ABSTRACT

Coordination of
Time-Overcurrent Relays for
High-Speed Power Line Protection

by
Nicos Charalambous

A properly coordinated protection system is essential to ensure that an electricity distribution network can operate within its requirements, regarding the safety of a power system. Automatic operation is necessary to isolate faults on a power system in a minimum time. The study of time coordination of relays suggests improved ways of power line protection. The protection must be sensitive enough to operate when a fault occurs under minimum fault conditions, yet be stable enough not to operate when its associated equipment is carrying the maximum rated current, which may be a short-time value. A power system is used as an example of time coordination of distance relays that are responsible for clearing any possible faults. The communication of the protection relays is associated with the backup protection which is responsible for covering the failure of the main protection system. In addition, the reliability of the power system is improved by establishing the right relay communication and settings.

COORDINATION OF TIME-OVERCURRENT RELAYS FOR HIGH-SPEED POWER LINE PROTECTION

by
Nicos Charalambous

A Thesis
Submitted to the Faculty of
New Jersey Institute of Technology
in Partial Fulfillment of the Requirements for the Degree of
Master of Science in Electrical Engineering

Department of Electrical and
Computer Engineering

January 1994

APPROVAL PAGE

Coordination of
Time-Overcurrent Relays for
High-Speed Power Line Protection

Nicos Charalambous

Dr. Walid Hubbi, Thesis Advisor | Date
Associate Professor of Electrical Engineering, NJIT

Dr. Edwin Cohen, Committee Member | Date
Professor of Electrical Engineering, NJIT

Mr. Hans Candia, Committee Member | Date
Senior Engineer, New York Power Authority

BIOGRAPHICAL SKETCH

Author: Nicos Charalambous

Degree: Master of Science in Electrical Engineering

Date: January 1994

Undergraduate and Graduate Education

- Master of Science in Electrical Engineering,
  New Jersey Institute of Technology,
  Newark, New Jersey, 1994

- Bachelor of Engineering in Electrical Engineering,
  City College of the City University,
  New York, 1991

Major: Electrical Engineering

This Master's Thesis is dedicated to
my family

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

Chapter **Page**

TABLE OF CONTENTS
(continued)

LIST OF TABLES

Table **Page**

LIST OF FIGURES

LIST OF FIGURES
(continued)

CHAPTER ONE

INTRODUCTION TO PROTECTION OF POWER LINES

Modern power systems have created needs that led to the expansion of the protection area which is one of the most important fields in Power Engineering. In the protection area, line protection has become complicated. In this study, I will examine the coordination of time-overcurrent relays for phase and ground faults in order to help coordinate the operation of the primary and the backup protection systems. Cyprus Power System will be used for examination and study. Cyprus has a relatively small power system, however, the transmission voltage level reaches up to 132 kV. In addition, there is going to be a study for better "relay communication", using new techniques, in order to minimize the number of failures of the circuit breakers. In other words, the reliability of the power system will also be emphasized. The main aim is to maximize the instantaneous coverage of line sections independent of system and fault-level variations and ensure high-speed line protection.

1.1 Line classification

Since we have various voltage levels in a power system, we have to classify the lines which connect all parts and equipment in the power system. A basic power system is associated with the following three words: Generation, transmission and distribution. Generation is made in low voltage levels and then the voltage is stepped up for transmission. The final step, the distribution is made after stepping down the voltage in the substations. According to the IEEE Power Engineering Society and Industrial Application Society, there are the following voltage categories:

(I) 34.5kV and below Industrial-distribution

(II) 34.5 to 138 kV Sub-transmission

(III) 115 kV and up Transmission

The last class is usually divided into three other classes:

(I) 115 kV to 230 kV high voltage (HV)

(II) 345 kV to 765 kV extra high voltage (EHV)

(III) 1000 kV and above ultra high voltage (UHV)

1.2 Radial and loop

In addition, the transmission lines are also classified into two other categories: Radial lines or feeders and loop type lines. Feeders or radial lines supply power usually to nonsynchronous loads. In this case, the fault is supplied from the source, without any other fault current from all other terminals. On the other hand, loop circuits are those where for line faults, fault current is supplied from all terminals.

1.3 Protecting zones

In a power system, it is wise to separate the system into zones. As a result, we can assign separate protection schemes of the whole power system for easier coordination. Figure 1.1 shows a classic example of zones of protection.

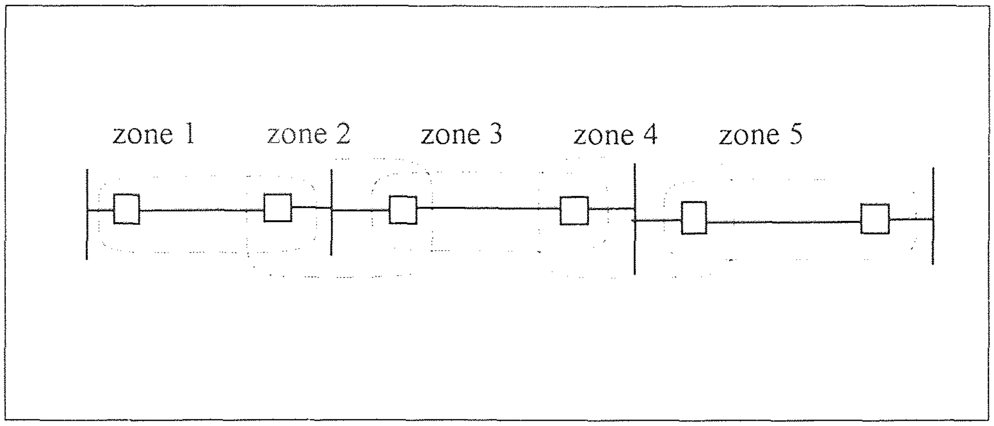

Figure 1.1 Zones of protection are shown by the dashed lines.

The boundary of each zone defines a portion of the power system such that for a fault anywhere within that zone, the protection system responsible for that zone takes action to isolate everything within that zone from the rest of the system. We notice that in each zone there are two circuit breakers and one or more power system components such as generators and transformers (not shown). In addition, the zones should always overlap. This overlap is necessary in order to cover the entire power system in terms of protection.

1.4 Protection coordination

The line protection is extending into adjacent lines and equipment such as, buses, transformers, motors. etc. Likewise, equipment protection overlaps into the lines. As a result the settings must be appropriate in order to ensure that the protection does not operate for faults in this overlapping area until the primary relays assigned to that area have had the opportunity to clear the fault. The process of setting is called coordination or selectivity. Phase and ground fault relays must coordinated. The phase relays are set according to the three-phase fault data and maximum short time load or transient inrush.

The ground relays are set according to the single phase to ground fault data and the maximum zero sequence load unbalance. In addition, fuses are involved in the coordination process, since they provide phase and ground fault protection. However, they receive only the line currents and the ground relays operate on $3I_0$ currents. In general, fuses are applied to radial systems where the line current is equal to $3I_0$. Nevertheless, fuses cannot be applied to loop systems where the faulted phase current is not equal to $3I_0$. Eventually, the coordination of relays and fuses becomes more complicated where the ground relays are set more sensitively. If we have ground relays being coordinated without the fuses, then we are dealing with a normal situation. If we include the fuses in the coordination process, then we require to raise the ground relay setting to that essentially equivalent to the phase relays.

1.5 Primary and backup

As I said before, our aim is to set the protection to operate as fast as possible for faults in the primary zone, yet delay enough for faults in the backup area. All power systems contain many subsystems and each subsystem and component is responsible for the removal of a fault. The primary protection systems are considered the systems that are primarily responsible for the removal of the fault as soon as possible while the losses are kept at minimum. However, sometimes the system's primary protection components fail to operate, and we have the so called backup protection which is responsible to cover the primary system's failure and clear the fault. The following example will illustrate the operation of the backup protection.

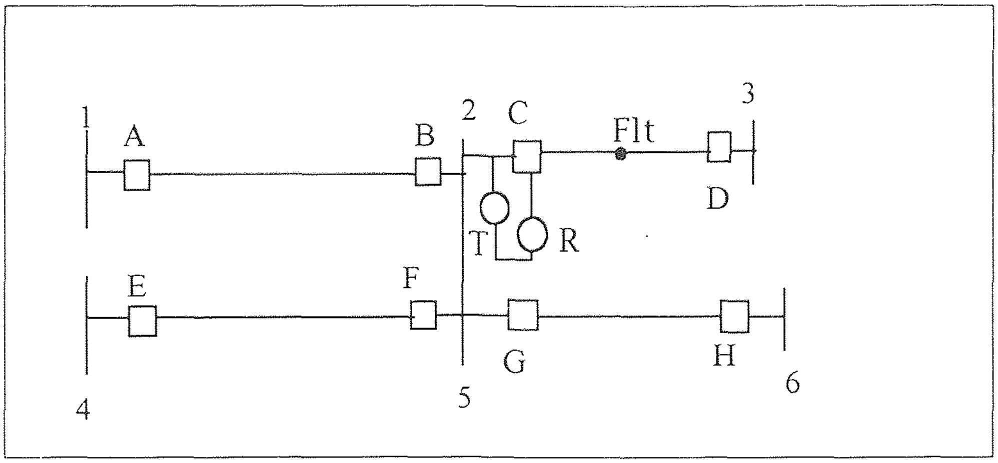

Figure 1.2 Basic backup protection system.

In figure 1.2 we have a basic protection scheme where backup protection is involved. Assume we have a fault at point Flt. Circuit breakers C and D must open in order to protect line 2-3. This is the primary protection system. Suppose the primary protection system at bus 2 has failed to operate. This failure must be recognized from the rest of the protection system in order to clear the fault at point Flt. The circuit breakers A, E and H must be tripped and the protection systems at buses 1, 4 and 6 must provide a backup protection for the primary protection system at bus 2 for line 2-3. In addition, the backup protection is a primary protection for line sections 1-2, 4-2 and 6-2. The operation of a remote backup system removes a far greater portion of the power system from service than does the operation of the primary protection system. The service to any loads that may be connected at buses 1, 4, and 6 may be affected, and there will be no service to bus 2. Moreover, the backup system must allow a sufficient time for the primary protection system to function normally. The backup system is made slower-acting by inserting a delay between the maximum time for fault clearing by the primary system, and the fastest possible response of the backup system. The inserted delay is called coordination time delay. Moreover, this is the time solution to the protection problem. In addition to the time solution, there is the so called communication solution.

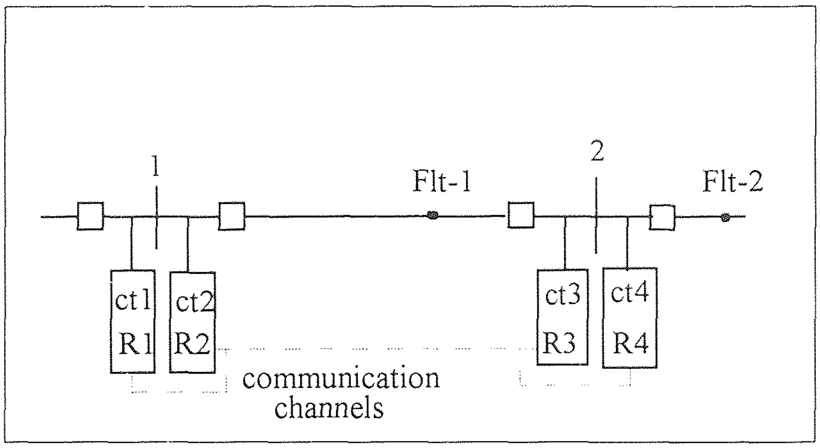

Figure 1.3 Communication is established between the distance relays, when an internal or external fault is occurred.

In figure 1.3 we have a communication example of the distance relays. In case of an internal fault (Flt-1) or an external fault (Flt-2), the relays at bus 1 indicate the direction of the power flow or the relative phase angle information whether the fault is external or internal. This information is communicated through channel to the relays at bus 1. Similarly, the relays at bus 1 communicate with the relays at bus 2. (ct1, ct2, ct3 and ct4 are current transformers). If the fault is in the primary zone (Flt-1), then both relays at 1 and 2 operate together at high speed. The communication process can be done through fiber optics cables which is a temporary technology in the communication area. The communication solution is part of the pilot relaying, a topic that I will examine in the next sections.

1.6 Types of relays

In this section, we are going to examine some of the basic types of relays that are used for the protection of the power lines. The *distance relay* is the main relay that we have to consider in our protection applications. The distance relays are mainly used for primary and backup protection on transmission and subtransmission lines where there is high-speed relaying and the voltage is above 34.5 kV.

The distance relay has its principle of operation based on the ohmic relays that use voltage and current inputs to provide an output signal if there is a fault within a certain distance from the relay. The distance is calculated according to a signal that is proportional to the voltage-to-current ratio that is the impedance, or according to a signal that is proportional to the imaginary component of the voltage-to-current ratio that is the reactance, or according to a signal that is proportional to the current-to-voltage ratio that is the admittance to the fault. One of the major advantages of the distance relay is that it responds to the system's impedance instead of the magnitude of the current. Therefore, the distance relay has a fixed distance reach.

A common type of distance relays is the *electromechanical-distance relay* that utilizes an induction cup in order to achieve operating times of 1-1.5 cycles. Another type is the static distance relay that utilizes an operating time of 0.25-0.5 cycles. The characteristics of the distance relays can be shown in terms of two variables, R and X or sometimes in terms of Z and Θ. (R is the resistance, X is the reactance, Z is the impedance and Θ is the angle by which current lags voltage). R-X diagrams can show the relay characteristics and the line impedance, helping us to analyze the protection scheme. We have to mention that regions of positive R and X represent impedance in a defined tripping direction and the regions of negative R and X represent the nontripping direction. Some figures are shown to understand the essence of the R-X diagrams.

Let's examine the *reactance type distance relay*. These relays measure the reactive component of the system complex impedance. Figure 1.4 shows us the generic reactance relay characteristic which appears on the R-X diagram as a straight line parallel to the R-axis.

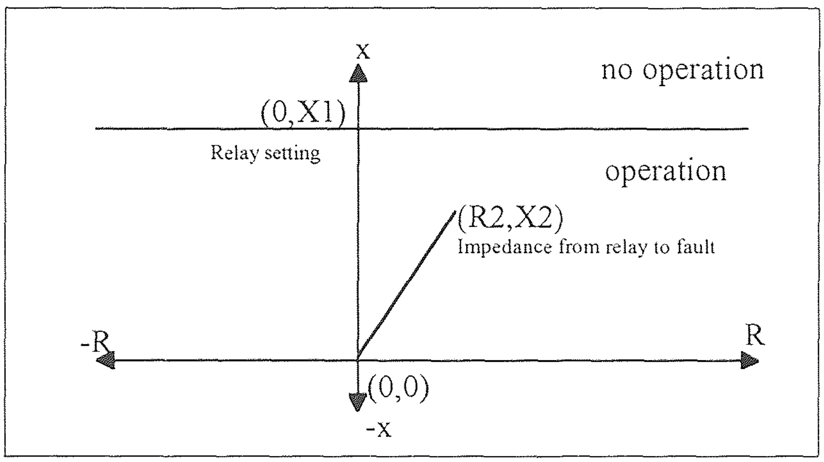

Figure 1.4 R-X diagram for the generic reactance relay.

Operation of the generic reactance relay occurs when the reactance from the relay to the point of fault, X_2, is less than or equal to the reactance X_1. The relay responds to any reactance in the negative direction and it is also nondirectional.

The most important relays for line protection, are the *time-overcurrent* and *instantaneous overcurrent relays*. These are the most commonly used relays and they are used as primary and backup protective devices. The time-overcurrent relay is selected to give a desired time delay tripping characteristic versus applied current, whereas instantaneous overcurrent relays are selected to provide high speed tripping (0.5-2 cycles).

The instantaneous overcurrent relays have been used for a long time in the protection scheme. The relay operation is based on the electromagnetic attraction and induction cylinder type. In recent years, solid-state overcurrent relays have become available and their characteristics are very similar to the electromagnetic relays except that solid-state relays provide faster reset times.

Another type of relays that is also very common in the protection, is the *induction type time-delay overcurrent relay*. This relay has its principal based on alternating current watt-hour meters and it provides different time-current characteristics, depending on differences in electrical and mechanical design. The basic components of the relay are the induction disk which is mounted on a rotating shaft. There is the moving contact that is fastened to the shaft. An electromagnet is also there in order to provide an operating torque to the disk. Basically, in order for the smooth operation of design and settings, the relay has two adjustments, the pickup current tap and the time dial. The pickup current is calculated by a series of discrete taps that are appointed in several current ranges. The time dial setting determines the initial position of the moving contact when the coil current is less than the tap setting. The setting controls the time necessary for the relay to close its contacts. The relay has an inverse time characteristic. Therefore, the relay operates slowly on small values of current above the tap setting. However, as the current increases, the time of operation decreases as well. If the current continues to increase, the time delay will become a constant value due to saturation of the electromagnet. The following graph, in figure 1.5, shows us different time-current curves that can be obtained by modifications of electromagnetic design.

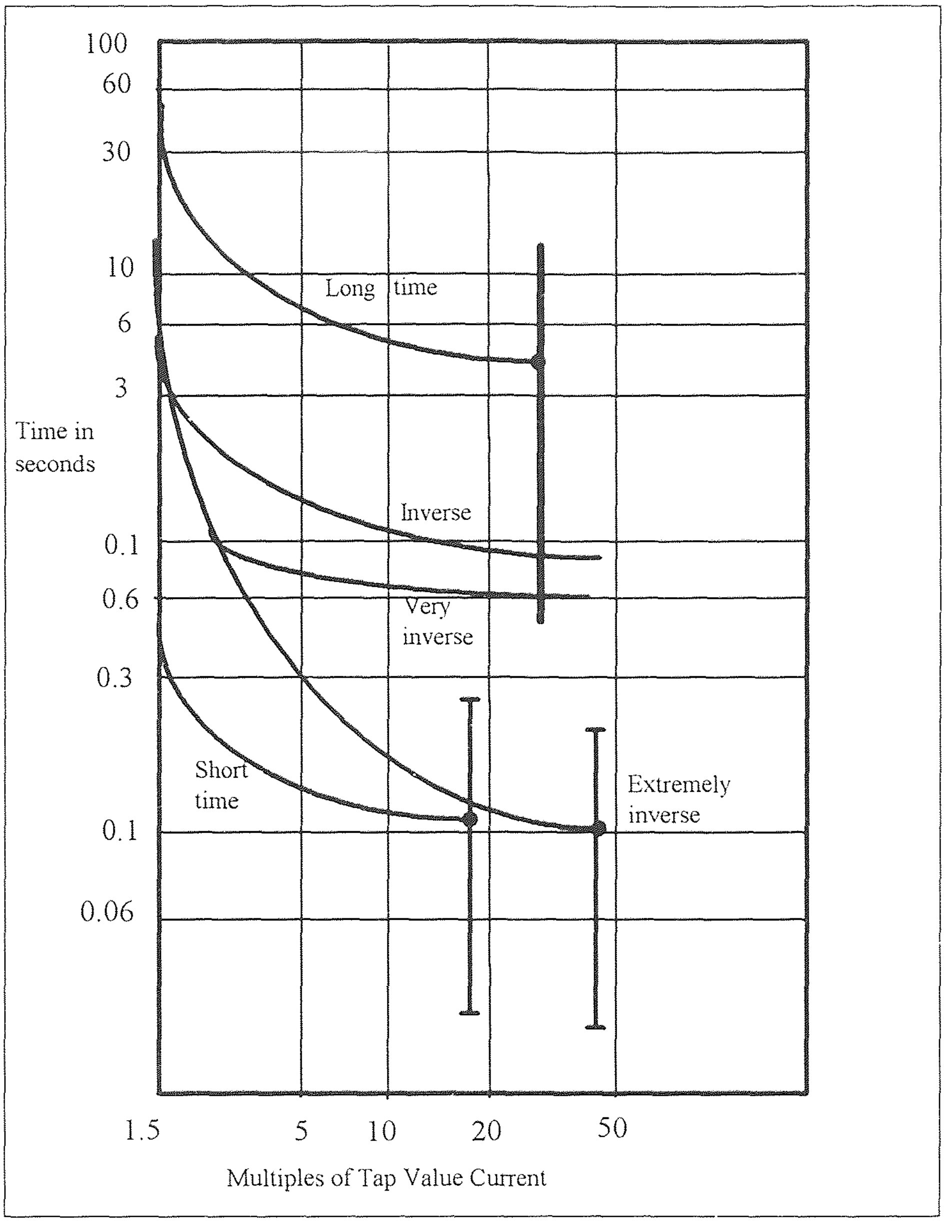

Figure 1.5 Typical curves for overcurrent relays.

The *pilot-wire relays* are also very important for the protection of the power lines. There are cases where lines should be capable of carrying maximum emergency load currents for any period of time and they should be removable from service quickly. The pilot-wire relay is capable of providing the right response to a situation like before. The pilot- wire relay is a type of differential relay and it operates on the principle of comparing the conditions at the two ends of the line. The relays are being connected to operate if the comparison indicates a fault in the line. All the fault information is transmitted through terminals over a pilot-wire circuit. However, since the pilot-wire relay is a differential relay, the relaying scheme does not provide protection for faults of adjacent section of lines and buses.

Finally, the *distance relays* are considered to be the most important protective devices for power line protection. As I mentioned before, the distance relays measure voltage and current, and the ratio is expressed in terms of impedance. This impedance is an electrical measure of the distance along a transmission line from the relay location to a fault. The measuring element is instantaneous in action, with time delay provided by a timer element so that the delay, after operation of a given measuring element, is constant. In a typical transmission line application, three measuring elements are provided. The first operates only for faults within the primary protection zone of the line and trips the circuit breaker without intentional time delay. The second element operates on faults in one adjacent or backup protection zone and initiates a tripping after a short time delay. The third element is set to include more remote zone and to trip after a longer time delay. The distance relays are more preferred in cases where changes in operating conditions cause wide variations in magnitudes of fault current, and where load currents may be large enough, in comparison with fault currents. In general, there are three main types of distance relays. The first one is the *impedance-type* which is used in phase-fault relaying for moderate length lines. The second type is called *mho-type* and it is used in phase-fault relaying for long lines or where severe synchronizing power surges may occur. Finally the third type is called *reactance type* and it is used in ground-fault relaying and phase-fault relaying on very short lines and lines of such physical design that high values of fault arc resistance are expected to occur. In addition, the reactance-type relays are used in systems where severe synchronizing power surges are not a factor.

There is no doubt that the system and equipment protective devices guard the power system from the threat of damage caused by overcurrents and transient overvoltages that can result in equipment loss and system failure. The coordination of the protective devices is one of the most important operation during design of a protection scheme. During the next chapter we will see how the coordination of the relays works and how we can improve their operation.

CHAPTER TWO

PROTECTION COORDINATION

2.1 Coordination scheme

In this chapter, I will take a closer examination of the protection coordination and analyze the loop line setup since Cyprus power system has a loop form. Like every other protection scheme, our aim is to set the protection to operate as fast as possible so that we can avoid any damage to our systems. Moreover, the protection should be responsible for the backup areas, therefore a proper delay for any faults should be inserted. The first thing we need to assume is a minimum fault current which should be able to operate all the protective devices. On the other hand, we have to consider the other extreme where we have maximum fault current during the peak-load periods. There are some cases where we have to take into account the possible margins according to the requirements of the relays' operation. Nevertheless, coordination is a process that requires trial and error. For instance, lines and feeders are to have the right coordination by plotting the time-current characteristics on a log paper and shifting the points until the right requirements are met. The loop systems require a more complicated procedure since the current in the relays being coordinated will be different for the fault. Therefore in such a case, we use coordination charts. The following figures shows an example of line protection.

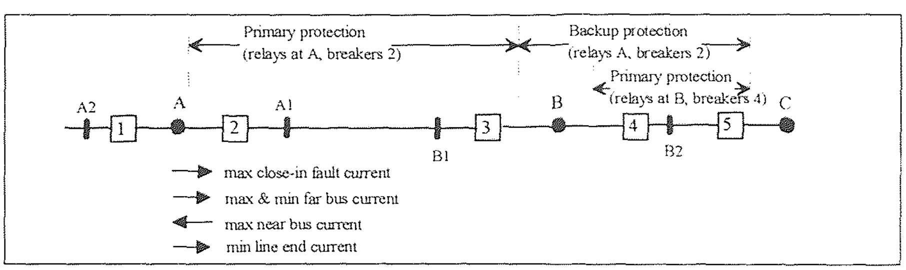

Figure 2.1 Sections of protection.

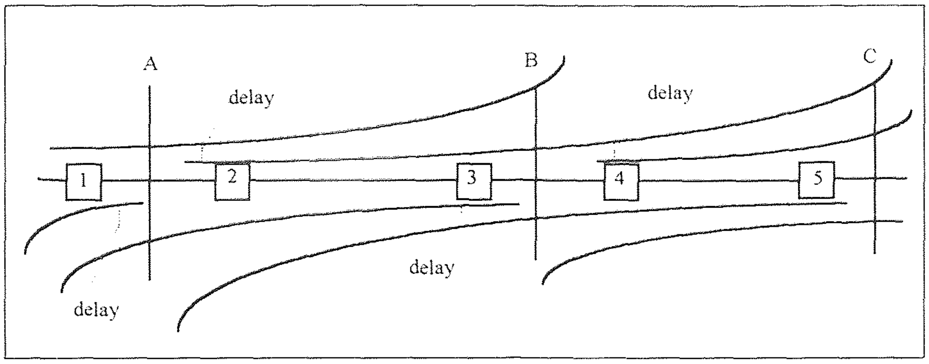

Figure 2.2 Delay setup.

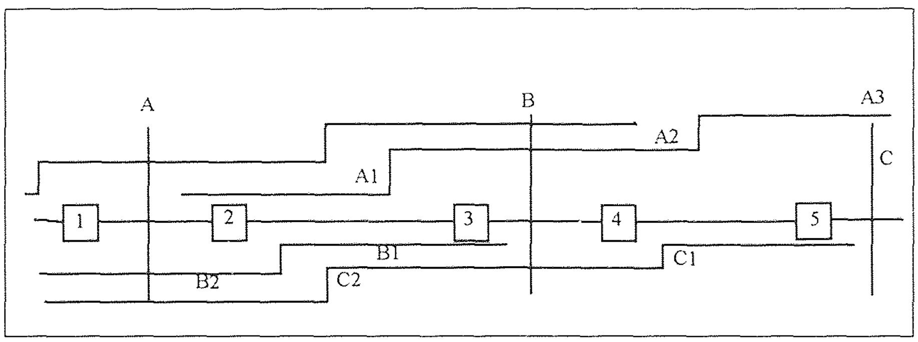

Figure 2.3 Coordination with instantaneous overcurrent and inverse time units.

Figure 2.1 shows the currents that are necessary for setting the relays at point A and circuit breaker 2, in order to protect line section AB. Figure 2.2 shows the coordination with instantaneous overcurrent and inverse time units. The "delay", that is shown in the figure, is the actual time interval between primary and remote backup protective devices. That time interval is a delay that is required for the relays at circuit breaker 2, station A, to permit breaker 4 relays at station B to clear the faults in line BC. Typical values for the delay are in between 0.2 and 0.5 s for electromechanical units. The clearing time for a fault is typically 0.033 to 0.133 s. Figure 2.3 shows the coordination with directional distance relays.

2.2 Loop system

In a loop system, the fault currents are coming from all terminals. A line could be a feeder type for positive and negative sequence but a loop for zero sequence. The circuit may have a power source at one end but be grounded at both ends. In addition, a line could be a loop type for positive and negative sequence but a feeder type for zero sequence. Since we have a multiple fault current sources, the coordination of the loop system is rather complicated. Let's take a look at an example of loop system in order to realize the protection concept. Figure 2.4 illustrates a loop system.

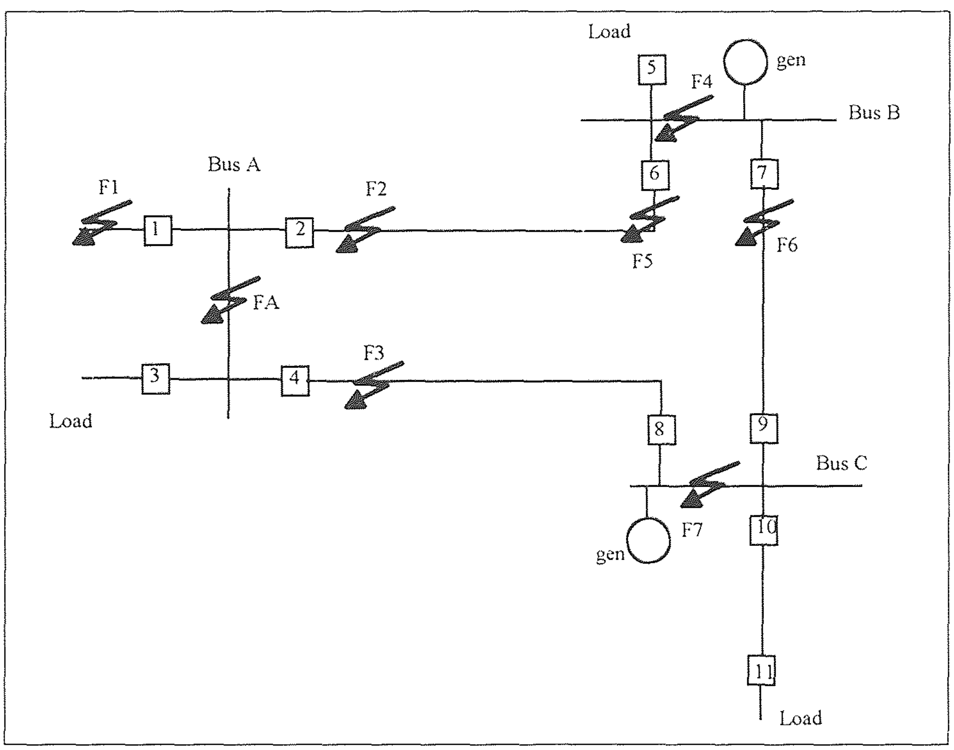

Figure 2.4 Loop system setup.

In figure 2.4, we have a typical loop system where the settings will be made for the phase relays. Setting ground relays for the system is similar using phase-to-ground fault data and relay pickup values. The taps should be one half or less of the phase relay taps.

The directional time-overcurrent relays are being set for the circuit breakers at 1, 2, 4, 6, 7, 9, and 8. If we take the relays around the loop clockwise, we have the following coordination scheme: Relays at 2 must coordinate with relays at 5 and 7. Relays at 7 must coordinate with relays at 8 and 12. Finally, relays at 8 must coordinate with relays at 1,2, and 3. If we take the relays counterclockwise, with the following coordination scheme: Relays at 4 must coordinate with relays at 9 and 1. Relays at 9 must coordinate with relays at 5 and 6. Relays at 6 must coordinate with relays at 1,3, and 4. We see that the loops are not independent with each other. The setting in both are dependent on the settings of the relays on other circuits from the several buses.

Our purpose is to set the relays around the loop. Therefore, we have to determine the settings and operating times for these relays. However, if we assume the settings for the relays, we make life a little easier. The phase relay at breaker 1, should not exceed 0.06s. We use typical times and 0.06s is an appropriate value to assume. A pilot relay could be used on this short line. The relay at breaker 5, is to have a maximum operating time 0.24 s, for fault at F4 . The relay at breaker 10, is to have an operating time 0.18 s, for fault F7 . Finally, the relay at breaker 3, is to have an operating time 0.21 s , for fault FA. The next step is to try to set each relay to operate in less than 0.2 s for the close in fault and at least 0.2 plus the delay time interval for the far-bus fault. The protection of the remote busses, requires relay operating time greater than 0.2 s and the setting should be that maximum time plus the delay interval. We usually assume the delay interval to be equal to 0.3 s. We see that the timing of the whole set-up should be made with a very careful way. The time dial setting is the most important setting of the overcurrent relays.

We have to select the right relay tap in order to have the right coordination of the relays. We get the time dial settings from curves that usually provided by the relay companies. Manufacturer's printed time-current curves show the relay operating times for a full range of time dial settings and multiples of tap current applied to the relay. Time-overcurrent relays are available with many different current ranges and tap settings. The following table shows typical tap ranges and settings.

Table 2.1 Typical Tap Ranges and Settings

TAP RANGE	TAP SETTING
0.5-2.5 or 0.5-2.0	0.5, 0.6, 0.8, 1.0, 1.2, 1.5, 2.0, 2.5
0.5-4.0	0.5, 0.6, 0.7, 0.8, 1.0, 1.2, 1.5, 2.0, 2.5, 3.0, 4.0
1.5-6.0 or 2.0-6.0	1.5, 2.0, 2.5, 3.0, 3.5, 4.0, 5.0, 6.0
4.0-16.0 or 4.0-12.0	4.0, 5.0, 6.0, 7.0, 8.0, 10.0, 12.0, 16.0
1.0-12.0	1.0, 1.2, 1.5, 2.0, 2.5, 3.0, 3.5, 4.0, 5.0, 6.0, 7.0, 8.0, 10.0, 12.0

Let's go back to our example in figure 2.4. The coordination process we can draw in one diagram, that is figure 2.5.

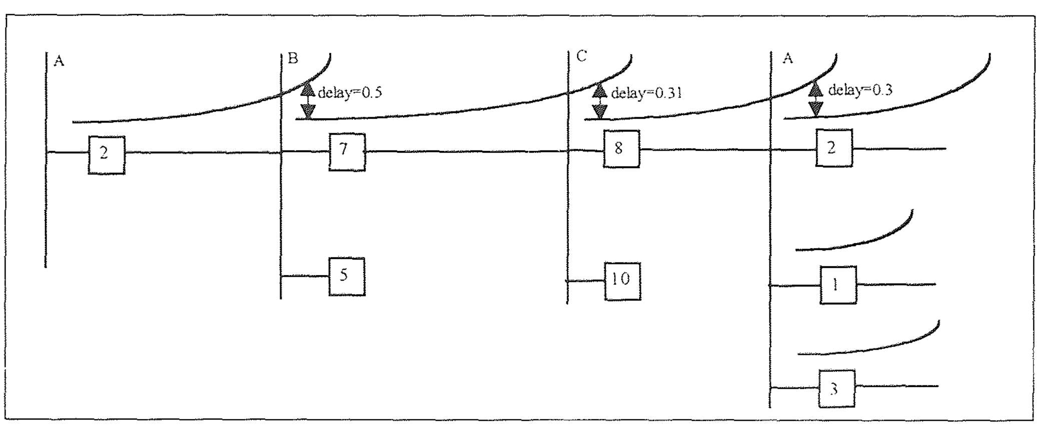

Figure 2.5 The coordination process.

If we take out the genarators at buses B and C, in order to achieve minimum condition, there is no current flow through the breakers 8 and 6 for any far faults. However, this changes after the far-bus relays 2 or 4 open and we have line faults from points F2 and F3. We have to make sure that the relays can respond to these line faults otherwise they will not be possible to be cleared. Our case is what we called a single loop operation. However, in real life there are several cases where several separate load areas exist. The advantage is that any one line circuit can be removed with service available to all the loads. The system in figure 2.4, the relays at breaker 6 do not need to coordinate with the relays at 1, 3 and 4 since they do not have current for fault FA. Similarly, relays at 8 do not need to coordinate with relays at 1, 3 and 2. The faults at F3 and F4 can be detected only after breaker 2 or 4. Load currents into the lines could be zero unless there are other line taps. Therefore, we can apply directional instantaneous relays at breakers 6 and 8 and we should set them very sensitively and below the line faults. This provides high-speed operation for the terminals.

In reality, we have to give emphasis to the possibilities of various lines that are out of service and other possible operating conditions. Therefore, it is wise to set all the relays to provide complete backup protection over all the adjacent remote lines. In our example, the relays at breaker 2 should be able to provide protection for faults to bus C and at load at breaker 5. However, we might not have success to this protection scheme since the infeed of fault current by the source at bus B tends to reduce the fault current through breaker 2 for faults on line BC and at bus B.

In addition, there is the case where an *instantaneous trip application* is necessary for a loop system. The fault current could exist between the close-in and far-bus faults and instantaneous units should be utilized in order to provide fast protection for faults out on the line. For instance, the system in figure 2.4, an instantaneous unit at relays 2 must be set to a value which is the maximum far-bus fault current multiplied by a factor greater than unity. This gives a sufficient coverage for the line compared to the close-in fault. The instantaneous trip units supplement the time-overcurrent protection to provide fast operation over part of the line sections.

However, these units, in some cases offer limited protection for the maximum fault condition and none for minimum faults. Therefore, their application becomes marginal from a protection point of view. Still, they can provide fast clearing for the heaviest close-in faults and for the non-directional type, the total cost increases very little.

The operating times of the time-over-current relays can be reduced with instantaneous units by coordinating at their pickup point rather than at the far bus, although, this becomes more difficult where the instantaneous unit reach varies considerably from system changes.

2.3 Phase fault distance protection

The distance protection for phase fault is applied mostly for lines at 69 kV and above. In this case, we are able to have a fixed reach as a function of the protected line impedance, something that is advantageous. Moreover, we have the ability to operate for fault currents near or less than maximum load current and minimum to no transient overreach.

In our protection scheme, first we have to define at least two zones that are necessary for primary protection. Both zones have to operate simultaneously, but one zone should be delayed by a time delay, the so called CTI, in order to provide coordination. However, it is wise to use a third zone in the protection scheme to apply backup protection of the remote lines.

The following method is a common practice in the United States and it utilizes separate distance units for the several protection zones. This is in contrast to distance relays that use a single distance measuring unit initially set for zone 1 reach. If we have a fault persistence, then we extend the reach by switching to zone 2 after T2 delay, then after T3 to zone 3. On one hand, separate units provide the comfort of redundancy since for faults in the zone 1 primary reach area, all three distance units will operate. Thus zones 2 and 3 are backup for failure of the zone 1 unit. On the other hand, the switched types do not provide this backup but they are more economical.

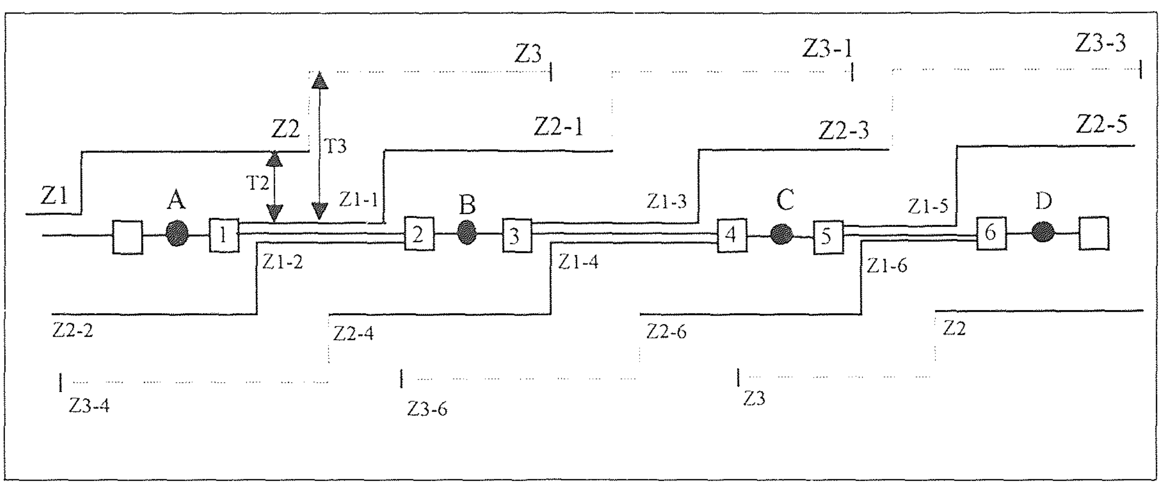

Figure 2.6 Zones and typical settings of distance relays.

The zones and typical settings are shown in figure 2.6. In this figure we see the zones at several locations. Typically, zone 1 is set for 90% of the positive sequence line impedance, zone 2 approximately 50% into the next adjacent line, and zone 3 approximately 25% into the adjacent line beyond. Zones 2 and 3 provide backup for all adjacent lines at operating times of T2 and T3.

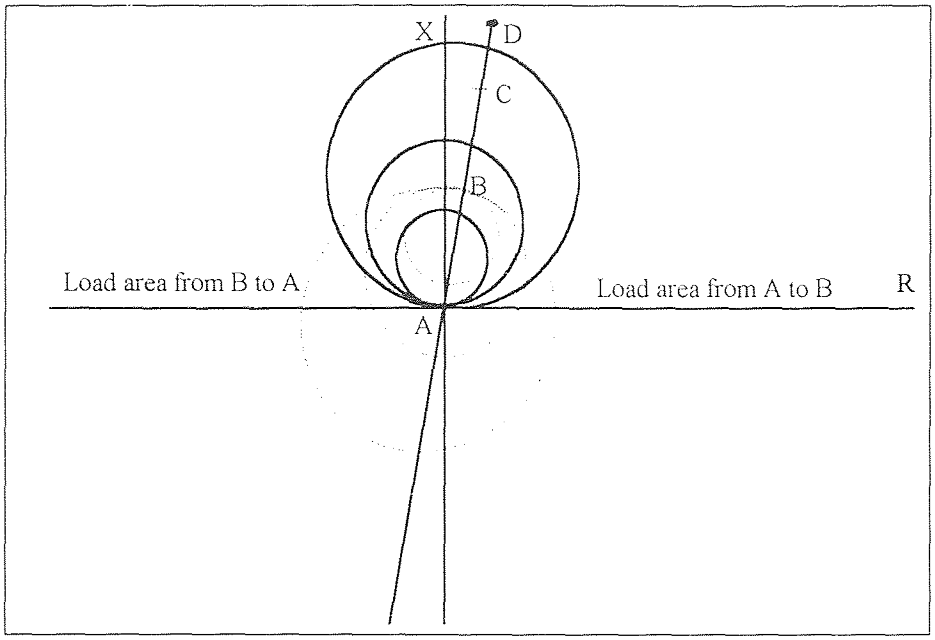

Figure 2.7 Operating circles of protected zones (R-X diagram).

In figure 2.7, we have a diagram that shows the operating circles for the three zones at bus A, breaker 1 and at bus b, breaker 2, plotted on the R-X diagram. The several lines are shown at their respective r+jx positions. The relays operate when the ratio of fault voltage to current falls within the circles. Load impedance falls in the areas shown. We have to note that the operating circles must be set so as not to operate on any system swings from which the system can recover. Such swings occur after a system disturbance, such as faults, sudden loss of generation, or load, or from switching operations.

Zone 1 at each end of the line provides the most desirable protection that is simultaneous protection high speed operation for the middle 80% of the line section. This can be increased to 100% only with pilot relaying.

As far as backup protection is concerned, we have the following typical example shown in figure 2.8.

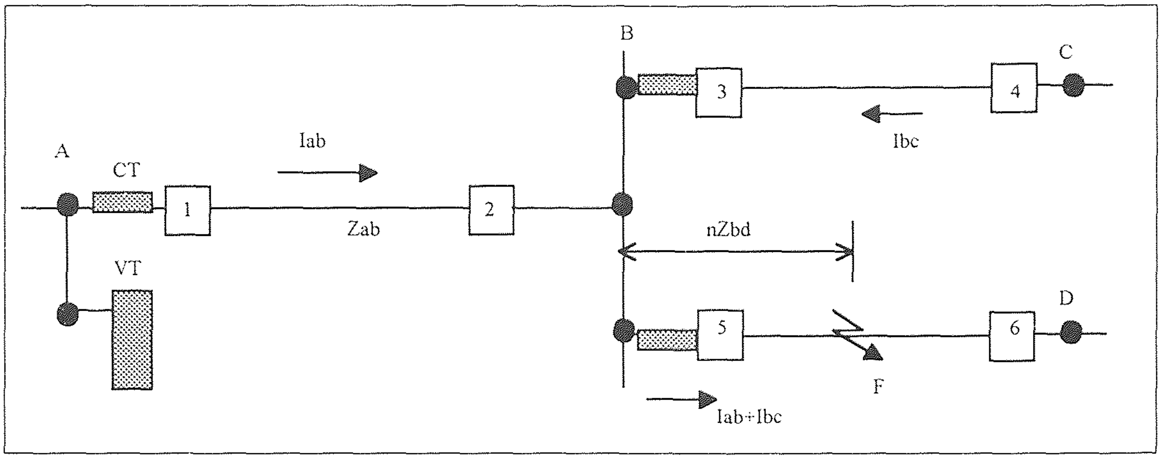

Figure 2.8 Backup protection example.

The relays at breaker 1, bus A protecting line AB look into lines BC and BD extending from bus B. Let's make the following assumptions: Line BC is short and line BD is long, zone 2 set for 50% of line BC will cover only a small percentage of line BD. If we set line BD for 50%, it will overreach and will not coordinate with Z2 of line BC unless T2 time is increased. However, due to the "infeed effect", the reach will not be as far as indicated. Fault current from other lines will cause relays at 1 to under reach. This effect can be seen by considering a solid three-phase fault at F. With $V_F = 0$, the relays at 1 receive current I_{AB}, but the bus A voltage is the drop $Z_{AB}I_{AB}+nZ_{BC}(I_{AB}+I_{BC})$. Relay 1 sees the following impedance:

$$Z_{apparent} = \frac{Z_{AB}I_{AB} + nZ_{BD}(I_{AB} + I_{BC})}{I_{AB}} \approx Z_{AB} + nZ_{BD}$$

As a result, if relay 1 is set to a value of the actual impedance of the previous equation, it would not see fault F. In other words, relay 1 "under reaches" as a result of the fault contributions from other lines connected to bus B. Setting the relays for the apparent impedance value has the danger of overreaching and miscoordination when the infeeds are removed or changed by operation.

2.4 Tapped and multiterminal lines

The following two figures show illustrate typical distance relay applications for tapped and multiterminal lines.

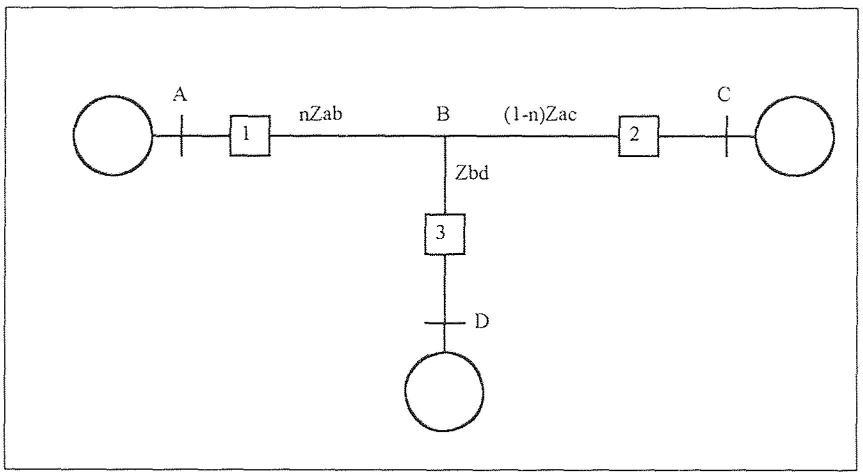

Figure 2.9 Relay application for tapped lines.

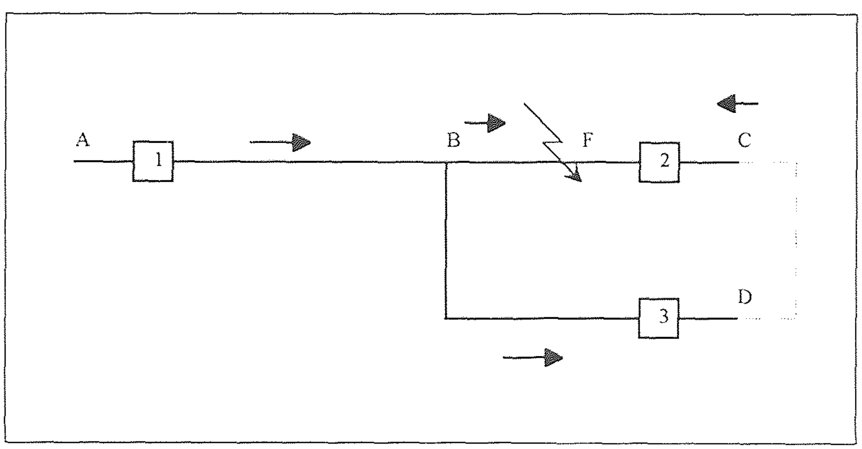

Figure 2.10 Relay application for multiterminal lines.

As we see in figure 2.9, the tap at point B could be a transformer at or near the line, so that Z_{BD} is the impedance from the tap plus the transformer impedance. The tap may serve as load, therefore very small amount of current is supplied through it to the line faults, or it may tie into a fault source at D. Figure 2.10 shows another illustration of tapped lines. In the case of figure 2.9, zone 1 should be set for k times the lowest actual impedance to any remote terminal, or for k times the lowest apparent impedance to any remote terminal for the case in figure 2.10. k is less than 1, usually 0.9. Zone 2 should be set for a value greater than the largest impedance, actual or apparent, to the remote terminals. Moreover, the zone timer T2 must be set so as not to cause wrong operation when any terminal is out of service to cause the distance unit to overreach.

However, the previous settings can make primary protection very difficult and limited as well. In figure 2.9, let's assume that the tap at point B is very close to point A, so nZ_{AC} is small and $(1\text{-}n)Z_{AC}$ is large with Z_{BD} very small. Then zone 1 at breaker 1, bus A must be set at 90% of $(nZ_{AB}+Z_{BD})$, which is a very small value compared with $(1\text{-}n)Z_{AB}$. Therefore, high-speed coverage of the line is almost negligible. On the other hand, if the tap is a load transformer where Z_{BD} is high relative to Z_{BC}, zone 1 at breakers 1 and 2 can be set for 90% of the line to provide good high speed protection.

If B is a load tap in figure 2.9, with negligible current to line faults, distance relays are not applicable at breaker 3, as opening breaker 1 and 2 terminates the line fault. There is trouble detecting the faults, if the impedance to a line fault from bus D is very large and approaches infinity.

In figure 2.10, current can flow out D terminal for an internal line fault near the C bus. Thus distance or directional relays at breaker 3 see the internal fault as external for no operation until after breaker 2 has opened.

Therefore, protection of tapped and multiterminal lines is more complex and requires specific data on the line impedances, location and type of tap or terminal, and fault data with current distributions for the various system and operating conditions. Most often, except for small transformer load taps, these types of lines are protected best by pilot relaying.

CHAPTER THREE

RELAY COORDINATION OF CYPRUS POWER SYSTEM

3.1 Circuit examination

In this chapter, I am going to examine Cyprus power system which is a small power system. The system belongs to the loop category which I examined in chapter two. The following figure shows the general system layout.

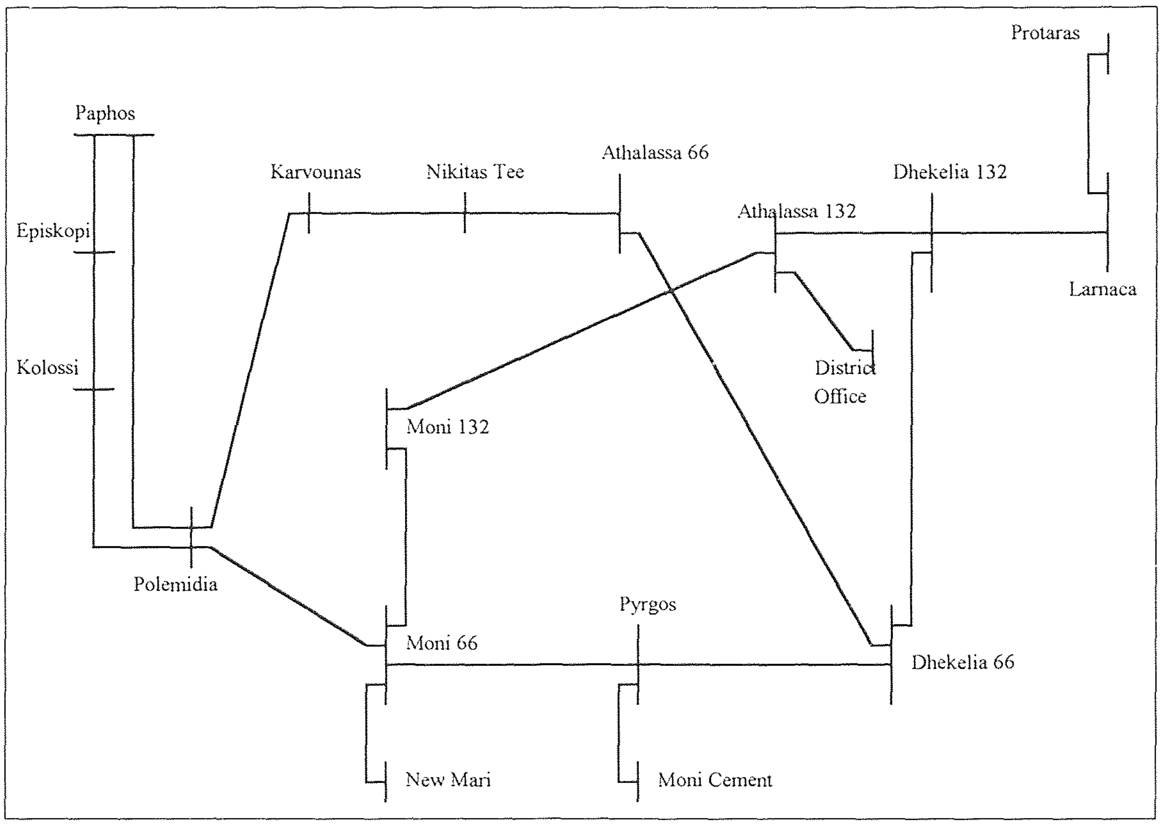

Figure 3.1 Cyprus power system in a simplified form.

Figure 3.1 shows the reduced form of the power system since we are interested in a general view of the protection. First, I am going to determine the time coordination of the relays and then give a better solution for the line protection of the above system. The system has to be divided into the protection zones that are easier to work with. We take each zone separately. The following figure shows the suggested zones of protection.

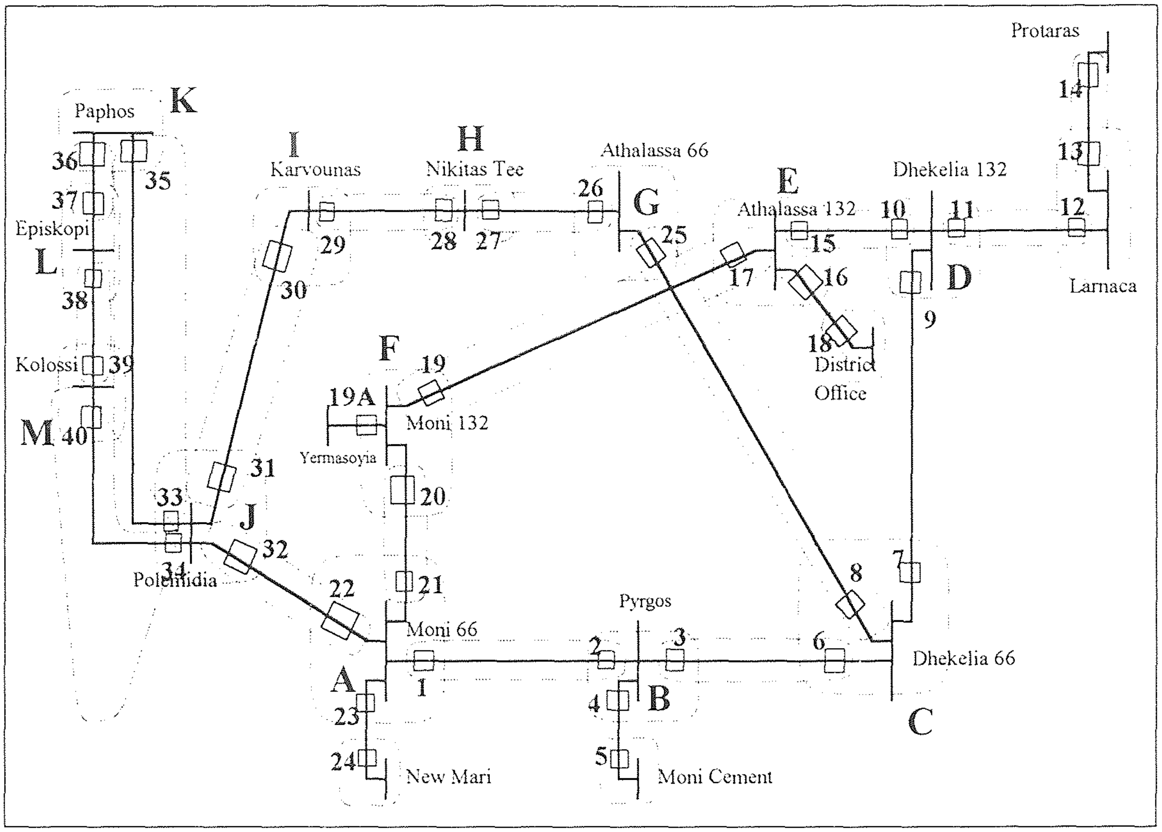

Figure 3.2 Protection zones and loops of Cyprus power system.

The power system can be divided into three main loops. However, I am examining the two major loops ABCDEFA and ABCGHIJA that are discussed separately. The transmission line data could be considered as well as the length of each conductor. Table 3.1 gives us the necessary information.

Loop ABCDEFA.

This loop includes four generator buses: Moni 66(A), Moni 13 (F), Dhekelia 66 (C), and Dhekelia 132(D). Actually, these are all the generator buses of the whole power system. The coordination has to be made according to typical settings for the phase relays. The phase-to-ground fault data and relay pickup values are used to set the ground relays for

Table 3.1 This table shows the length of the conductors and the per unit impedances on 100MVA base.

Circuit	Length (miles)	R1	X1
Athalassa132-District Office	5.5	2.15E-3	5.32E-3
Athalassa132-Moni132	36.7	2.04E-2	6.67E-3
Athalassa132-Dhekelia132	28	4.6E-3	3.215E-2
Athalassa66-Dhekelia66	21	1.521E-1	1.625E-1
Athalassa66-Nikitas Tee	27.8	6.875E-2	2.298E-1
Nikitas Tee-Karvounas	21.9	2.62E-1	3.457E-1
Karvounas-Polemidia	21	3.154E-1	3.386E-1
Paphos-Episkopi	29	4.603E-1	4.686E-1
Episkopi-Kolossi	3.9	3.057E-2	3.054E-2
Kolossi-Polemidia	3.5	2.403E-2	2.72E-2
Polemidia-Paphos	35.6	7.67E-2	2.623E-1
Moni66-Polemidia	14.4	3.085E-2	1.068E-1
Moni66-New Mari	8.5	1.665E-2	6.245E-2
Moni66-Pyrgos	2	3.17E-2	3.15E-2
Pyrgos-Moni Cement	1.1	1.73E-2	1.74E-2
Pyrgos-Dhekelia66	39.1	6.176E-1	6.315E-1
Dhekelia132-Larnaca	11.4	6.2E-3	2.08E-2
Dhekelia 132-Protaras	16.8	8.37E-2	3.13E-2

the system. The directional time-overcurrent relays have to coordinate in both clockwise and counterclockwise ways.

Loop clockwise:

- Relays at 21 must coordinate with relays at 19 and 19A.
- Relays at 19 must coordinate with relays at 15 and 16.
- Relays at 15 must coordinate with relays at 11 and 9.
- Relays at 9 must coordinate with relays 6 and 8.
- Relays at 6 must coordinate with relays at 2 and 4.

- Relays at 2 must coordinate with relays at 21, 22, and 23.

Loop counterclockwise:

- Relays at 1 must coordinate with relays at 3 and 4.
- Relays at 3 must coordinate with relays at 7 and 8.
- Relays at 7 must coordinate with relays at 10 and 11.
- Relays at 10 must coordinate with relays at 16 and 17.
- Relays at 17 must coordinate with relays at 20.
- Relays at 20 must coordinate with relays at 1, 22, and 23.

3.2 Time coordination technique

We notice that the loop is not independent since there are other loop circuits connected to several buses as well as generator buses. However, we are going to assume the operating times for relays that are interfaced with the other loop circuits. In the cases where we have short lines we should use relays with operating time not more than 0.06 s. For instance, the phase relays breakers at 23, 4 and 16 should have pilot relays with a 0.06 s operating time. The phase relays breaker at 8 has a maximum operating time 0.26 s, the phase relays breaker at 11 has a maximum operating time 0.19 s and the phase relays breaker at 22 has a maximum operating time 0.22 s. The operating times are assumed according to the complexity of the circuits and the length of the conductors that are involved. In addition, we have to note that buses A, C, D, and F include generator-transformer units and they have fast differential protection. However, differential protection is a different concept and we only assume the distance protection.

The relays' setting should be done in such a way so each relay operates in no more than 0.2 s for the close-in fault and at least 0.2 plus the CTI interval when there is a far bus fault. Let's take breaker 21 as a starting point and start to move clockwise. Buses A and F are drawn separately in figure 3.3 for convenience reasons.

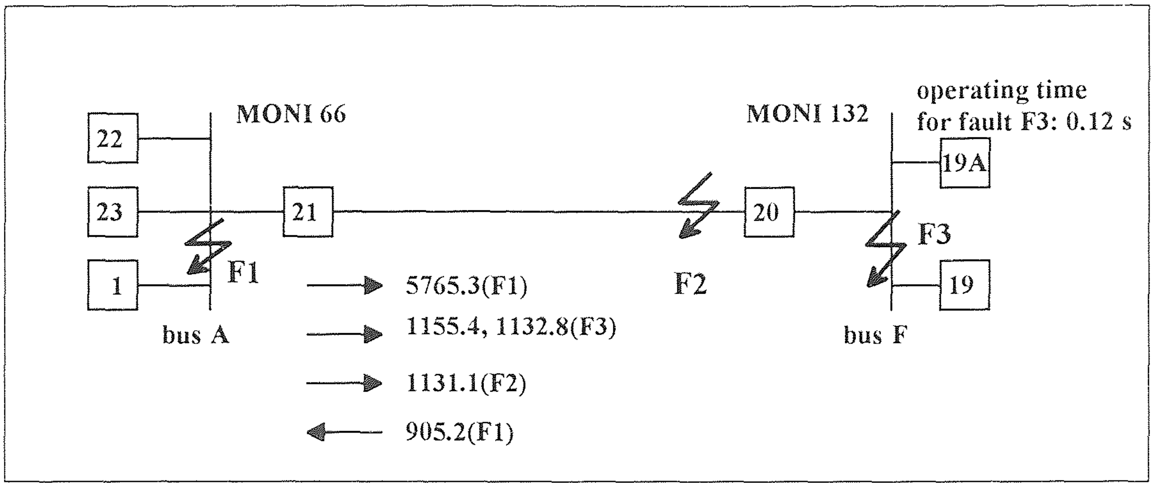

Figure 3.3 Coordination for section AF.

The currents that are shown in figure 3.3, are the tree phase fault currents. The arrows indicate the direction of flow and the second arrow has two values. The first value represents the maximum operating current and the second value represents the minimum operating current. Here, I have to introduce a very useful graph (figure 3.4) that helps the calculation of the time dial setting.

<u>Calculation of the time dial setting - coordination or not</u>

First we have to choose the suitable CT' s and a relay tap. The CT's could be 250:5 since the maximum load is 200 Amps for the specific line section. Therefore, the maximum load is 200/50 = 4 Amps (secondary). The best relay tap selection is the value 6 because it is

1.5 times the maximum load and gives a primary fault current pickup of 6X50=300 Amps.

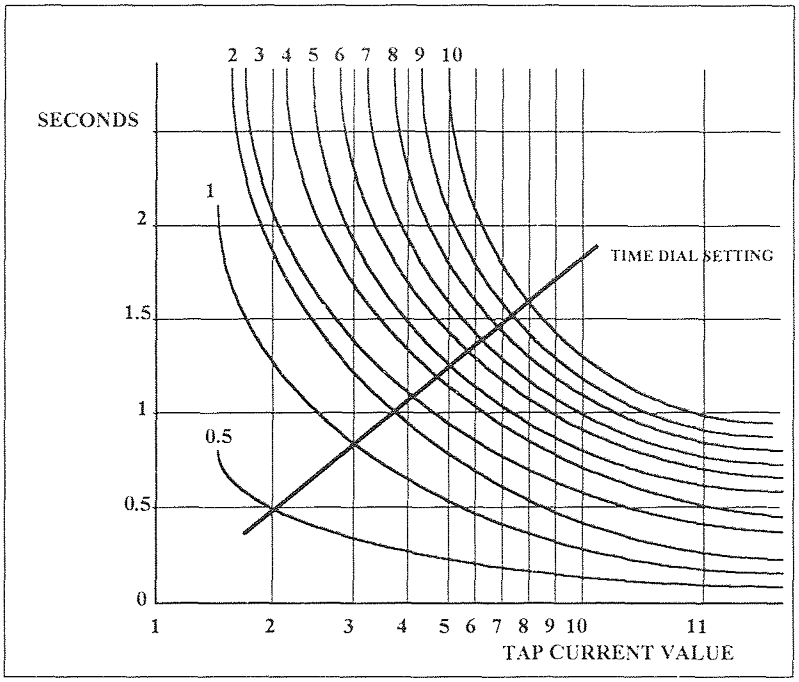

Figure 3.4 Typical inverse-time-overcurrent relay curves.

Relay 21 should have an operating time of 0.12 s plus the CTI value which is 0.3 s. (0.12+0.3=0.42 s) for fault F3. For a maximum fault F3, a current of 1155.4 Amps goes through relay 21. In order to find the multiple of pickup current we divide the maximum current by the primary fault current pickup which is 300 Amps. $\frac{1155.4}{300} = 3.85$. The value of 3.85 in figure 3.4, suggests a time dial setting of 1 and provides an operating time of 0.68 s. The value of 0.68 s implies coordination since the minimum operating time value is 0.42 s. For a minimum fault current at F3, we have: $\frac{1132.8}{300} = 3.78$. According to figure 3.4 the value 3.78 and a time dial setting of 1 imply an operating time of 0.75 s. In a similar way, we calculate the remainder operating times for relay 21. For a maximum close-in fault F1, the operating time is 0.16 s ($\frac{5765.3}{300} = 19.22$). The minimum line-end fault F2, the operating time is 0.77 s ($\frac{1131.1}{300} = 3.77$).

3.3 Coordination outlines of first loop

3.3.1 Coordination outline of Moni 66 - Moni 132 (section AF)

MAX LOAD = 200 A

CT's used: 250:5

MAX LOAD at secondary = 200/50 = 4 A

Select MTVC[1] = 6 (4X1.5) $\Rightarrow$ Primary Fault Current Pick-up = 6X50=300 A

Relay 21 op-time[2] for fault F3: 0.12 + 0.3(CTI) = 0.42 s

MAX FAULT op-time: $\frac{IF3\ max}{300} = \frac{1155.4}{300} = 3.85 \Rightarrow TD^{3}=1$ (See what time dial gives the immediate next op-time value for MTVC=6) **0.68 s**. Coordination: YES.

MIN FAULT op-time: $\frac{IF3\ min}{300} = \frac{1132.8}{300} = 3.78, TD = 1, TD = 1 \rightarrow$(implies) **0.75 s**

MAX CLOSE-IN FAULT op-time: $\frac{IF1}{300} = \frac{5765.3}{300} = 19.22, TD = 1 \rightarrow$ **0.51s**

MIN LINE-END FAULT op-time: $\frac{IF2}{300} = \frac{1131.1}{300} = 3.77, TD = 1 \rightarrow$ **0.77s**

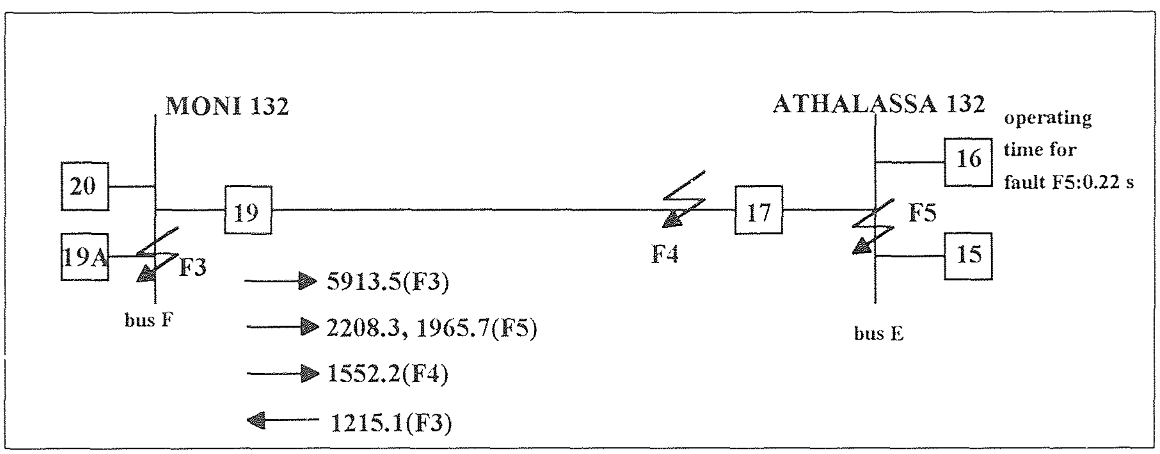

Figure 3.5 Coordination for section FE.

---

1 Multiple Tap Value Current
2 Abbreviation for operating times
3 We choose the right Time Dial according the relay's operating time

Let's move to the next line section which shown separately in figure 3.5. The FE line section is one of the longest of the power system (36.7 miles).

Calculation time dial setting - coordination or not

In this case, we note that the current values are higher than the previous line section. In addition, as far as the load is concerned in this line section, the load factor is higher as well. The minimum load is 400 Amps. Therefore, we use CT's with a ratio of 450:5. The secondary load is 400/90=4.44 Amps and it is wise to select a relay tap value of 6 because it provides a safer margin than a lower value. It is 1.35 times the maximum load and the primary pickup current is 6X90=540 Amps. Relay 21, from before, operates at 0.75 s for a minimum fault F3. Therefore, relay 19 should operate no more than 0.75-0.3 = 0.45 s for fault F3. Relay 16 should have an operating time of 0.22+0.3=0.52 s for fault F5. Relay 15 operating time is unknown. The following coordination schematic will give us the necessary values for the current coordination problem.

3.3.2 Coordination outline of Moni 132 - Athalassa 132 (section FE)

MAX LOAD = 400 A

CT's used: 450:5

MAX LOAD at secondary = 400/90= 4.44 A

Select MTVC = 6 (4.44X1.35) Primary Fault Current Pick-up = 6X90=540 A

Relay 19 op-time for fault F3: 0.75 - 0.3(CTI) = 0.45 s

Relay 19 op-time for fault F5: 0.51 + 0.3 = 0.81 s.

MAX FAULT op-time: $\frac{IF5\ max}{400} = \frac{2208.3}{400} = 5.52$, TD = 2 (For MTVC=6)→ **0.7s**[4].

MIN FAULT op-time: $\frac{IF5\ min}{400} = \frac{1965.7}{400} = 4.91 \rightarrow$ **0.79 s**

MAX CLOSE-IN FAULT op-time: $\frac{IF3}{400} = \frac{5913.5}{400} = 14.78 \rightarrow$ **0.47s**[5] Coordination: NO

MIN LINE-END FAULT op-time: $\frac{IF4}{400} = \frac{1552.2}{400} = 3.88 \rightarrow$ **1s**

We notice that the maximum close-in fault operating time is less than the operating time for relay 16 as far as fault F5 is concerned. Therefore, we do not have coordination. The solution is to increase the time dial for relay 21, in order to achieve the right operating times.

TD_{NEW}=1.5 (for relay 21)

MAX CLOSE-IN FAULT op-time: 0.26 s (MTVC=19.22)

MAX FAULT op-time: 0.9 s (MTVC=3.85)

The maximum fault operating time for relay 21, is 0.5 s greater than the operating time for relay 21. (Close-in fault).

The next section is ED which is shown in figure 3.6. The coordination of this section is done in a similar way. However, in the actual system we have to consider the possibilities with various lines out of service. A complete backup protection is usually suggested when real life is involved. In our examples, we assume the basic condition for a faulty situation.

---

4 Operating time should not be more than 0.45 s

5 Operating time should be at least 0.81 s

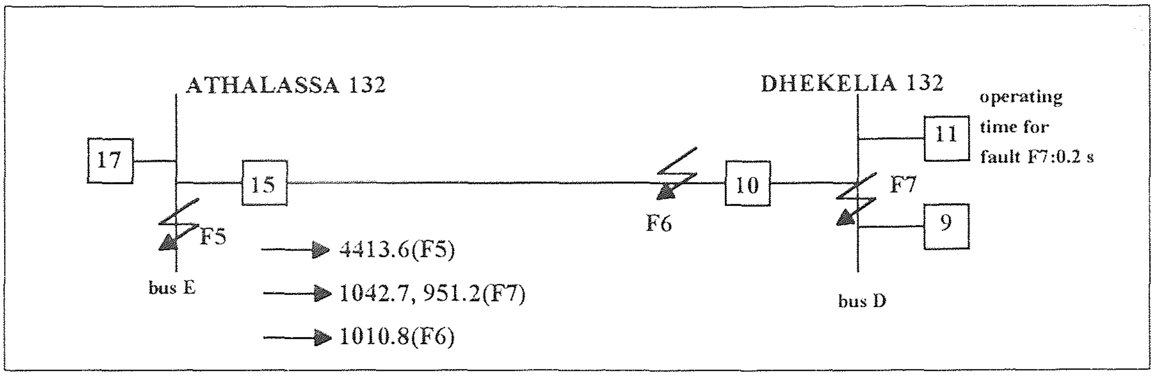

Figure 3.6 Coordination for section ED.

3.3.3 Coordination outline of Athalassa 132 - Dhekelia 132 (section ED)

MAX LOAD = 300 A

CT's used: 350:5

MAX LOAD at secondary = 300/70= 4.29 A

Select MTVC = 6 (4.29X1.40)   Primary Fault Current Pick-up = 6X70=420 A

Relay 15 op-time for fault F3: 0.79 - 0.3(CTI) = 0.49 s

Relay 15 op-time for fault F5: 0.4+ 0.3 = 0.7 s.

MAX FAULT op-time: $\frac{\text{IF7 max}}{300} = \frac{1042.7}{300} = 3.47$, TD = 1 (For MTVC=6)→ **0.6** s.

Coordination: NO.

MIN FAULT op-time: $\frac{\text{IF7 min}}{300} = \frac{951.2}{300} = 3.17 \rightarrow$ **0.7 s**

MAX CLOSE-IN FAULT op-time: $\frac{\text{IF5}}{300} = \frac{4413.6}{300} = 14.71$ **0.37 s**

MIN LINE-END FAULT op-time: $\frac{\text{IF6}}{300} = \frac{1010.8}{300} = 3.37 \rightarrow$**0.3 s**

We do not have coordination, since the maximum far-bus operating time is less than the required value which should be at least 0.7 s. Therefore, we have to change the time dial of relay 19 in order to change the operating times. A time dial setting of 2.5 would have the following scheme:

TD_{NEW}=2.5 (for relay 19)

MAX CLOSE-IN FAULT op-time: 0.5 s (MTVC=14.78)

MAX FAULT FAR-BUS op-time: 0.9 s (MTVC=5.52)

$0.9_{(\text{MAX FAULT FAR-BUS, RELAY 19})} - 0.37_{(\text{MAX CLOSE-IN FAULT, RELAY 15})} = 0.53$ s

The difference in time satisfies the condition that the relay 15 operating time for fault F3 should be at least 0.49 s. Relay 19 is 0.53 s above relay 15. Therefore, coordination is achieved by setting the time dial to 2.5 for section FE and setting the time dial to 1.5 for section ED. The rest of the line sections are outlined as well in the following pages.

3.3.4 Coordination outline of Dhekelia 132 - Dhekelia 66 (section DC)

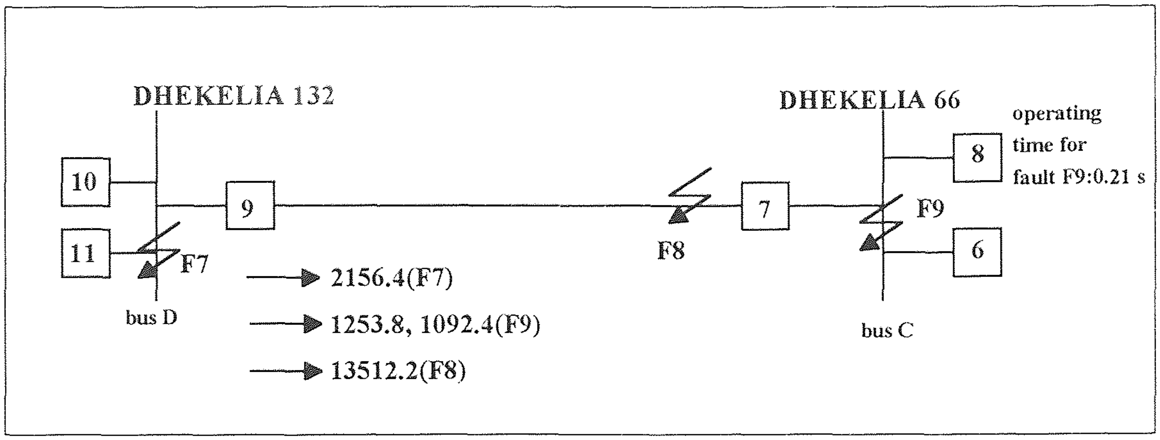

Figure 3.7 Coordination for section DC.

MAX LOAD = 200 A

CT's used: 250:5

MAX LOAD at secondary = 200/50= 4 A

Select MTVC = 6 (4X1.5) Primary Fault Current Pick-up = 6X50=300 A

Relay 9 op-time for fault F7: 0.7 - 0.3(CTI) = 0.4 s

Relay 9 op-time for fault F9: 0.37+ 0.3 = 0.67 s.

MAX FAULT op-time: $\frac{\text{IF9 max}}{200} = \frac{1253.8}{200} = 6.27, \text{TD} = 2 \rightarrow \mathbf{0.71}$ s.

MIN FAULT op-time: $\frac{\text{IF9 min}}{200} = \frac{1092.4}{200} = 5.46 \rightarrow \mathbf{0.8\ s}$

MAX CLOSE-IN FAULT op-time: $\frac{\text{IF7}}{200} = \frac{2156.4}{200} = 20.78 \rightarrow \mathbf{0.39\ s}$ Coordination: YES

MIN LINE-END FAULT op-time: $\frac{\text{IF8}}{200} = \frac{1351.2}{200} = 6.76 \rightarrow \mathbf{0.59\ s}$

3.3.5 Coordination outline of Dhekelia 66 - Pyrgos (section CB)

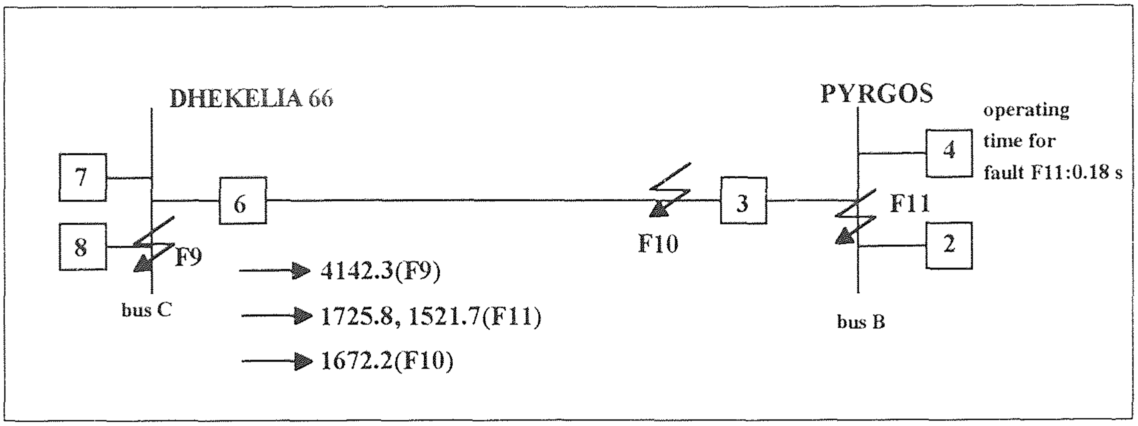

Figure 3.8 Coordination for section CB.

MAX LOAD = 300 A

CT's used: 350:5

MAX LOAD at secondary = 300/70= 4.29 A

Select MTVC = 6 (4.29X1.4)   Primary Fault Current Pick-up = 6X70=420 A

Relay 6 op-time for fault F9: 0.8 - 0.3(CTI) = 0.5 s

Relay 6 op-time for fault F11: 0.39+ 0.3 = 0.69 s.

MAX FAULT op-time: $\frac{\text{IF11 max}}{300} = \frac{1725.8}{300} = 5.75, \text{TD} = 2.5 \rightarrow$ **0.85 s**.

MIN FAULT op-time: $\frac{\text{IF11 min}}{300} = \frac{1521.7}{300} = 5.07 \rightarrow$ **0.92 s**

MAX CLOSE-IN FAULT op-time: $\frac{\text{IF9}}{300} = \frac{4142.3}{300} = 13.8 \rightarrow$**0.49 s** Coordination: YES

MIN LINE-END FAULT op-time: $\frac{\text{IF10}}{300} = \frac{1672.2}{300} = 5.57 \rightarrow$**0.9 s**

3.3.6 Coordination outline of Pyrgos - Moni 66 (section BA)

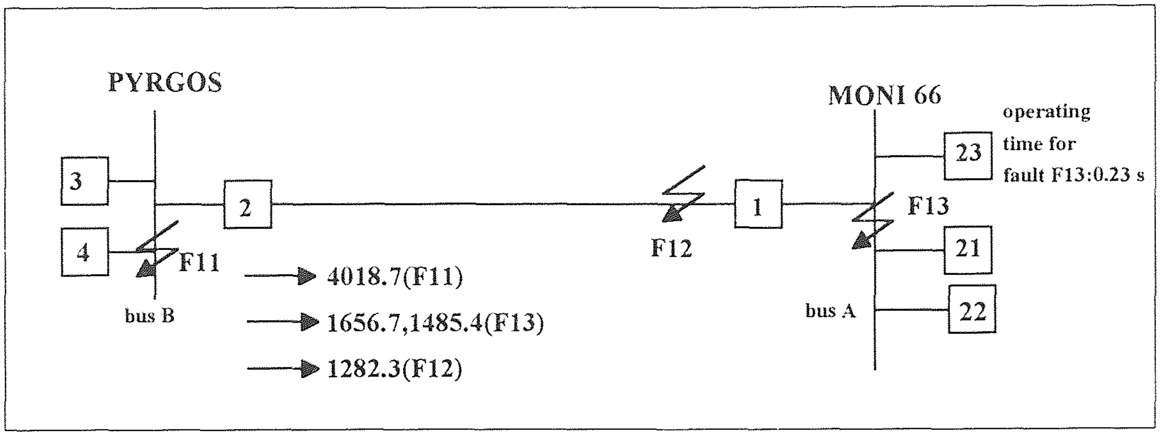

Figure 3.9 Coordination for section BA.

MAX LOAD = 350 A

CT's used: 400:5

MAX LOAD at secondary = 350/80= 3.38 A

Select MTVC = 5 (3.38X1.48)   Primary Fault Current Pick-up = 5X80=400 A

Relay 2 op-time for fault F11: 0.92 - 0.3(CTI) = 0.62 s

Relay 2 op-time for fault F13: 0.49+ 0.3 = 0.79 s.

MAX FAULT op-time: $\frac{\text{IF13 max}}{350} = \frac{1656.7}{350} = 4.73, \text{TD} = 2 \rightarrow \mathbf{0.81}$ **s**.

MIN FAULT op-time: $\frac{\text{IF13 min}}{350} = \frac{1485.4}{350} = 4.24 \rightarrow \mathbf{0.95}$ **s**

MAX CLOSE-IN FAULT op-time: $\frac{\text{IF11}}{350} = \frac{4018.7}{350} = 11.48 \rightarrow \mathbf{0.4}$ **s** <u>Coordination: YES</u>

MIN LINE-END FAULT op-time: $\frac{\text{IF12}}{350} = \frac{1282.3}{350} = 3.66 \rightarrow \mathbf{1.25}$ **s**

Here, the loop AFEDCBA is covered.

3.4 Coordination outlines of second loop

Loop ABCGHIJA

This loop also includes the generator buses which are the same as before. As a result, loop ABCDEFA overlaps with loop ABCGHIJA (figure 3.2). Similarly, the coordination has to be made according to typical settings for the phase relays. The fault data and relay pickup values are used in order set the ground relays for the system. As before, the directional time-overcurrent relays have to coordinate in both clockwise and counterclockwise ways.

Loop clockwise:

- Relays at 22 must coordinate with relays at 31, 33, and 34.
- Relays at 31 must coordinate with relays at 29.
- Relays at 29 must coordinate with relays at 27.
- Relays at 27 must coordinate with relays 25.
- Relays at 25 must coordinate with relays at 6 and 7.
- Relays at 6 must coordinate with relays at 2 and 4.
- Relays at 2 must coordinate with relays at 21, 22, and 23.

Loop counterclockwise:

- Relays at 1 must coordinate with relays at 3 and 4.
- Relays at 3 must coordinate with relays at 7 and 8.
- Relays at 8 must coordinate with relays at 26.
- Relays at 26 must coordinate with relays at 28.
- Relays at 28 must coordinate with relays at 30.

- Relays at 30 must coordinate with relays at 32, 33, and 34.
- Relays at 32 must coordinate with relays at 1, 21, and 23.

The loop is not independent and we have to assume the operating times of the relays that are interfaced with the other loop circuits. The operating times are assumed according to the complexity of the circuits and the length of the conductors that are involved. The relay's setting should be done as before and the relay should operate in no more than 0.2 s for the close-in fault and at least 0.2 plus the CTI interval (0.3 s) when there is a far bus fault. Starting point is relay 22. The coordination outlines and figures are discussed in the following pages. In addition, line sections CB and BA are not discussed since they were analyzed in the previous loop.

3.5 Coordination outlines of second loop

3.5.1 Coordination outline of Moni 66 - Polemidia (section AJ)

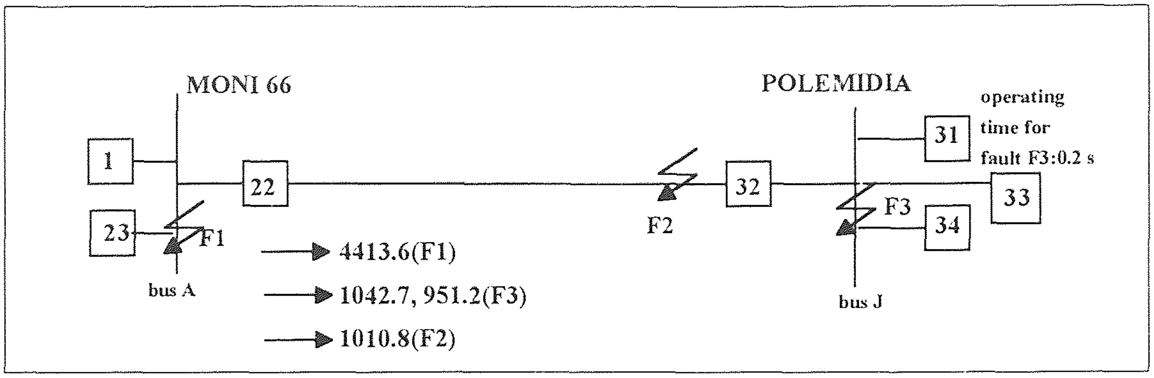

Figure 3.10 Coordination for section AJ.

MAX LOAD = 300 A

CT's used: 350:5

MAX LOAD at secondary = 300/70= 4.29 A

Select MTVC = 6 (4.29X1.40)   Primary Fault Current Pick-up = 6X70=420 A

Relay 22 op-time for fault F1(of previous loop): 0.79 - 0.3(CTI) = 0.49 s

Relay 22 op-time for fault F1(current loop): 0.4+ 0.3 = 0.7 s.

MAX FAULT op-time: $\frac{\text{IF3 max}}{300} = \frac{1042.7}{300} = 3.47$, TD = 1(For MTVC=6)$\rightarrow$ **0.6 s**.

Coordination: NO.

MIN FAULT op-time: $\frac{\text{IF3 min}}{300} = \frac{951.2}{300} = 3.17 \rightarrow$ **0.7 s**

MAX CLOSE-IN FAULT op-time: $\frac{\text{IF1}}{300} = \frac{4413.6}{300} = 14.71 \rightarrow$**0.37 s**

MIN LINE-END FAULT op-time: $\frac{\text{IF2}}{300} = \frac{1010.8}{300} = 3.37 \rightarrow$**0.3 s**

We do not have coordination, since the maximum far-bus operating time is less than the required value which should be at least 0.7 s. Therefore, we have to change the time dial of relay 2 in order to change the operating times. A time dial setting of 2.5 would have the following scheme:

TD_{NEW}=2.5 (for relay 2)

MAX CLOSE-IN FAULT op-time: 0.5 s (MTVC=14.78)

MAX FAULT FAR-BUS op-time: 0.9 s (MTVC=5.52)

$0.9_{(\text{MAX FAULT FAR-BUS, RELAY 2})} - 0.37_{(\text{MAX CLOSE-IN FAULT, RELAY 22})} = 0.53\ \text{s}$

The difference in time satisfies the condition that the relay 22 operating time for fault F11 should be at least 0.49 s. Relay 2 is 0.53 s above relay 22. Therefore, coordination is achieved by setting the time dial to 2.5 for section BA and setting the time dial to 1.5 for section AJ. The rest of the line sections are in the following pages.

3.5.2 Coordination outline of Polemidia - Karvounas (section JI)

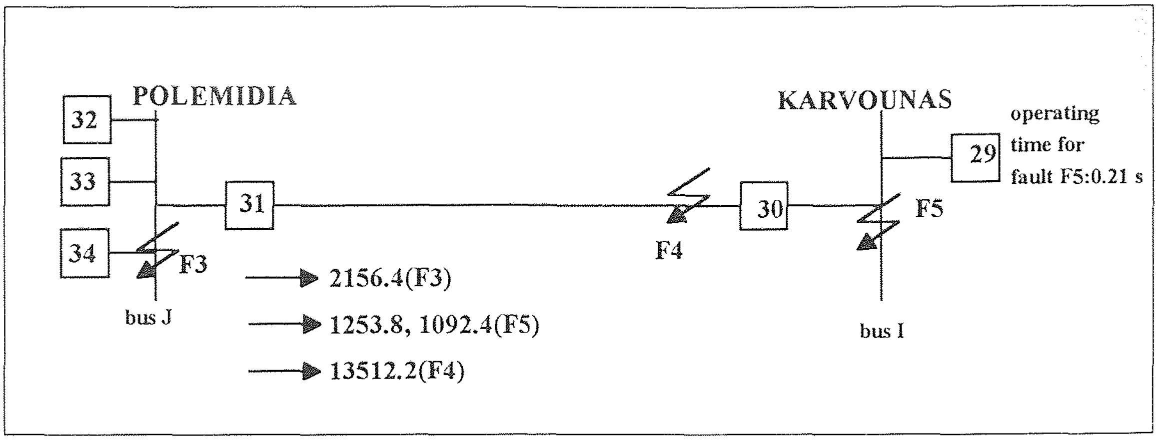

Figure 3.11 Coordination for section JI.

MAX LOAD = 200 A

CT's used: 250:5

MAX LOAD at secondary = 200/50= 4 A

Select MTVC = 6 (4X1.5) Primary Fault Current Pick-up = 6X50=300 A

Relay 31 op-time for fault F3: 0.7 - 0.3(CTI) = 0.4 s

Relay 31 op-time for fault F5: 0.37+ 0.3 = 0.67 s.

MAX FAULT op-time: $\frac{\text{IF5 max}}{200} = \frac{1253.8}{200} = 6.27, \text{TD} = 2 \rightarrow \mathbf{0.71}$ **s**.

MIN FAULT op-time: $\frac{\text{IF5 min}}{200} = \frac{1092.4}{200} = 5.46 \rightarrow \mathbf{0.8}$ **s**

MAX CLOSE-IN FAULT op-time: $\frac{\text{IF3}}{200} = \frac{2156.4}{200} = 20.78 \rightarrow \mathbf{0.39}$ **s** Coordination: YES

MIN LINE-END FAULT op-time: $\frac{\text{IF4}}{200} = \frac{1351.2}{200} = 6.76 \rightarrow \mathbf{0.59}$ **s**

3.5.3 Coordination outline of Karvounas - Nikitas Tee (section IH)

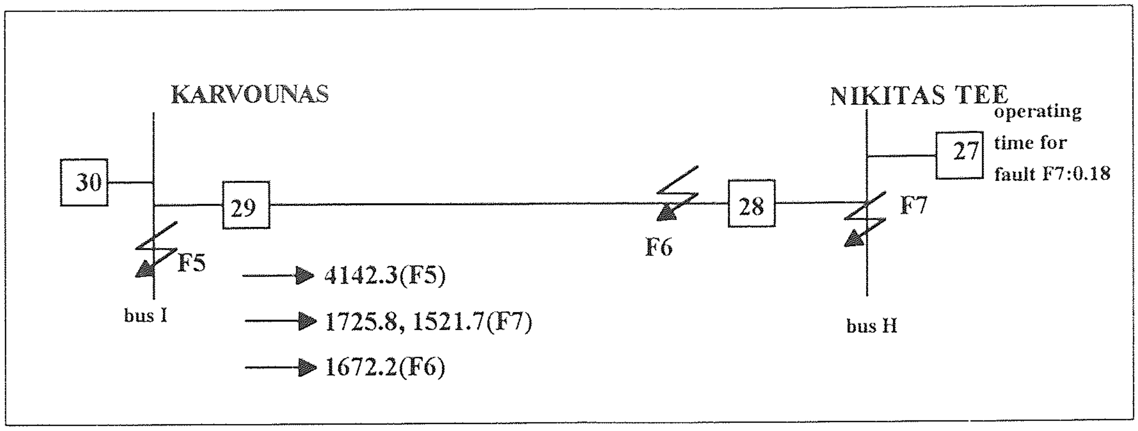

Figure 3.12 Coordination for section IH.

MAX LOAD = 300 A

CT's used: 350:5

MAX LOAD at secondary = 300/70= 4.29 A

Select MTVC = 6 (4.29X1.4)   Primary Fault Current Pick-up = 6X70=420 A

Relay 29 op-time for fault F5: 0.8 - 0.3(CTI) = 0.5 s

Relay 29 op-time for fault F7: 0.39+ 0.3 = 0.69 s.

MAX FAULT op-time: $\frac{\text{IF7 max}}{300} = \frac{1725.8}{300} = 5.75, \text{TD} = 2.5 \rightarrow$ **0.85** s.

MIN FAULT op-time: $\frac{\text{IF7 min}}{300} = \frac{1521.7}{300} = 5.07 \rightarrow$ **0.92 s**

MAX CLOSE-IN FAULT op-time: $\frac{\text{IF5}}{300} = \frac{4142.3}{300} = 13.8 \rightarrow$**0.49 s** Coordination: YES

MIN LINE-END FAULT op-time: $\frac{\text{IF6}}{300} = \frac{1672.2}{300} = 5.57 \rightarrow$**0.9 s**

3.5.4 Coordination outline of Nikitas Tee - Athalassa 66 (section HG)

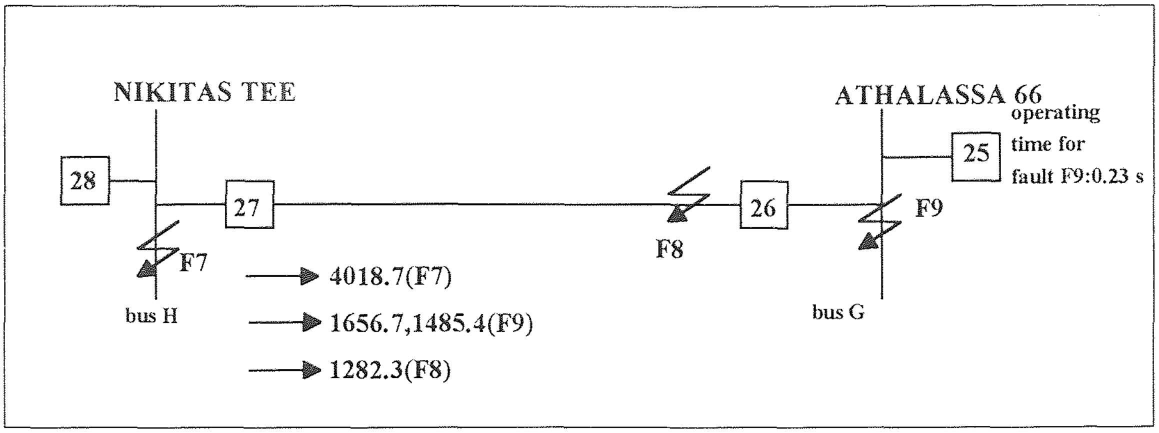

Figure 3.13 Coordination for section HG.

MAX LOAD = 350 A

CT's used: 400:5

MAX LOAD at secondary = 350/80= 3.38 A

Select MTVC = 5 (3.38X1.48) Primary Fault Current Pick-up = 5X80=400 A

Relay 27 op-time for fault F7: 0.92 - 0.3(CTI) = 0.62 s

Relay 27 op-time for fault F9: 0.49+ 0.3 = 0.79 s.

MAX FAULT op-time: $\frac{\text{IF9 max}}{350} = \frac{1656.7}{350} = 4.73, \text{TD} = 2 \rightarrow \mathbf{0.81}$ s.

MIN FAULT op-time: $\frac{\text{IF93 min}}{350} = \frac{1485.4}{350} = 4.24 \rightarrow \mathbf{0.95\ s}$

MAX CLOSE-IN FAULT op-time: $\frac{\text{IF7}}{350} = \frac{4018.7}{350} = 11.48 \rightarrow \mathbf{0.4\ s}$ Coordination: YES

MIN LINE-END FAULT op-time: $\frac{\text{IF8}}{350} = \frac{1282.3}{350} = 3.66 \rightarrow \mathbf{1.25\ s}$

3.5.5 Coordination outiline of Athalassa 66 - Dhekelia 66 (section GC)

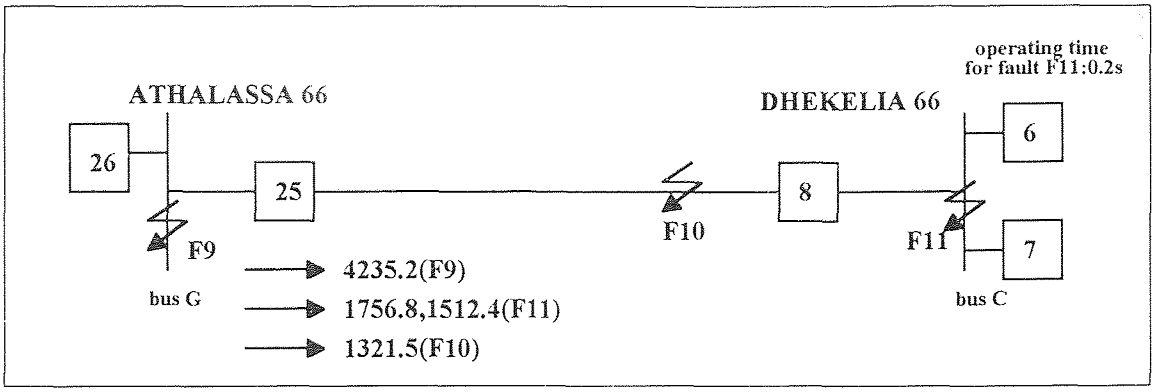

Figure 3.14 Coordiantion for section GC.

MAX LOAD = 400 A

CT's used: 450:5

MAX LOAD at secondary = 400/90=4.44 A

Select MTVC = 6(1.35X4.44) Primary Fault Current Pick-up = 6X90=540 A

Relay 25 op-time for fault F9: 0.95 - 0.3(CTI) = 0.65 s

Relay 25 op-time for fault F11: 0.4 + 0.3 = 0.7 s.

MAX FAULT op-time: $\frac{\text{IF11 max}}{400} = \frac{1756.8}{400} = 4.39, \text{TD} = 2 \rightarrow \mathbf{0.76\ s}$

MIN FAULT op-time: $\frac{\text{IF11 min}}{400} = \frac{1512.4}{400} = 3.78 \rightarrow \mathbf{0.9\ s}$

MAX CLOSE-IN FAULT op-time: $\frac{\text{IF9}}{400} = \frac{4235.2}{400} = 10.59 \rightarrow \mathbf{0.4\ s}$

MAXLINE-END FAULT op-time: $\frac{\text{IF10}}{400} = \frac{1321.5}{400} = 3.3 \rightarrow \mathbf{1.3\ s}$

Line sections CB and BA are covered in the first loop. The two loops that were analyzed, are the most important loops of the power system. However, the time coordination of the relays is not absolutely reliable since there are limitations in the relay protection. Therefore, we could have possible failures. The reliabilty concept is discussed in the later chapter. In this chapter we saw how adjustments could affect the whole coordination of the protection scheme. The relay timing is very sensitive and the time calculations have to be made very accurately in order to achive smooth coordination.

CHAPTER FOUR

RELAY CONTROL AND IMPROVEMENTS

The need for a better protection brought advanced technology into the scheme of relay protection in order to obtain better system performance and to improve the reliability of supplies to customers. In some systems, like Cyprus, electromechanical relays are still in use, although in recent years the old systems are replaced by modern solid-state systems. Microprocessor-based relays were installed recently and will replace the older types, particularly in the more complex protection arrangements like distance protection.

4.1 Automation of protection network

The aim of automation is improve the system performance by faster clearance of faults and restoration of supplies. Automation of protection can be defined in a various ways. The most common in this area, is the use of automatic tap changers and voltage regulators for voltage-drop compensation. With conventional distribution network arrangements any faulted feeder or line section was traced from the operation of the protection relays, and accurate location of the fault was not easy. In this case, the fault indicators are devices that help to locate and isolate the faulted section. The fault indicators are very important in a power system and their principle of operation is based on indicating the passage of fault current.

The use of microprocessor-based relays is part of sophisticated protection and fault-clearing schemes. The microprocessor-based relays are able to measure a number of input signals to derive the required operating sequence for the specific fault condition, as well as having built-in self-checking facilities. The use of microprocessor logic-control sectionalisers is removing the dependence on staff of the utilities, leading to a quicker isolation of faults and restoration of supplies. Telecontrolled disconnectors, distributed around the network, are a further extension of automating system operation to reduce down time for fault clearance or optimizing network flows to reduce system losses. Using suitable computer hardware and programs, network configurations can be automatically rearranged on the occurrence of faults to minimize the consequences of further system outages.

The advent of telecommunication channels to individual substations made it possible to provide more instruction codes to more equipment, and to receive information back on the state of equipment. Thus, a single relatively low-powered transmitter operating at a frequency of a few hundred megahertz can provide communication channels between local control centers and individual substations, and also between a central control point and several local control centers.

With the two-way facility available, system control and data-acquisition systems, known as SCADA, can be set up, where not only can instructions be transmitted to specific items of equipment at every telecontrol substation but also many and varied types of data can be transmitted to the control center. Circuit-overload and fault data, including equipment and protection faults, are instantly transmitted to the control center. The necessary action can then be taken in order to isolate faulty equipment or line sections and restore the network to a satisfactory configuration. Computer-based SCADA systems make it possible to preprogram various system-control operations to minimize down time in the event of a fault.

4.2 Autoreclosing arrangements

The automatic recloser was developed by arranging for the source circuit breaker to carry out a variable sequence of tripping and closing by suitable relaying. The tripping can either by instantaneous, clearing the fault in about 0.2-0.5 s, or be delayed with clearance times of tens of seconds. Up to four combinations of instantaneous and delayed tripping are usually available, but generally system arrangements are such that only two auto-reclosing operations are necessary. Where it is not desirable to install auto-reclosing on the source breaker, either because it is not suitable for this duty or because the first section of the feeder is underground cable, a high-speed pole-mounted auto-recloser can be installed at the beginning of the overhead network.

The automatic sectionaliser is another important equipment that is very important in the coordination scheme. Figure 4.1 shows a simple application of the automatic sectionalisers at a section of the Cyprus power system.

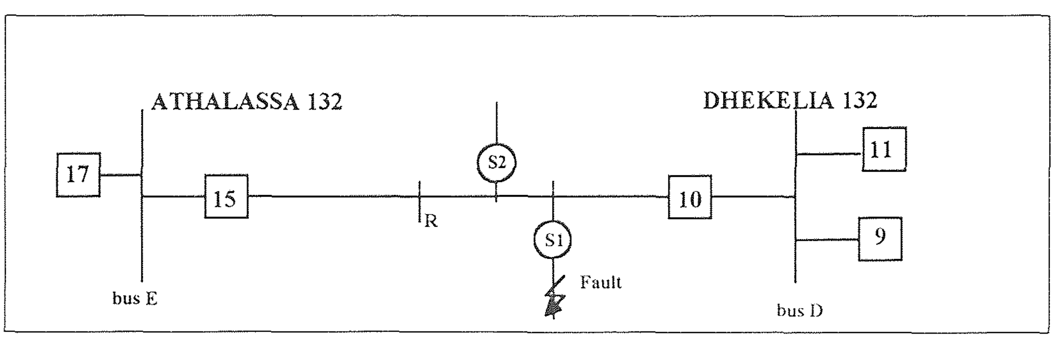

Figure 4.1 Use of autoreclosers and sectionalisers. (R: autoreclosing circuit breaker S1, S2: pole mounting automatic sectionalisers).

Automatic sectionalisers S are provided on a number of spur feeders in order to isolate any faulted branch during the dead time of the delayed automatic recloser at the substation R. A sectionaliser is not capable of breaking fault current, but may be closed on to a fault. It therefore requires a device to count the number of passages of fault current on the feeder as the recloser goes through its preset sequence of opening and closing operations. After registering a preset number of fault current pulses, the sectionaliser opens within the dead time of the recloser, to isolate the faulted section of the line without breaking fault current. The whole sequence is shown in figure 4.2.

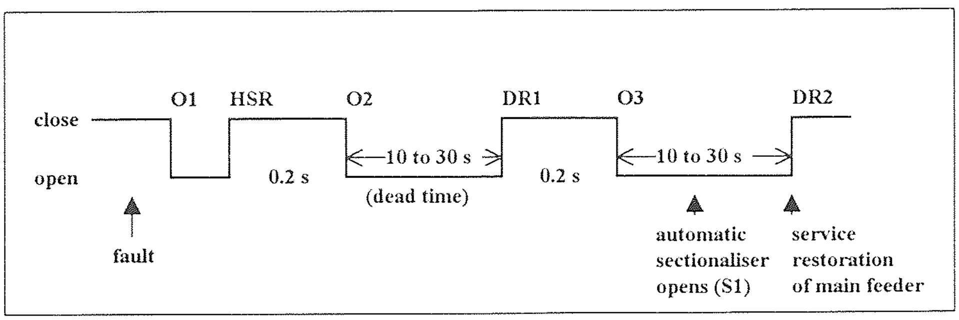

Figure 4.2 Time diagram of sectionalisers. (O1, O2, O3: circuit breaker opens
HSR: high speed automatic reclosing
DR1/DR2: delayed automatic reclosing)

The sequence is covering the case of a fault on a spur feeder connected to the main feeder by an automatic sectionaliser. For a transient fault, when the recloser restores supplies, the sectionaliser sensing devices note that only load current is flowing and return the sectionaliser to its normal state.

Sectionalisers can also be activated by voltage, usually obtained on the source side of the unit. Operated in this manner, the device is also suitable for systems where earth fault currents are limited. In figure 4.3, we see that if the fault is not cleared following a high-speed auto-reclosure on the feeder circuit breaker R, the automatic sectionalisers S1, S2, S3 are opened when no voltage is present, as in the sequence of closing and tripping shown in figure 4.4. When the voltage reappears after a delayed reclosure, the sectionalisers are closed after the other in sequence, in accordance with their time-delay settings.

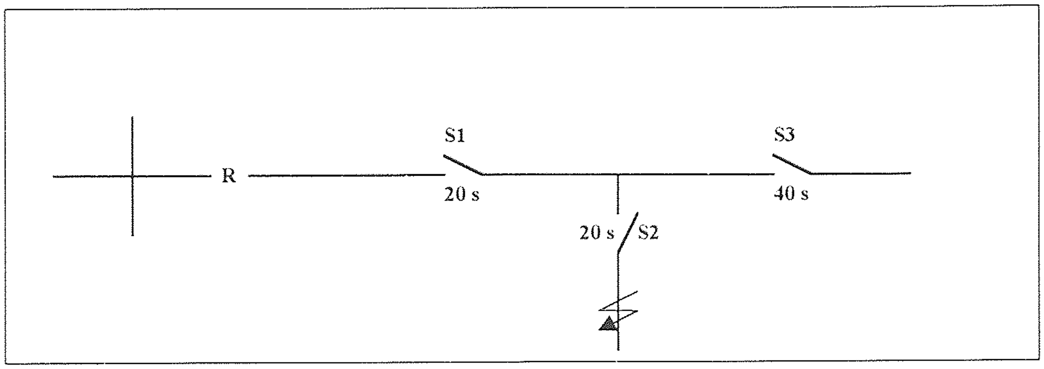

Figure 4.3 Voltage-controlled sectionalising arrangement with 20 s time delay setting.

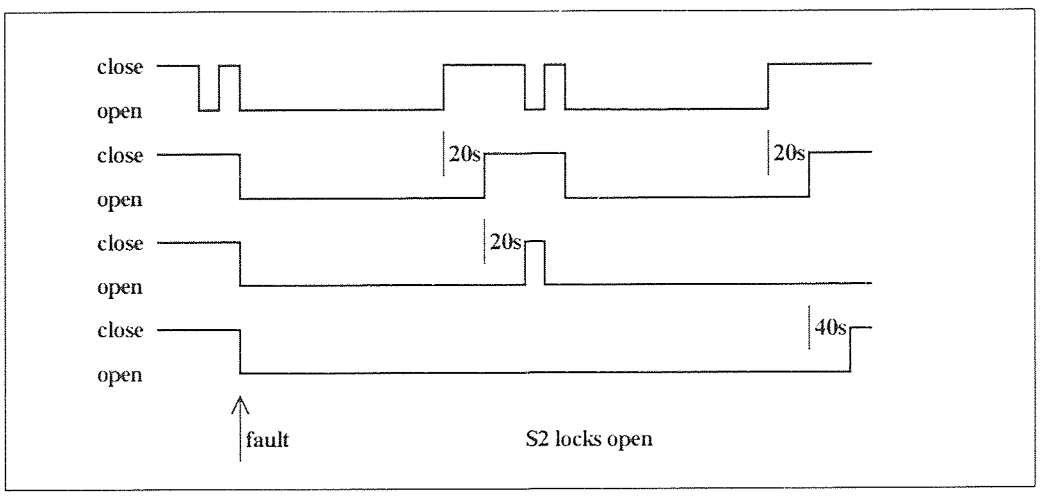

Figure 4.4 Voltage-controlled sectionalising operating sequence.

When the sectionaliser immediately upstream of the fault position is closed, in this case S2, the circuit breaker at the substation will open if the fault still exists. After a further high-speed reclosure all the sectionalisers will be opened again. The sectionaliser protecting the fault, S2, is now locked open and all the other sectionalisers are closed in sequence to restore supplies now that the faulted section is isolated from the system.

For all these sectionaliser operations, the isolated spur is not automatically identified at the control center, and this may therefore result in an extended outage time. However, the use of fault-passage indicators can assist in locating the faulty section. Furthermore, telecontrolled switches can avoid such situations. Such an arrangement is also relevant where sectionalisers revert from telecontrolled to automatic operation during periods when there is no human presence.

4.3 Digital Protection

Digital protection of power life is a new technique that is replacing the distance protection. In the case of parallel transmission lines, distance protection encounters some problems due to mutual coupling, back feed, in-feed, and poor discrimination between the faulty and healthy line especially in the case of faults near the far end bus. The directional relays, that are used in distance protection, are operating based on the voltage and direction of the current. This type of relays have difficulties of operation in the case of series compensated lines where the voltage and current direction may be reversed. However, there is the *transverse* directional protection, that is able to switch off the faulty line, can eliminate some of the problems of the simple directional protection. Nevertheless, by switching off the power line, could block the whole protection and special relays of complicated design is needed in order to ensure the stability of the protection.

The digital technique seems to be a better solution since the protection scheme can utilize a single relay at each end in the case of parallel transmission lines. (See figure 4.5)

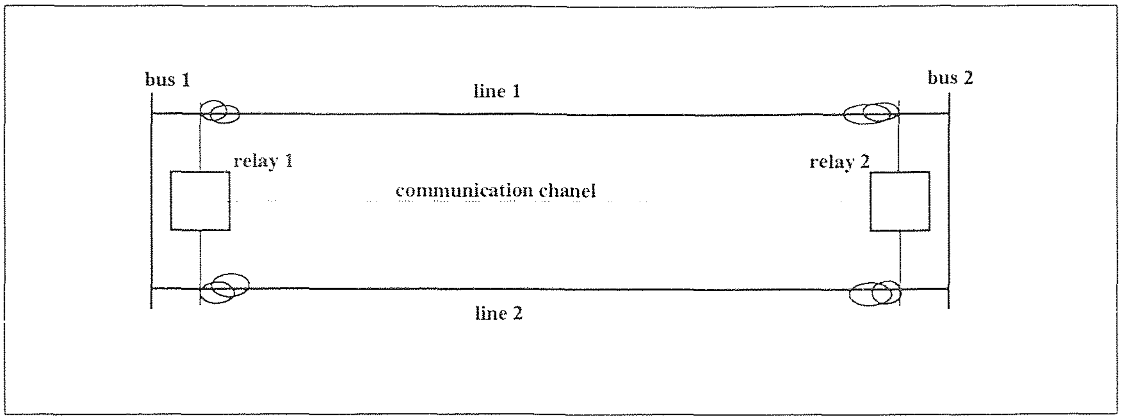

Figure 4.5 Parallel transmission lines, using one relay at each end.

The idea is the following: When the impedance of each circuit of a set of parallel lines is equal, the total current is distributed equally among all circuits under normal conditions and in the presence of an external fault. In the presence of a fault on one of the parallel lines, a larger amount of current from the source passes along the faulty line, while the healthy line carries a smaller current. By comparing the magnitudes of currents in the corresponding phases, the relay should be able to detect the faulted line correctly. In the digital form, the comparison can be made by comparing the magnitudes of the samples of current in the corresponding phases. However, this method is valid only in the case of permanent faults of any type under the condition that the two lines are identical and are fed from both ends. The method still has some problems such as phase shift between the currents may cause incorrect selection of samples. The digital approach of line protection is being improved by M. Gilany, O. Malik, and G. Hope, the three professors from the University of Calgary. They were able to modify the digital method by adding a new sample to the method. The new sample is a quantity proportional to the average of the current in each phase which is derived from the magnitude of the samples. They also filter the samples before processing since the high frequencies in the current samples may cause errors in the comparison between the two lines. We see that advanced digital signal processing is introduced to the power scheme and the older method of coordination of distance relays could be eliminated in the long run. The digital approach can provide fast tripping times like 4 ms that belongs to the ultra high-speed relay category.

4.4 Directional comparison protection

The directional comparison protection is an improved power line protection that has the ability to detect high resistance fault, a fast operating time, a wide application range, and an improved performance in the presence of distorted waveforms. In addition, this protection can withstand heavy circuit loading, it can remain stable against power swings and distortion caused by CT saturation. As far as the distance protection is concerned, the function of the distance zone is to provide an under-reaching instantaneous protection that can be used to trip the line for close-in internal faults without depending on the communication link. The communication link in many protection system is very important since it is responsible for the operation of the distance relays. If for some reason the communication link fails, the protection operation fails as well. The directional comparison protection offers a way that eliminates the communication link. The zone can be time delayed and set to over-reach the remote feeder-end, thus providing back-up protection to the whole feeder.

The operating principle is based on the directional elements that use the fault generated changes in the voltage and current signals at the relay location, referred to as the superimposed signals, to determine the direction to a fault. Figure 4.6 shows the relationship between the superimposed and the post-fault circuit.

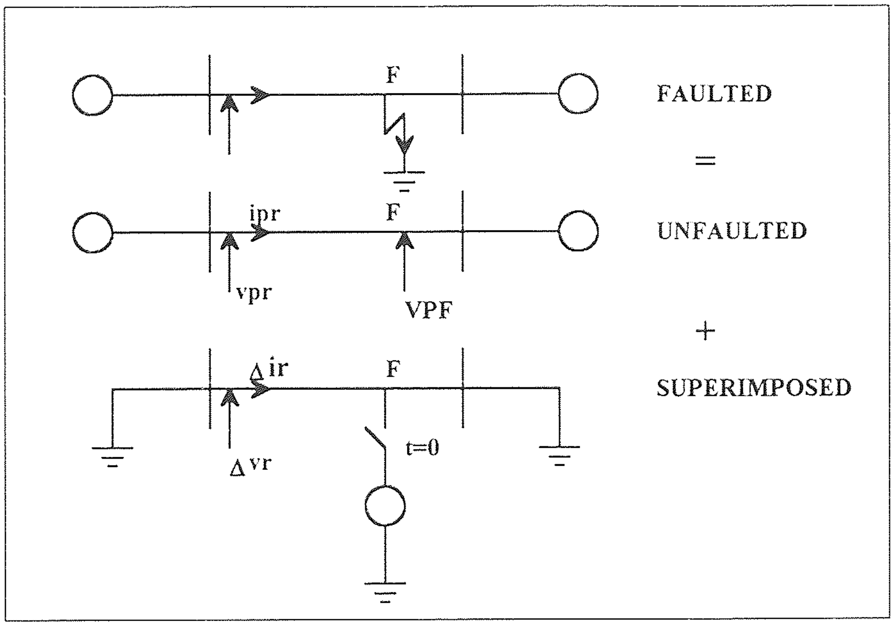

Figure 4.6 Superimposed and post-fault circuits.

The fault voltage can be considered to consist of two parts; the unfaulted voltage plus the superimposed voltage. Similarly, the fault current consists of the unfaulted current plus the superimposed current.

There is the following relationship between the superimposed voltage and current signals. For forward faults, the magnitude and angle of the superimposed current (Δi_r) is related to the superimposed voltage (Δv_r) by the source impedance behind the relaying point ($Z_S = |Z_S|\angle\phi_S$).

Therefore: $$\Delta i_r = -\frac{\Delta v_r}{|Z_S|\angle\phi_S} = -\frac{\Delta v_r}{|Z_S|}\angle -\phi_S$$

For a reverse fault: $$\Delta i_r = +\frac{\Delta v_r}{|Z_S|\angle\phi_S} = +\frac{\Delta v_r}{|Z_S|}\angle -\phi_S$$

Z_S is the effective source impedance corresponding to the protected line plus the source at the remote line. The polarity change between the forward and reverse faults show that a directional measurement exists. The signals required for comparison are the superimposed voltage phase delayed by an angle equal to the angle of the source impedance. These signals are of opposite polarity for a forward fault and vice a versa for a reverse fault, giving a very clear basis for directional discrimination. The magnitude of the source does not affect the polarity relationship. For a forward fault $\Delta v_r \angle \phi_R$ and Δi_r are of opposite polarity and for a reverse fault they are of like polarity. This comparison is performed by mixing $\Delta v_r \angle \phi_R$ and Δi_r in accordance with:

$$(S2 - S1) = |\Delta v_r \angle -\phi_R - \Delta i_r| - |\Delta v_r \angle -\phi_R + \Delta i_r|$$

For a forward fault, since the magnitude of the difference term $(\Delta v_r \angle -\phi_R - \Delta i_r)$ is greater than that of the sum term $(\Delta v_r \angle -\phi_R + \Delta i_r)$, (S2-S1) is positive. Likewise, for a reverse fault (S2-S1) is negative.

The distance protection is improved by the directional comparison method. As I mentioned before, the transmission lines are tripped without the dependence of the communication link. The relay incorporates one complete zone of distance protection and a switch-onto-fault (SOTF) detector. The SOTF detector is required to provide instantaneous protection of the whole line during manual or auto-reclosure of the circuit breaker. The distance zone and the SOTF detector are based on a digital version of a conventional amplitude comparator and operate when:

$$|IZ| > |V - IZ|$$

where V is the filtered fault voltage and IZ is the filtered fault current multiplied by the reach impedance.

4.5 Solid state directional protection

The block diagram that is outlined on figure 4.7, shows the solid state protection layout. The main features of the scheme are described below.

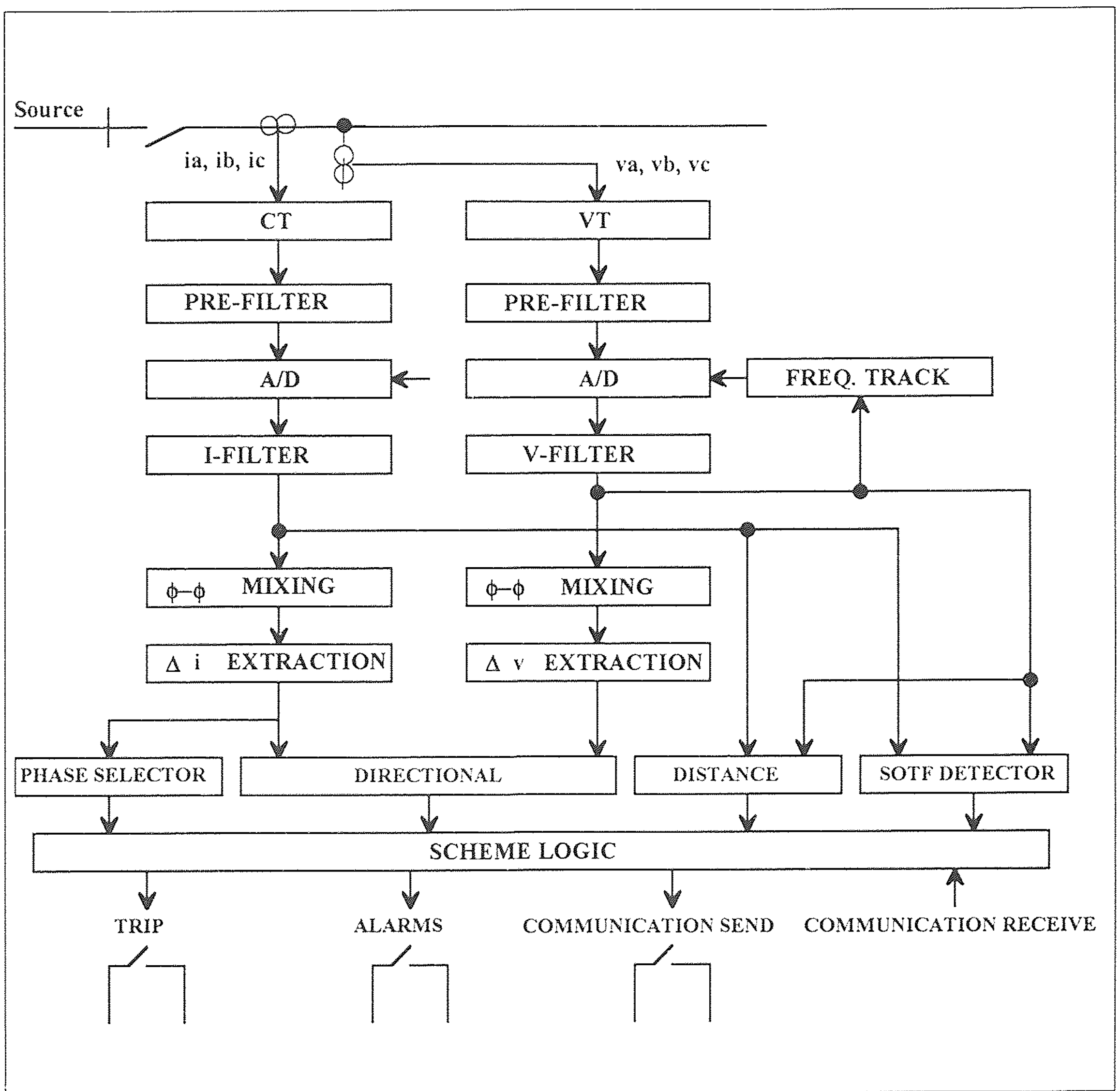

Figure 4.7 Relay block diagram for solid state protection.

The input voltage and current signals are converted to electronic signal levels by voltage and current transformers housed within the relay. These signals are then filtered by analog pre-filters designed to prevent aliasing distortion during digital processing. The pre-filtered voltage and current signals are sampled at a rate determined by the frequency track algorithm. These sampled values are then converted by a 12 bit analog to digital converter (A/D) into an equivalent digital number. The A/D converter output corresponding to an input current of 36.7 Amps peak (1 Amp relay) or an input voltage of 174 Volts peak is 2048 digital levels.

The frequency track algorithm adjusts the sample rate in accordance with the power system frequency; the relays samples each of the six relay input signals at exactly 50 samples/power frequency cycle.

The current filter attenuates high frequency transients in the current signal. The voltage filter is designed to phase delay the voltage signal with respect to the filtered current signal by the replica source angle. This filter also attenuates the high frequency transients generated by the fault; these transients may interfere with the directional/distance decision.

The phase-phase mixing algorithm derives voltage and current signals, formed as the difference of the a and b, b and c, a and a phase values respectively. The use of a phase-phase signal reduces the effect of mutual coupling on double circuit lines.

The superimposed signals are extracted by subtracting a one cycle delayed version of each signal from its non-delayed signal. When a fault occurs the Δv and Δi extraction filters transmit the difference between the post-fault and pre-fault signals for a period of one cycle after the fault. After this period, the output of an extraction filter is the difference between the instantaneous post-fault signal and a one cycle delayed post-fault signal.

There are three independent directional elements corresponding to the three sets of phase-phase signals (a-b), (b-c), (c-a). Each directional element processes the appropriate set of superimposed filtered voltage and current signals in accordance with the following sequence:

- Step 1: The Δv sample is scaled relative to the superimposed voltage setting; the scaled Δv equals the true Δv divided by the voltage setting.
- Step 2: The scaled Δv and the Δi samples are mixed to form a composite phase-phase sample: $(S2\text{-}S1) = |\Delta v - \Delta i| - |\Delta v + \Delta i|$
- Step 3: If the (S2-S1) sample is positive, it is compared with a positive forward threshold (27 digital levels). If the sample value is greater than the threshold, the output decision counter is incremented. This threshold was selected to ensure the relay will detect all forward faults, causing an rms current change of greater than 0.2 Amps and an rms voltage change of greater than the voltage threshold, within 0.5 power frequency cycles.
- Step 4: If the (S2-S1) sample is negative, it is compared with the negative reverse threshold (-18 digital levels). If the sample value is more negative than the threshold, the output decision counter is decremented. This threshold was selected to ensure the reverse sensitivity is always greater than the forward sensitivity.

- Step 5: The previous four steps are performed on each Δv and Δi sample pair at a rate of 25 samples/cycle. If the output decision counter reaches +3 or -3 the appropriate (a-b), (b-c), (c-a) forward or reverse directional flag is activated. The maximum allowable decision count is +8 for a forward fault and -8 for a reverse fault. These limits are imposed to ensure the relay can change its decision from reverse to forward or vice versa without an unacceptably long delay.

The function of the phase selector is to evaluate the faulted phases by processing the three superimposed phase-phase current signals. A single phase to ground fault is detected if two phase to phase signals exceed a threshold, while the third signal does not. The faulted phase is the phase involved in the two active signals. For instance, active (a-b) and (c-a) signals and an inactive (b-c) signal selects an a-ground fault. The threshold is chosen to ensure the phase selector is more sensitive than the directional/distance elements, thus all faults that can be detected by the relay are correctly phase selected. In general, the function of the phase detector is to direct the trip output of the protection to the correct phase.

The distance protection and the SOTF detector are both implemented using three-phase to neutral and three phase to phase amplitude comparison distance elements. The scheme logic has the function to control the protection scheme. The relay provides several options on the type of protection scheme required by the user, including blocking or permissive intertripping schemes. The operating decisions of the three directional elements, the phase selector, the six distance elements and the SOTF detector are transferred to the scheme logic. The scheme logic processes these decisions in conjunction with the communication signal received from the remote relay and sets the appropriate trip action.

Various tests and simulations show that the directional comparison protection performs very efficiently. It provides high speed operation with a high degree of security against maloperation. In short, the digital techniques are used in order to implement the protection, and it is based on the use of superimposed signals. The operation only occurs under the influence of the power frequency superimposed signals caused by the fault and it is not affected by the high frequency transients that exist immediately after the fault occurrence. The relay operating times are about 9 ms which when are used in conjunction with fast communication channel, the protection scheme satisfies the requirements of high speed fault clearance times. As far as the protection coordination of the power system is concerned, the digital protection offer a more reliable way and it eliminates the trouble of setting relay taps and timings. Only signal processing is the main tool for the smooth operation of the protection system.

CHAPTER FIVE

CONCLUSIONS AND SUGGESTIONS

Protection system coordination is a major problem for utilities since it affects most aspects of transmission and distribution and dramatically impacts transmission and distribution reliability. The lack of coordination can have far reaching effects, even to the point of grid disturbance. Computer technology has evolved such that the coordination process has been replicated, and the means for a system-wide, systematic, analytical solution to protection system coordination has been achieved. As I implied before, the ultimate purpose of protection is to provide power system reliability. It might seem that protection of equipment is the purpose of protection systems, but this misses the global picture. It is the integrity of the system which is being protected.

5.1 The nature of protection

As I mentioned in chapter one, the immediate area or zone of protection provided by a protective device is called the primary protection zone. Consideration of the protective devices on the system is necessary and this process of addressing protective devices on the system is called coordination. There two aspects to it. First, every device should be the first to trip for a fault in its primary zone of protection, i.e., the extend of power system isolation during a fault should be minimized. Second, protective devices should provide system redundancy, i.e., there should be a backup device which operates when the primary device fails. The primary device is the device in whose primary protection zone the fault occurs. The redundancy-producing primary-backup relationship, often called a device pair, is function of power system topology, protective device characteristics, and protection philosophy.

The primary-backup relationship have become complicated and it is responsible for the nature of networks: any protective device in a network may be involved in multiple primary-backup relationships. In other words, when a line feeds two others, its protective device may serve as backup for the primary devices of each of the other lines. With any type of network, chains of primary and backup relationships, or device pairs, may exist which result in multiple coordination paths for any device. Typically, one chain of device pairs will be critical in determining a device setting, and this chain is called the critical coordination path.

A fault study is part of every effort in protection system coordination. Fault conditions have been determined defining the span of fault conditions possible in the primary protection zone. Calculation of these fault levels is known as fault analysis and includes sorting to determine the relevant faults for primary protection zone settings. Nevertheless, the backup protection devices are always present. Analysis of the calculated faults is necessary to determine the fault situations critical for coordination and the resultant current pairs for each primary-backup relationship. Summarizing then and considering proper fault analysis, there are two analytical considerations:

- Primary zone protection
- System coordination

Primary zone protection is a local problem whereas coordination is a system problem.

5.2 A suggestive system analysis

In general, system analysis is defined as a system-wide, systematic, analytical evaluation. There is no doubt that the protection coordination is a system condition. Thus, coordination must be accomplished on a system-wide basis. The process must be systematic since random evaluation is insufficient according to certain analysis requirements. For example, automated, comprehensive fault calculation techniques provide a consistent approach to fault analysis. The evaluation must be analytical, but the explanation is more involved. The following three aspects should be applied during the study of a problem:

- Analytical solution
- Simulation
- Probabilistic simulation

Analytical solution is a deterministic, closed form, complete evaluation. The solution is consistent and repeatable, with the same input data providing identical results. Simulation is an alternative evaluation method where a model of a complete system is exercised for all possible situations. However, there are some certain situations. The system has to be implemented as a model and the number of situations must be limited. Simulation is often used to evaluate one mode of operation versus another. When the number of simulations becomes too large, there is the probabilistic simulation. It is not a closed solution with all possibilities analyzed and a large number of occurrences must be involved. Typically, the number of simulations could be very large for a complete test of every situation. Therefore, we could use a probabilistic distribution from which we could make some certain judgments. However, the results are not deterministic, but rather a probability of effect. The coordination problem is not based its solution on simulation and probabilistic distribution. The solution requires a deterministic approach that is both system-wide and systematic, i.e., systems analysis of protection coordination.

5.3 Essential Suggestions

The protection philosophy plays an important role for the overall design of a protection scheme. As I said before, the coordination problem is a function of system topology and protective device characteristics. Traditionally, coordination is accomplished manually on a device-pair-by-device-pair basis for the complete power system. However, power systems suffer modifications and changes. The changeability of the power systems creates the need for improving the operation of the protection scheme. Some suggestions are the following:

- Topological contingencies of a network

Day to day operations often include periodic line outages. These occur as a normal part of system operation. The line outages are not major system changes, but rather occur in the course of power system operation. These contingencies must be considered during coordination. Protection settings cannot be such that normal power system operation can upset the delicate balance of coordination and negatively impact reliability.

- Periodic coordination reviews

In the long term, power systems do not remain constant; physical changes occur over time. As a result, periodic evaluation of the protective system is suggested. Appropriate review periods can be set up, for instance, annual reviews could be the more suitable. Unless the system is periodically evaluated, the power system may become miscoordinated. In addition, the periodic reviews can have side benefits such as the training of the protection staff.

- Power system modification

Power system modifications are a fact of life. Power system planning monitors the need for change and seeks to implement the most cost-effective solution to any future service requirements. As far as the protection of the power system is concerned, any modifications may require recoordination of the protection system or even a change in protective device application. Whenever any power modification is considered, there is a protection impact immediate to the area of modification, especially the primary zones of protection. Regardless of the specifics, protective impact is not evaluated, and protection system changes as a path to accommodate whatever power system change is implemented. As a result, there are instances of physical miscoordination, i.e., protective devices that cannot be coordinated over the relevant range of fault situations. However, the problem could be attacked by considering the number of alternatives increases. Given more alternatives, greater analysis is necessary to evaluate the protective impact. In addition, the comparison of each alternative with the other could lead to the right protection scheme.

- Protective device optimization

Protective systems should be periodically evaluated for optimum device applicability. Device applicability must be evaluated from a system's point of view. Fault levels can change with power system modifications and directionally may be indicated, or an impedance relay may offer a better solution to the present device. Similarly, current transformers may be subject to saturation, or reclosers may require a higher rating. Special analysis should be emphasized in order to optimize a power system. However, optimization analysis often have a significant cost and therefore the cost-effectiveness factor should be considered as well.

- Protective devices outages

Occasionally, in the course of normal power system operation, it becomes necessary to outage a piece of protection equipment. This can occur for protective device repair or replacement of input sensing devices such as current or voltage transformers. Since protection coordination is based on device pairs (a primary and a backup device), any outage of a protective device probably disturbs at least two device pairs and at least one coordination path. Any device may be part of several device pairs and any device pair may be a part of several critical coordination paths. Protective equipment repair is normal; some means of accommodating the necessary outages is suggested since protection is essential to the integrity of a power system. In addition, some systematic, analytical means of coordination is needed to effect power system integrity.

- Adaptive relaying of networks

Adaptive relaying is often discussed in terms of sensitivity and selectivity improvement. Increased selectivity and sensitivity could allow greater power to be transmitted over current networks. Any application of adaptive relaying to transmission and distribution networks must address protection system coordination. Indiscriminate setting changes will reduce system reliability. Adaptive relaying can improve selectivity and sensitivity, by adjusting settings for temperature and topological changes, but the impact of system coordination must be addressed. Any device setting change must occur in the context of the entire protection system, which requires real-time systems-analysis of protection-coordination capability. Moreover, adaptive relaying affects some communication among protective devices of the network. In order to maintain reliability, which is the main reason of system protection, adaptive relaying must have a fallback setting in case of communication loss.

5.4 Summary

Protection coordination is a must for all utilities. The power system of Cyprus is a small network and most of the previous suggestions can be applied since the system is expanding and being modified. In chapter three, we saw the time coordination of the main line sections of the network. Traditional time coordination is not reliable enough. We saw in chapter three that in a case where we do not have time coordiantion, we have to alter the previous relay settings in order to achieve the proper coordination. The time curves and relay tap settings are methods that going to be substituted by modern digital methods. For instance, the digital directional comparison is a very important method that is going to be established by most utilities. Automatic reclosers is an economic way of protecting lines but the high speed protection is an unknown term. Microprocessor-based relays are the latest items of the protection technology. They provide sophisticated protection and fault clearing schemes. In addition, some essential suggestions, that are examined in this chapter, are very important for the smooth operation of a protection scheme. There is no doubt that protection coordination becomes more complicated in order to cover the contemporary needs of a power system. Fortunately, computer technology is evolving such that systems analysis of protection coordination is feasible and can provide the opportunity to improve power system operational reliability.

REFERENCES

Mason, C. R. The Art and Science of Protective Relaying. Wiley, New York, 1956.

Anderson, P. M. Analysis of Faulted Power Systems. Iowa, Iowa State University Press, 1973.

Lewis, W. A., and L.S. Tippet. 1947. "Fundamental Basis for Distance Relaying on a Three-Phase System." *AIEE Transactions.* vol. 66: 694-708

Johns, A.T., M.A. Martin, A. Barker, E.P. Walker, and P.A. Crossley. 1986. "A New Approach to EHV Directional Comparison Protection Using Digital Signal Processing Techniques." *IEEE Transactions.* vol. PWRD-1, 2: 24-34.

Juves, J.A., R.W. Johnson, E.J. Mayer, and S.S. Waters. 1986. "The Concept of Figure of Merit Applied to Protection System Coordination." *IEEE Transactions on Power Delivery.* October 1986: 31-40.