ELECTRICAL GENERATION PLANT DESIGN PRACTICE

INTERN EXPERIENCE AT

POWER SYSTEMS ENGINEERING, INC.

An Internship Report

by

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Submitted to the College of Engineering of
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ABSTRACT

A survey of the author's internship experience with Power Systems Engineering, Inc. during the period September 1980 through August, 1981 is presented. During this one year internship, the author was assigned to two engineering projects. One involved design of a 480 MW power plant. The other was the design of a 8.2 MW induction generator for cogeneration.

The author's activities during this period can be categorized into two major areas. First, technically oriented, he designed protective relaying and SCADA systems for the projects. Secondly, he assisted the Project Manager in project management activities such as project progress and cost control.

The intent of this report is to prepare a training manual for PSE young engineers. It covers both technical guidelines for power plant design and nonacademic professional codes. Although this report is primarily written for young engineers, it can also be used as a reference by older and experienced engineers.

ACKNOWLEDGEMENTS

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TO

My Father who gave me so much

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CHAPTER 1

INTRODUCTION

It is the intent of the Doctor of Engineering degree program to prepare the student either as a professional and qualified engineer with strong business and administrative background or as a manager with enough technical background. The internship, as required in the program, is designed to expose the student to the real industry environment and to bridge the gap, if any, between the academic and the industrial environments.

The objectives of the internship are as follows:

(1) To become familiar with the structure of the organization, organizational goals and objectives, departmental responsibilities and functions, project management procedures, technology assessments and engineering decision making procedures, and employee's performance evaluation and motivation.

(2) To make an identifiable contribution in the Electrical Engineering area of projects undertaken by the company.

(3) To gain experience in the non-academic technical and business activities of the company and to be aware of the industry standards, ethical practices, and the interactions between the company and the industrial environments.

In addition, the following considerations have also been taken into account in selecting a successful engineering firm to intern with:

(1) In Taiwan, it is very important either to improve the efficiency of energy usage or to find new energy sources other than petroleum since there are very few resources.

(2) In Taiwan, being an experienced engineer is almost the only way to become an engineering manager. Consequently, ever since I enrolled in the Doctor of Engineering program, I have been preparing myself to be a qualified engineer with sufficient business and administrative background to be an engineering manager; not a manager with an engineering background. Considering all these factors, I chose to have my internship with Power Systems Engineering, Inc., a Houston based professinal engineering and construction services organization.

1.1 History of Power Systems Engineering, Inc.

Power Systems Engineering, Inc., was founded early in 1969 by Mr. Albert J. Smith and Mr. Thomas C. McMichael, who at that time had over 50 years of combined experience in the design and installation of power generation equipment and industrial power systems. Since its inception, the firm has stamped itself as an innovator and a pioneer of high efficiency power generation in the power and process industries. Its first project was the design, construction, and the operation of a 300 MW combined cycle power generation plant, the largest base load combined cycle gas turbine power plant ever built at that time.

Today the firm provides engineering and project management services wherever required. Through one of its subsidiaries, Power Operating Company, the firm also provides services of operating and maintaining most types of power generating, steam or heating and cooling facilities for clients. In response to the critical demands imposed on industry by the shift in fuel cost and availability today, Power Systems Engineering is providing coal, lignite, and nuclear plant technology logistics and other energy-related services.

The firm's goals are innovation in high efficiency power generation, being owner-operator of cogeneration and heat recovery systems, and to maintain a sound and stable financial structure commensurate to the requirements of the firm's objectives.

Today, the firm's objectives include:

(1) To serve a great variety of energy-related industrial clients and meet their specific requirements by the most cost effective methods.

(2) To build up a highly qualified business team to develop cogeneration projects.

(3) To support energy intensive industries with energy resources such as coal, lignite and others.

(4) To continue development of a highly qualified engineering staff in all disciplines capable of implementing the design, engineering and construction of energy-related projects.

(5) To become an internationally recognized professional firm.

The firm's philosophy is based on innovation backed by thorough feasibility studies, conservative design and the use of proven components and systems best suited for a particular project. As an engineering consultant, the firm always tries its best to employ procedures and techniques which are cost effective and result in overall savings for its clients. Power Systems Engineering has designed and built a wide range of industrial power and utility projects from small to very large, complex systems, and has constructed numerous chemical plants, compressor stations and other chemical and petroleum industry oriented installations.

Figures 1.1 and 1.2 show the overall structure of the firm, with deparmental functions. It is clear that the organization form is of modified matrix type. Generally, one of the department managers is assigned as the Project Manager for a particular project, depending upon the nature of the project. This type of organizational structure has the following advantages for this particular firm:

(1) The project team can respond more quickly and move effectively to the client's needs.

(2) It is a flexible structure such that each employee can take more than one responsibility at a time, if required.

(3) Each individual employee takes wider and higher diversity of assignments and gains broader experience in all phases of project development than might be feasible in a larger firm.

(4) A closer personal relationship at the business level is possible between employees, clients, and the employer.

1.2 Project Management

For any project undertaken, Power Systems Engineering offers services covering all phases of project development: definition of the needs, conceptual development, feasibility studies, environmental permitting and licensing strategy and applications, preliminary engineering, design engineering, specification of equipment, procurement, cost control, complete working schedule, financing and leasing, construction management, start-up, operation and maintenance and others.

Engineering and corporate assignments are directed and oriented in a project manner. A Project Manager is assigned to act as liaison between the client representative and all organizational functions in the firm. This provides a single source of responsibility to the

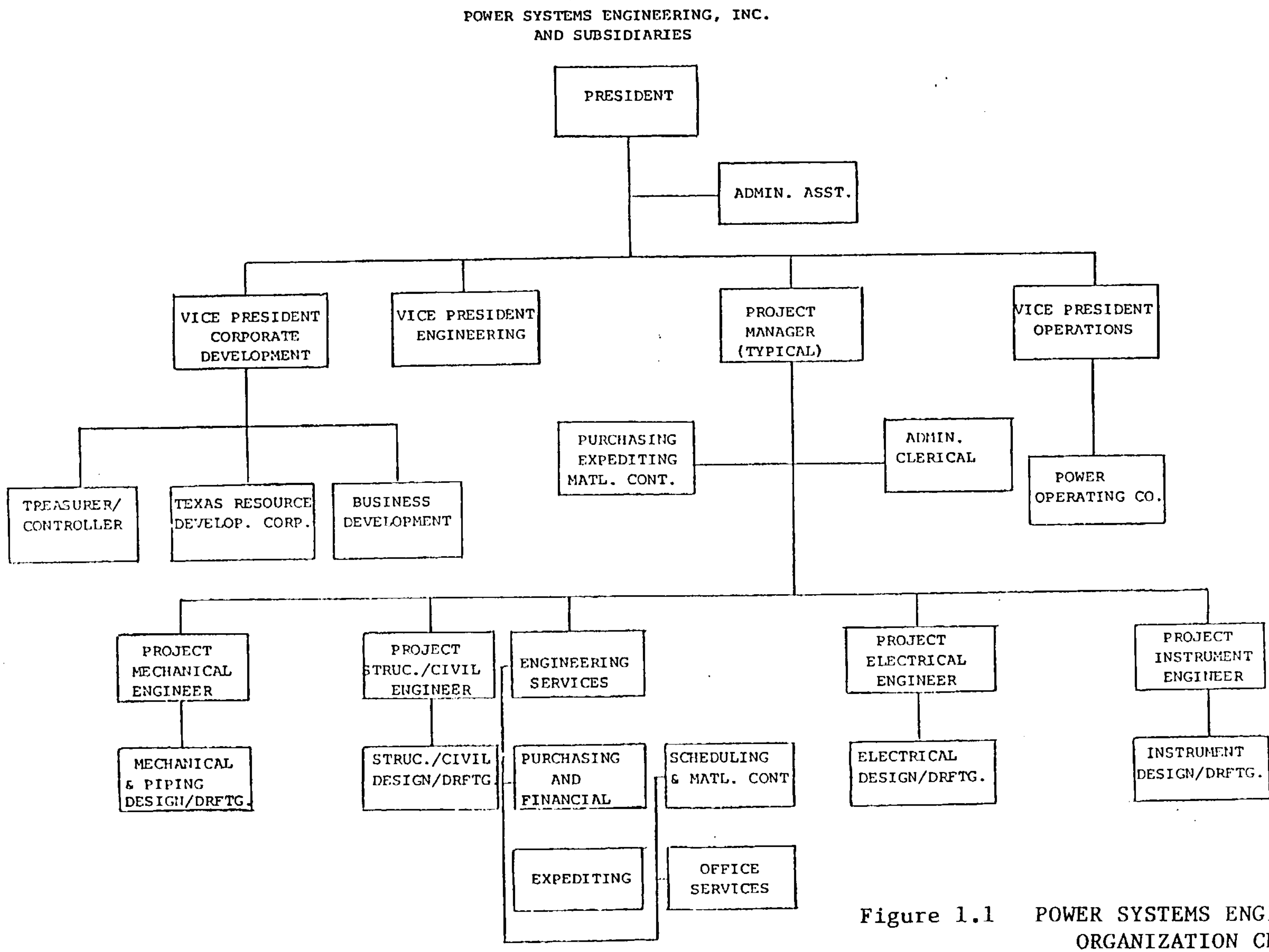


Figure 1.1 POWER SYSTEMS ENGINEERING ORGANIZATION CHART

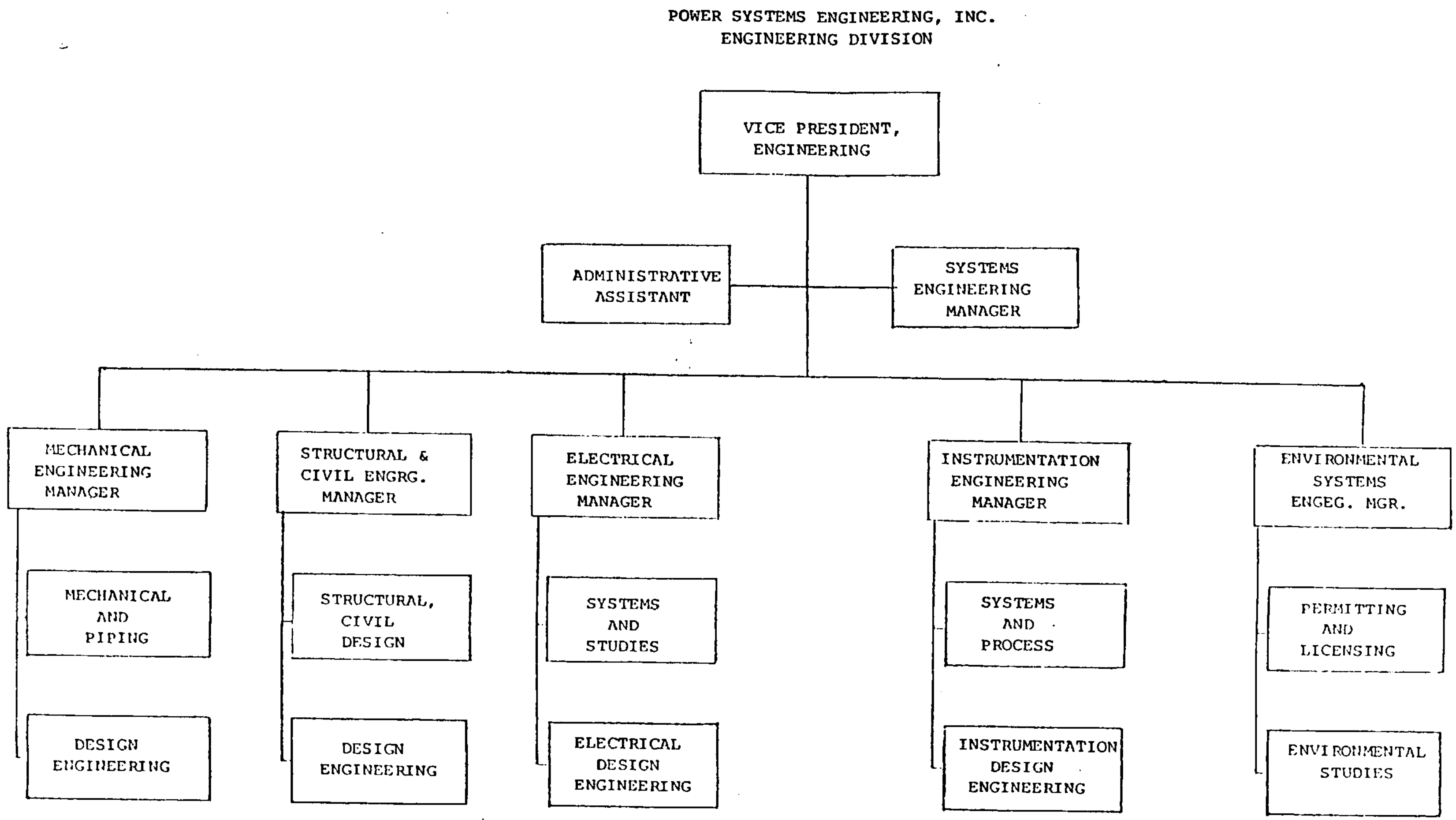


Figure 1.2 POWER SYSTEMS ENGINEERING, INC. ENGINEERING DIVISION

client such that the client's project can receive the maximum support from all corporate services. A responsible project engineer or engineers from each discipline as needed are assigned to handle all engineering requirements and are responsible to the Project Manager. Under the project engineer are design, drafting, and logistic teams. Each individual project engineer also acts as liaison with the client for his discipline through the Project Manager.

1.3 Scope of Internship Assignments and the Report

During a one year internship, I was assigned to two project teams for the following projects:

(1) Engineering and design of a 480 MW combustion gas turbine generation plant in Saudi Arabia.

(2) Engineering and design of a 8.2 MW induction generator for cogeneration in southern Texas.

My contributions to the firm included project electrical engineering design as well as engineering services. As an electrical engineer, I conceptually and detail designed protective relaying for the 480 MW power plant, wrote specifications of equipment, designed microprocessor-based supervision control and data acquisition (SCADA) and sequence of events (SOE) systems. I also implemented relay coordination and vendor's bid evaluations, both technically and economically. As an assistant to the engineering service manager, my accomplishments included designing a complete engineering progress control chart for electrical engineering discipline, helping the project engineers to process and expedite most of the procurement, and assiting the project manager to prepare cost control charts and monthly progress reports.

Another assignment during my internship was to standardize both technical and managerial guidelines for young engineers. This report summarizes and highlights the results of this assignment. It consists of two parts. Part one, including Chapter 2 through Chapter 5, covers technical fundamentals of electrical generation plant design. Part two, including Chapters 6 and 7, discusses business aspects of engineering projects and some engineering managerial considerations for young engineers.

CHAPTER 2

SOME FUNDAMENTALS OF ELECTRICAL POWER SYSTEM DESIGN

As stated in Chapter 1, the scope of engineering business includes marketing, planning, management, scheduling, control, and all technical activities. In this chapter only technical design tools such as short circuit current calculation, ampacity of electrical conductors, transient performance of conductors, instrument transformers, and the R-X diagram, will be covered.

Among these, the short circuit current calculation is the most important. It includes maximum and minimum current calculations under fault conditions. Both of these calculations will be discussed in Section 2.1 in detail. The selection of electrical conductors may generally be made on the basis of voltage drop, power loss, maximum allowable temperature rise, or mechanical strength. Each of these characteristics will be covered under Sections 2.2 and 2.3 separately. Instrument transformer performance and the R-X diagram are two key topics in power system relaying. They will be elaborated on under Sections 2.4 and 2.5 separately. Although this chapter and the following three chapters emphasize only technical aspects of engineering practices, by no means is it implied that other aspects are not important and can be neglected. In fact, it should be pointed out that economic considerations are usually at least as important as technical requirements. For example, in designing the substation buses to resist short circuit stresses, an economic balance should be reached by providing means for limiting possible short circuit forces by increasing bus spacing, or by changing bus arrangements. Frequently even landscaping becomes a deciding factor. Similarly, the application of protective relays to the system components is essentially a compromise between the cost of protection and the risk of no protection at all.

2.1 Fault Current Calculation

It is not feasible to design an electrical system completely free of faults. Even the best designed electrical system occassionally experiences short circuits resulting in high fault currents. Therefore, protective devices such as circuit breakers and fuses should be applied to isolate faults before any severe damage or long service interruption occurs. On the other hand, other parts of the system should be capable of withstanding the mechanical and the thermal stresses resulting from maximum flow of fault currents through them. The magnitude of fault currents are usually established by calculation. Most of the system components are specified and selected using the calculation results.

2.1.1 Two Simplifying Assumptions

The basic relationship used in determining fault current is Ohm's Law. There are several methods or algorithms for fault current calculation. However, certain simplifying assumptions are customarily made for engineering design purposes [1]. An important assumption is that the fault is bolted, that is, it has zero impedance. It should be recognized, however, that actual faults often involve arcing, which reduces the fault current magnitude due to arc resistance or impedance. Furthermore, a three-phase fault is generally assumed because this type of fault generally results in the maximum short circuit current available in a circuit. In high voltage systems the three-phase fault is frequently the only one calculated. In a low voltage system, ground currents are often less than the rated load currents, but can be very destructive. This condition leads to the requirement for line-to-ground fault calculation.

Impacts of these two assumptions on engineering design are not only simplifications of the calculation but also increases of safety margins on all the equipments selected on the basis of the calculation results.

2.1.2 Fault Current Calculation Results and Their Applications

It is well known that an electrical fault current is usually of an asymmetrical wave form whose magnitude varies with time after the fault. Then a question like "When should the fault current be calculated?" arises naturally.

According to IEEE Standard 141-1976, short circuit currents may be calculated at the following recommended times:

(1) The first cycle: First cycle maximum symmetrical values are always required. They are often the only values needed for low voltage systems and for fuses in general. These values are usually related to circuit breaker momentary (closing and latching) capabilities.

(2) From 1.5 to 4 cycles: Maximum values are required for high voltage circuit breaker applications. These values are generally related to contact interrupting capacities of high voltage circuit breakers.

(3) About 30 cycles: The reduced magnitude of the fault current gives the minimum available fault current supplied by the system. These minimum fault currents are important in protective device coordination in the system.

Generally speaking, the maximum fault current values are used to select adequate interrupting ratings and to check the ability of system components to withstand both mechanical and thermal stresses. The minimum values are needed to check the sensitivity requirements of protective relays. For overall coordination of system protective devices, both the maximum and the minimum values are often required. Sometimes, the minimum values are estimated as fractions of the maximum values for the sake of simplicity. In this case, only the maximum magnitude of fault current should be calculated.

2.1.3 Sources of Fault Current

Power frequency currents which flow during a fault come from electrical rotating machines. Rotating machines involved in fault calculations may be divided into the following categories:

(1) Synchronous generators

(2) Synchronous motors and condensers

(3) Induction machines

(4) Electric utility system

The fault current from each rotating machine source is limited by the impedance of the machine and the impedance between the machine and the fault. The impedance of a rotating machine is not a simple value, but is complex and varying with time. For purposes of fault current calculations, industry standard practice [1] has established the following guidelines for the application of this variable reactance.

For synchronous machines, the subtransient reactance (X_d'') should be used to determine fault current during first cycle after fault occurs; the transient reactance (X_d'), to determine fault current after several cycles (about 5 cycles at 60 Hz); the synchronous reactance (X_d), to determine the current flow after a steady-state condition is reached. As most fault protective devices, such as circuit breakers and fuses, operate well before steady-state conditions, X_d is seldom used in calculating fault currents for applications of these devices. For induction machines, only the subtransient reactance (X''_d) is used. This value is about equal to the locked-rotor reactance. Therefore, the fault current from an induction machine is approximately equal to the full voltage in-rush current of the machine, if shorted at the terminals.

Generally speaking, the current contributed to a fault from the utility system appears to be merely a small increase in load current to the remote and relatively large central station generators, and this current contribution tends to remain constant. Consequently, the utility system is usually represented by a constant voltage source behind a constant impedance whose value is determined as follows:

$$Z_{sys}\ (\text{ohm}) = \frac{(V_{1-1})^2}{\begin{array}{c}\text{Available short circuit level in MVA from}\\ \text{the utility sytem at the point of connection}\end{array}}$$

Where V_{1-1} is the system line-to-line operating voltage in KV.

2.1.4 Fault Curent Calculation Procedure [1]

The procedures for calculating system short circuit currents consist of the following steps:

(Step 1) Prepare system one-line diagram.

This diagram should show all sources of short circuit currents and all significant circuit elements.

(Step 2) Collect and convert impedance data to a common base for for all significant circuit elements.

A significant part of the preparation for a short circuit current study is establishing the impedance of each circuit element, and converting them to the same base. Sources of impedance values are nameplates, handbooks [3], standards [1] [4], manufacturers' catalogs, direct contact with the manufacturer and others.

The major elements of impedance include transformers, busways, cables, conductors, and rotating machines. There are other circuit impedances such as those associated with circuit breakers, instrument transformers, bus connections and structures, etc., which are usually negligibly small in high voltage (above 1 KV) systems. However, in low voltage systems, particularly at 208V, omission of these impedances may result in over-conservative results. All the impedances, except those for rotating machines, are assumed to be constants throughout the fault current calculation. The impedances of rotating machines depend upon the purpose of the study as discussed in further detail under Step 5.

Also, it is normal practice to disregard all static loads such as lighting, electric heating and so on in the network despite the fact that they are in parallel with other network branches. This is so because system load currents are usually negligibly small compared with the high fault current. This assumption implies that from a system operating point of view, the fault is essentially a disturbance around the prefault operating point. In other words, the prefault system voltage (Eo) can be taken as the system nominal voltage at the moment fault occurs. Therefore, when using the per-unit system, the driving voltage is equal to 1.0 per unit if the voltage bases are equal to system nominal voltages. This will greatly simplify the calculation in Step 5.

(Step 3) Prepare the system impedance diagram.

Impedance information gathered in Step 2 should be entered on the one line diagram obtained from Step 1. For many short circuit studies at medium or high voltages, and for a few at low voltage, it is sufficiently accurate to ignore resistances and use reactances only. However, for many low voltage calculations resistance should not be ignored because the calculated currents would be unnecessarily over-conservative.

Resistance data are definitely required for calculations of $^X/_R$ ratios when applying high and medium voltage circuit breakers, but they should be kept on a separate drawing called resistance diagram [1].

(Step 4) Combine impedances from sources to fault location. This step is the most straightforward one, but it may be most time consuming too.

(Step 5) Calculate short circuit currents to anticipated fault locations.

This step uses different impedances for the rotating machines to calculate the short circuit currents depending upon the purpose of the study. Industrial applications of short circuit calculation results can be classified into the following four general categories:

(a) First cycle duties for fuses and low voltage (below 1 KV) circuit breaker.

(b) First cycle duties for high voltage circuit breakers (1 KV and above).

(c) Interrupting duties for high voltage circuit breakers.

(d) Short circuit currents for time delayed relays.

Each of these categories will be discussed subsequently in further detail.

For first cycle duties of fuses, switches, and low voltage circuit breakers, the short circuit current should be calculated in accordance with ANSI C37.13, ANSI C37.41, NEMA AB, and NEMA SG latest standards. With low voltage fault calculations, all motors should be considered regardless of horsepower size. However, the standards allow using an equivalent reactance to represent a group of low voltage induction or synchronous motors fed from a low voltage substation. The equivalent reactance is 0.25 p.u. based on the lump sum KVA rating of the machines. For other machines, whether generators or motors, the subtransient reactance should be used in the equivalent network.

After the first four steps above, a single driving impedance Z_f for each fault location can be obtained. Then the symmetrical short circuit current can be calculated as follows:

$$I_{sym} = \frac{E_o}{Z_f} \quad \text{p.u.}$$

For those low voltage circuit breakers whose short circuit ratings are expressed in symmetrical rms currents, this is the minimum required capacity for satisfactory performance. For those whose ratings are given in terms of total rms currents, the symmetrical short circuit current obtained above should be multiplied by a multiplication factor according to ANSI Standard C37.13. This factor depends upon the X_f/R_f ratio at fault location. If X_f/R_f ratio is equal to or less than 6.6, the factor is 1. If X_f/R_f is greater than 6.6, a straight factor of 1.15 can generally be used for purposes of selecting the breakers.

For fuse application, the multiplication factor should be obtained from ANSI Standard C37.41.

For first cycle duties of high voltage circuit breakers, the calculation shall be implemented in accordance with the latest ANSI C37.5 and C37.010 standards. With the calculations, only motors with 50 HP or more ratings should be considered. Table 2.1 lists the reactances for rotating machines that should be used in the calculation.

After the first four steps stated above, a single impedance X_f for each fault location can be obtained. Then the first cycle asymmetrical short circuit duties can be calculated as follows:

$$I_{tot} = \frac{E_o}{X_f} \times 1.6$$

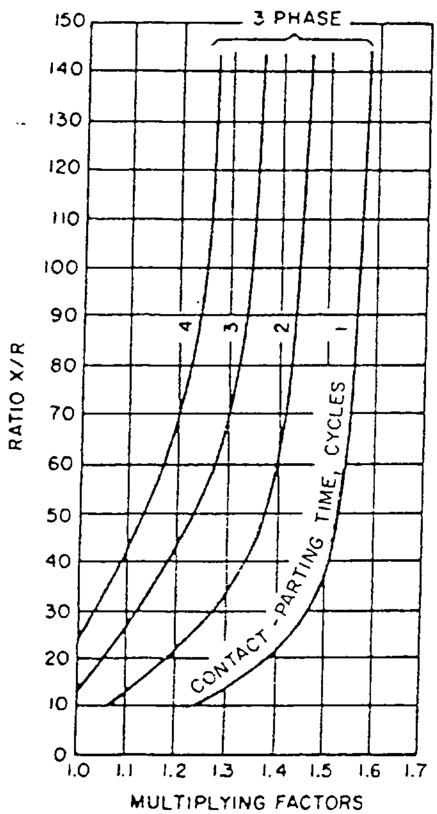
This is the short circuit duties for comparison with high voltage (above 1 KV) circuit breaker momentary ratings (total current rating basis) or closing and latching capabilities (symmetrical current rating basis).

There are significant differences between total current and symmetrical current calculations of high voltage circuit breaker interrupting duties. However, in both calculations, only motors rated 50 HP or more should be considered. The reactances used for the rotating machines is shown in Table 2.1. For these calculations, the resistance network is also necessary. In the resistance network each rotating machine resistance must be multiplied by the same factor as its corresponding reactance multiplier from Table 2.1. Consider first the duties for the high voltage circuit breaker rated on the total current basis. Reduce the reactance network to a single equivalent reactance X_f. Determine X_f/R_f and E_o/X_f ratios. Then select the multiplying factor for X_f/R_f correction from curves shown in figure 2.1 [5]. To use the curves

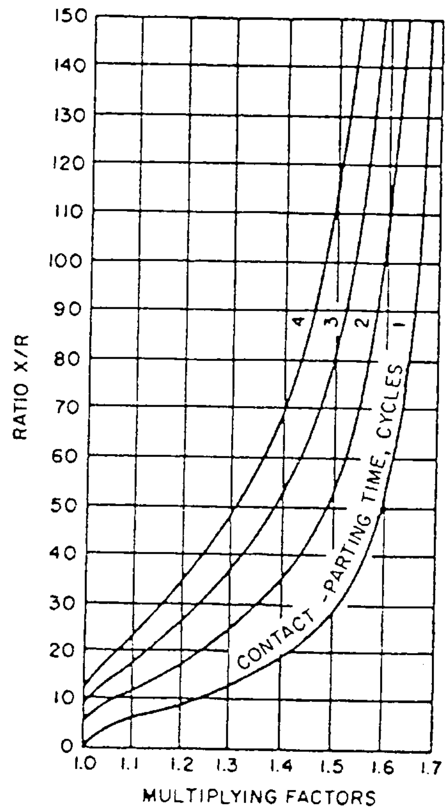
TYPE OF ROTATING MACHINE	MOMENTARY	INTERRUPTING
All turbine generators: all hydrogenerators with amortisseur windings, all condensers	1.0 X"d	1.0X"d
Hydrogenerators without amortisseur windings	0.75 X"d	0.75 X"d
All synchronous motors	1.0 X"d	1.5 X"d
Induction Motors (= 1800 RPM)		
Above 1000 HP	1.0 X"d	1.5 X"d
250 < HP ≤ 1000 HP	1.2 X"d	3.0 X"d
50 < HP ≤ 250 HP	1.2 X"d	3.0 X"d
HP < 50 HP	neglect	neglect
Induction Motors (= 3600 RPM)		
Above 1000 HP	1.0 X"d	1.5 X"d
250 < HP ≤ 1000 HP	1.0 X"d	1.5 X"d
50 < HP ≤ 250 HP	1.5 X"d	3.0 X"d
HP < 50 HP	neglect	neglect

See Table 18 IEEE Std. 141-1976, page 197 for typical reactance values of induction and synchronous machines, in per unit of machine KVA ratings

Table 2.1 ROTATING MACHINE REACTANCE MULTIPLIERS



Multiplying Factors (Total Current Rating Basis) for Three-Phase Faults Fed Predominantly from Generators Through No More Than One Transformation (Local)
[From ANSI C37.5-1969 (R 1974)]



Multiplying Factors (Total Current Rating Basis) for Three-Phase and Line-to-Ground Faults Fed Predominantly Through Two or More Transformations (Remote)
[From ANSI C37.5-1969 (R 1974)]

Figure 2.1 MULTIPLYING FACTORS FOR TOTAL CURRENT RATING BASIS DEVICES the following information must be known:

(a) Three-phase or single-phase short circuit study?

(b) Rating interrupting time of the circuit breaker used. Minimum contact parting times usually used in 60 Hz systems are defined following:

Rated interrupting time (cycles)	8	5	3	2
Contact parting time (cycles	4	3	2	1-1/2

(c) Fault point X_f/R_f ratio

(d) Proximity of generators. The proximity of generators determines the choice between graphs for fault fed predominantly from local or remote sources. Unfortunately, for hybrid type sources, that is, both significant local and remote sources exist, no single multiplying factor is available from related standards. Different methods have been suggested for industrial applications. One of the most usual methods is given in Huening's paper [6]. Then multiply E_o/X_f by the multiplying factor selected. This is the calculated total rms current interrupting duty to be compared with the circuit breaker interrupting capability.

Next consider the high voltage circuit breaker rated on the symmetrical current basis. Calculate E_o/X_f and X_f/R_f ratios and select the multiplying factor from Figure 2.2 as in the total current basis case. Then multiply E_o/X_f by the multiplying factor selected. The result is an interrupting duty only if the multiplying factor for E_o/X_f is 1.0. The rated symmetrical interrupting capablity of the circuit breaker is calculated as,

$$\text{minimum required symmetrical interrupting capability} = \frac{E_o}{X_f} \times \text{multiplying factor} \times \frac{\text{rated max. E}}{E_o}$$

MULTIPLYING FACTORS FOR SYMMETRICAL CURRENT RATING BASIS DEVICES	DWG. NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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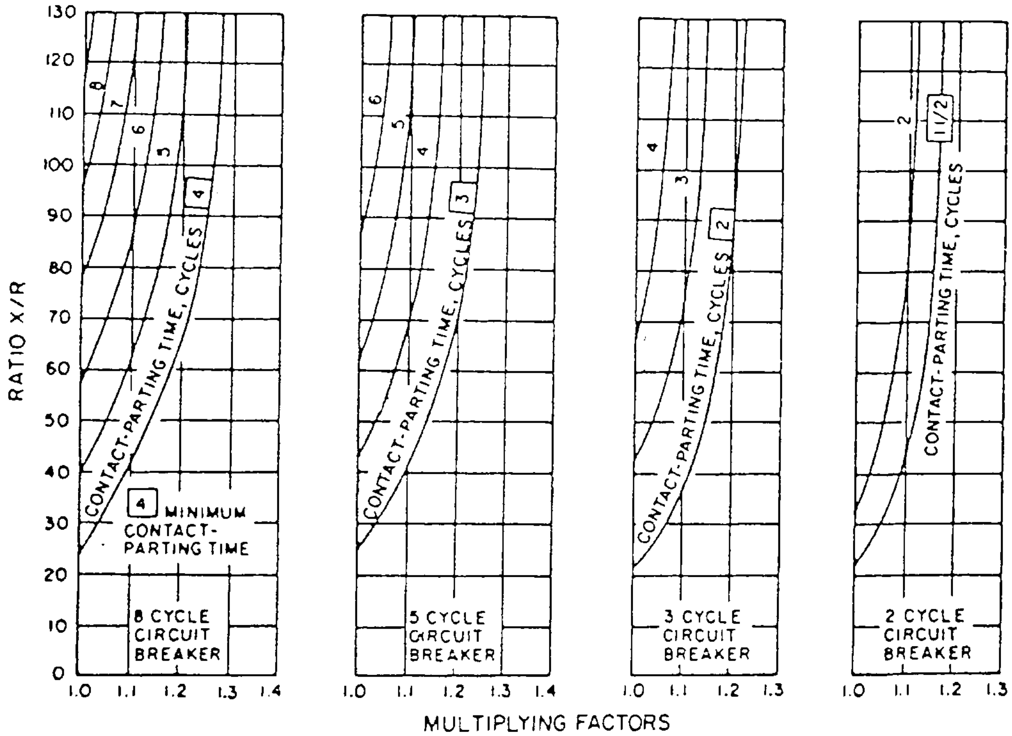
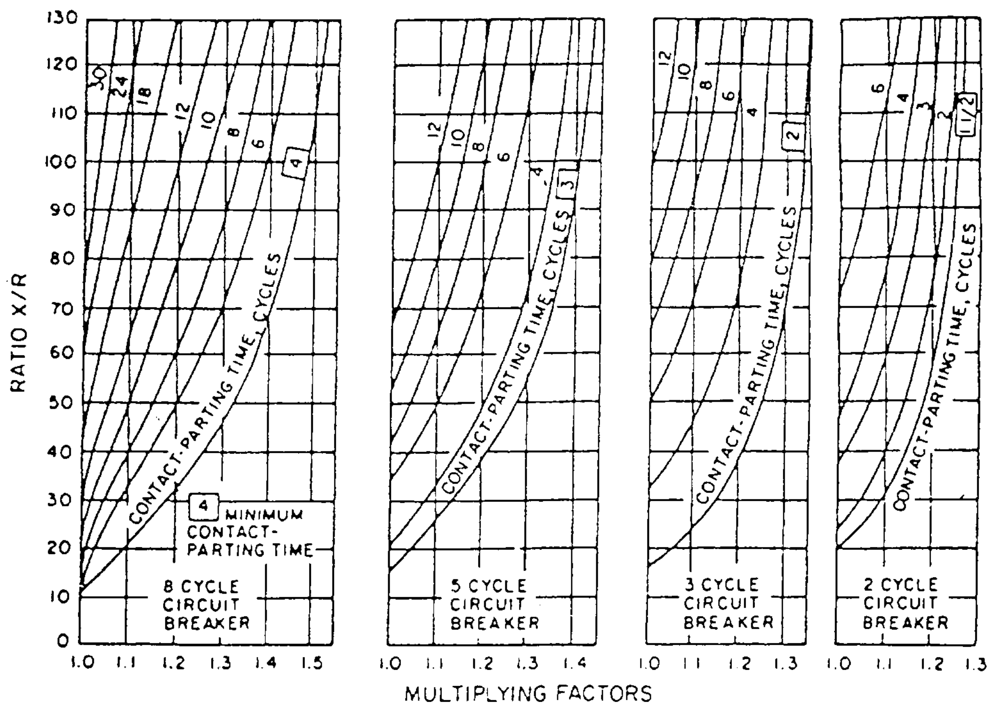


Multiplying Factors for Three-Phase Faults Fed Predominantly from Generators Through No More Than One Transformation (From IEEE Std 320-1972)



Multiplying Factors for Three-Phase and Line-to-Ground Faults Fed Predominantly Through Two or More Transformations (From IEEE Std 320-1972)

Figure 2.2 MULTIPLYING FACTORS FOR SYMMETRICAL CURRENT RATING BASIS DEVICES

The short circuit study for time delayed relays, known generally as 30 cycle study, is intended to investigate whether there are sufficient fault currents to operate relays. Consequently, the network used is often a minimum source representation and includes only generators that contribute fault current through the relay under consideration to the fault point. The generators should be represented by their transient impedance. All induction motors should be omitted in the calculation.

It becomes obvious that the complete procedure of short circuit study is tedious and long-hand calculation will soon become impractical and impossible as the size and complexity of the system increase. Digital computers are generally used for major fault studies in the industry.

2.2 Steady-State Performance of Electrical Conductors

Under normal operating conditions, the prime considerations in the applications of electrical conductors are current carrying capacity (defined as ampacity), and maximum allowable voltage drop, and energy losses. The cost of the energy losses through resistance is also important in the case of conductors carrying heavy currents at low voltages such as, for instance, in the electrochemical industry. In such cases, it may pay to use the conductors at less than their ampacity. If the selection of conductor size is based on energy loss and conductor cost, then the most economic choice of conductor according to classical economic theory is the one that makes the annual cost of the resistive losses equal to the annual interest on capital cost of the installed conductor material plus depreciation [7].

For substation buses, ampacity and energy loss are two factors which normally govern the selection of the conductors. For overhead transmission lines, ampacity and voltage drop determine the size of the conductor, and the voltage is considered in choosing the spacing and insulation of the line. Because of the extra high voltage generally used in transmission systems, corona plays a major role in the design of transmission systems. Besides these two factors, the overall system operation requirements may supersede all the considerations discussed so far and place a dominant limitation on the selection of the transmission conductor. For example, system stability may require a minimum conductor size. For overhead distribution in urban area, close voltage regulation and continuous service are two important factors to be considered. In addition, because of the heavy load involved, operating costs per unit of current must be kept as low as possible. Therefore, in the design of urban distribution systems, much study should be given to the most economical arrangement of the line, conductor sizes, and the methods of operationg, etc. For overhead distribution in rural area, it is extremely important that the line be low in initial construction cost, and still give satisfactory and reliable service. As a result, long spans are usually used. For building wires and cables, the determining factor is the ability of the insulation of the conductors to withstand heat without being deteriorated or damaged. On the other hand, the National Electric Code specifies that the size of feeder conductors should be such that the voltage drop will not be more than 3% for power loads and 2% for lighting loads or combined lighting and power loads.

In this section, calculation of ampacity for bare conductors will be discussed. Since the ampacity of an insulated conductor is limited by the maximum allowable temperature rise of the insulation used, it cannot be represented by a simple formula. In addition, ampacities can be easily obtained from NFPA Standard No. 70 [8]. Therefore, it will not be further considered thereafter. Neither voltage drop nor power loss calculation will be covered since they are very straightforward.

2.2.1 Ampacity of Bare Conductors

Electrical current carrying capacity of a bare conductor is determined by the tempeature rise resulting from the power loss of conduction and any other heat gained by the conductor. Since most equipment to which connections must be made from the conductor is designed to operate at a temperature rise of 30°C above 40°C ambient in accordance with NEMA and IEEE standards, it is undesirable to operate the conductor at a temperature that would cause heat to flow into the apparatus. Such heat may raise the temperature of that apparatus to a damaging point. In addition, the conductor may begin to oxidize at an excessively rapid rate at temperatures higher than 80°C. It is general practice to limit the maximum operating temperature below 80°C for copper conductors, below 100°C for aluminum conductors, below 95°C for single layer ACSR (aluminum conductor, steel-reinforced) and 105°C for multi-layer ACSR.

The heat caused by electrical losses in a conductor is dissipated primarily by convection and radiation. Under steady-state conditions, the rate of heat dissipation is equal to the rate of heat supply.

$$I^2R + \dot{Q}_s = \dot{Q}_r + \dot{Q}_c$$

where I = ampacity in amperes

$\dot{Q}_c$ = convected heat loss in watts/ft.

$\dot{Q}_r$ = radiated heat loss in watts/ft.

$\dot{Q}_s$ = heat gain from sun in watts/ft.

R = nominal AC resistance at operating temperature t_c in ohms/ft.

Table 2.2 summarizes atmospheric data required for ampacity calculation. Each of these items is discussed as follows:

(A) Convected heat loss $\dot{Q}_c$:

For natural convention cases, that is, no wind:

$\dot{Q}_c = 0.072 \ D^{0.75} (t_c - t_a)^{1.25}$ at sea level

$\dot{Q}_c = 0.283 \ d^{0.5} D^{0.75} (t_c - t_a)^{1.25}$ at high altitudes (10,000 feet and above)

For forced convection cases:

$$\dot{Q}_c = [1.01 + 0.371 \left(\frac{DdV}{u}\right)^{0.52}] \ K (t_c - t_a) \text{ if } 0.1 \leq \frac{D_o dV}{u} < 1{,}000$$

$$\dot{Q}_c = 0.1695 \left[\frac{DdV}{u}\right]^{0.6} \ K \ (t_c - t_a) \text{ if } 1{,}000 \leq \frac{D_o dV}{u} < 18{,}000$$

where D = conductor diameter in inches

D_o = conductor diameter in feet

t_c = conductor operating temperature in degrees C

t_a = ambient temperature in degrees C

d = air density at t_c in lb./cu. ft.

V = air velocity in feet per hour

u = absolute viscosity of air at $(t_c+t_a)/2$ in lb./(hr.-ft.)

K = thermal conductivity of air at $(t_c+t_a)/2$

Among these parameters, d, u, and K can be read from Table 2.2.

(B) Radiated heat loss $\dot{Q}_r$:

$$\dot{Q}_r = 0.138 \ D \ e \left[\left(\frac{K_c}{100}\right)^4 - \left(\frac{K_a}{100}\right)^4\right]$$

where e = coefficient of emissivity; 0.91 for black conductors, 0.23 for new conductors and 0.5 for average oxidized conductor.

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TABLE A VISCOSITY, DENSITY AT SEA LEVEL TO 15,000 FT, AND THERMAL CONDUCTIVITY OF AIR

TEMPERATURE °F	TEMPERATURE °C	TEMPERATURE K	$\left(\frac{K}{100}\right)^4$	ABSOLUTE VISCOSITY, U	DENSITY, d SEA LEVEL	DENSITY, d 5,000 FT	DENSITY, d 10,000 FT	DENSITY, d 15,000 FT	THERMAL CONDUCTIVITY, K
32	0	273	55.55	0.0415	0.0807	0.0671	0.0554	0.0455	0.00739
41	5	278	59.73	0.0421	0.0793	0.0660	0.0545	0.0447	0.00750
50	10	283	64.14	0.0427	0.0779	0.0648	0.0535	0.0439	0.00762
59	15	288	68.80	0.0433	0.0765	0.0636	0.0526	0.0431	0.00773
68	20	293	73.70	0.0439	0.0752	0.0626	0.0517	0.0424	0.00784
77	25	298	78.86	0.0444	0.0740	0.0616	0.0508	0.0417	0.00795
86	30	303	84.29	0.0450	0.0728	0.0606	0.0500	0.0411	0.00807
95	35	308	89.99	0.0456	0.0716	0.0596	0.0492	0.0404	0.00818
104	40	313	95.98	0.0461	0.0704	0.0586	0.0484	0.0397	0.00830
113	45	318	102.26	0.0467	0.0693	0.0577	0.0476	0.0391	0.00841
122	50	323	108.85	0.0473	0.0683	0.0568	0.0469	0.0385	0.00852
131	55	328	115.74	0.0478	0.0672	0.0559	0.0462	0.0379	0.00864
140	60	333	122.96	0.0484	0.0661	0.0550	0.0454	0.0373	0.00875
149	65	338	130.52	0.0489	0.0652	0.0542	0.0448	0.0367	0.00886
158	70	343	138.41	0.0494	0.0643	0.0535	0.0442	0.0363	0.00898
167	75	348	146.66	0.0500	0.0634	0.0527	0.0436	0.0358	0.00909
176	80	353	155.27	0.0505	0.0627	0.0522	0.0431	0.0354	0.00921
185	85	358	164.26	0.0510	0.0616	0.0513	0.0423	0.0347	0.00932
194	90	363	173.63	0.0515	0.0608	0.0506	0.0418	0.0343	0.00943
203	95	368	183.40	0.0521	0.0599	0.0498	0.0412	0.0338	0.00952
212	100	373	193.57	0.0526	0.0591	0.0492	0.0406	0.0333	0.00966

μ_f = absolute viscosity, lb/(hr)(ft).

ρ_f = density, lb of air/ft^3.

k_f = thermal conductivity of air, watts/(sq ft)(C) at $t_f = (t_c + t_a)/2$.

t_a = ambient temperature °C.

t_c = conductor temperature °C.

TABLE B HEAT-TRANSMISSION FACTOR FOR ALTITUDES ABOVE SEA LEVEL

ELEVATION ABOVE SEA LEVEL, FT	MULTIPLIER FOR VALUES IN TABLE C
0	1.00
5,000	1.15
10,000	1.25
15,000	1.30

TABLE C TOTAL HEAT RECEIVED BY SURFACE AT SEA LEVEL NORMAL TO SUN'S RAYS

SOLAR ALTITUDE, H_c, DEGREES	q_s, WATTS/SQ FT CLEAR ATMOSPHERE	q_s, WATTS/SQ FT INDUSTRIAL ATMOSPHERE
5	21.7	12.6
10	40.2	22.3
15	54.2	30.5
20	64.4	39.2
25	71.5	46.6
30	77.0	53.0
35	81.5	57.5
40	84.8	61.5
45	87.4	64.5
50	90.0	67.5
60	92.9	71.6
70	95.0	75.2
80	95.8	77.4
90	96.4	78.9

TABLE D ALTITUDE AND AZIMUTH IN DEGREES OF SUN AT VARIOUS LATITUDES AT DECLINATION OF 23.0 DEGREES, NORTHERN HEMISPHERE, JUNE 10 AND JULY 3

DEGREES NORTH LATITUDE	LOCAL SUN TIME 10:00 A.M. H_c	10:00 A.M. Z_c	12 NOON H_c	12 NOON Z_c	2:00 P.M. H_c	2:00 P.M. Z_c
20	62	78	87	0	62	282
25	62	88	88	180	62	272
30	62	98	83	180	62	262
35	61	107	78	180	61	253
40	60	115	73	180	60	245
45	57	122	68	180	57	238
50	54	128	63	180	54	232
60	47	137	53	180	47	223
70	40	143	43	180	40	217

Table 2.2 ATMOSPHERICAL DATA FOR AMPACITY CALCULATION

K_c = conductor operating temperature in degrees Kelvin

K_a = ambient temperature in degrees Kelvin

(C) Solar heat gain $\dot{Q}_s$:

$\dot{Q}_s = a\ q\ A \sin\theta$ and

$\theta = \cos^{-1}[(\cos H_c)\cos(Z_c - Z_e)]$

where a = coefficient of solar absorption; 0.95 for black conductor, 0.23 for new conductor and 0.5 for average oxidized conductor.

q = total solar and sky radiated heat in watts/ft.

θ = effective angle of incidence of sun's rays

A = projected area of conductor in sq. ft./linear ft. = D/12

H_c = altitude of sun in degrees

Z_c = azimuth of sun in degrees

Z_e = aximuth of conductor in degrees; 270° for E-W line and 180° for N-S line.

Among these, H_c and Z_c are available from Table 2.2.

It is important to notice that this equation is derived on the bases of the following two assumptions:

(1) Heat loss carried off by conduction through supports and connections is negligibly small. This is usually true in most cases.

(2) The conductor is isolated, that is, no proximity effect. Unfortunately, this is generally not true. However, the equation can still be used to calculate conductor ampacity if an effective resistance value including proximity and skin effects is used for R.

2.3 Transient Performance of Electrical Conductors and Supports

Under fault conditions, mechanical considerations rather than electrical requirements usually govern the selection and design of electrical installations, such as substation buses and supports, overhead lines, and cables. For medium voltage substations, the size of buses is generally dictated by mechanical stresses caused by short circuit currents. For high voltage buses, where currents are relatively lower and the phase spacing is larger, the deflection under short circuit of the conductor usually determines the bus size. A good practice is to limit the maximum deflection of the bus to $\frac{1}{150}$ of the span where only two supports are used and $\frac{1}{200}$ where three or more supports are used. For overhead lines, fault currents are more likely to cause thermal damage, which may be followed by loss of mechanical strength of the conductor, than direct mechanical damage. However, the high electromagnetic forces of fault currents play an important role in the design and selection of line supports, spacers, dampers, and other equipment. For all insulated wires and cables, heating caused by short circuit current is a deciding factor in their applications. On average, the life of cable and wire insulation is about halved and the failure rate is doubled for each 10°C increase in operating temperature. It is the intent of this section to cover various stresses, including mechanical stresses, thermal stresses, and other stresses under abnormal operating conditions.

2.3.1 Short Circuit Forces and Other Mechanical Stresses

Conductors carrying electric currents will exert forces on each other according to Ampere's Law. The basic formula for force between two infinite parallel conductors is: $F_s = \dfrac{5.4\ I_1\ I_2}{D\ (10^7)}$

Where I_1 and I_2 are current in each wire, D is center-to-center spacing of two conductors in inches, and F_s is the force acting on the conductors in pounds per foot. This equation is directly applicable to direct current systems.

Calculation of forces set up by alternating currents is somewhat complicated by the fact that fault currents are usually asymmetrical and are decreasing with time. There are various methods to calculate short circuit forces in industry. Some advocate the theory of natural frequency of vibration of the bus itself and possibility of resonance with the alternating current frequency. If resonance should occur, very great forces might result. This method involves data on buses, bus clamps, insulators, bases and structure which would be practically endless for all possible combinations. In fact, for reasons of clearance and economy, high voltage substations are generally designed with relatively long spans and relatively flexible structures. As a result, the natural frequencies of such high voltage bus systems are normally much lower than the frequency of the current in the bus. Even for those applications where resonance might occur, the problem can be easily solved by proper utilization of dampers or loose scrap conductors. Consequently, the resonance theory is unnecessarily complicated for general applications. Others advocate the use of the average force developed over a half cycle instead of that delivered by the wave peak. Since the deflection of the conductor subjected to successive impulses is proportional to the average magnetic force rather than to the maximum force [9]. This theory is true only if the average force is maintained indefinitely and the forces are a series of impulses. Even worse, there is no clearly defined safety margin for all design based on this theory.

The use of the first half-cycle peak value of the current wave is a sound and sensible basis for the worst case design. This gives the maximum forces as successive peak currents are smaller due to various decrements. Since part of this instantaneous force is absorbed by inertia of the conductor system, a safety factor is inherent. Generally, either a line-to-line or a three-phase fault is assumed because these types of fault will result in the maximum short circuit forces available in a single phase or a three phase system.

In the subsequent paragraphs, various short circuit force formulas are derived on the base of peak current value during the first half-cycle assuming that no decrement will be present during this period. A fully offset wave is assumed for asymmetrical calculations, which provides a ratio of $\sqrt{3}$ between the rms value of the composite current wave and the rms value of the corresponding symmetrical current wave if no offset is present.

(A) Line-to-Line Faults:

In the case of a symmetrical fault the fault current does not have any offset, the peak value of the wave is equal to $\sqrt{2}$ times the rms value.

$$F_s = \frac{5.4 \ (\sqrt{2} \ I_s)^2}{D(10^7)}$$

$$= \frac{10.8 \ I_s{}^2}{D(10^7)}$$

Where I_s is the rms symmetrical current value.

For an asymmetrical fault that is fully offset, if the rms symmetrical value is given, the peak current equals $2\sqrt{2}\ I_s$

$$F_s = \frac{5.4\ (2\sqrt{2}\ I_s)^2}{D(10^7)}$$

$$= \frac{43.2\ I_s^2}{D(10^7)}$$

If the rms asymmetrical value over the first half-cycle is given, the peak value equals 1.63 I_a as shown in Appendix 1.

$$F_s = \frac{5.4\ (1.63\ I_a)^2}{D(10^7)}$$

$$= \frac{14.4\ I_a^2}{D(10^7)}$$

where I_a is the rms asymmetrical current over the first half-cycle.

(B) Three-Phase Fault:

The usual three-phase conductor arrangement is a flat configuration with equally spaced conductors side by side vertically or horizontally. It is proven in Appendix 1 that the maximum possible force will be impressed on the center conductor, phase B in our case, and the short circuit must occur 45° after zero current value in phase B. Any other combination of circumstances gives a smaller force than this condition. At the instant of short circuit, phase B current will have the value of 0.7071 (that is, sin 45°) times the prefault current peak value; phase A current will have the value of 0.2588 (sin 15°) times and phase C current will have - 0.9659 (sin 255°) times the prefault current peak value. The instantaneous values of their transient direct current components will be the negatives of the above amounts.

The maximum force will then occur a half-cycle after the instant of short circuit [10]. Neglecting the decrement during the first half-cycle and multiplying phase current A by phase current B and B by C, the total force acting on conductor B is

$$F_s = \frac{18.7\ I_p^2}{D(10^7)}$$

where I_p is the peak value of the symmetrical alternating current component of the fault current.

In the case where the rms symmetrical value is given, the peak value equals $\sqrt{2}\ I_s$

$$F_s = \frac{18.7\ (\sqrt{2}\ I_s)^2}{D(10^7)}$$

$$= \frac{37.4\ I_s^2}{D(10^7)}$$

From Appendix 1, it is known that the maximum force obtainable from a three phase fault is $\sqrt{3}/2$ times that from a single phase fault, assuming that the current per phase of the two types of circuits are the same. However, on the same circuit, the three phase short circuit currents are usually greater than those of line-to-line faults and the short circuit forces are accordingly larger. Therefore, if given the half-cycle rms value of the fault current, the forces on phase B conductor can be calculated as following:

$$F_s = \frac{14.4\ (0.866)\ I_a^2}{D(10^7)}$$

$$= \frac{12.5\ I_a^2}{D(10^7)}$$

By a similar analysis, the maximum force on either outside conductor can be derived. Table 2.3 summarizes the maximum forces due to various currents, faults, and conductor configurations. It may be noticed that a symmetrical three phase fault is not covered in this table. This is so because a symmetrical three phase fault is impossible since the currents are 120° out of phase and no time can be selected so that all three are simultaneously zero. It should be pointed out that all formulas are derived on the basis of the following two assumptions:

(i) The largest dimension of the conductor is negligibly small compared with the center-to-center distance between the conductors. If this assumption is not true, then a shape correction factor should be applied to the force obtained from these formulas as shown in Figure 2.3.

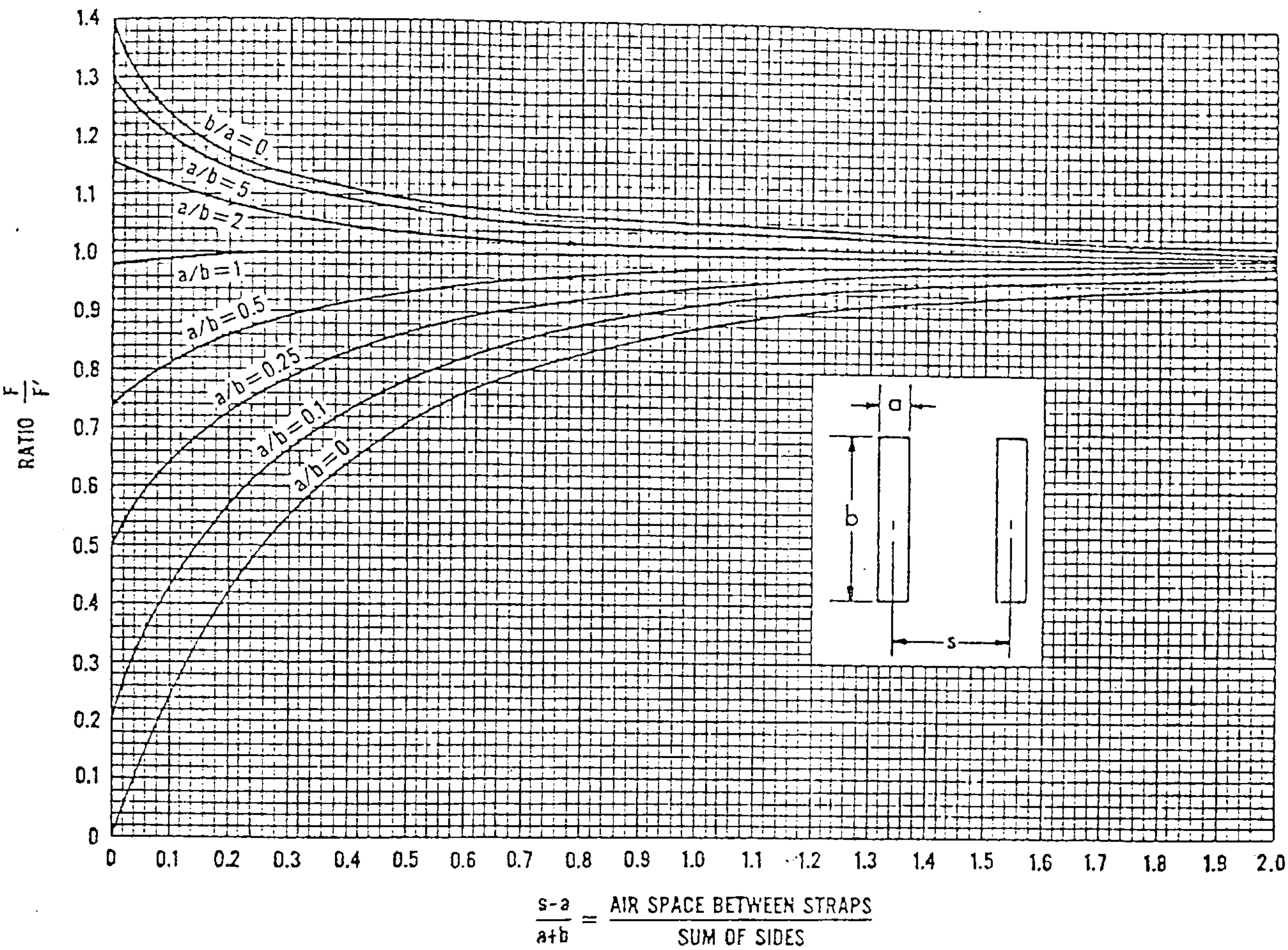
(ii) The conductors are assumed to be long, straight, and parallel to one another. When bends, crossovers, short lines, etc., must be considered, no simple and generally applicable formulas are available. Each application should be studied and analyzed individually.

Of extreme importance in calculating short circuit forces is that the short circuit current information obtained from short circuit studies should not be misused. Remember that in computing short circuit currents, the subtransient reactance of rotating machinery, except hydraulic generators, is used for the first cycle duty. Therefore, the amperes obtained are rms symmetrical containing no direct current component. <u>This component must be added to the calculated value before short circuit force analysis.</u> On the other hand, if the results from a

Table 2.3 SHORT-CIRCUIT FORCE ON BUS CONDUCTORS

SHORT-CIRCUIT CURRENT, I, GIVEN AS	TYPE OF FAULT	CONFIGURATION	FORCE ON CONDUCTOR	MAXIMUM F, IN POUNDS PER FT. (D in INCHES)
D-C		A B o o ├─D─┤	A or B	$F = \frac{5.4\, I^2}{D\,(10^7)}$
RMS symmetrical	Single-Phase Symmetrical	A B o o ├─D─┤	A or B	$F = \frac{10.8\, I^2}{D\,(10^7)}$
RMS symmetrical	Single-Phase Asymmetrical	A B o o ├─D─┤	A or B	$F = \frac{43.2\, I^2}{D\,(10^7)}$
RMS asymmetrical	Single-Phase Asymmetrical	A B o o ├─D─┤	A or B	$F = \frac{14.4\, I^2}{D\,(10^7)}$
RMS symmetrical	Three-Phase Asymmetrical	A B C o o o ├─D─┼─D─┤	B	$F = \frac{37.4\, I^2}{D\,(10^7)}$
RMS asymmetrical	Three-Phase Asymmetrical	A B C o o o ├─D─┼─D─┤	B	$F = \frac{12.5\, I^2}{D\,(10^7)}$
RMS symmetrical	Three-Phase Asymmetrical	A B C o o o ├─D─┼─D─┤	A or C	$F = \frac{34.9\, I^2}{D\,(10^7)}$
RMS asymmetrical	Three-Phase Asymmetrical	A B C o o o ├─D─┼─D─┤	A or C	$F = \frac{11.6\, I^2}{D\,(10^7)}$
RMS symmetrical	Three-Phase Asymmetrical	B D D A ├─D─┤ C	A, B or C	$F = \frac{37.4\, I^2}{D\,(10^7)}$
RMS asymmetrical	Three-Phase Asymmetrical	B D D A ├─D─┤ C	A, B or C	$F = \frac{12.5\, I^2}{D\,(10^7)}$

NOTE: Single-phase notation indicates either a single-phase system or a line-to-line fault on a three-phase system.



F=force between two equal long parallel bars
F'=force between two long parallel straight round conductors (see section on short circuit forces)

To use the curves, F¹ must be computed according to the discussion on forces due to short circuit currents before F can be determined.

The above curves have been drawn neglecting skin effect and assuming that the current density is uniform over the section of conductors.

Figure 2.3 SHAPE CORRECTION FACTORS FOR STRAP BUSES short circuit study are expressed in terms of rms asymmetrical values, it is necessary to ensure that these values are those immediately after short circuit and before the decrement sets in.

In addition to the short circuit forces described above, the conductor is also subjected to the loads from its own weight, ice, and wind. The weight loading is quite straightforward. Ice and wind loading are determined by geographical location. This country is divided into three districts for which standard loading conditions are specified in National Electric Safety Code [11]. The loading for the various districts is shown in Figure 2.4. The wind load on the conductor is

$$H = \frac{P(D + 2t)}{12}$$

where D = diameter of the conductor without ice in inches

t = thickness of ice in inches from Figure 2.4

P = horizontal wind pressure in pounds per square foot from Figure 2.4

H = wind force in pounds per foot.

The weight of ice on the conductor is

$$I = 1.24t\ (D + t)$$

in which I = weight of ice loading in pounds per foot.

Then the loaded weight on the conductor is the resultant of the vertical and horizontal weights plus the proper constant specified in Figure 2.4. The wind load is generally in the horizontal direction; the ice weight and the conductor weight are in the vertical direction; the short circuit forces can be either horizontal or vertical depending upon the physical layout of the conductor. Expressed in mathematical

ICE AND WIND LOADING ON ELECTRICAL CONDUCTORS	DWG.NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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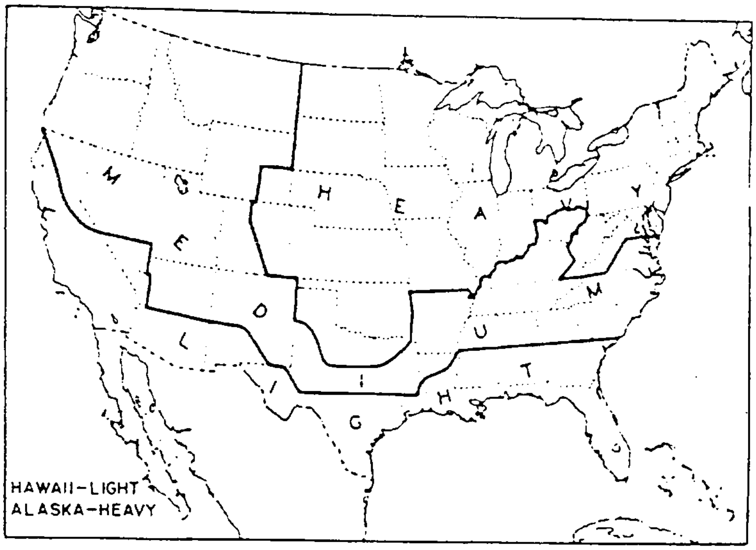

Fig 250-1
General Loading Map of United States with Respect to Loading of Overhead Lines

Table 250-1. Ice, Wind and Temperature

	Loading Districts (For use with Rule 250B)			Extreme Wind Loading (For use with Rule 250C)
	Heavy	Medium	Light	
Radial thickness of ice (in)	0.50	0.25	0	0
Horizontal wind pressure in lbs per sq ft	4	4	9	See Fig 250-2
Temperature (°F)	0	+15	+30	+60
Constant to be added to the resultant in pounds per foot: All conductors	0.30	0.20	0.05	0.0

From NESC Std. C2-1981, page 227

Figure 2.4 ICE AND WIND LOADING ON ELECTRICAL CONDUCTORS form, the resultant load on the conductor is:

$$F_t = \sqrt{F_h^2 + F_v^2 + K}$$

where F_t = resultant load on the conductor in pounds per foot

F_h = horizontal load on the conductor in pounds per foot

= sum of H and F_s, if applicable.

F_v = vertical load on the conductor in pounds per foot

= sum of I, the conductor weight, and F_s, if applicable

K = constant specified in Figure 2.4

During short circuits, the stresses imposed upon the conductor may be lateral, longitudinal, or torsional. These stresses are transferred to the insulator and other conductor support hardware. Of these three stresses, the lateral stress is probably the most destructive as it applies a strong cantilever force on the support system. In designing the conductor support systems, the following considerations can be taken as general guidelines.

(1) Try to keep the insulator in compression, if possible. This is because porcelain is roughly ten times stronger in compression than in either tension or cantilever.

(2) Good substation bus design, especially rigid metal bus, requires the use of flexible connectors at certain points in the bus. In general, they should be used at all terminals of machines, transformers, circuit breakers, disconnect switches and at intervals in long straight bus runs as required for thermal expansion.

Before leaving these topics, it is proper at this moment to discuss the calculation of the deflection of metallic buses and the mechanical stresses on the bus support systems. Because the loads to which they are subjected, that is, bus weight, short circuit forces, ice and wind, are uniformly distributed along their lengths, bus conductors are generally considered as uniformly loaded beams. For conductors requiring only two supports, deflection and stress calculations can be made by using the formulas for a simple beam. If more than two supports are required for a single length of bus, the formulas for a continuous beam apply. Formulas for these two cases are summarized in Table 2.4.

2.3.2 Transient Thermal Stresses

Electrical conductors are occasionally subjected to current overloads due to either short circuits or emergency conditions.

Under short circuit conditions, the ultimate conductor temperature depends upon (1) the magnitude of fault current, (2) the duration of fault current flow, (3) the material and cross sectional area of the conductor, and (4) the conductor temperature before short circuit occurs. Generally speaking, the duration of fault current flow is so short that for most practical purposes it can be assumed that no heat loss occurs by convection and radiation. Consequently, the temperature rise is determined by only the specific heat of the metal, the size of the conductor and the heat input. The specific heat varies as the temperature increases. Therefore, it is difficult to determine accurately the temperature rise of a conductor under short circuit conditions. For a particular type of conductors, manufacturers usually provide the short-time current temperature equation. For bare conductors, the maximum safe short circuit currents can be easily calculated from this equation, if given maximum allowable conductor temperature. Standard industrial practice recognizes a temperature of 300°C as the

BUS CONDUCTOR DEFLECTION AND STRESSES FORMULAS	DWG.NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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	Simple Beam	Beam Fixed at Both Ends	Continuous Beam 2 Spans	More Than 2 Spans
Maximum Deflection	$D=\frac{5wl^4}{384EI}$	$D=\frac{wl^4}{384EI}$	$D=\frac{wl^4}{185EI}$	①
Maximum Moment	$M=\frac{wl^2}{8}$ ②	$M=\frac{wl^2}{12}$ ③	$M=\frac{wl^2}{8}$ ④	$M=0.107wl^2$ ④
Fiber Stress	$f'=\frac{wl^2}{8S}$ ②	$f'=\frac{wl^2}{12S}$ ③	$f'=\frac{wl^2}{8S}$ ④	$f'=\frac{0.107wl^2}{S}$ ④
Maximum Load	$W'=\frac{8fS}{l}$	$W'=\frac{12fS}{l}$	$W'=\frac{8fS}{l}$	$W'=\frac{fS}{0.1071}$
Maximum Span	$l=\sqrt{\frac{8fS}{W}}$	$l=\sqrt{\frac{12fS}{W}}$	$l=\sqrt{\frac{8fS}{W}}$	$l=\sqrt{\frac{0.107fS}{W}}$

D = deflection in inches
w = load in lb/in. of length $\left(\frac{\text{Lbs per ft}}{12}\right)$
W' = total uniform load in pounds (wl)
l = span in inches
E = modulus of elasticity, lb/sq in.
I = moment of inertia, inches④
M = bending moment in pound-inches
S = section modulus, inches③
f' = fiber stress in lb/sq in.
f = maximum allowable fiber stress in lb/sq in. (The value of minimum yield strength is commonly used.)

①Maximum deflection occurs in the end spans and is only slightly less than that for a continuous beam of 2 spans.
②Maximum moment and fiber stress for simple beams occur at the center of the span.
③Maximum moment and fiber stress for beams fixed at both ends occur at the points of support.
④Maximum moment and fiber stress for continuous beams occur at the second support from each end.

Table 2.4 BUS CONDUCTOR DEFLECTION AND STRESSES FORMULAS maximum allowable for determining short time rating of buses; 340°C for all-aluminum conductors and 645°C for ACSR conductors. For insulated conductors, the IPCEA has established maximum allowable short circuit temperatures for various types of insulation.

Emergency loading normally occurs in transmission or distribution systems due to coincidence of peak loads with high summer ambients, shifting of additional loads to an already loaded conductor, use of high loadings to prevent icing and others. The procedure of determining maximum overload currents under emergency loading conditions is the same as that under short circuit conditions. In an emergency loading application, caution should be given to the fact that the effect of heating is cumulative.

2.3.3 Low Voltage Conductors: Special Considerations

As stated in Section 2.1, predictions of possible short circuit currents for high voltage circuits, where arcs are of a sustained character, can be made fairly accurately. However, in low voltage (600 volts or less), the effect of fault impedance is such that the actual current resulting from a fault is usually much smaller than that calculated. If this difference is not recognized, unnecessarily high costs for bus structures may be incurred.

Caution should also be exercised in applying relay current-time characteristics for the settings of protective relaying on low voltage lines that may be subjected to arcing burndown. The settings should be such that the relay will operate before any arcing burndown occurs.

2.3.4 Vibration of Overhead Conductors

Vibration is a frequent cause of failure or serious damage on overhead distribution and transmission lines. Because of the importance of such lines, even occassional failures must be avoided. Vibration of overhead conductors may be divided into two general classes:

(i) Resonant vibrations of high frequency and low amplitude. This type of vibration is most destructive and may be caused by either fatigue due to successive reflection of vibration or chafing. In either event, the failure usually takes place at the point of vertical support, and only occasionally elsewhere, such as at a dead-end, and even less frequently at a joint.

(ii) Vibrations of low frequency and high amplitude, usually known as dancing or galloping. This type of vibration is caused by passage of a current of air over the conductors perpendicular to the major axis. Damage caused by dancing conductors is usually due to flashover caused by conductors whipping about at high amplitudes and reducing the clearances.

To date, the most popular methods of minimizing the damage due to vibration involve either improvements in design of supporting clamps, or addition of accessories to the line. These methods come under three general categories as follows:

(i) Suspension clamps designed to permit vibration to pass through them without damaging reflection.

(ii) Reinforcements or armor rods at the suspension clamps which will increase the effective section modulus at the point of support.

(iii) Dampers which function to absorb vibration energy and prevent destructive vibration from building up.

2.4 Applications of Instrument Transformers

Instrument transformers are used both to protect personnel and apparatus from high voltage and to allow reasonable insulation levels and current carrying capacity in relays, meters, and instruments. Instrument transformer performance is critical in protective relaying, since the relays are only as accurate as the instrument transformers. Generally speaking, instrument transformers for metering and instrumentation require higher accuracy than those for protective relaying. In this section, only those instrument transformers for protective relaying will be covered. Special emphasis will be given to performance estimation of current transformer for relaying applications.

2.4.1 Applications of Current Transformers

The major criteria for selecting a current transformer ratio are the continuous current ratings of the connected relays and of the secondary windings of the current transformer itself. In practice, with load current normally flowing through phase relays, the ratio is usually selected so that the secondary output is around 5 amperes at maximum primary load current. In general, the performance of current transformers is not so critical for transmission and distribution line protection. However, it is most critical for differential protective schemes, particularly under transient conditions.

Since most relays commonly operate at currents of several times the maximum normal current of the current transformer, performance up to 20 times normal current is the basis for accuracy specification. At the same time there is usually little need to limit the ratio error to less than 10% and hardly any need to limit the phase angle for relaying. Consequently, the basis for classification of performance for relaying is an error of 10% at any current from 1.0 to 20 times normal current. Instead of a description of accuracy, ANSI accuracy classification is really a description of how much voltage the transformer can supply to the external circuit or burden. The performance of current transformers is then specified in terms of the secondary voltage which can be supplied by the transformers at 20 times normal current without exceeding the error limit of 10%. In addition to voltage ratings, the ANSI standard [12] also uses two letters, C and T, for class designation. Letter C means that the effective internal impedance is only secondary resistance. This implies that the exciting current by-passed through the exciting branch can be rather easily calculated if one has the saturation curve at hand. The C classification covers bushing current transformers with uniformly distributed windings, and any other transformers whose core leakage flux has a negligible effect on the ratio within the defined limits. On the other hand, letter T means that even if the internal reactance of the transformer is known, the calculation of the exciting current by-passed in the exciting branches is most tedious or even impractical. It is usual that performance of the transformer under this class should be determined only by test. The T classification covers most wound-type transformers and any others whose core leakage flux affects the ratio appreciably.

For relaying service application, the following current transformer data should be obtained from the manufacturer.

(1) Relaying accuracy classification.

(2) Mechanical and thermal short time (1 second) ratings. Both ratings define rms values that the transformer is capable of withstanding and should be checked against system fault current at the location of installation.

(3) Resistance of the secondary winding between the winding terminals.

(4) For Class C transformers, typical excitation curves on log-log coordinate paper are required. For Class T transformers, the manufacturers should supply typical overcurrent ratio curves on rectangular coordinate paper.

It is important to note that the above ANSI ratings are applicable to the full winding only. Where there is a tapped secondary, a proportionately lower voltage rating should be used for each tap.

From the preceding discussion, it is clear that the errors in ratio of a current transformer depend upon the total impedance connected to the secondary of the transformer. Unfortunately, many relays have variable impedance. For these applications, analysis of the transformer performance is usually based on an equivalent value at normal current. This can be justified on the basis that the burden at higher current is usually less and thus the current transformer will perform better than expected from the equivalent burden.

A current transformer's performance is measured by its ability to reproduce the primary current in terms of the secondary without saturation and large errors. Two common methods for performance estimation are excitation curve method and ANSI transformer relaying accuracy class method.

(A) Excitation curve method:

This method consists of the following steps.

(Step 1) Determine total burden on the transformer using the following expressions:

(1) with wye-connected current transformers:

$Z_t = 1.13\ R_1 + Z + R$ for three-phase faults

$Z_t = 1.13\ (2R_1) + Z + R$ for single phase-to-ground faults

(2) with delta-connected current transformers:

$Z_t = 3\ (1.13\ R_1 + Z + R)$ for three-phase faults

$Z_t = Z(1.13\ R_1 + Z) + R$ for single phase-to-ground faults

where R_1 = one-way lead resistance from the transformer to relays in ohms at 75°C

Z_t = total burden in ohms on the transformer

1.13 = a multiplier used to accommodate temperature rising during fault

Z = burden impedance of any devices connected or reflected to the current transformer in ohms

R = internal resistance of the transformer in ohms

(Step 2) Determine secondary CT voltage required, E_s, to deliver a given amount of secondary current, say I_s.

(Step 3) From excitation curve of particular tap of the transformer being used, determmine excitation current I_e corresponding to the required secondary voltage, E_s.

(Step 4) Determine the percentage error for the transformer. Applications of this method will be illustrated in Section 4.3, under the topics of differential protection.

(B) ANSI Transformer Relaying Accuracy Class Method:

In contrast with excitation curve method, this method gives only a qualitative appraisal for current transformer applications. To ensure the ratio error of a Class C transformer being less than 10% with maximum secondary fault current I_s flowing, the following criterion should be met.

$$NV + 100\ R > I_s\ (Z + R)$$

where N = proportion of total current transformer turns in use

V = voltage rating class, that is, Class C voltage

2.4.2 Applications of Potential Transformers

Two major criteria for selecting a potential transformer are the system voltage level and the basic impulse insulation level as required by the system on which they are to be used. ANSI Standard [12] recognizes three groups of potential transformers for different capabilities and connections.

Standard accuracy classification of potential transformers range from 0.3 to 1.2, representing percent ratio corrections to obtain a true ratio. These accuracies are normally high enough so that any standard transformer will not create any problem for relaying application as long as it is adequately used. Potential transformers are usually connected in open delta for balanced system; in wye-wye when line-to-neutral loading or metering is required; in wye-open delta for ground detection in an ungrounded system; and any specific connection as required by a particular relay.

2.5 The R-X Diagram

As the system complexity increases and higher operation reliability is required, it is an increasing trend to replace single operating quantity relays with multiple operating quantity relays. Surely this will increse performance exactness of protective relaying systems. But it raises the question, "How can we relate the characteristics of these more complicated relays to different system operation conditions?" The answer to this question will be found in the R-X diagram. Before examining this powerful tool, a brief review of ohmic relay characteristics is first given.

An ohmic relay is defined as a relay which responds to the following three variables: voltage, current, and phase angle. In general the relay will respond to at least three of the following four torque-producing components:

(1) Voltage component (torque proportional to V^2)

(2) Current component (torque proportional to I^2)

(3) Product component (torque proportional to VI $F(\theta)$)

(4) Control spring torque

Thus a general torque equation for the relay will look like:

$$\text{Torque} = \pm K_1 V^2 \pm K_2 I^2 \pm K_3 V I f(r, \theta) \pm K_4$$

where Torque is positive for a contact-closing torque

K_4 is a spring torque assumed to be constant

K_1, K_2, and K_3 are independent design constants of either sign and variable magnitudes.

r is the design angle of maximum torque.

Since a good example can serve hundreds of words, the following example will be used to illustrate the value of the R-X diagram. Considering a directional relay with voltage restraint, set $K_2 = K_4 = 0$ and select a minus sign for K_1, positive sign for K_3 and $F(r.\theta) = \sin (90° + r-\theta)$.

$$\text{Torque} = K_3 \; V \; I \sin (90° + r-\theta) - K_1 \; V^2$$

Consequently, the relay characteristic is

$$K_3 \; V \; I \sin (90° + r-\theta) = K_1 \; V^2$$

$$K_3 \; I \sin (90° + r-\theta) = K_1 \; V, \text{ if } V \neq 0$$

It is obvious that the relay characteristics are a function of system operation parameters V and I which are usually unknown under transient conditions. Even more complicated, prefault system operating conditions affect post-fault conditions, and different types of faults result in different system transient conditions for the same initial conditions. One key to this problem is the R-X diagram.

Remember $V/I = Z$.

$$Z = \frac{K_3}{K_1} \sin (90° + r-\theta)$$

It is obvious that system impedance seen by the relay should be less than $K_3/K_1 \sin (90° \; r-\theta)$ in order to operate the relay. From this example, it is clear that the value of the R-X diagram lies in the following two facts: relay characteristics can be simply shown and system conditions can also be shown on the same diagram as proven in the subsequent paragraph.

To illustrate how system conditions can be represented on the R-X diagram, a two machine system is shown on Figure 2.5(a). On the same figure is also shown the impedance seen by the relay located at substation A for different fault locations and one loading condition. By similar analysis, other system operation conditions can be shown on the diagram. Figure 2.5(b) illustrates loci of loss-of-excitation in

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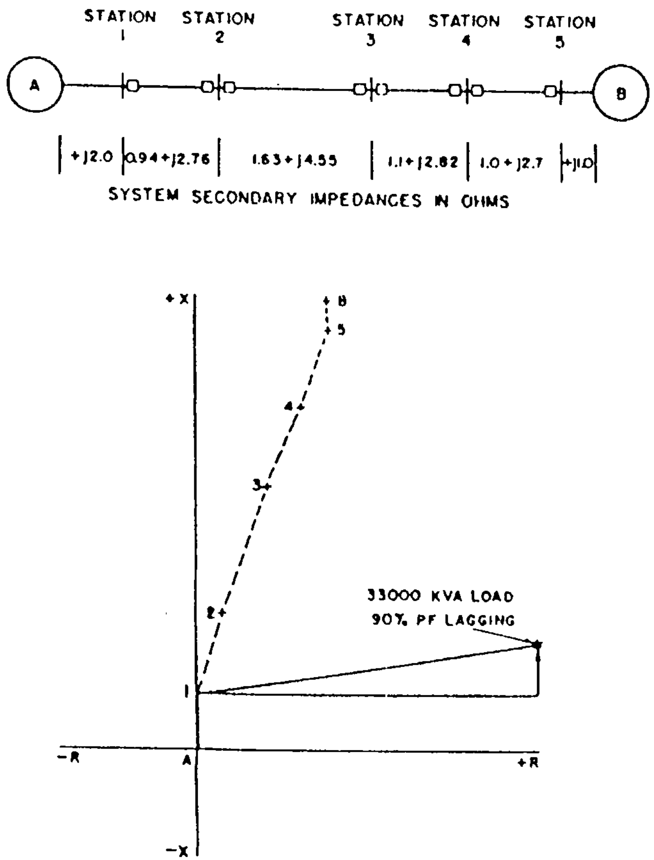
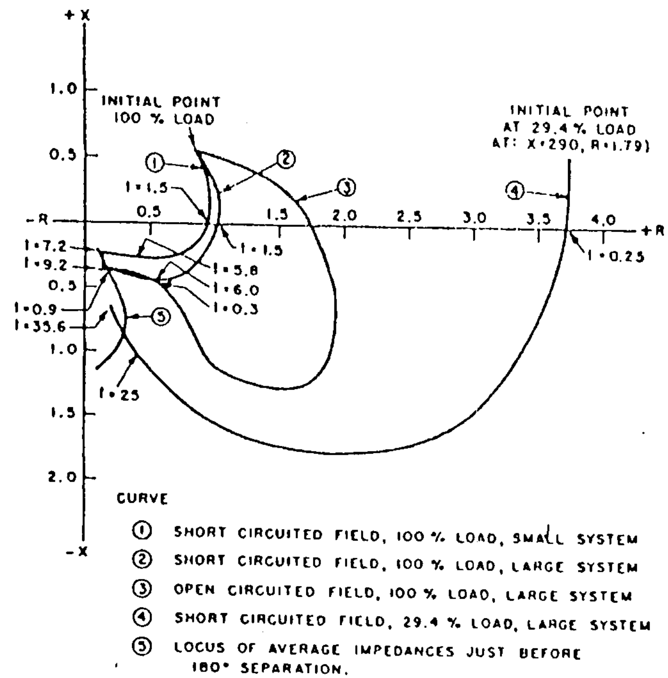


(a) *R-X Diagram of System Showing System Impedance Line and Large Load of Station 1 Single End Feed from Station A*



(b) *Typical Loss-of-excitation Curves and Average "Locus"*

Figure 2.5 SYSTEM CONDITIONS ON THE R-X DIAGRAM a synchronous generator.

After both the relay characteristics and system conditions have been plotted on the same diagram, the proper protective scheme for the system can be decided from the R-X diagram. This will be illustrated later in Chapters 3 and 4.

CHAPTER 3

GENERATOR PROTECTION

Surely the frequency of generator failure is low with modern design practices and improved materials. Yet failure can occur and may result in severe damage and long outages if not properly protected. The degree of protection for each generator is mainly a result of economic compromise. It should be carefully weighed against possible risk if no protection were applied, and acccording to the size and the importance of each individual machine in the system. Overprotection is as costly as underprotection. Optimum generator protection can only be obtained by individual engineering analysis of the particular installation. Since there are very few [4] provisions for generator protection, the design of generator protection will heavily rely upon individual engineering experience. This chapter will cover some recommended minimum protective features applicable to generators of various types and sizes together with some additional considerations in designing generator relaying schemes. Since the connection of a generator to an existing power system will dictate the type of grounding and protective system employed, system connection will be discussed briefly, too.

Generator faults can be either phase-to-ground or phase-to-phase faults, either in the stator winding (internal faults) or in the leads external to the machine terminals. Most generator faults will involve ground, and the amount of fault current will depend upon the method used to connect the generator to the system. Internal faults generally develop as a ground in one of the phase windings because of insulation failures and may occasionally involve more than one phase. Insulation failures occur due to overvoltage or reduced insulation strength, or more frequently a combination of both. Overvoltage caused by lightning and switching transients should be protected against by surge arrestors and will not be covered in this chapter. Reduced insulation strength is usually due to abuse and aging. Both result in drying out and baking the insulation until it loses its elasticity and approaches the carbonized stage. The most frequent types of abuse are overloading, lack of attention to the cooling system, and allowing dust to accumulate. All short circuits in the stator require the repair or replacement of the damaged stator coils. Consequently, it is extremely important to limit the duration of a stator fault for the following reasons:

(1) To prevent igniting the insulation material which may result in a fire.

(2) To prevent burning of the iron, possible costly replacement, and longtime service interruption.

3.1 Philosophy of Generator Protection

In order to minimize damage, when a short circuit develops in stator windings or in the connections up to and including the breakers, which connect the generator to the rest of the system, these breakers must be tripped immediately. This will prevent any outside source from supplying current to the short circuit. To stop a synchronous machine from feeding its own short circuit, it is also necessary to disconnect and collapse the field, and to de-energize the prime mover of the machine from its source of power. If the neutral of the generator is grounded through a neutral circuit breaker, the simultaneous tripping of this breaker along with the main breaker and the field circuit will help to limit the duration of arcing at a ground fault. It is general practice to trip all these breakers through a hand-reset auxiliary or lockout relay. This same relay should also shut down the prime mover and energize fire extinguishing equipment if required.

Overcurrent relays, which protect against ground faults only, may have very sensitive current settings. However, selectivity requirements may prevent the use of low current or fast time settings. It is also necessary to protect against those faults which start as phase-to-phase faults before the ground relays can operate. Unfortunately, phase-to-phase overcurrent protection has inherent limitations from the standpoint of sensitivity, selectivity, and speed of operation since overcurrent relays must be set above maximum load current and must also have time settings which should be coordinated with other relays in the system. For these reasons ordinary overcurrent relaying is seldom satisfactory for generator protection. Because of its selectivity and sensitivity, differential protection is generally accepted as standard for the protection of all generators above 1 MVA. The minimum size of machine for which it is desirable to provide differential protection is determined by balancing the cost of the protection against the importance of the machine. Differential protection is strongly recommended for smaller machines under the following conditions [4].

(1) Any KVA ratings, 5KV and higher

(2) 501 KVA and larger, 2.2 KV and higher

(3) Machines paralleled with larger machines or a system, which are differentially protected.

(4) Machines, regardless of size, which are important to the operation and reliability of the system.

In the instances where the cost of differential protection is not economically justifiable, current balance relaying can provide an acceptable substitute. In addition to winding faults, this type of relaying will also afford protection against single-phase operation.

Most field circuits of modern generators are usually operated ungrounded so that a single ground will not damage the machine at all. However, since a potential second ground may short part of the field winding and cause severe mechanical vibration, a ground indicating equipment should be used to detect the occurrence of the first ground and initiate an alarm.

The principles of external fault backup in generator protective relaying is to minimize damage from a feeder or bus fault in case the first line relays normally expected to protect these circuits fail to trip the proper circuit breakers. This backup relaying should be chosen to provide coordination with those first line relays.

For a turbine generator, a preheating schedule during startup may call for running the unit at reduced speed for several hours with the field energized. An induced voltage at reduced frequency will exist on the stator winding during this period. Adequate relays should be selected to detect possible faults during this reduced frequency operation.

For a hydro-generator, a sudden drop of full load may result in an overspeed of 14% or more of the rated value. The terminal voltage may reach as high as 200% or more if AC overvoltage protection is not provided. Therefore, overvoltage protection is essential and strongly recommended for all hydro-generators.

3.2 System Connection [13] [14]

The method of connecting a generator to an electrical system dictates the type of neutral grounding and protective schemes employed. In spite of various connection methods, all of these ramifications can be classified under two categories; direct-connected system and unit system, insofar as system protection is concerned.

(A) Direct-Connected System:

This system applies where at least some of the power generated will be distributed at the generator terminal voltage. It can be either solidly grounded or low resistance and reactance grounded. In its application, it has to be assured that sufficient ground fault current is available to operate system protective devices.

Where the ground fault capacity of the machine is approximately equal to the level required for the system protection, the machine could be solidly grounded although this is not generally recommended [13]. For installations where the possible ground fault level exceeds the values required by the system protection devices, the maximum ground fault current should be reduced to a level of 100 ampere minimum and 150% maximum of full load current by the use of grounding resistance or reactance. Usually, reactance grounding is applied where the generator supplies four-wire feeders at generated voltage, and resistance grounding, where three-wire feeders are supplied at generated voltage.

(B) Unit System:

In this system, each generator is directly connected to its individual transformer bank, the low-voltage side being delta, and the high-voltage size, wye. So far as ground fault currents are concerned, each machine is isolated from the others and the system. Hence, the generator ground fault currents can be limited to a very low value, but not less than the minimum necessary to actuate a protective relay [14]. A variation of this arrangement is sometimes used where two generators supply a common transformer bank.

The optimum method of limiting the ground fault current of a unit system is to insert the primary of a distribution transformer with a resistor across its secondary between the star point and the ground for a wye-connected generator. The resistor and the transformer are usually sized to limit the ground fault currents to a level of 5 to 15 amperes. For delta-connected generators [13] and unit generator system installations where there is no switching at generated voltage, potential transformer neutral grounding has also been applied successfully. In spite of these variations, both are known as high resistance grounding. Another alternative for limiting the ground fault current of a unit system is low reactance grounding. The neutral reactor will generally be selected so that ground fault current will not exceed the three-phase fault level.

3.3 Fault Protection

Generator fault protection functions to detect any faults either internally in stator windings or externally in terminal leads but within the generator relaying zone. It usually includes differential protection and stator ground fault protection. It is general practice that all fault protection devices should be arranged to trip the generator main circuit breaker, the field circuit and shut down the prime mover.

(A) Differential Protection (Device No. 87G)

In differential protection, the currents in each phase, on both sides of the machine, are compared in a differential circuit. The term "differential" is properly applied only to the connection of current transformers so that the net input to the relay is the difference between input and output currents. There are various modifications of the differential protection schemes, depending upon the type of relay used and the connection of the machine itself. However, in all these schemes, it is always good practice to use current transformers with the same characteristics wherever possible, and to avoid connecting any any other equipments such as meters and other relays to these circuits. It should also be noted that differential relays do not protect any open circuits, or turn-to-turn short circuits in most of these schemes.

Where perfectly matched current transformers at opposite ends of the windings are available, overcurrent relays in differential connection can provide excellent selectivity as well as very fast tripping. Actually, very few current transformers, even though they are commercially identical, have the same characteristics, especially under external fault conditions. Furthermore, the rapid increase in the complexity and loading of integrated power systems requires a more discriminative line of differential relays on each generator to all external faults without sacrificing selectivity and sensitivity.

The percentage differential relay meets all these requirements. This relay has two or more restraint windings which produce opening torques and desensitize the relay to high external fault currents. The percentage indicates the unbalanced current required to operate the relay as a percentage of the restraint currents. There are two types of percentage differential relays generally used for generator protection: constant percentage and variable percentage differential relays. A variable percentage differential relay is designed to be more sensitive and faster on light internal faults, but less sensitive on heavy external faults. However, it costs about 25% more than a constant percentage relay. It is generally recommended for the following applications:

(i) The situation where heavy saturation currents in current transformers may be encountered.

(ii) Full-voltage transformer energization during black start or following out-of-step synchronizing. This is so because these conditions will produce DC current flow in the machine. Since the time constant of rotating machinery is large, it may produce current transformer saturation, probably occurring at different times for the two current transformers in a given phase, that will persist for many cycles after the initial disturbance.

Most generators have wye-connected windings. Figure 3.1 shows a differential protective scheme for these generators, including DC tripping circuit. This scheme can protect against phase-to-phase fault whether generator neutral is grounded or not. With a solidly grounded neutral, the differential relay will operate on phase-to-ground short circuits in any part of the winding except a small portion very close to the neutral, depending upon relay sensitivity and setting. If

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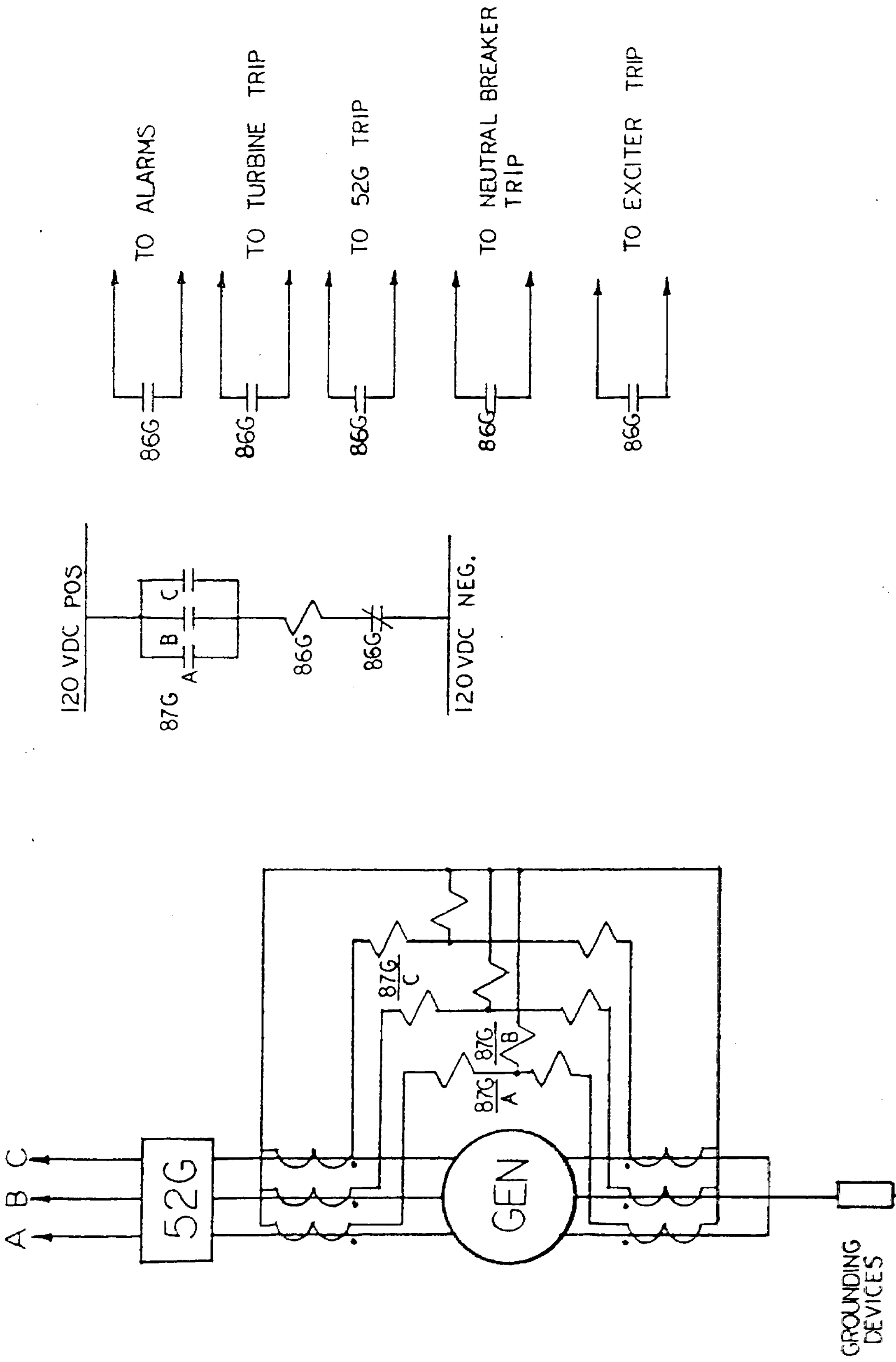

FIGURE 3.1 DIFFERENTIAL PROTECTION FOR A WYE-CONNECTED GENERATOR

current-limiting devices are inserted in the neutral, the effectiveness of differential relaying against phase-to-ground fault will be diminished slightly and there will be a somewhat greater portion of the winding next to the neutral for which no protection can be provided by the differential scheme. If the machine neutral is ungrounded, the scheme can still protect against phase-to-ground fault if the system is grounded elsewhere and the fault current is greater than the relay setting. It is quite obvious that the differential scheme will not respond to line-to-ground fault in a unit system. Figure 3.2(a) shows a differential scheme for a wye-connected generator having only one neutral lead brought out of the machine. In this scheme, residual line current, that is, the phasor sum of the line currents, is balanced against the neutral current. Consequently, it will protect against phase-to-ground faults for grounded neutral and ungrounded neutral providing the system is grounded elsewhere. However, phase-to-phase faults will not operate the relay and separate phase relays are required in this scheme. Figure 3.2(b) illustrates a similar protective scheme for delta connected generators. It will protect against phase-to-phase faults and phase-to-ground faults if the system is grounded elsewhere. In the instances where two sets of current transformers are not economically justifiable, a flux balancing differential scheme provides a substitute. Figure 3.2(c) shows an example of this scheme. This scheme requires that attention be given to the machine primary terminal connections since the generator protection zone will vary in accordance with the physical location of the current transformers.

(B) Stator Ground-Fault Protection (Device No. 51GN or 64GN)

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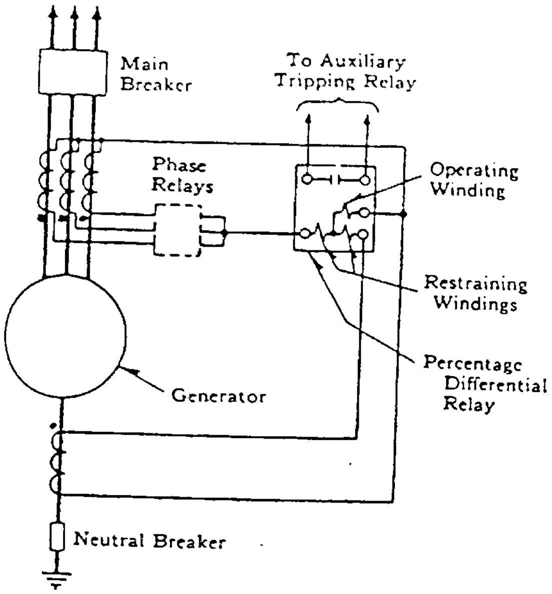
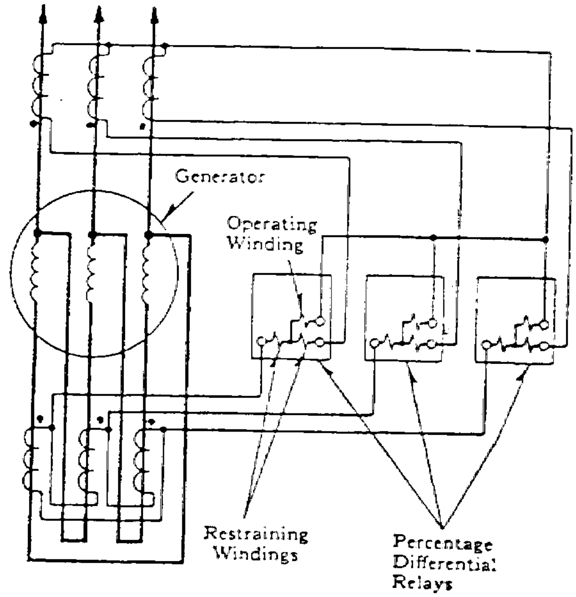


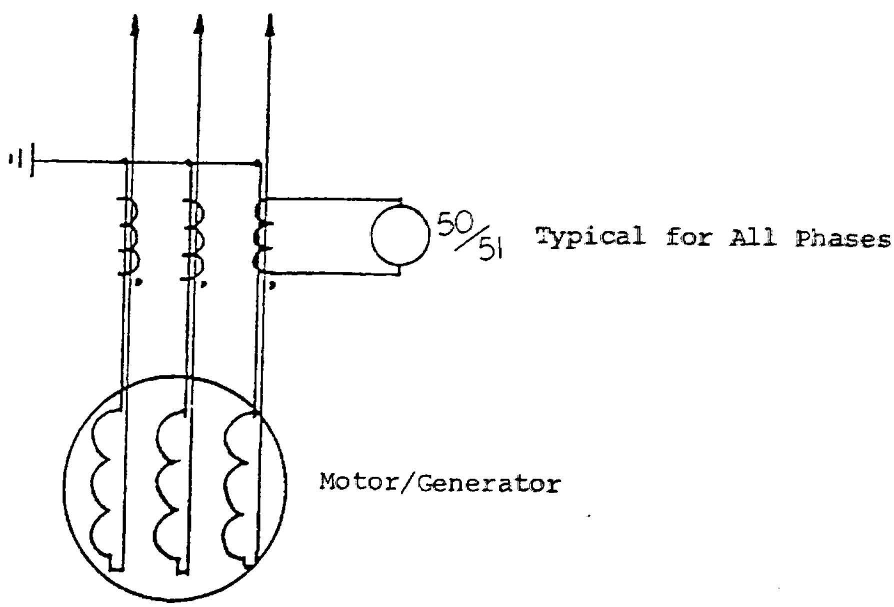
—Protection of a Generator Having Only Four Leads Brought Out.

(a) Protection of a Generator Having Only Four Leads Brought Out



—Differential Protection of a Delta Connected Generator

(b) Differential Protection of a Delta Connected Generator



(c) Flux Balancing Differential Scheme

Figure 3.2 TYPICAL DIFFERENTIAL PROTECTION SCHEMES

The method of grounding affects the degree of protection afforded by differential relays as described in the preceeding paragraph. Consequently, it is general practice to insert a separate ground fault relay in the neutral as a part of fault protection. This relay can be either a current sensitive type (Device No. 51GN or 50GN) or a voltage sensitive type (Device No. 64GN).

Typical applications of the current type ground fault relay are in direct-connected systems, that is, a generator connected directly to a bus with other circuits. Since a fault on one of these circuits might also misoperate the relay, a time delay is usually required to coordinate with other overlapping relays. Although this type of relay can provide sensitive protection to some extent, it becomes less applicable as the grounding impedance of the generator is increased. This is so because the lower the relay pickup, the higher its burden on the current transformer and the more difficult it is to discriminate ground fault current and the third harmonic current flowing in the neutral. This third harmonic current may reach 15% of the maximum generator output with solid grounding.

Applications of voltage sensitive type relays for ground fault protection can be best illustrated in a unit generator-transformer system. The relay used must be insensitive to the third harmonic voltage which may normally exist between neutral and ground, and yet still respond to the voltage shift of the generator neutral with respect to ground which accompanies a fault. Since the power transformer and the station service transformers are all connected in delta on the generator side, coordination with other protection is virtually unnecessary and the ground fault relay used can be very sensitive. However, some time delay in relay operation is usually provided to prevent tripping on system transient disturbances or faults in the potential transformers, if used. The general practice is to use the relay to trip the generator main circuit breaker and shut down the machine.

A ground fault relay is also economically justifiable in an ungrounded generator. Though no damage is likely to occur from a single ground, a second ground will result in phase-to-phase short circuit and requires a service interruption. The relay commonly used for such detection is a voltage-sensitive relay connected across the secondary of a potential transformer (bank) or an indicating voltmeter. The relay is generally used to initiate an alarm.

3.4 Abnormal Operation Protection

A generator in abnormal operation modes may be subjected to severe damage. The most frequent abnormal operation conditions include loss of excitation, motoring, negative sequence current, uncleared system fault, overloading, overtemperature, overvoltage, overspeed, over and under frequency, grounded rotor and so on. In addition to the potential damage to the generator, some of these conditions may also be disastrous to the system operation depending upon the relative size of the generator. In this section, protection schemes for these conditions will be discussed.

(A) Loss of Excitation (Device No. 40)

Partial or complete loss of excitation on a synchronous generator will result in a drop of terminal voltage, causing it to draw reactive power from the system. If the system is large enough to supply the deficiency in excitation through the armature, the machine will operate as an induction generator, running at 1 to 3 percent above the synchronous speed. Since synchrous generators are not designed for asynchronous operation, the machine output will oscillate as the rotor rotates in an attempt to lock into synchronism and severely damage the rotor, especially a non-salient one, by overheating. Furthermore, an excessive voltage drop represents a potential disaster. Consequently, it is a safety practice that loss of excitation protection should be provided for all synchronous generators. The decision remains as to whether the relay should trip the unit or sound an alarm. From the standpoint of generator protection, most modern generators can run two or three minutes at full load with zero excitation without endangering the generator. Consequently, the generator can stand a delay in tripping. From the standpoint of protecting the system against instability, the system cannot withstand the large reactive power displacement following loss of excitation accident. Therefore, it is a proper approach to plan to trip the generator on loss of excitation unless there is definite justification that the accident will not result in a major system disturbance.

Two types of relays are available for use as loss of excitation protection [1]. The simplest type is an undercurrent relay connected in series with the field circuit. However, this type of relay would not necessarily detect loss of excitation resulting from short circuit in the field winding. Where more complete protection is required, an impedance relay should be used. The basic element of loss of excitation relays is an impedance unit. When a generator loses excitation, the impedance seen by the relay looking into it will depend upon the machine characteristics, the load flow to the loss of excitation, and the type of excitation failure. Therefore, it may be necessary to use a timing unit, directional unit, undervoltage relay and others to prevent possible malfunctions of the impedance unit. As an example, Figure 3.3(a) illustrates application of an offset mho distance relay for a unit system protection [15]. Figure 3.3(b) shows system behavior under stable swings resulting from system disturbance. It is obvious from the R-X diagram that a time delay unit or another mho relay is required to prevent undesired tripping. This requirement depends upon the possible modes of generator operation, generator characteristics and the particular system concerned. Each application shall be individually evaluated and the generator manufacturer shall be consulted for protection requirements and relay settings.

An important consideration in the application of loss of excitation relays relates to the potential transformer secondary practice. In general, the potential transformers that provide potential to the relay will have other burdens connected between phases and possibly between phase and neutral. If a secondary fuse or circuit breaker on one phase is open, the potential on that phase will not necessarily go to zero. It will generally assume some potential depending on the impedance of the total burdens connected between that phase and the other phase and ground. <u>Thus, when potential transformer secondary fuses are used, it is recommended that the relay be fused separately from all other devices.</u> The blowing of a potential transformer primary fuse, when used, presents a similar problem that cannot generally be solved as

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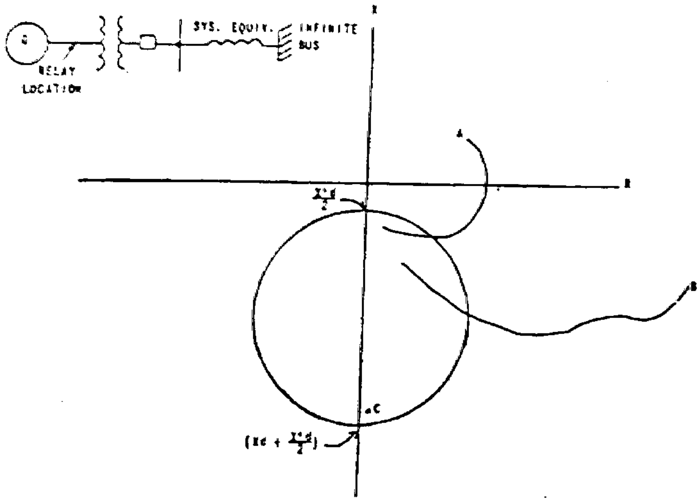
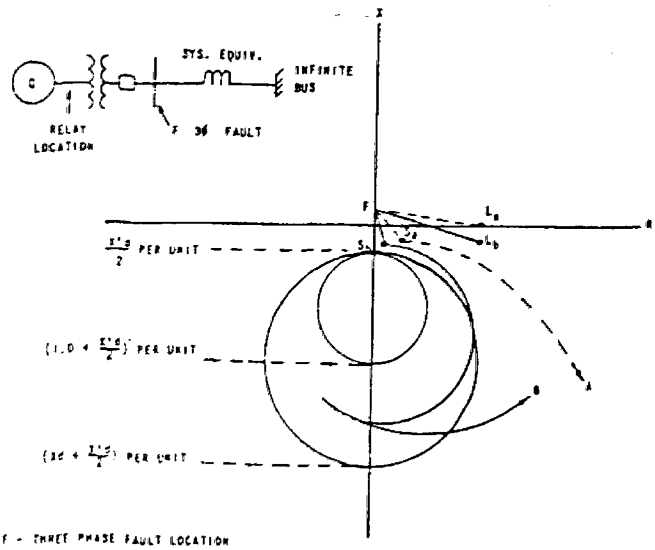


A - SHORT-CIRCUITED FIELD AT FULL LOAD
B - SHORT-CIRCUITED FIELD AT MODERATE LOAD
C - SHORT-CIRCUITED FIELD AT NO LOAD OR OPEN-CIRCUITED FIELD AT NO LOAD.

(a) Loss of Excitation for a Unit System by use of an Offset Mho Relay



F - THREE PHASE FAULT LOCATION
A - LOCUS OF SWING IMPEDANCE FOR CONDITIONS OF UNITY POWER FACTOR LOAD, AND/OR FAST FAULT CLEARING, AND/OR VOLTAGE REGULATOR IN SERVICE (DASHED LINES)
L_a - UNITY POWER FACTOR 1.0 PER UNIT LOAD IMPEDANCE.
S_a - IMPEDANCE IMMEDIATELY AFTER FAULT IS CLEARED
B - LOCUS OF SWING IMPEDANCE FOR CONDITIONS OF LEADING 0.95 POWER FACTOR LOAD, AND FAULT CLEARING AT CRITICAL SWITCHING TIME, AND VOLTAGE REGULATOR OUT OF SERVICE. (SOLID LINES)
L_b - 0.95 LEADING POWER FACTOR 1.0 PER UNIT LOAD IMPEDANCE
S_b - IMPEDANCE IMMEDIATELY AFTER FAULT IS CLEARED.

(b) System Behavior Under Loss of Excitation Conditions

Figure 3.3 LOSS OF EXCITATION PROTECTION easily as the secondary fuse situation. In order to prevent malfunction on a blown primary fuse, a voltage balance relay (Device No. 60) can be used to supervise the loss-of-excitation relay tripping contacts.

The basic considerations above apply to all types of prime movers. However, special caution must be observed in the case of hydro-generators and under-excited synchronous condensers. Hydroelectric generators may be operated severely underexcited during light load to compensate for system distributed capacitance. Therefore, the operating condition during a light load period can approach the loss of excitation condition in terms of impedance seen by the relay and may result in undesired tripping.

(B) Motoring Protection (Device No. 32)

If the turbine throttle or stop valves are closed while the generator remains connected to the system, the generator will run as a motor, receiving sufficient power from the system to supply friction and windage losses in the unit. The approximate power required to motor a generator depends upon the individual design of the generator. Listed below is the approximate power expressed as a percentage of nameplate rating from General Electric and Westinghouse catalogs.

	General Electric	Westinghouse
Condensing Steam Turbine	0.5 - 1.0%	3%
Noncondensing Steam Turbine	1 - 4%	>3%
Hydraulic Turbine	2 - 100%	0.2 - >2%
Gas Turbine	---	50%
Single-shaft Gas Turbine	100%	---
Double-shaft Gas Turbine	10 - 15%	---
Diesel Engine - 2 Cycle	25%	25%
Diesel Engine - 4 Cycle	15%	---

It should be noted that motoring will not endanger the generator itself at all. In fact, generator motoring protection is intended for the prime movers and the system as backup protection, rather than for the generator. For example, steam turbines will be overheated because of the lack of adequate steam flow to cool the blades and shroud, and generally will be protected by steam temperature devices. Similarly, hydraulic flow indicators will protect against blade cavitation on low water flow.

There are considerable variations in industry in the methods for protecting against damage from motoring conditions. There is so much divergence in practice that it is difficult to say which one is the most widely accepted. Since safe motoring times will usually be in the order of one minute or less, some companies, particularly in older or smaller stations, depend upon operators to notice the condition and initiate corrective measures. Other companies use directional power relays (Device No. 32) to detect the condition, to initiate an alarm, or to trip the generator main circuit breaker.

Regardless of these variations, a trend is developing to use an electrical reverse power relay to trip the unit from the system when motoring because of the increasing complexity of modern stations and the huge investment involved in larger generators. This is the protective scheme strongly recommended because it affords maximum protection to the prime mover. In case of diesel-engine generating units, reverse power relaying is imperative because of inherent danger of explosion and fire from unburned fuel.

(C) Unbalanced Current Protection: Negative Sequence Current (Device No. 46)

Negative sequence currents, inherent in unbalanced phase currents due to external phase faults or unbalanced loads, will induce twice-rated frequency rotor currents. These currents tend to flow in the rotor iron, slot wedges, and retaining rings, resulting in rotor heating. The capability of machines to withstand this heating can be best expressed as a function of the negative sequence current and of time [16]. This heating will not be excessive if the following condition is satisfied:

$(I_2)^2 t < k,$

where I_2 is the negative sequence current in p.u. stator current,

t is the duration of the fault in seconds, and

k is a constant for the machine.

Typical k values are tabulated below for design reference:

Type of Machine	k
Indirectly cooled Turbine Generators	30
Conductor-cooled Turbine Generators (up to 800 MVA)	10
Conductor-cooled Turbine Generators (800 MVA to 1600 MVA)	5
Hydraulic Turbine Generators	40
Engine Driven Generators	40
Synchronous Condensers	30
Frequency Changer Sets	30

Since the capability of machines to withstand unbalanced faults can be expressed as a function of $(I_2)^2 t$, the phase-balance current relay selected for generator protection shall have a time characteristic matching the $(I_2)^2 t$ characteristics of the machine.

There has been controversy on whether or not negative-sequence relaying is a primary protection. A fault which results in excessive negative-sequence heating will usually be detected by one of the first-line relays, either on the generator or on the system. In this respect, negative-sequence relaying may be regarded as backup relaying. On the other hand, none of the other relays are designed to protect expressly against this condition, nor can the negative-sequence relay serve as backup for balanced faults. Then, it seems proper to consider it as primary protection. Regardless of the above arguments and in view of possible major damage from overheating, it is recommended practice that all major generators be equipped with negative-sequence relays and that the relay trip the generator instead of initiating an alarm.

In case the negative-sequence relaying is intended as backup, it is essential that the relay time characteristic be coordinated with other relays in the system. If required, additional time delay units should be used to prevent undesired tripping due to system temporary disturbances. In the application of this relay, it is also important to check current transformer performance to assure that a false unbalanced current caused by current transformer errors will not trip the unit.

(D) System Fault Backup Protection (Device No. $51^{V}/21$)

Generator backup relaying is applied to protect either the machine itself or the external system in the event of failure of primary protection on the machine or system. The application and setting determination of backup relays are usually more difficult than for first-line relays. Not only is it necessary to foresee the system emergency conditions asking for the relay to operate, it is further necessary to know the operation of other protective devices under these conditions.

Because the application of backup relays depends so directly upon system conditions, no specific protective scheme can be recommended which will be suitable for all cases. However, it is general practice that some form of backup relaying be provided to open the generator main circuit breaker in case of system uncleared faults.

Following are two schemes which can satisfy requirements of most generator protection. One scheme uses three voltage sensitive time overcurrent relays, the other uses three single phase distance relays in conjunction with a timer. The choice between these two schemes is mainly governed by the type of system protective relaying with which these relays are to be selective. In general, the former scheme shall be used when the generator is directly connected to a bus at generator voltage, because such relaying is most selective with inverse time overcurrent characteristics generally used for lines connected to such a bus. The latter scheme is used with unit generator-transformer arrangement because the relay is most selective with distance or pilot wire relaying generally used for high-tension lines. In both schemes, the current source should be current transformers at the neutral ends of the generator windings if such CT's are available. With such connection, the relays will provide generator fault backup protection as well as system fault backup protection even if the generator main circuit breaker is open or there are no other generation sources in the system. If the neutral CT's are not available, then line-side CT's should be used. With such connection, the relays will backup the system and generator only when the generator main breaker is closed and there are no other sources of generation in the system. One point which deserves special caution in the design of external fault backup protection is that the phase-to-phase voltage shall be obtained from generator potential transformers. Loss of potential to the relays due to fuse blowing may cause misoperation of the relays. This can be resolved by the use of voltage balance relays (Device No. 60).

For protection of uncleared ground faults in the station bus, and the system, an inverse time overcurrent relay shall be used to provide backup protection. For directly connected machines, this backup protection can be obtained by connecting the relay across an additional CT on the neutral of the machine. For unit connected machines, a third harmonic restraint overcurrent relay in the generator neutral can detect ground faults only up to and within unit transformer low voltage windings. In order to obtain backup protection for uncleared faults on high voltage buses, transformer windings, or the system, another ground fault relay fed from a CT in the transformer high voltage neutral should be used.

In any scheme, backup protective relays should be arranged to trip the main circuit breaker, the field breaker and also shut down the prime mover.

(E) Overload and Thermal Protection

For most synchronous generators, overload protection is commonly supplied by temperature measuring elements embedded in the stator windings which will initiate an alarm. Thus, the condition can be corrected either by reducing the load, or by increasing any cooling means. Similarly, overheating of bearings (Device No. 38) shall also be alarmed by the same means. However, it is not general practice to provide relaying against rotor overheating since this heating is not measured directly. Usually a negative-sequence current relay is accepted as a substitute to indicate rotor heating.

(F) Voltage Relaying (Device No. 27, 59, or 60)

Voltage relays can be used for protection against alternating current over or under voltage, for permissive control or tripping of other devices, and for ground fault detection on equipments and feeders as discussed in the preceeding paragraphs.

Overvoltage relaying is recommended for prime mover generator installations, especially for hydro-electric generators, which may be subjected to overspeed and consequent overvoltage upon loss of load. In this application, the relay shall be arranged to open the generator and field circuit breakers. It may also be used as backup relaying for a voltage regulator and for its potential transformer in any installation since most overvoltage, that is overexcitation, cases are caused by leaving the voltage regulator on while generator speed is slowing down. In this application, the relay will either sound an alarm or initiate other equipment to reduce the generator excitation.

It is recommended practice to provide undervoltage relaying for synchronous converters and all alternating current motors. The relay will disconnect the armature circuit from the system upon loss of voltage or upon the occurrence of low voltage. Usually this protection should function with time delay dropout to prevent shutdown on transient voltage dips.

Voltage balance relaying is used to block relays or other devices that will operate incorrectly when a potential transformer fuse blows.

Some of these relays and devices are voltage restraint overcurrent relays, voltage controlled overcurrent relays, loss of excitation relays, synchronizing relays, automatic voltage regulators and some impedance relays. In this application, the voltage balance relay shall initiate an alarm as well as block the misoperation of other devices.

Another typical application of voltage relaying is capacitor switching control and automatic transfer of power supplies to critical circuits. In cogeneration applications, an induction generator may be operated in parallel with a capacitor bank. Overvoltage relaying is recommended for the capacitor protection. This application will be discussed in more detail later.

(G) Overspeed and Over Frequency Relaying (Device No. 81)

Since most modern generators are equipped with some type of mechanical or electromagnetic speed regulator, overspeed protection is not always necessary. In the absence of a mechanical overspeed protection, frequency relaying can be used to detect an overspeed condition indirectly. However, protection by mechanical devices is preferable because operation is more direct and does not depend on the presence of alternating current voltage.

(H) Rotor Ground Detection (Device No. 64F)

Although modern generator excitation systems are almost invariably operated ungrounded so that an accidental ground will not cause major damage, some means of continuous supervision of the field circuit to detect the first ground is generally applied. The detector will be used to initiate an alarm rather than trip the generator.

(I) Synchronism-Check and Synchronizing Relays [1]

The synchronism-check relay is used to verify when two alternating current circuits are within the desired limits of frequency and voltage phase angle to manually switch them to operate in parallel. These relays can also be employed on switching applications on systems known to be normally paralleled at some other location. In this case, they are only checking these two sources to insure that they have not become electrically separated or displaced by an unacceptable phase angle.

The synchronizing relay, on the other hand, monitors two separate systems that are to be paralleled and automatically initiates a switching action when the beat frequency, voltage deviation and phase angle difference are within the acceptable limits.

(J) Out-of-Step Protection [16]

As generator per-unit reactances have steadily increased over the years, and inertia constants have decreased with increased machine ratings, these conditions intensify the need for out-of-step detection as part of generator relaying complement. Ideally, generator out-of-step relaying should be designed to open circuit breakers at a few predetermined locations so that generation and load in each subsystem are reasonably balanced.

The basic element of an out-of-step relay is an impedance unit in conjunction with a timer, a directional unit, or another impedance unit. The relay differs from the loss-of-excitation relay in that it is usually equipped with undervoltage supervision.

3.4 Protection of Synchronous Generators

All power systems, whether utility, industrial, commercial, or residential, have a common purpose of providing electric energy to the utilization equipment as safely and reliably as is economically feasible. At present, synchronous generators play a core role in supplying electric energy in all these systems. This section will cover the minimum protective features for synchronous generators.

In industrial and commercial power systems, local generators are quite often included to either supply all or part of the total load or provide emergency power in the event of a failure of the normal source of energy. Generators used to supply all or part of the required system energy are operated almost continuously. They are usually turbine generators. Generation is usually at the system's higher voltage level. Those used to supply emergency power are normally shut down and are briefly operated when the normal power source fails or during maintenance, testing and inspection. They are usually diesel engine or gas turbine driven. Generation is usually at the voltage level of the largest load to be served. Generally, generators for industrial and commercial power systems are connected directly to the systems. Figure 3.4 shows the recommended protection for generators that are direct-connected to the system [4]. This figure is self-explanatory except 87G Relay. This relay is used to supplement the differential relay (87) where an impedance is applied to limit the maximum ground-fault current to less than the generator full load current. A current-polarized directional relay may be used for this application, its operating coil being connected to the differential circuit and its polarizing coil from a neutral current transformer.

Before leaving this topic, it is proper to clarify the following

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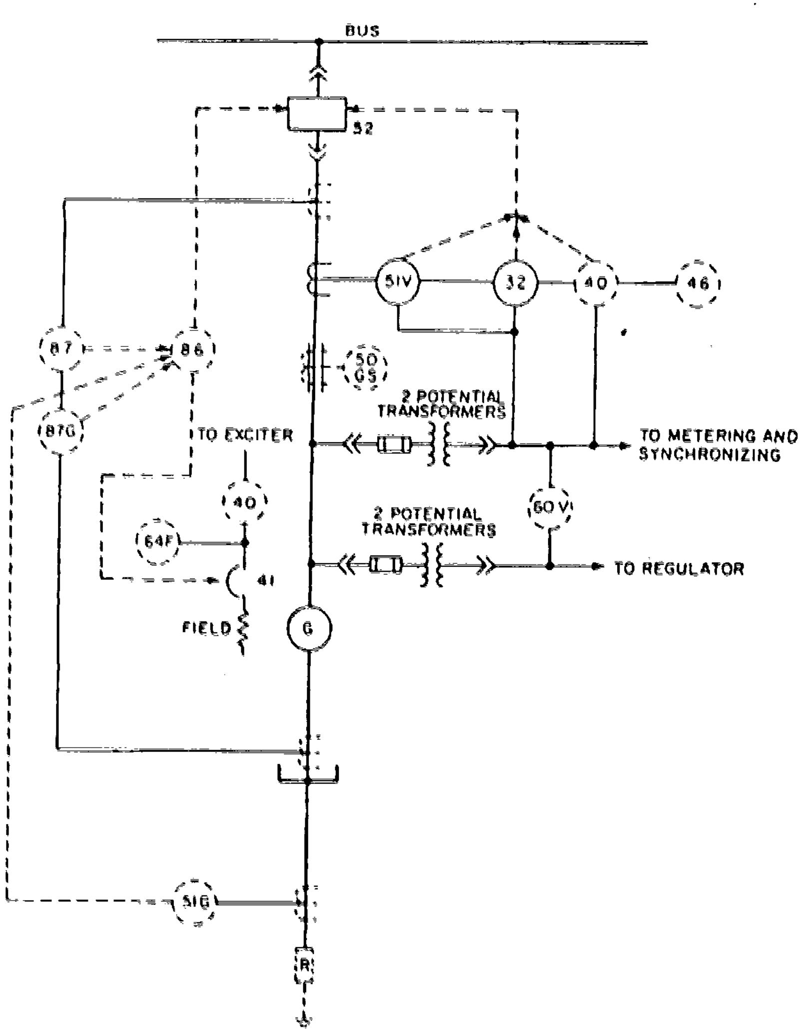

DEVICE NO.	DESCRIPTION
51V----------	Voltage-Controlled or Restrained Time Overcurrent Relays
51G----------	Time Overcurrent Relay (use if generator neutral is grounded)
50GS---------	Instantaneous Overcurrent Relay (use if generator neutral is not grounded)
32-----------	Power Directional Relay (may be omitted if protective function is included with steam turbine)
40-----------	Stator Impedance or Loss of Field Current Relay
46-----------	Negative Phase Sequence Current Relay
64F----------	Field Circuit Ground Detector
60V----------	Potential Transformer Failure Relay
86-----------	Lockout Relay (hand reset)
87-----------	Fixed Inverse-Time or Variable Instantaneous Percent Differential Relays
87G----------	Current-Polarized Directional Relay (Ground Fault Differential)

NOTES:
(1) ( ) denotes number of relays required.
(2) Devices shown dashed are optional for small or low-voltage machines
(3) Generators will be called "large" if:
   (a) 0-500 KVA (above 5 KV)
   (b) 500-1000 KVA (above 2.4 KV)
   (c) Above 1000 KVA (any voltage)
(4) Generators will be called "small" if:
   (a) 0-500 KVA (below 5 KV)
   (b) 500-1000 KVA (below 2.4 KV)

Figure 3.4 RECOMMENDED PROTECTION FOR SYNCHRONOUS GENERATORS, DIRECT-CONNECTED two points. First, where suitable current transformers are available, the flux balancing differential scheme shown in Figure 3.2(c) may be used. The relay for Device 87 should be of instantaneous type in this instance. In general, the sensitivity of this scheme should be selected as such not to require the use of 87G. Second, it is necessary that the static exciter, if energized from the stator circuit of the generator, shall include some means of maintaining excitation should the stator become short circuited. This is so because this condition may result in insufficient flow of fault current to ensure proper relay operation.

Contrasted with the direct connected system, the unit system is commonly used in generating stations. Figure 3.5 shows an overall protection scheme for a tandem compound unit connected generator. When a station service transformer is included in the zone of the generator differential protection, it may require that 87G utilize harmonic restraint. Generally, the type of generator prime mover will determine whether it is necessary to do so. In addition to the differential relay 87G protecting the generator, another percentage differential relay, 87T should be installed as shown in the figure. This relay serves as primary protection for faults in the generator leads and in the transformer as well as backup for the generator differential relay 87G. Current transformers for this relay should be installed on the bus side of the breaker in order to provide overlapping protection between the bus and the power transformer. Although the station service transformer is included in the power transformer protective zone, the differential relay 87T cannot be expected to protect the station service

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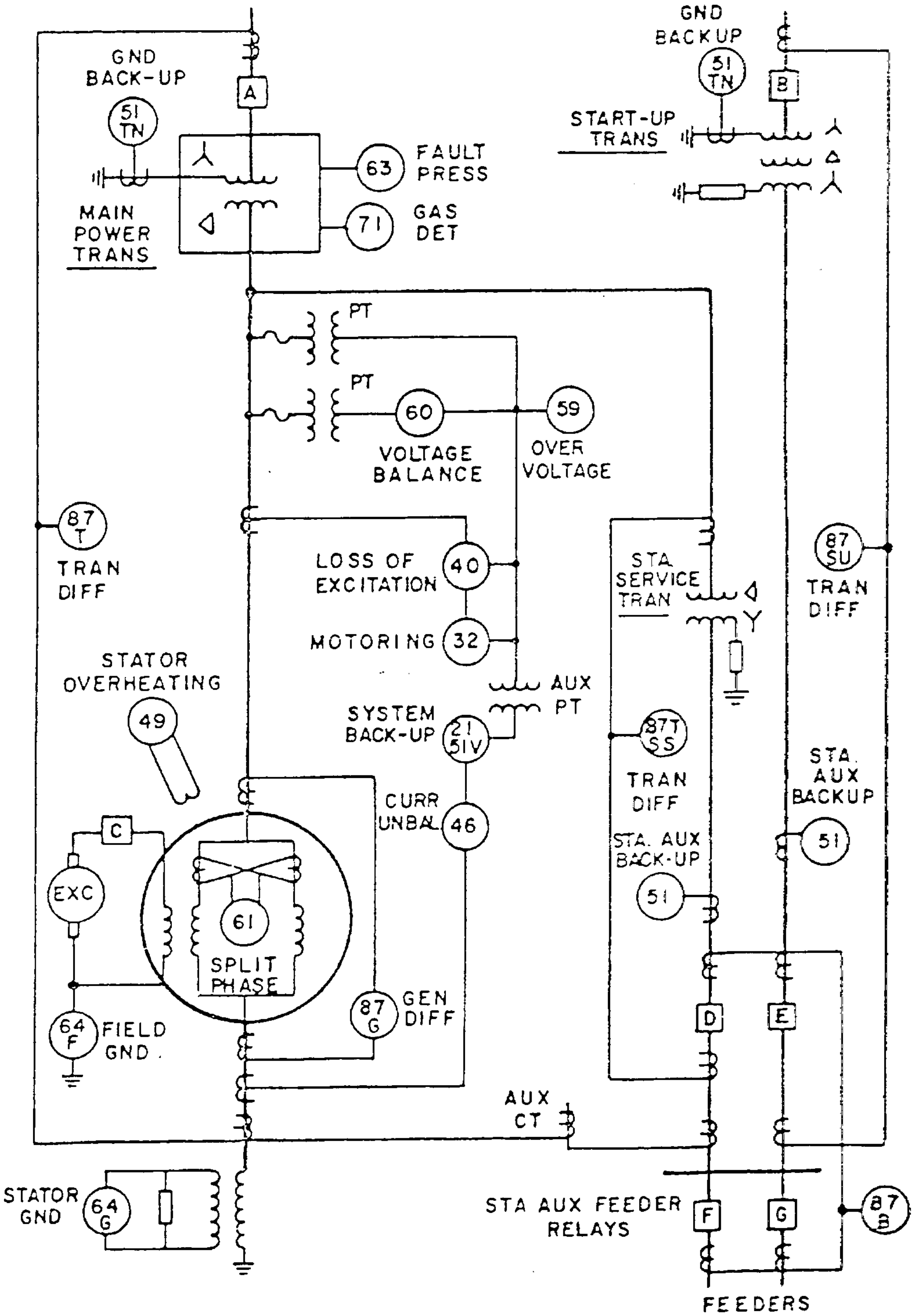

Figure 3.5 UNIT GENERATOR TRANSFORMER ARRANGEMENT

transformer due to the relatively small size of this transformer. A separate transformer or an overcurrent relay supplied from CT's in the station service transformer HV bushings will probably be required. Another overcurrent relay is also recommended to trip the station service LV circuit breaker only as a backup for the circuits on the station service bus.

Figure 3.6 illustrates an overall protection scheme for a cross-compound unit connected generator. It is self-explanatory except the following point. On cross-compound units, field is usually applied while the set is on turning gear. Application of field to such machines normally excites the generator step-up transformer as well as the generator so that protection is required for all of the unit system. The filter circuit of some harmonic-restraint relays may cause failure to operate if a fault occurs before the machine is up to synchronous speed. Since relay designs vary, the relay performance at reduced frequency should be checked.

3.5 Protection of Induction Generators

Recently, the cogeneration concept has gained the intense interest of electric utilities, industry, government, and most facilities with substantial energy requirements because of the increasing cost of fuel. Cogeneration is defined as the production of electric power and some other form of useful energy such as heat or process steam in the same or adjoining facilities.

Either the induction generator or the synchronous generator can be used in cogeneration applications. The induction generator has the advantage of simplicity in design and operation. The construction is

OVERALL PROTECTION SCHEME
OF CROSS-COMPOUND GENERATORS

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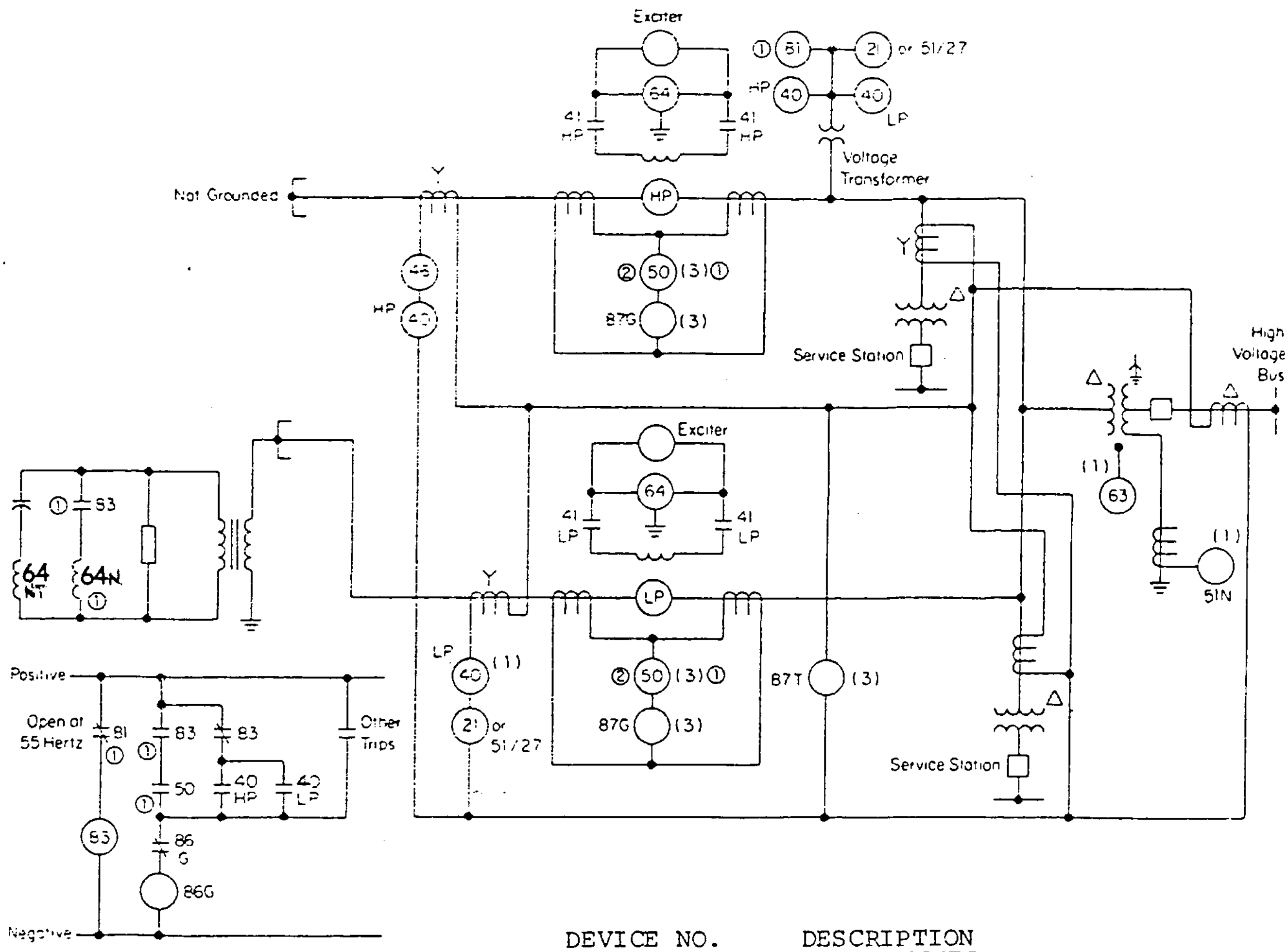

NOTE: ( ) shows number of relays required

DEVICE NO.	DESCRIPTION
21	Distance Relay
40	Loss-of-Excitation Relay
41	Field Circuit Breaker
46	Negative-Sequence Current Relay
50	Instantaneous Overcurrent Relay
$51^V/27$	Voltage Sensitive Time Overcurrent Relay
51N	Time Overcurrent Relay
64N	Voltage Sensitive Ground Fault Relay
64NT	Voltage Sensitive Ground Fault Relay
63	Sudden Pressure Relay
87G	Generator Differential Relay
87T	Transformer Differential Relay

Figure 3.6 OVERALL PROTECTION SCHEME OF CROSS-COMPOUND GENERATORS [16]

that of a squirrel cage induction motor. The field windings, provisions for rotating excitation supply to the field or separate field excitation equipment and slip rings as well as voltage regulation equipment are not required, but would be for a synchronous generator. The induction generator always assumes the same output voltage and frequency as that of the external system, so synchronizing equipment is not necessary. The protective relaying is essentially the same as that which would be provided for an induction motor of comparable size. However, the induction generator cannot be operated as an independent source when the external source is down because of its need for an external magnetizing power supply. Consequently, in an industrial plant where an uninterrupted supply is vital, the synchronous generator should be used.

Figure 3.7 illustrates a protection scheme for an induction generator. Unlike the protection scheme for a synchronous generator, the loss-of-excitation relaying is not required. Also, the flux self-balancing differential scheme is generally used for induction generator protection. The differential relay used can be the inverse-time overcurrent type, not the percentage type. The ground fault protection relay (50G) is generally fed from the residual of the primary side current transformers. Where a shunt capacitor bank is used to improve the overall power factor, the voltage relaying is required to protect the generator against over and under voltage. There are considerable variations in the industry in the applications of the anti-motoring protection to the induction generator. Where the machine is designed to operate both as a generator and a motor, the relay should be arranged to initiate an alarm but not to trip the unit circuit breaker. Where

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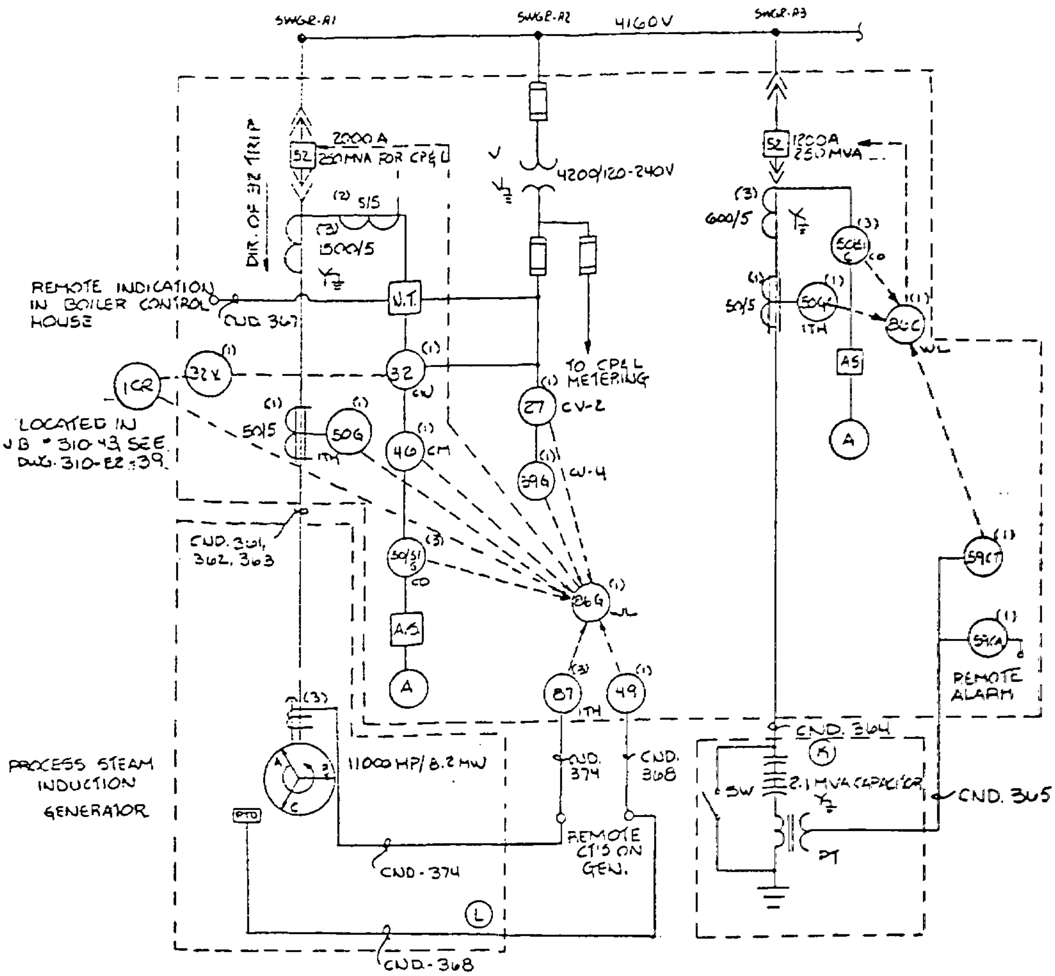

RELAY DEVICE LEGEND

27	WEST. CV-2	UNDERVOLTAGE RELAY
32	WEST. CW	DIRECTIONAL POWER RELAY
50151G	WEST. CO	EXTR. INVERSE OVERCURRENT RELAY
32X	WEST. SG	AUX RELAY
46	WEST. CM	PHASE BALANCE RELAY
50G	WEST. ITH	INST. OVERCURRENT RELAY
59G	WEST. CV-4	OVERVOLTAGE RELAY
87	WEST. ITH	GEN. DIFFERENTIAL RELAY
49	EDISON	TEMPERATURE MONITOR
86G/C	WEST. WL	LOCKOUT RELAY
50GC	WEST. ITH	INST. OVERCURRENT RELAY
59CT/CA	WEST	OVERVOLTAGE RELAY
1CR		TURBINE SHUTDOWN RELAY

Figure 3.7 PROTECTION OF AN INDUCTION GENERATOR

the machine is designated to operate only as a generator, the relay should trip the unit circuit breaker and shut down the generator. In some instances, reverse power relaying is provided to prevent power flow into the utility's incoming line. The relay for this purpose is usually arranged to trip the main incoming breaker. However, this type of application should be carefully studied for the particular installation since the tripping of incoming main breaker might be far more harmful than a reverse power flow to the utility.

CHAPTER 4

TRANSFORMER PROTECTION

At first thought, a power transformer might seem to be a highly reliable device, and this is correct as far as the mean failure rate is concerned. Yet, if we consider the mean down time per transformer-year, it is obvious that transformer protection is no less important than generator protection [4]. Contrasted with the several types of abnormal operation to which generators may be subjected, a transformer presents a much more limited protective problem.

A transformer may be subjected to short circuit, open circuit, and overload. Transformer failures can be grouped in the descending order of occurrence as follows [17]:

(1) Winding failures are the most frequent. Reasons for this include insulation failure and voltage surge. Voltage surge resulting from lightning and switching transients should be protected by voltage surge protective devices such as rod gaps and arresters. Two principal causes of insulation failure are overheating and overvoltage. Overheating because of overloading or failure of the cooling system will deteriorate the insulation. Insulation thus weakened may fail when it is stressed by only a moderate overvoltage. Insulation may also fail when a transformer is returned to service without first making sure that the insulation is free from moisture. Ground faults in ungrounded systems and sudden load shedding can subject transformer windings to severe voltage stress which may also cause winding failure.

(2) Tap changer and terminal board failures are attributed to improper design, assembly, handling in transportation, or mechanical

contact problems.

(3) Bushing failures due to aging, contamination, cracking, etc.

(4) Core failures involving clamping brackets or short circuited laminations.

(5) Miscellaneous failures including current transformer failures, liquid leakage, etc.

Transformer protection is generally achieved by current sensing devices, mechanical sensing devices, or more frequently combinations of the two. Current sensing devices including fuses, overcurrent relays, differential relays and pressure relays are used to protect transformers against short circuit. Mechanical sensing devices, including thermal relays, gas relays, etc., are designed to detect abnormal operating conditions.

Compared with other equipments in power systems, power transformer protection is different from others in the following aspects:

(1) Different voltage levels, including taps. This implies different primary current ratings in the connecting circuits, and consequently different current transformer types, ratios, characteristics with possible mismatch of ratios, etc. This might create problems in relaying.

(2) Magnetizing inrush current which appears to differential relays as an internal fault.

(3) Phase shift between the primary and the secondary.

Since published application guides covering transformers are few in number [17], protective relaying engineers must rely on their sound engineering judgment to achieve an adequate or optimal protection system. This chapter will outline some important points in designing power transformer protection systems. Special emphasis is put on power transformer relaying. Since magnetizing inrush has definite impact on relay function, it will also be briefly covered.

4.1 Philosophy of Power Transformer Protection

Among the current sensing devices for small transformer protection, fuses are widely used for this purpose. Although fuses have certain limitations, they have the merits of being economical, simple to maintain, and generally failsafe. This is true for many transformer sizes; however, transformers exceeding 2 MVA in rating are usually provided with more sensitive protection. Fuses can be reliably used to protect against external short circuit currents under most conditions, but cannot be relied upon to protect the transformer from internal faults or long time overload.

If considering fusing of a transformer, the following factors shall be taken into consideration in the selection of fuse links.

(1) Time current curves published by manufacturers should be corrected for ambient temperature conditions and prefault load currents.

(2) Maximum permissible load currents and the transformer heating curve recommended by standards.

(3) Transformer connections.

(4) Available primary system fault current and the transformer impedances.

(5) Coordination with low-side protection equipment.

(6) Maximum allowable fault time on the low-side bus conductors.

(7) Maximum degree of sensitivity for protection from high impedance faults.

Where more sensitive protection is required, it can be achieved by proper selection and combination of different types of relaying. Power transformer relaying in general includes abnormal operation sensing devices to protect the transformer and fault detecting devices to protect the system and limit damage in event of a fault. Abnormal operation sensing devices include thermal relays, pressure relief devices, gas detector, liquid level indicator, combustible gas relay, etc. Fault detecting devices include sudden pressure relays, overcurrent relays, differential relays and system backup relays. Again, differential relaying is the principal form of transformer protection. However, this type of protection cannot be as sensitive as that of generator protection due to the factors stated above although it does protect turn-to-turn and phaseto-ground faults. Pressure sensitive relays are generally used to detect either the rate of rise of gas pressure (sudden pressure), a slow accumulation of gas (gas detector), or more commonly a combination of both. Such relays are supplemental to differential and ground fault relaying for fault protection, and to overload relaying for abnormal operation protection. System backup protection and other forms of abnormal operation protection are sometimes used depending upon the requirements of the individual system design. In most cases, fault current sensing devices and combustible gas relays should be arranged to trip the transformer; on the other hand, abnormal operation relaying should be arranged either to initiate an alarm only or automatically shed parts of transformer loads.

4.2 Effects of Magnetizing Inrush on Differential Protection

The small component of current consumed in the power transformer for producing the necessary flux is negligible for differential relaying application in steadystate. This is true over the full range of transformer operation and even for several times full load current when a short circuit first occurs, because the unbalance due to the magnetizing current is small compared with the full load current and far below the relay pickup.

However, when a transformer is first connected to a power source after the transformer has been completely deenergized, there is a magnetizing inrush from 8 to 30 times that of full load current [16]. There are two other types of inrush, that is, recovery inrush and sympathetic inrush, but of lesser magnitude. There are several conditions that cause particularly severe magnetizing inrush phenomena. One involves the energizing of a transformer at a station at which at least one other transformer on the same bus is already energized. The inrush involves the already energized transformer as well as the one being energized, and the inrush transient is of particularly long duration. It is important to realize that the inrush into the transformer being energized occurs during the opposite half-cycle to that of the already energized transformer. Thus, the net inrush into all transformers on the same bus may be nearly a sine wave of fundamental frequency. This phenomenon makes necessary a separate harmonic suppression relay unit for each bank. Another inrush phenomenon involves the energizing of a transformer by means of an air switch. Arcing of the switch can result in successive half cycles of arc of the same polarity. Thus, if the first half cycle results in substantial residual magnetism in the transformer core, succeeding half cycles can cause a cumulative increase in residual magnetism, each time resulting in a more severe inrush.

Important differences between a magnetizing inrush current and a short circuit current are:

(1) A magnetizing inrush current has a dominant harmonic component generally either the second or the third order which is generally not present in a short circuit current.

(2) Accompanying a short circuit current, there is a voltage dip which is not present in a magnetizing inrush current.

To differential relays, the inrush current looks like an internal fault. Some methods commonly used to distinguish magnetizing inrush from fault include:

(1) Reduced sensitivity of percentage differential relays to the inrush current, that is, either a higher pickup setting or an intended time delay in operation.

(2) Restraints by harmonic components, especially the second order, of inrush current.

(3) Desensitization of the differential relays during energization.

In applying these methods, it is important that precaution shall be observed for the following considerations:

(1) While it is simple to prevent misoperation of a differential relay during inrush, care shall be taken that means should not delay tripping if a short circuit should occur during this period.

(2) When two or more transformers are connected to a common bus and switched separately, harmonic components generally existing in inrush currents may not be available for preventing mistripping depending upon the specific system configuration under consideration. This

is so because a transformer suddenly energized tends to take the harmonic components of the inrush current from the parallel banks while the fundamental component comes from the system [17].

(3) In the event of load injection, the transformer may be subject to substantial overvoltage and saturation. If saturation occurs, substantial exciting current will flow. In this case there are principally odd harmonics, particularly the third order. This may misoperate second-order harmonics constraint differential relays [17].

4.3 Fault Protection

Transformer fault protection should function to detect any faults either inside the transformer or outside in the terminal leads but within the transformer zone. It generally includes differential protection, ground fault protection, and sudden pressure relaying.

4.3.1 Differential Protection (Device No. 87)

(1) Types of differential relays:

ANSI Standard C37.91 [17] lists four general classes of transformer differential relays as follows:

(1) Differentially connected time-overcurrent relays

(2) Percentage differential relays

(3) Harmonic restraint percentage differential relays

(4) Desensitized percentage differential relays.

Among these, time-overcurrent relays connected in differential scheme are seldom used in transformer protection due to their susceptibility to misoperation from the magnetizing inrush.

The transformer percentage differential relay differs from that for generator protection in having higher percentage, that is, larger characteristic slope so that it has reduced sensitivity to the inrush current. The required percentage may vary between 15% and 50% depending on the type of the transformer protected and the system configuration. Generally speaking, 15% slope is for standard transformers; 25% to 50% for load tap-changing transformers, depending upon the range of tapping; 40% for special application [4]. Drawbacks of its application are:

(a) Its setting should be above the maximum possible inrush current. Since most pickups of differential relays on the market cannot be set in the field, replacement may be required as the system expands.

(b) Higher percentage means reduced sensitivity not only to inrush currents but also to fault currents.

This type of relay is particularly applicable to power transformers of moderate sizes located at some distance from the major source of generation [17].

The harmonic restraint relay makes use of harmonics, particularly the second order, present in the inrush current to discriminate magnetizing inrush from short circuit. It functions either to block false tripping or increase the pickup during the inrush period. Consequently, a lower normal pickup setting and a faster operation is possible without risk of false tripping. Unfortunately, there are still some problems as follows:

(a) During inrush, it will either not trip or delay tripping if a short circuit should occur.

(b) Sufficient harmonics may exist in high internal fault currents or in the system to inhibit relay operation.

(c) In the event of load rejection, it may respond to overvoltage magnetizing inrush.

The relay is most suitable for large power transformers located near large sources of generation where either severe inrush is highly likely or recovery and sympathetic inrush may create problems.

To overcome the inrush problem, the desensitized percentage differential relay utilizes the fact that a voltage dip always accompanies a short circuit. An undervoltage relay is used to control the desensitizing circuit of the differential relay. Under short circuit conditions, the undervoltage relay will remove the desensitizing circuit from the differential relay. Consequently, it also provides protection against short circuits happening during the inrush period.

(2) General Guidelines for Power Transformer Differential Relaying [16] As stated in prior sections, transformer protection design heavily relies upon engineeering experience and sound judgment. The following guidelines are designed to assist in selecting and applying differential relays for power transformer protection. These guidelines do not necessarily apply to special-purpose transformers such as those for power rectifiers, converters, inverters and induction furnaces

(a) There is no clear-cut answer to the questions of where a differential relay should be used, and which type should be selected if a differential relay is required. As a general rule, however, it is general practice to use percentage differential relays for all transformer banks rated 1 MVA and above and with 2400 V and above secondary voltage [4]. Percentage differential relaying is also recommended for transformer banks rated below 1 MVA that operate in parallel with differentially protected banks and have circuit breakers for all parallel-connected windings. This is so because it may prove just as damaging to the service as a similar fault occurring in a large bank if a fault occurring in a small parallel-operated bank is not promptly removed. For transformers from 1 MVA to 2 MVA and below 15 KV, desensitized percentage differential relays are recommended. For all transformers rated 2 MVA and above, or having windings rated 15 KV and higher, high-speed harmonic restraint percentage differential relays are recommended.

(b) Regarding the proper type of current transformers for differential relaying, it is general practice that bushing-type current transformers are used on the high tension side and are balanced either against other bushing type current transformers on the low tension side or against instrument type current transformers. Unfortunately, no general answer can be given to this question, but the procedures for current transformer accuracy calculation outlined in section 2.4 can be used to determine the answer to such a question.

In order that the relay will get as much current as possible, and hence be most certain to operate when transformer short circuits occur, the ratios of currrent transformers used should be chosen so that they will supply the relay with current approximately equal to its tap rating at maximum load. In case the multi-ratio current transformer is used, a tap which will give approximately 5 amperes at maximum load shall be used. This arrangement will generally provide good sensitivity without introducing thermal problems in the current transformer, the leads, or the relay itself.

In general, the use of low ratio bushing type current transformers should be avoided. Bushing type current transformers used for differential protection should have a minimum of 40 turns [17]. This is because these transformers show a marked departure from the turn ratio over the range from very low current to that limited by the power transformer on through faults, especially at 345 KV and higher.

For power transformers having three or more windings, all windings should be treated as having the same capacity as the KVA rating of the highest rated winding when determining the proper current transformer rating to use. This is because it is the voltage ratio, not the individual KVA rating of each winding which determines the current that will flow to an external fault. For tap changers, it is customary to choose current transformer ratios and relay adjustments on the basis of using a transformer tap at the middle of its range. Thus, with a plus or minus 10% range, the minimum current transformer unbalance will be plus or minus 10%.

In applications where a power transformer is connected to the rest of the system through two breakers, for example a ring bus or breaker-and-a-half arrangements, the CT ratios must be selected so that the secondary windings will not be thermally overloaded on load current flowing around the ring in addition to the transformer load current.

(c) A useful rule for determining current transformer connections in differential protection is as follows: The current transformers in the leads to a wye connected winding should be connected in delta; current transformers in the leads to a delta connected winding should be connected in wye. The connections should be so arranged as to block the zero sequence current from the differential circuit on external ground faults, and to compensate for the 30° phase shift introduced by the wye-delta connected power transformer bank.

For current transformer connections in a power transformer having three or more windings, consider any two windings first and connect the current transformers for those two windings as if they were the only windings; then consider a pair consisting of one of those windings and another, and so on till finishing all the connections.

Before leaving this topic, it is well to observe precaution never to ground interconnected current transformers such as those used for differential protection, at different points on a ground bus or to two different station grounds. A difference of potential betwen two points may occur and cause misoperation of the relay when ground current flows.

(d) Differential relays should be connected to receive "in" and "out" currents that are in phase for a balanced load condition. Where there are more than two windings, all combinations must be considered, two at a time.

(e) After the current transformer ratios have been determined, the relay taps should be so selected that the relay ratio is as close as possible to the ratio of the secondary current in the current transformers. Then the continuous rating of relay windings should be checked for compatibility with the power transformer load. If the currents supplied by the current transformers exceed the relay continuous rating, a higher current transformer ratio or relay tap should be used. However, it is desirable to increase CT ratio in preference to the relay tap. Since the relay burden is likely to be relatively small compared to the lead burden; increasing the CT ratio tends to improve the relative performance of the CT's as a result of reducing the maximum secondary fault current and increasing the accuracy of the CT's.

(f) The percentage of current mismatch should always be checked to ensure that the relay taps selected have an adequate safety margin. Percentage mismatch M can be determined as follows [17]:

$$M = \left(\frac{\dfrac{I_L}{I_R} - \dfrac{T_L}{T_R}}{S} \right) \times 100\%$$

in which I_L, I_R are currents supplied by current transformers on low and high voltage sides, respectively. T_L, T_R are relay tap settings for low and high voltage sides respectively. S is the smaller of (I_L/I_R) or (T_L/T_R).

For power transformers having three or more windings, all combinations should be calculated, two at a time. It is important that the total mismatch should include not only M but also load tap changing values (LTC).

(g) To ensure correct operation of the relaying scheme, the current transformer ratio error must not exceed a specific limit depending upon the specific relay characteristics used. Again, the procedures outlined in section 2.4 shall be applied to determine the percentage errors of the current transformers. In the next paragraph, an example will be used to illustrate checking the current transformer ratio.

(h) The total error of the differential scheme equals M plus LTC and CT ratio error. This value should be smaller than the relay slope used by a safety margin, usually at least 5%, to ensure correct operation of the scheme.

(i) It is not desirable to protect two or more power transformers connected in parallel with one set of differential protection as pointed out in section 4.2

(j) On a wye-delta transformer, which has a grounding transformer connected on the delta size, external ground faults on the delta side will cause zero sequence currents to flow in the wye connected CTs. These currents are not balanced by corresponding currents from the delta connected CTs and may cause spurious operation. To eliminate this misoperation, a zero sequence current trap can be inserted in the wye connected CTs circuit to correct the inbalance.

(3) Checks for Applying Transformer Differential Relays

The complete procedure for applying transformer differential relays is summarized in Figure 4.1 and can be best illustrated by the following example.

Considering the protection of a three-winding bank as shown in Figure 4.2, a harmonic restraint percentage differential relay with the following characteristics have been selected for the protection.

Tap Setting (A)	Operating Circuit Burden (VA)	Restraint Circuit Burden (VA)	Burden Impedance (Ohms)
2.9	3.2	1.3	0.180
3.2	2.7	1.2	0.156
3.5	2.4	1.1	0.140
3.8	2.0	1.0	0.120
4.2	1.9	0.9	0.112
4.6	1.6	0.8	0.096
5.0	1.5	0.7	0.088
8.7	0.7	0.5	0.048

The relay has a 25% slope and a time current characteristic curve as shown in Figure 4.3. The continuous and short time current ratings of

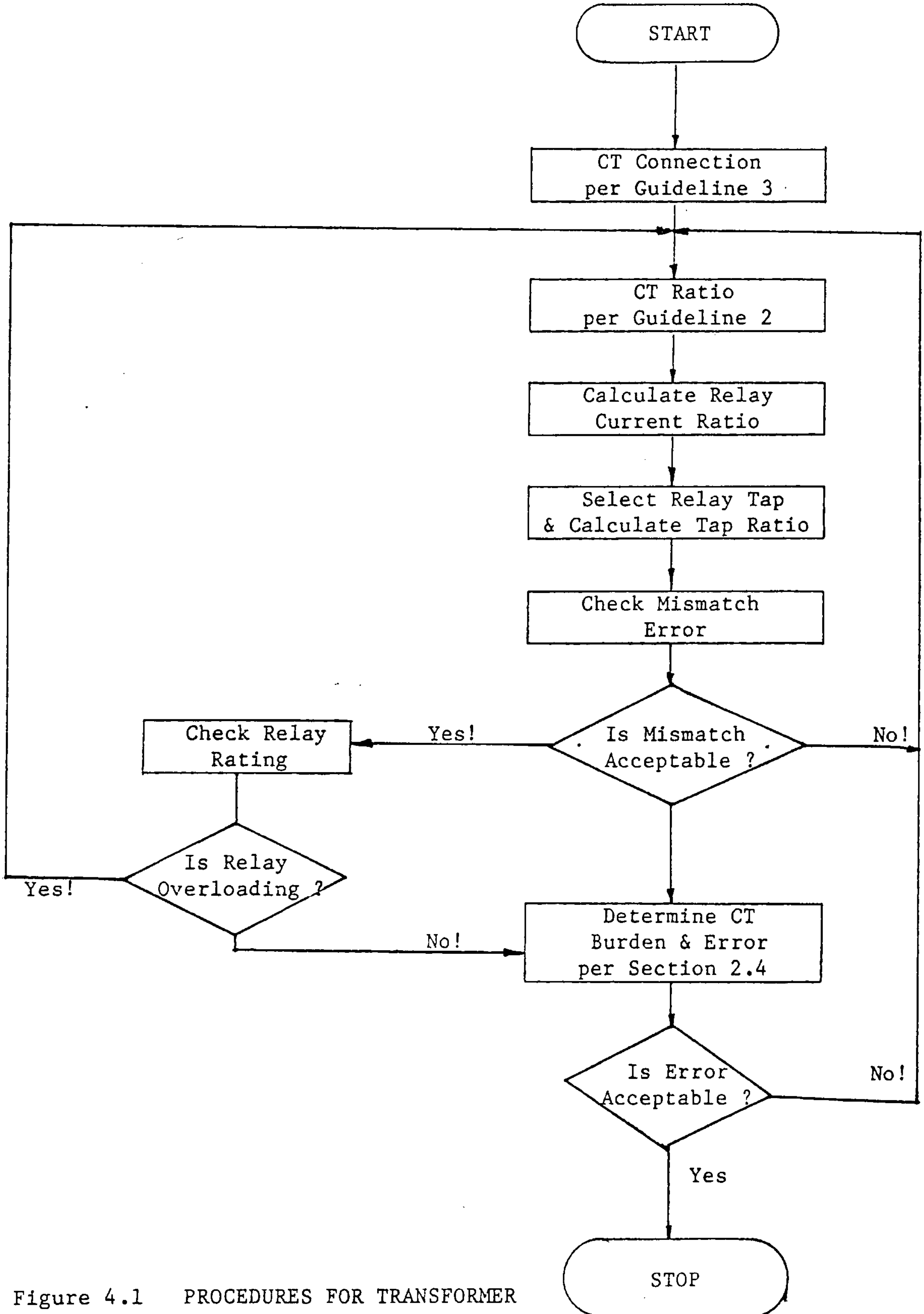

Figure 4.1 PROCEDURES FOR TRANSFORMER DIFFERENTIAL PROTECTION DESIGN

A THREE-WINDING TRANSFORMER BANK AND CTS' CONNECTION FOR DIFFERENTIAL PROTECTION	DWG.NO.	REV.	**Power Systems Engineering, Inc.** P.O. Box 19398 Houston, Texas 77024
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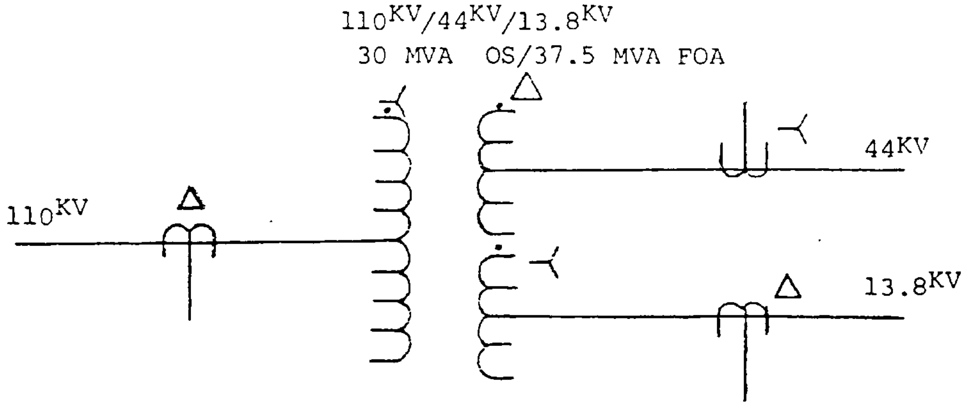

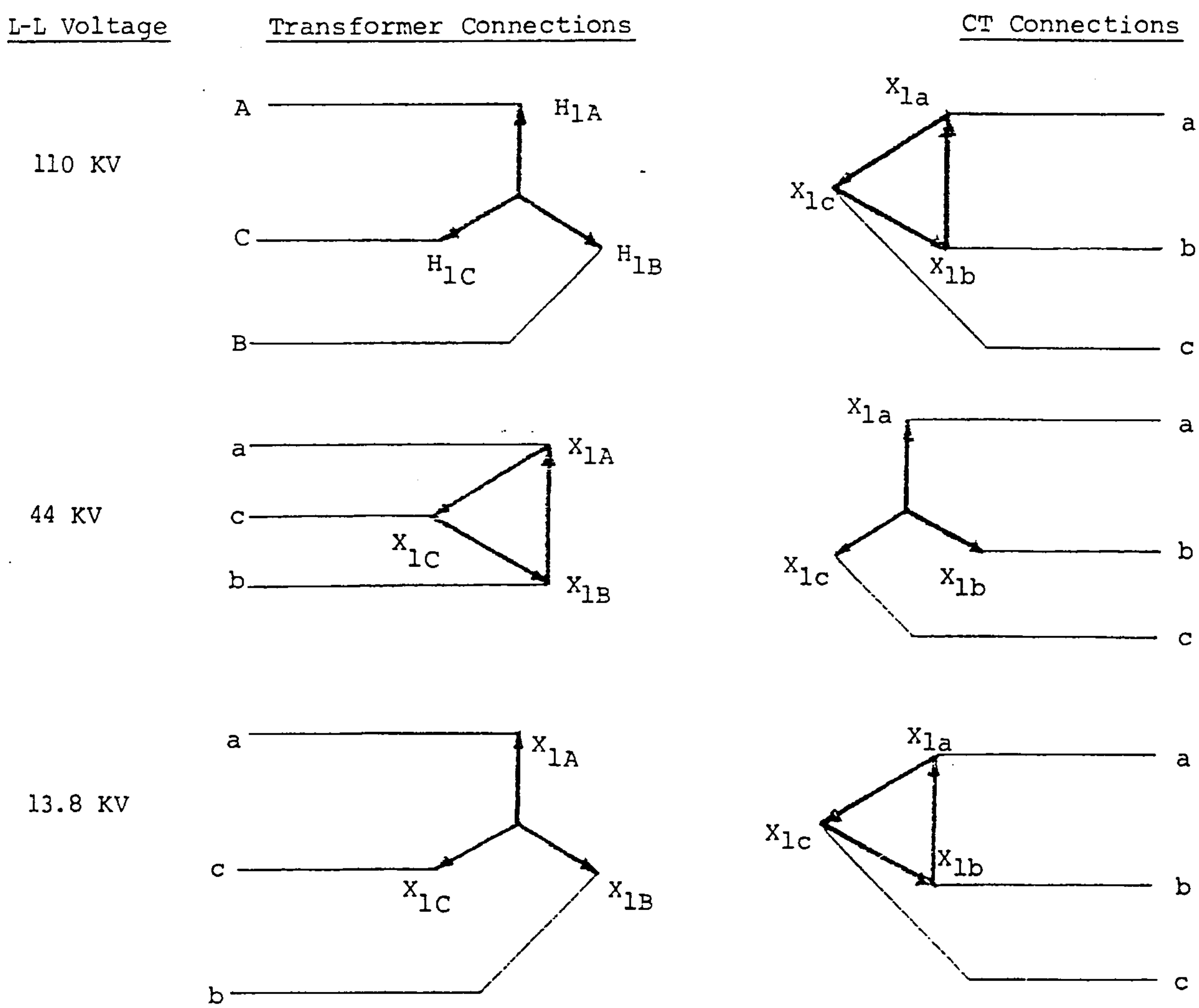

Figure 4.2 A THREE-WINDING TRANSFORMER BANK AND CTS' CONNECTION FOR DIFFERENTIAL PROTECTION

THE TIME CURRENT CURVES FOR THE TRANSFORMER DIFFERENTIAL RELAY	DWG.NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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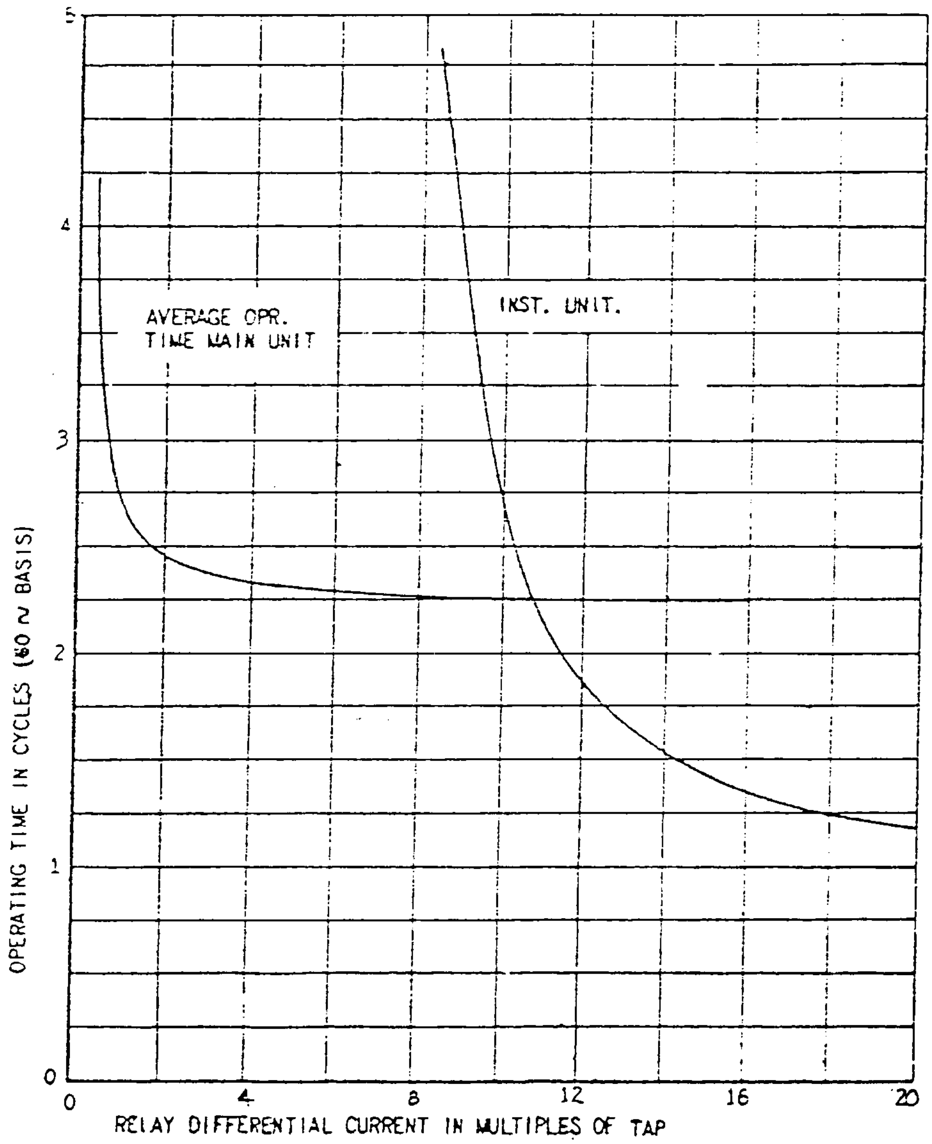

Figure 4.3 THE TIME-CURRENT CURVES FOR THE TRANSFORMER DIFFERENTIAL RELAY

the relay are 10 A and 220 A for one second, respectively. Furthermore, assume the maximum available fault level for a three phase fault is 1.6 GVA. Determine the differential protecting scheme for this transformer.

The designing procedure of the scheme is illustrated step by step as follows:

	TRANSFORMER WINDINGS		
	110 KV (Y)	44 KV (Δ)	13.8 KV (Y)
(i) Select CT ratio: $I_p = KVA/(\sqrt{3}\ V_{l-l})$			
$= 37{,}500/(\sqrt{3}\ V_{l-l})$	197 A	492 A	1,569 A
CT connections	delta	wye	delta
relay current factor (K_l)	$\sqrt{3}$	1	$\sqrt{3}$
CT ratio $\frac{I_p K_l}{5}$	400/5	500/5	3000/5
(ii) Select relay taps:			
Relay current (A)	4.27	4.92	4.53
tried relay taps (A)	4.2	5.0	4.6

(iii) Check mismatch errors:

Mismatch error between 110KV & 44 KV

$$= \left(\frac{\frac{4.27}{4.92} - \frac{4.2}{5.0}}{\frac{4.2}{5.0}}\right) \text{ X } 100\%$$

$$= 3.0\%$$

Mismatch error between 110 KV & 13.8 KV

$$= \left(\frac{\frac{4.27}{4.53} - \frac{4.6}{5.0}}{\frac{4.6}{5.0}}\right) \text{ X } 100\%$$

$$= 2.5\%$$

Mismatch error between 44 KV & 13.8 KV

$$= \left(\frac{\frac{4.92}{4.53} - \frac{5.0}{4.6}}{\frac{4.92}{4.53}}\right) \text{ X } 100\%$$

$$= 0.08\%$$

All are less than 5%, therefore, mismatch error is not excessive.

	110 KV (Y)	44 KV (Δ)	13.8 KV (Y)
(iv) Check relay ratings:			
continuous relay ratings (A)	10	10	10
maximum fault current (A)	8.398	20,995	66,941
$= 1.6\ GVA/(\sqrt{3}\ V_{l-l})$			
relay fault currents (A)	181	210	193

Select desired operating time according to the system requirement. From Figure 4.3, assume the required operating time is less than 3 cycles at 8 times relay tap value. This means that the current transformers should be able to supply the relay with 8 times rated relay tap current with an acceptable error. On the other hand, the relay short time current rating should be at least greater than the fault current supplied by the CTs. Given short time current rating of 220 A for one second, the short time rating for 3 cycles can be calculated as following:

$$(220)^2 \times 1 = (i)^2 \times \frac{3}{60}$$

$$i = 983 \text{ A for 3 cycles}$$

Therefore, both continuous and short time ratings are not exceeded.

(v) Check CT ratio errors:

Assume one way resistance is 0.25 ohms. The internal resistances of the CT's are 0.15 ohms for 400/5, 0.12 ohms for 500/5, and 0.09 ohms for 3000/5. Furthermore, assume that there are no other devices connected to these CT's. Then the total impedance burden on each CT can be easily calculated according to section 2.4. The results are:

Impedance burden, Ohms (Z)	1.33	0.49	1.23
8 times relay taps, amps (I_8)	33.6	40.0	36.8
Secondary voltage required (ZI_8)	44.7	19.6	45.3
Excitation current from excitation curve (I_E)	2.5	1.2	2.0
% ratio error (I_E/I_8)	7.4%	3.0%	5.4%

(vi) Check total errors:

Maximum of M + CT ratio errors = 10.4%

(vii) Safety margin available = 25% - 10.4% = 14.6% minimum.

Therefore, all CT taps selected are satisfactory.

4.3.2 Sudden Pressure and Buchholz Gas Protection (Device No. 63)

Buchholz relays can be applied to conservator type transformers and sudden pressure relays, to sealed tank construction transformers. These relays are more sensitive to light internal faults than the differential relay and generally recommended for all units of 5 MVA or more [16]. With the application of this type of pressure relay, many transformers can be simply protected by a plain differential relay with higher setting instead of harmonic-restraint type. Generally speaking, the relay should trip a separate lock-out relay from that tripped by the differential relay. In case the transformer is protected against short circuits by fuses, the relay should initiate an alarm.

4.3.3 Ground Fault Protection (Device No. 50/51N, or 67N)

It is general practice to apply ground overcurrent relays to each transformer winding which is supplied from a grounded system, to detect possible ground faults within that winding.

Where the transformer primary winding is not a zero sequence source and a single donut type CT can be fitted around all three phases, a sensitive instantaneous ground overcurrent relay should be used. If a donut type CT cannot be fitted, an inverse time/instantaneous overcurrent relay fed from the residual circuit of the phase CTs should be used.

Where a transformer primary winding is a zero sequence source, a sensitive instantaneous relay generally cannot be used since it will operate for primary system faults. An inverse time/instantaneous relay can be employed only if it can provide coordination with the system protection for both transformer and system faults. If the coordination required is difficult or even impossible to achieve, a product type directional ground overcurrent relay, current or potential polarized, should be used. If the current polarized relay is used, the phase and neutral CTs shall be relatively close together. If they are remote from each other, such as those in a transformer feeder, the potential polarized directional ground relay can be used. This relay should be fed from the phase CTs and polarized from an open delta potential transformer.

In general, an inverse time overcurrent relay fed from a CT in the grounded neutrals of all secondary windings and grounding transformers is used to provide transformer protection as well as system back-up protection.

In applying ground fault relays, precaution should be observed that only those circuit breakers connected between all ground fault current sources and the transformer will be tripped. This should be carefully studied and planned for the particular application. If the ground fault current can flow in either direction, the directional overcurrent relay should be used.

4.4 Abnormal Operation Protection

Transformer abnormal operation protection is designed to protect the transformer against any abnormal operation such as over-temperature, uncleared system faults, gas accumulation, and high pressure. It generally includes over-temperature protection, system backup protection, gas sensing and pressure devices. In this section, all mechanical devices, including gas sensing and pressure devices will not be elaborated since their applications are quite straightforward.

4.4.1 Over-Temperature Protection (Device No. 49)

Over-temperature relays, whose operation depends on the temperature of the transformer windings or the oil, are inherent selective and are recommended for all transformers 10 MVA and above [4].

These relays can be depended upon to trip the transformer main circuit breaker only when it becomes necessary, especially in unattended stations. In attended stations, they are generally arranged to initiate an alarm when the transformer overheats.

4.4.2 System Backup Protection (Device No. 51, 67, or 21)

A fault external to the transformer zone will result in an overload which can cause transformer failure if the fault is not cleared promptly. The transformer can be isolated from the fault before damage occurs by using either phase overcurrent relays or distance relays. As in generator protection schemes, the choice between these two types of relays is mainly determined by the type of system relaying with which the transformer relaying should be coordinated. As a rule of thumb, the same type of relaying should be used in both relaying systems, if possible.

Compared with generator protection, phase overcurrent relaying is far more complicated because of the wide range of load current and more coordination requirements in transformer protection. Generally speaking, system backup overcurrent protection should be fitted to all phases on the source side of the transformer. Overcurrent protection fitted to the load side of the transformer is considered as protecting the secondary system. For the transformer protected by separate differential scheme, phase overcurrent relaying also backs up the differential protection. For the transformer without differential relaying, it is considered as main protection for the transformer.

There are two types of overcurrent relays generally used for transformer protection. One is the inverse time overcurrent relay. This relay should have two elements, that is, instantaneous trip and inverse-time characteristic. The required degree of inverseness depends upon the particular application. To allow transformer overloading when necessary, the pickup value of the inverse unit should be set above this overload current. Settings of 200% to 300% of the transformer self-cooled rating are common, although higher values are sometimes used. Fast operation of the inverse time unit is usually impossible, since this relay must coordinate with all other relays it overreaches. Consequently, the applications of the overcurrent relay is limited by the insensitive setting and the delayed operation for coordination. Before advancing to the other type of overcurrent backup, it is proper to point out an application which requires special caution. Where an overcurrent is used to protect a grounding transformer, it should be fed from CTs connected in delta to prevent misoperation due to system ground faults.

The other type of overcurent relays generally used is the directional overcurrent relay. This relay provides best protection where fault current can flow in either direction. Generally, the relay should be connected to operate when the current flow is into the transformer. The directional element should be fed from the same CTs as the overcurrent element and, in addition, a polarizing voltage derived from a PT. In the applications of the directional overcurrent relay on a transformer primary which is a zero sequence source, it is general practice to use an inverse time overcurrent relay, fed from a CT in the primary winding neutral, to provide primary system backup protection. Of course, the relay should coordinate with other system relays. More discussions on the overcurrent backup protection will be covered in the next section.

The application of distance relaying on transformer backup protection is quite similar to that on generator backup protection. The distance relay used should be of the directional type. It should be connected to operate when the fault current flows toward the protected transformer. The setting should reach into, but not beyond, the transformer.

4.5 Protection of Power Transformer

Industrial applications of power transformers fall into the following four general categories; generator transformers, system interconnection transformers, power utilization transformers, and special purpose transformers such as voltage regulator, phase regulator, and so on. In this section, protective relaying for each category, except special purpose transformers, will be discussed. Some protection schemes are also given to illustrate the considerations covered in the first four sections. Since protective relaying design is really an art, the schemes given are for illustration only and should not be taken as standards. For any particular application, individual engineering study is required.

4.5.1 Protection of Generator Transformers

Since transformer protection of a unit connected generator is covered in section 3.4, no duplication will be given here. A protective scheme for a direct connected generator transformer is shown in Figure 4.4. Generally speaking, the transformer is a step-up transformer with its delta winding connected to the generator bus. The secondary winding can be either delta or wye connected depending upon the external system connection. The ground overcurrent relay (51G) in the grounded neutral of the wye winding should be of inverse time type and be coordinated with the system ground fault protection for a system ground fault. Similarly, the ground fault overcurrent relay (51G) in the grounded neutral of the grounding transformer is designed to backup generator bus ground fault protection and should be coordinated with generator bus ground fault relaying. In this scheme, a zero sequence trap is required on the primary side since a grounding transformer is shunt across the delta winding.

4.5.2 Protection of System Interconnection Transformers

A system interconnection transformer is used to interconnect two systems such as from transmission system to subtransmission system, or between two transmission systems of the same voltage, and so on. It is normally a wye-wye transformer or an autotransformer with a delta tertiary. The power flow can be in either direction. Figure 4.5 shows a protective scheme for a wye-wye transformer with delta tertiary. It is self-explanatory and straightforward except for the following considerations.

The tertiary winding is usually of much smaller rating than the

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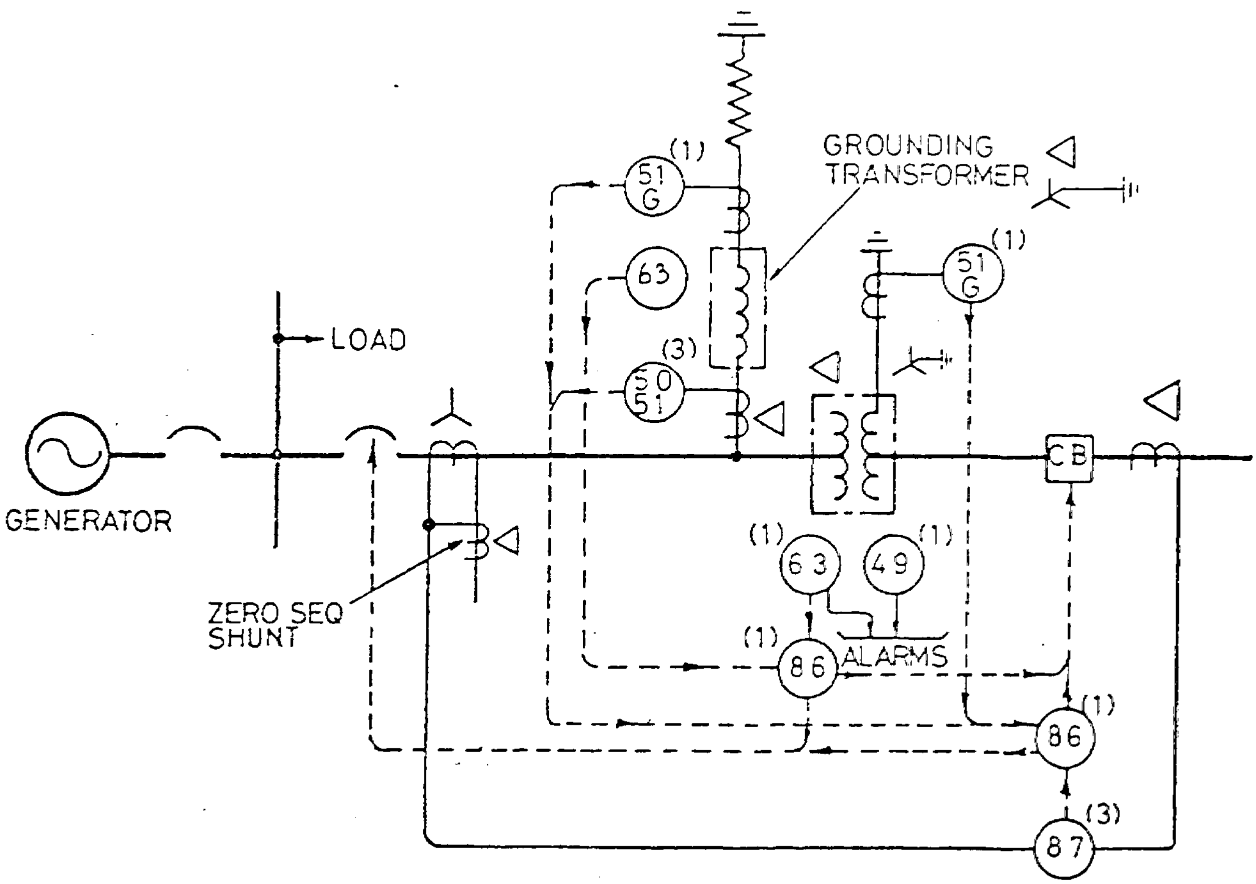

FIGURE 4.4 PROTECTION ARRANGEMENT FOR A GENERATOR TRANSFORMER

PROTECTION ARRANGEMENT FOR A WYE/WYE TRANSFORMER WITH DELTA TERTIARY (BURIED)	DWG.NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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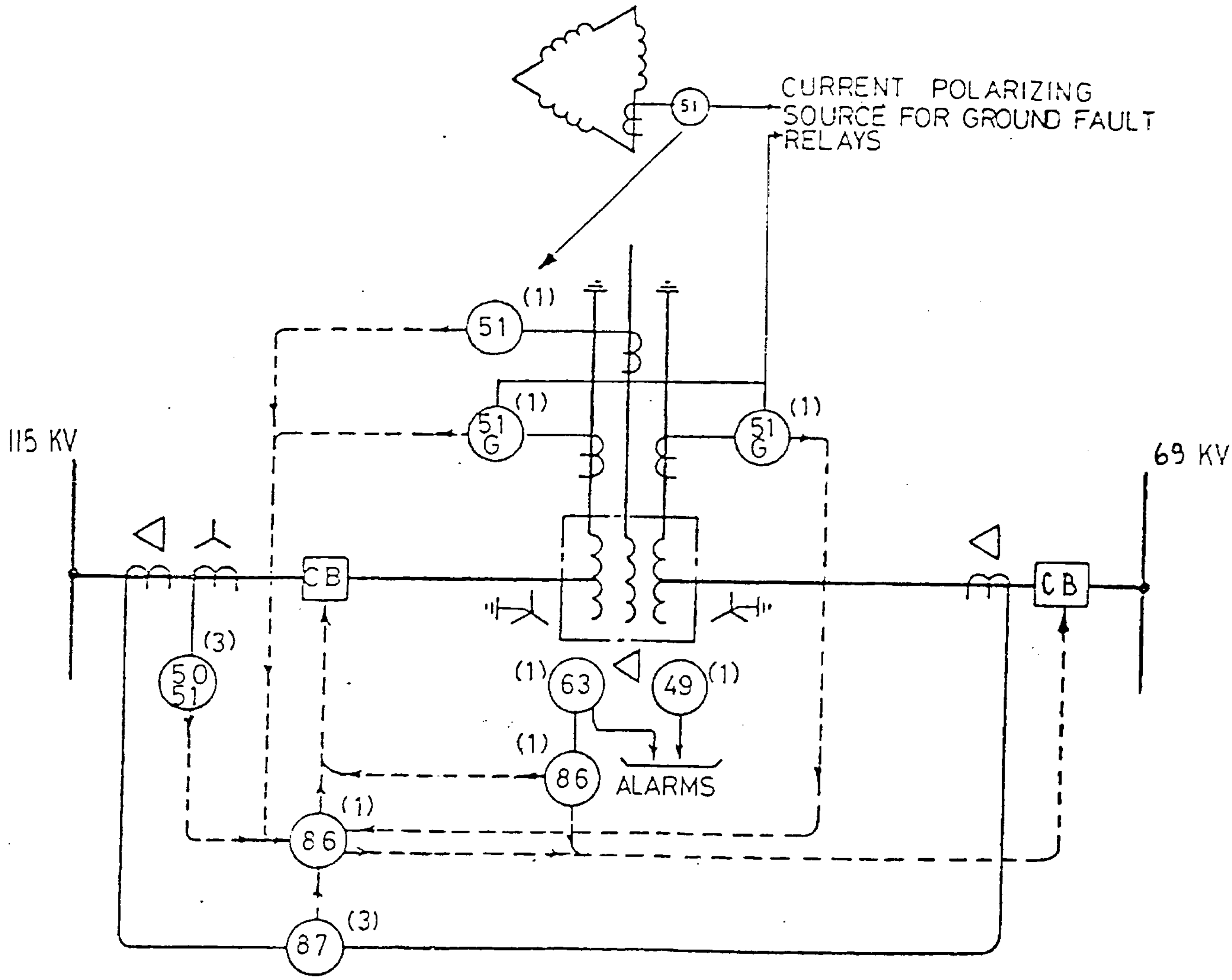

FIGURE 4.5 PROTECTION ARRANGEMENT FOR A WYE/WYE TRANSFORMER WITH DELTA TERTIARY (BURIED)

main windings and overcurrent relays set to protect the main windings offer very little protection to the tertiary. If the rating of the tertiary winding can be exceeded by the heavy fault current circulating in it on any external ground fault, a single inverse time overcurrent relay (51), fed from a current transforrmer in one leg of the delta should be fitted as shown. It is also noticed that two neutral current transformers and the current transformer on delta winding provide current polarizing sources for directional units, if used in the adjacent protection zones.

4.5.3 Protection of Utilization Transformers

Power utilization transformers are used at the point of industrial or other power consumption. They are normally step-down transformers connected between the high voltage (above 34.5 KV) power source and the distribution system or load. The power flow is normally from high voltage to low voltage. Since motors represent a typical load which requires special considerations in relaying design, they are the only load used for the purpose of illustration.

Various types of transformer installations and their protective schemes are shown in Figures 4.6 through 4.12. The characteristics of the phase overcurrent relays (50/51) should be of the inverse or very inverse type such that their settings can be coordinated with the secondary phase overcurrent relays (51), shown in dotted lines on the drawings. Along the same reasoning, 51 relays should coordinate with the downstream protection devices. When the motor is comparable in size with transformer rating, it may be difficult to coordinate the 51 relay with the motor protection while obtaining fast clearance times for high level faults and a low enough current setting to comply with the NEC, provision 340. Where the transformer supplies a single bus, this problem can be resolved by using a second set of phase overcurrent relays. One set should have a long time inverse characteristic and the second set normally has a standard inverse or very inverse characteristic. On the other hand, the motor must be protected by a differential scheme for sensitive fault detection. This arrangement can achieve good sensitivity as well as good selectivity, both of which may be unobtainable with only one set of overcurrent relays. Where the transformer is one of two or more feeding a multi-section bus, a partial differential scheme with a second set of phase overcurrent relays can provide the solution to the problem stated above.

If the motor on the low voltage bus is synchronous rather than induction type, it will continue to supply current to a fault until the motor comes to rest. For this protection, it is necessary to ensure that 50/51 relays will not operate for a high voltage system fault. If the misoperation may occur, directional overcurrent relays (67) should be used as shown in alternative 1 in Figures 4.6 through 4.12. For the same reason, directional overcurrent relays should also replace 50/51 relays if the low voltage bus has another infeed and fault current can flow through the transformer in either direction.

As shown in the figures, power transformers with a delta primary should be fitted with an instantaneous ground fault relay (50GS) supplied from a "donut" type current transformer. If a donut CT is not available, a relay with an inverse time/instantaneous characteristic (50/51N) supplied from the residual of the phase current transformers should be used. In case of a wye primary, the transformer contributes current to a high voltage system ground fault. Instantaneous ground fault relay (50GS) cannot therefore be used. A residual inverse time instantaneous overcurrent relay (50/51N) or a directional overcurrent relay (67N1) with another ground fault overcurrent relay (51G) should be used. The 51G relay should be fed from a transformer neutral current transformer and be coordinated with the high voltage system ground fault protection.

Power utilization transformers are sometimes provided with circuit switchers instead of circuit breakers. In the design of the protection scheme, it is necessary to block the circuit switcher from tripping when the fault current is above its interrupting capacity. This usually requires that the remote source relay operates instantaneously for faults above the circuit switcher interrupting capacity.

In designing protective schemes for parallel transformer banks, a separate differential scheme for each transformer is recommended. This is especially important when the transformers are of different sizes. If considering using only one differential relay, extra phase and ground overcurrent should be provided for the smaller transformer.

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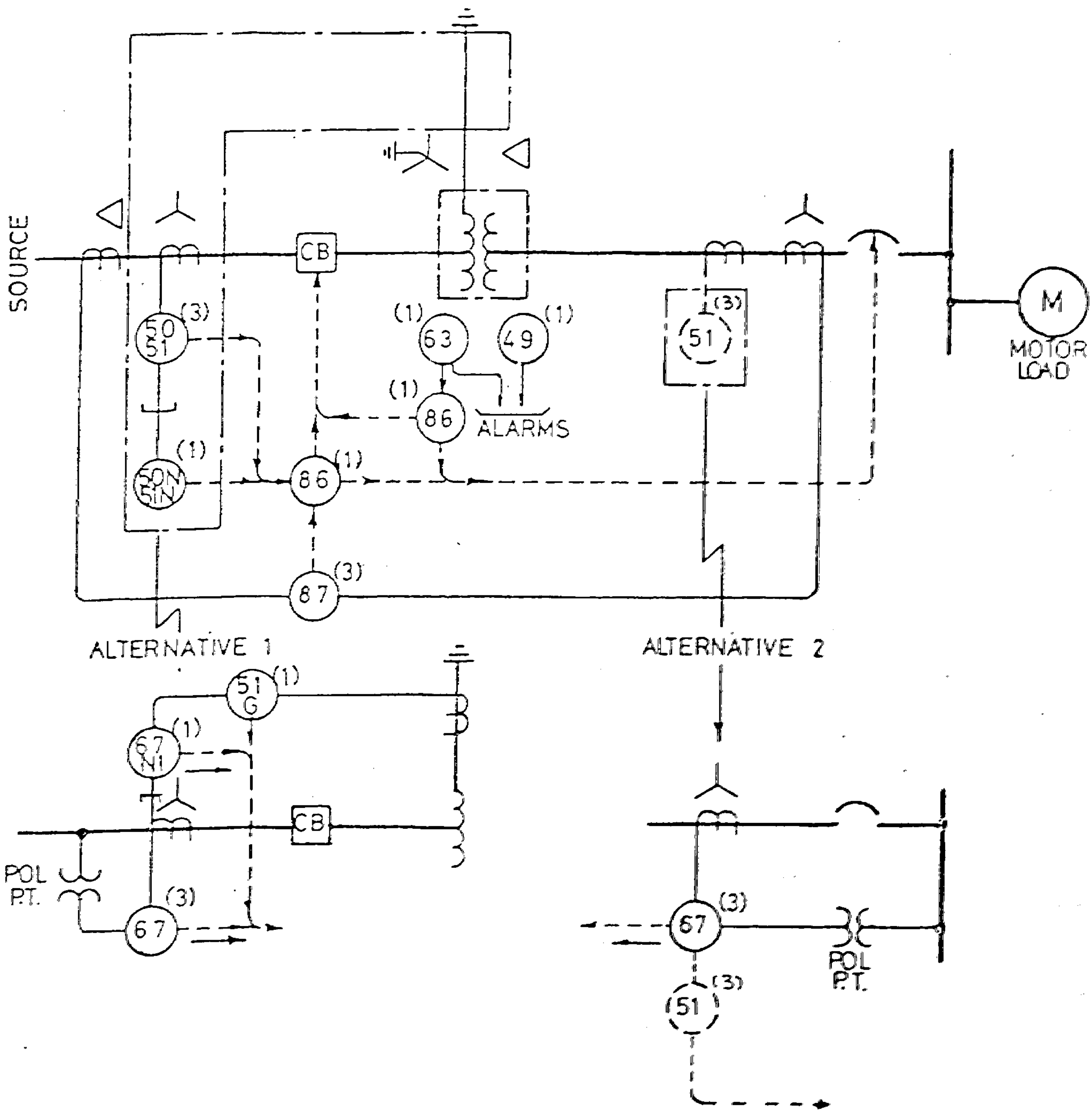

FIGURE 4.6 PROTECTION ARRANGEMENT FOR A WYE / DELTA TRANSFORMER

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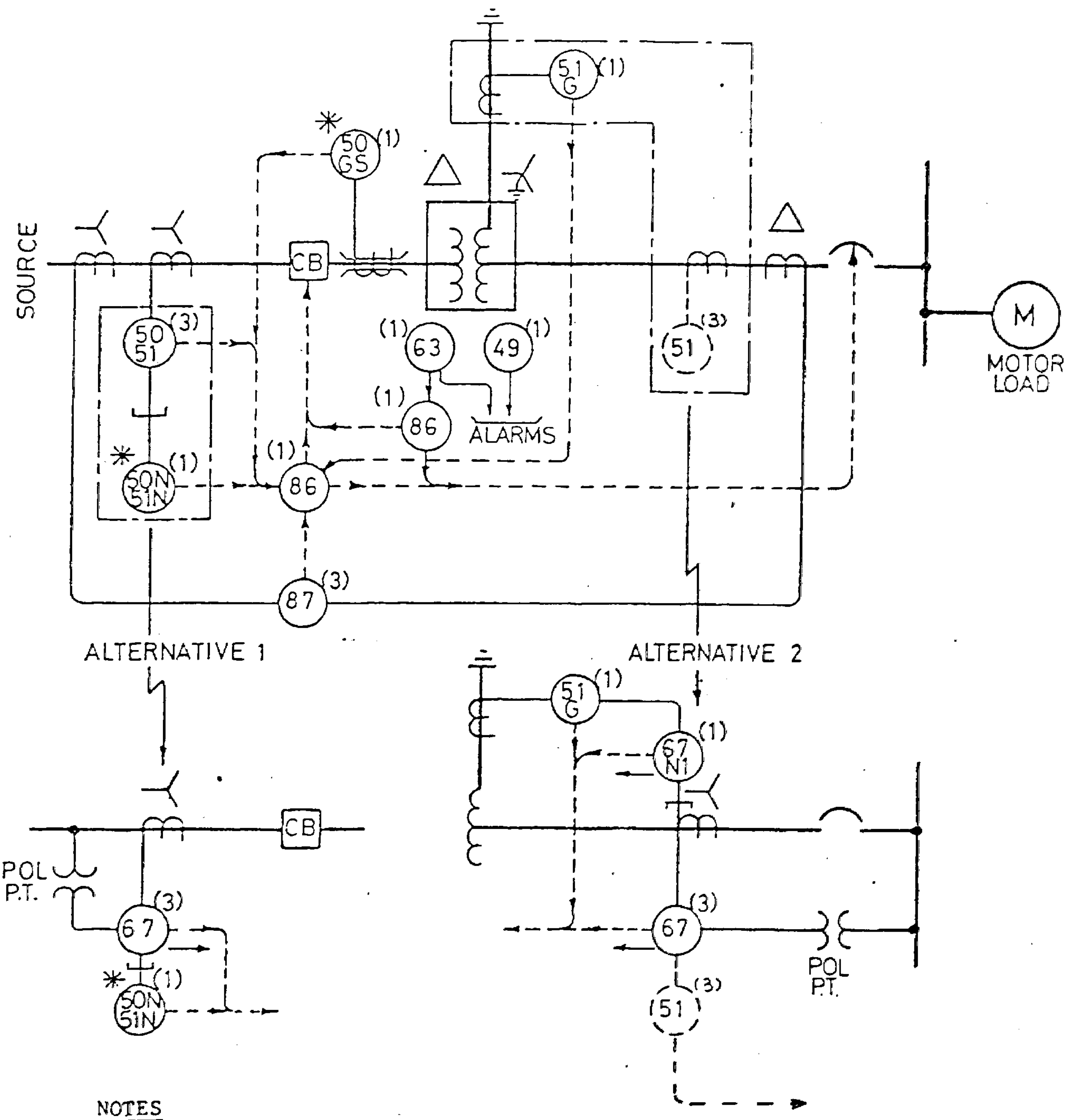

NOTES

1. Relays marked * are alternative. Relay 50GS is used with a donut CT, relay 50N/51N is used with phase CT's.

FIGURE 4.7 PROTECTION ARRANGEMENT FOR A DELTA/WYE TRANSFORMER

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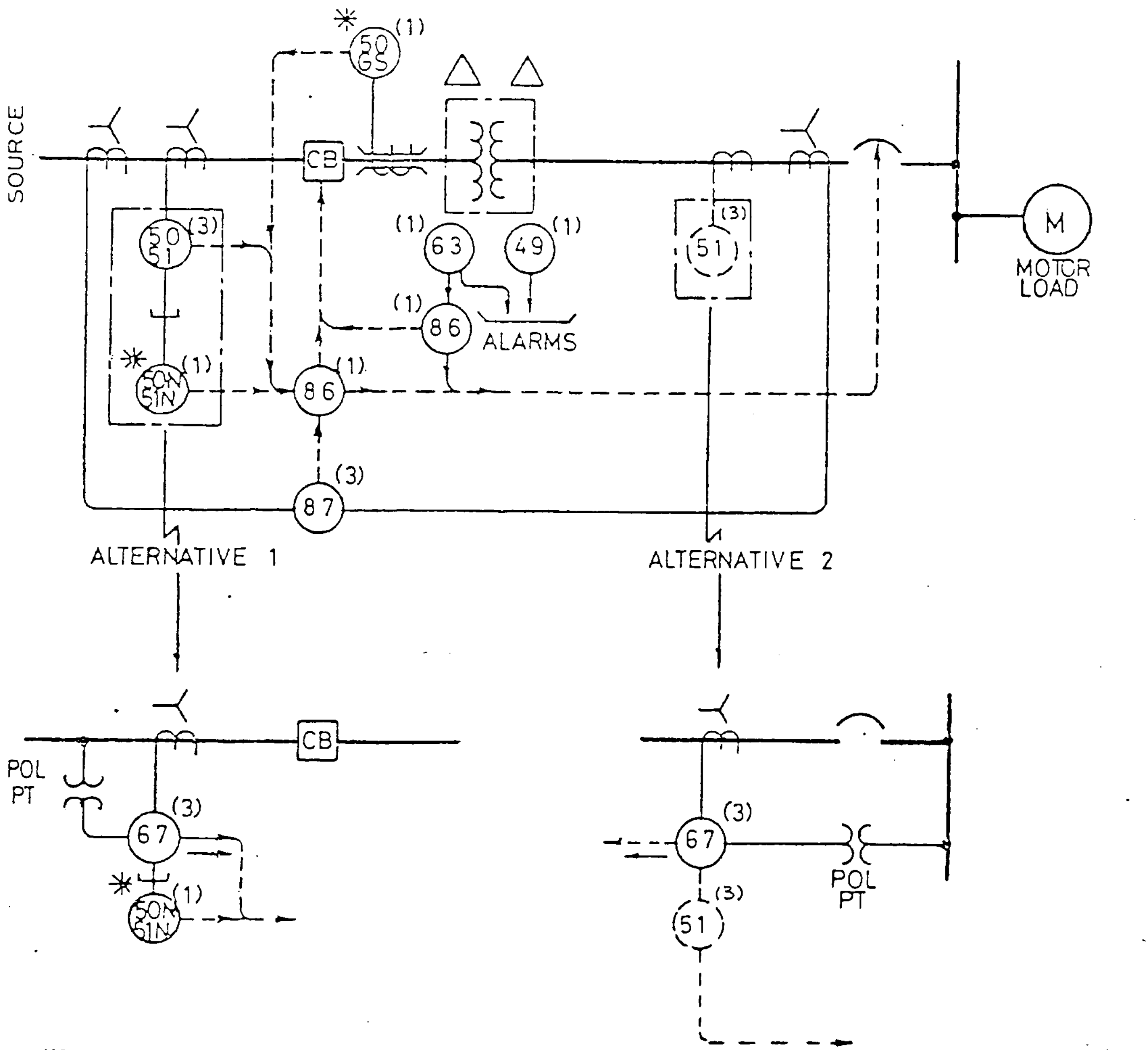

NOTE

1. Relays marked * are alternative. Relay 50GS is used with a donut CT. Relay 50N/51N is used with phase CT's.

FIGURE 4.8 PROTECTION ARRANGEMENT FOR A DELTA/DELTA TRANSFORMER

PROTECTION ARRANGEMENT FOR A WYE/DELTA TRANSFORMER WITH A GROUNDING TRANSFORMER	DWG.NO.	REV.	**Power Systems Engineering, Inc.** P.O. Box 19398 Houston, Texas 77024
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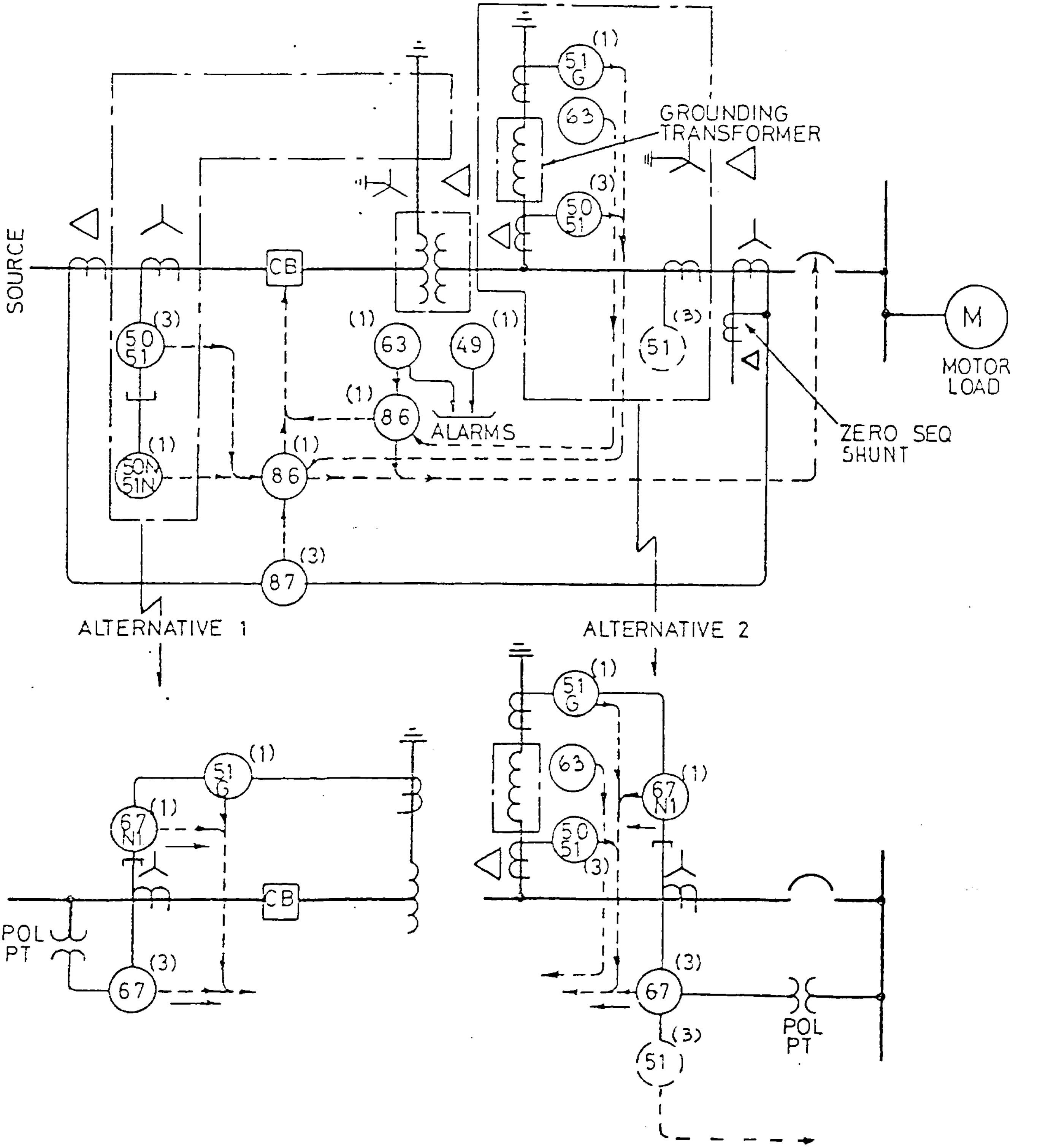

FIGURE 4.9 PROTECTION ARRANGEMENT FOR A WYE/DELTA TRANSFORMER WITH A GROUNDING TRANS.

PROTECTION ARRANGEMENT FOR A DELTA/DELTA TRANSFORMER WITH A GROUNDING TRANSFORMER	DWG.NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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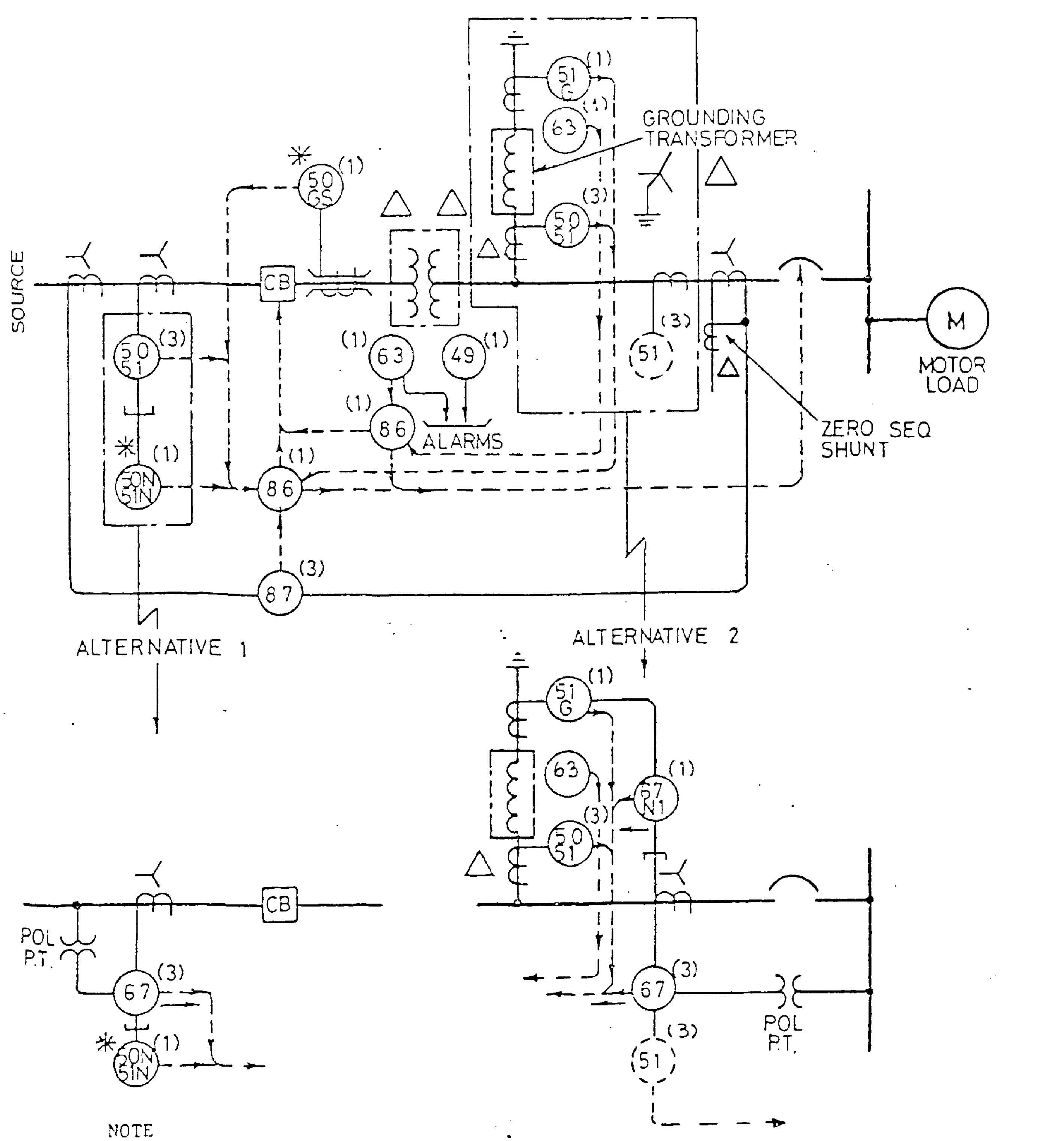

NOTE

1. Relays marked * are alternative. Relay 50GS is used with a donut CT, Relay 50N/51N is used with phase CT's.

FIGURE 4.10 PROTECTION ARRANGEMENT FOR A DELTA/DELTA TRANSFORMER WITH A GROUNDING TRANSFORMER

PROTECTION ARRANGEMENT FOR A DELTA/WYE TRANSFORMER WITH A CIRCUIT SWITCHER	DWG.NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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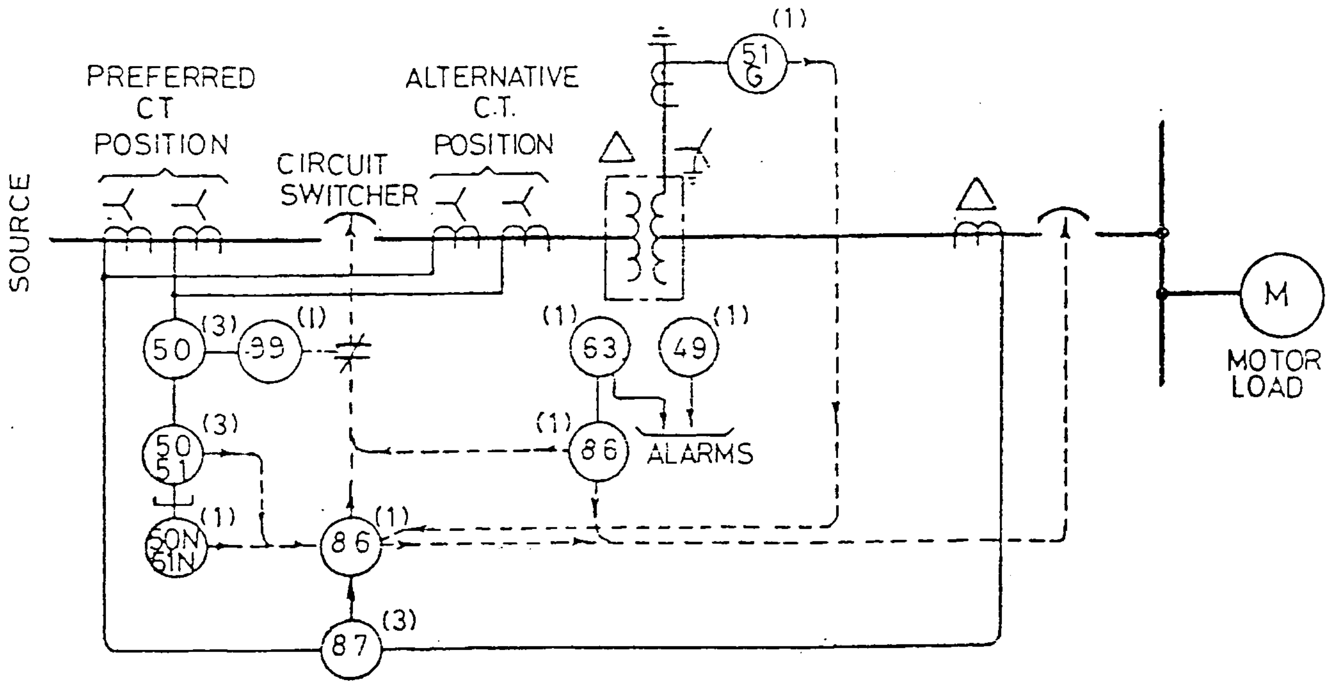

FIGURE 4.11 PROTECTION ARRANGEMENT FOR A DELTA/WYE TRANSFORMER WITH A CIRCUIT SWITCHER

PROTECTION ARRANGEMENT FOR A DELTA/WYE/WYE TRANSFORMER	DWG. NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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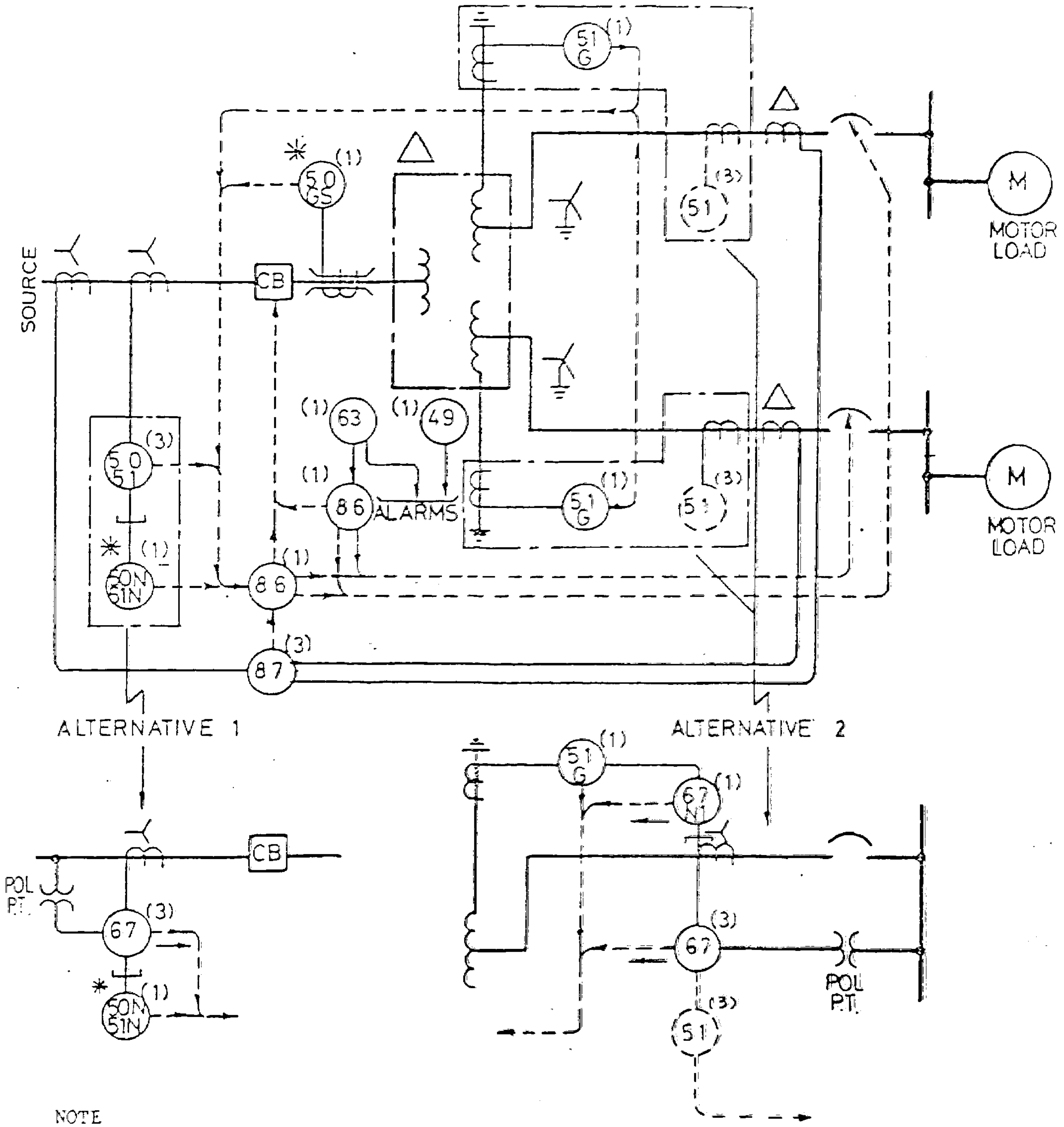

NOTE

1. Relays marked * are alternative. Relay 50GS is used with a donut CT Relay 50N/51N is used with phase CT's.

FIGURE 4.12 PROTECTION ARRANGEMENT FOR A DELTA/WYE/WYE TRANSFORMER

CHAPTER 5

MISCELLANEOUS ITEMS OF POWER SYSTEM SUPERVISION, PROTECTION AND CONTROL

One deciding factor in modern electric power system operation is service continuity. Service interruption means not only loss of revenue but, more importantly, possible social disasters. Various approaches for improving service continuity such as more lines, more generators, power pooling, etc., are widely used. Among these, a proper relaying system is the most important one. A well designed relaying scheme should trip all necessary circuits, not more or not less. Consequently, selectivity and sensitivity are two major considerations in the design of protective relaying. These two requirements are usually not hard to meet in primary protection through proper selection of different types of relays. However, this is not necessarily true for backup protection. For example, remote backup protection for a transmission line may trip circuit breakers on both ends and interrupt all loads tapped along the line, which may not be necessary. Breaker failure relaying is a local backup protection designed to solve this problem.

Applications of electronic computers for electric power system protection, operation control and supervision are not new at all. Electromagnetic protective relays, widely used since sixty years ago, are nothing more than analog computers designated for individual specific function. As an example, an impedance relay is an analog device to calculate the driving point impedance and to initiate other devices such as circuit breakers, if necessary. Since digital systems have definite advantages over analog systems, it is a natural trend to replace conventional devices by their digital equivalents wherever possible. In this chapter, microprocessor applications on SCADA (Supervision Control And Data Acquisition) systems will be discussed in detail.

5.1 Transmission Substation Configurations

Generally speaking, transmission switchyards can make use of the following four arrangements: the single bus, the double bus, the ring bus and the breaker-and-a-half arrangements.

The single straight bus configuration is the simplest arrangement and is usually applied where circuit outage for equipment maintenance is acceptable. In the event that the loss of all circuits due to any single bus fault or breaker failure is intolerable, bus sectionalization should be provided.

The double bus configuration can provide a higher degree of reliability than the single bus. It permits equipment maintenance without circuit outages. Its design consists, essentially, of the compromises between cost of transferring circuit protection and cost of service interruption. As with the single bus arangement, sectionalization may be necessary for the same consideration.

The ring bus and the breaker and a-half configuration provide both the maximum degree of reliability and the ability to maintain equipment without more than two circuit outages. The use of the ring bus arrangement is limited to no more than four circuits. For applications of more than four circuits, the breaker-and-a-half scheme should be used.

5.2 Breaker Failure Protection [16]

In the past, it was standard practice to backup transmission line protection simply by overreaching primary protection to line sections beyond the remote bus. Selectivity of this remote backup depends mainly upon the time settings of the relays involved. Frequently, unnecessary tripping and service interrupting occurred. Remote backup, in addition to not being selective, may also not be sensitive enough because of the relatively small proportion of the total fault current flowing from the remote bus. This is true especially when very long transmission lines are involved.

With the advent of extra high voltage systems and increasing concern about service continuity and possible breaker failures, a trend to use breaker failure protection is developing. Unlike remote backup protection, this local backup is applied at a local station. If the primary relays fail, local secondary relays will trip the local breakers. In case the local breaker fails, either the primary or the secondary relays will initiate the breaker failure protection to trip all local breakers adjacent to the failed breaker. It should be noticed that although breaker failure protection has advantages and is widely used now, remote backup protection can not be completely eliminated.

Breaker failure protection is usually applied to equipment such as generators, transformers, and substation buses. In this section, basic schemes and operation theory of breaker failure protection will be discussed. Typical schemes for various equipment will be given in the subsequent section.

Figure 5.1 illustrates a basic simplified breaker failure scheme.

SIMPLIFIED BREAKER FAILURE PROTECTION SCHEMES	DWG.NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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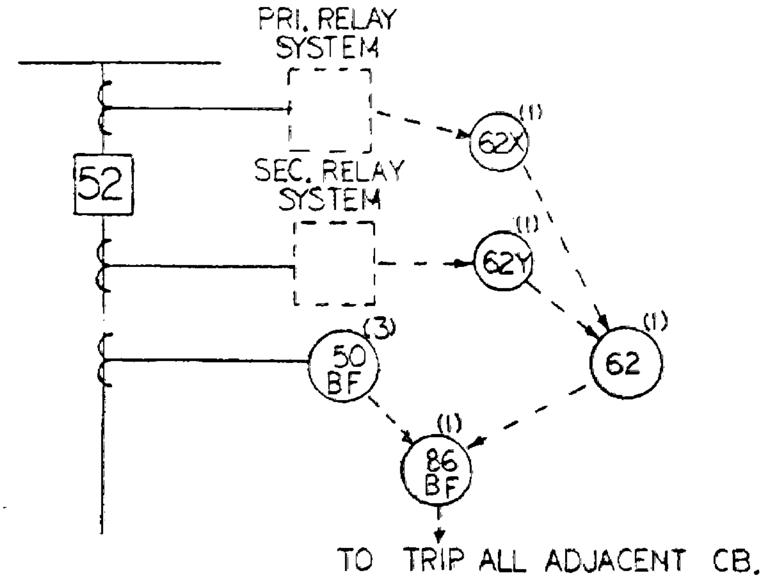

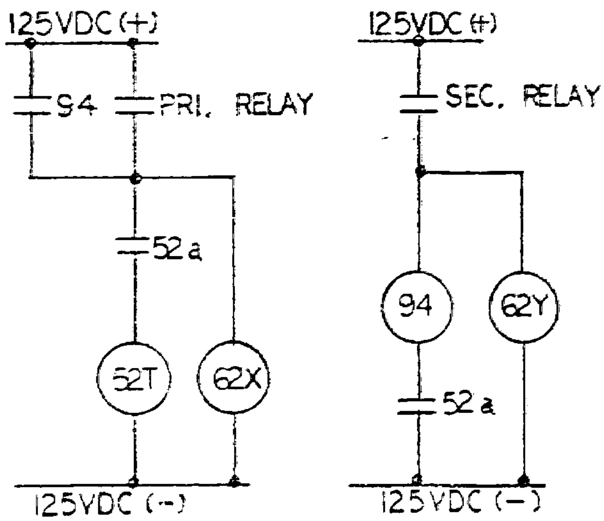

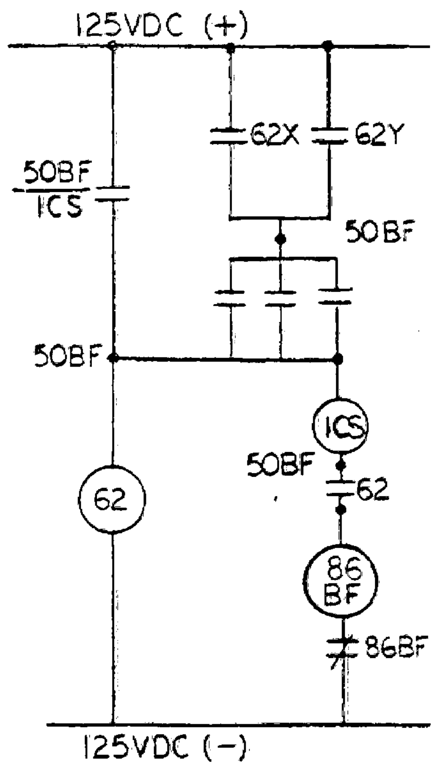

NOTES: 1) 94 Function is Auxiliary Tripping Relay Which may not be Required With Dual Trip Coils.

2) Multi-Contacts to Trip Local Circuit Breakers around Failed Circuit and Initiate Remote Trip as Required to Isolate Fault, Block Reclosing, etc.

Figure 5.1 SIMPLIFIED BREAKER FAILURE PROTECTION SCHEMES

Operation of either the primary or the secondary relays will trip the circuit breaker and start the timer 62 through auxiliary relays 62X and 62Y. If the circuit did not open before 62 times out, this indicates a failure to clear the fault. Then failure detector (device No. 50BF shown in the figure) will energize a hand-reset multi-contact auxiliary relay 86BF, which in turn will trip all the adjacent breakers. Usually, the 86BF relay is also arranged to block reclosing, to initiate transfer trip, and to stop carrier with blocking-type pilot relaying.

Normally, timer 62 should be supervised by instantaneous overcurrent relay 50BF rather than the breaker "a" contact. This is because the "a" contact may be open while the main contacts in a damaged breaker are actually closed. Three overcurrent units used can be set below minimum fault current for better sensitivity. Where transformer faults do not provide sufficient current to operate 50BF relays, a transformer differential relay contact can be used instead, supervised by a breaker "a" contact.

It is recommended practice that, (i) one breaker-failure circuit per breaker be applied, regardless of substation bus configurations, (ii) all adjacent breakers be tripped, regardless of fault location, and (iii) one timer per breaker be used, rather than one timer per bus. This practice will provide maximum flexibility in design and, more important, maximum selectivity.

5.3 Typical Schemes for Breaker Failure Protection

As stated in the last section, current flow should cease shortly after the trip circuit is energized in a properly functioning breaker. The time interval between trip energization and current flow cessation is the breaker interrupting time. If interruption does not occur in about this much time, the breaker is assumed to have failed and the breaker failure relaying should initiate tripping of adjacent and/or remote breakers to isolate the protected breaker. Today, breaker failure protection is mostly used in high voltage substation bus protection. In this section, breaker failure protection for various bus configurations will be discussed [16].

Figure 5.2 shows the simplest breaker failure scheme for the single bus configuration using one timer per bus. In transmission line protection, it is general practice to connect primary and secondary line relays to separate current transformers and separately fused direct current supplies as shown in the figure. Two zener diodes TRB-2 are used to prevent false indication of supervision lights, R and W. The zener diode inside each overcurrent detector isolates the multiple trip circuits of all overcurrent detectors on the same bus so that only the desired target will drop.

Figure 5.3 shows breaker failure relaying for the same bus arrangement using one timer per breaker. Although using a separate timer for each breaker is more costly than a timer for each bus, the following advantages can pay for the price:

(1) If the breakers on the bus have different interrupting times, the common timer must be set to accommodate the slowest breaker. Sep- a rate timers provide faster backup clearing for faster breakers.

(2) If a fault begins on one line and subsequently spreads to another, the common timer might misoperate and strip the bus. As the number of lines increase, it might become impossible to set the timer properly.

SINGLE BUS BREAKER FAILURE PROTECTION USING ONE TIMER EACH BUS	DWG.NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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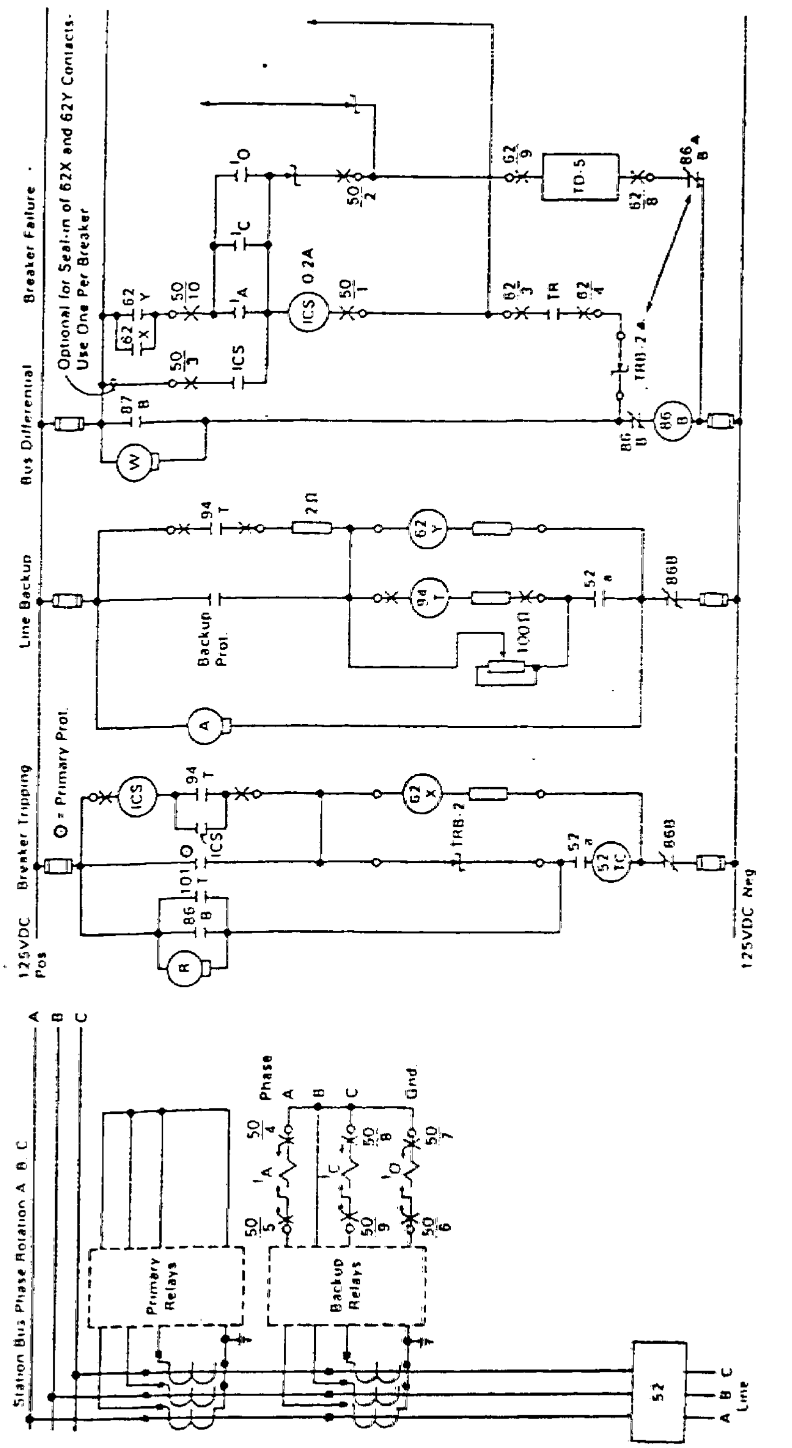

* = High-Threshold Type (4MS Pickup)
▲ = With Supervising Light, use either 86B Contact or TRB-2 Blocking Zener but not both.

Device No.	Type	Function
	TRB-2	Zener Tripping Unit
50		Overcurrent Detector
50X		Overcurrent Aux (Optional)
52		Power Circuit Breaker
62		Breaker Failure Timer
62X		Breaker Failure Initiating Aux.
62Y		Breaker Failure Initiating Aux.
86B		Bus Diff Lockout Aux.
87B		Bus Diff. Relay
94T		Tripping Aux.

Figure 5.2 SINGLE BUS BREAKER FAILURE PROTECTION USING ONE TIMER EACH BUS

SINGLE BUS BREAKER FAILURE PROTECTION
USING ONE TIMER PER BREAKER

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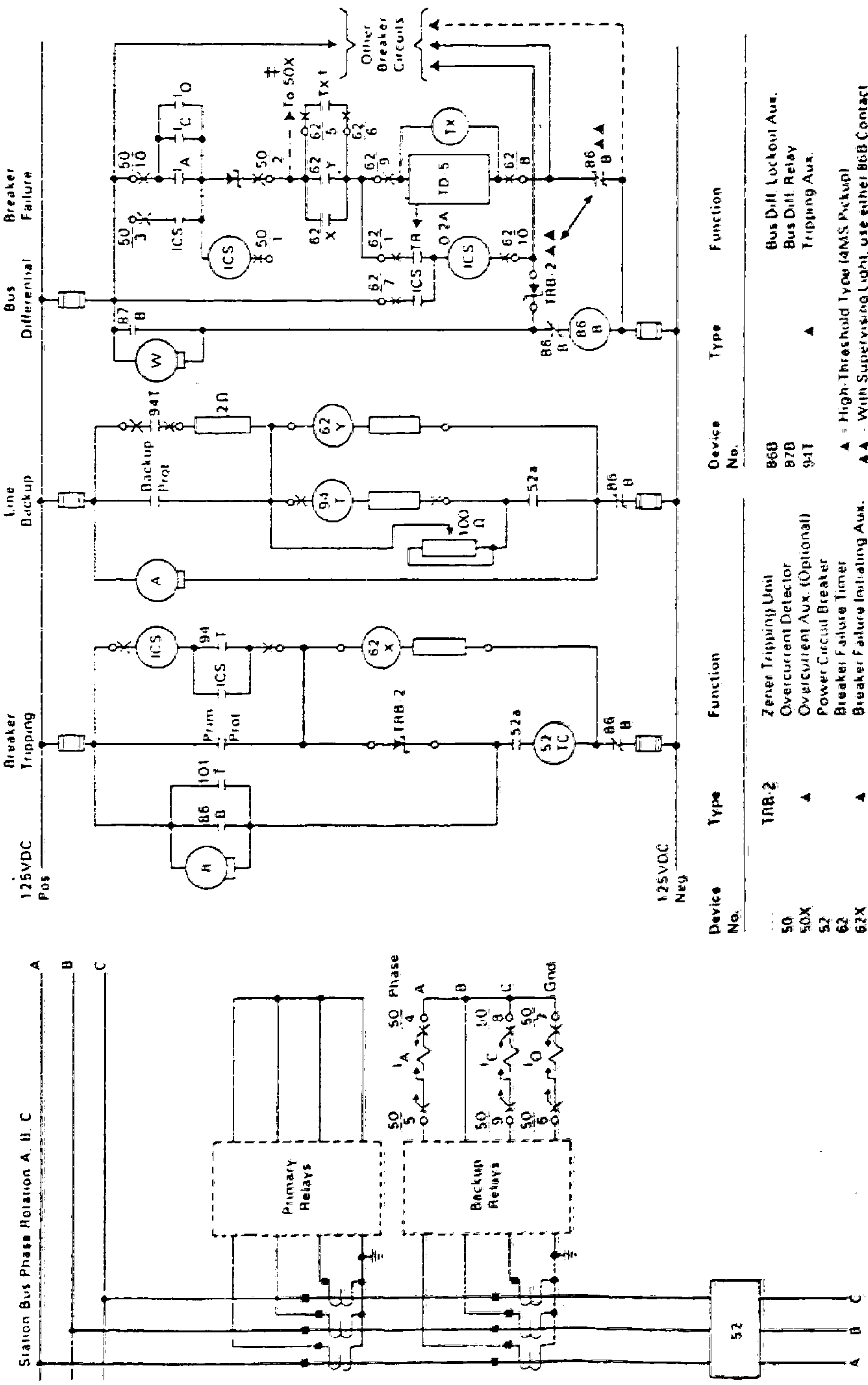
BY JL | JOB NO. N/A | DATE | Sh. 1 of 1



Device No.	Type	Function
...	TRB-2	Zener Tripping Unit
50	▲	Overcurrent Detector
50X		Overcurrent Aux. (Optional)
52		Power Circuit Breaker
62		Breaker Failure Timer
62X	▲	Breaker Failure Initiating Aux.
62Y	▲	Breaker Failure Initiating Aux.

Device No.	Type	Function
86B		Bus Diff. Lockout Aux.
87B		Bus Diff. Relay
94T	▲	Tripping Aux.

▲ = High-Threshold Type (4MS Pickup)
▲▲ - With Supervising Light, use either 86B Contact or TRB-2 Blocking Zener but not both
† = Optional for Seal-in of 62X and 62Y Contacts.
‡ = Optional for Contact Multiplication of KC-4 Overcurrent Detector

Figure 5.3 SINGLE BUS BREAKER FAILURE PROTECTION USING ONE TIMER PER BREAKER

(3) With separate timers, the bus can be reconfigured without rewiring the breaker failure circuits.

The telephone relay TX as shown in the figure should be used when breaker failure initiate auxiliary relays 62X and 62Y are energized by potential polarized relays. This is because of the possible collapse of polarizing potential during bus faults.

Figures 5.4 and 5.5 show breaker failure relaying for the breaker-and-a-half bus and the ring bus, respectively. The basic functioning of these schemes is the same as for the single bus, and requires no further explanation. To conclude this section, an overall protection scheme for a generator pair is shown in Figures 5.6 and 5.7. The scheme includes both generator and bus breaker failure relaying.

5.4 Digital Computer Applications on System Supervision and Control

5.4.1 SCADA Systems

SCADA systems for power system applications are designed to provide remote control and monitoring of substation and power plant equipment from the system control center. The equipment should be controlled and monitored by a local remote terminal unit (known as RTU) which in turn is under the direct control of the SCADA central processor. Communications link between RTU's and the SCADA master station can be voice grade, telephone, microwave, or power line carrier circuit, depending upon particular application requirements.

Information flow between the master station and RTU's is bi-directional. RTUs transmit status, analog, and digital information to the station; the master station, on the other hand, issues control commands to RTUs. Status information includes dry contact open/closed messages

BREAKER-AND-A-HALF BREAKER FAILURE RELAYING USING ONE TIMER PER BREAKER	DWG.NO.	REV.
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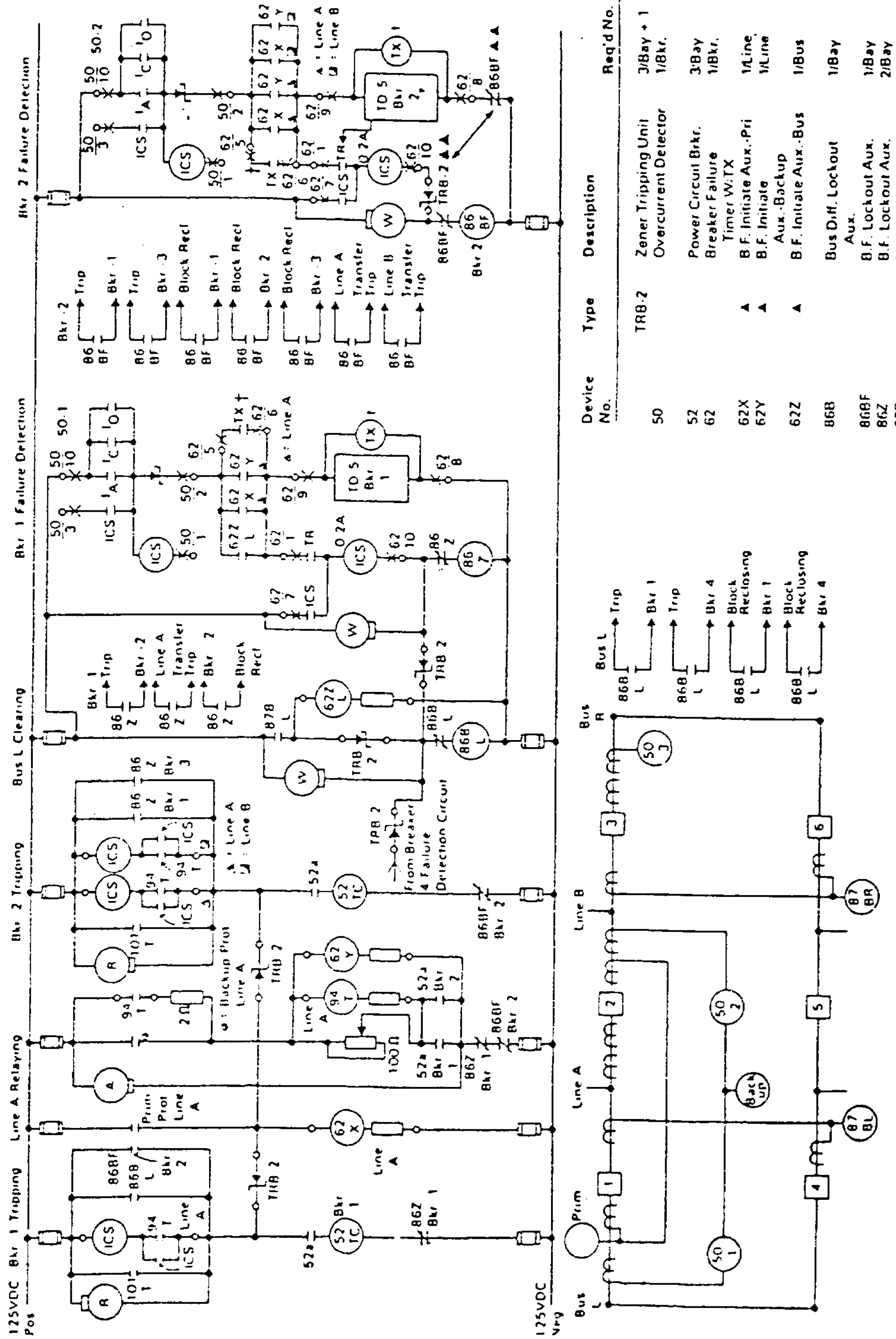

Device No.	Type	Description	Req'd No.
50	TRB-2	Zener Tripping Unit Overcurrent Detector	3/Bay + 1 1/Bkr.
52		Power Circuit Brkr.	3/Bay
62		Breaker Failure Timer W/TX	1/Bkr.
62X	▲	B.F. Initiate Aux.-Pri	1/Line
62Y	▲	B.F. Initiate Aux.-Backup	1/Line
62Z	▲	B.F. Initiate Aux.-Bus	1/Bus
86B		Bus Diff. Lockout Aux.	1/Bay
86BF		B.F. Lockout Aux.	1/Bay
86Z		B.F. Lockout Aux.	2/Bay
87B		Bus Diff. Relay	1/Bus
94T	▲	Tripping Aux.	1/Line

▲ = High-Threshold Type (4MS Pickup)
▲▲ = With Supervising Light, use either 86B Contact or TRB 2 Blocking Zener but not both.
† = Optional for Seal-in of 62X and 62Y Contacts.

Figure 5.4 BREAKER-AND-A-HALF BREAKER FAILURE RELAYING USING ONE TIMER PER BREAKER

BREAKER FAILURE RELAYING FOR A RING BUS	DWG.NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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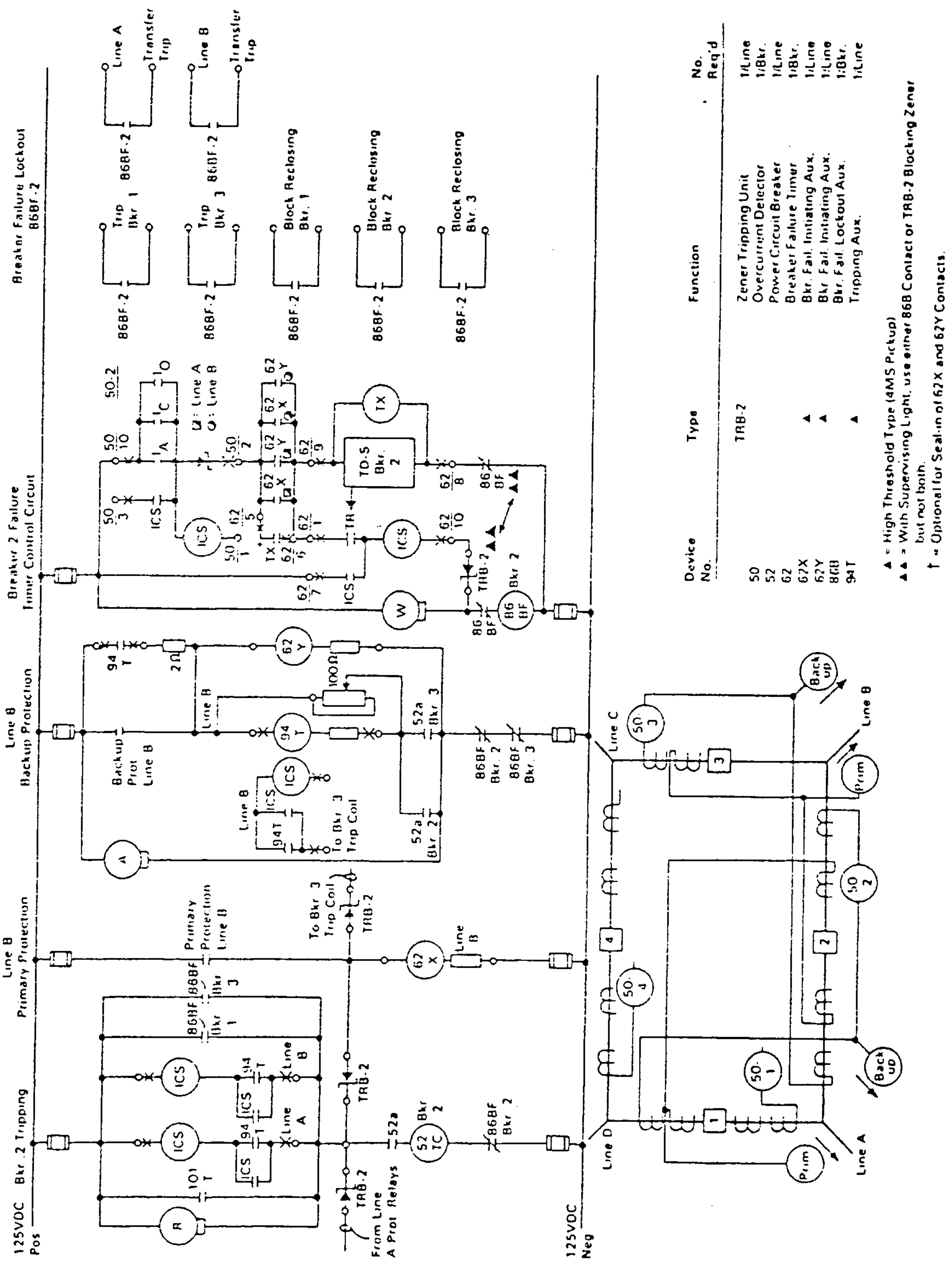
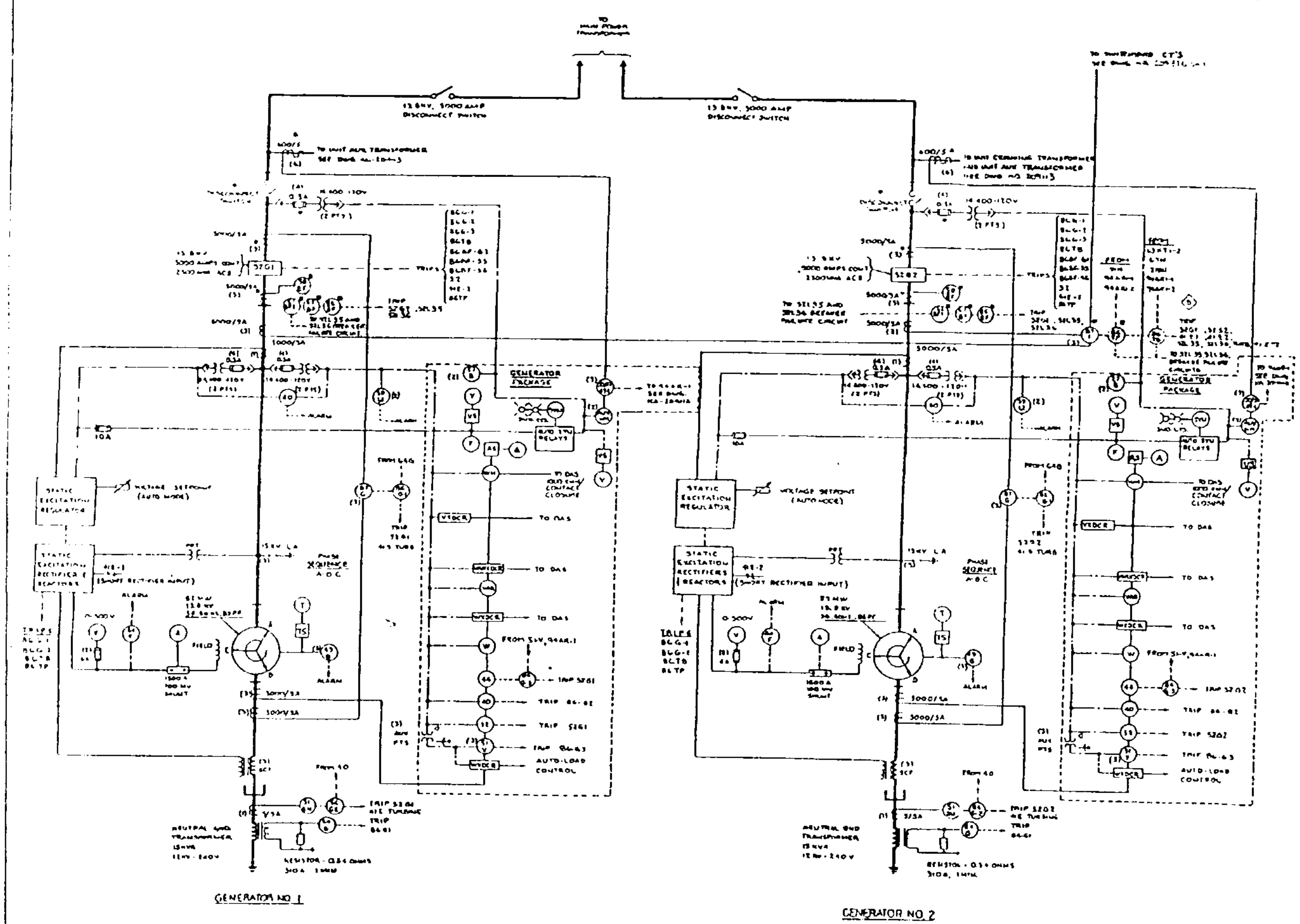


Device No.	Type	Function	No. Req'd
	TRB-2	Zener Tripping Unit	1/Line
50		Overcurrent Detector	1/Bkr.
52		Power Circuit Breaker	1/Line
62		Breaker Failure Timer	1/Bkr.
62X	▲	Bkr. Fail. Initiating Aux.	1/Line
62Y	▲	Bkr. Fail. Initiating Aux.	1/Line
86B		Bkr. Fail. Lockout Aux.	1/Bkr.
94T	▲	Tripping Aux.	1/Line

▲ = High Threshold Type (4MS Pickup)
▲▲ = With Supervising Light, use either 86B Contact or TRB-2 Blocking Zener but not both.
† = Optional for Seal-in of 62X and 62Y Contacts.

Figure 5.5 BREAKER FAILURE RELAYING FOR A RING BUS



A	AMMETER
AS	AMMETER SWITCH
DAS	DATA AQUISITION SYSTEM
F	FREQUENCY METER
LA	LIGHTNING ARRESTER
PT	POTENTIAL TRANSFORMER
SCT	SATURATING CURRENT TRANSFORMER
SYN	SYNCHRONIZER
T	TEMPERATURE METER
TS	TEMPERATURE METER SWITCH
V	VOLTMETER
VAR	VARMETER
VS	VOLTMETER SWITCH
W	WATTMETER
WH	WATTHOUR METER
XDCR	TRANSDUCER
21BU	TRANSFORMER BACKUP DISTANCE RELAY
27B	BUS UNDERVOLTAGE RELAY
32	REVERSE POWER RELAY
40	LOSS OF EXCITATION RELAY
41E	EXCITER FIELD CONTACTOR
41S	GEN. FIELD SUPPRESSION CONTACTOR
46	NEGATIVE SEQUENCE RELAY
49T	STATOR TEMPERATURE RELAY
50/51	OVERCURRENT RELAY
50BF	OVERCURRENT BREAKER FAILURE RELAY
51GN	GENERATOR GROUND RELAY
51N	TRANSF. NEUTRAL OVERCURRENT RELAY
51V	SYSTEM PHASE FAULT RELAY
52G	GENERATOR BREAKER
52L	230 KV OIL CIRCUIT BREAKER
59-1,2	GENERATOR OVERVOLTAGE RELAY
60	VOLTAGE BALANCE RELAY
62BF	BREAKER FAILURE
62BFI	BREAKER FAILURE INITIATE
63	TRANSFORMER SUDDEN PRESSURE RELAY
64F	GENERATOR FIELD GROUND RELAY
64G	GENERATOR GROUND RELAY
67N	TRANSF. GROUND BACKUP OVERCURRENT
86BF	GENERATOR BREAKER FAILURE
86G-1,2,3	GENERATOR LOCKOUT RELAY
86TP/B	TRANSFORMER LOCKOUT RELAYS
87G	GENERATOR DIFFERENTIAL RELAY
87T	TRANSFORMER DIFFERENTIAL RELAY
94AR-1	AUX. POWER RUNNING TRIP RELAY

Figure 5.6 GENERATOR PAIR PROTECTIVE SCHEME

NO.	REVISION	BY	DATE	ISSUED FOR	DATE	INIT.
				PRELIM.		
				APPV.		
				BID		
				CONST.		
				REV.		
				FINAL		

SCALE
DWN. DATE
CHK. DATE
APPV. DATE

Power Systems Engineering, Inc.
HOUSTON, TEXAS

GENERATOR PAIR PROTECTIVE SCHEME

DWG. NO.

CLIENT:

PROJECT NO.

SHT. 1 OF

SUBSTATION PROTECTION SCHEME	DWG.NO.	REV.	**Power Systems Engineering, Inc.** P.O. Box 19398 Houston, Texas 77024
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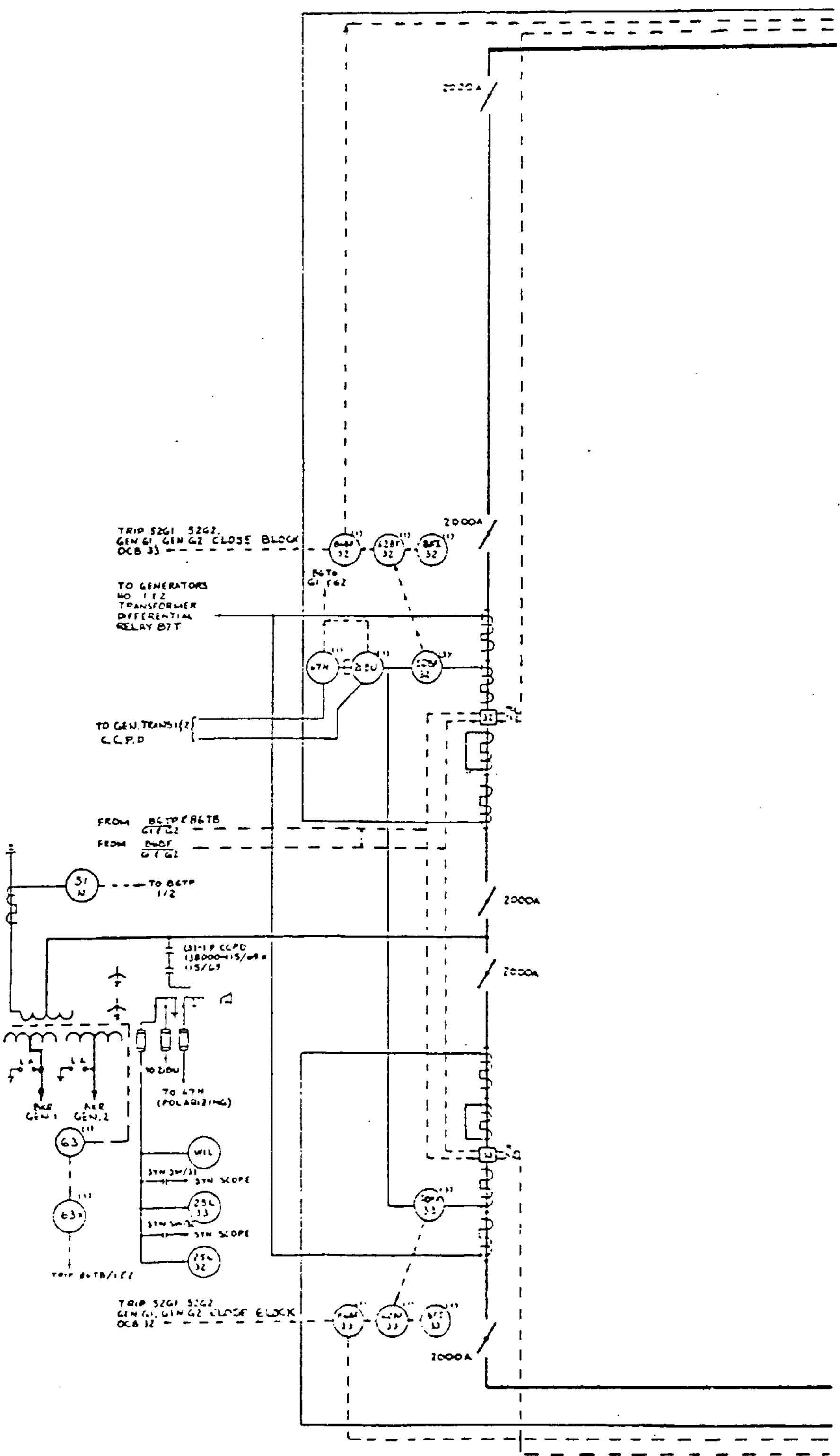

Figure 5.7 SUBSTATION PROTECTION SCHEME

and is used for such functions as alarms, system topology update, etc. Analog information includes variable voltage and current levels and is used for transmitting such quantities as line voltages, currents, watts, vars, frequency, turbine and/or generator temperature, wind speed and transformer tap position. Digital words represent information such as total number of contact transitions since last polling, etc. Control information is usually of a digital nature and contains the address of the equipment under control and control signal itself. It usually accomplishes a relay closure which in turn controls an appropriate item of substation or power plant equipment such as breaker close/open, transformer tap raise/lower and generator governor raise/lower.

In addition to data acquisition and control discussed above, a modern SCADA system should also have the following functions:

(1) Data Base:

The effectiveness value of a SCADA system is primarily a function of the data processing efficiency of the digital computer subsystem as measured by data thruput. To enhance the data thruput, the SCADA system requires an efficient and effective data base subsystem. Therefore, from the data thruput point of view, the data base is the heart of the SCADA system.

(2) Operating System (also known as the Executive):

The operating system is required to provide a real-time priority oriented processing environment and to allocate computer resources accordingly.

(3) Man-Machine Interface:

This sybsystem is designed to provide capabilities such as CRT displays, alarm generation, data entry, data logging and picture compiler.

(4) Performance Monitoring:

This subsystem functions to enhance the operational availability of the SCADA or central control system. Generally, every primary hardware subsystem should have an identical unit for backup.

Each of these functions is a highly specialized topic and the design of a complete SCADA system may require huge engineering effort. Consequently, no further discussion on SCADA systems will be given. In the subsequent paragraphs, emphasis will be placed exclusively on RTU design. An example is given to illustrate the organization and operation of a RTU system.

A remote terminal unit (RTU) is a part of a process controller and/or SCADA system in which automatic functions are implemented within the RTUs. An intelligent RTU is one in which much of the logic associated with each function has been programmed and is executed locally in a digital processor (usually microprocessor) instead of transmitting data to and processing in the central processor of the SCADA system.

The first point of consideration in RTU design is the content of data required. Usually it is the responsibility of the operations and application groups to determine what data is needed for power system operation, control and for data input to SCADA programs. They should also define the required data characteristics of accuracy, resolution, sampling period, range, format, etc. Generally speaking, an intelligent RTU should have the following basic functions and capabilities.

(1) Data Acquisition:

It includes (a) discrete inputs such as status monitoring, pulse counting and pulse timing; (b) digital inputs such as byte codes, binary coded decimal and others; (c) analog inputs to maintain a fresh internal data base.

(2) Control Outputs:

Included are (a) supervisory and manually initiated control such as check back-before-operate interlocks, etc.; and/or (b) fully automatic and software or firmware initiated control.

(3) Communications, including communications with SCADA master station and service communications interface to prevent the loss of data.

(4) Operational Security:

It includes (a) minimization of false commands and data due to communication errors, component failure, electromagnetic interface, etc.; (b) internal monitoring of analog reference inputs, power failure and restart, etc.

(5) Functional and Field Expandability:

Expandability includes processor time, memory, input and output resources, wiring and space spare for the future addition of new points or functions. As a rule, future expansion of points or functions should not require any modifications to the RTU controlling logic circuits.

In addition to these basic functions and capabilities, optional functions such as data concentration, sequence of events reporting, digital metering, digital relaying, control sequences and many others can also be implemented in an intelligent RTU as necessary.

After these functional requirements are defined, the operating environment for RTUs should be designed accordingly. The environment for

RTU operation must provide not only the data and instructions associated with a particular function but, more importantly, must provide these inputs in a predefined priority order. The controlling logic in an RTU processor must decide how, when and to whom the processing resources are to be allocated according to a predefined priority order. Methods generally used by the controlling logic to manage processing resources include event interrupts (a hardware contact is closed), time interrupt, timer interrupts (a predefined time period has elapsed) and flag (a predefined condition is recognized).

The next step is to determine whether hardware or firmware should be used for a particular function defined above. As a rule of thumb, those general purpose functions making up the microprocessor should be implemented in firmware; those special functions such as operational security in hardware. However, the trade-offs between hardware and firmware are actually an art and should be carefully studied for any particular application.

Possibly the most important design consideration related to RTU systems is how to manage the resources of the microprocessor such that data is not lost and is processed correctly. A communications interface is the key point in the consideration. As the number of points increases, the microprocessor executive overhead may be overloaded by huge communication requirements so incurred. Generally used communications interface techniques include polling and interrupt approaches. Implementing a communications interface by interrupt technique requires that the microprocessor be able to handle external hardware interrupts in addition to the real time clock interrupts. The advantage of the interrupting interface over the polling approach is a reduction of microprocessor executive overhead. In a well designed system, communications functions should not use more than 30% of microprocessor resource time.

As in the SCADA system, it is desirable that every primary hardware subsystem or module have an identical unit for backup. It is also preferable to have automatic switchover (known as failover), and recovery and restart characteristics to achieve high reliability and availability as usually required.

Figure 5.8 shows a functional block diagram of a RTU system. This system has capabilities ranging from a few status or analog points up to many hundreds of point types including SOE, set points, raise-lower, etc. It has a dual-redundant backup. It is divided into the following modules: common control, control and indication, accumulator, analog to digital, raise-lower and power supply module.

The common control module performs message buffering between the various point modules and communication subsystems. The central element is a microprocessor with communication to and from all other modules. The interrogation of the point modules is under direct control of the microprocessor and the remote scan program stored in ROM. Figure 5.9 shows internal organization of the common control module. The watchdog timer is designed to provide a programmable timing signal which is fed into an interrupt generation logic circuit. If the timer is timed out, a signal is sent to initiate an interrupt to the CPU.

The control and indication module continuously scans its indication points and maintains a queue of all changes. On request from the SCADA

FUNCTIONAL BLOCK DIAGRAM - RTU SYSTEM	DWG.NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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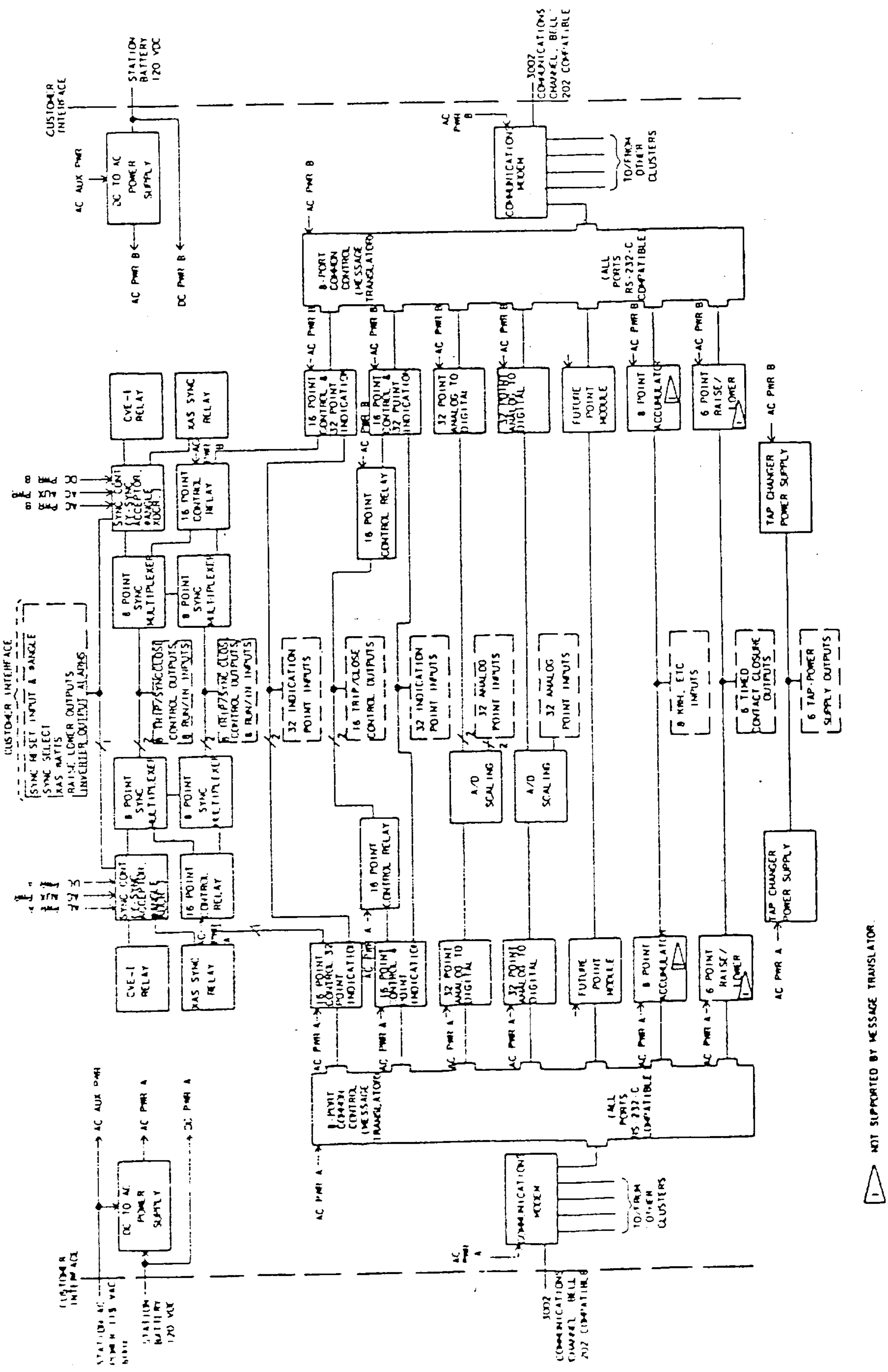

Figure 5.8 FUNCTIONAL BLOCK DIAGRAM - RTU SYSTEM

COMMON CONTROL MODULE	DWG.NO.	REV.	Power Systems Engineering, Inc. P.O. Box 19398 Houston, Texas 77024
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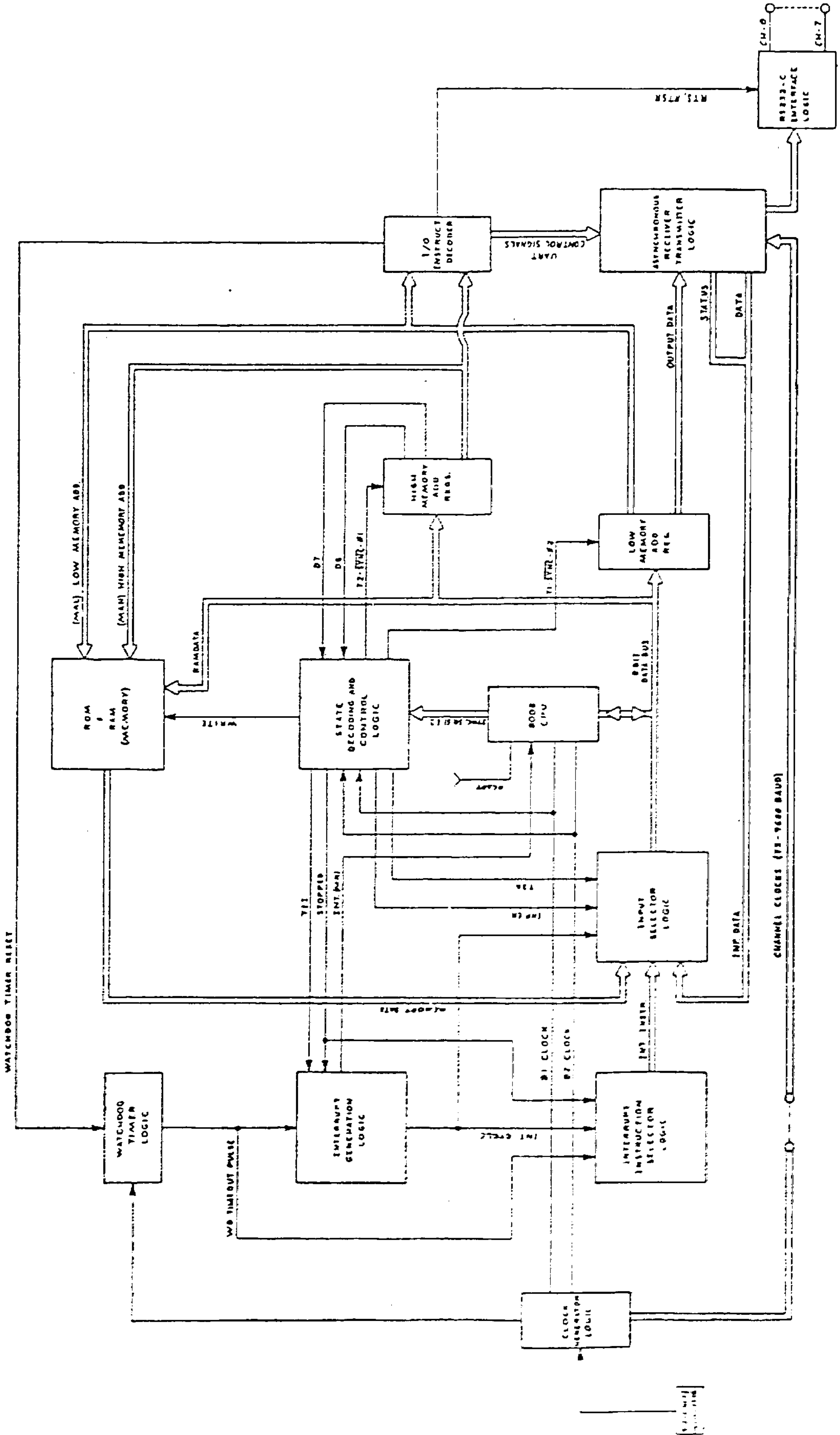

Figure 5.9 COMMON CONTROL MODULE

master station, the module can report the number of state changes accumulated, point address, and the present state of each point. Remote control of a point requires the reception of two sets of point address. The module compares these two sets of point address; if they agree, the control operation will take place.

The analog to digital module digitizes each analog input in sequence and produce a serial bit pattern for serial transmission. The module in cooperation with a precision direct voltage source and resistive tap change potentiometer can also provide remote indication of transformer tap position in the SCADA master station.

The raise-lower module provides remote control of transformer tap from the SCADA master station. As in the control module, two sets of point address are required before the operation occurs.

CHAPTER 6

BUSINESS ASPECTS OF ENGINEERING PROJECTS

During my internship, I was under the direct guidance of project managers. Consequently, I also gained broad experience in engineering project management. My activities in this area included market analysis, feasibility study, vendors' bid evaluation, and project supervision and control. This chapter will highlight some of my experience. It is divided into two parts; part one discusses life cycle of engineering projects, part two concentrates on legal aspects of engineering.

6.1 The Life Cycle of Engineering Projects

Generally speaking, the life cycle of an engineering project begins with identification of needs (or market analysis), followed by feasibility study, preliminary design, detailed design, purchasing, formal design review, and ended with hand over and completion. Interweaving through these phases of project life is project supervision and control. In this section all these different stages will be briefly discussed.

The purpose of market analysis is to view the project over its life cycle on the basis of economic considerations. A market can exist due to either current deficiencies or anticipated future deficiencies. The data collected at this stage is usually quite rough and a decision is usually made on the considerations of the market potential and size, competition, possible obsolescence, and so on.

The purpose of a feasibility study is to extend the market analysis with the intent of arriving at a proposed system configuration in response to an identified need. In general, feasibility studies include the following aspects:

(1) Technical study: choice of technologies, design requirements, manpower requirements, etc.

(2) Economic and financial study: cost-benefit analysis, cash flow study, adequacy of funds, supply-demand analysis, and marketing program.

(3) Social and political study: community resistance, legal constraints, environmental suitability, and so on.

The results of the feasibility study are generally presented in the form of a proposal to management or clients covering the aspects stated above.

Preliminary design constitutes the starting point of a design project and directs toward defining a set of useful solutions or system configuration to the problem being addressed. It starts with the technical baseline for the system defined in the feasibility study and proceeds to translate the established system level requirements into detailed qualitative and quantitative design requirements. Usually it includes functional analysis and allocation, trade-offs and optimization, and synthesis. In this stage, the following specifications should be prepared by design engineers: system specification, development specification, and procurement specifications.

The detailed design phase begins with the concept and configuration derived through preliminary system design, and includes system component design and interface, preparation of design documentation. In this stage specifications of process, material, and construction should be prepared.

Purchasing is one of the key engineering functions. It consists of purchase requisitions, sources of supply, request for quotation, source selection and quotation evaluation, and placement of purchase order.

The functions of formal design review are:

(a) It provides a formalized check of the project. Major problem areas are discussesd and resolved.

(b) It provides a common baseline for all project personnel.

(c) It provides a means for solving interface problems and promotes the assurance that all system elements will be compatible.

The completion and hand over phase of a project prepares the project for phasing out and hand over to another form of administration. Project completion consists of scaling down and dismantling the project organization. It also involves the transfer of project personnel, assets or other facilities.

Project supervision and control is the backbone to an engineering project. Generally speaking, it consists of accomplishments evaluation, expenditure control, and investment control. The tools generally used are simple bar chart, milestone chart, program evaluation and review technique (PERT), critical path method (CPM), PERT/COST, Gantt chart, and line of balance (LOB).

6.2 Legal Aspects of Engineering

Never before in its history has the engineering profession faced the legal exposure that it does today. The rapid expansion of technology has stimulated equally rapid developments in the law. Merely keeping abreast of developments in the laws that have a direct effect on an engineer would be a full-time task. Lack of time will prevent engineers from developing familiarity with all the laws that may affect the engineering profession. However, ignorance of the law is no excuse is still a valid maxim.

The engineer must develop a sixth sense that will alert him to possible legal implications and permit him to seek competent advice before undertaking any project. This sixth sense can be developed by acquiring an awareness of major legal concepts that affect the engineering profession. Of current significance to all engineers is the concept of product liability. "Product liability" is a collective term describing three legal theories. These theories, which form the basis for recovery against the manufacturer and seller of a defective product, are: (1) breaches of express and implied warranty; (2) negligence; and (3) strict or absolute liability. Because of his relationship to the design and manufacture of products, there is a strong likelihood that the engineer will become involved in a product claim or litigation as an "expert." The engineer called upon to render technical assistance as an expert should ensure that he has the requisite educational background and practical knowledge regarding the subject of the controversy. The engineer can also prove instrumental in avoiding product liability exposure by instigating and pursuing preventive management techniques.

CHAPTER 7

SOME MANAGERIAL CONSIDERATIONS FOR YOUNG ENGINEERS

C. R. Gow reported in his book [19] that the chief obstacles to the success of each individual or of the group comprising a unit were of a personnel and administrative rather than a technical nature. What Gow said in 1932 still holds true. This is largely due to the fact that 99% of the emphasis in the training of engineers is placed upon purely technical or formal education.

In this chapter a set of "house rules" or professional code for young engineers will be discussed. They are results of my observations or experience during my internship. Although they are not exhaustive, they may be of worth to young engineers just starting their careers, and to "older" engineers as well who know these things perfectly well but who all to often fail to apply them in practice.

This chapter is divided into two parts; part one discusses purely personality and character considerations for engineers, part two concentrates on what a young engineer really needs to learn at once and consists of three sections - in relation to your work, in relation to your boss, and in relation to your associates and clients [20].

Just one point should be clarified before entering into the context: none of these rules is theoretical or imaginary, and however obvious and bromidic they may appear, their repeated violation, in my experience, is a main source of frustration and embarrassment in an engineering career.

7.1 Character and Personality Considerations

The subject of personality and character is, of course, very broad and much has been taught in schools from the social, ethical, and religious points of view. In this section, the following considerations are given and discussed from a purely practical point of view based upon principles of general engineering practice.

One of the most important personal traits of engineers is the ability to get along with all kinds of people. This is rather a comprehensive quality but it defines the prime requisite of personality in any type of industrial organization. Of course, it is a mistake to try too hard to get along with everybody merely by being agreeable and friendly on all occassions. You must earn the respect of your associates by demonstrating your will to stand up for your belief. This is extremely important, especially when you know you are in the right. If you can be pushed around easily, the chances are that you will be pushed around. Just remember do not be too affable. There will be times when you do well to start a fight yourself, when your objectives are worth fighting for.

Self-respect is another important character for engineers. One of the most striking phenomena of an engineering office is the transparency of character among the members of any group who have been associated for any length of time. In fact, it frequently happens that a man is much better known and understood by his associates, collectively, than he knows and understands himself. It is also usually true that people respect only those who respect themselves. Consequently, regard your personal integrity as one of your most important assets and maintain the highest standard of ethics of which you are capable.

It is also important to note that engineering is essentially a gentleman's profession, and a little profanity may go a long way. Therefore, watch your p's and q's and be careful of your personal appearance.

Dependability is another important personal trait for any successful engineer. In fact, a reputation of dependability and reliability can be one of your most valuable assets.

7.2 In Relation to Your Work

Rule 1: No matter how menial and trivial your early assignments may appear, give them your best efforts.

Many young engineers feel that the minor chores of a technical project are beneath their dignity and unworthy of their professional training. They are anxious to prove their extraordinary capability in some major enterprise. Actually, the spirit and effectiveness with which you tackle your first humble tasks will usually be carefully watched and may affect your entire career. Remember, there is always a premium upon the ability to get things done. Do your present job well and the future will take care of itself.

Rule 2: In carrying out a project, do not wait for others to hand you results; go after your results and keep everlastingly after them.

This is one of the first things a young engineer has to learn in entering engineering business. It is not sufficient to place the order and sit back waiting for the result. In fact, most jobs move in direct proportion to the amount of follow-up and expediting applied. Look immediately for some way around each obstacle encountered and keep the job rolling without losing momentum.

Rule 3: When sent out on any field assignment, stick with it and see it through to a successful finish.

Rule 4: Before asking for approval of any major action, have a definite plan and program worked out to support it.

It always pays for the time to prepare a well considered proposal rather than a half-baked one. OR you will not get credit for your great ideas.

Rule 5: Strive for conciseness and clarity in oral or written reports.

There is a wisespread tendency among engineers to surround the answer to a simple question with so many preliminaries and commentaries that the answer itself can hardly be understood. It is so difficult to get a clear answer out of the answer that its usefulness is thereby greatly diminished. Therefore, try to convey the maximum of significant information in the minimum time and by the minimum words.

Rule 6: Don't be timid, speak up and express yourself and promote your ideas.

Many young engineers tend to think that their job is simply to do what they are told to do. Of course, there are times when it is very wise and prudent to keep your mouth shut, but, as a rule, it pays to express your point of view whenever you can contribute something.

Rule 7: Be extremely careful of the accuracy of your statements.

This sounds almost as trite as one plus one equals two, but many engineers lose the confidence of their superiors and associates by habitually guessing when they do not know the answer to a direct question. Remember next time, if you do not know, say so, but always say, "I will find out as soon as possible."

7.3 In Relation to Your Boss

To get along with your boss, the basic principle is that he must know what is going on in his territory. From this idea are derived the following rules.

Rule 1: Do not overlook the fact that you are working for your boss.

It is not uncommon for young engineers, in their impatient zeal to get things done, to ignore the boss, or attempt to go around him. Sometimes they move a little bit faster that way for a while, but eventually they find that such tatics do not work at all.

Rule 2: Whatever the boss wants done takes top priority.

Unless you obtain permission it is unwise to put any other project ahead of a specific assignment from your own boss. As a rule, always take for granted that your boss has good reasons for wanting his job done now. Also, if you are instructed to do something and you subsequently decide it is not worth doing because of new data or events, don't forget to inform your boss of your intentions and reasons.

Rule 3: Try your best to inform your boss of all significant developments.

Since your boss is constantly called upon to account for, defend, and explain your activities to the higher-ups as well as to coordinate these activities with other departments, he needs to know all information promptly and accurately.

Rule 4: Do not be too anxious to follow the boss's leads.

In general, the program laid down by the department head is tentative, and is intended to serve only until a better program is proposed and approved. Therefore, do not just follow the lines laid down by your boss. Try to sell your ideas to him and make contributions.

Rule 5: Be as particular as possible in the selection of your boss.

It is well known that the influence of the senior engineer, or even the boss, is a major factor in molding professional character of younger engineers. Consequently, if your boss turns out to be somewhat less than half the man he ought to be, transfer to some other company at the first opportunity. Remember, a person who constantly plays golf with a dub becomes a dub.

7.4 In Relation to Your Associates and Clients

Rule 1: Never invade the territory of any other department without the knowledge and consent of the executive in charge.

Rule 2: In all transactions be careful to deal-in everyone who has a right to be in.

Be especially careful about whom you mark for copies of letters, memos, etc., when the interests of other departments are involved.

Rule 3: When you are dissatisfied with the services of another department, make your complaint to the individual most directly responsible for the function involved.

Complaints made to a man's superior should be resorted to only when direct appeal fails. Give the man a fair chance to correct the grievance before filing a complaint with his superior.

Rule 4: In dealing with customers and outsiders, remember that you represent the company, ostensibly with full responsibility and authority.

CHAPTER 8

SUMMARY AND CONCLUSIONS

During a one year internship, I made the following contributions to the firm:

(1) Technical Activities - I designed a protective relaying scheme for the 480 MW power plant, microprocessor-based SCADA and SOE systems. I also designed the power plant overhead and underground distribution circuits as well as substations.

(2) Engineering Services - Designing a complete engineering progress control chart and helping the Project Manager to prepare cost control charts for a project which cost over $1.4 million merely for engineering.

(3) Standardization of the managerial procedures for young engineers in the firm. This report summarizes and highlights the results of this standardization process. It is prepared to be a training manual for young engineers just starting their engineering careers.

This report is divided into two parts. Part one emphasizes the following technical design guidelines:

(1) Fundamentals of Electrical Power System Design

Technical design tools such as short circuit current calculation, ampacity of electrical conductors, instrument transformers, and the R-X diagram.

The short circuit current calculation includes both maximum and minimum current calculations under fault conditions. The maximum fault current values are used to select adequate interrupting ratings and to check the ability of power system components to withstand both mechanical and thermal stresses. The minimum values are needed to check the sensitivity requirements of protective relays. For overall coordination of system protective devices, both the maximum and the minimum values are often required.

Under normal operating conditions, the prime considerations in the applications of electrical conductors are ampacity, maximum allowable voltage drop, and energy losses.

Under fault conditions, mechanical considerations such as minimum required mechanical strength and maximum allowable deflection usually govern the selection and design of electrical installations.

Instrument transformers are used to protect personnel and apparatus from high voltage and to allow reasonable insulation levels in relays, meters, and other instruments. Their performance is critical in protective relaying. Consequently, performance estimation of instrument transformers is elaborated in the report.

The R-X diagram is another important tool for protective relaying design. It integrates both system operation conditions and relay characteristics in the same diagram. Its applications are also illustrated in Chapter 2.

(2) Generator Protection

Generator fault protection functions to detect any faults either internally in stator windings or externally in terminal leads but within the generator relaying zone. It includes differential and stator ground fault protection. On the other hand, generator abnormal protection is designed to protect the following abnormal operation conditions: loss of excitation, motoring, negative sequence current, uncleared system fault, overloading, overvoltage, overspeed, grounded rotor and loss of synchronism.

(3) Power Transformer Protection

Power transformer relaying includes fault detecting devices and abnormal operation sensing devices. Fault detecting devices function to protect the system and limit damage in the event of a fault. Abnormal operation relaying is designed to protect the transformer and includes overtemperature and system backup protection.

(4) Power System Supervision, Protection and Control

Miscellaneous items such as transmission substation configurations, breaker failure protection and SCADA system design are discussed.

Part two gives business aspects of engineering projects and in-house guidelines to young engineers. These guidelines are given to help young engineers who are starting their professional careers to adjust themselves to the industrial environment. The guidelines fit into the following four topics: character and personality consideration, in relation to your work, in relation to your boss, and in relation to your associates and clients.

From a personal point of view, my internship has been one of the best possible and the three internship objectives have been met. The positive attitude of my internship supervisor, Mr. E. E. Hogwood, and all of my colleagues was a significant factor in the success of my internship.

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APPENDIX I

Figure 7.1 shows a simplified circuit for fault current calculation. Since a fault may occur at any instant defined by θ shown in the figure, when θ is the angle between the instant of positive voltage crest and the instant of closing switch. Expressed in mathematical form, the fault current i_f for a single line to ground fault is

$$L \frac{d}{d_t} i_f = ig(t) = E\,(\cos wt + \theta)$$

$$\frac{d}{d_t} i_f = \frac{E}{L} \quad (\cos wt + \theta)$$

$$i_f(t) = \frac{E}{WL} \quad \sin\,(wt + \theta) + \text{constant}$$

Initial condition at t=o,

$$i_f\,(o) = o$$

$$\text{constant} = -\frac{E}{WL}$$

$$i_f(t) = \frac{E}{WL}\,[\sin\,(wt + \theta) - \sin\theta]$$

To find θ values such that $i_f(t)$ will have maximum value

$$\frac{d}{d_\theta} \quad i_f = \frac{E}{WL} \quad [\cos\,(wt + \theta) - \cos\theta]$$

$$= 0$$

$$\cos wt \;\; \cos\theta - \sin wt \sin\theta - \cos\theta = 0$$

$$(\cos wt - 1) \cos\theta - \sin wt \sin\theta = 0$$

$$\boxed{\theta = \pm\, 90° \text{ for maximum amplitude of } i_f}$$

and the peak of i_f occurs at wt = ±180°, that is, a half-cycle after the fault occurrence.

EFFECT OF INSTANT FAULT OCCURRENCE ON THE FAULT CURRENT i_f	DWG.NO.	REV.	**Power Systems Engineering, Inc.** P.O. Box 19398 Houston, Texas 77024
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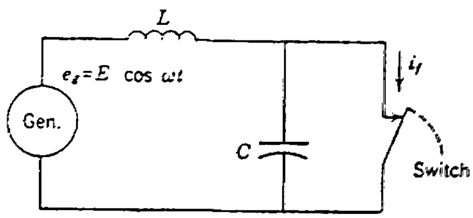

Single Frequency Circuit for
Fault Current Calculation

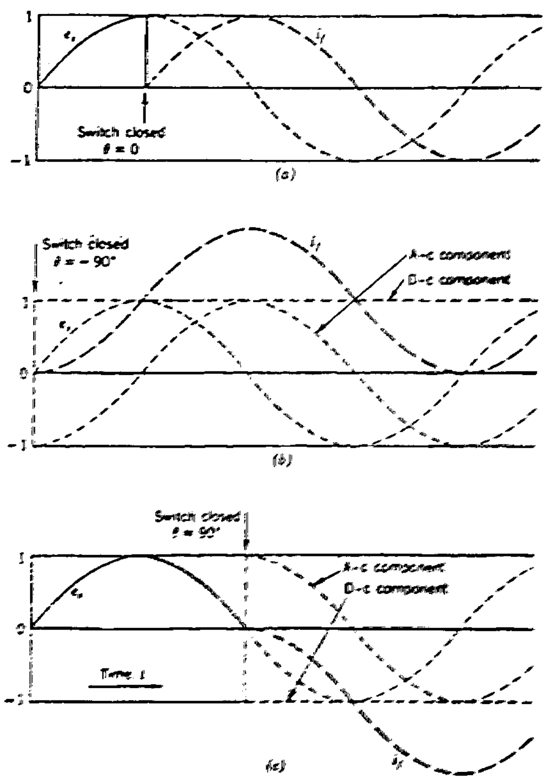

Figure A.1 EFFECT OF INSTANT FAULT OCCURRENCE
ON THE FAULT CURRENT i_f

Consequently, the maximum fault current can be shown as

$$i_f\ (t) = \frac{E}{WL}\ [-\cos wt \pm 1]$$

peak value of $i_f(t)$ is $2\sqrt{2}$ times the rms value of its symmetrical component $(-\frac{E}{WL}\ \cos wt)$.

$$\boxed{\begin{aligned} I_p &= \text{peak of } i_f(t) \\ &= 2\sqrt{2}\ I_s \end{aligned}}$$

The rms value of i_f (t) over the first half-cycle after fault occurrence is

$$I_a = \frac{E}{WL} \cdot \sqrt{\frac{\int_0^{\pi} (-\cos wt \pm 1)^2\ dwt}{\pi}}\ ,$$

$$= \frac{E}{WL} \cdot \sqrt{\frac{\int_0^{\pi} 1-2\cos wt + (\cos wt)^2\ dwt}{\pi}}$$

$$= \frac{E}{WL} \cdot \sqrt{\frac{3}{2}}$$

$$\boxed{I_p = \frac{2}{\sqrt{3/2}}\ I_a = 1.63\ I_a}$$

Obviously, $\boxed{I_a = \sqrt{3}\ I_s}$

To prove that the maximum short circuit force impressed on phase B conductor, the short circuit must occur at $\theta = 45°$, consider a three phase symmetrical fault.

$$i_{fa} = \frac{E}{WL}\ [\sin (wt + \theta + 120°) - \sin (\theta + 120°)]$$

$$i_{fb} = \frac{E}{WL} [\sin(wt + \theta) - \sin\theta]$$

$$k_{fc} = \frac{E}{WL} [\sin(wt + \theta - 120°) - \sin(\theta - 120°)]$$

F_s = short circuit force on phase B conductor

$$= \frac{5.7}{D(WL)^2(10)^7} [\sin(wt + \theta + 120°) - \sin(wt + \theta - 120°) - \sin(\theta + 120°) + \sin(\theta - 120°)] [\sin(wt + \theta) - \sin\theta]$$

$$= \frac{-22.8}{D(WL)^2(10)_7} \sin(wt + 2\theta) \sin^2 \frac{wt}{2}$$

$$\frac{d}{d\theta} F_s = \frac{-45.6}{D(WL)^2(10)^7} \sin^2 \frac{wt}{2} \cos(wt + 2\theta)$$

$$\cos(wt + 2\theta) = 0$$

$$\boxed{0 = \pm 45°}$$

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