not significant. A specific investigation should be made before neglecting the contribution from a wound-rotor motor.

Capacitors

The discharge current from power capacitors to a system fault is of a high-frequency nature with a time constant of only one or two cycles in most cases. Therefore the effect from power capacitors on system fault currents can usually be neglected. Unnecessary tripping of the capacitor bank breaker on capacitor inrush or discharge currents is avoided by the use of overcurrent relays having a short time delay. Accordingly it is not usual practice to calculate capacitor discharge currents.

Fundamentals of Fault-Current Calculation

Ohms Law, $I = E/Z$, furnishes the relationship used in determining fault current, where I is the desired current, E is normal system voltage at point of fault, and Z is the impedance from source to fault including the impedance of the source. Rigorous calculations generally introduce tedious and time consuming complications and experience has shown that simplifying assumptions can be made which detract little from accuracy and much from labor.

Type of Faults

In the usual procedures of fault-current calculation it is assumed that the fault is a zero impedance, "bolted" fault with no current-limiting effect due to the fault itself. Such calculations are used to determine the maximum short-circuit current value for the purpose of selecting devices of adequate interrupting rating, momentary rating, and to determine the maximum value of current at which time-current coordination need exist in relay studies. The three-phase fault condition is frequently the only one considered since, in an industrial system, this type of fault generally results in maximum current.

In medium- and high-voltage systems line-to-line fault currents are approximately 87 percent and line-to-ground fault currents can range from about 60 percent to possibly 125 percent of the three-phase value. However, line-to-ground fault currents of more than the three-phase value are rarely encountered in industrial systems. Because of this, only the method of calculating three-phase fault currents is presented here. Calculations are vastly simplified by assuming a three-phase fault condition because the system including the fault remains symmetrical about the neutral point whether or not the neutral point is grounded and regardless of star or delta transformer connections. The current can be calculated on a single-phase basis using only line-to-neutral voltage and impedance.

It should be recognized however that faults which occur in practice generally involve the impedance of an arc, with its varying limitation on the magnitude of fault current. In low-voltage systems there is a trend toward taking this factor into account in order to calculate the minimum value of fault current, which is of interest when specifying the necessary sensitivity for protective devices. (Reference 7). Approximate minimum value of arcing-fault current in per unit of three-phase voltage value for typical cases equal: 0.89 at 480 volts, 0.12 at 208 volts for three-phase arc; 0.74 at 480 volts, 0.02 at 208 volts for line-to-line single-phase arc; 0.19 at 480 volts, 0.00 at 208 volts for line-to-neutral single-phase arc.

Voltage and Impedance

The voltage which serves as a basis for fault current calculation is derived from the rated nameplate voltage of the generator or transformer supplying the faulted element of the system. As explained previously this value will be a line-to-neutral voltage or

$$\frac{\text{Rated Line-to-Line Voltage}}{\sqrt{3}}$$

In alternating-current circuits the impedance is the vector sum of resistance and reactance. In major elements such as generators and transformers the reactance is usually at least 5 times the resistance. The fault current calculated by neglecting the resistance of the major elements and using only reactance will be in error by only a few percent. This error is on the safe side for calculating interrupting duty for fault protective devices. Because of this, the resistance of generators, transformers, motors, reactors and large bus work is not considered regardless of system voltage.

In systems above 600 volts the resistance of other circuit elements, such as cables, is generally neglected. In systems below 600 volts when calculating faults out on branch feeder circuits, resistance should generally be considered. If conductor resistance is important in calculating faults at any point in the system, it is likely to be in low-voltage branch feeder circuits where the wire size is small. It is suggested that the following procedure be used for low-voltage feeder circuits. If the resistance of the feeder circuit is ¼ or more of the total reactance from source to fault, resistance should be included in the calculations. The resistance of the system up to the feeder should now be included and an approximate total resistance obtained by adding to the resistance of the feeder a resistance equal to ¼ of the total reactance of the system from source to feeder. Using this value of total equivalent resistance R, and the total equivalent reactance X, the impedance to the fault is found by the expression:

$$Z = \sqrt{R^2 + X^2}$$

It is important to consider the reactance of all circuit elements in calculating fault currents on low-voltage systems. The importance of small elements of reactance, in limiting total fault current becomes great in systems below 600 volts.

Symmetry of Fault Current—Direct-Current Component

In determining the maximum value of fault current which can occur at some point in a system, it must be considered that the fault-current wave is likely to not be symmetrical about the zero current axis for several cycles after the fault occurs. System voltage and fault current are substantially sine wave in shape and are related in phase angle by the impedance angle of the system to the point of fault. Since the resistance will usually be negligible in comparison to the reactance, the fault current will usually lag the source voltage by nearly 90 degrees. This means that when a fault occurs at or near the peak of the voltage wave, the fault-current wave starts at zero and is symmetrical about the zero axis. When a fault occurs at or near the zero point of the voltage wave, the fault-current wave again starts at zero on the original zero axis. However, at the start of the fault the current magnitude should be at or near peak because the voltage leads by 90 degrees and is at zero magnitude. To meet this requirement, the fault-current wave becomes symmetrical about a new zero axis and is offset or asymmetrical to the zero axis of the voltage wave.

The magnitude of offset for any fault will be between the two extremes described above. When the resistance of the system to the point of fault is not negligible, the point of the voltage wave at the time the fault occurs, to produce maximum or minimum asymmetry, will be different than for the circuit containing negligible resistance. Maximum asymmetry occurs at a time angle equal to 90° + θ (measured in degrees from the zero point of the voltage wave), where tangent θ equals the X/R ratio of the circuit.

For convenience purposes the asymmetrical fault-current wave can be considered as composed of two basic components. With the zero axis of the voltage wave as a reference, the symmetrical alternating-current component of fault current (as determined by E/Z), has superimposed on it a direct-current component whose magnitude is determined by the point on the voltage wave at which the fault occurs.

The magnitude of the direct-current component can vary from zero to a maximum equal to the peak of the symmetrical alternating-current component. The initial magnitude of the direct-current component is equal to the value of the alternating-current symmetrical component at the instant the fault occurs. At any instant after the fault, the magnitude of current is equal to the sum of the alternating-current and direct-current components (see Figure 4.1).

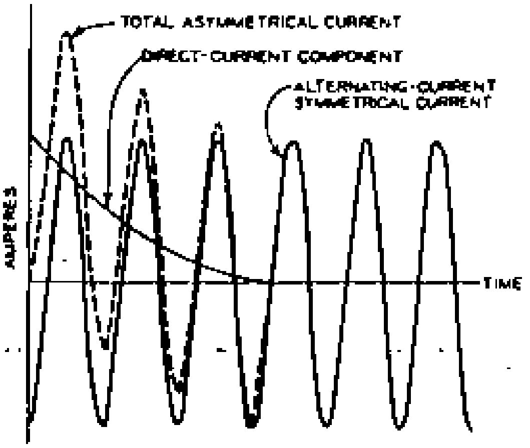


Figure 4.1
Typical system fault current

In a theoretical system with zero resistance, the direct-current component of fault current would remain at a constant value. However, in an actual system where resistance is present, the direct-current component decays to zero as the stored energy it represents is expended in the form of I^2R loss in the resistance of the system. The rate of decay of the direct-current component is proportional to the ratio of reactance to resistance (X/R ratio) of the system from source to fault. The lower the X/R ratio the more rapid is the decay of the direct-current component. The effect of this decay is that the fault current gradually changes from an asymmetrical to a symmetrical current with respect to the zero-voltage axis.

There are thus two factors which result in the initial magnitude of fault current being greater than the steady-state fault current. One of these is the variable reactance of rotating machines and is accounted for in fault-current calculations by using the initial value of machine reactance, that is, the subtransient value. The second factor is the initial asymmetry explained in terms of a decaying direct-current component. This second factor does not readily lend itself to a mathematical analysis and is most easily accounted for by the use of simple multipliers applied to the calculated symmetrical value of fault current.

In the past these multipliers were applied to determine asymmetrical fault-current values. These fault currents were then used in the selection of equipment which had asymmetrical current capability ratings. A definite trend is now taking place toward the elimination of the use of asymmetrical equipment ratings. Table 4.12 lists the asymmetrical multiplying factors still in use at the time of this writing. Multipliers are applied to the calculated rms symmetrical fault current to obtain the rms asymmetrical value desired for application of protective devices.

DETAILED PROCEDURE

Calculations Using Ohms, Percent Reactance or Per Unit Reactance

The determination of short-circuit currents has been shown to be dependent principally upon the reactance X from the source (or sources) to the fault. The principal problem of short-circuit current determination is one of determining this reactance. To obtain it, the reactance of each significant element in the electric circuit must be determined and the elements combined in series or parallel.

At the outset a decision must be made concerning the system used for expressing the reactance of the elements. Three systems can be used with reactance expressed either in ohms or in percent or per unit on a chosen base value. It is often convenient to use the per unit system in calculations involving a system with several different voltage levels. When reactances are expressed as per unit quantities on a chosen kva base, they can be combined directly without regard for transformer turns ratio in systems utilizing more than one voltage level. In this chapter the per unit system will be used.

Conversion equations for the three systems are as follows:

Per unit reactance =

$$\frac{\text{percent reactance}}{100} \tag{4.1}$$

Per unit reactance (on chosen kVA base) =

$$\frac{\text{ohms} \times \text{kVA base}}{1000 \times \text{kV}^2} \tag{4.2}$$

Per unit reactance (on chosen MVA base) =

$$\frac{\text{ohms} \times \text{MVA base}}{\text{kV}^2} \tag{4.2a}$$

Percent reactance (on chosen kVA base) =

$$\frac{\text{ohms} \times \text{kVA base}}{10 \times \text{kV}^2} \tag{4.3}$$

Percent reactance (on chosen MVA base) =

$$\frac{\text{ohms} \times \text{MVA base}}{\text{kV}^2} \times 100 \tag{4.3a}$$

where: Ohms are line-to-neutral values (single conductor).

kVA base is the three-phase base kVA.

kV is line-to-line voltage.

MVA = 1000 kVA.

The per unit and percent systems are methods of expressing numbers in a form that allows them to be easily compared. Actually they are a ratio based on a prechosen base number. In determining fault currents a convenient base kva number must be chosen. Reactances for buses, cables, lines, current transformers, air circuit breakers, etc., will be given in ohms, and it will be necessary to convert these values into percent or per unit reactances on a chosen kva base by means of equations (4.2) and (4.3).

Elements in the system such as transformers, generators, motors, etc., normally will have their reactance given in percent based on their own kva rating. These reactances must be converted to the chosen kVA base as follows:

Per unit reactance on base kVA = (4.4)

$$\text{Per unit reactance on kVA rating} \times \frac{\text{base kVA}}{\text{kVA rating}}$$

For example, assume a value of 1000 kVA has been chosen as a kVA base. One of the elements of reactance is a 500-kVA transformer with a reactance of 5 percent on its kVA rating. This transformer would then be represented by the following per unit reactance on the chosen kVA base:

$$X_{pu} \text{ (on kVA rating)} = \frac{5\%}{100} = .05$$

$$X_{pu} \text{ (on base kVA)} = (.05)\frac{1000}{500} = .10$$

First Step—Preparing of System Diagrams

Prepare a One-Line Diagram

Preparation of a one-line diagram is the first step in making a short-circuit study. This diagram should show all the sources of short-circuit current and all the significant circuit elements. Figure 4.4 is a one-line diagram of a hypothetical industrial system.

The following tabulation will serve as a guide to proper choice of reactances and impedances to be used for determining fault currents above and below 600 volts.

For faults above 600 volts

- Utility supply reactance
- Main plant substation transformer reactance
- Plant generator reactance
- Plant primary feeder reactances
- Plant secondary substation reactance
- Plant distribution circuit reactance
- High-voltage (above 600 volts) motor reactances
- Contribution through transformers from low-voltage motors

For faults below 600 volts

- Utility supply reactance
- Main plant substation transformer reactance
- Plant generator reactances
- Plant primary feeder reactances
- Plant secondary substation reactance
- Plant distribution circuit reactance
- Branch feeder circuit reactance and resistance (see page 92).
- Motor reactances (both above and below 600 volts)
- Impedance of any significant low-voltage bus runs
- Low-voltage circuit breaker reactances
- Current transformer reactances

Prepare Reactance Diagram

Simplify the one-line diagram when desirable by making a reactance diagram. This is a one-line diagram in which all the significant equipment reactances are indicated. Figure 4.5 is a reactance diagram for the one-line diagram shown in Figure 4.4. In many cases clarity of the one-line diagram can be maintained and it will prove most convenient to add the reactance data to the one-line diagram.

Second Step—Assign Reactance Values

Assign reactance values to all system elements shown on reactance diagram.

Below is a listing of reactance tables available in this chapter.

- Table 4.1 Reactance Values for Synchronous Machines.
- Table 4.2 Reactance Values for Induction Motors.
- Table 4.3 Reactance Values for Transformers.
- Table 4.4 Representative Conductor Spacing for Overhead Lines.
- Table 4.5 Constants of Copper Conductors for One Foot Symmetrical Spacing.
- Table 4.6 Constants of Aluminum Conductors for One Foot Symmetrical Spacing.
- Table 4.7 60-Hertz Reactance Spacing Factor (X_d) Ohms Per Conductor Per 1000 Feet for Feet and Inches.
- Table 4.8 Reactance Values for Typical Three-Phase Cable Circuits.
- Table 4.9 Reactance of Low-Voltage Power Circuit Breakers.
- Table 4.10 Reactance of Low-Voltage Disconnect Switches.
- Table 4.11 Reactance Values for Current Transformers.
- Table 4.12 Multipliers and Reactances to be Used in Short-Circuit Calculations.

Figures 4.3a through 4.3f give reactances for bus bars.

Table 4.1

Typical Reactance Values for Synchronous Machines Per Unit Values on Machine kVA Rating*

	X''_d	X'_d
**Turbine Generators		
2 pole	.09	.15
4 pole	.15	.23
**Salient Pole Generators with damper windings		
12 poles or less	.16	.33
14 poles or more	.21	.33
Synchronous Motors		
6 pole	.15	.23
8-14 pole	.20	.30
**Synchronous Condensers	.24	.37
**Synchronous Converters		
600 volts direct current	.20	—
250 volts direct current	.33	—

*Use manufacturer's specified values if available.
**X'_d not normally used in short-circuit calculations.

Note: Synchronous motor kVA bases can be found from motor horsepower ratings as follows:
.8 pf motor — kVA base = hp rating
1.0 pf motor — kVA base = 0.8 x hp rating

Reactancias típicas de motores de inducción en p.u. base kVA de la máquina.

Table 4.2

Typical Reactances of Induction Motors Per Unit Values on Machine kVA Base (horsepower rating)

	X''	X'
Above 600 volts (Arriba de 600 volts)	.17	—
600 volts and below (o menos)	.25*	—

*The value of X'' for motors 600 volts and below has been increased slightly to compensate for the very rapid short-circuit current decrement in these small motors.

El valor de X'' para motores de 600 volts o menos ha sido incrementado ligeramente para compensar el rápido decremento de la corriente de corto circuito en estos pequeños motores.

Table 4.3

Typical Reactances of Transformers Per Unit Reactance on Transformer kVA Rating*

Primary Voltage Rating	Bank kVA (Three-Phase or 3 Single-Phase) 25-100	100-500	Above-500
2400/4160 volts	(.015 — .018)	.050	.055
13.8 kV	(.015 — .025)	.050	.055
46 kV	—	.060	.065
69 kV	—	.065	.070

*Use manufacturer's specified values if available.

Table 4.4

Representative Conductor Spacings for Overhead Lines

System Nominal Voltage	Equivalent Delta Spacing in Inches
120	12
240	12
480	18
600	18
2,400	30
4,160	30
6,900	36
13,800	42
23,000	48
34,500	54
69,000	96
115,000	204

Note: When conductors are not arranged in a delta, the following formula may be used to determine the equivalent delta:

$$d = \sqrt[3]{A \times B \times C} \qquad (4.7)$$

When the conductors are located in one plane and the outside conductors are equally spaced from the middle conductor, the equivalent spacing is 1.26 times the distance between the middle conductor and an outside conductor, for example:

$$\text{Equivalent delta spacing} = \sqrt[3]{A \times B \times C} = 1.26\,A$$

Table 4.5

Constants of Copper Conductors for One-Foot Symmetrical Spacing
Use Tables 4.7 and 4.8 of Spacing Factors for Other Spacings

Size of Conductor Circular Mils	AWG	r_a *Resistance Ohms/Cond./1000 Ft at 50°C, 60 Hertz*	x_a *Reactance at 1 Foot Spacing; 60 Hertz Ohms/Cond./1000 Ft*
1,000,000		0.0130	0.0758
900,000		0.0142	0.0769
800,000		0.0159	0.0782
750,000		0.0168	0.0790
700,000		0.0179	0.0800
600,000		0.0206	0.0818
500,000		0.0246	0.0839
450,000		0.0273	0.0854
400,000		0.0307	0.0867
350,000		0.0348	0.0883
300,000		0.0407	0.0902
250,000		0.0487	0.0922
211,600	4/0	0.0574	0.0953
167,800	3/0	0.0724	0.0981
133,100	2/0	0.0911	0.101
105,500	1/0	0.115	0.103
83,690	1	0.145	0.106
66,370	2	0.181	0.108
52,630	3	0.227	0.111
41,740	4	0.288	0.113
33,100	5	0.362	0.116
26,250	6	0.453	0.121
20,800	7	0.570	0.123
16,510	8	0.720	0.126

For a three-phase circuit the total impedance line-to-neutral is:

$$Z = r_a + j\,(x_a + x_d)$$

Table 4.6

Constant of Aluminum Cable Steel Reinforced
For One-Foot Symmetrical Spacing

Size of Conductor Circular Mils	AWG	r_a *Resistance Ohms/Cond./1000 Ft at 50°C, 60 Hertz*	x_a *Reactance at 1 Foot Spacing; 60 Hertz Ohms/Cond./1000 Ft*
1,590,000		0.0129	0.0679
1,431,000		0.0144	0.0692
1,272,000		0.0161	0.0704
1,192,500		0.0171	0.0712
1,113,000		0.0183	0.0719
954,000		0.0213	0.0738
795,000		0.0243	0.0744
715,500		0.0273	0.0756
636,000		0.0307	0.0768
556,500		0.0352	0.0786
477,000		0.0371	0.0802
397,500		0.0445	0.0824
336,400		0.0526	0.0843
266,800		0.0662	0.1145
	4/0	0.0835	0.1099
	3/0	0.1052	0.1175
	2/0	0.1330	0.1212
	1/0	0.1674	0.1242
	1	0.2120	0.1259
	2	0.2670	0.1215
	3	0.3370	0.1251
	4	0.4240	0.1240
	5	0.5340	0.1259
	6	0.6740	0.1273

For a three-phase circuit the total impedance line-to-neutral is:

$$Z = r_a + j\,(x_a + x_d)$$

Table 4.7

60-Hertz Reactance Spacing Factor (X_d)
Ohms Per Conductor Per 1000 Feet

Separation—Inches

Feet	*0*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*
0	.....	—0.0571	—0.0412	—0.0319	—0.0252	—0.0201	—0.0159	—0.0124	—0.0093	—0.0066	—0.0042	—0.0020
1	0	0.0018	0.0035	0.0051	0.0061	0.0080	0.0093	0.0106	0.0117	0.0129	0.0139	0.0149
2	0.0159	0.0169	0.0178	0.0186	0.0195	0.0203	0.0211	0.0218	0.0255	0.0232	0.0239	0.0246
3	0.0252	0.0259	0.0265	0.0271	0.0277	0.0282	0.0288	0.0293	0.0299	0.0304	0.0309	0.0314
4	0.0319	0.0323	0.0328	0.0333	0.0337	0.0341	0.0346	0.0350	0.0354	0.0358	0.0362	0.0366
5	0.0370	0.0374	0.0377	0.0381	0.0385	0.0388	0.0392	0.0395	0.0399	0.0402	0.0405	0.0409
6	0.0412	0.0415	0.0418	0.0421	0.0424	0.0427	0.0430	0.0433	0.0436	0.0439	0.0442	0.0445
7	0.0447	0.0450	0.0453	0.0455	0.0458	0.0460	0.0463	0.0466	0.0468	0.0471	0.0473	0.0476
8	0.0478											

Table 4.7a

60-Hertz Reactance Spacing Factor (X_d) in Ohms Per Conductor Per 1,000 Feet

Inches	Separation—Quarter Inches: *0*	*1/4*	*2/4*	*3/4*
0	.....	.....	—0.0729	—0.0636
1	—0.0571	—0.0519	—0.0477	—0.0443
2	—0.0412	—0.0384	—0.0359	—0.0339
3	—0.0319	—0.0301	—0.0282	—0.0267
4	—0.0252	—0.0238	—0.0225	—0.0212
5	—0.0201	—0.01795	—0.01795	—0.01684
6	—0.0159	—0.01494	—0.01399	—0.01323
7	—0.0124	—0.01152	—0.01078	—0.01002
8	—0.0093	—0.00852	—0.00794	—0.00719
9	—0.0066	—0.00605	—0.00529	—0.00474
10	—0.0042			
11	—0.0020			
12	0.00			

Table 4.8

60-Hertz Reactance of Typical Three-Phase Cable Circuits Reactance in Ohms Per 1,000 Feet

Cable Size 4 to 1	*240V*	*480V*	*600V*	*2400V*	*4160V*	*6900V*	*13800V*
3—1/C cables in magnetic conduit	0.0521	0.0546	0.0520	0.0620	0.0618	....	....
1—3/C cable in magnetic conduit	0.0381	0.0400	0.0381	0.0384	0.0384	0.0522	0.0526
1—3/C cable in nonmagnetic duct	0.0310	0.0326	0.0310	0.0335	0.0335	0.0453	0.0457
Cable Size 1/0 to 4/0							
3—1/C cables in magnetic conduit	0.0495	0.0515	0.0490	0.0550	0.0550	....	....
1—3/C cable in magnetic conduit	0.0360	0.0380	0.0360	0.0346	0.0346	0.0448	0.0452
1—3/C cable in nonmagnetic duct	0.0291	0.0300	0.0290	0.0300	0.0300	0.0386	0.0390
Cable Size 250 MCM to 750 MCM							
3—1/C cables in magnetic conduit	0.0450	0.0478	0.0450	0.0500	0.0500	....	....
1—3/C cable in magnetic conduit	0.0325	0.0342	0.0325	0.0310	0.0310	0.0378	0.0381
1—3/C cable in nonmagnetic duct	0.0270	0.0284	0.0270	0.0275	0.0275	0.0332	0.0337

Note: Above values may also be used for magnetic and nonmagnetic armored cables.

Table 4.9

Reactance of Low-Voltage Power Circuit Breakers

Breaker Interrupting Rating—Amperes	*Ampere Rating*	*60-Hertz Reactance in Ohms*
15,000	15 to 35	0.04
and	50 to 100	0.004
25,000	125 to 225	0.001
	250 to 600	0.0002
50,000	200 to 800	0.0002
	1000 to 1600	0.00007
75,000	2000 to 3000	0.00008
100,000	4000	0.00008

Note: Due to the method of rating low-voltage power circuit breakers, the reactance of the breaker which is to interrupt the fault is not included in calculating fault current.

Table 4.10

Reactance of Low-Voltage Disconnect Switches

The reactance of disconnecting switches for low-voltage circuits (600 volts and below) is in the order of magnitude of 0.00008 ohm per pole to 0.00005 ohm per pole at 60 hertz for switches rated 400-4000 amps respectively.

Table 4.11

Approximate Reactances of Current Transformers

Primary Current Ratings Amperes	*60-Hertz Reactance in Ohms for Various Voltage Ratings*: *600-5000V*	*7500V*	*15000V*
100 to 200	0.0022	0.0040	0.0009
250 to 400	0.0005	0.0008	0.0002
500 to 800	0.00019	0.00031	0.00007
1000 to 4000 (thru-type)	0.00007	0.00007	0.00007

Table 4.12
Table of Multiplying Factors and Machine Reactances
To be used for Calculating Short-Circuit Currents for Circuit Breaker, Fuse, and Motor Starter Applications

Classification	Circuit Voltage	Location in System	Multiplying Factor	Machine Reactances to Use: Generators / Synchronous Converters / Synchronous Condensers / Frequency Changes	Machine Reactances to Use: Synchronous Motors	Machine Reactances to Use: Induction Motors
*Power Circuit Breakers				*Interrupting Duty*		
Eight cycle or slower (general case)	Above 600 V	Any place where symmetrical short-circuit kVA is less than 500 MVA	**1.0	Subtransient	Transient	Neglect
Five cycle	Above 600 V		**1.1	Subtransient	Transient	Neglect
				Momentary Duty		
General case	Above 600 V	Near generating station	1.6	Subtransient	Subtransient	Subtransient
Less than 5 kV	601 to 5 kV	Remote from generating station (X/R ratio less than 10)	1.5	Subtransient	Subtransient	Subtransient
Medium-Voltage Fuses				*Maximum rms Ampere Interrupting Duty*		
All types, including all-current-limiting fuses	Above 600 V	Anywhere in system	1.6	Subtransient	Subtransient	Subtransient
Non-current-limiting types only	601 to 15 kV	Remote from generating station (X/R ratio less than 4)	1.2	Subtransient	Subtransient	Subtransient
Medium-Voltage, Fused Motor Starters				*Maximum rms Ampere Interrupting Duty*		
All horsepower ratings	2400 & 4160 V	Anywhere in system	1.6	Subtransient	Subtransient	Subtransient
Medium-Voltage Motor Starters				*Interrupting Duty*		
Circuit breaker or contactor type	601 V to 5 kV	Anywhere in system	1.0	Subtransient	Transient	Neglect
				Momentary Duty		
Circuit breaker or contactor type	601 V to 5 kV	Anywhere in system	1.6	Subtransient	Subtransient	Subtransient
Circuit breaker or contactor type	601 V to 5 kV	Remote from generating station (X/R ratio less than 10)	1.5	Subtransient	Subtransient	Subtransient
Apparatus, 600 Volts and Below				*Interrupting or Momentary Duty*		
Low-voltage power molded case circuit breakers, or low-voltage fuses	600 V or less	Anywhere in system	†1.0	Subtransient	Subtransient	Subtransient
Low-voltage motor starters (with fuses or molded-case breakers)	600 V	Anywhere in system	†1.25	Subtransient	Subtransient	Subtransient

* Revisions to USA Standard C37.10 have been proposed (References 8, 9). These revisions eliminate the use of these multiplying factors in applying power circuit breakers.

**These factors are increased to 1.1 and 1.2 respectively if the symmetrical fault level is above 500 MVA and the system is fed predominantly by generators or through current-limiting reactors.

† Fuses which operate in under 0.004 second have a multiplying factor of 1.4 to 1.6.

Third Step—Combine Reactances

It is now necessary to combine reactances to the point of fault into a single equivalent reactance.

Most industrial distribution systems are relatively simple and merely require the combination of branches in series or parallel. In some instances, the layout may involve three branches tied together. Wye-delta or delta-wye transformations state that the reactances joining three different points in a system may be optionally represented by a wye or delta connection. One of these connections may be more suitable for combination with external branches of the circuit than the other. Figure 4.2 gives equations for transforming and combining system reactances.

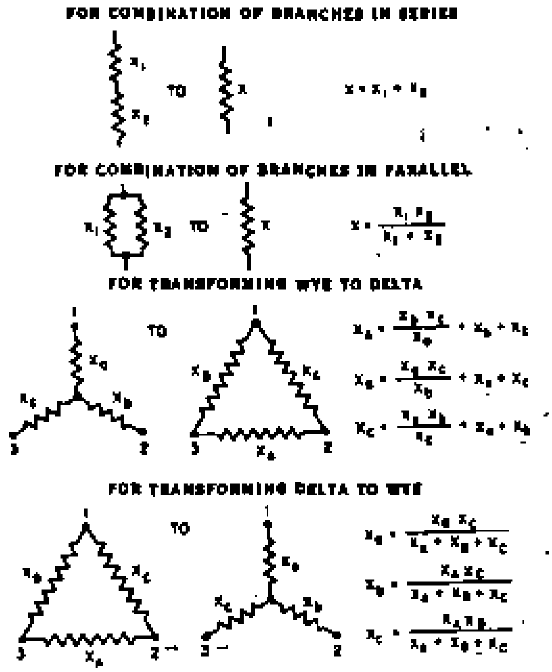


Figure 4.2

Fourth Step—Determine Fault Current or kVA

Determination of short-circuit current or short-circuit kVA at the point of fault using the equivalent reactance.

After combining the reactances of the reactance diagram to a single equivalent reactance it is now possible to arrive at a value of symmetrical short-circuit kVA.

If the equivalent reactance is X per unit, then:

$$\text{Symmetrical short-circuit kVA} = \frac{\text{Base kVA}}{X \text{ per unit}} \qquad (4.5)$$

then:

$$\text{Symmetrical short-circuit current} = \frac{\text{Base kVA}}{X \text{ per unit } \sqrt{3} \times \text{kV}} \qquad (4.6)$$

where kV is the line-to-line kV.

Since it is convenient to use a 3-phase base kVA and as reactance values are single-phase values, it becomes necessary to use line-to-line voltage in equation (4.6) above.

To determine the short-circuit current that the protective device will be called upon to interrupt and the momentary short-circuit current refer to Table 4.12. Table 4.12 also indicates types of machine reactances to be used in making calculations.

Reactance Data

How to Calculate Utility System Reactance

The short-circuit kVA of the utility is the maximum three-phase short-circuit kVA that the utility can produce; therefore, the per unit reactance of the utility on its own short-circuit-kVA base is 1.0. It follows from equation 4.4 that the per unit reactance of the utility on the chosen kVA base is therefore equal to

$$\frac{1.0 \times \text{chosen kVA base}}{\text{Utility short-circuit kVA}} \qquad (4.7)$$

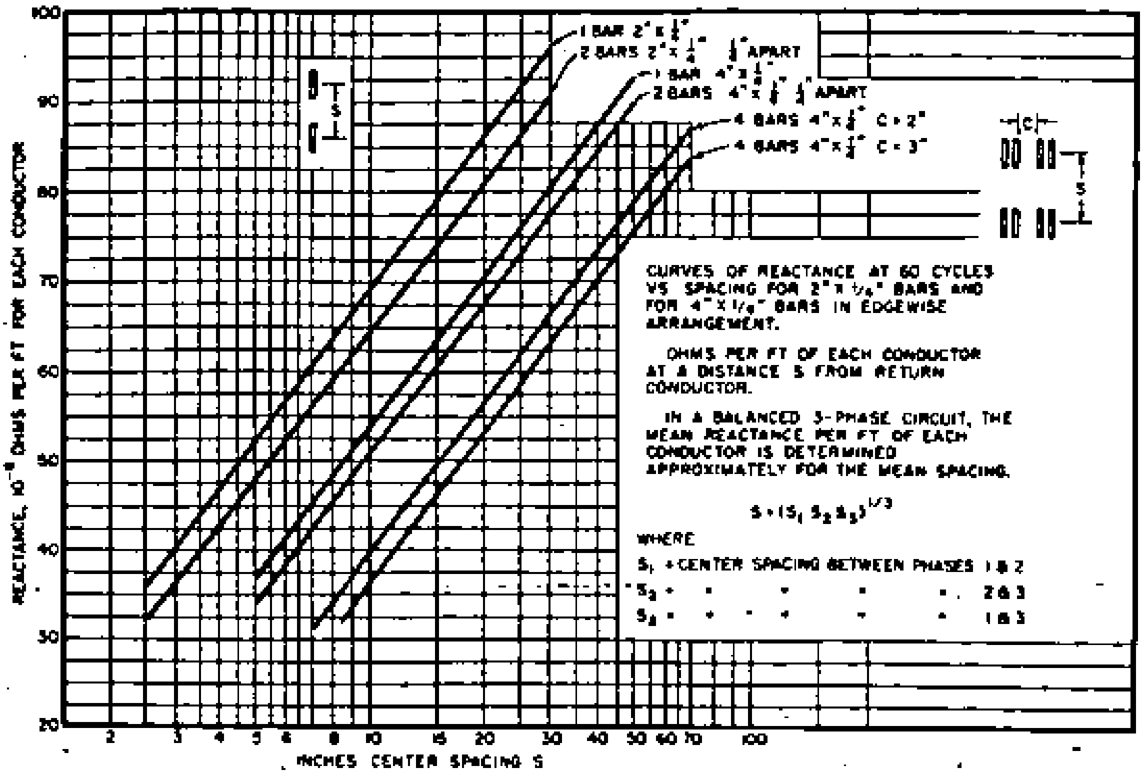


Figure 4.3a
2" x 1/4" and 4" x 1/4" edgewise

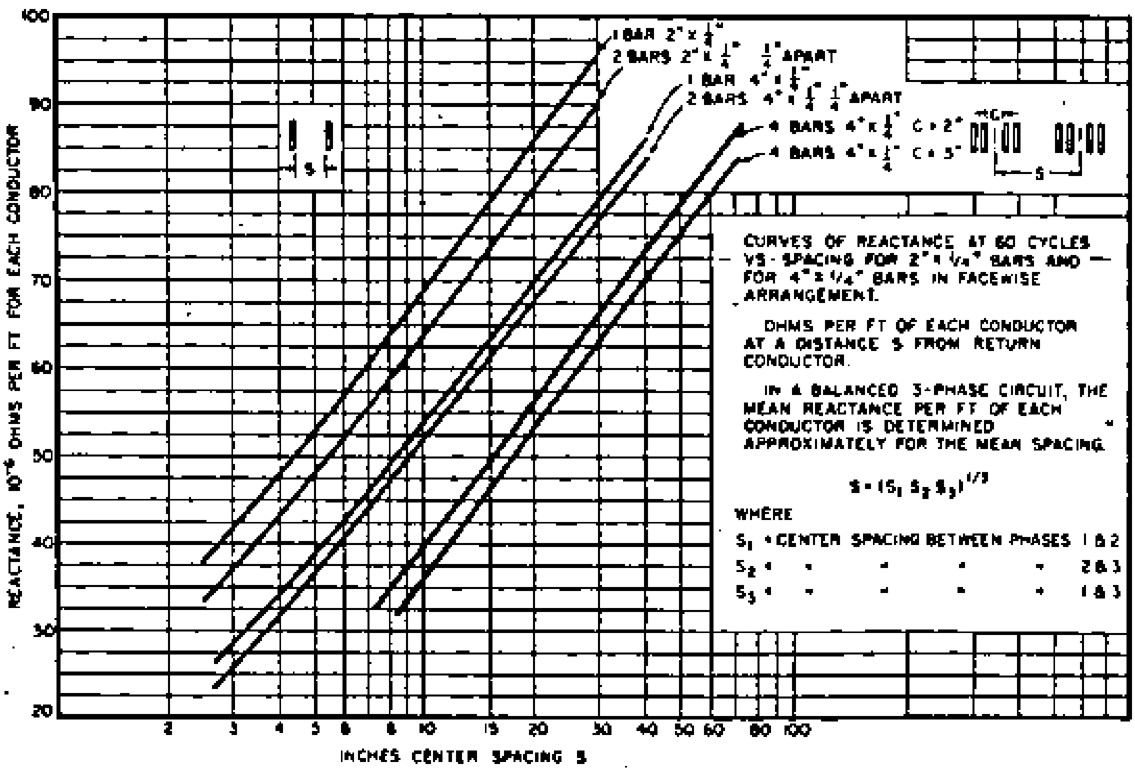


Figure 4.3b
2" x 1/4" and 4" x 1/4" facewise

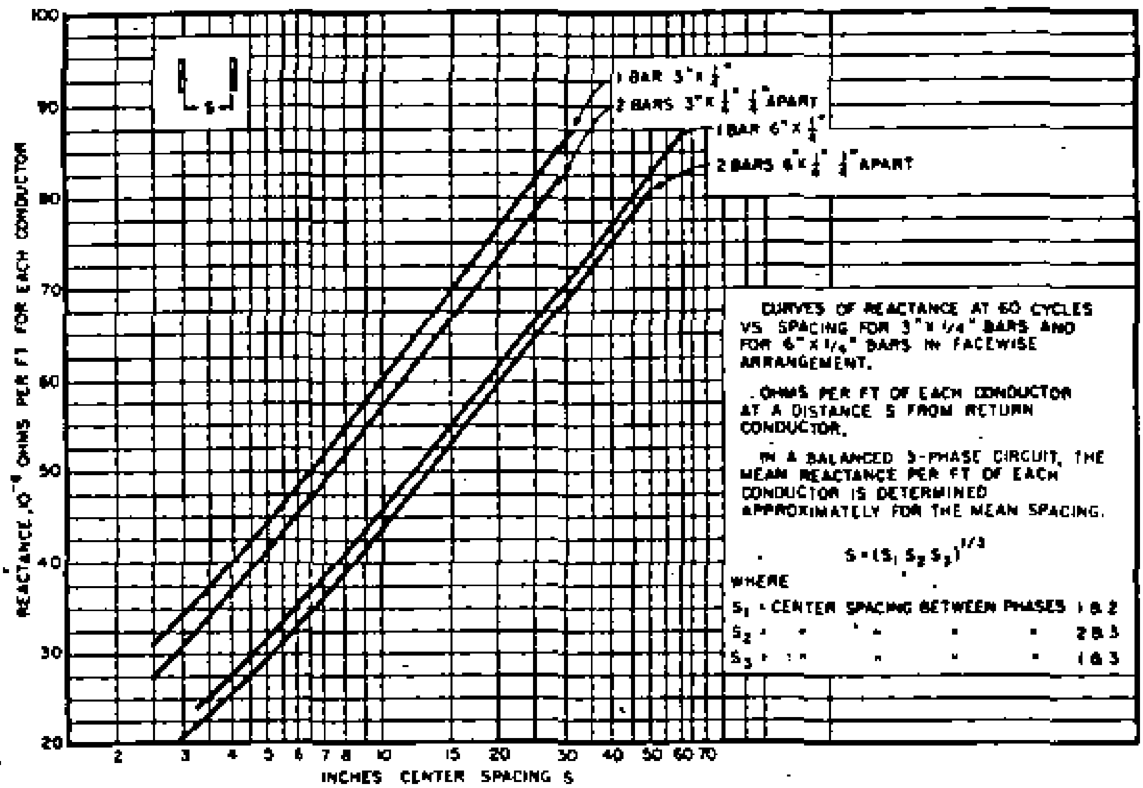


Figure 4.3c
3" x 1/4" and 6" x 1/4" facewise

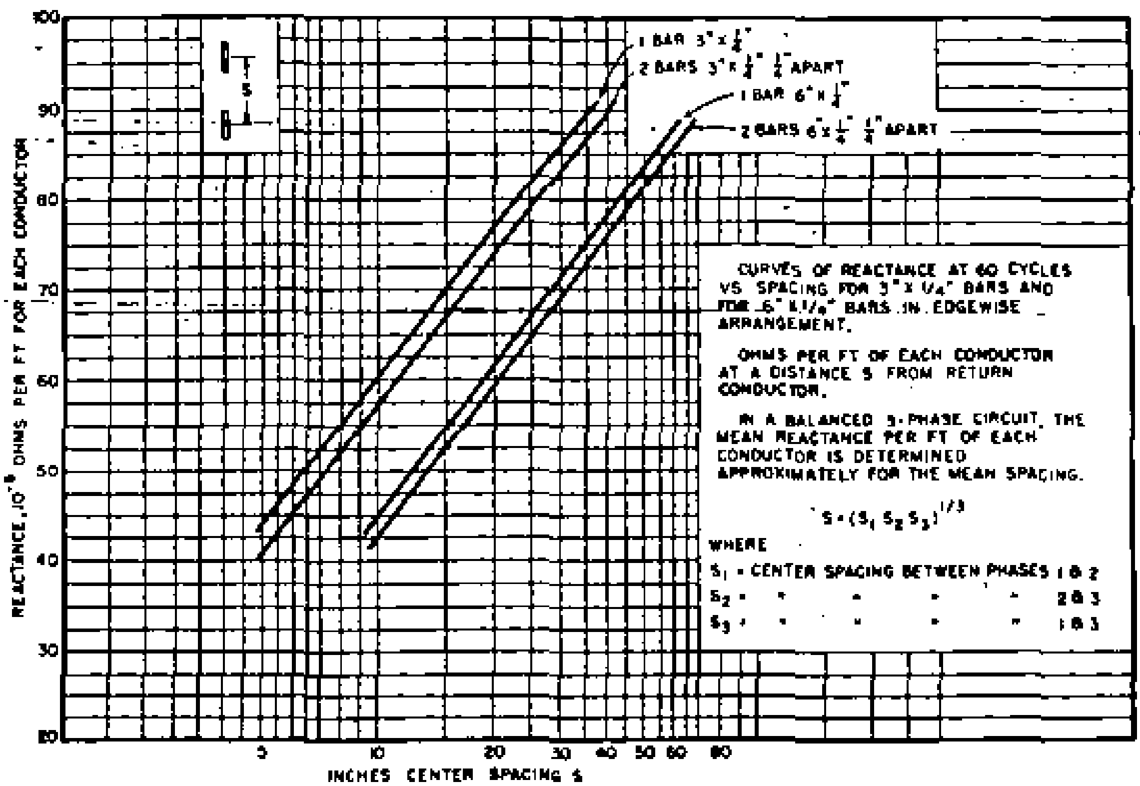


Figure 4.3d
3" x 1/4" and 6" x 1/4" edgewise

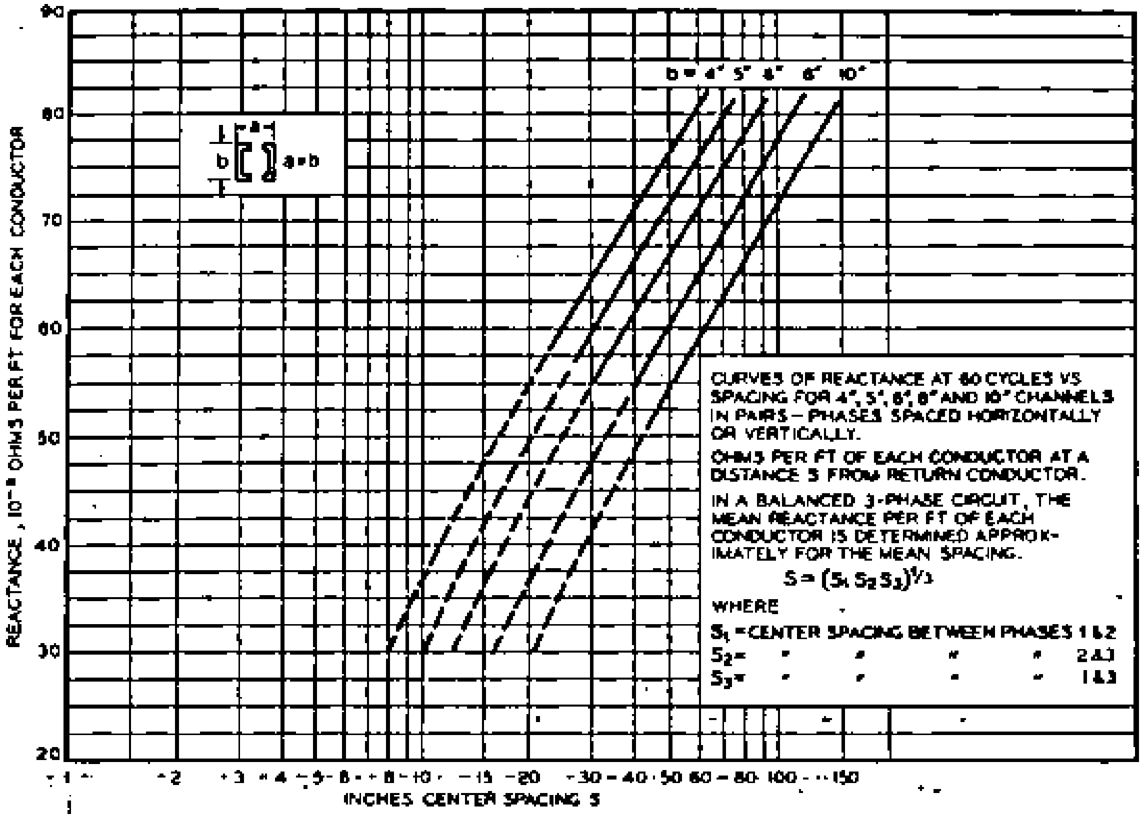


Figure 4.3e
Pairs of channels

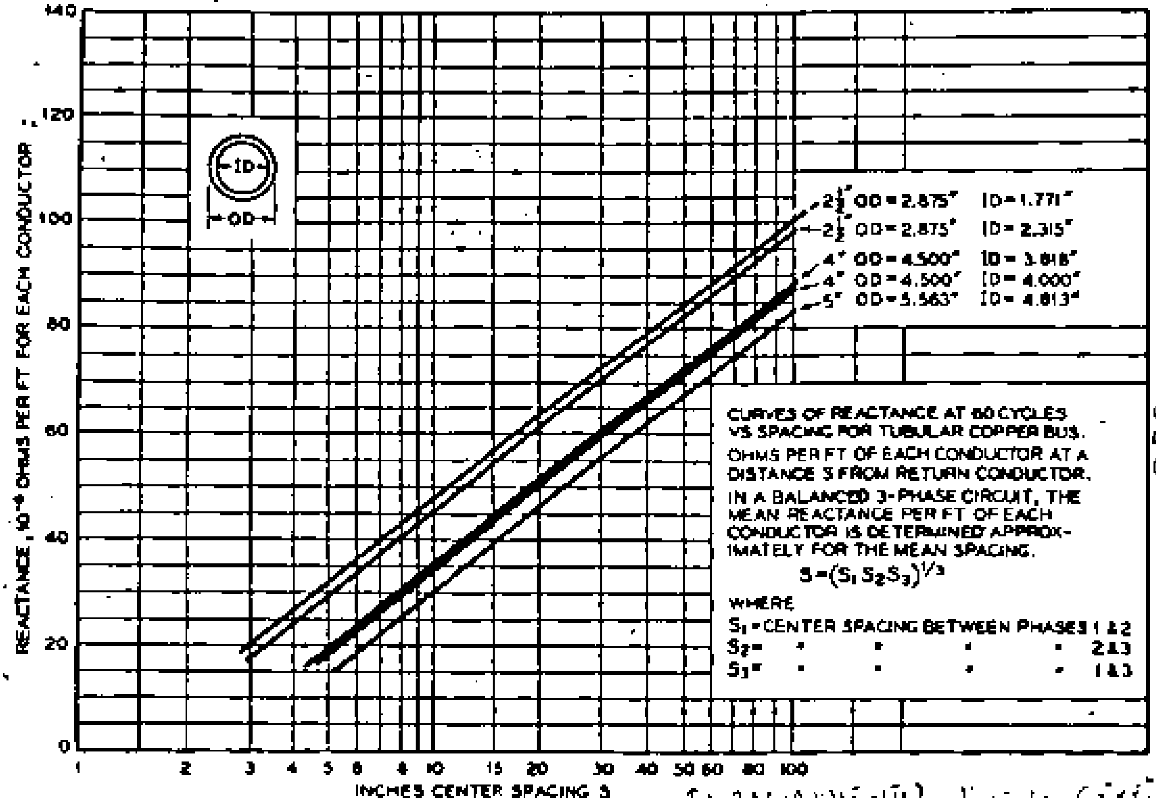


Figure 4.3f
Tubular bus

TABLA DE LA FIGURA 19

EXAMPLE OF A-C FAULT-CURRENT CALCULATIONS

The procedure to be followed in calculating fault currents is best illustrated by an example. Figure 4.4 shows a hypothetical power distribution system typical of those to be found in industrial plants. The circuit components and arrangement do not necessarily conform to practices outlined in other chapters, but have been chosen to illustrate the fundamentals and procedures involved in making fault-current calculations.

A complete fault-current study would involve the calculation of fault currents at all locations in the system. This example will illustrate the calculations for only a few significant locations.

This example will be worked in the per unit system. A similar procedure would be followed if it were worked in percent or ohmic values.

The base kVA will be chosen as 10,000 kVA. This will result in per unit values that are easy to work with; that is, values which are neither too large nor too small. Equation (4.2) gives the value by which ohmic values of reactance must be multiplied to convert them to per unit values on the chosen kVA base.

(a) at 4160 volts:

$$\text{Per unit reactance} = \frac{(\text{ohms reactance})\ (10{,}000\ \text{kVA base})}{(4.16\ \text{kV})^2\ (1000)} = (\text{ohms reactance})\ (0.576)$$

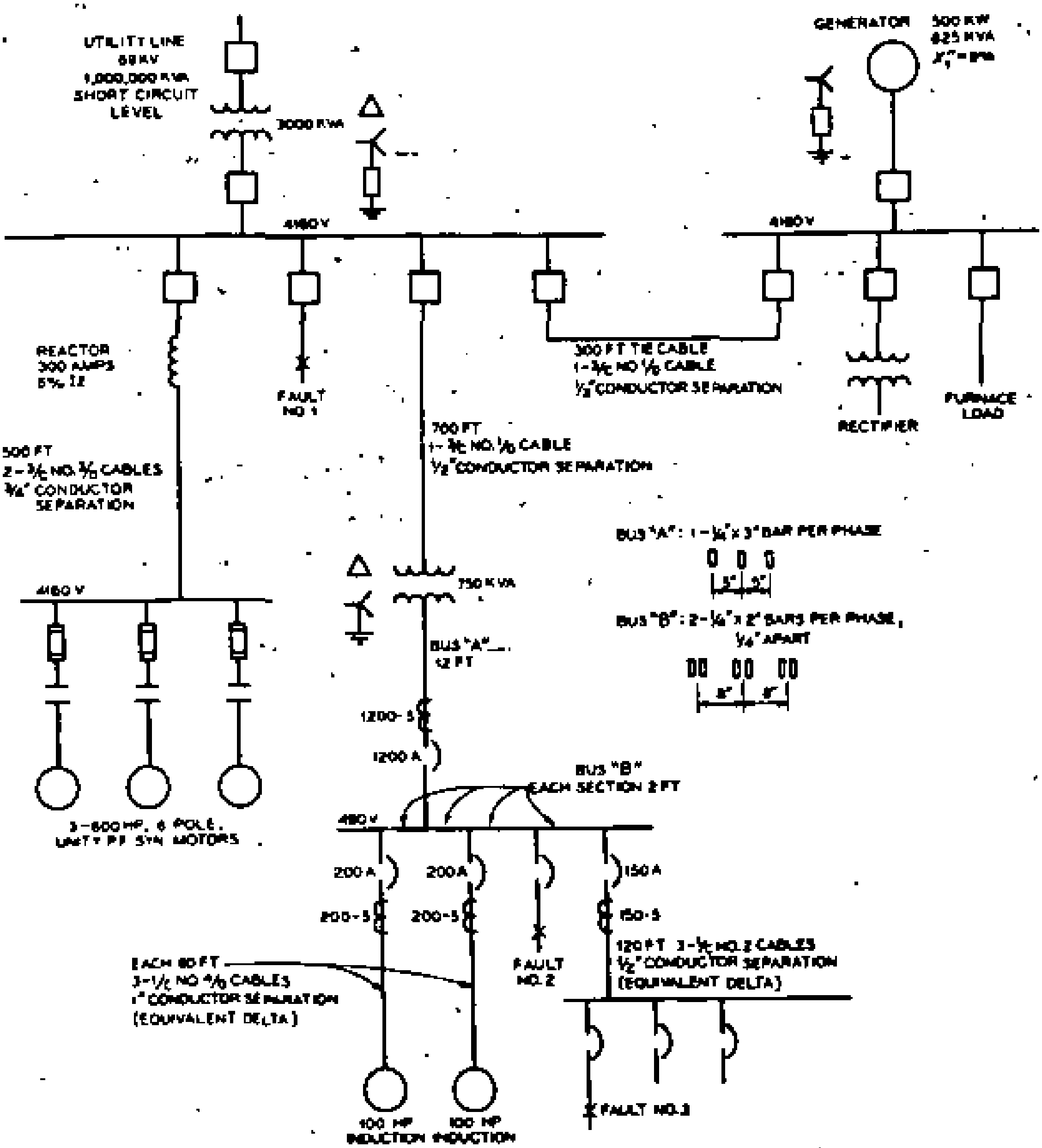


Figure 4.4

(b) at 480 volts:

$$\text{Per unit reactance} = \frac{(\text{ohms reactance})\ (10{,}000\ \text{kVA base})}{(0.480\ \text{kV})^2\ (1000)} = (\text{ohms reactance})\ (43.4)$$

These multipliers will be used in the example to simplify the conversion from ohmic to per unit values.

The first step is to calculate the per unit reactance value for each significant circuit element that will contribute to or limit the fault current.

Utility Supply Equivalent Reactance

From Equation 4.7,

$$\text{Per unit reactance} = \frac{(1.0)\ (10{,}000\ \text{kVA base})}{1{,}000{,}000\ \text{kVA}} = 0.01$$

3000 kVA Transformer

From Table 4.3,

Per unit reactance = 0.07 on transformer rating kVA base.

From equation (4.4),

$$\text{Per unit reactance on 10,000 kVA base} = 0.07\ \frac{10{,}000\ \text{kVA}}{3{,}000\ \text{kVA}} = 0.233$$

625 kVA Generator

Given X''_d = 9 percent reactance

From equation (4.1),

$$\text{Per unit reactance} = \frac{9}{100} = 0.09 \text{ on generator rating kVA base}$$

From equation (4.4),

$$\text{Per unit reactance on 10,000 kVA base} = 0.09\ \frac{10{,}000\ \text{kVA}}{625\ \text{kVA}} = 1.44$$

300-Foot Tie Cable

From Table 4.5 $\quad X_a = 0.103$ ohm/1000 ft.

From Table 4.7a $\quad X_d = -0.073$ ohm/1000 ft. for ¾ inch spacing

Total reactance $\quad X_T = X_a + X_d$

$X_T = 0.103 - 0.073 = 0.030$ ohm/1000 ft.

For 300 feet, $\quad X_T = 0.030\ \frac{300}{1000} = .00900$ ohm

Per unit reactance = (.00900) (0.576) = 0.005184

500-Foot Feeder Cable

From Table 4.5 $\quad X_a = 0.0981$ ohm/1000 ft.

From Table 4.7a $\quad X_d = -0.0636$ ohm/1000 ft. for ¾ inch spacing

Total reactance $\quad X_T = X_a + X_d$

$X_T = 0.0981 - 0.0636 = 0.0345$ ohm/1000 ft.

For 500 feet, $\quad X_T = 0.0345\ \frac{500}{1000} = 0.01725$ ohm

For two parallel conductors per phase,

$X_T = ½\ (0.01725) = 0.008625$ ohm

Per unit reactance = (0.008625 (0.576) = 0.00496

700-Foot Feeder Cable

From the calculation for the 300-foot tie cable,

$X_T = 0.030$ ohm/1000 ft.

For 700 feet, $\quad X_T = 0.030\ \frac{700}{1000} = 0.021$ ohm

Per unit reactance = (0.021) (0.576) = 0.0121

Rectifier and Furnace Loads

These loads will neither contribute to nor limit the fault current in the system, and so are neglected for the purposes of calculating fault currents.

Current Limiting Reactor

Per unit reactance on the reactor kVA base = 0.06

Reactor through kVA rating = $\sqrt{3}$ (300) 4.16 = 2160

From equation (4.4),

Per unit reactance on 10,000 kVA base =

$$0.06\ \frac{10{,}000\ \text{kVA}}{2{,}160\ \text{kVA}} = 0.277$$

750 kVA Transformer

From Table 4.3,

Per unit reactance on transformer kVA base = 0.055

From equation 4.4,

Per unit reactance on 10,000 kVA base =

$$0.055\ \frac{10{,}000\ \text{kVA}}{750\ \text{kVA}} = 0.733$$

600 Horsepower Synchronous Motors

From Table 4.1,

Per unit reactance X''_d = 0.10 on motor kVA base

Per unit reactance X'_d = 0.15 on motor kVA base

Motor kVA base = (0.8) (600) = 480 kVA

Per unit reactances on 10,000 kVA base:

$$X''_d = 0.10\ \frac{10{,}000\ \text{kVA}}{480\ \text{kVA}} = 2.08$$

$$X'_d = 0.15\ \frac{10{,}000\ \text{kVA}}{480\ \text{kVA}} = 3.13$$

Bus "A"

From Figure 4.3c, for an equivalent delta spacing of

$$\sqrt[3]{(5)\ (5)\ (10)} = 6.3 \text{ inches},$$

Reactance = 0.000049 ohm/foot

For 12 feet, reactance = (12) (0.000049) = 0.000588 ohm

Per unit reactance = (0.000588) (43.4) = 0.0255

Bus "B"

From Figure 4.3b, for an equivalent delta spacing of

$$\sqrt[3]{(8)\ (8)\ (16)} = 10.08 \text{ inches},$$

Reactance = 0.0000645 ohm/foot

For 2 feet, reactance = (2) (0.0000645) = 0.000129 ohm

Per unit reactance = (0.000129) (43.4) = 0.0056

60-Foot Motor Feeder Cables

From Table 4.5, $X_a = 0.0953$ ohm/1000 ft.

From Table 4.7a, $X_d = -0.0572$ ohm/1000 ft. for 1 inch spacing

Total reactance $X_T = X_a + X_d$

$X_T = 0.0953 - 0.0572 = 0.0381$ ohm/1000 ft.

For 60 feet, $X_T = 0.0381 \frac{60}{1000} = 0.00229$ ohm

Per unit reactance = (0.00229) (43.4) = 0.0995

100 Horsepower Motors

From Table 4.2, per unit reactance X''_d = 0.25 on motor kVA base

Motor kVA base = hp rating approximately = 100 kVA

Per unit reactance on 10,000 kVA base

$$X''_d = 0.25 \frac{10{,}000 \text{ kVA}}{100 \text{ kVA}} = 25.0$$

120-Foot Feeder Cable

From Table 4.5, $X_a = 0.108$ ohm/1000 ft

From Table 4.7a, $X_d = -0.0729$ ohm/1000 ft for ½ inch spacing

$$X_T = 0.108 - 0.0729 = 0.035 \text{ ohm/1000 ft.}$$

For 120 feet, $X_T = 0.035 \frac{120}{1000} = 0.0042$ ohm

Per unit reactance = (0.0042) (43.4) = 0.182

Air Circuit Breakers

From Table 4.9,

Reactance of 1200-ampere breaker = 0.00007 ohm

Reactance of 150 and 200-ampere breakers = 0.001 ohm

Per unit reactances
of 1200-ampere breaker = (0.00007) (43.4) = 0.00304
of 150 and 200-ampere breakers = (0.001 (43.4) = 0.0434

Current Transformers

From Table 4.11,
reactance of 1200-5 CT = 0.00007
reactance of 150-5 and 200-5 CT's = 0.0022

Per unit reactances
of 1200-5 CT = (0.00007) (43.4) = 0.00304
of 150-5 and 200-5 CT's = (0.0022) (43.4) = 0.0954

The next step is to draw a reactance diagram showing the calculated per unit reactance values in one-line form. Figure 4.5 shows the values arranged similar to the circuits of Figure 4.4.

Many of the reactances can be combined with ease. Series reactances can be added up and represented as a single reactance. Parallel reactances can also be combined into a single value. When motors and generators are represented by their per unit reactances on a common kva base, all of their "neutral" or "center" points are considered to be connected to the same bus as is the utility supply equivalent reactance. Thus the utility supply equivalent reactance is in parallel with the motor and generator reactances.

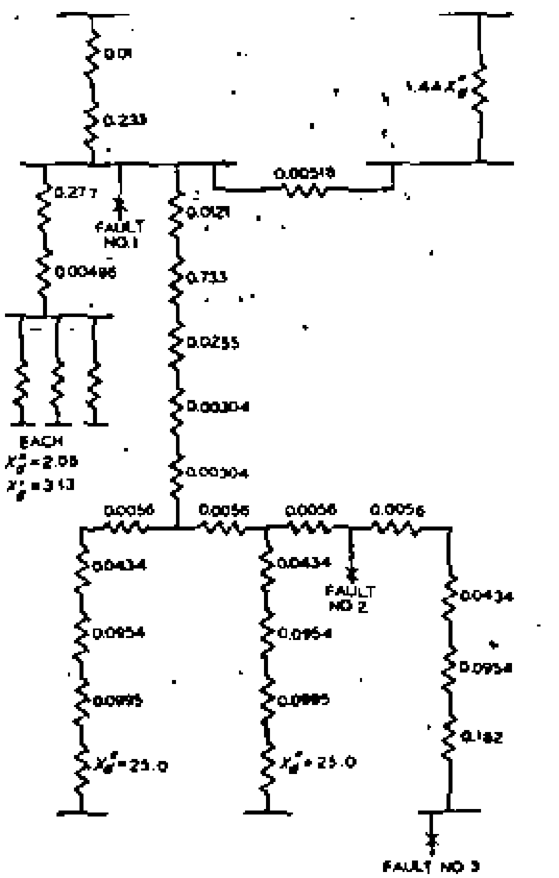


Figure 4.5

The reactance diagram should be simplified as much as possible, retaining the points at which the fault current is to be calculated. Figure 4.6 illustrates the simplification of Figure 4.5 by combining series and parallel reactance values. The dotted lines indicate buses of "equal potential" so far as the fault-current calculations are concerned.

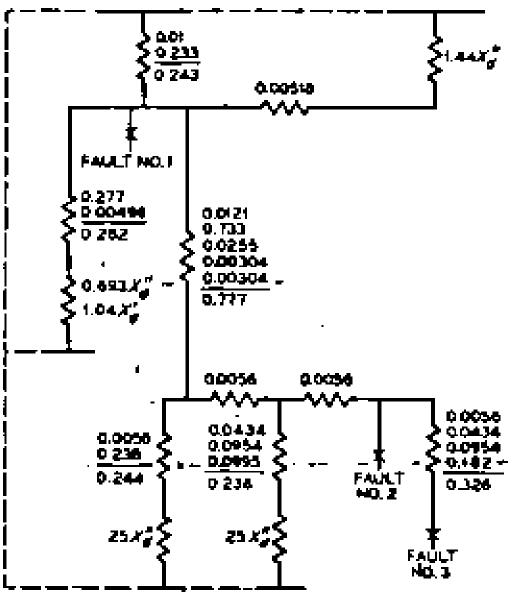


Figure 4.6

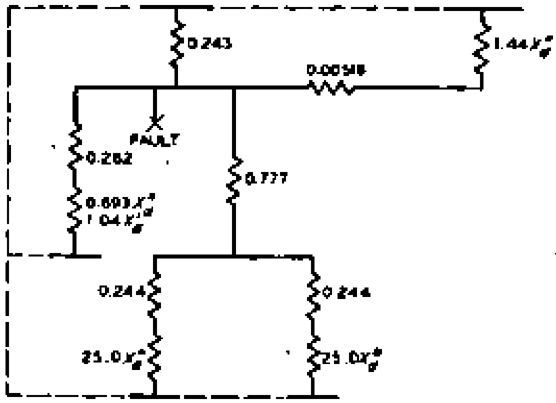


Figure 4.7a

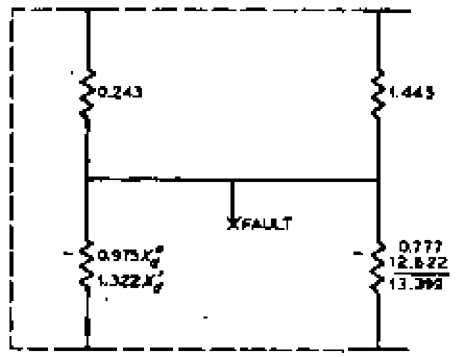


Figure 4.7b

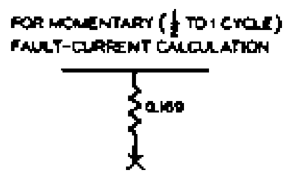
Further simplification of the reactance diagram can be made only for a specific fault location. For a fault at location No. 1, for example, it is no longer necessary to retain fault locations No. 2 and No. 3, and further simplifications of the reactance diagram can be made.

Fault No. 1

The simplification of the reactance diagram into a single equivalent reactance is shown in Figures 4.7a, 4.7b, 4.7c, and 4.7d. Because it is desired to calculate the fault current both at ½ to 1 cycle and at 8 cycles, both X''_d and X'_d values must be included, and separate single equivalent reactances determined. For the momentary-fault-current calculations, the utility supply reactance and the X''_d values are used. For the interrupting duty fault-current calculations, the utility supply reactance, the generator X''_d value, and the synchronous motor X'_d values are used. The induction motor reactance values are not used when calculating the interrupting fault current values, since their fault current contribution is negligible after a few cycles. In Figures 4.7c and 4.7d, the reactances are combined into separate single equivalent values.

From equation (4.6), the symmetrical rms fault current is:

$$\frac{10{,}000\text{ kVA}}{(\sqrt{3})\ (4.16\text{ kV})\ (0.169)} = 8{,}220\text{ amperes}$$

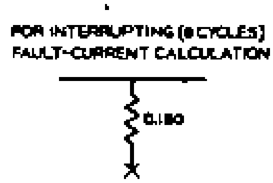


$$\frac{1}{X} = \frac{1}{0.975} + \frac{1}{0.243} + \frac{1}{1.445} + \frac{1}{13.399}$$

$$\frac{1}{X} = 5.913$$

$$X = 0.169$$

Figure 4.7c



$$\frac{1}{X} = \frac{1}{1.32} + \frac{1}{0.243} + \frac{1}{1.445}$$

$$\frac{1}{X} = 5.57$$

$$X = 0.180$$

Figure 4.7d

From Table 4.12, a multiplication factor of 1.6 must be applied to account for the effect of the direct-current component of initial fault current. The rms asymmetrical fault current is then:

$$(1.6)\ (8{,}220) = 13{,}140 \text{ amperes}$$

From equation 4.5, the symmetrical rms (8-cycle breaker) fault kVA is:

$$= \frac{10{,}000\ \text{kVA}}{0.180} = 55{,}600\ \text{kVA}$$

From equation 4.6, the symmetrical rms (8-cycle breaker) fault current is:

$$= \frac{10{,}000\ \text{kVA}}{(\sqrt{3})\ (4.16\ \text{kV})\ (0.180)} = 7{,}720 \text{ amperes}$$

From Table 4.12, a multiplying factor of 1.0 should be applied to obtain the interrupting requirement for an 8-cycle power circuit breaker.

For proper protection, the 4160-volt power circuit breakers would have to be capable of interrupting 55,600 kva (7,720 amperes at 4160 volts) and be capable of withstanding a momentary current of 13,140 amperes.

Fault No. 2

Figure 4.6 must be simplified in another manner for the calculation of fault currents at location No. 2. In systems of 600 volts and less, only the momentary (½ to

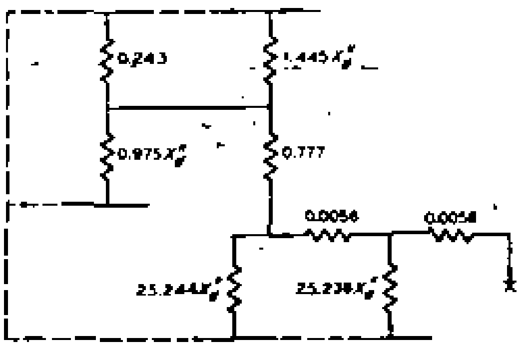


Figure 4.8a

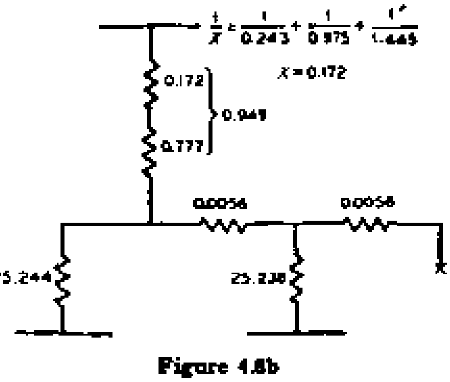


Figure 4.8b

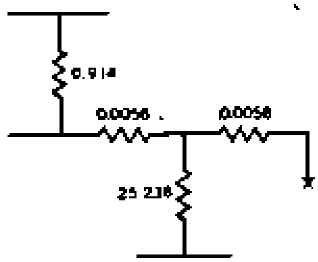


Figure 4.8c

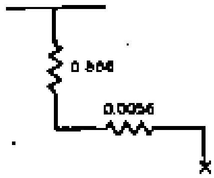


Figure 4.8d

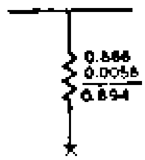


Figure 4.8e

1 cycle) fault current value is of interest. Figures 4.8a, 4.8b, 4.8c, 4.8d, and 4.8e show the process of reducing the reactance diagram of Figure 3 to a single equivalent reactance.

From equation 4.6, the symmetrical momentary fault current is

$$= \frac{10{,}000\ \text{kVA}}{(\sqrt{3})\ (0.480\ \text{kV})\ (0.894)} = 13{,}470 \text{ amperes}$$

Fault No. 3

Figure 4.9a shows the simplified reactance diagram for fault location No. 3. The value 0.881 is the single equivalent reactance for fault location No. 2, and the value 0.326 is the reactance between locations No. 2 and

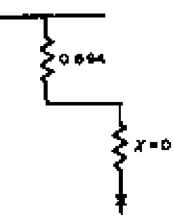


Figure 4.9a

No. 3 (see Figure 4.6). The total reactance from source to fault is then

$$0.894 + 0.326 = 1.220$$

A check of Table 4.5 indicates that the resistance of the 120-foot feeder cable is high in comparison to the system equivalent reactance from source to fault. The per unit value of resistance is

$$(0.181)\frac{120}{1000}(43.4) = 0.943$$

This per unit resistance is

$$\frac{0.943}{1.220} \times 100 = 77\%$$

of the system reactance from source to fault. It now becomes necessary to include the effect of the resistance of the feeder cable in order to arrive at a realistic value of fault current. Figure 4.9b shows the simplified reactance-resistance circuit.

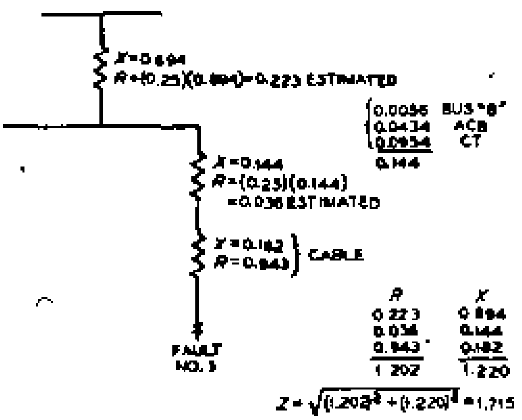


Figure 4.9b

Account should also be taken of the resistance of the system up to the feeder. Assume a per unit resistance equal to 25 percent of the corresponding per unit reactance from source to feeder. This is at best an estimate, but it will hold fairly true for most low-voltage systems not having any generators or a large proportion of motors connected to it.

Figure 4.9b shows the calculation of the single equivalent impedance, Z for fault No. 3. From Equation (4.6) the symmetrical rms fault current is:

$$\frac{10{,}000 \text{ kVA}}{(\sqrt{3})\ (0.480 \text{ kV})\ (1.715)} = 7010 \text{ amperes}$$

The value of symmetrical rms fault current if determined by reactance alone would be:

$$\frac{10{,}000 \text{ kVA}}{(\sqrt{3})\ (0.480 \text{ kV})\ (1.220)} = 9{,}860 \text{ amperes}$$

This would represent an error of 41 percent if resistance were not considered in the calculation of fault 3.

Calculation of D-C Fault Currents

The calculation of direct-current fault currents is increasing in importance with the growing utilization of direct current in industrial plants. These calculations are essential to the design, selection, and application of direct-current power apparatus such as generators, motors, rectifiers, cable and busways, and protective equipment such as circuit breakers, relays, and fuses. A knowledge of mechanical stresses based on these calculations is also important in the installation of cables, buses, and their supports.

As in the calculation of alternating-current fault currents, the magnitude of the available direct-current fault current is the prime consideration. However, high-speed direct-current protective devices can interrupt the flow of fault current before the maximum value is reached. In these cases, the rate of rise of the fault current must be considered along with the interruption time of the protective device in order to calculate the maximum current that will actually be obtained. Lower speed protective devices will generally permit the maximum value to be reached before interruption.

The magnitude of the direct-current fault current and its rate of rise are functions of the characteristics of the fault current source and of the external circuit between the source and the point of fault. The values of the fault current and rate of rise can be obtained from typical sources and circuit characteristics for general cases, or from actual tests in specific cases.

The most frequently encountered sources of direct-current fault current are:

1. Generators
2. Synchronous Converters
3. Motors (pump-back)
4. Electronic Rectifiers
5. Semiconductor Rectifiers
6. Batteries
7. Electrolytic Cells

Simplified procedures for calculation of direct-current fault currents are still not well established. Accordingly this chapter does not include this material. The following references contain helpful information on this subject: 3, 4, 5, 6, 11, 12, 13.

It is recognized that direct-current power systems are important in industry today and do require the careful attention of the system designer to ensure safe and satisfactory performance. Direct-current system fault-current calculations must be made to ensure obtaining adequate fault-current capability in the components chosen for direct-current power system. Therefore it is hoped that considerable progress will be made in the near future by the appropriate IEEE committees in establishing approved simplified procedures for making all types of direct-current system short-circuit fault calculations.

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CHAPTER V

GROUNDING

All phases of the subject of grounding within the scope of this publication have been studied by an IEEE Subcommittee on Grounding Practice in Industrial Plants. Their publication "Grounding of Industrial Power Systems"[1] constitutes the basic reference material on the subject.

This chapter, therefore, will simply identify the nature and broad classification of the industrial grounding problem with references pointing out the appropriate sections of the basic IEEE Grounding Publication.

The considerations of grounding that are involved in industrial power distribution systems may be subdivided into four headings namely:

1. System Grounding
2. Equipment Grounding
3. Static and Lightning Protection Grounding
4. Connection to Earth

SYSTEM GROUNDING

Electric power distribution system grounding is concerned with the nature and location of an intentional electric interconnection between the electric system conductors and ground (earth). The most common classifications of grounding to be found in industrial power distribution systems are:

1. Ungrounded
2. Resistance grounded
3. Reactance grounded
4. Solidly grounded

The nature of electric system grounding may have a striking effect on the magnitudes of line-to-ground voltages which must be endured both under steady-state and transient conditions. Electric systems which allow more severe overvoltage hazards can expect reduced useful life of insulation, which will make itself felt as more frequent insulation failures or circuit breakdowns occur. In rotating electric machines where insulation space is limited this conflict between voltage stress and the useful life is particularly acute.

In addition to the control of system overvoltages, intentional electric system neutral grounding makes possible sensitive and speedy fault protection based on detection of ground current flow. Grounded systems, in most cases are arranged so that circuit protective devices will remove a faulty circuit from the system regardless of the type of fault. Any contact from phase to ground in the grounded system thus results in immediate isolation of the faulty circuit and its loads. However, the experience of some operators has been that greater service continuity can be obtained with grounded neutral than with ungrounded neutral systems. Furthermore, a very high order of rotating machine fault protection may be acquired by a simple, inexpensive ground overcurrent relay. It will also be found that the protective qualities of rotating machine differential protection will be enhanced by grounding the power supply system.

It has become recommended practice to ground the neutral of industrial electric power systems in accordance with the following table.

120/240 volt, 3-wire, single-phase (solid)

208Y/120 volt, 4-wire, three-phase (solid)

4160Y/2400 volt, 4-wire and 3-wire, three-phase (solid, resistance or reactance)

13,800 volts, 3-wire, three-phase (resistance)

In recent years the trend is toward the adoption of system neutral grounding at intermediate voltage levels including principally:

480Y/277 volt, 4-wire and 3-wire, three-phase (solid and resistance)

600Y/346 volt, 4-wire and 3-wire, three-phase (solid and resistance)

2400 volt, 3-wire, three-phase (resistance)

6900 volt, 3-wire, three-phase (resistance)

It will be noted that there is today a divided opinion among operators as to the seriousness of the overvoltage problem on ungrounded low-voltage (600 volts and below) systems and the likelihood of its affecting the service continuity of ungrounded operation. Some operators feel that service continuity is improved and have experienced a reduction in equipment failures by using the grounded system. Others feel that, under proper operating conditions, the ungrounded system offers a valuable added degree of service continuity not jeopardized by any serious likelihood of dangerous transient overvoltages. A detailed discussion of the factors influencing a choice of the grounded or ungrounded system is given in Chapter 1 of the Grounding Publication.[1]

The ungrounded system (so-called) is actually high reactance capacitively grounded as a result of the capacitance coupling to ground of every energized cable conductor, bus bar, or machine coil. The operating advantage sometimes claimed for the ungrounded system stems from the fact that a single line-to-ground fault, if it so remains, will not result in an automatic tripout of the circuit. This results merely in the flow of a small charging current to ground. It is quite generally conceded that this practice introduces potential hazards to other apparatus. (Reference 5). For the duration of the ground fault on one conductor, the other two phase conductors throughout the entire metallic system are subjected to 73 percent overvoltage on a sustained basis. It is, therefore, extremely important to locate the faulty circuit promptly and repair or remove it before the abnormal voltage stresses produce breakdown on other machines or circuits. Because of the capacitance coupling to ground, the ungrounded system is subject to dangerous overvoltages (five times normal or more) as a result of an intermittent contact ground fault (arcing ground), or a high inductive reactance connected from one line to ground. So long as no disturbing influences occur on the system, the line-to-ground potentials (even on an ungrounded system) remain steady at about 58 percent of the line-to-line voltage value. Accumulated operating experience indicates that, in general purpose industrial power distribution systems, the overvoltage incidents associated with ungrounded operation so diminish the useful life of insulation that electric circuit and machine outages occur more frequently than they do on grounded systems. The advantage of an ungrounded system, in not immediately dropping load upon the occurrence of a ground fault, may be largely destroyed by the practice of ignoring a ground, allowing it to remain on the system until a second one occurs causing an outage. An adequate detection system together with an organized program for removing grounds is considered essential for best operation of the ungrounded system. These observations are limited to alternating-current systems. Direct-current system operation is not subject to many of the overvoltage hazards to be found on alternating-current systems.

Resistance-grounded systems employ an intentional resistance connection between the electric system neutral and ground. This resistance appears in parallel with the system-to-ground capacitive reactance and makes this circuit behave more like a resistor than a capacitor. Even a high-resistance connection ($R \leqq X_{co}/3$) will suffice to curb the overvoltage producing tendencies of a pure capacitively grounded system. A low-resistance connection will exercise a more rigid control of line-to-ground potentials and also make available a substantial (controlled) magnitude of line-to-ground fault current for securing selective ground-fault relaying.

High-resistance grounding, for effective control of the severe transitory overvoltages should introduce between electric system and ground a resistance whose ohmic value is of the same order (or lower) than the total system-to-ground capacitive reactance ($X_{co}/3$). This will limit to moderate value the overvoltages created by an inductive reactance connection from one phase to ground or from an intermittent contact line-to-ground short circuit. It will not avoid the sustained 73 percent overvoltage on two phases during the presence of a ground fault on the third phase. Nor will it have much effect on a low impedance overvoltage source such as an interconnection with conductors of a higher voltage system, a ground fault on the outer end of an extended winding transformer or step-up autotransformer, or a ground fault at the transformer-capacitor junction connection of a series capacitor welder.

Low-resistance grounding calls for a grounding connection of very much lower resistance. The resistance magnitude is tailored to provide a ground-fault current magnitude which is acceptable for relaying purposes. Typical current values used range from 400 amperes on modern systems using sensitive window current transformer ground-sensor relaying up to perhaps 2000 amperes in the larger systems using ground responsive relays connected in current transformer residual circuits. In the mobile electric shovel application field, much lower levels of ground-fault current (50-25 amperes) are dictated by the more acute shock hazard considerations.

Reactance-grounded systems are not ordinarily encountered in industrial power systems. The permissible reduction in ground-fault current is limited to a boundary of about 25 percent of the three-phase short-circuit current without incurring the risk of transitory overvoltage troubles due to repetitive restrike in an arc in the ground-fault circuit. The resistance-grounded system remains free of this trouble in view of the fact that the resistor is a nonreactive impedance. Every watt of power delivered to the resistor is at once converted to heat, never to return to the electric system.

Solidly-grounded systems exercise the greatest control over overvoltages, but result in the highest magnitudes of ground-fault current. The latter effect may, in itself, bring in its own family of problems and greatly intensify the problem of effective equipment grounding design.

Solid grounding is used extensively in low-voltage systems (600 volts and less). A large magnitude available ground-fault current is desirable to secure optimum performance of phase-overcurrent trips or interrupters. The low line-to-neutral driving voltage of the supply system (346 volts in the 600-volt system and 277 volts in the 480-volt system) lessens the likelihood of dangerous voltage gradients in the ground return circuits even when higher-than-normal ground return impedances are present.

Equipment Grounding

The subject of equipment grounding pertains to that system of electric conductors by which all metallic structures, through which energized conductors run, will be interconnected.

The main purposes of equipment grounding are:

1. To maintain low potential difference between nearby metallic members in any area to insure freedom from electric shock hazard to personnel in the area, such as machine operators, electricians, maintenance men, etc. (Reference 7.)

2. To provide an adequate, effective electric conductor system over which short-circuit currents involving ground can flow without sparking or other evidence of thermal distress so as to avoid fire hazard to combustible material or gas ignition in combustible atmospheric areas. (References 2, 9.)

All electric conductor housings, equipment enclosures, and motor frames shall be interconnected by an equipment grounding system which will satisfy the foregoing requirements. The rules regarding equipment grounding as embodied in the NEC and the NESC have as their objectives the attainment of the same end results.

In case of an insulation failure along a power conductor of an electric power circuit, allowing an electric connection between the energized conductor and some portion of a metal enclosure, there exists the tendency to impart to the metal enclosure the same electric potential as exists on the power conductor. Unless all such conductive enclosures have been intentionally grounded in an approved manner, the occurrence of an insulation breakdown on the power conductor may cause to appear on such enclosure a voltage of great enough magnitude as to constitute a dangerous electric-shock hazard to anyone who touches it. A round-about grounding connection to the enclosure may be insufficient to avoid dangerous electric shock hazard; yet permit a substantial amount of ground-fault current to flow. The consequent heat released can be responsible for a definite fire or explosion hazard in addition.

Only by intentionally grounding the metallic enclosures in a manner which assures the presence of adequate current-carrying capability and an adequately low value of ground-fault circuit impedance can both electric-shock hazard and fire hazard be avoided. In a great many application areas the applicable electrical codes prescribe such grounding practices as a mandatory requirement.

Industry electric accident statistics compiled by the State of California makes it clearly evident that a great many personal injuries are regularly occurring as a result of electric shock when making contact with metallic members that are normally not energized and should have reasonably been expected to remain nonenergized. Effective equipment grounding practices would eliminate these personal injuries. (Reference 10).

Fire insurance companies, when presenting summaries of industrial experience, have indicated that, in their judgment, something like one out of every seven fires in industrial establishments owes its origin to the electric system. While these reports undoubtedly contain some unjustified assignments under the category of simply defective wiring; nonetheless, there is reason to suspect that difficulties in electric system operation are responsible for a greater number of fires than would be first imagined. Perhaps, the development and adoption of more effective practices in equipment grounding systems can effect a marked reduction in fire hazard aspects.

Recent technical investigations[1,3] point out the necessity of making good electric junctions between sections of conduit or metal cable raceways and insuring adequate cross-sectional area or conductivity in these enclosures. In power circuit wiring associated with electric conductors of 1/0 cross-section or larger, there is unmistakable evidence that the short-circuit current flowing by way of ground will seek a path close to the outgoing conductor that will usually consist of the conduit or the metal enclosing raceway. This is so even though the conduit or raceway may be repeatedly bonded to heavy steel building members or nearby piping systems. In order to provide an effective current-carrying path, either the cross-sectional area of the conduit or raceway must be increased, or a paralleling grounding conductor must be run inside of the conduit or raceway. Paralleling conductors or circuits running external to the conduit or raceway are quite ineffective in shunting short-circuit currents away from the metallic conductor enclosure.

Preferred methods of grounding the following types of equipment are given in detail in Chapter II of the Grounding Publication.[1]

1. Structures
2. Outdoor Stations
3. Large Generators and Motor Rooms
4. Conductor Enclosures
5. Miscellaneous Motors
6. Portable Equipment

STATIC AND LIGHTNING PROTECTION GROUNDING

Static Grounding

Industrial plants, commercial establishments and institutions handling solvents, dusty materials, or other flammable products, often have a potentially hazardous operating condition because of static accumulating on equipment, on materials being handled or even on operating personnel.

The discharge of a static charge to ground or to other equipment in the presence of flammable or explosive materials is often the cause of fires and explosions which result in the loss of many lives each year, and with an accompanying financial loss of millions of dollars.

The simple expedient of grounding equipment is not always the solution of the problem; therefore, it is necessary to study each installation in order that an adequate method of control may be selected.

Protection of human life is the first objective in attempting to control static charges. Besides the danger to lives because of explosions or fires that may result from a static discharge, there is also the danger of a person becoming startled if suddenly subjected to a static shock, which may result in falling or accidentally coming into contact with some moving equipment.

The second aim in eliminating or controlling static is to prevent the loss of:

1. Capital investment in buildings and equipment
2. Operating funds in stored materials
3. Profits because of the loss of production

If losses such as cited above can be avoided by proper static control, the expenditure required to secure this protection is good insurance.

An additional need for static control may be for improvement in product quality. For example, static in grinding operations prevents grinding to a fine degree. Static in certain textile operations causes fibers to stand on end instead of lying flat which often affects the quality of the material.

Material handled by chutes or ducts have been known to accumulate static charges causing the material to cling to the inside surfaces of the chutes or ducts and, thus, clog them.

Chapter III of the Grounding Publication,[3] should be referred to for a discussion of:

1. Fundamental Causes of Static
2. Methods of Testing for Static
3. Hazards in Various Types of Industries
4. Methods of Static Control

Lightning protection grounding is concerned with the conduction to earth of current discharges in the atmosphere originating in nature's power house of electric charges in cloud formations. The function of the lightning grounding system is to convey these lightning discharge currents safely to earth without incurring damaging potential differences across electrical insulation in the industrial power system; without overheating lightning grounding conductors; and without the disrupting breakdown of air between the lightning ground conductors and other metallic members of the structure. (Reference 6, 7.)

Lightning represents a very vicious source of overvoltage. It is capable of imparting a potential of one-half million volts or more to a stricken object. The magnitude of current in the direct discharge may be more than 100,000 amperes. The rate at which this current builds up can be extremely rapid and may be as much as 10,000 amperes per microsecond.

The high magnitudes of current which may be encountered emphasize the need for low-resistance circuits and high discharge capacities in lightning arresters. The extremely rapid rates of rise mean that minute values of inductance can be responsible for creating large voltage drops. For example, should a direct stroke which has made contact with a rod or mask on an industrial building encounter an inductance of so small a value as one microhenry with a current build-up rate of 10,000 amperes per microsecond, would result in a 10,000-volt potential drop across this small inductance. It is largely this inductive voltage drop which is responsible for application rules which demand that the lightning down-leads either be bonded to the building structure or separated therefrom by several feet. Lightning protective grounding circuits should be as short and direct as possible with no unnecessary turns or corners.

In general, except for overhead circuits, electric power distribution system conductors are not particularly subject to direct lightning exposure. However, lightning may strike the overhead high-voltage power lines serving the plant. An overvoltage surge whose magnitude is limited by the sparkover potential of the electric overhead conductor system or the protective level of lightning arresters will be imparted to the high-voltage electric conductors. This overvoltage condition will take the form of a steep-front overvoltage surge which will travel away from the stricken point in all directions along the power system conductors. As the surge travels along the conductors, inevitable losses are incurred such that the magnitude of the voltage surge is constantly diminishing. If the voltage magnitude is sufficient to produce corona, the decay of the voltage surge will be fairly rapid until below the corona starting voltage. Beyond this point, the decay will be more deliberate. Station-type lightning arresters at the industrial plant terminal of the high-voltage incoming line will function to reduce the overvoltage magnitude to a level which the terminal station apparatus can withstand.

In instances where the local industrial plant system is itself without lightning exposure except from the exposed high-voltage feeder lines through step-down transformers effectively protected with high-side lightning arresters, the developed surges within the industrial system are generally quite moderate. It would be expected that line-to-ground potentials on the local system would not reach arrester sparkover values. The multiplicity of radiating cable feeder circuits with their array of connected apparatus acts to greatly curb the slope of the voltage surge which reaches any particular item of connected apparatus. However, if apparatus is such as may be susceptible to voltage surges as indicated by experience, it is advisable to fully investigate the possibility of damaging voltage surges.

There are, however, numerous industrial operations which make use of open-wire, overhead feeder lines which are, of course, subject to direct exposure to lightning. In such cases, severe lightning surges may be introduced directly into the industrial distribution system and constitute a real hazard. Rotating machines are particularly vulnerable to steep-wave surges due to the rather 'large' coil-to-ground' capacitance resulting from the fact that each motor coil is individually surrounded by ground core iron. This tends to concentrate the voltage stress of a steep voltage wave across the terminal coil and the terminal turns of that coil. Special protective equipment is available for rotating machines, consisting of capacitors for connection between line and ground, whose function is to reduce the steepness of the wave front, and special station-type lightning arresters, whose function is to limit further the crest magnitude of overvoltage appearing at the machine terminals.

Dry type transformers generally possess basic insulation level values well below those of standard liquid-filled units of the same voltage class. The application of such transformers to industrial systems subject to surge voltages requiring lightning arrester action for protection warrant a careful check on protection adequacy. In some instances assured protection cannot be achieved unless the service system is of solid-multigrounded design to allow the use of grounded neutral arresters. In less critical areas protection may be achieved with low-cost line-to-line rated arresters with perhaps a limit on the separation distance between the arrester and the transformer. The application should be checked as to the type of lightning arrester needed under the system grounding characteristics to protect the transformer's basic insulation level and as to the existence of arrester location restrictions.

The effective resistance of grounding electrodes to lightning currents may be quite different from that determined by direct-current or commercial-frequency alternating-current measurement. For example, an insulated conductor running parallel to a high-voltage line near ground level will represent a usable grounding electrode for discharge of lightning currents although a direct-current resistance measurement between this conductor and earth would show infinite resistance. An extreme in the other direction might be represented by the running of a grounding cable, perhaps 500 feet, to metallic plates buried in a lake or pond. Such a circuit arrangement might show very low direct-current ground resistance, yet present a very high effective resistance to lightning discharge currents controlled by the characteristics of the long interconnecting grounding cable.

CONNECTION TO EARTH

Introduction

Connections to earth having acceptable low values of resistance are needed to discharge lightning currents, dissipate the released bound charge resulting from nearby strokes, and drain off static voltage accumulations. (Reference 1.) The presence of overhead high-voltage transmission circuits may introduce a requirement for a connection to earth to safely pass the ground-fault current which would result from a broken line conductor falling on some part of the building structure.

In general, the internal electric distribution system installed within commercial buildings and industrial plants is entirely enclosed in grounded metal. All conductors and buses are enclosed in conduit, metallic armor, or metal raceway. All other electric elements of equipments and machines can be expected to be encased in metal cabinets or metallic machine frames. All of these metallic enclosures will be intentionally interconnected and, in turn, will be interconnected with other metallic components within the area such as building structural members, piping systems, messenger cables, etc. Thus, the local electric system will be self-contained within its own shell of conducting metal and can be designed to operate adequately and safely without any connection to earth itself. This can be likened to the electric distribution system as installed on a large airplane. The structure contains its own reference ground system and operates safely and adequately with no connection whatever to earth.

Recommended Acceptable Values

The most elaborate grounding system that can be designed may prove to be inadequate unless the connection of the system to the earth is adequate and has a low resistance. (Reference 7.) It follows, therefore, that the earth connection is one of the most important parts of the whole grounding system. It is also the most difficult part to design and to obtain.

The perfect connection to earth should have zero resistance, but this is impossible to obtain. Ground resistances of less than one ohm can be obtained, although this low a resistance may not be necessary in many cases. Since the resistance required varies inversely with the fault current to ground, the larger the fault current the lower must be the resistance.

For larger substations and generating stations, the earth resistance should not exceed one ohm. For smaller substations and for industrial plants, in general, a resistance of less than five ohms should be obtained if practicable. The National Electrical Code (1968) states that the maximm resistance shall not exceed 25 ohms.

Resistivity of Soils

The resistivity of the earth at the desired location of the connection should always be investigated. The resistivity of soils varies with the depth from the surface, with the moisture content, and with the temperature of the soil. Presence of surface water does not necessarily indicate low resistivity. For representative values of resistivity for general types of soils and the effects of moisture and temperature, refer to Chapter IV of the Grounding Publication.[1]

Soil Treatment

Soil resistivity may be reduced anywhere from 15 to 90 percent, depending upon the kind and texture of the soil, by chemical treatment. There are a number of chemicals suitable for this purpose, including sodium chloride, magnesium sulphate, copper sulphate, and calcium chloride. Common salt and magnesium sulphate are most commonly used.

Chemicals are generally applied by placing them in the circular trench around the electrode in such a manner as to prevent direct contact with the electrode. While the effects of treatment will not become apparent for a considerable period, they may be accelerated by saturating the area with water. Also, such treatment is not permanent and must be renewed periodically, depending on the nature of chemical treatment and the characteristics of the soil.

Existing Electrodes

Basically, all ground electrodes may be divided into two groups. The first comprises underground metallic piping systems, metal building frameworks, well casings, steel piling and other underground metal structures installed for purposes other than grounding. The second comprises made electrodes specifically designed for grounding purposes.

The National Electrical Code states that continuous underground water or gas piping systems generally have a resistance to earth of less than three ohms, and that metal building frames, local metallic underground piping systems, metal well casings, and the like, have, in general, a resistance to earth of substantially less than 25 ohms. For safety grounding and for small distribution systems where the ground currents are of relatively low magnitude, such electrodes are usually preferred because they are economical in first cost. However, before reliance can be placed on any electrodes of this group, it is essential that their resistance to earth be measured to insure that some unforeseen discontinuity has not seriously affected their suitability. The use of plastic pipe in new, and of wooden ones in older water systems may seriously impair its value as a grounding electrode. Even iron or steel piping may include gaskets which act as insulators. Sometimes small metal (brass) wedges are used to insure electrical continuity. These wedges must be carefully replaced when repairs are made. In all cases, it is important that interior piping systems which are likely to become energized be bonded to the electric system grounding conductor. If the piping system contains a member designed to permit easy removal, a bonding jumper should be installed bridging the removable member.

Made Electrodes

Made electrodes may be subdivided into driven electrodes, buried strips or cables, grids, buried plates, and counterpoises. The type selected will depend upon the type of soil encountered and the available depth. Driven electrodes are generally more satisfactory and economical where bedrock is 10 feet or more below the surface, while grids, buried strips or cables are preferred for lesser depths. Grids are frequently used for substations or generating stations to provide equipotential areas throughout the entire station where hazards to life and property would justify the higher cost. They also require the least amount of buried material per ohm of ground conductance. Buried plates have not been used extensively in recent years because of the higher cost as compared to rods or strips. Also, when used in small numbers, they are the least reliable type of made electrode. The counterpoise is a form of the buried cable electrode and its use is generally confined to locations having high resistance soils, such as sand or rock, where other methods are not satisfactory.

There has been a trend toward steel in place of copper for earthing electrodes particularly in corrosive soil to minimize galvanic corrosion of other electrically connected buried steel pipes or building structural members. The connection to such steel electrodes commonly uses insulated copper cable with adequate protection against local galvanic corrosion at the copper-steel junction.

A discussion on methods of calculating and measuring resistance to earth, current loading capacity of soils, as well as recommended methods and techniques of constructing connections to earth may be found in Chapter IV of the Grounding Publication.[1]

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CHAPTER VI

POWER FACTOR

POWER FACTOR FUNDAMENTALS

Alternating-Current Power Concepts

Active or real power flows in one direction from the generator source to the load where it is converted into another form of energy, usually mechanical, external to the circuit. Reactive or apparent power flows to and fro and remains within the electric circuit without performing useful work. Lagging reactive power from a magnetic field is opposite in time phase to leading reactive power from an electrostatic field, and when the two are present in equal quantities at the load end of the circuit, no reactive power flows between the generator and the load. Where the leading and lagging reactive power flows are unequal the difference will flow between the generator and the load. The term "power factor" is the mathematical ratio of active to total current.

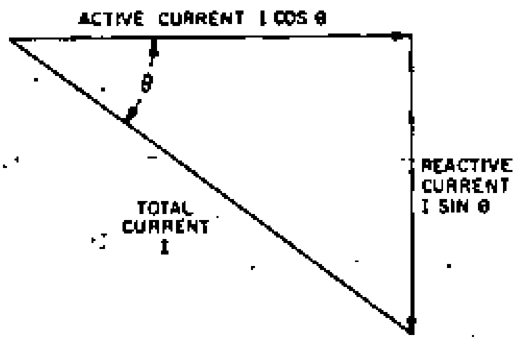


Figure 6.1
Angular Relationship of Current in Alternating-Current Circuits

Most utilization devices require two components of current, magnetizing current (reactive current) and power-producing current (active current). These two components of current are vectorially at right angles to each other, (Figure 6.1), and the total current can be determined from the expression:

$$(\text{total current})^2 = (\text{active current})^2 + (\text{reactive current})^2 \quad (1)$$

At a common voltage point, kVA and kW are proportional to current, therefore

$$(VI)^2 = (VI\cos\theta)^2 + (VI\sin\theta)^2 \quad (2)$$

$$(\text{kVA})^2 = (\text{kW})^2 + (\text{kVAr})^2 \quad (2a)$$

Power factor can be expressed as the ratio of active current to the total current. In more useful form, it is the ratio of kW to the total kVA. Thus,

$$\text{Power factor} = \frac{\text{kW}}{\text{kVA}} \quad (3)$$

From the right-triangle relationship of Figure 6.1,

$$\text{kW} = \text{kVA} \times \cos\theta$$

$$\text{Thus, PF} = \cos\theta \quad (4)$$

The angle θ is known as the power factor angle. Power factor is the cosine of that angle, usually expressed as a percent.

Leading and Lagging Power Factor

Power factor may be "lagging" or "leading" depending on the direction of both kilowatt and magnetizing kilovar flow. From the standpoint of an industrial load which requires kilowatts, its power factor is "lagging" if it requires kilovars and "leading" if it supplies kilovars. Thus, an induction motor has a lagging power factor because its magnetizing kilovars must be supplied by other kilovar sources. On the other hand, a capacitor or an overexcited synchronous motor can supply magnetizing kilovars and, therefore, these have leading power factors. Thus, in effect, leading kilovars balance lagging kilovars. Incandescent lamps require no kilovars and, therefore, have unity power factor; that is, neither lagging nor leading.

Group Loads

The power factor of a group of loads can easily be calculated by adding the kilowatts numerically and adding the kilovars algebraically after which the two components are combined vectorially as shown in the example of Figure 6.2. Since, in the example of Figure 6.2, the lagging kilovars exceed the leading kilovars, the resulting power factor of the group of loads is still lagging. If a capacitor rated 90 kVAr were added to the system of Figure 6.2, it would supply 90 leading kilovars to balance the 90 lagging kilovars and the resulting power factor of the group would be increased to 100 percent. In actual practice, it is generally not necessary to improve the power factor to 100 percent so a smaller capacitor rating would be used.

POWER FACTOR IMPROVEMENT

Benefits

All the benefits provided by power factor improvement stems from the reduction of magnetizing kilovars. This reduction results in lower purchased-power costs, increased system capacity, voltage improvement and lower system losses. Maximum benefits are obtained when capacitors or synchronous motors are located at the load where the low power factor exists.

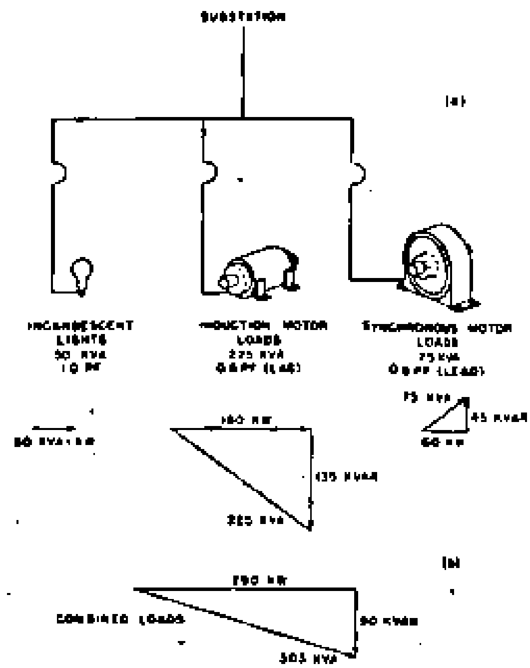


Figure 6.2
Example of Combined Power Factor of Group of Loads

Power Cost Savings

The rate structures of many utility companies include power factor clauses which result in increased power costs when the power factor is below a specified level. Power factor may be the monthly average, or it may be measured at time of maximum kilowatt demand, or during normal demand. The daily load chart will show how much improvement in power factor can be obtained during each period and permit a calculation of the power bill savings based on the particular power factor clause.

System Capacity Increased

When the reactive current in a circuit is reduced, the total current is also reduced. Thus, if a capacitor is connected to a lagging power factor load, the total or line current is reduced. This is shown pictorially in Figure 6.3. Thus, if the circuit were rated 100 amperes, it would be fully loaded with the 100-ampere induction motor load. With the addition of the capacitor at the load, the line circuit in this example need supply only 80 amperes of current. Therefore, an additional load up to 20 amperes could be added to the circuit without overloading it. Thus, system capacity has been released. The same release of system capacity can be obtained wherever a cable, transformer or generator is loaded at a low power factor.

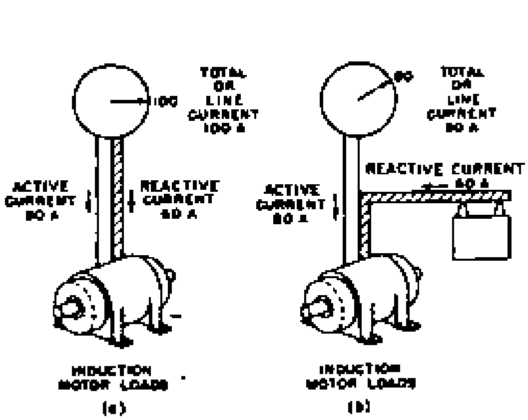


Figure 6.3
Capacitors Supply Kilovars Locally, Releasing System Capacity for Additional Load

The additional load that can be added due to power factor improvement is termed, "amount of capacity released". Since this additional load may be at any power factor, no simple curve can be drawn. However, if the new load is at the same power factor as the original load, the amount of capacity released and the final power factor can be determined by the chart of Figure 6.4.

Since system capacity can be increased by additional substation and distribution facilities, as well as by power factor improvement with capacitors or synchronous machines, the installed costs of the various alternate equipment must be compared. In many cases, the cost comparison will be in favor of adding capacitors. In those cases where the costs are equal, the addition of capacitors may be warranted because of other benefits, such as reduced losses and voltage improvement.

Voltage Conditions Improved

Although it is not usually economical to improve power factor solely to improve system voltage, the voltage improvement is a significant benefit. Since circuit current is reduced when the power factor is improved, the voltage drop is also reduced. The amount of reduction depends on the reactance of the circuit, as well as the magnitude and power factor of the load. Refer to Chapter II for information on calculating voltage drop.

The voltage *regulation* of a system from no load to full load is not affected by the amount of capacitors on a system unless the capacitors are switched but the voltage *level* is raised by the presence of the capacitors. The voltage rise due to capacitors in most industrial plants with modern power distribution systems is rarely more than 5 percent. The approximate voltage rise through a transformer due to capacitors installed at the transformer secondary can be calculated by means of equation (5):

$$\text{percent } V_r = \frac{\text{ckVAr}}{\text{transformer kVA}} \times \text{percent transformer reactance} \qquad (5)$$

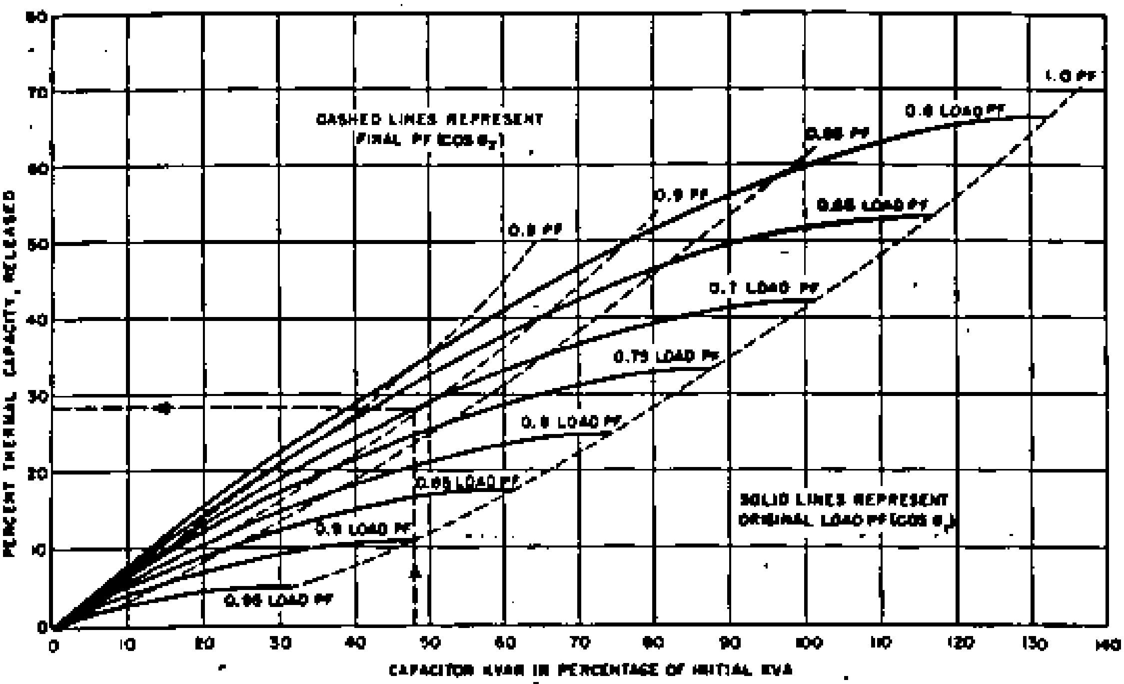
where,

V_r = voltage rise due to capacitors

ckvar = kVA of capacitors

Decreased Power Losses

The reduction in electric losses due to power factor improvement can result in an annual gross return of as much as 15 percent of the investment in power factor improvement. Losses are proportional to the total current squared. Since total current varies with the power factor,



EXAMPLE:

IF A PLANT HAS A LOAD OF 1000 KVA AT 70 PERCENT POWER FACTOR AND 480 KVAR OF CAPACITORS ARE ADDED, THE SYSTEM ELECTRIC CAPACITY RELEASED IS APPROXIMATELY 28.5 PERCENT: THAT IS, THE SYSTEM CAN CARRY 28.5 PERCENT MORE LOAD (AT 70 PERCENT POWER FACTOR) WITHOUT EXCEEDING THE KVA BEFORE THE POWER FACTOR WAS IMPROVED. THE FINAL POWER FACTOR (COS θ_3) OF THE ORIGINAL LOAD PLUS THE ADDITIONAL LOAD IS APPROXIMATELY 90 PERCENT.

Figure 6.4
Percent Capacity Released and Approximate Combined Load Power Factor with Capacitors

the reduction in losses is inversely proportional to the square of the power factor.

$$\text{Loss reduction} = \text{original loss}\left[1-\left[\frac{\text{original pf}}{\text{improved pf}}\right]^2\right] \qquad (6)$$

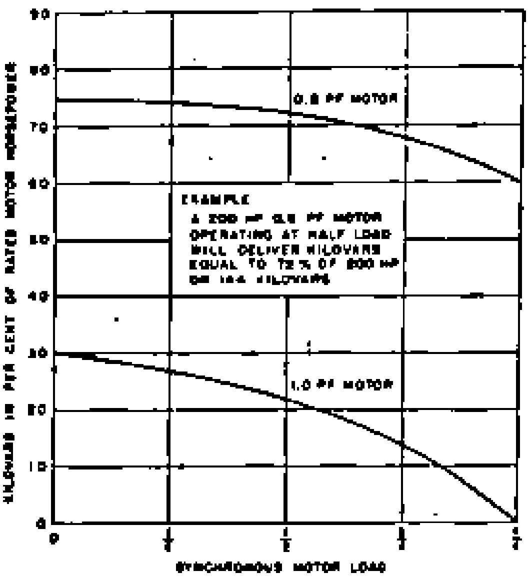
Equation (6) assumes that the kilowatt load remains the same. If the kilowatt load is increased to take advantage of the released system capacity, the loss reduction will not be as great.

Methods of Power Factor Improvement

Power factor in industrial plants can be improved by the use of capacitors or synchronous machines since both can supply magnetizing kilovars to the system.

Both unity power factor and 0.8 power factor synchronous motors improve system power factor. However, the 0.8 power factor motor is more effective because it supplies leading kilovars at all loads up to its rating, whereas the unity power factor motor supplies leading kilovars only when operating at reduced loads.

The kilovar output of synchronous motors varies with the excitation and with load. The curves of Figure 6.5 show the kilovars which a synchronous motor can deliver



SYNCHRONOUS MOTOR KILOVARS VS LOAD AT RATED EXCITATION

Figure 6.5
Approximate Kilovars Supplied by Synchronous Motors

at various loads with normal excitation. At high overloads even the 0.8 power factor motor may draw magnetizing kilovars.

Most capacitors used in industrial plants are connected across the line in shunt with the load and, hence, are called shunt capacitors. Series capacitors, which are connected in series with the load, find occasional use on weak power systems to reduce voltage drops and on fluctuating loads to reduce voltage flicker. The proper application of series capacitors is somewhat complex and their use is so specialized that they will not be covered here. (See Bibliography, Reference No. 5.)

Induction motors plus capacitors are often more economical than synchronous motors alone. Sometimes, the type of drive will dictate the use of one type of motor, but where a free choice can be made, an economic comparison should be made. The capacitor-induction motor combination has the advantage of lower maintenance, and in many cases will prove less expensive in first cost.

Calculation of Kvars Required

The amount of magnetizing kilovars which must be supplied from capacitors or synchronous machines to make a desired improvement in the power factor can be calculated by using the basic relationship shown in Figure 6.1, or it can be determined by using the "kW multiplier" tables, Table 6.1.

Table 6.1 -
Kilowatt Multipliers for Determining Capacitor Kilovars

Original Power Factor ($\cos \theta_1$)	*Desired Improved Power Factor ($\cos \theta_2$)*				
	100	*95*	*90*	*85*	*80*
60	1.333	1.004	0.849	0.713	0.583
62	1.266	0.937	0.782	0.646	0.516
64	1.201	0.872	0.717	0.581	0.451
66	1.138	0.809	0.654	0.518	0.388
68	1.078	0.749	0.594	0.458	0.328
70	1.020	0.691	0.536	0.400	0.270
72	0.964	0.635	0.480	0.344	0.214
74	0.909	0.580	0.425	0.289	0.159
76	0.855	0.526	0.371	0.235	0.105
78	0.802	0.473	0.318	0.182	0.052
80	0.750	0.421	0.266	0.130	0.000
82	0.698	0.369	0.214	0.078	
84	0.646	0.317	0.162	0.026	
86	0.593	0.264	0.109		
88	0.540	0.211	0.056		
90	0.484	0.155	0.000		
92	0.426	0.097			
94	0.363	0.034			
96	0.292				
98	0.203				
100	0.000				

As an example of the use of Table 6.1, assume that the original power factor is 70 percent, the original load is 100 kVA and the improved power factor is to be 95 percent.

The load kW is:

$kw = .7 \times 100 = 70$

From Table 6.1, the "kW multiplier" is 0.691 for improving the power factor from 70 percent to 95 percent. The capacitor kVAr required is then found to be:

$ckVAr = 70\ kW \times 0.691 = 48.4$

Location of Corrective Equipment

It is important to remember that all the benefits obtained by installing capacitors or synchronous machines for power factor improvement result from the reduction of kilovars. They should, therefore, be installed as close to the load as possible. Figure 6.6 shows four possible

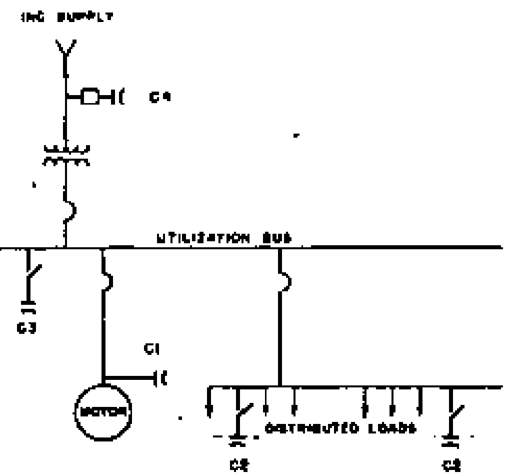


Figure 6.6
Possible Shunt Capacitor Locations

capacitor locations. The most desirable location for power factor improvement is C1; then, in following order, C2, C3 and C4.

The same principle applies to the location of synchronous motors as far as power factor improvement is concerned, although the motors are usually not economical for 240 or 480-volt systems.

Economics must be considered when determining the capacitor location. The cost of a switching device, where required, should be included in the cost comparison.

Capacitor Characteristics

The operating voltage will seldom be exactly equal to the rated capacitor voltage and as a result the actual kilovar output will not equal the capacitor rated kilovars.

The following expression may be used to determine the actual output.

$$\text{Actual ckVAr} = \text{rated ckVAr} \times \left[\frac{\text{operating voltage}}{\text{rated voltage}}\right]^2 \qquad (7)$$

Capacitors are suitable for operation at a maximum voltage of 110 percent of rated capacitor voltage.

Figure 6.6a
An installation of a power factor improvement capacitor directly at the motor terminals

The kilovar output is also affected by the frequency of the voltage and the actual ckvar can be determined from the following expression:

$$\text{Actual ckVAr} = \text{rated ckVAr} \times \frac{\text{operating frequency}}{\text{rated frequency}} \quad (8)$$

Capacitors are suitable for operation at frequencies below their rated value with resulting reduced kilovar output.

Harmonics of the fundamental-frequency voltage will also increase the kilovar output. High harmonic currents are unusual, however, and capacitors are seldom overloaded by harmonic currents.

Capacitors manufactured in accordance with NEMA requirements are capable of supplying 135 percent of rated kilovars. This includes kilovars due to overvoltage, overfrequency, harmonics and manufacturing tolerance of the capacitor.

Capacitors will hold a charge when disconnected from the line and be a hazard to personnel, unless some means is provided to discharge them. The National Electrical Code requires capacitors rated 600 volts or less to be discharged to 50 volts or less in one minute and capacitors rated above 600 volts to be discharged to 50 volts or less in five minutes. Modern capacitors have built-in discharge resistors to meet this requirement. This feature, however, supplements rather than displaces the necessity of short circuiting the capacitor before handling.

Selection of Capacitors for Induction Motors

It is common practice to connect capacitors directly at the motor terminals and switch the capacitor and the motor as a unit. This method insures that the capacitors are connected when the motor is energized. As shown in Figure 6.7, the capacitors can be located in three possible locations. The arrangement of Figure 6.7a or 6.7b is preferred since the motor and capacitor are switched together by the motor contactor. The connection in Figure

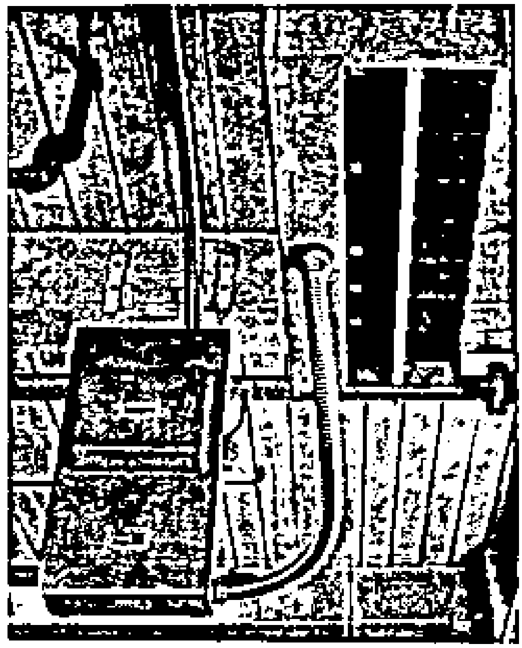


Figure 6.6b
A ceiling suspended installation of a 160-kVAr capacitor bank in an industrial plant

6.7c may be used for capacitors which are permanently connected to the system, thus eliminating a separate switching device for the capacitor. Care should be taken to install the proper overload element in the motor starter since the current through it will be less when the capacitors are connected on the load side (6.7a) than when the capacitors are installed on the line side of the overload element (6.7b or 6.7c).

There are two important considerations which limit the capacitor kilovars which can be connected to the motor terminals and switched with the motor. The first is overvoltage due to self-excitation, and the second is high transient torques. When a motor and capacitor combination is disconnected from the line, the motor continues to rotate for some period of time dependent on the total inertia of the drive. During this period, the capacitor supplies magnetizing kilovars to excite the motor which then acts as a generator. The voltage which can be produced by this generator action is dependent upon the capacitor kilovars connected to the motor and the motor speed. It is possible to produce an overvoltage of 140-160 percent. This voltage is called self-excitation voltage and may be determined mathematically or graphically (Bibliography Reference 7).

The second consideration, transient torques, is probably the most important. If the motor and capacitor combination is reclosed on the line and the motor, acting as a generator, is producing a voltage, it is possible to obtain transient torques as great as 20 times full-load motor

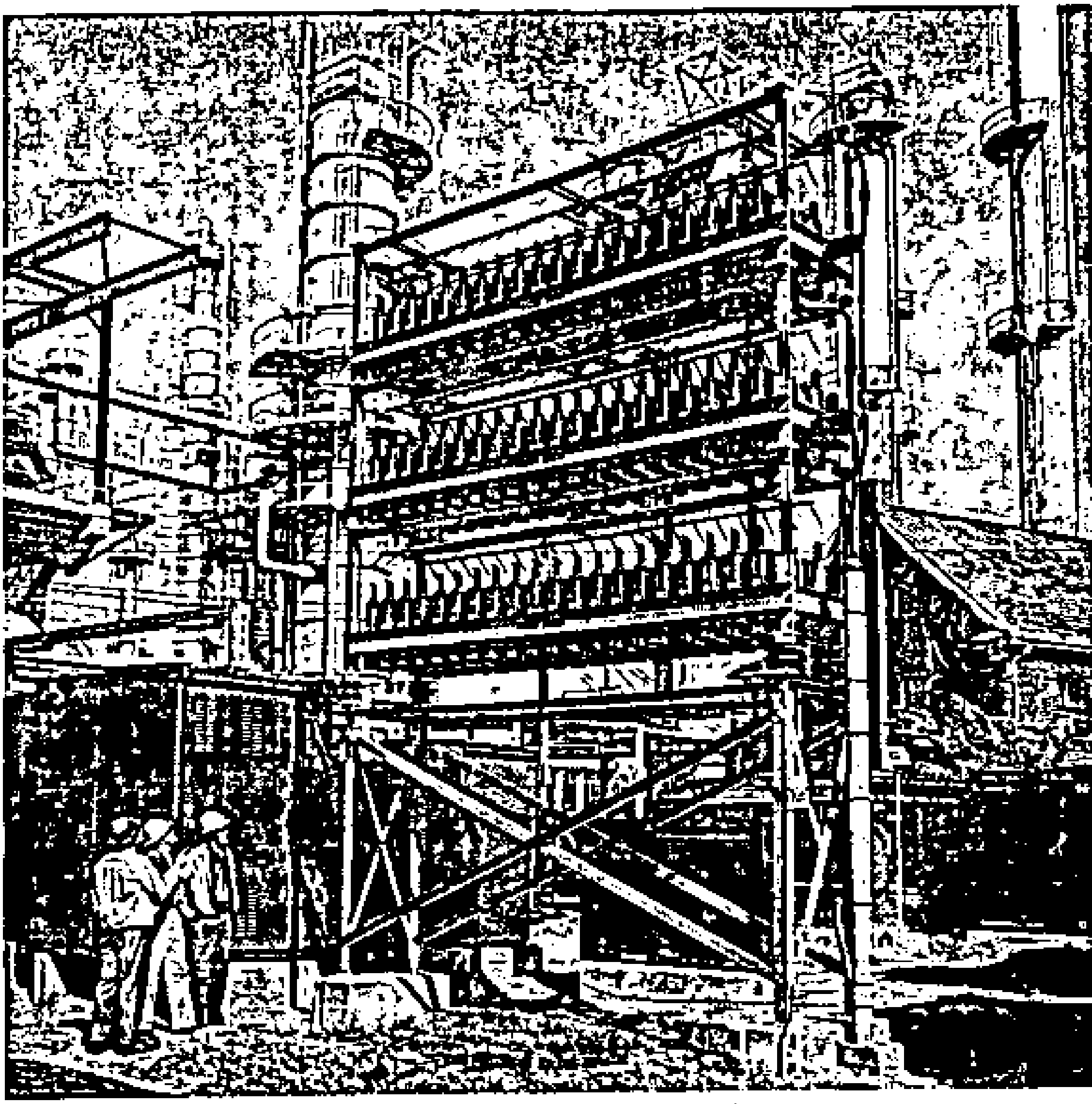


Figure 6.6c
A 6000-kVAr, 13.8kV, 60-hertz outdoor stack-rack capacitor bank applied at a main power bus in industrial service

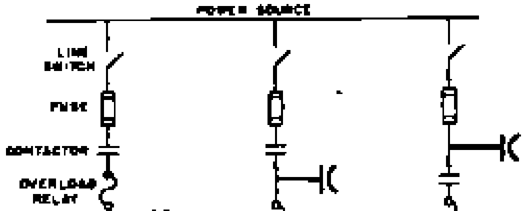


Figure 6.7
Possible Location of Motor Capacitors for Power Factor Improvement

torque. The actual transient torque developed depends primarily upon the magnitude of the motor voltage, the angle between the motor voltage and line voltage when the reclosure takes place, and the ratio of load inertia to total inertia. These torques may also occur when a motor is transferred from the reduced voltage tap to the full-voltage position of an autotransformer type starter, or when changing speeds on multispeed induction motors. (Reference 3).

The recommendation of the motor manufacturer should be followed to assure proper application of capacitors to induction motors.

The same two factors, overvoltage due to self-excitation, and transient torques, must be considered when capacitors are applied to a bus serving a group of motors. The situation will be most critical when all the capacitors and only part of the motors are connected to the bus. The transient torque problem can be eliminated if the reclosure of the bus onto the line is delayed until the motors have slowed down enough to permit the bus voltage to collapse. Or the capacitor feeder breaker may be interlocked with the source breaker so the capacitors are disconnected from the bus when the source breaker opens.

Selection of Conductor Size

The conductors used for capacitor applications should be selected on the basis of the 35 percent overload which NEMA Standards permit on capacitors. Consideration should be given to the ambient temperature and to the fact that capacitors operate at full load whenever energized.

NEC Installation Requirements

The National Electrical Code sets forth the requirements concerning capacitor installations. These requirements concern the means and time of discharging, conductor rating, overcurrent protection, disconnecting means, grounding, mechanical considerations and capacitor rating when the capacitor is switched with the motor.

Effect of Ambient Temperature

The NEMA Standards require capacitor units to be suitable for operation at ambient air temperatures generally not exceeding 40°C. when installed in accordance with their recommendations. It is important that capacitors not be subjected to improper ambient temperatures, as this may cause them to function improperly and shorten their life.

Fuses

Care should be taken to properly protect each capacitor unit and this usually requires an individual fuse on each unit.

Most low-voltage capacitor units include fuses mounted on the unit. Capacitor equipments usually have individual fuses for each capacitor unit.

Switching Device

There are two major requirements when applying a switching device: (1) it must have an adequate continuous current rating, and (2) it must have a short-circuit interrupting capacity adequate for the system to which it is connected.

The NEMA Standards require that fusible safety switches shall have a current rating of not less than 165 percent of rated capacitor current and that contactors and low-voltage power circuit breakers shall have a current rating of not less than 135 percent of rated capacitor current. For molded-case circuit breakers, obtain manufacturer's recommendation.

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Standards

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2. Shunt Capacitors, NEMA Pub. No. CP-1, Latest Edition.

CHAPTER VII

POWER EQUIPMENT

This chapter covers information on the requirements for and application of major items of low-, medium-, and high-voltage equipment required in an industrial electric distribution system, together with data on surge protection of transformers, distribution lines, circuit breakers, and rotating equipment. Data on conductors such as cables, wires and buses are treated in Chapter IX.

The subject matter is broad and in this publication only the highlights are covered. Much useful information is available in the USA and NEMA Standards and manufacturers' publications; it is suggested that these be referred to for more detailed information.

Voltage Classes

For purposes of identification in this chapter the various voltage levels may be classified as follows:

1) 600 volts and less (low voltage)

2) 601 to 15000 volts (medium voltage)

3) above 15000 volts (high voltage)

Protection

The word protection as applied to an electric circuit implies relief of undesirable abnormal conditions. Usually, the means used consists of equipment sensitive to these conditions which opens when the undesirable abnormal conditions occur, isolates the circuit or apparatus in trouble and stops the flow of energy into the equipment. The problem of protection usually resolves itself into two parts; protection of the device itself and protection of the circuit to the device.

It is to be noted that protection against circuit abnormality is not necessarily limited to the particular abnormal circuit, but is often with respect to other circuits, apparatus or processes and provides for the elimination from the system of the particular seat of trouble. The nature of the protective device depends upon just what its function is. A particular problem may be to prevent a motor from overheating due to continued overload. The second problem may be to prevent shutdown of the whole system in the event of a fault on only one circuit. In the first case, a contactor or magnetically-operated switch will do the job under the direction of relays which respond to the motor current or motor temperature. In the second case, the magnitude of the current to be broken usually is beyond the interrupting ability of contactors, and a device desiged for interrupting high currents, such as a circuit breaker or a set of fuses, is to be used.

Heat Losses

The heat generated by power losses in electric distribution equipment, particularly transformers, switchgear, large rectifiers and motor-control centers is frequently overlooked in the design phase, and then must be corrected later by makeshift manual means. A realistic summing of the electric losses, which generally show up as heat, should be developed and added to the cooling requirements of the rest of the building. Simply exhausting the air from the equipment location, and allowing air to enter through screens or filters is not necessarily the best answer. The large air volume required may make the power for ventilation quite costly and filter replacement very frequent. Drawing in large quantities of cooler outside air can cause condensation in metal-clad switchgear and busway. Some alternatives which are often practicable include heat removal by air conditioning, or outdoor location of the main heat-producing equipment, particularly transformers.

Circuit Opening Devices

Circuit opening devices provide for normal circuit switching operations and provide a means for disconnecting a faulty circuit or equipment from the electric system with minimum damage and disturbance.

There are six general types of circuit opening devices for medium- and high-voltage applications. These are: (1) circuit breakers; (2) fuses; (3) interrupter switches; (4) load-break switches; (5) disconnect switches; and (6) contactors. The first two types only are suitable for automatic operation to clear fault currents. Circuit breaker-fuse combinations and interrupter switch-fuse combinations may be used for automatic fault clearing. The load-break switch is normally designed to carry 1.5 times rating. Interrupter switches and disconnecting switches are manually-operated switch devices used for circuit and equipment isolation. Generally, interrupter switches are suitable for opening and closing normal load currents whereas disconnect switches may, in general, be safely operated only on de-energized circuits.

A circuit opening device should meet the following requirements for short-circuit protection:

1—It should be capable of carrying and opening the normal load current within its rating.

2—It should safely interrupt any current that may flow through it within its rating.

3—It should be capable of being safely closed on any load current or short circuit within its rating.

Control Power

Successful operation of switchgear embodying electrically operated devices is dependent on a reliable source of control power which at all times will maintain voltage at the terminals of such devices within their rated operating-voltage range. In general the operating-voltage range of a switchgear equipment is determined by the rated operating-voltage range of the component electrically operated circuit breakers. These ranges are established by appropriate NEMA Standards for power circuit breakers.

There are two primary uses for control power in switchgear: tripping power and closing power. Since an essential function of switchgear is to provide instant and unfailing protection in emergencies, the source of tripping power must be one that will always be available. It is generally preferable that the source of closing power also be independent of voltage conditions on the power system associated with the switchgear. However, more consideration may be permitted cost as a factor in selecting a source of closing power than is permissible with the essential tripping power.

Four practical sources of tripping power are:

(1) Direct current from a storage battery.

(2) Direct current from a charged capacitor.

(3) Alternating current from the secondaries of current transformers in the protected power circuit.

(4) Direct or alternating current in the primary circuit passing through direct-acting trip devices.

Where a storage battery has been chosen as the source of tripping power it can also supply closing power. An added consideration, however, is the present trend to incorporate stored-energy (spring-mechanism) closing on both low- and medium-voltage power circuit breakers. General distribution systems, whether alternating-current or direct-current, cannot be relied upon to supply tripping power because outages are always possible, and are most likely to occur in times of emergency when the switchgear is called upon to perform its protective functions.

Other factors influencing the choice of control power are:

(1) Availability of adequate maintenance for a battery and its charger.

(2) Availability of suitable housing for a battery and its charger.

(3) Advantages of having removable breaker units interchangeable with those in other installations.

(4) Necessity for closing breakers with the power system de-energized.

Circuit Breakers

By definition a circuit breaker "is a device for interrupting a circuit between separable contacts under normal or abnormal conditions. Ordinarily, circuit breakers are required to operate only infrequently, although some classes of breakers are suitable for frequent operation. (*Normal* indicates the interruption of currents not in excess of the rated continuous current of the circuit breaker. *Abnormal* indicates the interruption of currents in excess of rated continuous current, such as short circuits.) The rating of a circuit breaker should be equal to or greater than the system short-circuit duty."

Circuit breakers are commonly used instead of fuses on utility and industrial power distribution systems in order to provide essential switching flexibility and circuit protection.

Circuit breakers are available for the entire voltage range and may be furnished single-, double-, triple-pole or more and arranged for outdoor or indoor use, except that breakers above 34.5 kV are generally open type and used outdoors.

The rating of a power circuit breaker in the medium- and high-voltage class includes the following items.

(1) Rated voltage,

(2) Maximum design voltage,

(3) Minimum voltage for rated interrupting mva,

(4) Rated impulse withstand voltage,

(5) Rated frequency,

(6) Rated continuous current,

(7) Rated momentary current,

(8) Rated 4-second current,

(9) Rated 3-phase interrupting MVA,

(10) Rated interrupting current at rated voltage,

(11) Rated maximum interrupting current,

(12) Rated interrupting time in cycles.

The voltage and current ratings generally listed are based on altitudes up to 3300 feet. Derating factors, as well as detailed information on the above, are given in the USA Standards; but Table 7.1 is a handy reference for power circuit breakers.

The rated momentary and interrupting-current-carrying capacities are very important factors for use in the application of the medium- and high-voltage circuit breakers. Low-voltage power circuit breakers have the following ratings:

1. Rated Voltage.
2. Rated Maximum Design Voltage.
3. Rated Maximum Voltage.
4. Rated Frequency.
5. Rated Continuous Current.
6. Rated Short-Time Current.
7. Rated Short-Circuit Current.
8. Rated Control Voltage.

Table 7.1

Standard Power Circuit Breakers for Industrial and Commercial Building Electric Systems for Operating Voltages between 1.5 and 115 kV at an Operating Frequency of 60 Hertz

Voltage Ratings			Insulation Level: Withstand Level		Current Ratings in Amperes			Interrupting Ratings			Rated Interrupting Time in Cycles (60 hertz basis)
Rated	Maximum Design kV	Minimum Operating kV at Rated MVA	Low Frequency rms kV	Impulse Crest kV	Continuous at 60 Hertz	Short-time: Momentary	Short-time: 4-Second	3-phase Rated MVA	In rms Total Amperes: At Rated Voltage	In rms Total Amperes: Maximum Rating	
Nonoilight and Panel-Mounted Oil Circuit Breakers (0 + CO Duty)											
2.5		2.1	15	45	200	6500	3800	15000	3500	3800	
2.5		2.1	15	45	400	6500	3800	15000	3500	3800	
4.16		2.3	19	60	600	10000	6300	25000	3500	6300	
Indoor Oil Power Circuit Breakers (0 + CO Duty)											
4.16	4.76	2.3	19	60	600	10000	6300	25	3500	6300	8
4.16	4.76	2.3	19	60	1200	20000	12500	50	7000	12500	8
7.2	8.25	2.3	26	75	600	20000	12500	50	4000	12500	8
7.2	8.25	2.3	26	75	600	40000	25000	100	8000	25000	8
7.2	8.25	2.3	26	75	1200	40000	25000	100	8000	25000	8
7.2	8.25	2.3	26	75	2000	40000	25000	100	8000	25000	8
13.8	15.0	4.0	36	95	600	35000	22000	150	6300	22000	8
13.8	15.0	4.0	36	95	1200	35000	22000	150	6300	22000	8
13.8	15.0	4.0	36	95	1200	60000	36000	250	10600	36000	8
13.8	15.0	6.6	36	95	1200	70000	44000	500	21000	44000	8
13.8	15.0	6.6	36	95	2000	70000	44000	500	21000	44000	8
14.4	15.5	6.6	50	110	1200	70000	44000	500	20000	44000	8
14.4	15.5	12	50	110	1200	77000	48000	1000	40000	48000	8
14.4	15.5	12	50	110	3000	77000	48000	1000	40000	48000	8
14.4	15.5	12	50	110	2000	115000	72000	1500	60000	72000	8
14.4	15.5	12	50	110	4000	115000	72000	1500	60000	72000	8
34.5	38	23	80	200	1200	61000	38000	1500	25000	38000	8
34.5	38	23	80	200	3000	61000	38000	1500	25000	38000	8
Indoor Oilless Power Circuit Breakers (0 + CO Duty)											
4.16	4.76	3.5	19	60	1200	20000	12500	75	10500	12500	8
4.16	4.76	3.5	19	60	1200	40000	25000	150	21000	25000	8
4.16	4.76	3.85	19	60	1200	60000	37500	250	35000	37500	8
4.16	4.76	3.85	19	60	2000	60000	37500	250	35000	37500	8
4.16	4.76	4.0	19	60	1200	80000	50000	350	48600	50000	8
4.16	4.76	4.0	19	60	3000	80000	50000	350	48600	50000	8
7.2	8.25	6.6	36	95	1200	51000	32000	250	20000	32000	8
7.2	8.25	6.6	36	95	1200	70000	44000	500	40000	44000	8
7.2	8.25	6.6	36	95	2000	70000	44000	500	40000	44000	8
13.8	15.0	6.6	36	95	1200	20000	13000	150	6300	13000	8
13.8	15.0	6.6	36	95	1200	35000	22000	250	10600	22000	8
13.8	15.0	11.5	36	95	1200	40000	25000	500	21000	25000	8
13.8	15.0	11.5	36	95	2000	40000	25000	500	21000	25000	8
13.8	15.0	11.5	36	95	1200	60000	37500	750	31500	37500	8
13.8	15.0	11.5	36	95	2000	60000	37500	750	31500	37500	8
13.8	15.0	11.5	36	95	1200	80000	50000	1000	42000	50000	8
13.8	15.0	11.5	36	95	3000	80000	50000	1000	42000	50000	8
14.4	15.5	12	50	110	1200	77000	48000	1000	40000	48000	8
14.4	15.5	12	50	110	3000	77000	48000	1000	40000	48000	8
14.4	15.5	12	50	110	2000	115000	72000	1500	60000	72000	8
14.4	15.5	12	50	110	4000	115000	72000	1500	60000	72000	8
14.4	15.5	12	50	110	5000	190000	120000	2500	100000	120000	8
34.5	38	23	80	200	1200	61000	38000	1500	25000	38000	8
34.5	38	23	80	200	3000	61000	38000	1500	25000	38000	8
34.5	38	24	80	200	3000	96000	60000	2500	42000	60000	8
Outdoor Oil Power Circuit Breakers (0 + CO Duty)											
14.4	15.5	3.85	50	110	600	24000	15000	100	4000	15000	8
14.4	15.5	5.8	50	110	600	40000	25000	250	10000	25000	8
14.4	15.5	5.8	50	110	1200	40000	25000	250	10000	25000	8
14.4	15.5	12	50	110	600	38000	24000	500	20000	24000	8
14.4	15.5	12	50	110	1200	38000	24000	500	20000	24000	8
14.4	15.5	12	50	110	1200	77000	48000	1000	40000	48000	8
14.4	15.5	12	50	110	3000	115000	72000	1500	60000	72000	8
14.4	15.5	12	50	110	4000	115000	72000	1500	60000	72000	8
23	25.8	12	60	150	600	19000	12000	250	6300	12000	8
23	25.8	12	60	150	1200	38000	24000	500	12600	24000	8
34.5	38	23	80	200	1200	20000	12600	500	8400	12600	8
34.5	38	23	80	200	1200	40000	25000	1000	17000	25000	8
34.5	38	23	80	200	1200	61000	38000	1500	25000	38000	8
34.5	38	24	80	200	2000	96000	60000	2500	42000	60000	8
46	48.3	40	105	250	1200	12000	7200	500	6300	7200	8
46	48.3	40	105	250	1200	35000	22000	1500	19000	22000	8
69	72.5	60	160	350	1200	16000	9600	1000	8400	9600	8
69	72.5	60	160	350	1200	23000	14500	1500	12600	14500	5
69	72.5	60	160	350	1200	38000	24000	2500	21000	24000	5
69	72.5	66	160	350	2000	70000	44000	5000	42000	44000	5
115	121	105	260	550	800	13300	8300	1500	7500	8300	5
115	121	110	260	550	1200	39000	26000	5000	25000	26000	3
115	121	110	260	550	1600	78000	52000	10000	50000	52000	3
Outdoor Oilless Power Circuit Breakers (0 + CO Duty)											
34.5	38	23	80	200	1200	61000	38000	1500	25000	38000	5
69	72.5	66	160	350	2000	66000	44000	5000	42000	44000	3
115	121	110	260	550	1600	78000	52000	10000	50000	52000	3

Data from: NEMA SG4-2.04 (1963) and USAS C37.6 (1966) and C37.06 (1966)

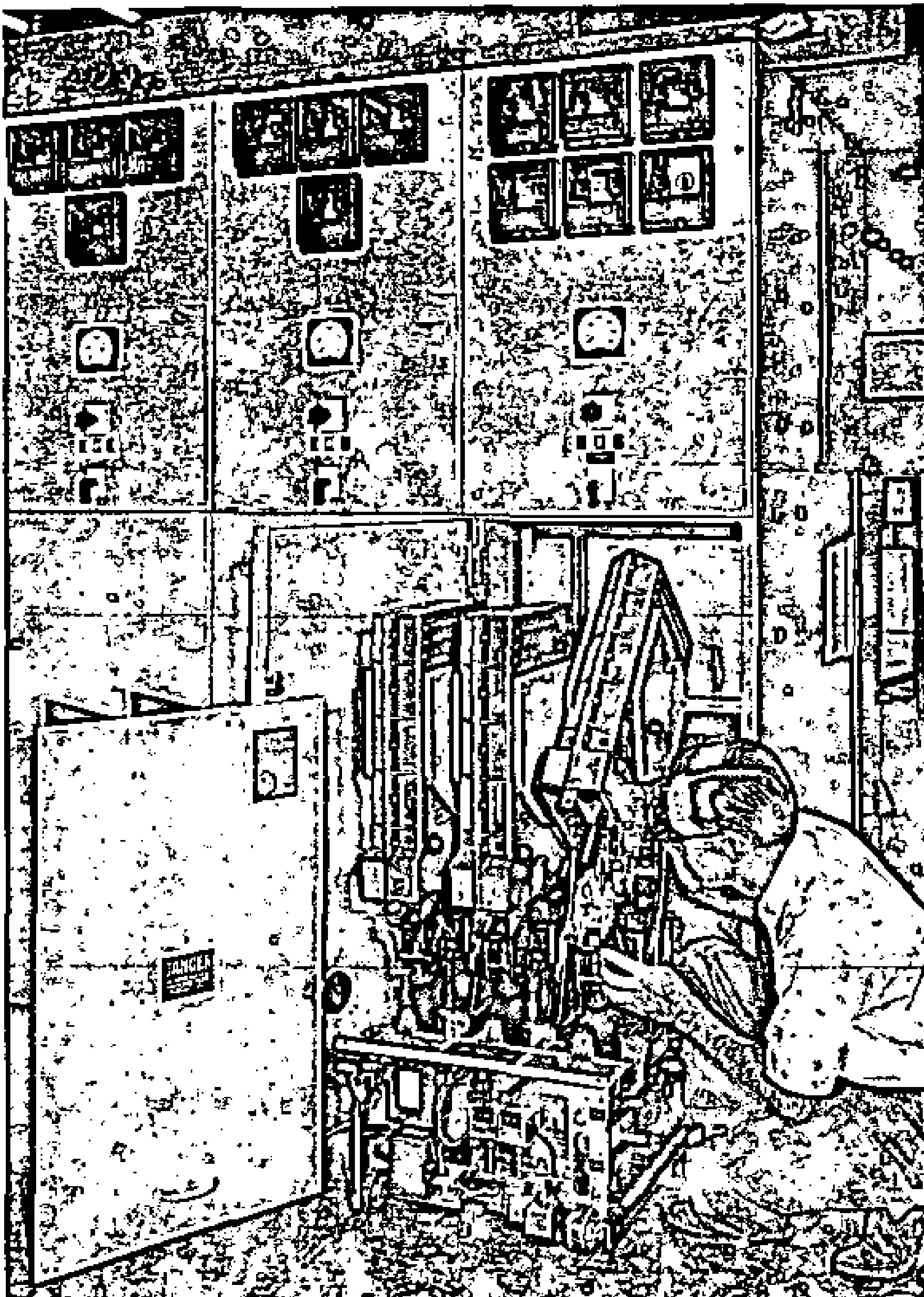


Figure 7.1
Installation of drawout, medium-voltage air circuit breaker

Figure 7.2
Installation of low-voltage draw-out switchgear

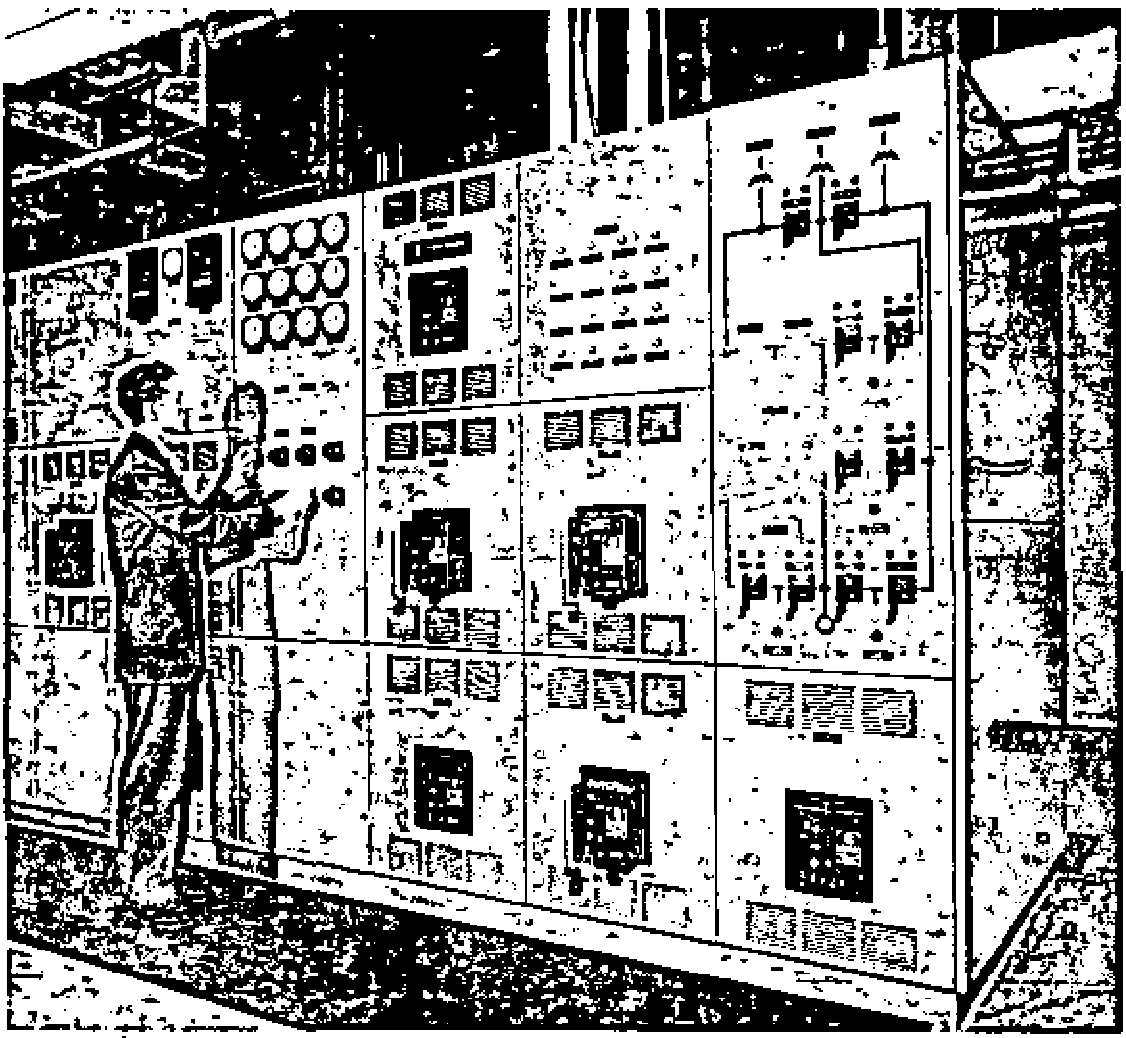


Figure 7.3
Centralized control board in an industrial plant

Associated with this type of switchgear is the metal-enclosed centralized control boards called the duplex switchboard.

In outdoor applications a switchgear is available with a protected maintenance aisle. The equipment is designed with either a duplex board or local control.

Typical installations of these types of equipments are shown in Figures 7.1, 7.2, and 7.3.

The National Electrical Code defines a panelboard as "a single panel, or a group of panel units designed for assembly in the form of a single panel; including buses, and with or without switches and/or automatic overcurrent protective devices for the control of light, heat, or power circuits of small individual as well as aggregate capacity; designed to be placed in a cabinet or cutout box placed in or against a wall or partition and accessible only from the front."

Panelboards are of two general classes: (a) lighting and appliance branch circuits and (b) power and feeder distribution. Principal difference is that lighting and appliance panelboards use single-pole circuit devices of relatively low current rating, while the distribution panelboard may contain two- and three-pole breakers or fused switches of various sizes up to 600 amperes.

Panelboards are of three kinds with respect to the circut elements—(a) plug fuses only, (b) switches and fuses, and (c) circuit breakers. When the circuit elements are only fuses, only the plug fuse is allowed. Panelboards differ as to the treatment of the mains. Some panelboards provide only main lugs and others provide a main circuit breaker or main disconnecting means. Where a neutral is involved in the system, connection for the neutral cable is provided for in the panelboard.

Since panelboards are comprised of circuit protective devices, such as fuses and circuit breakers, magnitude of short-circuit current at the place of installation must be carefully considered. The circuit protective devices must have adequate interrupting ability.

Transformers

By definition, a distribution transformer is any transformer having a rating between 3 and 500 kVA, inclusive; transformers with ratings above 500 kVA are classed as power transformers. Note that by this definition only kva rating is involved.

Much information pertaining to transformer features and characteristics is included in the USASI and EEI-NEMA publications. Some of the following were extracted from these sources. It is suggested that the reader refer to these as well as manufacturers' publications for more complete information.

Most transformers in industrial plants are associated with secondary unit substations, generally in ratings of 500-1500 kVA, askarel-filled or with dry-type insulation (ventilated or sealed and gas filled), and located indoors. When transformers are located outdoors, they are usually of the oil-filled type. Practically all of these transformers in industry are of three-phase construction. It is uncommon to find an industrial plant who now uses single-phase units to make up a three-phase bank; three-phase transformers have an excellent service record, cost less and require less space.

In many ways the power transformers for most types of industrial service have similar requirements. This has resulted in standardization of characteristics, so wherever possible, it is suggested that the transformers conforming to these be specified, since repetitive-manufacturing methods applying to such USA Standard transformers usually result in lower cost than for non-standard units.

In the selection of a transformer for a particular application, consideration must be given to the following characteristics which determine its rating structure:

1. kVA rating,
2. Voltage ratings and ratios,
3. Voltage taps,
4. Type of cooling,
5. Insulation level,
6. Sound level,
7. Impedance.

The kVA rating must primarily be sufficient to handle the immediate load required. Consideration should be given also to possible future load growth which might be required by expanding facilities.

The voltage ratio and taps are selected to provide the correct voltage at the load terminals, taking into account the variations in supply voltage as well as the voltage drop through the transformer and in the distribution lines. (See Chapter II). Most power transformers are selected with the incoming voltage rating equal to the nominal value of supply voltage and with two 2½ percent taps above and below the rated voltage to adjust for variations in supply voltage. These taps are for de-energized operation only, and hence are not intended for adjusting the output voltage with variations in load. The taps above rated voltage in a step-down transformer will increase the turns in the high-voltage winding. With a fixed incoming voltage, therefore, selection of a higher than normal tap will result in a lowering of the output voltage. This allows some leeway in the selection of taps to help compensate for part of the voltage drop in the transformer and the distribution lines, but it should be remembered that the main purpose of the taps is to adjust for the level in the supply voltage, not for secondary regulation.

Table 7.3 defines various types of transformer cooling methods.

The relationships between self-cooled and forced-air-cooled kVA ratings for oil-immersed and ventilated dry-type transformers will be in accordance with Table 7.4. Each kVA rating for any given transformer will be based on its rated temperature rise (55°-65° C for oil-immersed, 55°, 80°, 115°, 150° C for dry-type transformers).

Table 7.6 gives representative impedance values of power transformers. These values are useful for calculation of voltage regulation, and short-circuit currents.

Audio levels are becoming more important. Handy representative values are given in Tables 7.7 and 7.8.

Industry is becoming more concerned with reducing voltage spread in the interest of better performance and longer life of electric equipment. This is generally accomplished by regulating equipment, such as the automatic-tap-changing-under-load feature on power transformers or individual circuit regulators.

Table 7.3

Classes of Transformer Cooling Systems

Type Letters	*Method of Cooling*
OA	Oil-immersed, self-cooled
OW	Oil-immersed, water-cooled
OW/A	Oil-immersed, water-cooled/self-cooled
OA/FA	Oil-immersed, self-cooled/forced-air-cooled (above 500 kVA)
OA/FA/FA	Oil-immersed, self-cooled/forced-air-cooled/forced-air-cooled (10,000 kVA and larger)
OA/FOA/FOA	Oil-immersed, self-cooled/forced-air-forced-oil-cooled/forced-air-forced-oil-cooled (10,000 kVA and larger)
FOA	Oil-immersed, forced-oil-cooled with forced-air-cooler (10,000 kVA and larger)
FOW	Oil-immersed, forced-oil-cooled with forced-water-cooler (10,000 kVA and larger)
AA	Dry-type, self-cooled
AFA	Dry-type, forced-air-cooled
AA/FA	Dry-type, self cooled/forced-air-cooled (above 500 kVA)

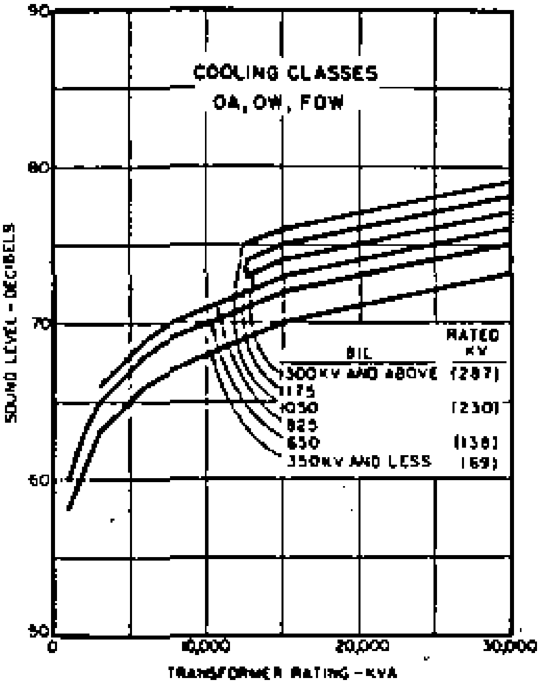
From USAS C57 and NEMA TR1 (1968)

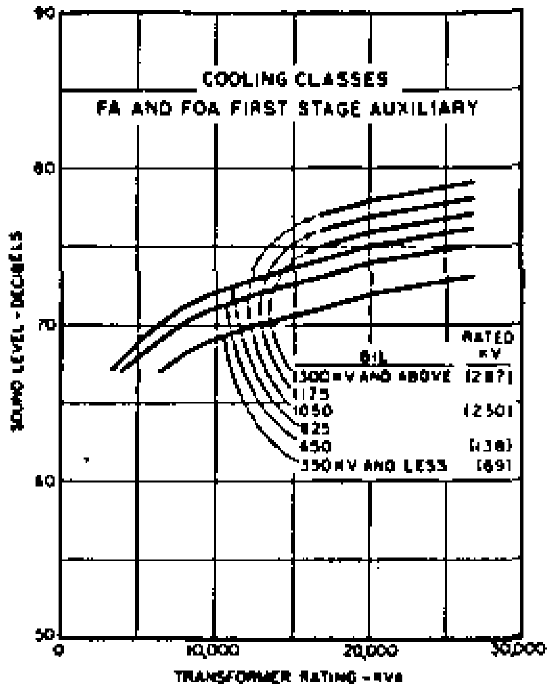
Table 7.4

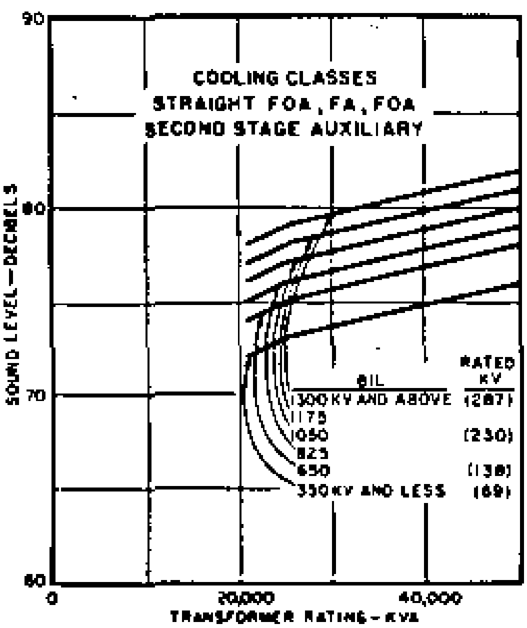
Transformer Capabilities with Forced Cooling*

	Self-Cooled Rated kVA		*Percent of Self-Cooled kVA with Auxiliary Cooling*	
Type of Cooling	*Single-Phase*	*Three-Phase*	*First Stage*	*Second Stage*
OA/FA	501-2499	501-2499	115	.....
	2500-9999	2500-11999	125	.....
	10000 and larger	12000 and larger	133⅓	.....
OA/FA/FA	10000 and larger	12000 and larger	133⅓	166⅔
AA/FA#	501 and larger	501 and larger	133⅓	.....

* From NEMA TR1 (1968)
# Not applicable to sealed dry type transformers.







The sound levels are average values around the periphery of the transformer.

The values do not apply during the interval that internal power-operated switches are in operation.

From NEMA TR1 (1962).

Table 7.7
Audible Sound Levels or Oil-Immersed Power Transformers, 60 Hertz and Below

Table 7.8a
Audible Sound Levels for Dry Type Transformers 15,000-Volt and Below Insulation Class

Equivalent Two-Winding kVA	*Average Sound Level, Decibels Self-Cooled, Class AA*		*Equivalent Two-Winding kVA*	*Average Sound Level, Decibels Forced-Air-Cooled, Class FA and AFA*
	Ventilated	*Sealed*		
0- 300	58	57		
301- 500	60	59		
501- 700	62	61		
701-1000	64	63	3- 1167	67
1001-1500	65	64	1168- 1667	68
1501-2000	66	65	1668- 2000	69
2001-3000	68	66	2001- 3333	71
3001-4000	70	68	3334- 5000	73
4001-5000	71	69	5001- 6667	74
5001-6000	72	70	6668- 8333	75
6001-7500	73	71	8334-10000	76

These Standards are not applicable to rectifier, railway, furnace, grounding, mobile, and mobile unit substation transformers.

The tabulated values represent the average sound level which will not be exceeded on the base transformer, exclusive of sound emitted by integral load tap changing mechanisms, disconnecting switches, or grounding switches.

From NEMA Standard TR1-1962.

Table 7.8b
Audible Sound Levels, Oil-Immersed Distribution and Network Transformers, Class OA, OW, and FOW

Distribution Transformers		*Network Transformers*	
Equivalent Two-Winding kVA 15 kV and Below Insulation Class	*Average Sound Level, decibels*	*Equivalent Two-Winding kVA 69 kV and Below Insulation Class*	*Average Sound Level, decibels*
0- 50	48	300	55
51-100	51	500	56
101-300	55	700	57
301-500	56	1000	58
		1500	60
		2000	61
		2500	62

From NEMA Standard TR1 (1962)

Substations

Industry favors the unit-type or factory-assembled substation rather than the field-assembled type. Therefore, this discussion will be directed primarily to the unit type of substation.

Substations are generally divided into two classifications—primary unit substations and secondary unit substations.

NEMA Standards No. 201 to 207 contain much useful information on primary substations. Similar information concerning secondary unit substations is found in NEMA Standards No. 210 to 213.

By definition, a unit substation is "a substation which consists primarily of one or more transformers which are mechanically and electrically connected together, and which are coordinated in design with one or more switchgear or motor control assemblies, or combinations thereof. Unit substations are essentially power transformers of standard ratings throat connected or connected by a metal-enclosed bus to metal-clad switchgear or motor control equipment of standard ratings."

Also by definition, "A primary unit substation is a unit substation whose secondary is medium voltage (601 to 15,000 volts)."

And by definition, "A secondary unit substation—often called a load-center unit substation—is a unit substation which has a low-voltage rating of 600 volts or below." In addition, the primary voltage is usually below 15 kV.

Typical primary and secondary substations are shown in Figures 7.4, 7.5, and 7.6. Figure 7.7 shows a special type of unit substation including a rectifier for direct-current power supply.

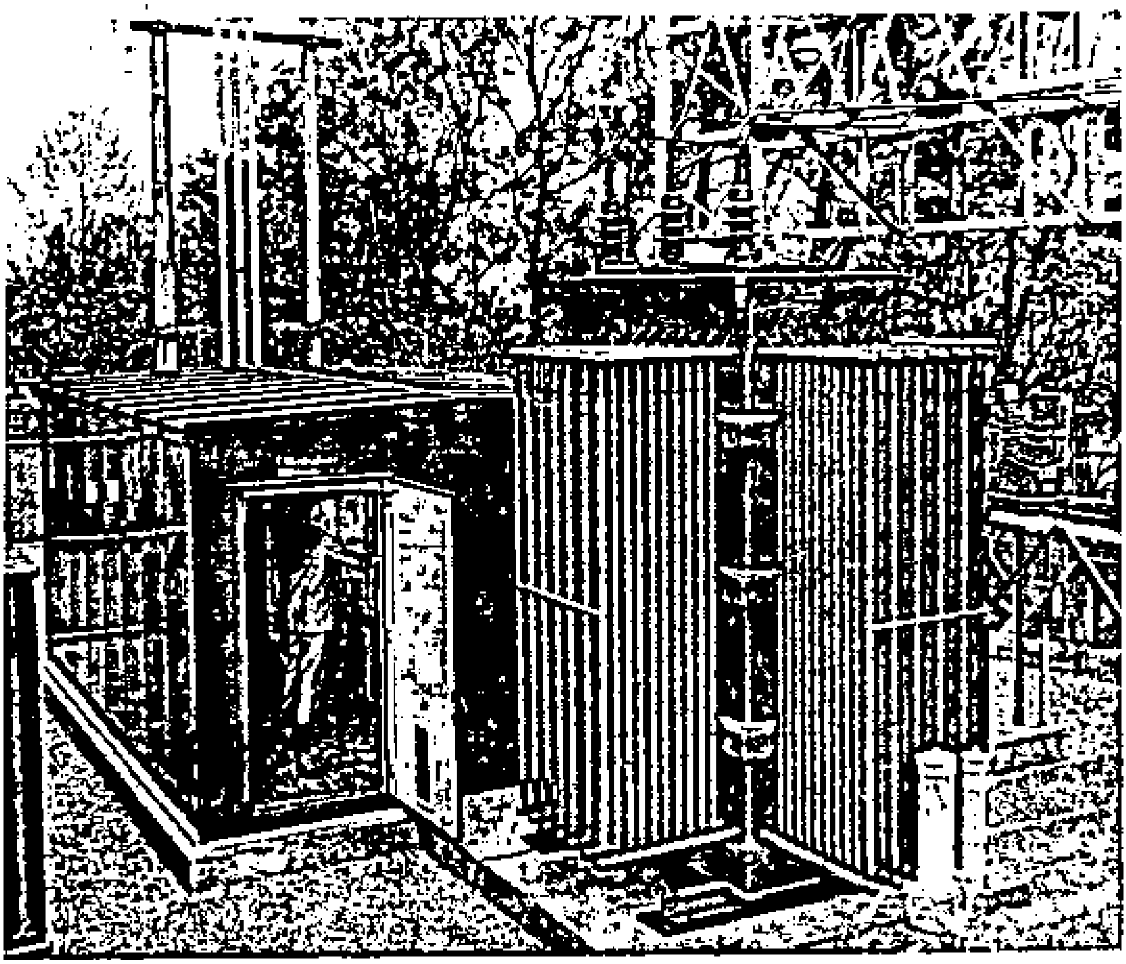


Figure 7.4
Plant primary substation with sheltered-aisle switchgear

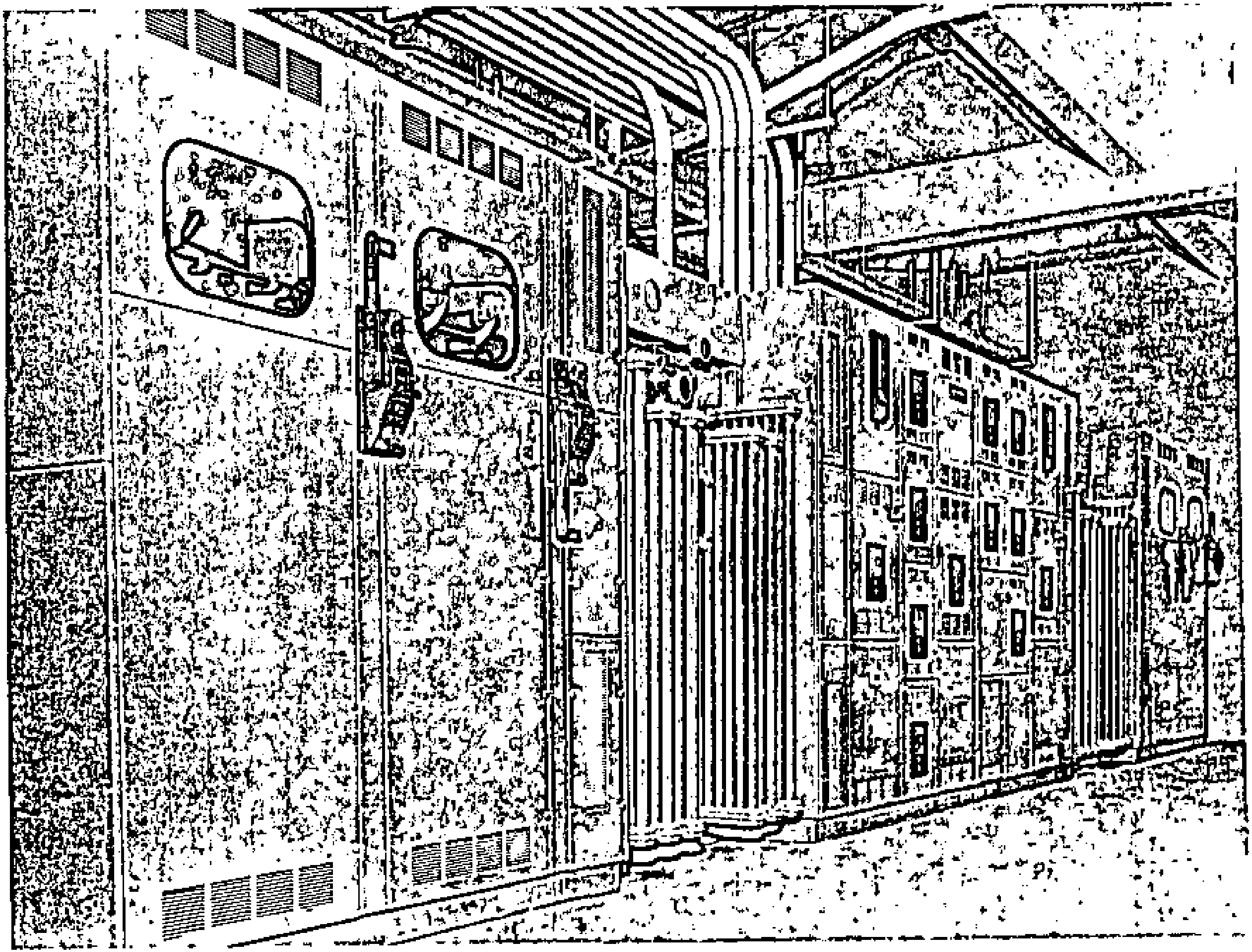


Figure 7.5
Double-ended secondary substation with askarel-filled transformers

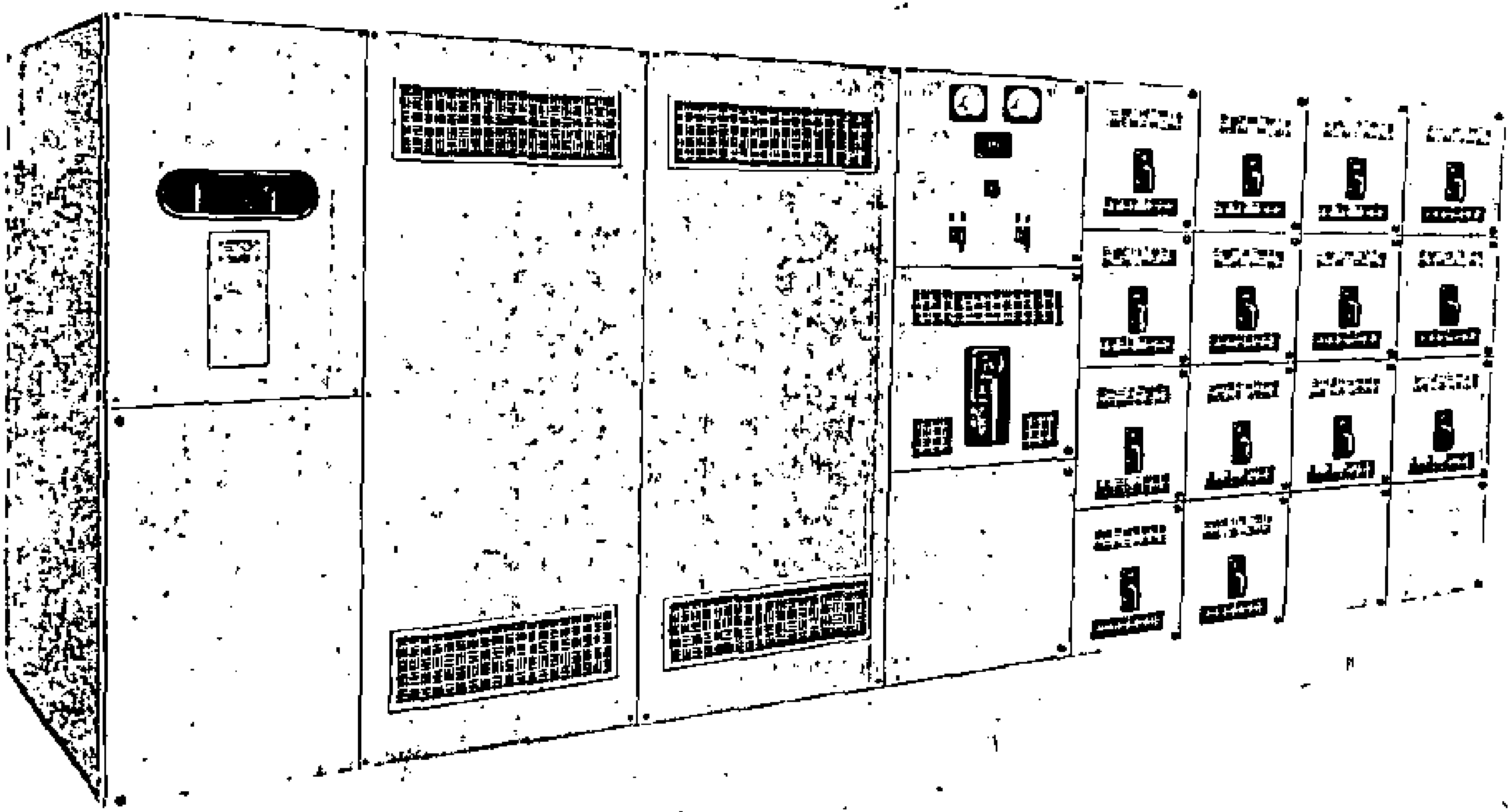


Figure 7.6
Secondary substation with dry-type transformers

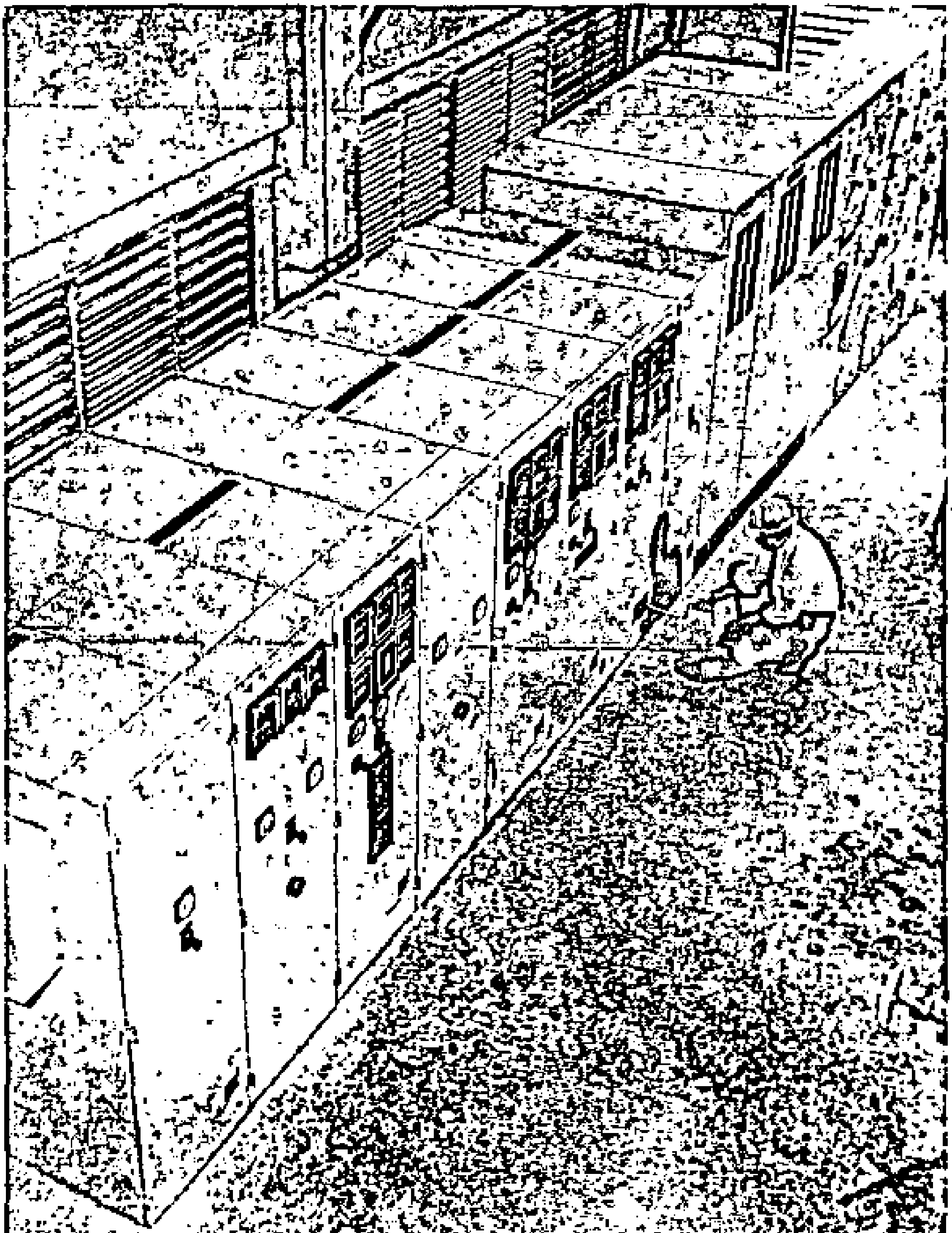


Figure 7.7
Direct-current substation with silicon rectifiers

There are many items to be considered in the selection and location of substations. A few of these are: kVA rating, voltage rating, allowance for future growth, appearance, atmospheric conditions, outdoor versus indoor location, station lighting, ventilation, service facilities, storage space, type of structures, etc.

Substation structures and equipments operating at voltages above 15 kV are usually limited to outdoor installations by building costs. Portions of the substation operating at 15 kV and below may be indoor or outdoor. These portions of the substation may be of open construction or utilize metal-clad switchgear for either indoor or outdoor installations. Very frequently the high-voltage structure and power transformer will be located outdoors and the metal-clad switchgear located indoors. Highly corrosive atmospheres generally make it advisable to locate as much of the equipment as possible indoors. The space requirements of outdoor substations are greater than those of indoor equipment. The cost of indoor equipment is lower and maintenance is more convenient and less expensive but building costs may be greater. Where the indoor equipment may be located in a portion of a building used to house other equipments, the building costs may be reduced appreciably.

Low-Voltage Overcurrent Protection

There are two types of low-voltage alternating-current protective systems, referred to as "selective" and "cascade" systems. The basic reason for the two systems is one of economics.

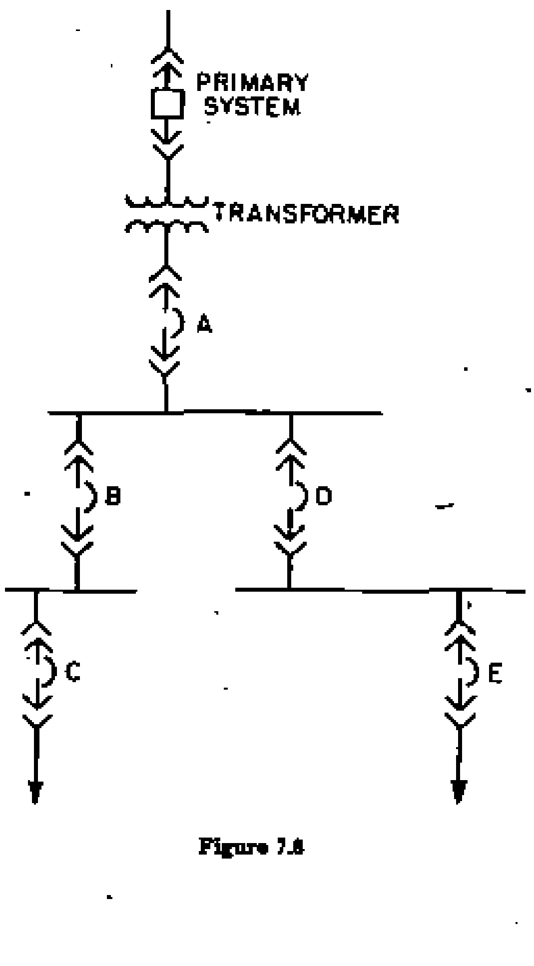


Figure 7.8

Selective Tripping Applications

The discussion of the "selective" system will refer to Figure 7.8. The objective of selective tripping is to remove only that portion of the system which is faulted. As only a single circuit breaker is expected to open in interrupting the fault current, all breakers in a "selective" system (circuit breakers A, B, and C in Figure 7.8) must have full interrupting capability. All circuit breakers in the series chain are equipped with direct-acting tripping means. Two zones of overcurrent are recognized—the moderate overcurrent range, and the short-circuit or fault range. Each is provided for separately on the circuit breaker. In both ranges, the circuit-breaker tripping time delay becomes successively shorter for breakers farther removed from the power source. Thus for a fault in the load circuit beyond circuit breaker C, circuit breaker C being set to trip in a shorter time than either B or A, would be the only one to open. After C operates, the tripping devices of circuit breakers B and A must automatically reset so as to duplicate their original action should a subsequent fault occur on another load circuit. In case the fault should occur just beyond circuit breaker B, only circuit breaker B would open since its tripping device is set to operate in shorter time than breaker A. In any chain of selectively coordinated circuit breakers, the occurrence of a circuit fault will cause the opening of only the one circuit breaker next to the fault on the supply side.

The standardized time-current characteristics of trip units for application in selective systems are such that, when required, four circuit breakers may be operated selectively in series. One of these must be the load circuit breaker having an instantaneous-trip element. Breakers with delayed trips and without instantaneous trips applied where the available fault current exceeds 15,000 amperes must have independent-manually-operated or electrically-operated closing mechanisms.

It is important to recognize that selective tripping of low-voltage breakers requires coordination with the rest of the system. The relays or fuses on the high-voltage side of the transformer bank, for instance, must be in proper coordination with the breakers in the selective tripping series on the low-voltage side. Low-voltage circuit breakers are quite frequently combined with current-limiting fuses to extend the application of the breakers. Fuses and breakers in these combinations are coordinated according to the manufacturer's specifications.

Selective tripping may not be applicable on some direct-current systems. The time delay of the selective trip device would in certain instances permit the direct-current short-circuit current to assume a magnitude and duration beyond the withstand limits of machine commutators or rectifier cells.

In fully-rated applications, the individual circuit breakers are capable of interrupting the full available short-circuit current unassisted but incorporate an instantaneous trip. Systems making "fully rated" application of circuit breakers can exhibit selectivity under some conditions. Such selective properties in fully rated systems have come to be termed "Zone Selective."

Cascade Application

The fundamental principles of a "cascade" system is also illustrated in Figure 7.8. Breaker E is considered to be subject to an available short-circuit current in excess of its interrupting rating and will be examined as to its acceptability for cascade application with circuit breaker D. Circuit Breaker D must have an interrupting capability at least equal to the available short-circuit current at the contemplated point of installation. The advantage of the cascade system is lower cost. Its disadvantage is that a fault on a cascaded feeder circuit may shut down a much larger portion of the electric power system than the faulted feeder circuit itself.

Rules governing cascading of large air circuit breakers require: (1) the number of steps of cascade is not to exceed two, (2) the particular breakers used in cascade are only those which the breaker manufacturer recommends for such application, (3) circuit breaker D must be fully rated, (4) circuit breaker E must have an interrupting rating not less than one-half the available short-circuit current, (5) after an interruption of a short circuit, all breakers shall be inspected before attempting to reclose them, especially breaker E. To curtail hazard to personnel, circuit breaker E should be electrically operated from a remote position.

All circuit breakers in a cascade arrangement have instantaneous, as well as time-delay trips to take care of the overcurrent range. The instantaneous trip of breaker D is set to operate when the current flowing through breaker E exceeds 80 percent of its interrupting rating. This is to insure that the cascaded breaker is properly backed up by the fully rated breaker D.

At present, only low-voltage power air circuit breakers are approved for use in cascade. Molded-case breakers cannot be cascaded and can be used only where the available fault current at the point of installation does not exceed the breaker's interrupting rating.

Presented in Table 7.10 is convenient reference data for selecting circuit breakers in selective and cascade arrangements for a variety of step-down transformer kVA and secondary voltage ratings.

Table 7.9

Selection of Transformer Section of Load-Center Unit Substations (Indoor Service)*

		Liquid Type	Dry Type	
		Askarel	*Ventilated*	*Sealed*
Exposure to Lightning	(A) Where transformers are connected to circuits exposed to lightning and the usual protection is provided**	Yes	No	No
	(B) Where study has determined that the amount of lightning exposure is negligible, or the possible resultant voltage stresses can be adequately taken care of by lightning protection	Yes	Yes	Yes
Atmospheric Conditions	(C) Where atmospheric conditions are clean, such as in plants producing aircraft, instruments, precision parts and certain types of machine shops, assembly plants, food processing plants, and in clean, dry vaults	Yes	Yes	Yes
	(D) Where dirt conditions are severe, such as foundries, steel mills, flour mills, cement mills, or other similar dusty or dirty locations	Yes	No	Yes
	(E) Where moisture conditions are severe, such as in geographical locations of high humidity and where the transformers may be subjected to partial or total submersion	Yes	No	Yes
	(F) Where units are subjected to acid, oil, or corrosive vapors	Yes	No	Yes
	(G) Where units are subject to oil or flammable vapors and location is classified as hazardous or semi-hazardous. (See Article 500 of National Electrical Code for guidance)	Yes	No	Yes
	(H) Where transformers are located overhead on platforms or in roof trusses	No#	Yes	Yes
Future Application	(I) Where possible rearrangement may cause transformers to be moved outdoors at a later date	Yes	No	Yes

* In a condensed guide such as this, it is only possible to cover the more usual types of installations. It, therefore, should be recognized that there are many special applications or combinations of factors outside the scope of this condensed guide that may affect the decision as to the type of transformer section to be used. In such cases good sound engineering judgment coupled with the economics of the situation should be used in reaching a decision.

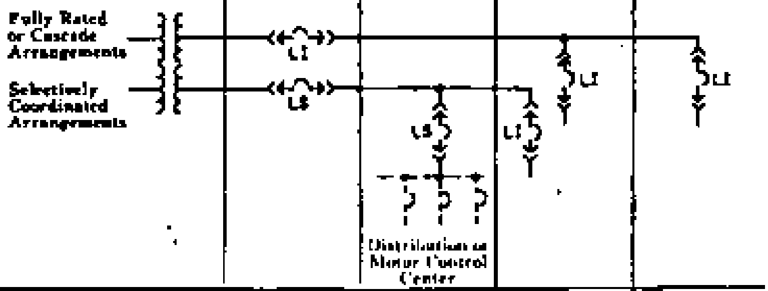
** The basic insulation level of dry-type transformers is only about half that of liquid-filled transformers, an important factor in case of exposure to lightning or switching surges.

\# From an engineering standpoint, a dry-type or an askarel transformer section is equally satisfactory for overhead locations but since the ventilated dry-type transformer section is generally the lighter construction, a less expensive supporting structure may be provided.

Table 7.10

Application Tables, Selective, Fully-Rated, and Cascade

Low-Voltage Power Circuit Breakers—
208 Volts, Three-Phase

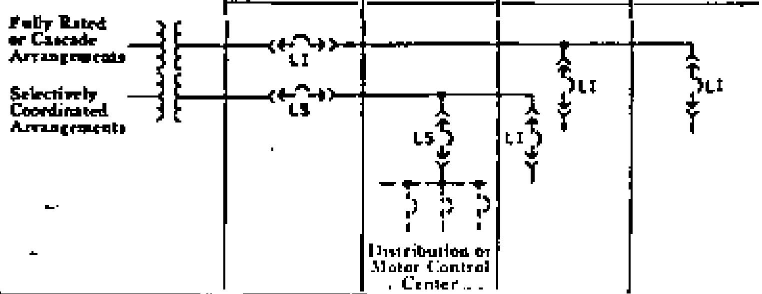


Transformer Rating 3-phase kVA and Impedance Percent	Maximum Short-Circuit MVA Available From Primary System	Normal-Load Continuous Current amp	Short-Circuit Current rms Symmetrical Ampere: Transformer Alone	Short-Circuit Current rms Symmetrical Ampere: 50% Motor Load	Short-Circuit Current rms Symmetrical Ampere: Combined	Main (Fully Rated or Selective): Long-Time Instantaneous or Long Time Short-Time	Feeder Circuit Breakers, Selective: Long Time Short-Time	Feeder Circuit Breakers, Fully Rated: Long-Time Instantaneous	Feeder Circuit Breakers, Cascade: Long-Time Instantaneous
						*Minimum Frame Size Recommended			
300 5.0%	50	834	14,800	1700	16,500	1600	600	225	225†
	100		15,700		17,400				
	150		16,000		17,700				
	250		16,200		17,900				
	500		16,400		18,100				
	750		16,500		18,200				
	Unlimited		16,600		18,300				
500 5.0%	50	1388	23,100	2800	25,900	1600	1600	600	225
	100		25,200		28,000				
	150		26,000		28,800				
	250		26,700		29,500				
	500		27,200		30,000				
	750		27,400		30,200				
	Unlimited		27,700		30,500				
750 5.75%	50	2080	28,700	4200	32,900	3000	1600	600	225
	100		32,000		36,200				
	150		33,300		37,500				
	250		34,400		38,600				
	500		35,200		39,400				
	750		35,600		39,800				
	Unlimited		36,200		40,400				
1000 5.75%	50	2780	35,800	5600	41,400	3000	1600	600	225
	100		41,100		46,700		3000	1600	
	150		43,200		48,800				
	250		45,100		50,700				600
	500		46,600		52,200				
	750		47,300		52,900				
	Unlimited		48,200		53,800				
1500 5.75%	50	4160	47,600	8300	55,900	No Main Breaker Available	3000	1600	Cascade Not Possible Since No Main Breaker Available
	100		57,500		65,800		4000	3000	
	150		61,700		70,000				
	250		65,600		73,900				
	500		68,800		77,100				
	750		69,900		78,200				
	Unlimited		72,400		80,700				

L — Long-Time delay trip (overload tripping).
S — Short-Time delay trip (selective fault tripping).
I — Instantaneous trip (high fault fast tripping).
* Based on Interrupting Ratings as listed in Table 7.2.
† Fully rated in these applications.

Table 7.10 (continued)

Low-Voltage Power Circuit Breakers—
240 Volts, Three-Phase



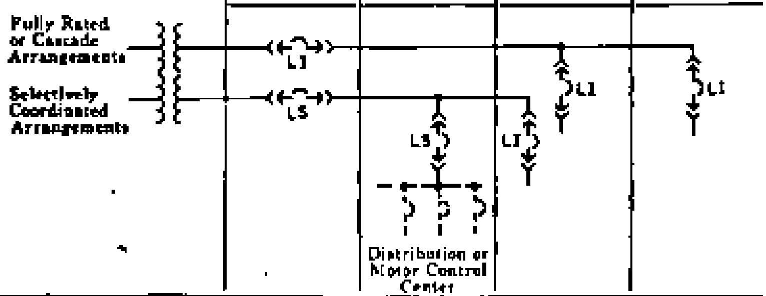
Transformer Rating 3-phase kVA and Impedance Percent	Maximum Short-Circuit MVA Available From Primary System	Normal-Load Continuous Current amp	Short-Circuit Current rms Symmetrical Ampere: Transformer Alone	Short-Circuit Current rms Symmetrical Ampere: 100% Motor Load	Short-Circuit Current rms Symmetrical Ampere: Combined	Main: Fully Rated or Selective — Long-Time Instantaneous or Long-Time Short-Time	Feeder Circuit Breakers: Selective — Long-Time Short-Time	Feeder Circuit Breakers: Fully Rated — Long-Time Instantaneous	Feeder Circuit Breakers: Cascade — Long-Time Instantaneous
						*Minimum Frame Size Recommended			
300 5.0%	50	722	12,900	2900	15,800	1600	600	225	225†
	100		13,600		16,500				
	150		13,900		16,800				
	250		14,100		17,000				
	500		14,200		17,100				
	750		14,300		17,200				
	Unlimited		14,400		17,300				
500 5.0%	50	1203	20,100	4800	24,900	1600	1600	225	225†
	100		21,900		26,700			600	225
	150		22,600		27,400				
	250		23,100		27,900				
	500		23,600		28,400				
	750		23,800		28,600				
	Unlimited		24,100		28,900				
750 5.75%	50	1804	24,900	7200	32,100	3000	1600	600	225
	100		27,800		35,000				
	150		28,900		36,100				
	250		29,800		37,000				
	500		30,600		37,800				
	750		30,800		38,000				
	Unlimited		31,400		38,600				
1000 5.75%	50	2406	31,100	9600	40,700	3000	1600	600	225
	100		35,700		45,300		3000	1600	
	150		37,500		47,100				
	250		39,100		48,700				
	500		40,500		50,100				600
	750		41,000		50,600				
	Unlimited		41,900		51,500				
1500 5.75%	50	3609	41,300	14400	55,700	4000	3000	1600	600
	100		49,800		64,200				
	150		53,500		67,900		4000	3000	
	250		56,900		71,300				
	500		59,700		74,100				
	750		60,600		75,000				
	Unlimited		62,800		77,200				

L — Long-Time delay trip (overload tripping).
S — Short-Time delay trip (selective fault tripping).
I — Instantaneous trip (high fault fast tripping).
* Based on Interrupting Ratings as listed in Table 7.2.
† Fully rated in these applications.

Table 7.10 (continued)

Low-Voltage Power Circuit Breakers—
480 Volts, Three-Phase

	Main	Feeder Circuit Breakers		
	Fully Rated or Selective	Selective	Fully Rated	Cascade

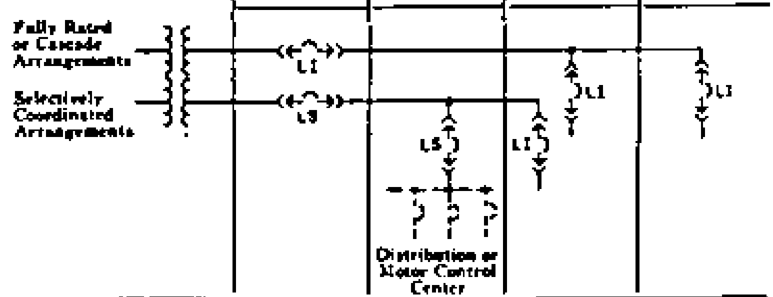


Transformer Rating 3-phase kVA and Impedance Percent	Maximum Short-Circuit MVA Available From Primary System	Normal-Load Continuous Current amp	Short-Circuit Current rms Symmetrical Ampere: Transformer Alone	Short-Circuit Current rms Symmetrical Ampere: 100% Motor Load	Short-Circuit Current rms Symmetrical Ampere: Combined	Long-Time Instantaneous or Long-Time Short-Time (*Minimum Frame Size Recommended)	Long-Time Short-Time (*Minimum Frame Size Recommended)	Long-Time Instantaneous (*Minimum Frame Size Recommended)	Long-Time Instantaneous (*Minimum Frame Size Recommended)
300 5.0%	50	361	6,500	1,400	7,900	600	225	225	225†
	100		6,900		8,300				
	150		7,000		8,400				
	250		7,100		8,500				
	500		7,200		8,600				
	750		7,200		8,600				
	Unlimited		7,300		8,700				
500 5.0%	50	601	10,000	2,400	12,400	1,600	225	225	225†
	100		10,900		13,300				
	150		11,300		13,700				
	250		11,600		14,000				
	500		11,800		14,200		600		
	750		11,800		14,300				
	Unlimited		12,000		14,400				
750 5.75%	50	902	12,500	3,600	16,100	1,600	600	225	225†
	100		13,900		17,500				
	150		14,400		18,000				
	250		14,900		18,500				
	500		15,300		18,900				
	750		15,400		19,000				
	Unlimited		15,700		19,300				
1000 5.75%	50	1,203	15,300	4,800	20,300	1,600	600	225	225†
	100		17,800		22,600		1,600	600	225
	150		18,800		23,600				
	250		19,600		24,400				
	500		20,200		25,000				
	750		20,500		25,300				
	Unlimited		20,900		25,700				
1500 5.75%	50	1,804	20,600	7,200	27,600	3,000	1,600	600	225
	100		24,900		33,100			1,600	
	150		26,700		33,900				
	250		28,400		35,600				
	500		29,800		37,000				
	750		30,300		37,500				
	Unlimited		31,400		38,600				
2000 5.75%	50	2,406	24,700	9,600	34,100	3,000	1,600	1,600	225
	100		31,100		40,700				
	150		34,000		43,600		3,000		600
	250		36,700		46,300				
	500		39,100		48,700				
	750		40,000		49,600				
	Unlimited		41,900		51,500			3,000	
2500 5.75%	50	3,008	28,000	12,000	40,000	4,000	1,600	1,600	600
	100		36,400		48,400				
	150		40,500		52,500		3,000	3,000	1,600
	250		44,500		56,500				
	500		48,100		60,100				
	750		49,500		61,500				
	Unlimited		52,300		64,300				
3000 5.75%	50	3,607	30,700	14,400	45,100	4,000	3,000	1,600 3,000	600
	100		41,200		53,600				
	150		46,500		60,900				
	250		51,900		66,300		4,000	4,000	1,600
	500		56,800		71,200				
	750		58,700		73,100				
	Unlimited		62,700		77,100				

L — Long-Time delay trip (overload tripping).
S — Short-Time delay trip (selective fault tripping).
I — Instantaneous trip (high fault fast tripping).
* Based on Interrupting Ratings as listed in Table 7.2.
† Fully rated in these applications.

Table 7.10 (continued)

Low-Voltage Power Circuit Breakers—
600 Volts, Three-Phase



Transformer Rating 3-phase kVA and Impedance Percent	Maximum Short-Circuit MVA Available From Primary System	Normal-Load Continuous Current amp	Short Circuit Current rms Symmetrical Amperes			Main	Feeder Circuit Breakers		
			Transformer Alone	100% Motor Load	Combined	Fully Rated or Selective	Selective	Fully Rated	Cascade
						Long-Time Instantaneous or Long Time Short-Time	Long Time Short-Time	Long-Time Instantaneous	Long-Time Instantaneous
						*Minimum Frame Size Recommended			
300 5.0%	50	289	5,100	1,200	6,300	600	225	225	225†
	100		5,400		6,600				
	150		5,500		6,700				
	250		5,600		6,800				
	500		5,700		6,900				
	750		5,700		6,900				
	Unlimited		5,700		6,900				
500 5.0%	50	481	8,000	1,900	9,900	600	225	225	225†
	100		8,800		10,700				
	150		9,000		10,900				
	250		9,300		11,200				
	500		9,300		11,400				
	750		9,500		11,400				
	Unlimited		9,600		11,500				
750 5.75%	50	722	9,900	2,900	12,800	1,600	225	225	225†
	100		11,100		14,000				
	150		11,500		14,400		600	600	225
	250		11,900		14,800				
	500		12,200		15,100				
	750		12,300		15,200				
	Unlimited		12,500		15,400				
1000 5.75%	50	962	12,500	3,800	16,300	1,600	600	600	225
	100		14,300		18,100				
	150		15,000		18,800				
	250		15,700		19,500				
	500		16,200		20,000				
	750		16,400		20,200				
	Unlimited		16,800		20,600				
1500 5.75%	50	1,444	16,500	5,800	22,300	1,600	1,600	1,600	225
	100		19,900		25,700				600
	150		21,400		27,200				
	250		22,700		28,500				
	500		23,800		29,600				
	750		24,200		30,000				
	Unlimited		25,100		30,900				
2000 5.75%	50	1,924	19,700	7,700	27,400	3,000	1,600	1,600	600
	100		24,800		32,500				
	150		27,200		34,900				
	250		29,400		37,100				
	500		31,200		38,900				
	750		32,000		39,700				
	Unlimited		33,500		41,200				
2500 5.75%	50	2,406	22,400	9,600	32,000	3,000	1,600	1,600	600
	100		29,200		38,800			3,000	1,600
	150		32,400		42,000				
	250		35,700		45,300		3,000		
	500		38,300		48,100				
	750		39,600		49,300				
	Unlimited		41,900		51,500				
3000 5.75%	50	2,784	23,700	11,500	34,800	3,000	1,600	1,600	600
	100		31,800		42,900		3,000	3,000	1,600
	150		35,900		47,000				
	250		40,100		51,200				
	500		43,900		55,000				
	750		45,300		56,400				
	Unlimited		48,300		59,600				

L — Long-Time delay trip (overload tripping).
S — Short-Time delay trip (selective fault tripping).
I — Instantaneous trip (high fault fast tripping).
* Based on Interrupting Ratings as listed in Table 7.2.
† Fully rated in these applications.

Motor-Starting and Control Equipment

For switching devices, such as motors, welders, heaters, or other devices, under ordinary conditions, and particularly where the switching is to be remotely or automatically controlled, the magnetic switch or contactor is used. They are available for direct current and for alternating current. (In some cases where starting is infrequent breakers can be used for the switching device.) Contactors for direct current are usually single-pole and those for alternating current three-pole. Standard eight-hour ratings are from 10 to 2,500 amperes.

On alternating-current contactors, the ratio of magnet coil current inrush may be 10 to 15 times the hold-in current. This matter must be considered in choosing the size of conductor, particularly if the circuit be long.

Types of Control Circuits

There are two forms of control circuits: *undervoltage release* and *undervoltage protection*. In the first, if the voltage drops to a low value, or if the control-circuit voltage fails, the contactor will drop out but will reclose as soon as the voltage is restored. With undervoltage protection low voltage or failure of the control-circuit voltage will cause the contactor to drop out, but the contactor will not reclose upon restoration of voltage.

Contactors and Starters

Contactors are intended for repetitive operation. The normal life of some sizes may be a million or more operations. The interrupting capacity of a contactor is of the order of 10 times its continuous current rating, so other means such as fuses or breakers are used for short circuit protection.

In alternating-current motor starters, contactors are generally used for controlling the circuits to the motor. The simplest starter is the across-the-line or full-voltage type, such as shown in Figure 7.9, wherein a contactor is the sole main switching means. When the contactor closes, the motor starts with full voltage applied at once. Other forms of starters may involve control of primary resistors, secondary resistors, transformers, or separate windings on the motor. Here, the discussion will cover the main contactor for starting and stopping the motor, its control, and means for motor protection.

Overload Protection

Motor starters are equipped with overload relays. These relays may be magnetic or thermal type. If of the magnetic type, a dash pot allows the necessary time for the proper flow of starting current. If of the thermal type, this time delay is inherent. The magnetic type requires a particular coil to adapt the relay for a given size motor. In the thermal type adaption is accomplished by a heater of a particular size, corresponding to the motor. By the I^2R due to motor load current flowing through the heater, an element affected by that heat is made to respond to a particular set of conditions. The National Electrical Code Section 430 covers the requirements for motor protection.

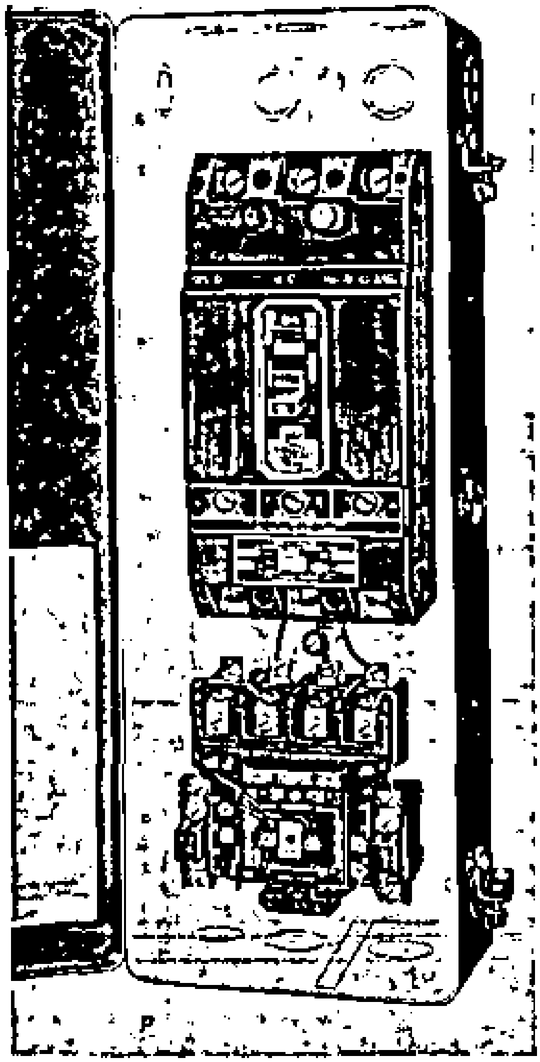


Figure 7.9
Combination full-voltage starter typical of 480-volt industrial applications

In the standard motor starter, the overload relay has two current responsive elements, one in each of two conductors. In industrial services supplied by delta-wye or wye-delta transformers having fuses rather than breakers for transformer protection and switching, there may be cases where three-element overload protection is required. In most industrial applications where three-pole breakers are used—and single-phasing is thereby avoided, two overload elements suffice.

Motor starters are available in standard sizes, rated in horsepower. A starter is adapted to a particular motor by proper choice of overcurrent relay. With the thermal-type of overcurrent relays, this means simply insertion of the appropriate heaters in the relays.

In order that circuit and motor may both have protection, the starter with its overcurrent relays is mounted in an enclosure which also contains a fused switch or a circuit breaker such as shown in Figure 7.9. The switch or circuit breaker is operable without opening the enclosure and usually some means is provided for locking it in the open position. Combination starters are rated in horsepower and voltages.

In application of combination starters, it is essential that interrupting capacity of the circuit protective part of the combination be adequate.

Motor starters may be combined in motor-control substations as shown in Figure 7.10.

Incoming-Line and Rotating-Machine Protection

In the simplest analysis, surge protection for industrial systems can be divided into two general classifications.

1. Protection of lines and apparatus connected to overhead lines exposed to lightning.
2. Protection of rotating machines not directly connected to exposed circuits.

Incoming-Line Protection

The insulation level of overhead lines is necessarily considerably higher than the insulation level of terminal apparatus such as transformers, switchgear, potheads, etc., which comprise the service entrance to the industrial plants. Such overhead lines are vulnerable to overvoltage principally from direct or induced lightning strokes and switching surges. These overvoltages could have values varying from several times the impulse and low-frequency withstand strength of the terminal apparatus down to very low values.

It is a fundamental characteristic of traveling voltage waves that they tend to increase when they arrive at equipment having a surge impedance higher than that of the incoming line. The magnitude of such incoming waves will approximately double at the terminals of a transformer or an open power circuit breaker. Because of this characteristic, equipment connected by cable to overhead circuits generally requires arrester protection at each end of the cable to guard against the possibility of double voltage.

Protection against direct strokes is usually provided at outdoor substation installations in the form of grounded masts and/or overhead ground wires stretched above the installation to intercept lightning strokes which might otherwise terminate on the lines or apparatus.

In addition to direct-stroke protection it is essential that the entrance equipment, such as transformers, circuit breakers, etc., be protected from traveling waves by the installation of lightning arresters having protective characteristics below the impulse insulation strength of the terminal apparatus. It is recommended that lightning arresters be installed as close as possible to the high-voltage terminals of the power transformer, and that other equipment requiring surge protection be grouped as close as possible to the arresters.

Air-insulated transformers have impulse insulation values approximately half as great as liquid-filled apparatus. Arresters are required at the terminals of such transformers when connected to exposed circuits, and may even be required if supplied over cables connected to exposed circuits directly or through transformers.

Arresters for industrial service are classified in the following general types in the order of decreasing protective margin, discharge ability, and cost: (1) station-class arresters, (2) intermediate-class arresters, (3) rotating machine type.

The station type arrester provides by far the best protective level and the highest surge discharge ability and is usually recommended for important installations. The intermediate class is used for less important installations and for line protection where the cost of station type would be prohibitive.

Rotating-Machine Protection

The basic insulation level of rotating equipment is approximately half that of liquid-insulated equipment of the same voltage class. In addition, the effectiveness of turn-to-turn insulation is dependent on the rate of change of voltage (steepness of voltage wave). For these reasons it is recommended that all machines connected to exposed circuits be protected by rotating machine type arresters and surge-protective capacitors at or near the terminals of the machine. This protection is in addition to the lightning arresters required at the junction with the incoming line. The purpose of the capacitors is to reduce the steepness of the lightning or switching wave, thereby reducing the stress on the turn insulation of the machine winding. Some reduction in magnitude of the incoming wave will also be provided by the capacitors.

Even though rotating equipment, especially generators or large or important motors, are not directly exposed to lightning, it may still be desirabe to provide arresters and surge capacitors to reduce the effects of overvoltages such as induced lightning surges or switching surges.

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The following Standards and Code references are listed for convenience. These are, Institute of Electrical and Electronics Engineers (IEEE—formerly AIEE), National Electrical Manufacturers Association (NEMA), United States of America Standards Institute (USASI),

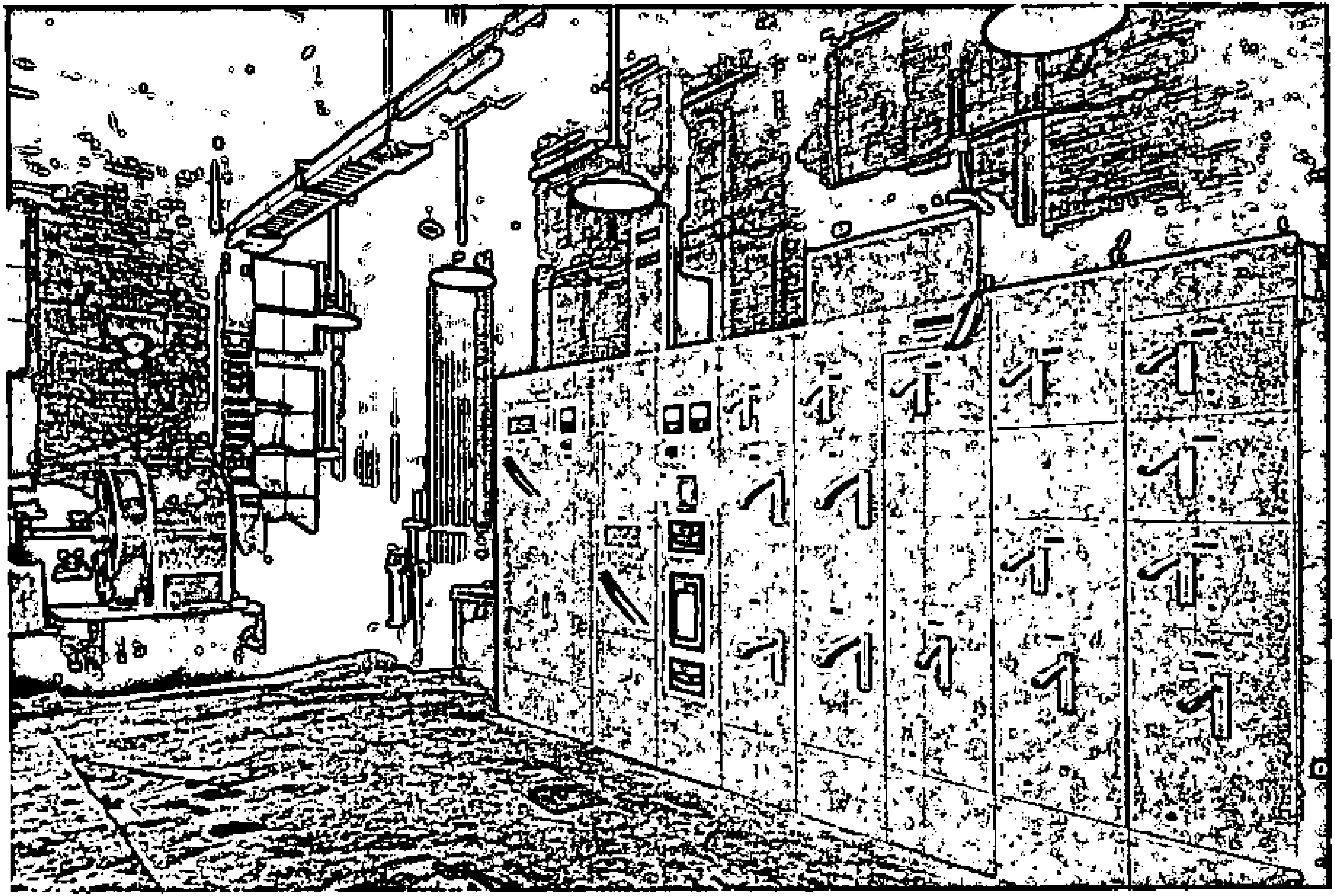

Figure 7.10
Motor control center installation

and National Fire Protection Association (NFPA). A brief description of the purpose of each of these Standards may be helpful in selecting the appropriate information.

IEEE

The chief purpose of the IEEE Standards is to define terms and conditions which characterize the rating and behavior of electric machinery and apparatus with special reference to conditions of compliance tests.

NEMA

The NEMA Standards provide practical information concerning the classification, rating, manufacturing, performance testing and application of products. Primarily, these Standards are intended for manufacturing, construction, and dimensional information.

USASI

The USASI is the authoritative body in the United States for approving the USA Standards, and acts as a clearing house for Standards. The USASI *does not* make Standards, but rather makes or sets up procedures and provides the machinery for creating voluntary Standards. A USA Standard defines a product, process, or procedure with reference to one or more of the following: nomenclature, composition, construction, dimensions, tolerances, safety, operating characteristics, performance, quality, rating, certification, testing, and the service for which it was designed.

NFPA

The NFPA is the sponsor of the National Electrical Code (NEC) and other related Standards. The purpose of this Code is the practical safeguarding of persons and of buildings and their contents, from (electrical) hazards arising from the use of electricity for light, heat, power, radio, signalling and for other purposes.

This Code contains basic minimum provisions considered necessary for safety. Compliance therewith and proper maintenance will result in an installation essentialy free from hazard, but not necessarily efficient, convenient, or adequate for good service. This Code is not intended as a design specification nor an instruction manual for untrained persons.

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CHAPTER VIII

INSTRUMENTS AND METERS

This chapter covers instruments and meters utilized in industrial power distribution systems. Metering and instrumentation are essential to satisfactory plant operation, the amount required depending upon the size and complexity of the plant, as well as economic factors. Instruments and meters are needed to monitor plant operating conditions, as well as for power billing purposes, and for determination of production costs.

An instrument is defined as a device for measuring the present value of the quantity under observation. Instruments may be either indicating or recording type.

A meter is defined as a device that measures and registers the integral of a quantity with respect to time. The term meter is also commonly used in a general sense as a suffix or as part of a compound word (e.g., voltmeter frequency meter), even though these devices are classed as instruments.

Basic Objectives

The basic objective of instrumentation and metering is to assist operators in proper operation of the plant. To operate properly, information relative to magnitudes of loads, energy consumption, load characteristics, load factor, power factor, voltage, etc., are required. Certain checks are required on plant electric equipment, prior to placing it in service to be sure that the insulation is in proper condition for application of voltage, and that connections have been properly made. After equipment is in service, certain periodic checks are necessary to be sure the equipment remains in proper operating condition. Instruments and meters are used to perform these and many other important functions.

Means Available

A large variety of instruments and meters are available to measure alternating current, voltage, power consumption, etc. In most cases, their current coils are rated 5 amperes and their potential coils are rated 120 volts. Whenever the current and voltage of the circuit exceeds the rating of the instruments, it is common practice to use instrument current and potential transformers with them.

Current transformers serve to insulate the instrument circuit from the primary circuit and reduce the current through the instrument to values within the rating of the instrument element. The current transformer ratio selected should be as low as possible without exceeding rated current in the secondary winding. If possible, a ratio should be used which will give a normal current reading at about one-half to three-quarters scale on the instrument. On ungrounded three-wire circuits, two current transformers are sufficient for metering, although a third transformer is sometimes used for checking the ratio of others. On a three-phase grounded system, three current transformers are needed. Usually the turns ratio of a current transformer is such that dangerously high potentials result when the secondary circuit is opened, hence a test switch or current jack must be provided to short-circuit the transformer secondary while testing the meter, or for use of plug-in portable meters. Current transformers should have their secondary circuits grounded.

Potential transformers serve to reduce the voltage of higher voltage circuits to values within the rating of the instrument potential coils. Single-phase transformers are usually employed with two connected in open delta for three-phase circuits. For four-wire systems, three potential trnasformers are used for billing purposes and for loads connected line-to-neutral. Switches should be provided in the potential transformer secondary circuit to take potential off the meter for testing. This circuit is also grounded.

Direct-current measurements of amperes or energy utilize shunts to carry the main current to be measured. A shunt is made up of metal of low temperature coefficient of resistance; and low thermoelectric effect with respect to copper; such as manganin, or other material of high specific resistance. Strips of resistance metal are brazed into heavy copper blocks which become the terminals for the line and the leads to the instrument. Ordinarily the leads must be calibrated with the shunt with which they are to be used. The direct-current ammeter actually measures the millivolt drop across its shunt and is calibrated in terms of the ampere rating of its associated shunt. Meters reading up to fifty amperes or less may have the shunt within the meter case. External shunts are available in ratings up to many thousands of amperes.

Another method of direct current measurement of large magnitudes is by use of a current transductor. The transductor is a form of a magnetic amplifier or saturable core reactor. It makes use of two double-circuit transformers, with one winding of each connected in the direct-current circuit and the secondary windings excited by an alternating voltage. An alternating-current instrument calibrated to read direct-current amperes is connected in the secondary circuit of the transductor. This method has two definite advantages over the shunt method. The secondary circuit is insulated from the measured source, and the user may add one or more instruments, relays, or other current-operated devices to the secondary of the transductor. For very high current values the lower cost and greater reliability of the transductor give it a decided advantage over the shunt. Transductors are especially useful where remote metering of large direct currents is involved since calibrated leads are not required.

The measurement of electrical quantities on alternating-current systems can be made through the use of a transducer which utilizes the Hall effect. This device is commonly referred to as a Hall generator. The Hall generator acts as a multiplying device, outputting a direct-current millivolt signal which is proportional to the product of the current and a magnetic field input. The magnetic field may be developed from a current or a voltage source. The output signal may be used to operate a direct-current voltmeter calibrated to the product units or as an input to telemetering or recording devices.

The Hall generator principle has been applied to devices for the measurement of voltage, current, watts, vars, power factor, and frequency.

Some of the advantages of the Hall generator type of transducer are its small, all-solid-state construction, its relatively high output signal level, and its high speed. Also, its output is isolated from the measured quantity, i.e. the transducer inputs.

INSTRUMENTS

Ammeters

Ammeters are used to measure the current which flows in a circuit. An ammeter is directly connected in series or has its associated current transformer primary in series with the circuit being measured.

Voltmeters

Voltmeters are used for measuring the potential difference between conductors or terminals. A voltmeter is connected directly, or through a potential transformer, across the points between which potential difference is to be measured. For voltmeters operating on direct-current circuits above 300 volts, external series resistors are commonly needed.

Wattmeters

A wattmeter is an instrument for measuring the magnitude of true work-producing electric power being delivered to a load or group of loads. Indicating, in effect, the product of voltage and in-phase current, the wattmeter has both potential coils and current coils.

Varmeters

A varmeter is an instrument for measuring reactive power. A varmeter is essentially a wattmeter which will indicate reactive power with the current coils connected in series with the circuit and the current in the voltage element shifted to 90 electrical degrees from the voltage across the circuit. Varmeters usually have the zero point at the center of the scale, since reactive power may be leading or lagging. The varmeter has an advantage over a power-factor meter in that the scale is linear and small variations in vars can be read. A power-factor meter may be difficult to read when operating near unity power factor.

Power-Factor Meters

A power-factor meter is an instrument which indicates the power factor of the load. It is a direct-reading instrument which will indicate the power factor of a three-phase load if the voltage and load are balanced on the three phases. The meter consists of both current and voltage elements, utilizing instrument transformers where necessary. The meter indicates unity power factor on scale center and lead or lag for any power factor other than unity. It is possible to obtain average power factor over a definite period, like a day, week or month, by use of the readings of an integrating kilowatt-hour meter and a kilovar-hour meter. However, a power-factor meter provides a convenient method of obtaining the power factor immediately and directly.

Frequency Meters

The frequency (hertz, or the number of cycles per second) of an alternating-current power supply, can be measured directly by means of instruments called frequency meters. There are two commonly used types, pointer-indicating type and vibrating-reed type. The pointer-indicating types are connected directly across the line or the secondary of the potential transformer, only single-phase connections being required. These instruments may have a scale range such as 55 to 65 hertz or 58 to 62 hertz for use on a normal 60-hertz system and the moving pointer indicates the exact value.

The vibrating-reed frequency meter is based upon the principle of mechanical resonance. The instrument has a number of reeds in a line, which are free to vibrate. It is connected directly across the line or the secondary of the potential transformer the same as the pointer-indicating type. The reed which is most nearly in tune with the line frequency will respond with the greatest amplitude of motion thus indicating frequency.

Synchroscopes

Synchroscopes, which are synchronism indicators, are utilized whenever two generators or systems are to be paralleled. Lamps were used in the early days to indicate synchronism but such lamps have given place to the more accurate synchroscope. A synchroscope has the appearance of a switchboard instrument, except that the pointer is free to revolve through 360 degrees. When the frequency to be synchronized is low, the pointer revolves in one direction; and conversely when high, the pointer rotates in the opposite direction. When the frequency is correct, the pointer stands still; and when the circuits are "in phase", the pointer so indicates, and the systems may be safely paralleled. A single-phase synchroscope may be used on a three-phase system provided proper checks are made initially relative to phasing, and thereafter neither the direction of rotation or connections are changed.

Elapsed Time Meters

Elapsed time meters are small synchronous-motor-driven cyclometer dials for registering the amount of time a circuit or electrically-driven piece of machinery is in operation. They provide important data for efficiency and life studies.

Portable Instruments

Most instrument are permanently mounted on switchboards, but many of them also can be obtained in portable types. Portable instruments are useful for special tests or for augmenting those mounted on the switchboard. Provisions should be made on the secondaries of instrument transformers to provide for readily connecting the portable instruments into the circuit. Current jacks are particularly applicable for current circuits. Portable current and potential transformers also are available for cases where the self-contained range of the portable instrument is not sufficient for the values of current or voltage to be measured.

The portable instruments most used are ammeters, voltmeters, and wattmeters and may be indicating or recording depending on the type of test or data required. A combination, alternating-current portable instrument, sometimes called a circuit analyzer, is available which will read amperes, volts, watts and power factor. Others are available for current, voltage and ohms, and some can be operated on either alternating or direct current, thereby giving the plant electrician very flexible instruments for certain conditions.

A split-core current transformer with its associated leads and ammeters either recording or indicating, is a convenient instrument for load checks. The clip-on type instrument frequently is suitable and is even easier to use than the split-core current transformer type.

Ammeters with back-up pointers can be used to measure short-duration loads that a normal instrument will not indicate; such as, welder loads. The pointer-stop instrument contains a hand-operated stop which restrains the indicating hand from returning to zero. The stop point is raised to successively higher levels until the surge of current just causes the hand or point to flutter, thus giving the actual current reading. If the duration of the load swing is less than 10 cycles, the point-stop instrument will not indicate accurately. An oscillograph or oscilloscope is recommended for load swings of such short duration.

Recording Instruments

Most of the instruments available as direct reading, indicating instruments also are available as recording or curve-drawing instruments. It is often important to have a continuous record of current, voltage, kilowatts, frequency, etc., available for economic, statistical, and engineering studies, as well as for checking on operator and machine performance. The record is traced automatically on either a strip or circular chart, by a pen fastened to the end of the pointer of the instrument. The chart is moved at a constant speed by a clock mechanism. Certain design problems are present in recording instruments that do not exist with indicating instruments. One is the necessity of providing sufficient torque for overcoming pen friction, without impairing the accuracy of the instrument.

Some recording instruments have adjustable speeds for movement of the chart. Normal records are obtained at a speed consistent with chart changing schedules, types and load characteristics, etc. Special tests may require a more rapid chart speed in order to obtain proper data.

Miscellaneous Instruments

Temperature Indicators—Several types of temperature indicating and temperature control devices are used in industrial plants. There are the following general types: liquid, gas or saturated-vapor thermometers; resistance thermometers; bi-metal thermometers; radiation pyrometers; and thermoelectric pyrometers. These devices may be obtained as indicating instruments or as recorders. They are used for measuring temperatures of electric windings, bearings, oil, air, and conductors. Some of them can be obtained with electric contacts for use on an alarm device or relay circuit. Pyrometers are generally used for indication of furnace temperatures and control thereof.

Cycle Counters—This instrument, generally consisting of a synchronous motor together with necessary clutch, brake and indicator, is used to indicate the number of cycles for an operation. One use of the cycle counter is to determine relay and circuit breaker operating times.

Megohmmeters—A megohmmeter is an instrument for measuring the insulation resistance of electric cables, insulators, buses, motors and other electric equipment. It is a complete instrument consisting of either a hand- or motor-driven direct-current generator and resistance indicator. It is calibrated in megohms with a maximum indication of 10,000 megohms or infinity and is available in different voltage ratings, usually 250, 500 or 2500 volts. An insulation resistance test on electrical insulation prior to placing equipment in service or during routine maintenance will give a good indication of the condition of the insulation. Wet insulation can be detected very readily. However, a high reading does not necessarily mean that equipment can withstand rated potential since the instrument does not apply rated potential. A high-potential test along with this test is desirable but may not be practicable. In lieu of a high-potential test it may be sufficient to make a dielectric-absorption test using a megohmmeter. Recording and plotting periodic resistance readings will show trends and may often indicate imminent insulation failure.

A ground ohmmeter is utilized for measuring the resistance to earth of ground electrodes. It is calibrated in ohms, usually zero to 300 ohms.

Low-Resistance Ohmmeters—Very-low-reading ohmmeters are available for low-resistance measurements; such as electric conductors, joints, contact surfaces, and electric windings. This instrument is not considered as a laboratory, high-precision type but can be very useful in field testing of either original installations or for trouble shooting. Instruments of this type contain a source of direct current and a meter calibrated to read directly the low resistance in microhms.

Ground Detectors—A ground detector is a device which indicates a ground on an ungrounded system. Direct-reading types are available to match the ammeter, voltmeters, etc. An incandescent lamp ground detector connected either directly to low-voltage systems or to potential transformers on high-voltage systems, also is available. In this type the voltage rating of the lamp is such that the lamp glows red on the normal system. Whenever a ground occurs on one phase of the system, the lamp connected from that phase to ground will go out or dim and the other two lamps will glow brightly. With a fault of sufficiently low resistance on one phase, the lamp glow differential can be detected by the eye. A voltage relay can be added to the circuit and an alarm, such as a bell, sounded whenever a ground occurs.

Cable-Fault Locators—Any plant that has an extensive cable installation should find use for instruments for locating cable insulation faults. Several instrument utilizing various methods are available for fault location. Description of the various locators will not be given herein, but any plant engineer should find it well worth while to investigate the instruments available.

Oscillographs and Oscilloscopes—An oscillograph is an instrument for observing and recording rapidly changing values of short duration, such as the wave form of alternating voltage, current, or power. This instrument has many uses in engineering fields; such as, determining load characteristics, wave shapes, and phenomena which occur too rapidly for measurement by indicating meters. They are available for frequencies up to about 10,000 hertz. Most magnetic-type oscillographs consist of a galvanometer (which gives deflections closely proportional to the instantaneous value of current or voltage) an optical system (using a light beam from a mirror rather than usual pointers) and the recording device (film or light-sensitive material which can be moved rapidly). Multi-element oscillographs are available for recording several different values simultaneusly such as three-phase amperes, voltage, kilowatts, etc.

Direct-writing oscillographs are available which record the phenomena or transients directly on a paper chart, utilizing an inking pen. Due to the pen inertia, this type of instrument has a limited frequency range, in the order of 0.5 to 100 hertz. There are many investigations or measurements which can be made on this type of instrument.

Oscilloscopes are electronic instruments which are available to study very high frequencies or phenomena of short duration. They can be used to study transients which occur in power circuits. These instruments use electronic controls and an electron beam, thereby eliminating the inertia of mechanical instruments. A fine electron beam is made to impinge on a fluorescent screen. The electron beam is deflected by electrostatic or magnetic field, set up by the voltage or current to be investigated. Oscilloscopes can be used for any frequencies up to millions of hertz. A camera such as the Polaroid camera can be used in conjunction with the oscilloscope to record permanently the wave shape.

Computers—A computer is a device that will perform mathematical operations according to a predetermined plan, or program, upon information fed into it. Presently computers follow two basic patterns, the analog type and the digital type. The analog type computers use physical units to simulate conditions of the problem to be solved, *e.g.*, the network analyzers (used primarily in solving electrical problems) in which small units of resistance, capacitance, and inductance are used to simulate actual quantities in the problem. The digital type computers are made up of units to perform certain mathematical and logic functions which are wired, or programmed, to solve a mathematical equation of the problem.

Computers are used to solve all types of problems which require repetitive complex solutions.

The information fed to computers can be actual numerical information, or electric or mechanical energy of a desired value and the solution can be numerical information, or electric or mechanical energy for the control of some component. The uses of computers appear to be unlimited. The purpose here is to call attention to computer systems not only for the solution of problems where previously gathered data is fed into the device, but also to the possibilities of on-the-spot solution with information fed from operating systems for monitoring the more complex industrial power systems, and even (where the added cost can be justified) of complete automatic control of systems for optimum performance. This is now being done in power utility systems with a savings in manpower, maintenance, and expense due to operating errors. Such systems are custom designed but can be divided into three basic sections consisting of:

1. The sensing devices (current or potential transformers, relays, thermocouples).
2. The computer, with input and output circuits.
3. The control equipment (motor or solenoid-operated valves control relays, data logging equipment, etc.).

Presently computers are used to solve distribution system problems, such as determining the normal division of load, and the available fault current at various points on the more complicated network systems.

Meters

Watthour Meters

Watthour meters are utilized for measuring the amount of energy consumed by a load. Watthour meters with totalizing registers may be used in assigning electric energy costs to segments of production. Alternating-current watthour meters employ induction disc type of mechanism; the disc being arranged to revolve at a speed proportional to the rate at which energy is passing through the meter. The number of revolutions, through a gear train, is recorded on a dial in terms of kilowatt-hours. The watthour meter may be used to calculate the power required by a load. Count the number of revolutions of the disc for any number of seconds and use this formula:

$$\text{Power (kilowatts)} = \frac{3600 \times R \times Kh}{1000 \times S}$$

where Kh = meter constant (marked on meter disc or nameplate), R = number of revolutions, and S = seconds.

Instrument transformer ratios must be taken into account if they are utilized. Current and potential instrument transformers are used, when necessary, with these meters just as they are used with a wattmeter. On three-phase, three-wire circuits, two current element meters are used. On four-wire circuits, three current element meters are necessary.

Dynamometer type watthour meters are used for direct-current measurement.

Demand Meters

Because of appreciable variation in power requirement of many industrial plants and the effect of resulting low load factor on power system investment, the maximum amount of energy used in any period of a prescribed length is often used as a factor in determining power bills. This maximum demand is measured by some type of demand meter. Various types of meters, both indicating and recording, are available for this purpose, the following being commonly used:

Curve-drawing wattmeters by recording the load time curve of the system can be used to determine maximum demand by averaging the load over the selected demand interval of time.

Integrating demand meters totalize the energy used over the demand interval and either record the average demand for each interval or by means of a maximum indicating pointer, indicate the maximum demand that has occurred since the meter was last read and reset.

Lagged demand meters usually obtain their demand interval by some thermal time lag means. Such meters are usually adjusted so that the indicating element reaches 90 percent of the maximum value of a suddenly-applied steady load at the end of the selected demand interval.

Contact-Operated Demand Meters—Contactors can be attached to watthour meters so that impulses are transmitted at a rate proportional to the load on the meter. These impulses operate the demand meter to drive a pointer on the indicator type or a pen on the graphic type. These are reset at the end of the demand interval by a synchronous or key-wound clock. These demand meters have the advantage of easy servicing as compared to the combined watthour meter and demand meters. Also the demands of several lines or loads can be combined through a totalizing relay to operate one demand meter, thereby giving total demand. Phase-shifting transformers and scale plates are available to make the meters read kva demand. Demand in kva may be more useful in determining actual load in terms of equipment rating.

Printing Demand Meter—Another type of contact-operated demand meter is the printing demand meter which records the demand for each interval by printing it on a tape together with the time of day. This type requires a separate contact-making clock to reset the instrument at the end of the demand interval.

A variation of the printing demand meter is the magnetic-tape metering concept. Instead of printing the demand and time on paper tape, kilowatthour pulses and time pulses are simultaneously recorded on magnetic tape. This tape can be fed into a translator which will transfer the demand information directly to key punch cards or magnetic tape for computer input. The major advantage of this type of system is the elimination of manual chart or tape reading and manual computations. This method allows completely automatic data processing.

Typical Installations

The following combinations of instruments and meters are typical of those used in various applications.

2400 Volts and Above

Incoming line or lines from utility:
- Voltmeters
- Ammeters
- Wattmeters
- Varmeters or Power Factor Meters
- Watthour Meters
- Demand Meters
- Frequency Meters

Plant Feeders:
- Ammeters
- Wattmeters
- Varmeters or Power Factor Meters
- Watthour Meters (Demand attachment optional)
- Test blocks for portable instruments

Generators:
- Voltmeters, a-c and d-c
- Ammeters, a-c and d-c
- Wattmeters
- Varmeters (Power Factor Meter—optional)
- Synchronoscope (with two or more generators or utility tie)

Other optional equipment may include:
- Watthour Meters
- Frequency Meters
- Recording meters and instruments

Motors—Synchronous:
- Voltmeters (optional or d-c only)
- Ammeters, a-c and d-c
- Wattmeters (optional)
- Varmeter or Power Factor Meter (optional)
- Watthour Meter (optional)
- Elapsed-Time Meter (optional)

Motors—Induction:
- Voltmeters (optional)
- Ammeters
- Watthour Meters (optional)
- Elapsed-time Meters (optional)

Low-Voltage (600 Volts and Below)

Incoming utility circuits:

Same, in general, as for 2400 volts and above.

Feeders:

Voltmeters (optional)
Ammeters (optional)
Watthour Meters (optional)

Because of the added cost these instruments and others are only used in low-voltage feeders when justified by a potential savings in operation and maintenance of equipment. Without permanent instrumentation, it is common practice to check periodically with portable instruments.

Generators:

Same, in general, as for 2400 volts and above.

Motors—Synchronous:

Same as for 2400 volts and above.

Motors—Induction:

Ammeters on large motors.
Generally no instruments on small motors.

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CHAPTER IX

INSULATED CABLES, TERMINATORS, AND BUSWAY

INSULATED CABLES

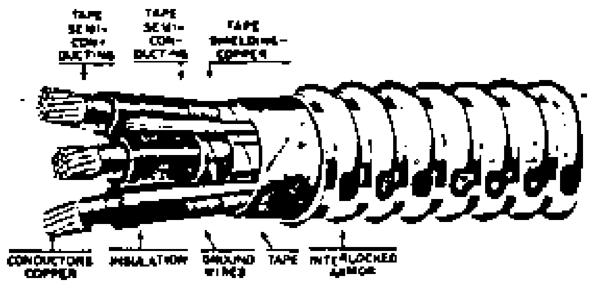

Figure 9.1
Tyical Interlocked Armor Cable (5-15 kV) Showing Internal Components

Conductors

Conductor materials in common use are:

a. copper

b. aluminum

Copper is predominantly used for conductor material. The prime advantage of copper is its high electric conductivity, which results in small cable sizes. *Aluminum* conductors have been used with success in the larger sizes and in those applications where its advantages, such as light weight, price, availability and nonmagnetic properties make it a desirable substitute.

Insulations

There are four basic insulation materials:

1. Paper
2. Varnished cloth
3. Synthetic compounds
   a. Thermoplastic materials
      1. Polyvinyl-chloride (PVC)
      2. Polyethylene
   b. Thermosetting materials
      1. SBR (Buna S) rubber
      2. Butyl rubber
      3. Oil-based rubber
      4. Cross-linked polyethylene
      5. Silicone rubber
      6. Ethylene-propylene rubber
      7. Chlorosulphated polyethylene
4. Mineral-insulated cable

Paper

Historically, oil impregnated paper insulation has long been used because of its excellent electrical properties and consequent smaller outside diameters. Because of its high susceptability to moisture absorption and poor mechanical strength and flexibility it is always necessary to cover the paper with a lead sheath for good protection. Also, these properties of paper make it very difficult to handle, and the cable crew must be highly skilled in order to satisfactorily make up splices and pothead terminals.

Varnished Cloth

Varnished-cambric cable is insulated with tapes of varnished cambric wrapped around the conductor with a "slipper" compound between the layers to improve the flexibility. Varnished-cambric insulation is commonly used for distribution cables and can be used in dry locations without a lead sheath. The varnished-cambric, however, is not waterproof and when used underground or in conduit subject to condensation, varnished-cambric cables should be lead covered.

Varnished-cambric insulation generally has a maximum operating conductor temperature of 77°C at 15 kV and 85°C at 5 kV and below. Recent developments make use of synthetic and glass fibers instead of cotton to gain increased mechanical strength and moisture resistance, permitting a maximum operating temperature of 85°C up to 15 kV. The maximum short-circuit temperature is 200°C.

Lead-covered, varnished-cambric insulated cables should be treated exactly the same as paper-insulated cables, that is, the joints should be encased in lead sleeves and potheads should be used for terminating. It is, however, sometimes permissible to terminate varnished-cambric cables operating at 5000 volts or below in dry locations without potheads. In this case it is assumed the lead sheath is required for part of the run but that the terminals are in a dry location. Wherever it is permissible to use nonleaded varnished-cambric cables both splices and terminals may be made without a moistureproof covering.

Synthetic Compounds

Moisture resistance, ease of handling and of splicing and its extreme flexibility have contributed to the great popularity that synthetic rubber insulated cable has long enjoyed, especially at voltages 15 kV and below. Earlier oil-based natural-rubber insulating compounds, however, had many disadvantages. Synthetic materials having superior electrical and mechanical properties are now being used extensively.

Synthetic insulation materials can be divided into two categories:

Thermoplastics, a family of materials which will soften when heated. They are extruded around the conductor material by supplying sufficient heat to cause the compound to flow, but since no significant reaction takes place they will soften when reheated. Polyvinyl-chloride (PVC) and polyethylene are commonly used thermoplastics.

Thermosettings, a family of materials which requires heat to vulcanize or cross-link it. Vulcanization causes a permanent chemical reaction so that the material will have very little tendency to soften if reheated. Styrene-butadiene rubber (Buna S), butyl, cross-linked polyethylene and silicone rubber fall in this category.

Polyvinyl-chloride (PVC), although like rubber in its characteristics, contains no rubber. It resists oils, acids, sunlight, ozone, is flame-resistant, has moisture resistance and good electrical properties. PVC was developed as a result of the search for an oil-resistant cable and is, therefore, the first choice for wiring machine tools. PVC cable is flexible, has a high degree of resistance to moisture and requires no impervious jacket, such as lead. A protective jacket will be required if mechanical abuse is severe. Cables using this insulation are rated up to 600 volts. NEC types T and TW have a maximum operating conductor temperature of 60°C for power applications and a maximum short-circuit temperature of 150°C. NEC type TWH has a maximum operating temperature of 75°C and type THH a maximum operating temperature of 90°C. PVC compounds are available in several colors and are used extensively in control cable.

Polyethylene (except the cross-linked variety) melts at a relatively low temperature. This fact must be borne in mind when specifying it. It is also severely affected by corona cutting and great care is necessary in cable design. Because of its high coefficient of thermal expansion during load cycles, it is desirable to use a resilient type of shield construction on the shielded types. This is usually accomplished by the use of a semiconducting butyl bedding tape under the metallic shield.

Polyethylene possesses excellent electrical properties, and excellent moisture and chemical resistance. These properties, along with its relatively low cost, have led to its extensive use for low-voltage power cables. Many engineers expect polyethylene to be used widely for cable insulation up to 35 kV, and occasionally at higher voltages. Polyethylene has an excellent record in the many applications where it has been used in place of paper in medium-voltage cable.

Jacketed with PVC the maximum operating conductor temperature and short-circuit temperatures of conventional polyethylene are 75°C and 150°C respectively.

Styrene-butadiene rubber (SBR) exhibits many desirable properties of a low-voltage insulation. It is heat and moisture resistant, has excellent aging qualities but lacks ozone resistance. SBR is recommended for important low-voltage circuits, where a long-life high-quality rubber insulation is required. It is listed by the Underwriters' Laboratories as heat and moisture-resistant insulation.

NEC type RHW has a maximum operating conductor temperature of 75°C. NEC type RHH has a maximum normal operating temperature of 90°C. The short-circuit temperature limit is 200°C.

To protect the SBR insulation against certain types of mechanical damage, a protective covering is usually applied over the insulation.

Butyl rubber insulation has not only a high dielectric strength, but is also highly resistant to moisture, heat, and ozone. The last characteristic makes this insulation exceptionally suitable for medium voltage cable circuits (up to and including 15 kV) where there is always the threat, if not the presence, of corona, and subsequent ozone formation. This is the reason why ozone resistance is one of the prime requisites of a high-voltage insulation.

Butyl-insulated cables are recommended for medium-voltage transmission and distribution, for station and apparatus circuits, for aerial and submarine cable, and directly buried circuits. For mechanical protection a jacket, usually neoprene (and under some conditions PVC), is applied over the insulation.

The maximum operating conductor temperature is 90°C up to and including 5 kV and 85°C for 15-kV cables. The maximum short-circuit temperature is 200°C. The NEC designation is type RHH.

Oil-based rubber compounds have been in use for more than 30 years and are still frequently used. They have a maximum conductor temperature of 75°C.

Cross-linked polyethylene. Changing polyethylene from a thermoplastic to a thermosetting material through chemical cross-linking (or vulcanizing) results in a superior insulation with excellent thermal and electrical properties. It may be used in applications where butyl cable was recommended above. The maximum operating conductor temperature is 90°C up to and including 15 kV and maximum short-circuit temperature is 250°C.

Silicone rubber is extremely resistant to heat and exhibits an outstanding resistance to ozone and corona. This insulation can be used in wet or dry locations, exposed or in conduit, where subjected to constant high temperatures. Mechanical protection is obtained by an asbestos or glass braid.

The cost of a silicone rubber cable is competitive with asbestos for high-temperature applications. This fact together with the added moisture resistance of silicone rubber accounts for the increasing use of silicone rubber where asbestos would formerly have been specified. The maximum operating conductor temperature for silicone is 125°C, and the maximum short-circuit temperature is 250°C.

Mineral Insulated Cable

Mineral insulated cable differs widely in design and characteristics from conventional types. Basically it consists of a single or multiplicity of conductors insulated with or separated by magnesium oxide and sheathed with a copper tubing. It has been in long-time use in Europe under the trade name "Pyrotenax" and was introduced in our country around 1950. This construction is capable of withstanding continuous operating temperatures up to 250°C. However, mainly because of temperature limitations of approved terminating fittings it is recognized by the NEC for general use at a maximum operating temperature of 85°C. This cable is completely sealed against the entrance of liquids and vapors along the cable run. It is designed for operation up to 600 volts. Special care is required in making splices and terminations due to the hygroscopic nature of the insulation material. Because of its lower impulse strength compared with conventional cable, it should be protected by lightning arrestors when connected to exposed circuits.

SHIELDING (Metallic Shielding)

Shielding of a cable is accomplished by wrapping a thin (0.005 inch) copper (or tinned copper on rubber-insulated cables) tape spirally around the insulation to form a continuous shield along the entire length of the cable. This tape may or may not be perforated to reduce losses and is held at ground potential by suitable grounding.

Shielding is necessary on medium- and high-voltage cables because of the danger of damage from corona or ionization. The purpose of shielding a cable is to confine its dielectric field within the conductor insulation. This results in a symmetrical radial stress distribution within the insulation as shown in Figure 9.2. In addition, it will

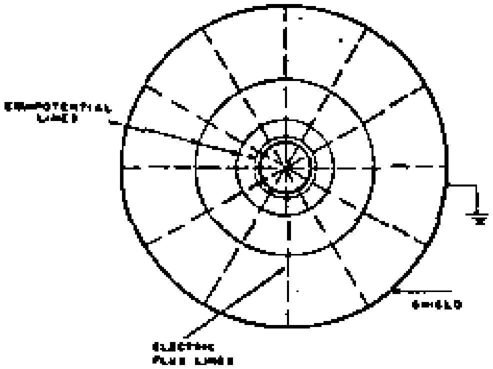

Figure 9.2
Voltage Stress Lines in a Shielded Cable

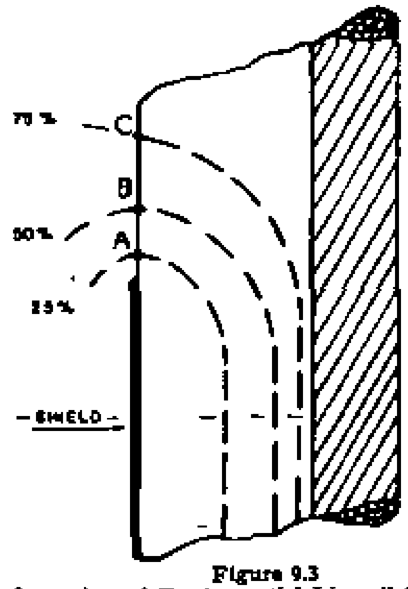

Figure 9.3
Configuration of Equipotential Lines if Shielding had been Terminated without a Stress Relief Cone

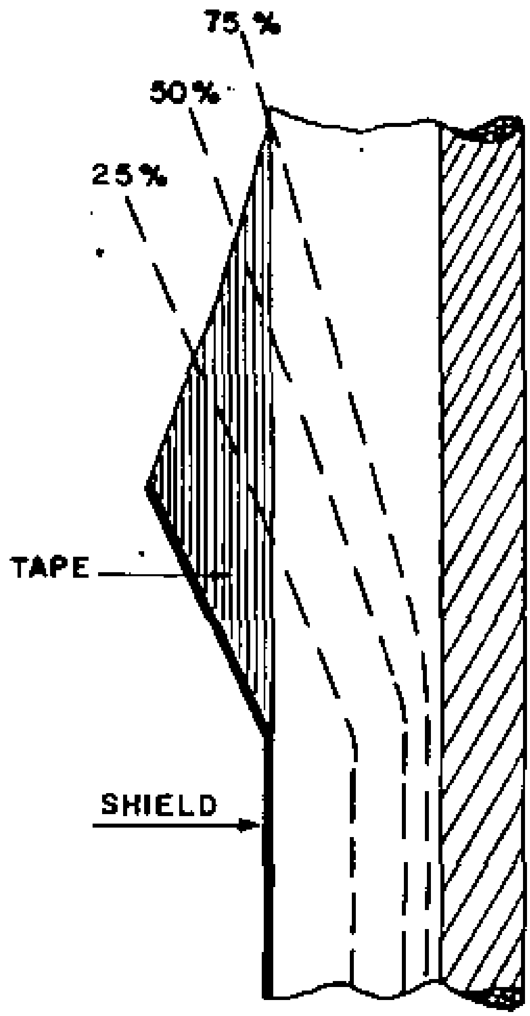

Figure 9.4
Configuration of Equipotential Lines when Terminated with a Stress Relief Cone

help protect cables, installed overhead or connected to overhead lines, from being subjected to induced voltages. It will also provide increased safety to human life.

This shielding must be grounded at one end and preferably at more than one point. The usual practice is to ground the shield at each splice and termination. *If for any reason the shielding is not grounded, it should be treated as a live conductor.*

Stress relief cones are used in terminating and splicing a shielded cable for the purpose of relieving the concentration of voltage stress at the shielding tape termination. This cone, if built up properly, effectively decreases the stress on the insulation as shown in Figures 9.3 and 9.4. The equipotential lines for 25, 50 and 75 percent voltage shown in Figure 9.3 indicate that a 25 percent potential difference exists between the points A and B and between B and C. Assuming a 13.8-kV system this represents $0.25 \times \frac{13.8}{\sqrt{3}} = 2$ kV. A comparison between Figures 9.3 and 9.4 clearly displays the greatly increased electric gradient at the end of the shielding tape in the absence of a stress relief cone (between the shielding tape end and point "A" of Figure 9.3) in contrast with the controlled termination gradient with a stress relief cone, Figure 9.4. Either corona formation at the shielding tape termination or simple overstressed insulation at this location can be responsible for premature cable failure. A cross section view of a stress cone construction for rubber-insulated cable is shown in Figure 9.5.

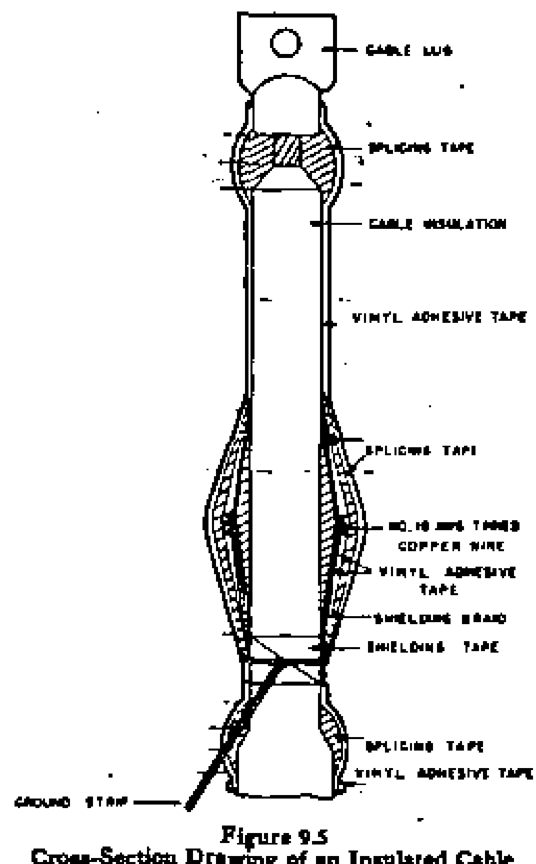

Figure 9.5
Cross-Section Drawing of an Insulated Cable Termination with a Stress Relief Cone

Semiconducting Tape

To prevent possible damage of the insulation from corona and ionization, a semiconducting layer is normally used to separate the conductor from the rubber or rubber-like insulation on all cables rated above 2000 volts. The semiconducting layer may be cotton-graphite tape, nylon-semiconducting rubber tape or extruded semiconducting material.

These same types of semiconducting layers are being used to separate metallic shielding tape and insulation for the same reason as described above. The tape, bonded to the insulation, prevents possible air spaces between the insulation and metallic shielding tape from being subjected to high-voltage stresses.

FINISHES

A wide variety of finishes is used. They are sometimes referred to as jackets, sheath, armors, or braids. Usually one or more types of coverings are required over the insulation, primarily because of the physical or chemical characteristics of the particular insulation involved. Some of these factors are poor moisture resistant characteristics, low abrasion resistance, low resistance to attack by oil and similar compounds, etc. Of course, not all types of insulations require coverings because some insulations, in themselves meet the jacket requirements.

As to the material employed, finishes can be divided into metallic and nonmetallic finishes.

Metallic Finishes

Metallic armor should be applied where a high degree of mechanical protection is required. In addition it is valuable for rodent or termite protection, since termites attack any nonmetallic finish and some rodents and insects actually attack lead. In this application a bronze, aluminum, or steel finish may be good protection. These metallic finishes can be protected against corrosion by the application of a protective jacket.

Magnetic armors should be avoided *on single-conductor alternating-current cables* because of the high sheath losses. In this case the sheath losses are in the order of 1200 percent of the conductor losses. In the case of three-conductor cables, these losses are in the order of 3-5 percent of the losses in the conductor. Naturally, high sheath losses produce a great amount of heat and may destroy the cable quickly.

If two metallic finishes of different materials are used, they should be separated by a nonmetallic layer to prevent electrolytic action, if applied in wet locations.

All metallic sheaths are liable to be damaged by electrolytic action and a protective coating or jacket should be used as a first line of defense. These inert barriers are lower in cost and easier to justify economically as compared to other protection schemes. Neoprene, polyvinylchloride, and polyethylene have been used successfully to combat corrosion due to galvanic action. In other instances, cathodic protection may be justifiable to curb corrosion.

Figure 9.6
Illustration of a Lead Sheath Applied to a Multiconductor Cable

Lead sheath (Figure 9.6) is one of the earliest types of metallic sheaths used and is still being used. Either pure lead or alloy lead has been used, depending upon the type of application. Pure lead is used for approximately 95 percent of all applications of leaded sheaths. It should not be used if frequent movement of the cable (as in aerial cable applications) is involved since it is subject to fatigue failures. In such cases alloy lead should be used instead. In some cases a PVC jacket is used over the lead sheath to reduce fatigue failures.

Lead sheaths are used extensively on paper and varnished-cambric underground cables, because a completely water- and moisture-resistant finish is essential. Since pure lead is rather weak mechanically it is often used in combination with one of the other finishes if moisture resistance and mechanical strength are required. Alloy lead is a good deal harder and may not require additional mechanical protection.

Figure 9.7
Varnished-Cambric, Flat-Band, Steel-Armor Cable

Flat-band armor (Figure 9.7) is generally associated with the term "parkway" and usually consists of a jute bedding, two helical tape wraps and a protective jute covering over the tapes. The tapes may be either galvanized or plain steel. Stainless steel tapes are sometimes used for installations where chemical agents may affect steel.

Flat-band armor is satisfactory on three-conductor cables, but its use presents problems when used on single-conductor cable. Magnetic-armored single-conductor cable is limited to low-current series streetlighting applications.

Interlocked armor (Figure 9.1) is a particularly versatile type of armor inasmuch as protective conduit is never needed with this construction. The armor consists of a galvanized steel, aluminum or bronze strip applied over-all around the cable in such a way that mechanical protection and flexibility are maintained. An impervious jacket (polyvinyl-chloride) is required under the armor if used on varnished-cambric insulation which is to be installed in moist locations. To protect the armor against chemical or corrosive atmospheres, a polyvinyl-chloride jacket can be applied over the armor.

Power and control cables are available with a metallic armor which is formed from a continuous seam welded tube. The tube is corrugated after welding to produce an external appearance similar to that of interlocked armored cable. This results in a product whose flexibility compares to that of interlocked armored cable. This armoring system is watertight and is pressure tested after completion to assure freedom from leaks.

If aluminum-sheathed cables are used underground, or in concrete, they should be protected by a protective jacket. This added protection is also required if the cable is used in areas where it is known that aluminum will be attacked.

Wire armors are available in two types in common use today, round-wire and basket-weave or braided-wire armor.

Figure 9.8
Varnished-Cambric, Steel-Wire, Armor Cable

Round-wire armored cable (Figure 9.8) is an extremely strong cable particularly suitable for submarine applications. It has high tensile strength which makes it very good for vertical applications. Because of its magnetic properties, the use of this armor on single-conductor cables should be avoided. Nonmagnetic aluminum alloy is sometimes used for these installations.

Basket-weave or braided-wire armor consists of a braid of metal wire woven directly over the cable as an outer covering, where additional mechanical protection is required for such service as indoor installations in powerhouses, substations, marine vessels, or similar applications. Either galvanized steel, bronze, or aluminum can be used for the braid, depending upon the service for which the cable is intended. Cables with braided-wire armor used for interior work can be installed without conduit. Lightweight, compactness and flexibility are the important features of this type of armor.

Grounding of Cable Sheaths

All metallic cable sheaths should be grounded to the best system ground available. The primary object of grounding is for safety and to provide a low-resistance path for short-circuit currents. All cable sheaths should normally be bonded together and grounded at frequent intervals. Also, all metallic sheaths and shields should be electrically continuous through joints and taps.

In order to eliminate circulating currents and reduce sheath losses and thereby increase the current-carrying capacity on large single-conductor cables, installed in separate ducts or where spacing between phases is appreciable, insulating joint sleeves may be used to break the continuity of the cable sheath. When insulated sleeves are so used, various connections may be employed for bonding and grounding cable sheaths such as grounding each section of sheath at one point only, cross bonding sheaths in such a way as to neutralize the induced voltage, or by grounding adjacent sections through bonding transformers.

Circulating currents and corresponding losses may exist in the shielding tapes of single-conductor nonmetallic sheathed cables although in this case the higher resistance of the shielding tape, resulting in lower loss, usually permits this cable to be operated with the shielding tape bonded and grounded at both ends.

Cables connected to overhead lines or to equipment subject to disturbances from lightning should be protected with lightning arresters. This can best be accomplished by interconnecting the arrester ground to the cable sheath with as short a lead as possible. This limits the voltage rise across the arrester itself and provides the best protection to the cable. It is important that the resistance of the lightning-arrester ground be adequately low. This is particularly important with nonmetallic-sheathed cables.

Nonmetallic Finishes

An extruded moisture resistant jacket is usually recommended where a nonmetallic finish with moisture-resistant characteristics is required. This finish can be used as a substitute for a lead sheath in many applications. Armor is sometimes applied over it to protect against mechanical damage. The extruded jacket is not affected by electrolytic action and stands up successfully in most chemical atmospheres.

Braids. Generally present-day trends are away from the use of nonmetallic braid coverings. However, there are a number of braid types in common use, such as cotton, glass, and asbestos.

Characteristics

Resistance

The 60-hertz resistance of a conductor is a function of the cable construction and the type of installation. The alternating-current resistance of conductors is usually calculated by multiplying the direct-current resistance of the conductor by a specific multiplying factor.

The direct-current resistance of copper and aluminum conductors at 25°C (77°F) are listed in Table 9.1. The following formulas can be used to calculate the resistance at other temperatures.

$$\text{For copper, } R_t = R_{25} \, [1 + 0.00385 \; (t\text{-}25)]$$

$$\text{For aluminum, } R_t = R_{25} \, [1 + 0.00395 \; (t\text{-}25)]$$

where R_t = direct-current resistance at t C

R_{25} = direct-current resistance at 25°C, read from Table 9.1

Table 9.2 lists the temperature correction factors for commonly used temperatures.

The alternating-current resistance of cables is appreciably higher than the direct-current resistance due to the presence of magnetic flux, which is created by the alternating current in the conductor and also the electric field around the conductor. A conductor carrying alternating current experiences additional losses, which appear as actual watt-losses in the conductor. Since these losses have to come from the electric energy put into the conductor, they will appear to the system as a higher I^2R loss, regardless of whether the loss appears in the conductor itself or in the other cable components. The resultant effect is an increased alternating-current resistance of the conductor.

Loss categories considered in the calculation of alternating-current resistance are:

1. Extra conductor losses, due to skin and proximity effects.
2. Sheath loss, due to circulating currents and/or eddy currents in metallic sheath, shields, or armor.
3. Conduit loss, due mainly to eddy currents and, to a lesser degree, to hysteresis effect in the conduit, if the conduit is magnetic.

Extra Conductor Losses

The resistance of an isolated single conductor in air or nonmagnetic conduit is only affected by "skin effect." This effect is negligible on small conductors and increases with conductor size. It tends to cause the current to flow on the outer surface of the conductor and causes the center of the conductor to operate at a lower current density than would be the case if the current were uniformly distributed across the conductor cross section. The increase in resistance per circular mil with conductor size contributes toward a decrease of ampere rating per circular mil (Figure 9.9).

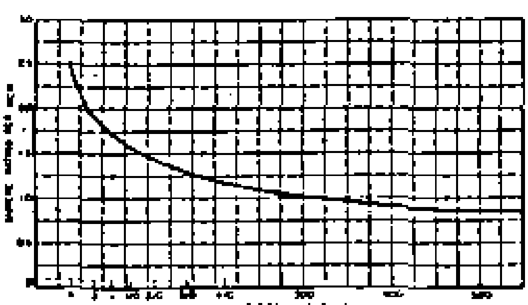

Figure 9.9
Graph Showing the Effect of Conductor Size on Allowable Current Density

The resistance of two or more conductors in air or nonmagnetic conduit operating in close proximity is also affected by "proximity effect." The magnetic flux, created by the current in the conductor, causes an induced current to flow in other conductors running in parallel and in close proximity. The effect of this phenomenon is appreciable if the conductors are closely grouped, as in three-conductor cables. It is also influenced by the relative magnitudes and phase relation between the conductor currents.

The presence of a magnetic conduit further increases the skin and proximity effects due to the high permeability of iron conduit.

Sheath and Armor Loss

A single-conductor shielded cable carrying alternating current comprises within itself all the elements of a transformer. The conductor acts as the primary, the sheath or any other metallic finish acts as the secondary. The alternating magnetic flux, which is set up by the current in the conductor linking the sheath, induces voltages in the sheath. These voltages may cause eddy currents to flow in the sheath or any metallic finish. In a magnetic armor, these eddy current losses may be severe, due to high concentration of flux lines.

If the sheath is grounded in two or more places, circulating currents will be produced which travel along the sheath of one cable and return along the ground path or the sheaths of the other cables. The losses associated with these currents exist in addition to the eddy-current loss.

If the sheath is grounded at only one point, the induced voltage in the sheath will appear as a voltage to ground; the magnitude of voltage being directly proportional to the current in the conductor and the distance of the point under consideration to where the sheath is grounded.

To illustrate the effect of sheath operation, the following data indicate the approximate relative magnitudes of sheath loss under various conditions. The sheath loss of an open-circuited lead-sheathed cable without armor, spaced one foot, is taken as the standard of reference.

Table 9.1
Conductor and Resistance Data

Size AWG or MCM	Circular Mils	Number of Wires Class B Stranding	Nominal Diameter Inches	D-c Resistance Ohms/1000 Ft. at 25°C (77°F)			60 Hertz R_{ac}/R_{dc} Ratios							
							Copper						Aluminum	
							Non-metallic Duct 3/c and 3-1/c		Metallic Duct 3/c and 3-1/c		Interlocked Armor All Voltages		3/c and 3-1/c	
				Bare Copper	Thinned Copper	Bare Aluminum	600 V 5 kV-n.s.	5 kV-s 15 kV	600 V 5 kV-n.s.	5 kV-s 15 kV	Aluminum Bronze	Galv. Steel	Non-mag. Duct	Mag. Duct
14	4,017	7	0.0726	2.63	2.69	4.31	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
14-solid	4,017		0.064	2.58	2.68	4.22								
12	6,530	7	0.0915	1.65	1.72	2.71								
12-solid	6,530		0.080	1.62	1.68	2.66								
10	10,380	7	0.116	1.04	1.08	1.70								
10-solid	10,380		0.101	1.02	1.06	1.67								
8	16,510	7	0.146	0.654	0.679	1.07								
8-solid	16,510		0.128	0.641	0.659	1.05								
6	26,250	7	0.184	0.410	0.427	0.674								
6-solid	26,250		0.162	0.403	0.415	0.661								
4	41,740	7	0.232	0.259	0.269	0.424								
4-solid	41,740		0.204	0.253	0.261	0.416								
2	66,370	7	0.292	0.162	0.169	0.266								
1	83,690	19	0.322	0.129	0.134	0.211								
1/0	105,500	19	0.373	0.102	0.106	0.168		1.01	1.01	1.01	1.01	1.01	1.001	
2/0	133,100	19	0.418	0.0811	0.0842	0.133		1.01	1.01	1.02	1.01	1.01	1.001	
3/0	167,800	19	0.470	0.0642	0.0668	0.105		1.01	1.01	1.02	1.02	1.02	1.001	1.01
4/0	211,600	19	0.528	0.0509	0.0525	0.0836	1.01	1.02	1.02	1.03	1.03	1.03	1.001	1.01
250		37	0.575	0.0431	0.0449	0.0708	1.01	1.02	1.03	1.04	1.04	1.04	1.002	1.02
300		37	0.630	0.0360	0.0374	0.0590	1.01	1.03	1.04	1.06	1.05	1.05	1.003	1.02
350		37	0.681	0.0308	0.0302	0.0506	1.02	1.04	1.05	1.07	1.06	1.06	1.004	1.03
400		37	0.728	0.0270	0.0278	0.0442	1.03	1.05	1.07	1.09	1.08	1.09	1.005	1.04
450		37	0.772	0.0240	0.0247	0.0393	1.03	1.06	1.09	1.11	1.09	1.11	1.006	1.05
500		37	0.814	0.0216	0.0222	0.0354	1.04	1.07	1.11	1.13	1.11	1.13	1.007	1.06
600		61	0.893	0.0180	0.0187	0.0295	1.06	1.10	1.15	1.18	1.15	1.17	1.010	1.08
750		61	0.998	0.0144	0.0148	0.0236	1.10	1.15	1.22	1.26	1.22	1.26	1.015	1.12
1000		61	1.152	0.0108	0.0111	0.0177	1.18	1.24	1.38	1.42	1.35	1.42	1.026	1.19

s.—shielded
n.s.—nonshielded

Conductor alone,

- open-circuited sheath, no armor— 100%
- short-circuited sheath, no armor— 180%
- lead sheath and copper armor, both short-circuited— 130%
- lead sheath and steel wire armor, both short-circuited— 260%
- in iron pipe— 2500%

In using long and large single-conductor metallic-sheathed cables special techniques may be required to eliminate circulating-current losses, such as insulating sleeves at various points along the sheath or transposing the sheath.

In a multiconductor cable, forming part of a polyphase circuit, with all the conductors enclosed under one common sheath, eddy-current losses in sheath and enclosure are reduced to approximately 3-5 percent of the conductor losses, while circulating current losses can be neglected. This is due to the almost complete cancellation of the magnetic flux outside the cable construction. Only a small resultant rotating flux will cause some losses, mentioned above.

Conduit Loss

Current-carrying conductors, installed in magnetic conduit, cause additional losses in the conduit in the same way as explained under sheath loss. These losses arise from both hysteresis and eddy current effects in the magnetic conduit. The losses in a magnetic and nonmagnetic, metallic enclosure are not widely different. In a magnetic enclosure, such as conduit, the hysteresis loss will be high, but the eddy-current loss will be low, due to the high resistivity of the conduit. Nonmagnetic, metallic enclosures experience no hysteresis loss, but high eddy-current loss.

Table 9.2
Resistance Temperature—Correction Factors

Temperature °C	*Multiplying Factor*	
	Copper	*Aluminum*
25	1.000	1.000
40	1.058	1.059
50	1.096	1.099
55	1.116	1.119
60	1.135	1.138
65	1.154	1.158
70	1.173	1.178
75	1.193	1.198
80	1.212	1.217
85	1.231	1.237
90	1.250	1.257
100	1.289	1.296
105	1.308	1.316
125	1.385	1.395
130	1.404	1.415
150	1.481	1.494
200	1.674	1.691

Table 9.3
Reactance Correction Factors for Various Constructions and Installations

Cable Installation	*3/c cable in conduit, duct or armor cable*		*3-1/c in conduit or duct random lay*	
Enclosure	*non-magnetic*	*magnetic*	*non-magnetic*	*magnetic*
Cond. size 250 MCM and smaller	1.0	1.149	1.2	1.5
300	1.0	1.146	1.2	1.5
350	1.0	1.140	1.2	1.5
400	1.0	1.134	1.2	1.5
500	1.0	1.122	1.2	1.5
600	1.0	1.111	1.2	1.5
700	1.0	1.100	1.2	1.5
750	1.0	1.095	1.2	1.5

Inductive Reactance

Skin and proximity losses affect not only the alternating-current resistance, but also the inductive reactance of conductors. While these tend to increase the alternating-current resistance, they decrease the inductive reactance. However, their effect on inductive reactance is much smaller. In fact, it is so small that it can be neglected without appreciable loss in accuracy.

Neglecting skin and a proximity effect, the inductive reactance, X of standard stranded three-conductor cable, single-conductor cable operated with open-circuited sheath, isolated single-phase or isolated three-phase circuits with equilateral triangular arrangement could be calculated, using the formula:

$$X = 2\pi f\left(140.4 \log_{10} \frac{S}{r} + 15.2\right) 10^{-6}$$

where:

X = inductive reactance to neutral, ohms per 1000 feet.

f = frequency, hertz

S = distance between conductors, center to center, inches

r = radius of conductor, inches

If the arrangement of the conductors is not equilateral the average reactance can be calculated from the formula:

$$X = 2\pi f\left(140.4 \log_{10} \frac{\sqrt[3]{S_{ab}\, S_{bc}\, S_{ca}}}{r} + 15.2\right) 10^{-6}$$

where

S_{ab} = spacing between a and b conductors in inches, etc.

$\sqrt[3]{S_{ab}\, S_{bc}\, S_{ca}}$ = equivalent delta spacing.

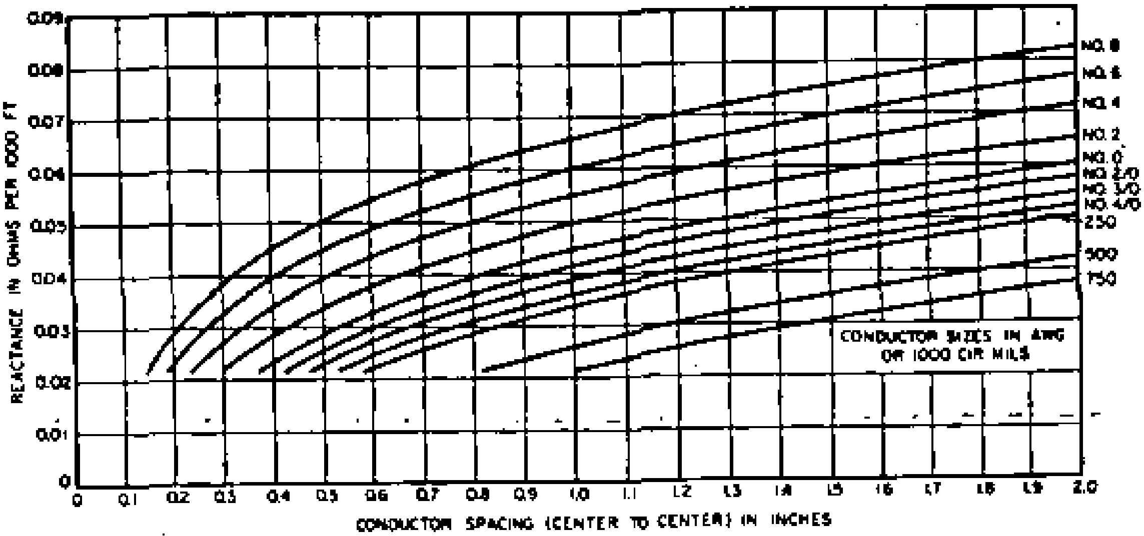

Figure 9.10
– Reactance, in Ohms per 1000 Feet at 60 Hertz, Line to Neutral

For closely spaced conductors, as in a three-conductor cable, in air or nonmagnetic duct, the reactance can be determined from Figure 9.10. The conductor spacing can be taken as the outside diameter of the cable.

To account for random lay of three single conductors in nonmagnetic duct, the reactance obtained from Figure 9.10 is multiplied by 1.2 (see Table 9.2).

If installed in a magnetic enclosure, the approximate multiplier is 1.5. This number takes also into account the increased inductance due to the high flux concentration in the magnetic enclosure. Reactance correction factors for three-conductor cables in magnetic duct account for increased inductance only.

Ratings

Current Rating

The current rating of a cable is affected by many factors, the most important of which are the total watt loss of the cable construction, the thermal resistance of media the heat must pass through in order to be completely dissipated, the maximum allowable conductor temperature and the ambient temperature.

The total watt loss of the cable is a function of I^2R_e, where R_e is the effective alternating-current resistance of the conductor at the maximum allowable conductor temperature. Consequently, all factors which have been discussed under the heading of cable resistance also effect the total watt loss in the cable.

The maximum conductor temperature is determined by the maximum temperature the insulation can withstand successfully for a long period of time. Higher temperature insulating compounds will, therefore, have a higher current rating as illustrated in Figure 9.11. The maximum operating temperature of insulations are listed in Table 9.4. The current rating of a cable is also affected by the ambient temperature. See Figure 9.12. It is obvious that

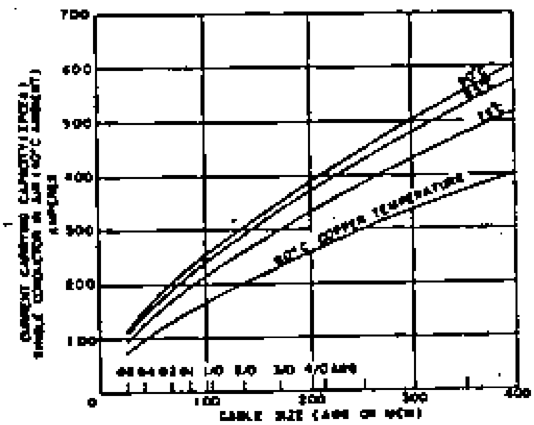

Figure 9.11
Graph Showing the Effect of Maximum Temperature on Conductor Ampacity

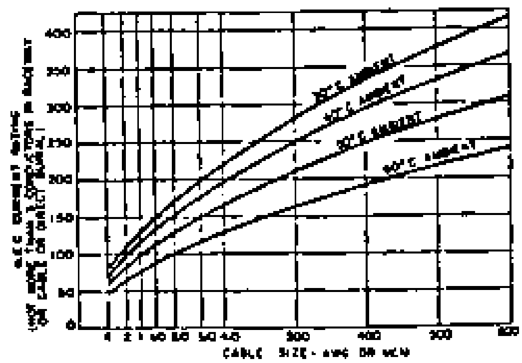

Figure 9.12
Graph Showing the Effect of Ambient Temperature on Conductor Ampacity

the lower the ambient temperature is, the higher the current rating will be since in all cases the sum of ambient temperature and temperature rise has to be equal to the maximum allowable conductor temperature.

The term "ambient temperature" is used to define the temperature of the surrounding medium into which the cable dissipates its generated heat. The cable manufacturer designates the allowable ambient temperature under which his cable can carry its rated current at rated frequency without causing any of the insulating material to exceed its assigned maximum operating temperature.

The precise manner in which an ambient temperature is to be determined is not given in available Standards. The actual ambient temperature of one particular cable will be the base ambient of the bare space increased by the temperature increment produced by every other heat-dissipating member in the immediate area. This will include the effect of nonelectrical sources such as steam pipes, furnaces, hot-water pipes, etc. as well as electric things like motors or other loaded cables.

To a considerable degree, the treatment of ambient conditions relative to conductors suggests that it is the general ambient in which the conductors are placed (without recognizing the temperature increment which their presence will create) which is intended. Mutual thermal effects are compensated for by devising appropriate multiplying factors by which the individual cable current-carrying capabilities are reduced when other loaded cables are located alongside. The same technique is used to reduce the allowable individual-cable current-carrying capacity when a multiplicity of cables are run in a common duct bank. An alternative procedure could have been devised by which the true ambient temperature for the individual cables would be determined and the allowable current capability then determined from the computed ambient temperature without application of further multipliers.

The NEC current-carrying capacity tables 310-12 through 310-15 are based on a 30°C reference ambient temperature. A table of multipliers provides for appropriate reduction in current capability in the presence of higher reference ambient temperatures up to 140°C. To account for the mutual heating effects of adjacent loaded conductors, an additional adjustment in current capability is made by a different set of multipliers.

The manner of handling the ambient temperature problem in the AIEE-IPCEA loading tables is very much the same.

The earth ambient temperature used as a reference for underground cable installations is quite commonly adjusted for latitude. In the United States commonly used reference ambient temperatures are: 20°C for the Northern Section, 25°C for the Central Section, and 30°C for the South and Southwest Sections.

For outdoor installations, a 40°C reference ambient temperature is commonly used for a shaded location, and a 50°C reference is commonly used where there is exposure to the sun.

Emergency Overloading

Normal loading limits of insulated wire and cable are based on many years of practical experience and represent a rate of deterioration that results in the most economical and useful life of such cable systems. The rate of deterioration is expected to develop a useful life of about 20 to 30 years and, according to service records, results in an average of about six service failures per hundred miles of circuit per year from all causes, including mechanical

Table 9.4
Maximum Continuous Operating Temperature and Maximum Short-Circuit Temperature for Various Cable Insulations

Cable Insulation	*(nearest) NEC Designation*	*Voltage Class*	*Maximum Continuous Conductor Temperature (°C)*	*Maximum-Overload Temperature (°C)*	*Maximum Short-Circuit Temperature (°C)*
Varnished cloth	V	5-kV & below	85		
		7.5 kV	84		200
		15 kV	77		
Thermoplastics					
Polyvinyl-chloride	T-TW	600 V	60	85	
	THW	600 V	75	95	150
Polyethylene	—	600 V	75	95	
Thermosettings					
SBR (Bunas)	RHW	600 V	75	95	
Butyl	RHH	5-kV & below	90	105	200
		Above 5 kV	85	100	
Cross-Linked Polyethylene	—	15 kV & below	90	130	250
Ethylene Propylene Rubber		15 kV & below	90	130	250
Silicone	SA	5-kV & below	125	150	250

damage, corrosion, inherent weakness, etc. The life of cable insulation is about halved and the average rate of service failures about doubled for each 5 to 10°C increase in normal daily load temperature. Besides, sustained operation over and above maximum operating temperatures is not a very effective or economical expedient, because temperature rise is directly proportional to copper loss, and increases as the square of the current. The increased voltage drop might also enlarge the risks to equipment and service continuity.

As a practical guide, the IPCEA has established maximum emergency-overload temperatures for various types of insulations. A partial listing of these IPCEA ratings has been included in Table 9.4. Operation at these emergency-overload temperatures should not exceed 100 hours per year and such 100-hour overload periods should not exceed five.

To calculate the emergency-overload current of a cable from the current rating, the following formula can be employed:

$$i_e = i_c \sqrt{\frac{(t_e - t_a)}{(t_c - t_a)} \times \frac{R_c}{R_e}}$$

where: i_e = emergency-overload current

i_c = continuous-current rating

t_e = emergency-overload temperature

t_a = ambient temperature

t_c = maximum operating temperature

R_c = conductor resistance (or resistance-temperature correction factor, listed in Table 9.2 at maximum operating temperature)

R_e = conductor resistance (or resistance-temperature factor, listed in Table 9.2 at emergency-overload temperature)

Short-Circuit Current-Time Limits

Under short-circuit conditions, the temperature of the conductor rises rapidly. Then, due to thermal characteristics of the insulation, sheath, surrounding materials, etc., it cools off slowly when the short-circuit condition is removed.

The transient temperature limit depends on the type of insulation and should not exceed the temperatures listed in Table 9.4. These temperatures have been recommended by IPCEA* for short circuits not in excess of 10 seconds.

Failure to check the conductor size for short-circuit heating could result in severe permanent damage to the cable insulation due to disintegration of organic insulation material, which is accompanied by smoke and combustible vapors. These vapors might, under certain conditions, touch off an explosion or fire. Besides, the sheath of the cable may be expanded to produce voids. This becomes especially serious in 5-kV and 15-kV cables.

*IPCEA—Insulated Power Cable Engineers Association

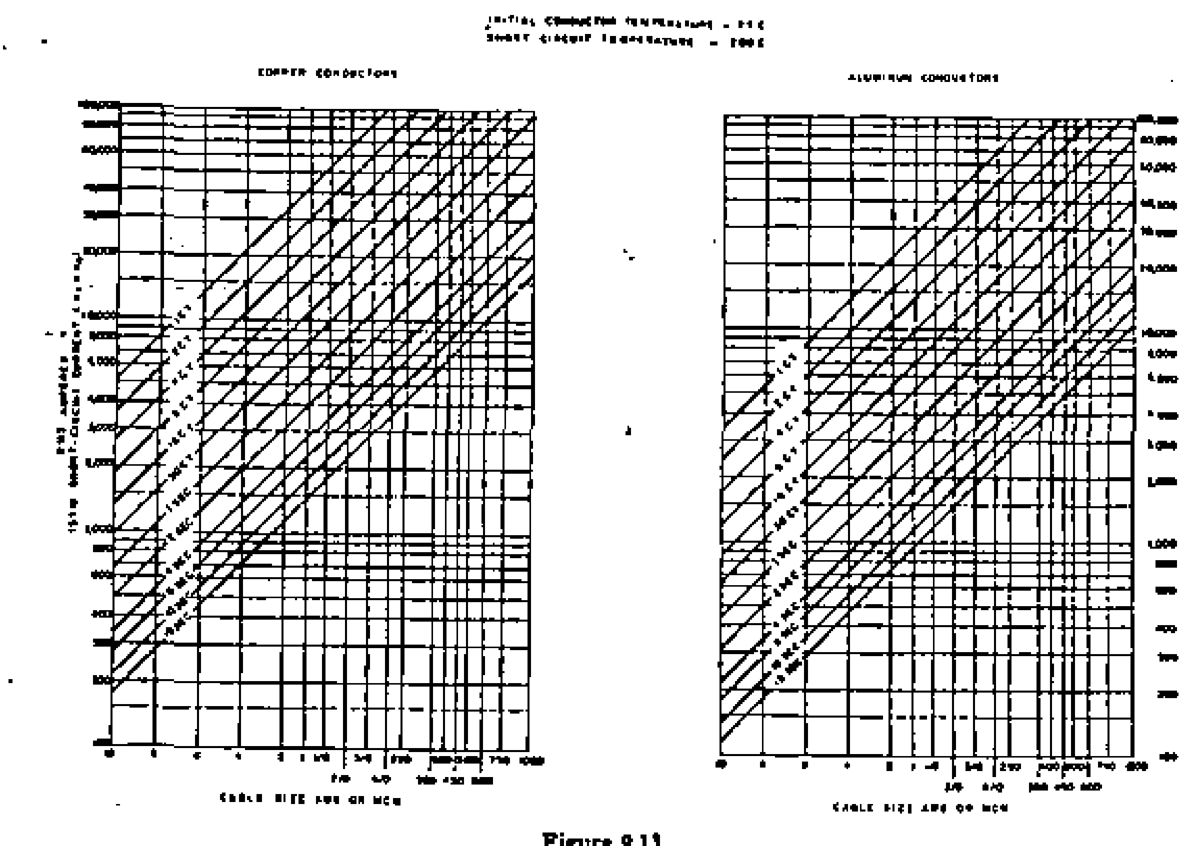

Figure 9.13
Size of Conductor for a Conductor Temperature Change from 75 C Initial 200 C Final During a Single Interval of Short-Circuit Current Flow

Besides the thermal stresses, there are mechanical stresses set up in the cable through expansion upon heating. As the heating is rapid, these stresses may result in considerable cable movement. However, on modern cables, reinforcing binders and sheaths considerably reduce the effect of such stresses. Within the range of temperatures limiting the thermal stresses, the mechanical aspects can usually be discounted except with old cables.

On the basis that in the period of time considered (a few seconds) there is no loss of heat from the conductor by conduction or convection and that radiation is negligible, the conductor heating can be expressed mathematically as follows:

Copper conductors

$$\left(\frac{I}{CM}\right)^2 t = 0.0297 \log_{10} \frac{(T_2+234)}{(T_1+234)}$$

Aluminum conductors

$$\left(\frac{I}{CM}\right)^2 t = 0.0125 \log_{10} \frac{(T_2+228)}{(T_1+228)}$$

where: I = rms amperes during the entire interval of current flow

t = duration of short-circuit flow, in seconds

CM = conductor cross section, in circular mils

T_1 = initial conductor temperature, in degrees C

T_2 = final conductor temperature in degrees C

To simplify the application, these relationships are presented graphically in Figure 9.13. These graphs apply only to an initial conductor temperature of 75°C and a short-circuit temperature of 200°C. The initial temperature is in general not known accurately since it depends upon the loading of the cable and ambient conditions. In those cases the initial temperature is assumed to be equal to the maximum operating temperature of the insulation, which is conservative. In critical cases a more accurate analysis might be required using a more realistic temperature and the actual short-circuit temperature of the insulation. Temperature correction factors (K_t) taking into account the actual allowable temperature rise can be obtained from Figure 9.14.

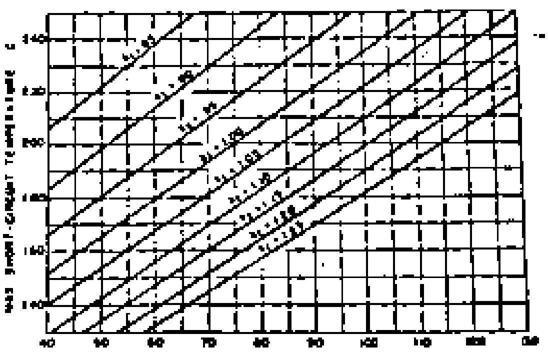

Figure 9.14
Correction Factors K_t for Other Temperature Boundaries

Root-Mean-Square Current

The rms current as used in Figure 9.13 is defined as the root-mean-square value for the total interval of current flow. The initial temporary direct-current component encountered in alternating current circuits increases the rms current, but to a lesser extent as the interval of current flow becomes longer. Figure 9.15 gives K_o factors

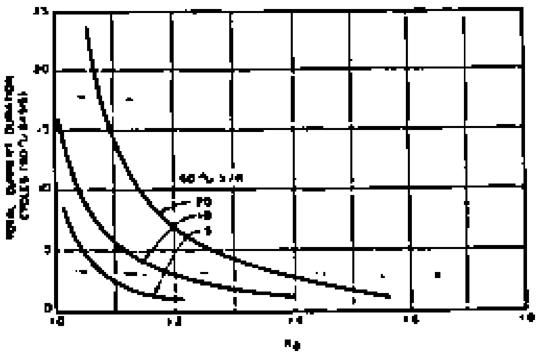

Figure 9.15
Correction Factors K_o for the Direct Current Component of Current

which compensate for the current offset. Appropriate K_o multipliers should be applied to the available symmetrical short-circuit current to obtain "rms amperes" for use in Figure 9.13.

If the X/R ratio of a circuit is not known, conservative factors (K_o) for the more common application conditions are:

Low-voltage power circuit breakers tripped instantaneously	K_o = 1.3
Power circuit breakers, 8-cycle, instantaneously tripped	K_o = 1.1
Any industrial power distribution problem with short-circuit duration of ½ second or more	K_o = 1.0

While the above factors are approximate, their use will usually provide good estimates of rms amperes. Current-limiting characteristics of certain low-voltage circuit breakers and differences in tripping times of the various types of breakers have not been taken into account. If a more accurate analysis of the circuit is required, Figure 9.15 should be used to determine the appropriate K_o factor.

Selection and Application

The selection of any cable system could be broken down into five parts:

1. Operating conditions
2. Type of cable installation
3. Selection of cable construction

4. Type of insulation and jacket

5. Selection of cable size

It is pointed out that this sequence should be followed in each application since each of the first four parts will affect the selection of the required cable size.

Operating Conditions

The current that the cable has to carry is determined by the load it is serving. This number is usually available or can be obtained from the nameplate of the apparatus. However, some Code requirements and special considerations which enter into the selection of the cable size need to be considered and will be discussed here.

The National Electrical Code specifies, in Section 430-22, that branch-circuit conductors supplying an individual motor shall have a current-carrying capacity not less than 125 percent of the motor full-load current rating if the motor is used for continuous duty. Any motor is considered to be for continuous duty unless the nature of the apparatus which it drives is such that the motor will not operate continuously with load under any condition of use.

Section 430-24 indicates that the conductors of any circuit supplying two or more motors shall have a current-carrying capacity not less than 125 percent of the full-load current of the highest rated motor in the group, plus the sum of the full-load currents of the remainder of the motors.

Conductors supplying a combination motor and lighting load shall have a current-carrying capacity sufficient for the non-motor load plus required capacity for the motor load determined in accordance with NEC Section 430-25.

For conductors supplying motors used for other than continuous duty, refer to NEC Section 430-22.

The equivalent current-carrying capacity of cables subjected to a load cycle can be approximated using the formula:

$$I_{eq} = \sqrt{\frac{\Sigma I^2 t}{T}} \text{ amperes}$$

where I_{eq} = equivalent current-carrying capacity

I = constant current during a certain time interval

t = time interval of constant current flow

T = total time, expressed in same unit as incremental time intervals, to complete one duty cycle, not exceeding 1 to 2 minutes.

This equivalent current-carrying capacity should be used only for selecting the conductor size from a thermal heating standpoint. In checking voltage regulation, the highest current in the load cycle should be used to determine the maximum voltage drop.

In selecting cables for shunt-capacitor applications, allowance must be made for the harmonic content of the current. NEMA Standard CP1-1963 indicates that the current-carrying capacity of the cable shall be at least 135 percent of the rated current of the shunt capacitor. Since most capacitors for industrial service are designed for use in an ambient of 40°C maximum, the cable rating should also be selected for that ambient operation, unless it is definitely known that the ambient temperature is less.

Type of Cable Installation

There are several types of cable installations, each having its advantages and disadvantages. Local conditions, past experience or Company rules oftentimes favor a particular type of installation.

Overhead Circuits—Outdoors

Open Wiring

Open-wire circuits on insulators are used for outdoor primary distribution where the plant covers a large area. In these cases they are the cheapest in first cost and are, in general, satisfactory for primary distribution circuits. They may be mounted on poles or attached to buildings, the conductors being either bare or weatherproof. The wires are exposed and hence are subject to interference from equipment such as cranes. They should not be used in congested areas or where there is any possibility of objects interfering with them from the ground or dropping on them from overhead.

Open wiring, although exposed to greater likelihood of damage, possesses an offsetting advantage in that the line fault, generally a broken conductor or a faulty insulator, is more easily located and repaired than with other constructions.

Due to their relatively large spacing open-wire circuits exhibit a high reactance resulting in high voltage drops, especially in low-power-factor circuits.

Exposed open-wire circuits are more susceptible to outages from lightning than underground or aerial cable circuits. The mitigation of lightning interference on such lines and connected apparatus may be accomplished by the use of overhead ground wires, lightning arresters, and other protective measures.

Aerial Cable

Insulated cable may be used along the sides of buildings or on pole lines and provide a more reliable circuit than open wiring and at the same time requires less space. Properly protected cables are not easily injured by casual contact but are open to the same objections as open wire so far as clearance over roadways and between buildings is concerned. When used in long spans, cable is usually supported on a messenger which provides high strength and helps to prevent loss of the cable due to storms or injury to supporting poles.

The supporting messenger may also serve as the grounding conductor of the power circuit. In one form the insulated cable conductors may be continuously laced to the messenger with a spiral metal band. Motorized spinner heads are available which will apply the spiral banding in the field. Factory-assembled aerial cable is finding increasing use for industrial wiring. This cable is assembled with a supporting messenger at the cable factory and its use simplifies the installation. This type cable can be obtained with any type insulation and any type covering, although the most common type is synthetic rubber insulated with a neoprene sheath.

A convenient feature available in factory-assembled aerial cable makes it possible to connect a circuit tap without cutting the cable conductors. Because the direction of spiral of the stranded conductors is reversed regularly every 10 or 20 feet it is possible to form a slack loop without cutting the conductors.

Another variation of the messenger suspension idea makes use of plastic spacer supports which clip onto the messenger and contain slots for supporting the individual power cables in a balanced geometric pattern. The distance between supports can be set to meet the service conditions. They are available for circuit operating voltages of 15,000 and less.

Underground Circuit—Outdoors or Indoors

Most underground circuits are installed in duct banks to facilitate installation and replacement. Manholes or pulling chambers are provided for splicing and pulling individual lengths of cable. These ducts may be run under buildings or across open country. Good practice requires that extra ducts be provided when a circuit is installed so that additional cables may be added as required without further excavation. Duct systems are particularly advantageous in heavily loaded areas where additional feeders may be required.

Cables may also be buried directly in the ground. This type of construction has some advantages and is somewhat cheaper in first cost but cannot be maintained or added to as readily. Buried cables are finding increased use in connection with primary feeders to widely separated buildings where it is desired to keep the cables underground and avoid an expensive duct bank. The current-carrying capacity of buried cables is, in general, better than for cables installed in duct banks. It is important to protect buried cable under roadways and other heavily loaded surfaces.

Buried sacrificial anodes are sometimes employed to protect metallic sheathed underground cables. When properly designed, such a system affords excellent protection for buried cables. Since the anodes are consumed through their normal operation, it is imperative that they be maintained and renewed when required in order to achieve adequate protection.

Indoor Circuits

There are numerous advantages in the practice of enclosing indoor electric power circuits in a grounded metal shell such as conduit, metal raceway, or integrally applied metallic armor. Such a metal sheath tends to minimize electric and magnetic fields external to this metallic shell. This in turn correspondingly minimizes the electrostatic and electromagnetic coupling to communication or instrumentation circuits in the area. The induction of objectionable circulating current in nearby metallic structures is also eliminated practically. The superior performance of an enclosing metallic sheath as the power-circuit grounding conductor is indirectly a reflection of the properties just mentioned.

To a limited extent, open exposed wiring is used in open-bay manufacturing areas. The power conductors tend to be run parallel with and supported from horizontal beams or girders. The supports frequently take the form of porcelain spools or insulating clamp type supports.

Armored Cable

Armored cable, because of is flexibility, can conveniently be used in many locations by strapping the cable along girders or by carrying it on messengers, cable trays, or ladders. It is particularly convenient for adding circuits to existing installations, where a duct system is filled up and new ducts or conduits are difficult to install.

The use of multiconductor armored cables for voltages up to 15 kv is finding more and more favor. These are usually carried on racks through factory buildings. For large capacities, several cables may be operated in parallel. This construction gives better regulation than would be obtained from heavy open secondary feeders on cleats, offers greater safety and is economical in cost. A lead sheath is not required under the armor for varnished cambric where the cables are not placed underground, nor under any conditions for cables insulated with moisture-resistant insulations.

Metallic-armored cable is preferable to nonarmored cable as it provides better mechanical and fire protection and more positive grounding.

Jackets may be applied over the metallic armor where corrosive conditions exist. Voltage identification may be obtained by the use of colored jackets.

Raceways

Conduit wiring is a common type used in buildings and provides the best mechanical protection. Metallic conduit is ordinarily used unless some condition such as corrosive vapors or the use of single-conductor cable in individual conduits prohibits its use. Conduits may be any of the standard metallic types, including rigid conduit, electrical metallic tubing, flexible metal conduit, etc., or nonmetallic types such as fibre, transite, or rigid plastic. Only a nonmagnetic variety of metallic conduit (such as aluminum) should be used if only one conductor (or a group of conductors in a common phase) of an alternating-current power circuit are run alone in a single conduit. The conduit, if so used, shall be appropriately insulated except at one grounding point to avoid objectionable induced circulating current.

Cable Trays

Another method of installation involves the use of racks and trays which provide simplicity of installation, easy access to cable, and mechanical protection. Trays are furnished in various degrees of ruggedness and are sometimes furnished with covers where additional mechanical protection is necessary. Barrier strips are provided for adequate separation of cables or phases. Trays can be provided suitably protected where corrosive conditions are present.

Selection of Cable Arrangement

Single- Versus Three-Conductor

Single conductors are easier to handle, especially the large sizes, and they can be used to form a multiple-cable circuit. They are easier to splice, but the reactance of three single-conductor cables is usually slightly higher than the three-conductor construction. On large-size shielded single-conductor cables, attention must be given to the best method of shield operation to prevent severe overheating of the cable due to high shield currents.

Three-conductor constructions with an over-all jacket have the lowest reactance. Also, due to the equivalent spacing between conductors, these reactances are balanced.

Ground Wires

In the past little or no emphasis was placed on the use of ground wires since it was generally believed that equipment grounding could be obtained by grounding the electric equipment to steel building structures. Recent investigations indicated, however, that this type of equipment grounding is quite ineffective.

In addition to a resistance, an inductive reactance value is associated with every conductor. The inductive reactance increases as the spacing between the conductors increases. This indicates that the reactance of a current path closely paralleling the phase conductors offers a lower impedance to the ground-fault current than any other current path regardless of the lower resistance of these other current paths. Especially in heavy circuit constructions will the reactance exercise predominant control over the current division in parallel ground return paths. This explains the strong tendency for ground return currents to seek a path physically close to the power conductor over which the outgoing current flows. The presence of magnetic material in the power conductor enclosure introduces additional inductive effects tending to confine the return ground currents within the magnetic enclosure.

The preceding background information indicates clearly that ground wires in the cable interstices or as a fourth conductor installed in the same enclosure will constitute such a low-impedance path. Attempting to relieve the conductor enclosure by installation of an external grounding conductor is sometimes ineffective (Figure 9.16). Connections to nearby building structural members are equally ineffective.

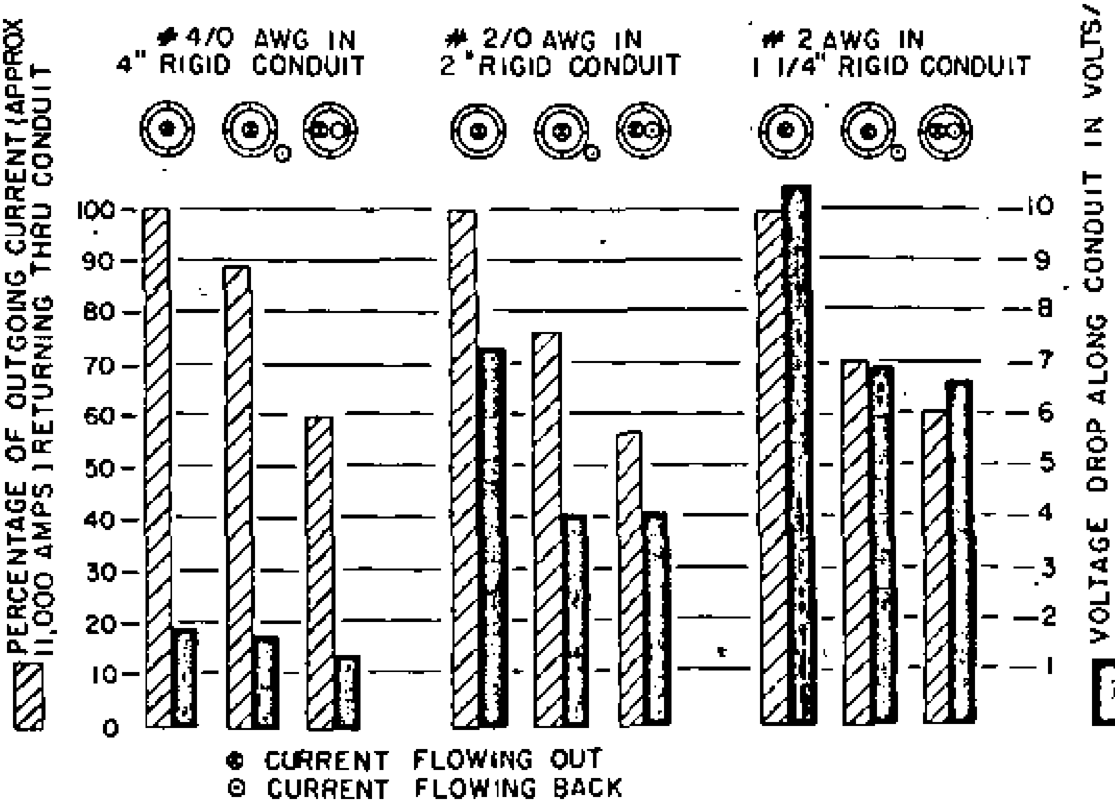

Figure 9.16
Graph Showing the Effectiveness of Ground Wires

It should be realized that all or a part of the total ground-fault current will flow through the enclosure, which indicates the necessity for solid bonds between conduits and connections with junction boxes, etc. In case of interlocked armor installations it is recommended that the armor be clamped down on the racks or ladders at regular intervals and that the ladders be solidly bonded at their connections. Interlocked armor carried from one rack on to another requires a metallic connection between the two runs of ladders. Failure to establish this metallic connection will result in severe sparking and damage to armor and insulation.

Circuits feeding three-phase loads require only one ground conductor whereas circuits feeding three-phase and single-phase loads require both a neutral (white) ground conductor and an equipment ground (green) conductor (Figure 9.17). These installations require a four-conductor arrangement with interstitial ground wires or five single conductors in one enclosure.

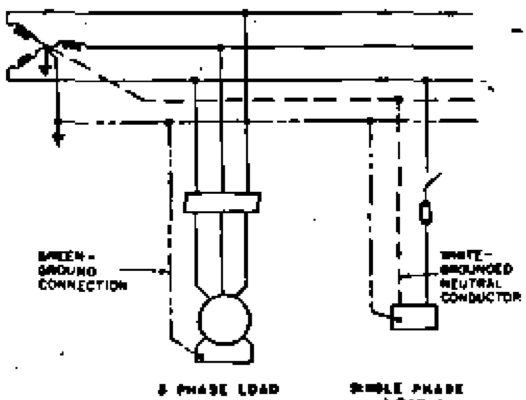

Figure 9.17
A Wiring Diagram Showing the Functional Distinction between a Grounding Conductor (green color) and a Grounded Power Conductor (white color)

Type of Insulation and Jackets

The selection of the preferred types of cable insulation and jacket is not only based on the type of installation, but also on the ambient temperature, type of service, unusual service conditions, personal preference, and past experience. It is, therefore, impossible to simply recommend a preferred insulation or jacket material. In fact, two or more insulations might be equally suitable for one particular application. In those cases, economics usually will eliminate some insulations.

Selection of Cable Size

The selection of conductor size is principally based on three considerations:

1. Current-carrying capacity
2. Voltage regulation
3. Short-circuit requirements

Each of these points should be checked before deciding on the required cable size. Failure to do this might result in improper functioning of the utilization equipment or endangering the proper operation of the cable.

Current-Carrying Capacity

The selection of a cable size based on its thermal heating is usually considered first. Current-carrying capacity tables are available from the IEEE in publication S-135 (AIEE-IPCEA Ampacity Tables) and have been adopted universally for the standard types of cables. These Standards give a complete description of the calculation of current-carrying capacities and the constants on which they are based.

The National Electrical Code should be checked when determining the sizes of conductor for building purposes where the Code authority has jurisdiction. Conductor sizes cannot be smaller than allowed by the Code but conservative engineering, future load growth, voltage-drop considerations or short-circuit heating may make the use of larger conductors desirable. Some jurisdictions, as in the State of California, publish rules and conductor capacity tables which differ from the NEC, and these govern the minimum requirements in their areas.

Grouping of cables has a large effect on the current-carrying capacity. Large groups should be avoided both in underground installations and in buildings. Several smaller groups are preferable to one large group. When it is impossible to separate cables or conduit, derating factors should be used, to prevent excessive temperatures. Refer to NEC 310-11.

If the required conductor size is computed to be larger than 500 MCM, paralleling should be considered. Some industrials prefer to parallel even smaller sizes. Paralleling is desirable because the ampere rating per circular mil of conductor decreases with the increase in cable size. One reason for this decrease is skin effect and other alternating-current losses; the other, less radiating surface per circular mil. Also, the material cost of cable is usually less for two smaller conductors than for one large conductor; this is somewhat offset by higher installation costs.

In rewiring circuits for larger current ratings and utilizing existing conduit, advantage can be taken of the higher current ratings of high-temperature insulations. In such cases, the NEC allows a greater conduit fill, which will further increase the ampere rating of the largest size of new cable that can be installed in existing conduit (see NEC, Chapter 9, Table 3).

Voltage Regulation

The second consideration in selecting conductor size is that of voltage regulation. In properly designed modern systems, this consideration is usually not limiting. However, for unusually long runs of cable, particularly at low voltage and when applying high-temperature insulations, the voltage regulation should be checked to be sure of satisfactory operation. In case of motor circuits, not only the steady-state voltage drop, but also the short-time voltage drop due to motor starting should be within certain limits to assure that the motor will start and run satisfactorily. Besides, transient voltage dips may cause flicker in the light output of lamps, especially incandescent lamps, supplied by combined lighting and motor feeders.

The procedure to calculate voltage drop has been covered extensively in Chapter 2. The NEC requires that the voltage drop between the source of power and final distribution point shall not be more than 3 percent for power or heating circuits and not more than 1 percent for lighting loads or combined power, heating and lighting circuits (NEC, Section 215-3).

If voltage drop appears to be excessive, the next larger conductor size should be selected or, in some cases, power-factor improvement may be applied at the load.

Short-Circuit Requirements

The cable size should finally be checked from a short-circuit standpoint to avoid severe permanent damage to cable insulation during an interval of fault-current flow in the system. The following application procedure may be used to check the conductor size for short-circuit heating:

1. Evaluate the symmetrical short-circuit current at the source side of the cable circuit.
2. Define the initial operating temperature and short-circuit temperature of the insulation being considered. Find the appropriate temperature correction factor (K_t) on Figure 9.14.
3. Define the clearing time of the protective device at the magnitude of current found in Step 1. Find the applicable direct current offset correction factor (K_o) on Figure 9.15.
4. Multiply the symmetrical short-circuit current by K_t and K_o. Enter Figure 9.13 with this value to find the smallest permissible conductor size.
5. Some single circuits consist of two or more cables in parallel. For a single-cable fault, the total short-circuit current distribution in two or more parallel paths will vary considerably depending on the fault location and the number of paths available. However, application of the single-cable overheating criteria conservatively requires that each of the two or more parallel-connected cables must be able to withstand the total fault current.

Terminators

General

As used in this chapter, the word terminators is meant to include connectors, terminal lugs, potheads and all types of devices intended to be applied to cable ends. There is a great variety of designs depending on the type of insulation, and type of insulation-protective covering. The cable manufacturers should be consulted for their recommendations, which should be followed. In this publication only the basic principles involved in the selection and use of terminators can be covered.

Types Available

Terminators may be divided into two general classifications depending upon the method of attaching them to the conductors. The two methods may be designated as thermal and pressure.

Thermal types of terminators include those involving the use of heat to make soldered, silver soldered, brazed, welded or cast-on terminals. Soldered connections have been used with copper conductors for many years and their use is well understood. Aluminum connections may also be soldered satisfactorily with the proper materials and technique. However, soldered joints are not commonly used with aluminum. Shielded arc welding of aluminum terminals to aluminum cables makes a very satisfactory termination and this method is quite common on cable sizes larger than 4/0. Torch brazing and silver soldering of copper cable terminations are in common use, particularly for underground connections with bare conductors such as are found in grounding mats. Thermite type welding kits utilizing carbon molds are also in common use for making connections with bare copper cable for ground mats and junctions generally which will be below grade. The thermite welding process has also proved very satisfactory for attaching terminations to insulated power cables.

Two basic types of pressure terminators are currently available for making joints in electric conductors. One is mechanical while the other is compression.

Mechanical type terminators may be defined as those in which the pressure to attach the terminator to the electric conductor is applied by integral screw, cone or other mechanical parts. A mechanical terminator thus applies force, and distributes it properly, through the use of bolts or screws and properly designed sections. The bolt diameter and number of bolts are selected to produce the clamping and contact pressures required for the most economical design. The sections are made heavy enough to carry rated current and withstand the mechanical operating conditions.

Compression terminators may be defined as those in which the pressure to attach the terminator to the electric conductor is applied externally, changing the size and shape of the terminator.

The compression terminator is basically a tube with the inside diameter slightly larger than the outer diameter of the conductor. The wall thickness of the tube is designed to carry the current, withstand the installation stresses, and withstand the mechanical stresses resulting from thermal expansion of the conductor. A joint is made by compressing the conductor and tube into another shape by means of a specially designed die and tool. The final shape may be indented, cup, hexagon, circular, or oval. All methods have in common the reduction in cross sectional area by an amount sufficient to assure intimate and lasting contact between the terminator and the conductor.

Small terminals can be applied with a small hand tool. Larger terminals are applied with a hydraulic compression tool.

A properly crimped joint deforms the conductor strands sufficiently to have good electrical conductivity and mechanical strength but not so much that the crimping action over-compresses the strands thus weakening the joint. The optimum depth of indent is determined by "work curves" which plot the depth of indent of the indenting die against pull-out force and conductivity of the joint.

Performance Requirements

Electric terminators for industrial plants are designed to meet the requirements of the National Electrical Code. They are evaluated on the basis of their ability to pass secureness, heating, and pullout tests as outlined in Underwriters' Laboratories "Standard for Wire Connectors and Soldering Lugs." These tests are considered adequate to represent the type of duty normally encountered in industrial plants. When used for power generation and distribution, terminator requirements are even more severe than those set up by Underwriters. They must be able to meet electrical and mechanical operating requirements. Electrically the terminators should carry the current without exceeding the temperature rise of the conductors being joined. Joint resistance not appreciably higher than that of an equal length of conductor being joined is recommended to assure continuous and satisfactory operation of the joint. In addition, the terminator must be able to withstand momentary overloads or short circuits to the same degree as the conductor itself.

Mechanically a terminator should be able to withstand the effects of the environment within which it is operating. If outdoors, it must stand up against wind, sleet, vibration, corrosion, etc. If used indoors, any vibration from rotating machinery, corrosion caused by plating or manufacturing processes, high temperatures from furnaces, etc. must not materially affect the performance of the joint.

Insulated Terminators —

Where several relatively large insulated cables must be joined together, it is frequently more economical to use an insulated terminator. These terminators, called "moles" or "crabs", are fundamentally insulated buses with provision for making a number of tap connections which can be very easily taped. Terminators of this type enable a completely insulated multiple connection to be made without the skilled labor normally required for careful "crotch" taping or the expense of special junction boxes. One widely used type is a preinsulated multiple-outlet joint in which the cable connections are made mechanically by compression cones and clamping nuts. Another type is a more compact preinsulated multiple joint in which the cable connections are made by standard compression tooling which indents the conductor to the tubular cable sockets.

Insulated terminators lend themselves particularly well to underground services and industrial wiring where a large number of multiple-connection joints must be made.

Voltage Considerations

Standard mechanical or compression type terminators are recommended for all primary voltages provided the bus is uninsulated. Welded terminators may also be used for circular-mil-sized conductors. Up to 600 volts, standard terminator designs present no problem for insulated or uninsulated conductors. The standard compression type terminators are recommended for use on insulated conductors up to 2.5 kV. Above 2.5 kV, corona considerations make it desirable to use tapered-end compression terminators. Stress relief cones at terminations, made up in the manner described early in this chapter, should be applied in the case of shielded conductor cables.

In terminating a high-voltage cable or in making a cable termination in the presence of adverse atmospheric conditions or objectionable contaminents a pothead is commonly used. A pothead consists of a pot for holding insulating compound inside of which the actual cable terminations and connections are made. The cable, if lead sheathed, will have its sheath wiped to a sleeve provided on the pot for that purpose. Otherwise, a compression fitting will be supplied to clamp the cable sheath, or a fitting may be provided to terminate the conduit containing the cable. One or more porcelain tubes are attached to the pot for the outlets to overhead lines. After the joints are made the pothead is assembled and filled with hot insulating compound, the objective being to seal out all moisture from the joints and cable insulation. Potheads are frequently of the disconnecting type for ease of maintenance or operation.

Terminators for Aluminum

General

Aluminum conductors are different from copper conductors in several ways, and these differences should be considered in specifying and using terminators for aluminum conductors. The normal oxide coating on aluminum is of relatively high resistance. Aluminum has a coefficient of thermal expansion higher than that of copper. The ultimate and yield strength properties and the resistance to creep of aluminum are different than corresponding properties of copper. Because with several electrolytes, aluminum is anodic to other commonly used metals, corrosion is possible under some conditions.

Mechanical Properties and Resistance to Creep

The ultimate and yield strengths of electric-conductor grade aluminum are somewhat less than those of copper, and so aluminum of that grade can be plastically deformed somewhat more readily than copper.

Creep has been defined as the phenomenon of continued deformation of a material under stress. For equal unit bearing loads, the resistance to creep of electric-conductor grade aluminum is somewhat less than that of copper. The effect of excessive creep, resulting from the use of an inadequate terminator, could be a relaxation of contact pressure within the terminator and resulting deterioration of the electric connection.

The provision of adequate contact areas, in mechanical terminators for aluminum cable, can limit unit bearing loads to reasonable values, with resulting minimum plastic deformation and creep. Similarly, maximum unit bearing loads can be limited by the use of a terminator which fits only a specific size of conductor or a narrow range, rather than a wide range, of sizes. Such a terminator also provides lower contact resistance because of greater contact area. The effect of creep can be minimized by the provision of "spring follow" in the design of the terminator.

It has been found that connections to aluminum cables with semiannealed strands are less subject to possible trouble due to creep of the conductor than connections to similar conductors with hard-drawn strands.

Oxide Film

The surface oxide film on aluminum, though very thin and quite brittle, has a relatively high electrical resistance and therefore must be removed or penetrated to assure a satisfactory electric joint. This film can be substantially removed by coating the aluminum surface with a suitable joint compound and abrading with a wire brush, steel wool, or emery cloth, or similar abrasive tool or material, with the compound in place. The wiping action during installation of compression fittings satisfactorily removes the film on new conductors without additional cleaning. Weathered surfaces should be cleaned by abrasion. Some fittings are factory-filled with a compound, which is beneficial.

Some compounds contain metallic particles which aid in obtaining low contact resistance. Other compounds remove the oxide film by chemical action. All effective compounds act to seal connections against oxidation and corrosion by preventing air and moisture from reaching contact surfaces. Where it is obvious that the surfaces to be joined should be further cleaned after rough cleaning by wire brushing, final removal of oxide should be done by abrading through the joint compound.

Thermal Expansion

The linear coefficient of thermal expansion of aluminum is greater than that of copper. This consideration is important in the application of terminators on aluminum conductors. The use of metal with coefficients of expansion less than of aluminum can result in high stresses in the aluminum conductor during heat cycles. These stresses can cause additional plastic deformation and significant creep. Stresses can be quite high because the terminator may operate at an appreciably lower temperature than the conductor. To minimize the effects of differences of coefficients of expansion, it is necessary that aluminum terminators be used on aluminum conductors.

Corrosion

Galvanic corrosion can occur between dissimilar metals in the presence of an electrolyte. Aluminum is anodic to copper and several other metals in the presence of several types of electrolyte. Under these conditions, aluminum can corrode sacrificially to protect the copper or certain other metals.

Galvanic corrosion can be minimized by the proper use of a joint compound to keep moisture away from points of contact between dissimilar metals. The use of relatively large anodic areas and masses can be used to minimize the effects of galvanic corrosion. Although not common practice, a properly designed aluminum terminator can be satisfactorily used directly on copper under many exposure conditions, though care should be taken in the adequate use of a joint compound. Some users have had many years of satisfactory service with such connections. In a properly designed terminator for such service, the area and volume of the aluminum terminator, the anode, would be large compared to the copper conductor, the cathode.

Soldered copper bushings in aluminum terminators have been used succesfully for many years for aluminum-to-copper connections. The soldered connection between the bushings and the terminators must be free of voids to minimize the possibility of corrosion of the soldered bonds. Bimetallic liners, consisting of copper on one side and aluminum on the other side, have been used for aluminum to copper connections. Plated terminators have been used, but care in selection of plating material and in obtaining a nonporous coating is essential.

Thorough use of joint compounds is recommended for all types of copper-to-aluminum, or aluminum-to-aluminum connections.

Types of Connections Recommended for Aluminum

Underwriters' Laboratories has listed terminators approved for use on aluminum. Such terminators have successfully withstood Underwriters' Laboratories performance tests. Both mechanical and compression type terminators are available. The most satisfactory terminators are specifically designed for aluminum conductors, to prevent any possible troubles from creep, corrosion, the presence of the oxide film, and the differences of coefficients of expansion of aluminum and other metals. Mechanical aluminum terminals are now available which perform satisfactorily on both copper and aluminum cables.

When aluminum terminals are connected to aluminum or copper pads, best results are obtained if both contact surfaces are abraded through a coating of joint compound. The use of aluminum alloy bolts for such connections is recommended. If steel bolts are used, Belleville spring washers are recommended to maintain constant pressure on the connections.

Welded Aluminum Terminals

For aluminum cables in the circular mil sizes, carrying heavy currents, excellent terminations can be made by welding special terminals to the cable. This is best done by means of the inert gas shielded metal arc method. The use of argon gas eliminates the need for any flux to be used in making the weld. The welded type terminal is smaller than a compression terminal because the barrel for holding the cable can be very short. It, therefore, has the advantage of requiring less room in junction or terminal boxes of equipment. The main advantage, however, is due to the reduction of resistance in the connection.

Each strand of the cable is bonded to the terminal resulting in a continuous metallic path for the current from every strand of the cable to the terminal. Welding terminals are cast from electric-conductor grade aluminum.

The tongues or pads of the welding type terminals, like the larger compression type, are drilled for two bolts on 1¾ inch centers to conform to the NEMA standards for terminals to be used on outdoor equipment.

Precautions for Terminating Aluminum Conductors

1. When cutting cable, avoid nicking the strands. Nicking makes the cable subject to easy breakage.
2. Contact surfaces should be cleaned. The abrasion of contact surfaces, preferably through a compound, is helpful even with new surfaces, and is essential with weathered surfaces.
3. Use only terminators specifically recommended by the manufacturer for use on aluminum conductors.
4. Always use a joint compound as recommended by the manufacturer. The oxide film penetrating or removing properties of some compounds aid in obtaining high initial conductivity. The corroson inhibiting and sealing properties of compounds help insure the maintenance of continued high conductivity and prevention of corrosion.
5. In making an aluminum-to-copper connection which is exposed to moisture, place the aluminum conductor above the copper. This prevents soluble copper salts from reaching the aluminum conductor, which could result in corrosion. If there is no exposure to moisture, the relative position of the two metals is not important.
6. When using insulated conductors outdoors, extend the conductor insulation or covering as close to the terminator as possible to minimize weathering of the joint. Outdoors, whenever possible, joints should be completely protected by tape or other effective means. If outdoor joints are to be covered or protected, the protection should completely exclude moisture, as the retention of moisture could lead to severe corrosion.

Busway

Busway, sometimes called bus duct, is an installation of conductors supported on insulators in an enclosure. Busway may be either totally enclosed (no perforations) or may be perforated to provide ventilation.

Busway is particularly advantageous where numerous taps are to be made of a semipermanent nature such as in production line manufacturing plants where changes in machine location are made. It is also used for high-current feeder runs.

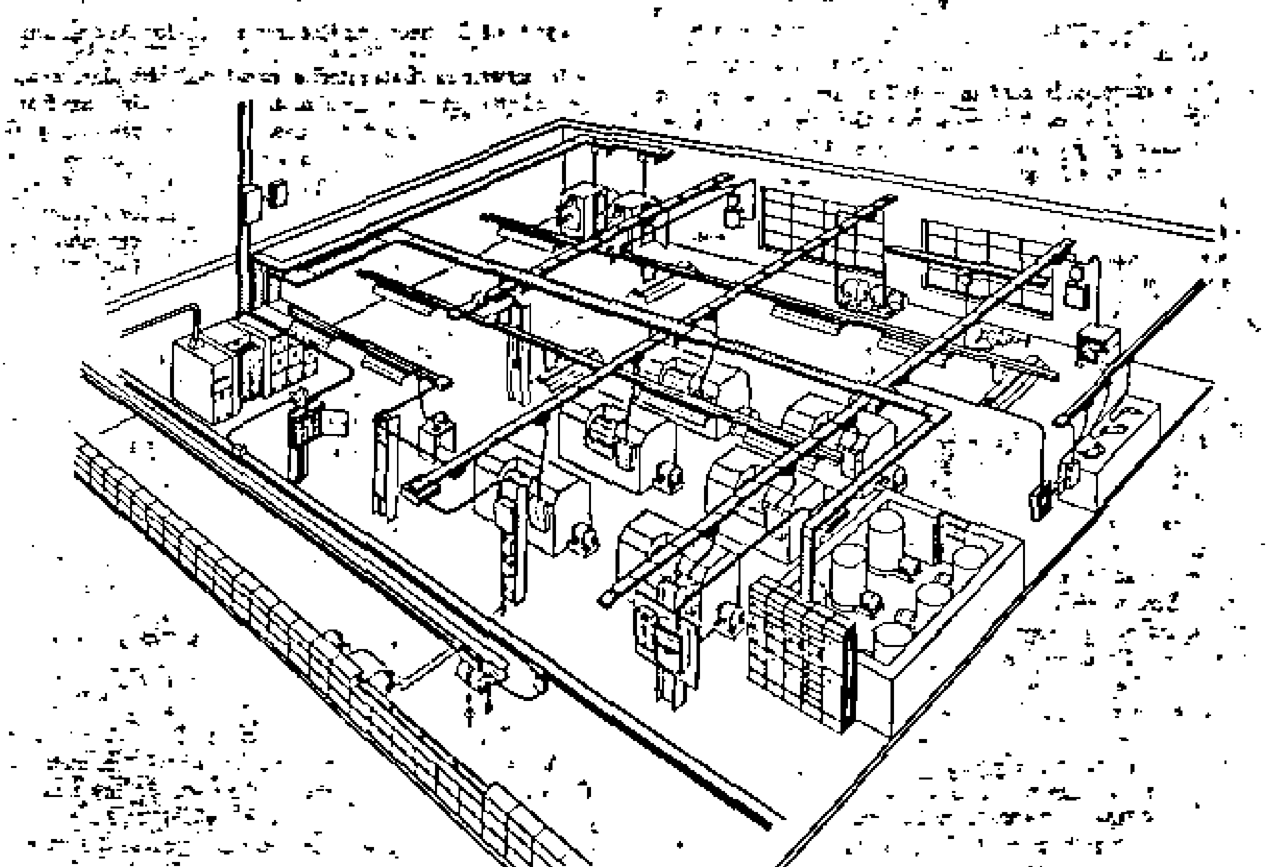

Figure 9.18
The Versatility of Busway is Illustrated in this Sketch Showing the Use of Feeder, Plug-in, and Trolley Types; and Application to Distributed Lighting Fixtures

Busway is usually made in ten-foot sections. The necessary accessories such as elbows, tees, crossovers, cable tap boxes, bus plugs, expansion joints, switchboard flange connections etc., are available to make a complete installation. Standard busway is manufactured in current ratings from 50 to 5000 amperes at 600 volts or less; and for single-phase as well as three-phase service. Neutral conductors can be included if required. Three types of busway are available, complete with fittings and accessories, providing a unified and continuous system of enclosed conductors. (1) Plug-in busway incorporates convenient outlets closely spaced along the run for easy connection of loads. (2) Feeder busway is intended for a direct low-impedance transmission channel between a point of supply and a delivery point. (3) Trolley busway provides mobile power "tap-offs" using moving (or stationary) plug-in devices for connection to electric hoists, cranes, high-speed portable tools, etc.

On many installations the busway system consists entirely of 400-ampere or 600-ampere plug-in busway. A variation of low-impedance busway is available with covered plug-in openings to receive busway plugs containing fused switches or molded-case circuit breakers. Both the plug-in type and the feeder type low-impedance busway is available with copper or aluminum bus bars and with totally enclosed or ventilated enclosures. The feeder type is available in both indoor and outdoor type. Other variations of busway are available in the form of multi-circuit busway, current-limiting busway, direct current busway, and high-frequency busway.

Plug-in Busway

The most common use of plug-in busway in industrial plants is an overhead system to supply readily available power to adjacent machine tools, and other electric equipment. See Figure 9.18.

A plug-in busway may be considered as an elongated switchboard or panelboard running throughout the area with the plug-in devices placed on the busway near the machines which they supply.

Covered openings are provided at regular intervals along each side of the busway to accommodate plug-in devices. These plug-in devices include switches, circuit breakers, static voltage protectors, ground indicators, or capacitor plugs. Figure 9.19 illustrates the construction.

Plug-in busway, as customarily used for industrial plant distribution, is manufactured with standard current ratings of 225, 400, 600, 800, and 1000 amperes. The plug-in variety of feeder busway is available in higher current ratings, of 1000, 1350, 1600, 2000, 2500, 3000, 4000, and 5000 amperes.

Figure 9.19
An Installation View of Medium-Current Plug-in Busway Showing Individual Short-Circuit-Protected Power Take-Off Cables

The maximum temperature rise to be expected in plug-in busway is about 55°C at the hottest point, and this decreases beyond each load tap-off. The voltage drop in plug-in and trolley busway ranges from 1 to 3 volts per 100 feet line-to-line for the typical distributed type of loading. If the entire load is concentrated at the end of the run, these values would be doubled. Refer to Chapter 2 for voltage-drop characteristics.

The bus bars in busway are subjected to electromagnetic forces of considerable magnitude during short circuit. The generated force per unit length of bus bar is directly proportional to the square of the short-circuit current and is inversely proportional to the spacing between bus bars. The natural frequencies of vibration of the bars and supports have pronounced effects on the stress magnitudes at the supports.

Some busway manufacturers have conducted short-circuit tests in order to assign short-circuit current ratings to their various busway designs. In general, these ratings range from 15,000 to 100,000 amperes average rms asymmetrical.

In application, the required short-circuit rating should be determined by calculating the available value of short-circuit current at the point where the input end of the busway is to be connected. Since this is generally the same point where the protective device is located, only one short-circuit calculation is necessary to determine the required short-circuit rating of the protective device and the busway.

Since busway is braced for maximum short-circuit currents, busway ratings are given in average rms asymmetrical amperes. It is, therefore, necessary to know the X/R ratio of the system to the point of fault in order to determine the required bracing requirements of the busway. Busway bracing is tested on a system with an X/R ratio of not less than 6.6 (NEMA Standard BU1-1955). This is the same X/R ratio that is used on test circuits for low-voltage power and molded-case circuit breakers. The corresponding asymmetry factor is 1.17 to obtain three-phase rms asymmetrical current. This multiplier may be used to obtain the three-phase rms asymmetrical current from the calculated value except in the following cases.

1. Where current-limiting reactors or busway is included in the system.
2. Where transformers of 1500 kVA or larger are connected in the system.
3. Where the system includes directly connected generators.

A typical short-circuit rating for 600-ampere plug-in type busway with bus supports at 24-inch intervals might be 25,000 amperes. Designs are available using more secure bus supports at closer intervals which carry assigned short-circuit ratings of 50,000 amperes. In the case of feeder type busway in current ratings of 3000 amperes or more, a short-circuit rating of 75,000 or 100,000 amperes is not uncommon and still higher short-circuit ratings can be secured if needed.

Feeder Busways

Modern designs of feeder busway utilize close phase-to-phase spacing of bus bars to provide low impedance. Figure 9.20 illustrates a low-impedance busway. In general, feeder busway is manufactured in a higher range of current ratings than plug-in busway. In contrast to plug-in busway, which is used usually to distribute electric power to a large number of small loads, feeder type busway is generally used to carry a relatively large current from one specific point to another.

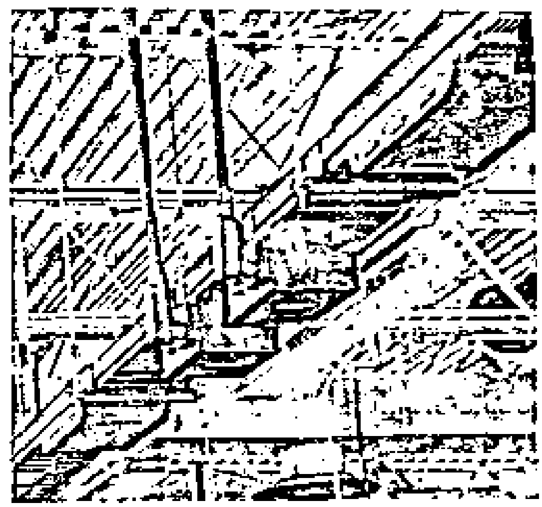

Figure 9.20
An Industrial-Plant Installation of Large Low-Impedance Busway of the Plug-In Type

The copper or aluminum cross-sectional area per phase conductor required in busways is based on a permissible hot-spot temperature rise of 55C. It varies with the type of construction, whether totally-enclosed or ventilated, and in some cases with the mounting position. A current density in copper bus bars greater than 1000 amperes per square inch is achieved in many of the ventilated busway designs and in the smaller rated totally enclosed plug-in busway. In the larger rated totally enclosed feeder busway, however, it is generally necessary to use a current density less than 1000 amperes per square inch. The use of the old simple "rule of thumb" of 1000 amperes of continuous rating per square inch of copper cross section would: (1) increase unnecessarily the size and cost of conductors in ventilated busway, and (2) result in undesirably high operating temperature in the large totally enclosed feeder type busway.

The voltage drop of low-impedance feeder busway at rated current loading (with the entire load at the end of the run) ranges from about 1 to 2.5 volts per 100 feet line-to-line in the totally enclosed type and slightly higher in the ventilated type.* Refer to Chapter 2 for detailed voltage drop information.

Current-Limiting Busway

Current-limiting busway is designed to have high reactance for feeder or service entrance applications. A short-circuit current of 200,000 symmetrical rms amperes available at the service entrance stubs of a 480Y/277-volt supply, for example, can be reduced to 100,000 amperes in a 45-foot run of 4000-ampere-rated current-limiting busway.*

The application of current-limiting busway must include a voltage drop calculation. In addition, consideration must be given to the total current available to the low-voltage circuit protective devices at the termination of the busway, i.e., the current through the busway plus the motor feedback current which is not limited by the busway that would be seen by feeder circuit protective devices.

High-Frequency Application

The increasing use of high-frequency power in industry has led to the development of very low-impedance busway systems with interleaved phase conductors for use at these higher frequencies. The use of standard 60-hertz conductor arrangements at higher frequencies may result in excessive voltage drop unless the ampere rating is reduced. Design of these systems is somewhat specialized and should be referred to the manufacturer.

Trolley Busway

Trolley busway is a special form of busway constructed so it can receive stationary or trolley type tap-off devices. It is particularly applicable on a moving production line where, for example, it is sometimes necessary to supply electric power to a motor or a portable tool moving with the production line; also where operators move back and forth over a range of ten to twenty feet, as they perform their specific operations.

Trolley busway is used for lighting distribution because it provides continuously available access to the electric supply conductors permitting any desired arrangement and rearrangement of lighting fixtures.

Trolley busway is available in several styles: first, a heavy-duty, three-phase busway, rated at 100 amperes, designed primarily for portable tools or other moving loads where it is necessary to supply power to the equipment while in motion; and second, light-duty busway with current ratings up to 50 amperes, designed primarily for lighting circuits, but also used for portable tools, etc.

The portable tools or other moving loads are connected by flexible cable to trolleys which move on rollers in the busway. These trolleys are provided with brushes or rollers which make electric contact with the bus bars. Trolleys are available either fused or unfused. Also, trolleys can be furnished with boxes containing circuit breakers or motor starters.

Trolley busway, as now being manufactured, operates at a very low temperature rise, generally below 30°C. The voltage drop is only about one or two volts per hundred feet at rated current, assuming a uniformly distributed load.

Selection and Application of Busway

The selection of busway for a given application has been shown to be simply a matter of selecting a busway that will carry the required amount of current and provide satisfactory voltage at the load. The nominal values of temperature rise and voltage drop given for plug-in and feeder busway are satisfactory for preliminary rough estimates or for calculations of installations where extreme accuracy is not required, or on installations where it is difficult to estimate the current and power factor of the loads. On an important installation where the current and load power factor can be determined, it is advisable to make a thorough study of the busway installation and use accurate formulas to determine the busway performance characteristics. This is especially important on low-voltage, high current busway.

The four major items that the plant engineer should consider in designing a busway distribution system are: continuous current-carrying capacity, voltage drop, short-circuit capacity, and energy losses.

Voltage Drop

The generalized treatment of voltage-drop problems and specific voltage-drop data of busway varieties will be found in Chapter 2 of this book.

The voltage drop in a section of plug-in busway, serving a group of individual loads distributed uniformly along the busway length, can be correctly evaluated by considering that the entire load group is fed from the center point of the busway length. The voltage drop so computed will be that which would be observed at the remote end of the run.

In busway runs of unsymmetrical spacing (flat spacing of phase conductors A, B, C) the busway voltage drop will contain an element of voltage unbalance. For long runs of the larger ampere loaded busway, the aggregate voltage unbalance may become large enough to be objectionable. Wherever desired, the unbalanced voltage drop can be eliminated by introducing two transpositions along the busway run. Each phase will then have occupied each possible physical bus bar position for an equal effective length of the run. The result is equal effective impedance in each phase. (The low-impedance type busway employs a repeating pattern of symmetrically distributed bus bars which makes it free of unbalanced voltage drop.)

Short-Circuit Stresses

The short-circuit current withstand capabilities of the various types of busway as reflected in their assigned short-circuit ratings have been touched upon in several places in the busway section.

It is significant to note that the ability to withstand a higher available short-circuit current can be obtained by more rugged construction and closer spacing of bus supports, but may also be obtained without a physical change in the busway by the introduction of a high-speed fault-current interrupter (i.e., current-limiting fuse) at the power-supply end of the busway.

The extent of short-circuit damage at a fault point within a run of busway can be greatly curbed by more quickly interrupting the flow of fault current (Refer to Chapter 3, Fault Protection).

Losses

The power loss in a busway comprises the resistance losses in the conductors and the eddy-current and hysteresis losses in the housing. However, when measurements of busway constants are made with the housing in place, the housing losses, if present, show up as apparent resistance losses in the bus bars.

The measured average resistance of the busway will, therefore, include not only the resistance of the conductors but, also, an additional apparent resistance due to induced losses in the housing. Busway manufacturers can supply loss data for their systems and this information should be obtained when an installation is being designed.

These losses are dependent on the frequency so that buses designed for 60-hertz service may not be suitable for use at higher frequencies without reducing the current-carrying capacity. Changes may also be necessary in the bus arrangement or housing material at higher frequencies.

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CHAPTER X

RELATIVE COST OF INDUSTRIAL DISTRIBUTION SYSTEMS

The electrical engineer in an industrial plant is confronted with the fact that electric power is not the product being sold. It is, instead, an item of cost, and the emphasis is always upon economics in the power system. The electric system must furnish safe, dependable power to the plant at a cost less than that of any other competitive methods or be replaced by that method. In the field of lighting electricity has won the economic battle with gas and oil. In communications electric forms have almost completely eliminated competing types. In the power field, however, there is considerable competition. Compressed air is widely used for many power applications in industrial plants, in direct competition with the electric system. Steam power is still very much in the picture, particularly in applications where large units of equipment are used. At the present time the gas turbine is developing rapidly as a power source for large centrifugal compressor drives.

For the majority of industrial plant power applications electricity is still the most economical and convenient form of energy that can be used. In order to meet the plant power requirements for the least investment in the electric system, an important stage in planning is the economic comparison of alternative system arrangements. It should be emphasized that system cost, while important, is but one of several factors which should be considered in planning the most suitable distribution system. Since the cost of the electric system will usually be less than 10 percent of the total plant investment it is important not to jeopardize maximum return on plant investment because of inadequate power distribution.

For the discussion in this chapter it is assumed that the load survey has been prepared for a new plant, or is known for a plant being modernized. The kva or kw load, the area, the location, and the utility services available to the plant should be known. The nature of the load, the size and location of the major loads, the degree of reliability required, the flexibility needed for changes, and the requirements for expansion should also be determined. After the load requirements are known there are a number of economic decisions that must be made in planning the distribution system. Among these are the following items, which are of varying importance depending upon the size and type of plant under consideration.

Power Supply

A second utility supply source, valuable from a reliability point of view, should be investigated to see if it is economically justifiable.

For the majority of plants it is seldom possible to justify power generation. Where the demand for steam is large or where the process produces steam or fuel as a by-product, the merits of local generation should be investigated.

Voltage Level

The selection of the distribution voltages is an important factor that must be considered. The voltage selection is governed by many factors such as available utility supply voltage, cost of equipment, size of transformers, size of motors, location and size of the various loads, interrupting-capacity requirements of the system, length of cable runs, voltage regulation, and the rating of standard equipment.

Reliability of the Distribution System

The selection of the type of distribution system in an industrial plant resolves itself into an economic consideration of the factors concerning the loss in production and revenue from outages caused by failure of the distribution system. In making the study the engineer should remember the distribution system is one element in the production chain and must be considered in its proper perspective in the total plant equipment. The possibility of outages in the primary power supply and of mechanical failure of the machine being operated from the electric system must also be considered. The cost of power failure must include loss of production, spoilage of material under process, cost of re-establishing production and possible damage to machinery and buildings.

The plant distribution system normally consists of switching and protective devices, transformers and conductors. The failure of the electric equipment can be from many causes, but the installation of adequate equipment and routine preventive maintenance can reduce the number of failures to a minimum.

Failure rates of electric equipment depend on how the equipment is operated. Some useful data is given in Reference 5 of Chapter I.

Economic Comparisons

The following data are presented solely for the purpose of making comparative system studies. Under no conditions must these data be used to obtain cost or appropriation figures, since market and product changes and other factors affect the final costs of the electric distribution system. These estimating data are sufficiently accurate for nearly all general system comparison economic studies. To obtain estimating or actual cost figures contact the manufacturers, or electrical contractors who have facilities to furnish accurate up-to-date cost figures.

In making economic comparisons it is important that the entire system be included, as each part of the system is economically related to the whole.

Installation Costs

The cost figures in this chapter cover equipment costs only and do not include installation except in Tables 10.9 and 10.10.

However, where no accurate information is available, the following figures may be used to obtain a reasonable approximation for installation for comparative purposes only. These figures do not include foundations and any special requirements.

Power Transformers

The installation of a three-phase transformer consisting of placing it on the foundations and making connections is approximately 7 percent to 15 percent of the cost of the transformer.

The installation of a bank of three single-phase transformers is approximately 15 percent to 25 percent of the cost of the transformers. If a separate structure is required to make the wye or delta connections this additional cost should be added.

Table 10.1

Incoming Line Structure

Comparative Cost Data for Equipment Only

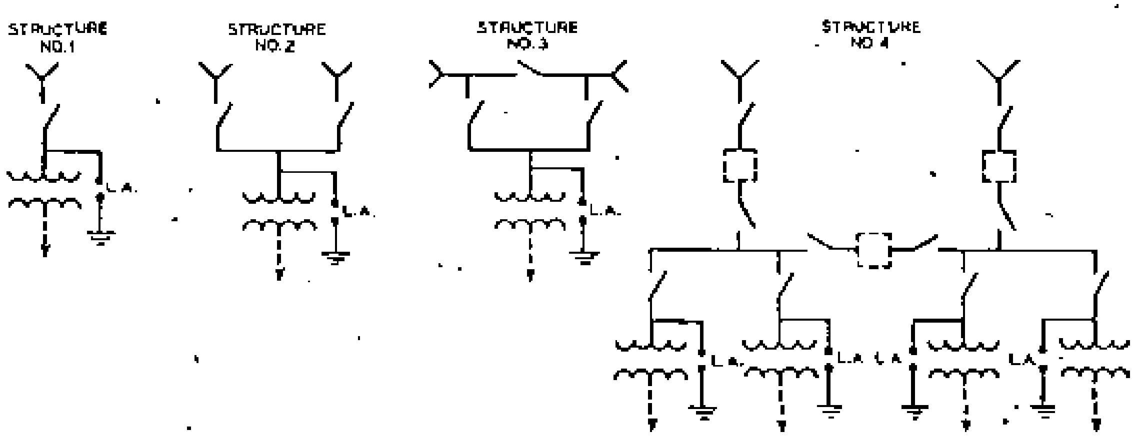
Structure No. 1 is a simple single-bay steel structure for one incoming line. Material consists of steel structure, one three-pole manually-operated disconnect switch, three lightning arresters, one set of insulators and copper connections.

Structure No. 2 is a simple two-bay steel structure for two incoming lines. Material consists of steel structure, two three-pole manually-operated disconnect switches, three lightning arresters, one set of insulators and copper connections.

Structure No. 3 is a four-bay steel structure for two feeders radial or loop circuit with manual sectionalization and manual selection for energizing the load. Material consists of steel structure, three three-pole manually-operated disconnect switches, three lightning arresters, and one set of insulators and copper connections.

Structure No. 4 is an eight-bay steel structure for two incoming radial feeders and for four outgoing feeders. Material consists of steel structure, ten three-pole manually-operated disconnect switches, twelve lightning arresters and one set of insulators and copper connections so that three breakers can be used, two for incoming lines and one for tie line. Price of breakers not included. Obtain price of breakers from Table 10.2 and add to above prices.

Schematic Diagram



Type of Structure	*13.8 kV*	*23 kV*	*34.5 kV*	*46 kV*	*69 kV*
No. 1	$ 4,000	$ 4,500	$ 6,000	$ 7,000	$ 8,000
No. 2	7,500	8,500	11,500	12,500	15,500
No. 3	9,500	12,000	13,500	16,500	20,000
No. 4	11,500	16,500	19,000	22,500	26,500

The above tabulation indicates only a few of the available types of outdoor structures and gives comparative prices only. *These are not to be used* to determine budget or appropriation costs. Costs do not include circuit breakers and transformers.

Factory Assembled Equipment

The installation of factory-assembled equipment such as medium-voltage metal-clad switchgear, low-voltage assembled switchgear, unit substations and load or power centers is approximately 15 percent of the cost of the equipment.

Cable

Estimating installed costs for cable are given in Tables 10.9 and 10.10. These costs can vary widely but are entirely suitable for making comparison studies.

Motors and Control

In general it should not be necessary to consider installation costs of motors, as the installation costs of high- and low-voltage motors are essentially the same.

Preparing Economic Comparisons

This chapter lists the comparative estimating costs of the major items of equipment used in industrial electric distribution systems. These cost figures are tabulated for individual equipment in order to make it more versatile, and make it more applicable to the various types of electric distribution systems.

The tables list typical ratings of equipment, and makes no attempt to cover all the standard or special ratings available in the various types of equipment listed. The prices listed in the tables are for equipment only.

A suggested method of procedure in preparing cost comparisons of various distribution systems is as follows:

(1) Outline the main points of the problem;

(2) Make single line diagrams of the systems being compared;

(3) Designate numbers to the various items to be compared;

(4) Make tabulation of the various items checking the capability of each item;

(In the early stages it is often necessary to make estimates of the loads and the item required.) The information in other chapters of this book will assist the engineer in making reasonable assumptions.

(5) Tabulate the cost figures from this chapter;

(6) These are estimating figures to be used in comparison calculations only. If estimating figures for the entire distribution system are required additional costs must be added to cover engineering and drafting costs, overhead, contingencies, and local conditions. The amount to be added may range from 20 percent to 60 percent. If accurate prices are required consult manufacturers, consulting engineers, or contractors.

Table 10.2

High-Voltage Outdoor Oil Circuit Breakers

Comparative Cost Data for Equipment Only

Comparative cost covers one 3-pole, 60-hertz outdoor oil circuit breaker. Control switch, protective relays, or power supply for breaker operation is not included.

kV Rating of Breaker	*Ampere Rating of Breaker*	*3-phase Interrupting Rating MVA*	*Amperes Momentary Rating*	*Amperes Interrupting Current at Rated kV*	*Amperes Interrupting Rating Current Limitation*	*Cost Dollars*
14.4	600	250	40,000	10,000	25,000	4,000
14.4	1,200	500	40,000	20,000	25,000	4,500
14.4	1,200	1,000	77,000	40,000	48,000	10,500
14.4	3,000	1,500	115,000	60,000	72,000	21,000
14.4	4,000	1,500	115,000	60,000	72,000	25,000
23	600	500	38,000	12,600	24,000	5,500
23	1,200	500	38,000	12,600	24,000	10,500
34.5	1,200	1,500	61,000	25,000	38,000	10,500
34.5	2,000	2,500	96,000	42,000	60,000	20,500
34.5	3,000	2,500	96,000	42,000	60,000	23,000
46	1,200	1,500	35,000	19,000	22,000	12,000
69	1,200	2,500	38,000	21,000	24,000	14,500
69	1,200	3,500	49,000	29,000	31,000	15,000
69	2,000	5,000	70,000	42,000	44,000	28,000

Table 10.3

Medium-Voltage Indoor Metal-Enclosed Interrupter Switchgear

Comparative Cost Data for Equipment Only

Comparative cost covers indoor free-standing metal-enclosed switchgear assembly complete with interrupter switch (either unfused or with non-current-limiting fuses with renewable elements as indicated), three-phase bus and interconnections, ground bus, observation windows, and door interlock. The interrupting ratings may vary from manufacturer to manufacturer of fuses.

Rated kV	System kV	Unfused			Fuses Rated 200E Max. Amperes Interrupting Rating Three-Phase Symmetrical		Fuses Rated 400E Max. Amperes Interrupting Rating Three-Phase Symmetrical	
		Continuous Amperes	Momentary Amperes	Cost	MVA	Cost	MVA	Cost
4.16	2.4	600	40 kA	$1500	70	$2000	155	$2200
4.16	4.16	600	40 kA	1500	125	2000	270	2200
4.8	4.8	600	40 kA	1600	145	2200	225	2400
7.2	7.2	600	40 kA	1700	195	2200	325	2400
13.8	12	600	40 kA	1700	260	2300	520	2500
13.8	13.2	600	40 kA	1700	285	2300	570	2500
14.4	14.4	600	40 kA	2000	310	2600	620	2900

For outdoor equipment, including necessary construction features, finish, gasketing, space heaters, etc., add $125 per unit.

For automatic operator, add $1700.00 per unit.

For "emergency-preferred" automatic transfer panel to control two automatic operators, add $960 plus cost, installed, of potential transformers required for voltage sensing as follows:

System kV	Single-Phase Sensing	Three-Phase Sensing
4.8 and below	$550	$1200
7.2	600	1450
13.8	750	2100
14.4	750	2100

Table 10.4

Power Fuses

Comparative Cost Data for Equipment Only

Comparative cost covers three fuses including mounting details, supports and copper connections to be mounted on structures listed in Table 10.1. Interrupting ratings may vary from manufacturer to manufacturer of fuses.

Voltage kV	Max. Ampere Rating	Type	Int. Rating MVA	Cost
13.8	200E	Non-Dropout	300	$ 450
	400E	Non-Dropout	600	700
23.0	200E	Non-Dropout	375	500
	300E	Non-Dropout	750	750
34.5	200E	Non-Dropout	375	600
	300E	Non-Dropout	1000	900
	100E	Dropout	400	450
	200E	Dropout	1000	750
	300E	Dropout	2000	1000
69	100E	Dropout	400	700
	200E	Dropout	1000	1100
	300E	Dropout	2000	1400

Table 10.5

Power Transformer

Comparative Cost Data for Standardized Design Equipment Only

Comparative cost covers an outdoor oil-insulated self-cooled, three-phase, 60 hertz, 55°C rise transformer with low voltage of 2400, 4160 or 13,800 volts, with high- and low-voltage bushings, and necessary insulating oil.

Without Load Tap Changing
Nominal High-Voltage Rating

kVA	*13.8 kV*	*23 kV*	*34.5 kV*	*46 kV*	*69 kV*
1,000	$ 9,000	$10,000	$11,000	$ —	$ —
1,500	10,500	11,500	12,500	15,500	18,500
2,000	13,000	13,000	14,000	17,000	20,000
2,500	14,000	15,000	15,500	19,000	22,000
3,750	18,000	19,000	19,500	22,500	26,000
5,000	22,000	23,000	23,500	26,500	30,000
7,500	30,500	31,000	31,500	34,500	38,000
10,000	—	39,000	40,500	42,500	46,000

With ± 10 Percent Load Tap Changing
Nominal High-Voltage Rating

kVA	*13.8 kV*	*23 kV*	*34.5 kV*	*46 kV*	*69 kV*
1,000	$21,000	$22,000	$23,000	$ —	$ —
1,500	22,500	24,000	25,000	28,000	32,000
2,000	24,000	26,000	27,000	30,500	34,000
2,500	26,000	28,500	29,000	33,000	36,500
3,750	31,500	34,500	35,000	39,000	43,000
5,000	37,000	41,000	42,000	46,000	50,000
7,500	47,500	51,500	52,000	56,000	61,500
10,000	—	60,000	61,000	65,500	71,000

Addition for Forced Air Cooling

kVA	*Cost*
1,000	$1,100
1,500	1,100
2,000	1,100
2,500	1,200
3,750	1,200
5,000	1,350
7,500	1,600
10,000	2,000

Table 10.6

Indoor Air Metal-Clad Switchgear

kV Rating of Breaker	*Maximum Breaker Current Rating Amperes*	*Breaker Interrupting Capacity Rating MVA*	*Breaker Momentary Current Rating*	*Breaker Interrupting Capacity Maximum Amperes*	*Feeder Unit*	*Induction Motor Full-Voltage Starter*	*Induction Motor Reactor Starter*	*Synchronous Motor Full-Voltage Starter*	*Synchronous Motor Reactor Starter*
1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*
2.4/4.16	1200	50/75	20,000	12,500	$ 4,900	$ 6,000	$10,400	$ 9,800	$14,200
2.4/4.16	1200	150/250	60,000	37,500	6,100	7,100	12,700	11,000	16,600
2.4/4.16	2000	150/250	60,000	37,500	7,900	8,900	14,600	12,800	18,500
4.16	1200	350	80,000	50,000	8,400	9,500	17,300	13,600	21,500
4.16	3000	350	80,000	50,000	15,000	16,000	24,000	20,100	28,000
7.2	1200	500	70,000	44,000	8,300	9,700	17,600	13,600	21,500
7.2	2000	500	70,000	44,000	9,900	11,200	19,100	15,100	23,000
13.8	1200	500	40,000	25,000	8,000	9,800	17,300	13,600	21,200
13.8	2000	500	40,000	25,000	9,600	11,400	19,000	15,200	22,800
13.8	1200	750	60,000	37,500	10,700	12,500	22,600	16,400	26,500
13.8	2000	750	60,000	37,500	13,800	15,600	25,700	19,500	29,600
13.8	1200	1000	80,000	50,000	14,700	16,600	31,000	21,000	35,000
13.8	3000	1000	80,000	50,000	22,600	24,500	39,000	28,900	42,900

For outdoor sheltered-aisle equipment add $1600 per unit.

Control power source required for each installation not included.

Two potential transformers for motor or incoming line add 4 kV $1400. 7.2 or 13.8 kV $1800.

Motor differential and current balance relays with (6) current transformers add $3200.

Enclosed starting reactors *not* included above—Estimate from Table 10.6.1.

Comparative Cost Data or Equipment Only

Column 6: Feeder Unit consists of a metal-clad metal-enclosed structure in which is mounted a removable breaker element with electric operating mechanism for 125 volts direct current close and trip, complete with bus and connections, three current transformers, cable termination facilities, one ammeter and transfer switch, one circuit breaker control switch with two indicating lamps, and three overcurrent relays.

Column 7: Induction Motor Full-Voltage Starter consists of a metal-clad metal-enclosed structure in which is mounted a removable breaker element with electric operating mechanism for 125 volts direct current. Close and trip, complete with bus and connections, three current transformers, cable termination facilities, one set of surge capacitors three-phase for mounting at motor terminals by the purchaser, one ammeter, one motor control switch with two indicating lamps, one undervoltage relay, two thermal overload relays, and three overcurrent relays. Potential transformers not included.

Column 8: Induction Motor Reactor Starter consists of an induction motor full-voltage starter, a reactor breaker unit, plus necessary relays. Estimate enclosed starting reactor from Table 10.6.1.

Column 9: Synchronous Motor Full-Voltage Starter is a duplicate of an induction motor full-voltage starter plus one field ammeter with shunt, one varmeter, mounting for manually operated exciter field rheostat, one complement of devices to provide field application and field protection, and one field discharge resistor.

Column 10: Synchronous Motor Reactor Starter consists of a synchronous motor full-voltage starter, a reactor breaker unit, plus necessary transfer relays. Estimate enclosed starting reactor from Table 10.6.1.

Outdoor: Outdoor equipment consists of necessary changes in enclosure to make unit suitable for use outdoors and including sheltered aisle for maintenance.

For definition of metal-clad switchgear, see Chapter II.

Table 10.6.1

Metal Enclosed Starting Reactor Units

Price Additives

HP	2.4 kV	4.16 kV	7.2 kV	13.8 kV
500	$ 3,100	$ 3,600	$ 4,200	$ —
1,000	3,800	5,000	5,500	6,000
1,500	4,700	6,100	6,600	7,400
2,000	5,700	7,000	7,600	8,600
2,500	6,300	8,000	8,600	9,700
3,000	7,000	8,800	9,500	10,800
3,500	7,600	9,500	10,100	11,700
4,000		10,200	11,000	12,700
4,500		10,800	11,600	13,400
5,000		11,400	12,500	14,400
5,500		11,700	12,600	15,200
6,000		12,000	13,800	15,900
7,000			16,200	21,200
8,000			17,500	22,900
9,000			19,000	25,200
10,000			20,200	26,900

Table 10.7

Secondary Unit Substation Transformers

Comparative Cost Data for Equipment Only

Comparative cost covers a secondary unit substation transformer three-phase 60-hertz with voltages as shown. Transformers are standardized design with primary cable air filled terminal chamber and provision for direct connection to switchgear housing. All bushings are side wall mounted.

Transformers are equal cost askarel filled 65°C rise or ventilated dry 150°C rise indoor design.

	2,400 or 4,160			7,200 or 13,800		
kVA	to 208Y/120	240	480 480Y/277	to 208Y/120	240	480 480Y/277
112.5	$ 4,800	$ 4,600	$ 4,000	—	—	$ 5,600
150	4,800	4,600	4,000	—	—	5,600
225	4,800	4,600	4,000	—	—	5,600
300	5,300	5,200	5,000	$ 6,500	$ 6,300	6,100
500	7,000	6,800	6,500	7,900	7,600	7,300
750	9,300	9,000	8,700	9,900	9,200	8,800
1,000	11,500	10,400	10,100	11,400	10,400	10,100
1,500	—	—	13,100	—	—	13,100
2,000	—	—	16,000	—	—	16,000
2,500	—	—	18,900	—	—	18,900

For outdoor oil transformer use multiply by 0.80.

For 55°C rise liquid use 1.05 x price of transformer.

Table 10.8

Comparative Cost Data for Secondary Substation Switchgear for Use with Transformers—Table 10.7

Switchgear is three-phase 60-hertz four-wire indoor with individually mounted breakers manual operation except 3000-4000 amperes are electrically operated—control source not included.

Transformer & Main Bus Amperes		*Molded Case Rear Accessible Breaker*	*Metal Frame Drawout Breaker*
225	$ 600	$ 325	$ 900
600	700	950	1,000
1,600	800	2,800	2,200
2,000	1,000	2,900	6,400
2,500	1,150	4,600	
3,000	1,600	—	6,400
4,000	2,200	—	9,600

See Table 7.10 for transformer full-load current—selective—fully rated and cascaded application of breakers.

Table 10.9

Relative Cost of 15 kV and 5kV Cables Installed in Rigid Steel Conduit

Comparative Cost per 100 Ampere Feet

Comparative cost covers one three-conductor or three single-conductor cables in steel conduit and direct labor for installation including splicing and termination.

Many other types of cable and methods of installation are available. Many of these can be installed at a lower total cost than shown in the following table.

Cost of terminators not included.

Rated current on basis of 40°C ambient per IPCEA.

Cable Size AWG or MCM	*Rated Current Amperes*	*15 kV Type VCL One Three-Conductor in Conduit $/100 Ampere Feet*	*Rated Current Amperes*	*RHW Type Rubber Three Single Conductors in Conduit $/100 Ampere Feet*
6	60	18.30	—	—
4	79	17.60	—	—
2	101	14.70	118	14.00
1	115	13.20	136	12.00
1/0	129	15.30	155	11.50
2/0	147	13.90	180	10.40
3/0	167	12.60	207	10.10
4/0	190	11.50	238	9.30
250	210	10.70	264	8.90
350	252	10.60	320	8.80
500	300	9.40	386	8.30

Ungrounded Non-shielded

Cable Size AWG or MCM	*Rated Current Amperes*	*5 kV Type VCL One Three-Conductor in Conduit $/100 Ampere Feet*	*Rated Current Amperes*	*RHW Type Rubber Three Single Conductors in Conduit $/100 Ampere Feet*
6	58	9.80	72	8.00
4	76	8.20	95	6.70
2	102	7.60	124	5.60
1	118	7.00	142	6.10
1/0	134	7.30	162	5.80
2/0	154	6.70	184	5.50
3/0	175	6.40	208	5.70
4/0	199	6.60	237	5.40
250	218	6.40	262	5.40
350	264	6.40	321	5.30
500	325	6.80	394	6.40

Table 10.10

Relative Cost of Three-Conductor 600-Volt Cables Installed in Rigid Conduit

Comparative Cost per 100 Ampere Feet

Comparative cost covers aluminum or copper conductors in aluminum or steel rigid conduits and direct labor for installation including splicing and termination.

Many other types of cable and methods of installation are available. Many of these can be installed at a lower total cost than shown in the following table.

Cost of terminators not included.

Rated current or basis 30°C ambient.

Cable Size AWG or MCM	*Rated Current Amperes*	*Aluminum Type RHW Rubber Three Single Conductors in Steel Conduit*	*Aluminum Type RHW Rubber Three Single Conductors in Aluminum Conduit*	*Rated Current Amperes*	*Copper Type RHW Rubber Three Single Conductors in Steel Conduit*	*Copper Type RHW Rubber Three Single Conductors in Aluminum Conduit*
6	50	$4.3	$3.9	65	$3.7	$3.4
4	65	3.8	3.4	85	3.4	3.0
2	90	3.1	2.8	115	3.0	2.6
1	100	3.1	2.8	130	3.0	2.8
1/0	120	3.5	2.9	150	3.4	3.0
2/0	135	3.2	2.8	175	3.2	2.8
3/0	155	3.1	2.6	200	3.1	2.7
4/0	180	3.5	3.0	230	3.5	3.1
250	205	3.3	2.8	255	3.5	3.2
350	250	3.5	3.0	310	3.6	3.3
500	310	3.1	2.7	380	3.5	3.2
700	375	3.8	3.2	—	—	—

NOTE: All figures include material cost of conduit fittings, and cable (except terminators), labor cost to install conduit, cable and terminations, as well as job expenses including taxes, insurance, supervision, handling of material, expendable tools, etc. plus normal overhead and profit (material costs based on present market).

Table 10.11

Large Squirrel-Cage Induction Motors

Comparative Cost Data for Equipment Only

Comparative cost covers a two-bearing, open type motor, 2300 volts, 3-phase, 60 hertz, for coupled service with standard torques. No special features included. 1.0 service factor.

HP	*1800 r/min*	*600 r/min*	*300 r/min*
100	$ 1,624	$ 3,530	$ 7,440
125	1,852	4,040	8,345
150	2,123	4,653	9,282
200	2,570	5,695	10,847
250	3,194	6,482	12,449
300	3,746	7,505	14,187
400	4,870	9,398	17,246
500	5,975	11,136	20,306
700	7,966	14,637	25,225
1,000	11,320	20,150	33,381
2,000	22,759	37,257	57,037
3,000	34,138	53,932	80,107
5,000	56,897	87,358	125,177
10,000	113,794	170,922	229,486

Price Additions Above 2300 Volts

HP	*4000 Volt*	*6600 Volt*	*13,200 Volt*
100	40%	—	—
125	25%	—	—
150	25%	—	—
200	25%	—	—
250-500	16%	56%	+
501-1000	16%	52%	+
2,000	12%	42%	62%
3,000	6%	34%	52%
5,000	6%	34%	52%
10,000	No Increase	28%	40%

+ Available but seldom used.

Table 10.12

Full-Voltage Starters for Large Induction Motors

Comparative Cost Data for Equipment Only

Comparative cost covers full-voltage starter for large induction motors consisting of a high-voltage air contactor, high-voltage fuses and necessary protective relays mounted in a steel enclosure.

These starters are limited to the horsepower sizes and voltages listed.

The interrupting capacity is 150 MVA at 2400 volts, and 250 MVA at 4160 volts.

For larger horsepower rating, higher-voltage rating, and higher interrupting rating of motor starters use metal-clad switchgear listed in Table 10.6.

HP	*2400 Volt*	*4160 Volt*
50-700	$5,600	—
701-1000	6,150	—
1001-1500	6,160	—
50-1250	—	$5,600
1251-2500	—	6,150

Table 10.13

Small Squirrel-Cage Induction Motors

Comparative Cost Data for Equipment Only

Comparative cost covers two-bearing, open-type, 1.15 SF squirrel-cage induction motors, 220 or 230 and 440 or 460 volts, three-phase 60 hertz, for coupled service with standard torques. No special features included.

HP	*1800 r/min*	*900 r/min*
5	$ 84.50	$ 199
10	128	300
15	180	394
20	220	475
25	262	563
40	397	790
50	463	942
60	540	1,092
75	651	1,308
100	850	1,654
125	1,027	2,842*
150	1,484	3,626*
200	1,910	4,597*
250	2,730*	5,414*
300	3,345**	6,196**
400	4,552**	6,943**

* For 220 or 230 volt, add 5%

** For 220 or 230 volt, add 10%

Table 10.14

Full-Voltage Starters for Small Induction Motors

Comparative Cost Data for Equipment Only

Comparative cost covers low-voltage alternating-current magnetic full-voltage combination motor starters with circuit breakers in NEMA Type 1 enclosures for induction motors.

HP	*NEMA Size*	*230 Volt*	*460 Volt*
7.5	1	$ 106	$ 135
10	1	—	135
15	2	161	190
25	2	—	190
30	3	275	275
50	3	—	275
50	4	600	—
100	4	—	600
100	5	1,349	—
200	5	—	1,467
200	6	2,941	—
400	6	—	2,941

Table 10.15

Synchronous Motors

Comparative Cost Data or Equipment Only

Compaartive cost covers open-type two-bearing, 2300-volt, three-phase, 60-hertz, 100 percent power factor with the following torques:

Motor Rating	Start	Torque Pullin	Pullout
250-1000 1800-600 r/min	60	60	150
1250-10,000 hp 1800-600 r/min	40	60	150
250-10,000 hp 300 r/min	40	30	150

Cost of exciter is not included.

HP	1800 r/min	1200 r/min	600 r/min	300 r/min
250	$	$ 4,900	$ 6,337	$ 10,554
300		5,600	6,842	11,513
400		7,200	8,295	13,203
500	9,155	8,144	9,695	14,968
700	12,205	10,736	12,516	18,653
1,000	17,217	14,303	16,687	23,904
2,000	34,432	25,267	29,560	39,255
3,000	51,647	34,802	41,718	53,621
5,000	86,079	52,443	64,362	79,499
10,000		99,325	120,777	144,743

For voltages above 2300 volts add as follows:

HP	4000 Volt	6600 Volt	13,200 Volt
250-400	10%	*	*
450-1,000	7½%	*	
700-1,000	—	37%	*
2,000	5%	27%	65%
3,000	5%	24%	55%
5,000	No increase	22%	45%
10,000	" "	17.5%	32%

* Available but seldom used.

Table 10.16

Full-Voltage Starters for Large 1.0 PF Synchronous Motors

Comparative Cost Data for Equipment Only

Comparative cost covers full-voltage starter for synchronous motors consisting of a high-voltage air contactor, high-voltage fuses, field application relay, field contactor and necessary protective relays mounted in a steel enclosure. These starters are limited to the horsepower sizes and voltages listed. The interrupting capacity is 150 MVA at 2300 volts, and 250 MVA at 4160 volts.

For larger horsepower rating, higher-voltage rating and higher interrupting rating use metal-clad switchgear listed in Table 10.6.

HP	2300 Volts	4160 Volts
50-250	$6,500	—
251-900	6,500	—
901-1250	8,550	—
1251-1500	8,650	—
1501-1750	8,650	—
50-250	—	$7,150
251-1500	—	7,350
1501-1750	—	8,650
1751-3000	—	8,750

Example of the Use of Comparative Cost Figures

Assume a plant being located where 34.5 kV power is available from the utility and the estimated initial load is 6500 kVA with a possible growth to 8,500 kVA.

The present load consists of the following:

1—2500-hp 600 r/min synchronous motor

1— 500-hp 1200-r/min synchronous motor

1— 300-hp 1800-r/min induction motor

4—1000 kVA secondary unit substations. Each having load of:

800 hp of 460-volt motors including diversity and 200 kVA of lighting low voltage 480Y/277.

Incoming line requires a breaker having 1,000 MVA interrupting capacity (value obtained from utility) outdoor steel structure with a single incoming line.

Large motors are located from the main distribution switchgear as follows:

2500-hp motor 200 feet

500-hp motor 300 feet

300-hp motor 200 feet

4—1000 kVA secondary unit substations, each an average of 1000 feet from the main substation and from each other.

Problem:—

The following problem is presented to illustrate the use of the tables in this chapter. Other chapters of this publication contain information to determine type of distribution system, type and size of equipment, voltage of the system and other factors that most adequately meet the requirements of a particular plant.

Single-Line Diagrams:

The single-line diagrams for the two systems are as follows:

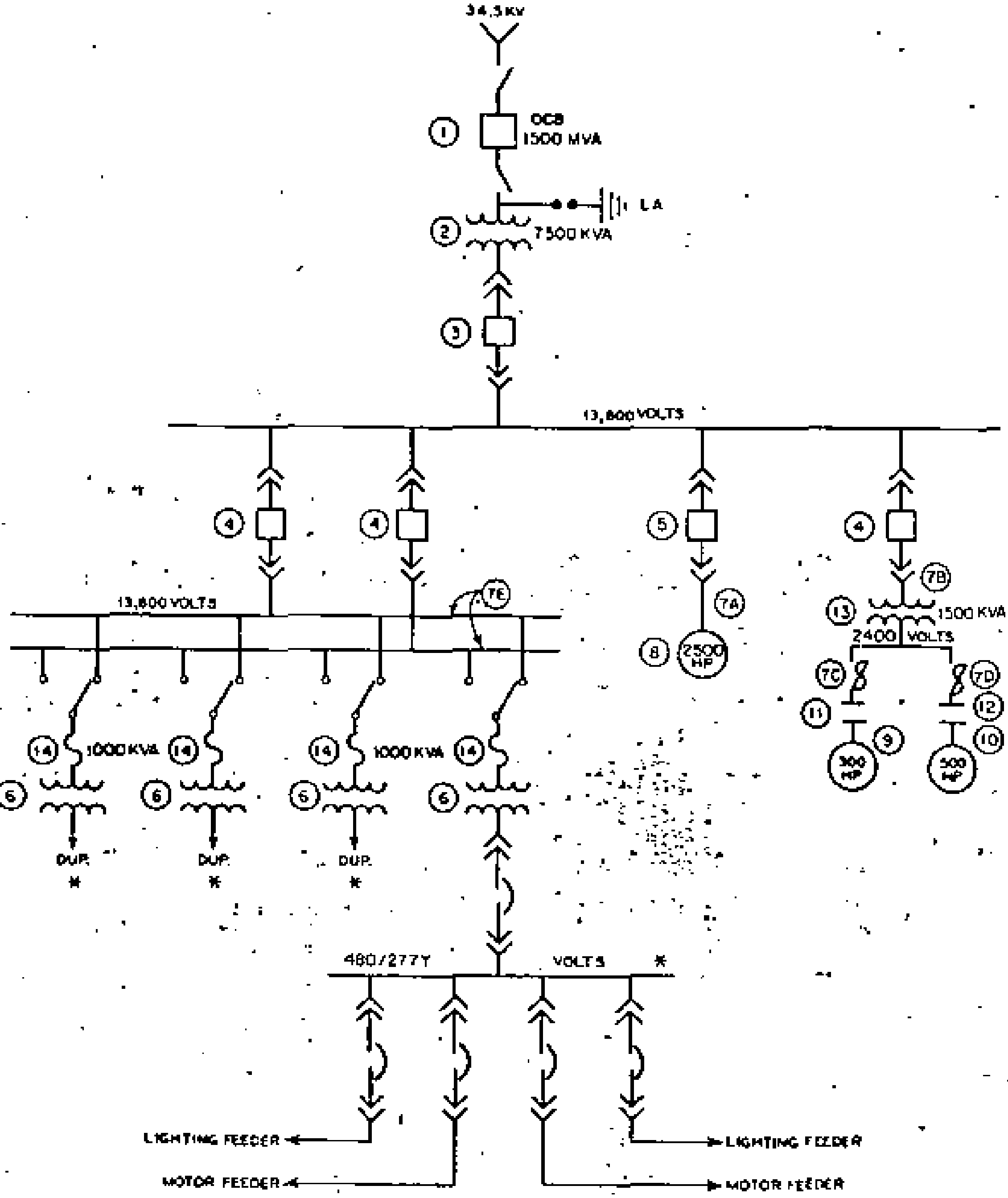


Figure 10.1
Single-Line Diagram for 13.8 kV

* 480Y/277 Equipment Not Considered in Problem

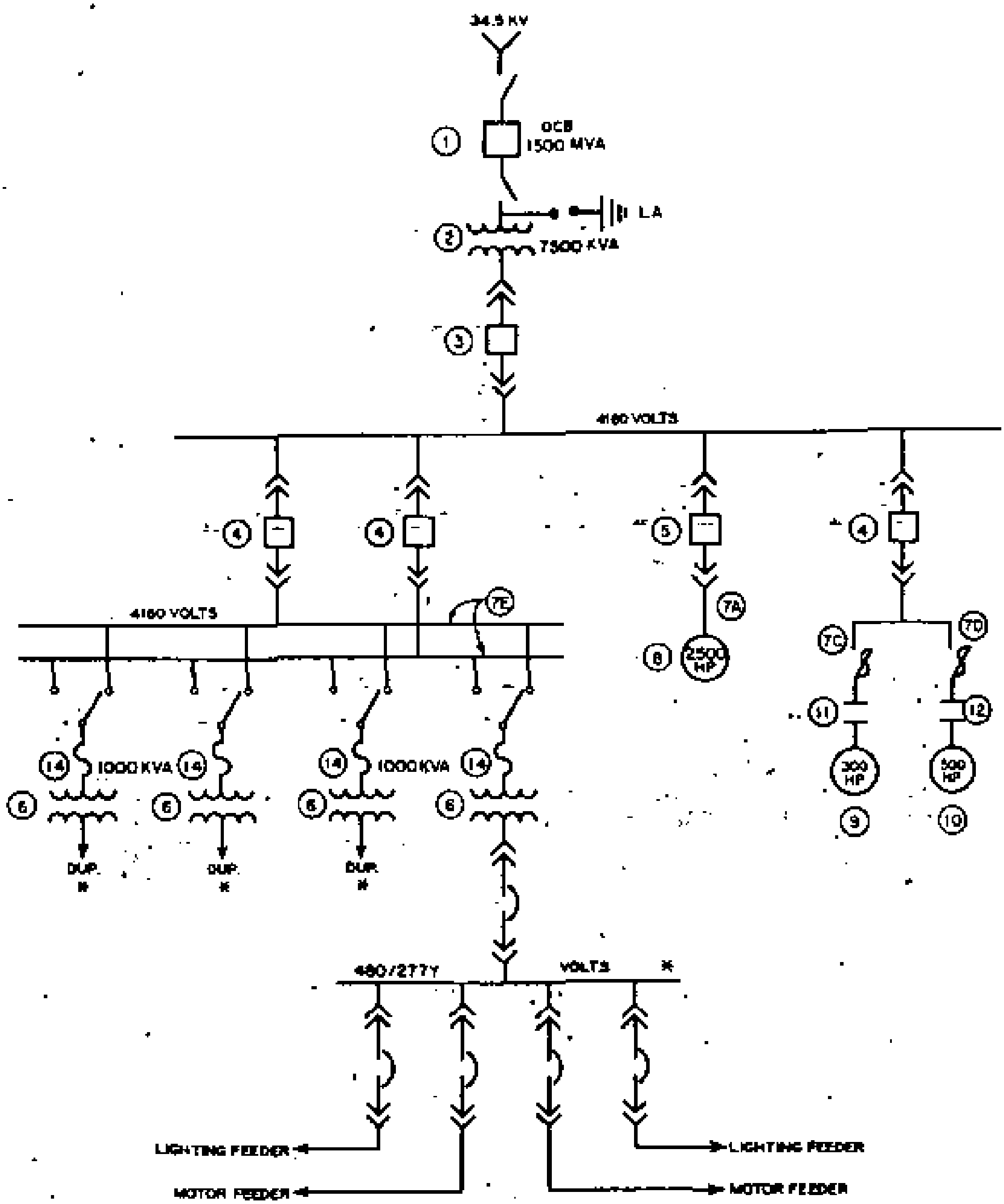


Figure 10.2
Single-Line Diagram for 4160 volts

* 480V/277 Equipment Not Considered in Problem

Equipment which affects the cost comparison plus the 34.5 kV structure.

Item (1) 34.5 kV Structure No. 2 (Table 10.1)
Oil circuit breaker (Table 10.2)

(2) 7500-kVA Transformer (Table 10.5)

(3) Secondary breaker (Table 10.6)

(4) Feeder breakers (Table 10.6)

(5) 2500-hp Synchronous motor starter breaker (Table 10.6)

(6) 4 1000-kVA Transformers 480Y/277 volts secondary (Table 10.5)

(7) 15-kV and 5-kV cable (Table 10.9)

(8) 2500-hp Synchronous motor, 600 r/min (Table 10.15)

(9) 300-hp Induction motor, 1800 r/min (Table 10.11)

(10) 500-hp Synchronous motor, 1,200 r/min (Table 10.15)

(11) 300-hp Induction motor starter (Table 10.12)

(12) 500-hp Synchronous motor starter (Table 10.16)

(13) 1500-kVA Transformer 13.8/2.4 kV (Table 10.5)

(14) Medium-Voltage air interrupter switches and fuses for transformers (Table 10.3)

Determine equipment requirements:

Ampere capacity and short-circuit requirements of metal-clad switchgear.

7,500 kVA @ 13.8 kV equals 330 amperes. Use 1200-ampere breaker.

7,500 kVA @ 4.16 kV equals 1050 amperes. Use 1200-ampere breaker.

Other breakers can all be 1200 ampere at 13.8 kV or at 4160 volts.

Interrupting capacity requirements (see Chapter IV for details of calculation).

Utility short-circuit kVA equals 1,000 MVA.

2500-hp synchronous motor X_d'' equals .20 PU.

500-hp synchronous motor X_d'' equals .15 PU.

Use 1,000,000 kVA base.

Utility short-circuit impedance	equals	1.0 PU.
7,500-kVA transformer	equals	8.7 PU.
2,500-hp synchronous motor	equals	100.0 PU.
500-hp synchronous motor	equals	375.0 PU.

Impedance of utility incoming line and transformer equals 1 plus 8.7 = 9.7 PU.

$$\text{Total impedance equals } \frac{1}{\frac{1}{9.7} \text{ plus } \frac{1}{100} \text{ plus } \frac{1}{375}}$$

equals 8.7 PU.

$$\text{Short-circuit kVA equals } \frac{1{,}000{,}000 \text{ (base)}}{8.7 \text{ PU}}$$

equals 115,000 kVA.

Use 250-MVA circuit breaker as calculations are under 250 MVA.

Cable requirements for 13.8 kV are as follows:

(a) 2500 hp—200 feet—105 amperes

(b) 1500-kVA transformer—250 feet—63 amperes
These motors are at 2,400 volts.

(c) 500-hp motor—50 feet—121 amperes

(d) 300-hp motor—50 feet—73 amperes

(e) Four 1,000 kVA—1,000 feet—164 amperes

Cable requirements for 4160 volts are as follows:

(a) 2500 hp—200 feet—340 amperes

(b) 500 hp—300 feet— 70 amperes

(c) 300 hp—200 feet— 42 amperes

(d) Four 1,000 kVA—1,000 feet—564 amperes

Calculation of comparative cost difference between 13.8 kV and 4160 volt distribution systems—

		Figure 10.1	Figure 10.2
Item 1—34.5-kV structure with a 1,500 MVA oil circuit breaker			
Structure	$11,500		
Oil circuit breaker	10,500		
Total	$22,000	$ 22,000	$ 22,000
Item 2—7,500-kVA transformer without tap changing; provision for future forced air cooling		31,500	31,500
Item 3—Secondary breaker			
13.8 kV, 1200 ampere 500 MVA $8,000 + $1,800		9,800	
4.16 kV, 1200 ampere, 250 MVA $6,100 + $1,400			7,500

	Figure 10.1	Figure 10.2
Item 4—Feeder breakers (3)		
13.8 kV, 1200 ampere, 500 MVA		
$8,000 × 3	24,000	
4.16 kV, 1200 ampere, 250 MVA		
$6,100 × 3		18,300
Item 5—2500-hp synchronous motor breaker		
13.8 kV, 1200 ampere, 500 MVA	13,600	
4.16 kV, 1200 ampere, 250 MVA		11,000
Item 6—1000-kVA transformers 480/277 volts Y sec. (4)		
$10,000 × 4	40,400	40,400
Item 7—Cable—VCL only		
$\frac{\text{Cost}}{\text{100 amp. feet}} \times \text{amperes} \times \frac{\text{feet}}{100} \times \text{number of feeders}$		
(a) 2500-hp synchronous motor feeder 200 ft.		
13.8 kV (No. 1) $13.20 × 115 × 2	3,020	
4.16 kV (500 MCM) $6.80 × 325 × 2		4,430
(b) 1500-kVA transformer 250 ft.		
13.8-kV (No. 2) $14.70 × 101 × 2.5	3,730	
4.16-kV Not needed		—
(c) 300-hp induction motor feeder		
2.4 kV (No. 2) $7.60 × 102 × .5	388	
4.16 kV (No. 3/0)* $6.40 × 175 × 2		2,240
(d) 500-hp synchronous motor feeder		
2.4 kV (No. 2/0) $6.70 × 154 × .5	$ 560	
4.16 kV (No. 3/0)* $6.40 × 175 × 3		$ 3,360
(e) 4—1000-kVA transformers 2 feeder, 2000 ft. each		
13.8 kV (No. 3/0) $12.60 × 167 × 40 × 2	168,400	
4.16 kV (350 MCM) $6.40 × 264 × 40 × 2		
2 cables per phase		271,000
Total cable cost	$176,098	$281,030

* Minimum size of cable to withstand 15 cycles maximum fault current

	Figure 10.1	Figure 10.2
Item 8—2500-hp synchronous motor		
13.8 kV 157% × 45,594	72,000	
4.16 kV 109% × 45,594		50,000
Item 9—300-hp induction motor		
4.16 kV 116% × 3746		4,350
2.4 kV 100% × 3746	3,746	
Item 10—500-hp synchronous motor		
4.16 107½% × 8144		8,750
2.4 kV 100% × 8144	8,144	
Item 11—Cost of starter for 300-hp induction motor		
4.16 kV		5,600
2.4 kV	5,600	
Item 12—Cost of starter for 500-hp synchronous motor		
4.16 kV		7,350
2.4 kV	6,500	
Item 13—1500-kVA transformer 13.8/2.4 kV	10,500	
Item 14—One fused and one unfused switch for each transformer		
13.8 kV 4 × (2200 + 1600)	15,200	
4.16 kV 4 × (2200 + 1450)		14,600

Summary of Savings

	13.8-kV System Fig. 10.1	4.16-kV System Fig. 10.2
Item 1	—	—
Item 2	—	—
Item 3	—	$ 2,300
Item 4	—	5,700
Item 5	—	2,600
Item 6	—	—
Item 7	$104,932	—
Item 8	—	22,000
Item 9	604	—
Item 10	606	—
Item 11	—	—
Item 12	850	—
Item 13	—	10,500
Item 14	—	600
Total	$106,992	$43,700

Total savings in favor of Fig. 10.1 the 13.8-kV system = $63,292

Comments on Problem

The problem is presented to illustrate the use of the tables in this chapter and not to indicate a preference for a particular type of system or a specific voltage. Many changes could be made to this problem that would affect the final results. A few are as follows:

(1) It may be preferable to feed the four secondary unit substations with a radial system instead of a primary-selective system.

(2) For the 13.8 kV system it may be desirable to operate the large motors at 2300 volts.

(3) A less-expensive type of cable installation may be used.

Many factors as outlined in other chapters must be considered in making the final selection of the electric distribution system. The cost figures given in this chapter are to be used for comparative purposes only.