• 9 • Overcurrent Protection for Phase and Earth Faults

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9.1 INTRODUCTION

Protection against excess current was naturally the earliest protection system to evolve. From this basic principle, the graded overcurrent system, a discriminative fault protection, has been developed. This should not be confused with 'overload' protection, which normally makes use of relays that operate in a time related in some degree to the thermal capability of the plant to be protected. Overcurrent protection, on the other hand, is directed entirely to the clearance of faults, although with the settings usually adopted some measure of overload protection may be obtained.

9.2 CO-ORDINATION PROCEDURE

Correct overcurrent relay application requires knowledge of the fault current that can flow in each part of the network. Since large-scale tests are normally impracticable, system analysis must be used – see Chapter 4 for details. The data required for a relay setting study are:

- **i.** a one-line diagram of the power system involved, showing the type and rating of the protection devices and their associated current transformers
- **ii.** the impedances in ohms, per cent or per unit, of all power transformers, rotating machine and feeder circuits
- **iii.** the maximum and minimum values of short circuit currents that are expected to flow through each protection device
- **iv.** the maximum load current through protection devices
- **v.** the starting current requirements of motors and the starting and locked rotor/stalling times of induction motors
- **vi.** the transformer inrush, thermal withstand and damage characteristics
- **vii.** decrement curves showing the rate of decay of the fault current supplied by the generators
- **viii.** performance curves of the current transformers

The relay settings are first determined to give the shortest operating times at maximum fault levels and then checked to see if operation will also be satisfactory at the minimum fault current expected. It is always advisable to plot the curves of relays and other protection devices, such as fuses, that are to operate in series, on a common scale. It is usually more convenient to use a scale corresponding to the current expected at the lowest voltage base, or to use the predominant voltage base. The alternatives are a common MVA base or a separate current scale for each system voltage.

The basic rules for correct relay co-ordination can generally be stated as follows:

a. whenever possible, use relays with the same operating characteristic in series with each other

b. make sure that the relay farthest from the source has current settings equal to or less than the relays behind it, that is, that the primary current required to operate the relay in front is always equal to or less than the primary current required to operate the relay behind it.

9.3 PRINCIPLES OF TIME/CURRENT GRADING

Among the various possible methods used to achieve correct relay co-ordination are those using either time or overcurrent, or a combination of both. The common aim of all three methods is to give correct discrimination. That is to say, each one must isolate only the faulty section of the power system network, leaving the rest of the system undisturbed.

9.3.1 Discrimination by Time

In this method, an appropriate time setting is given to each of the relays controlling the circuit breakers in a power system to ensure that the breaker nearest to the fault opens first. A simple radial distribution system is shown in Figure 9.1, to illustrate the principle.

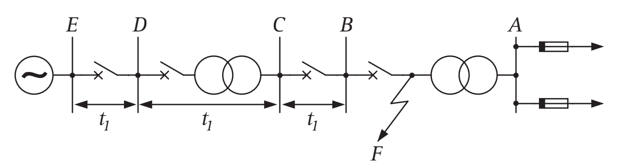


Figure 9.1: Radial system with time discrimination

Overcurrent protection is provided at B, C, D and E, that is, at the infeed end of each section of the power system. Each protection unit comprises a definite-time delay overcurrent relay in which the operation of the current sensitive element simply initiates the time delay element. Provided the setting of the current element is below the fault current value, this element plays no part in the achievement of discrimination. For this reason, the relay is sometimes described as an 'independent definite-time delay relay', since its operating time is for practical purposes independent of the level of overcurrent.

It is the time delay element, therefore, which provides the means of discrimination. The relay at B is set at the shortest time delay possible to allow the fuse to blow for a fault at A on the secondary side of the transformer. After the time delay has expired, the relay output contact closes to trip the circuit breaker. The relay at C has a time delay setting equal to t_1 seconds, and similarly for the relays at D and E.

If a fault occurs at F, the relay at B will operate in t seconds and the subsequent operation of the circuit breaker at B will clear the fault before the relays at C, D and E have time to operate. The time interval t_1 between each relay time setting must be long enough to ensure that the upstream relays do not operate before the circuit breaker at the fault location has tripped and cleared the fault.

The main disadvantage of this method of discrimination is that the longest fault clearance time occurs for faults in the section closest to the power source, where the fault level (MVA) is highest.

9.3.2 Discrimination by Current

Discrimination by current relies on the fact that the fault current varies with the position of the fault because of the difference in impedance values between the source and the fault. Hence, typically, the relays controlling the various circuit breakers are set to operate at suitably tapered values of current such that only the relay nearest to the fault trips its breaker. Figure 9.2 illustrates the method.

For a fault at F_1, the system short-circuit current is given by:

$$I = \frac{6350}{Z_S + Z_{L1}} A$$

where Z_s = source impedance

$$= \frac{11^2}{250} = 0.485\Omega$$

Z_{L1} = cable impedance between C and B

$$= 0.24\Omega$$

Hence $$I = \frac{11}{\sqrt{3} \times 0.725} = 8800A$$

So, a relay controlling the circuit breaker at C and set to operate at a fault current of 8800A would in theory protect the whole of the cable section between C and B. However, there are two important practical points that affect this method of co-ordination:

a. it is not practical to distinguish between a fault at F_1 and a fault at F_2, since the distance between these points may be only a few metres, corresponding to a change in fault current of approximately 0.1%

b. in practice, there would be variations in the source fault level, typically from 250MVA to 130MVA. At this lower fault level the fault current would not exceed 6800A, even for a cable fault close to C. A relay set at 8800A would not protect any part of the cable section concerned

Discrimination by current is therefore not a practical proposition for correct grading between the circuit breakers at C and B. However, the problem changes appreciably when there is significant impedance between the two circuit breakers concerned. Consider the grading required between the circuit breakers at C and A in Figure 9.2. Assuming a fault at F_4, the short-circuit current is given by:

$$I = \frac{6350}{Z_S + Z_{L1}} A$$

where Z_S = source impedance

$= 0.485\Omega$

Z_{L1} = cable impedance between C and B

$= 0.24\Omega$

Z_{L2} = cable impedance between B and 4 MVA transformer

$= 0.04\Omega$

Z_T = transformer impedance

$$= 0.07\left(\frac{11^2}{4}\right)$$

$= 2.12\Omega$

Hence $$I = \frac{11}{\sqrt{3} \times 2.885}$$

$= 2200\ A$

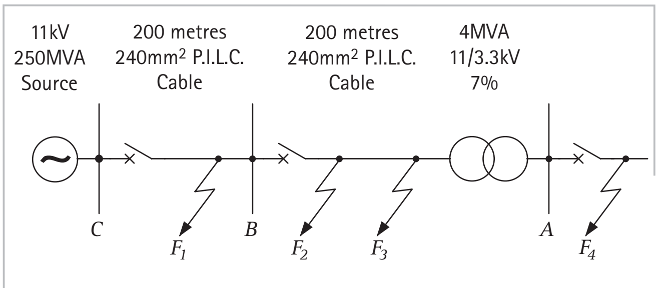


Figure 9.2: Radial system with current discrimination

For this reason, a relay controlling the circuit breaker at B and set to operate at a current of 2200A plus a safety margin would not operate for a fault at F_4 and would thus discriminate with the relay at A. Assuming a safety margin of 20% to allow for relay errors and a further 10% for variations in the system impedance values, it is reasonable to choose a relay setting of 1.3 x 2200A, that is 2860A, for the relay at B. Now, assuming a fault at F_3, at the end of the 11kV cable feeding the 4MVA transformer, the short-circuit current is given by:

$$I = \frac{11}{\sqrt{3}\,(Z_S + Z_{L1} + Z_{L2})}$$

Thus, assuming a 250MVA source fault level:

$$I = \frac{11}{\sqrt{3}\,(0.485 + 0.24 + 0.04)}$$

$= 8300\ A$

Alternatively, assuming a source fault level of 130MVA:

$$I = \frac{11}{\sqrt{3}\,(0.93 + 0.214 + 0.04)}$$

$= 5250\ A$

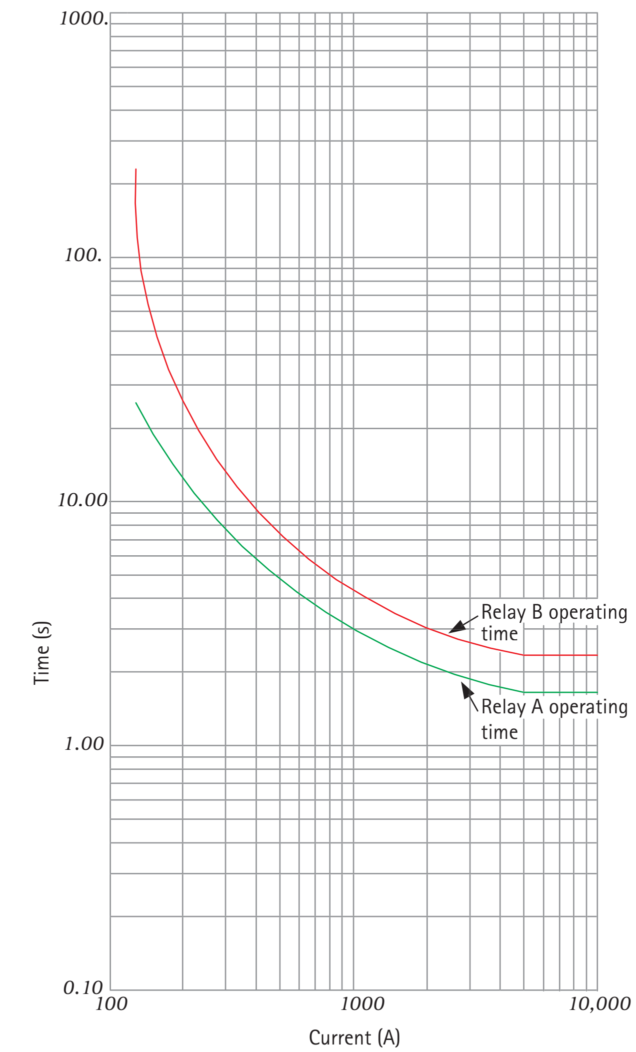
In other words, for either value of source level, the relay at B would operate correctly for faults anywhere on the 11kV cable feeding the transformer.

9.3.3 Discrimination by both Time and Current

Each of the two methods described so far has a fundamental disadvantage. In the case of discrimination by time alone, the disadvantage is due to the fact that the more severe faults are cleared in the longest operating time. On the other hand, discrimination by current can be applied only where there is appreciable impedance between the two circuit breakers concerned.

It is because of the limitations imposed by the independent use of either time or current co-ordination that the inverse time overcurrent relay characteristic has evolved. With this characteristic, the time of operation is inversely proportional to the fault current level and the actual characteristic is a function of both 'time' and 'current' settings. Figure 9.3 illustrates the characteristics of two relays given different current/time settings. For a large variation in fault current between the two ends of the feeder, faster operating times can be achieved by the relays nearest to the source, where the fault level is the highest. The disadvantages of grading by time or current alone are overcome.

The selection of overcurrent relay characteristics generally starts with selection of the correct characteristic to be used for each relay, followed by choice of the relay current settings. Finally the grading margins and hence time settings of the relays are determined. An iterative procedure is often required to resolve conflicts, and may involve use of non-optimal characteristics, current or time grading settings.



Relay A: Current Setting = 100A, TMS = 1.0
Relay B: Current Setting = 125A, TMS = 1.3

Figure 9.3: Relay characteristics for different settings

9.4 STANDARD I.D.M.T. OVERCURRENT RELAYS

The current/time tripping characteristics of IDMT relays may need to be varied according to the tripping time required and the characteristics of other protection devices used in the network. For these purposes, IEC 60255 defines a number of standard characteristics as follows:

Standard Inverse (SI)
Very Inverse (VI)
Extremely Inverse (EI)
Definite Time (DT)

Relay Characteristic	Equation (IEC 60255)
Standard Inverse (SI)	$t = TMS \times \frac{0.14}{I_r^{0.02} - 1}$
Very Inverse (VI)	$t = TMS \times \frac{13.5}{I_r - 1}$
Extremely Inverse (EI)	$t = TMS \times \frac{80}{I_r^2 - 1}$
Long time standard earth fault	$t = TMS \times \frac{120}{I_r - 1}$

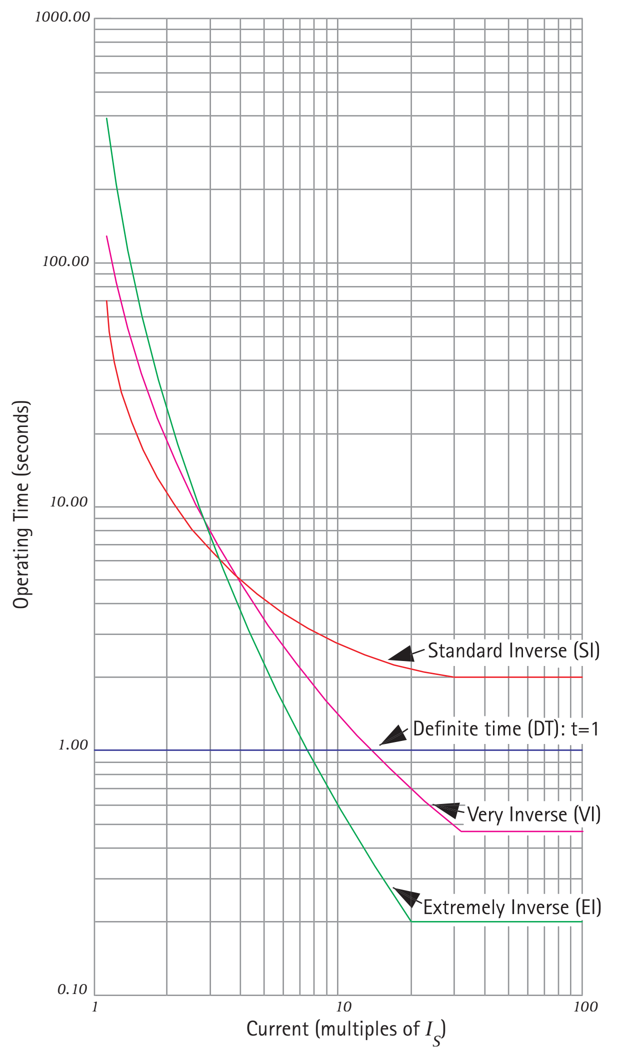
(a): Relay characteristics to IEC 60255

Relay Characteristic	Equation (IEC 60255)
IEEE Moderately Inverse	$t = \frac{TD}{7}\left\{\left(\frac{0.0515}{I_r^{0.02} - 1}\right) + 0.114\right\}$
IEEE Very Inverse	$t = \frac{TD}{7}\left\{\left(\frac{19.61}{I_r^2 - 1}\right) + 0.491\right\}$
Extremely Inverse (EI)	$t = \frac{TD}{7}\left\{\left(\frac{28.2}{I_r^2 - 1}\right) + 0.1217\right\}$
US CO8 Inverse	$t = \frac{TD}{7}\left\{\left(\frac{5.95}{I_r^2 - 1}\right) + 0.18\right\}$
US CO2 Short Time Inverse	$t = \frac{TD}{7}\left\{\left(\frac{0.02394}{I_r^{0.02} - 1}\right) + 0.01694\right\}$

$I_r = (I/I_s)$, where I_s = relay setting current
TMS = Time multiplier Setting
TD = Time Dial setting

(b): North American IDMT relay characteristics

Table 9.1: Definitions of standard relay characteristics



(a) IEC 60255 characteristics ; TMS=1.0

Figure 9.4 (a): IDMT relay characteristics

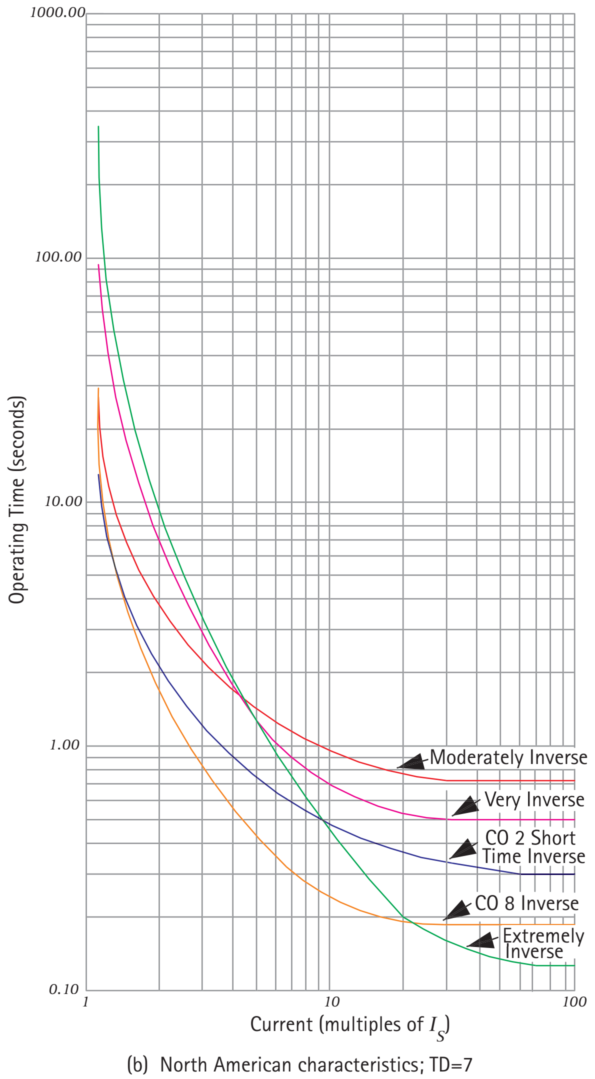


Figure 9.4 (b): IDMT relay characteristics

The mathematical descriptions of the curves are given in Table 9.1(a), and the curves based on a common setting current and time multiplier setting of 1 second are shown in Figure 9.4(a). The tripping characteristics for different TMS settings using the SI curve are illustrated in Figure 9.5.

Although the curves are only shown for discrete values of TMS, continuous adjustment may be possible in an electromechanical relay. For other relay types, the setting steps may be so small as to effectively provide continuous adjustment. In addition, almost all overcurrent relays are also fitted with a high-set instantaneous element.

In most cases, use of the standard SI curve proves satisfactory, but if satisfactory grading cannot be achieved, use of the VI or EI curves may help to resolve the problem. When digital or numeric relays are used, other characteristics may be provided, including the possibility of user-definable curves. More details are provided in the following sections.

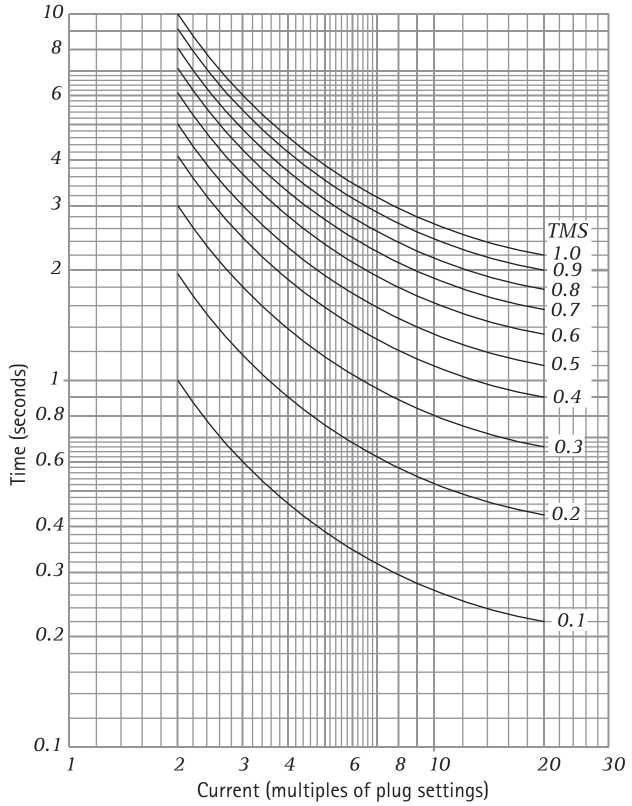


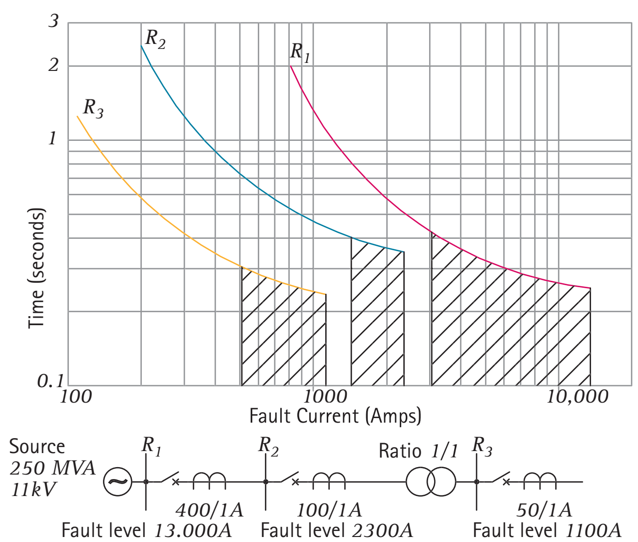
Figure 9.5: Typical time/current characteristics of standard IDMT relay

Relays for power systems designed to North American practice utilise ANSI/IEEE curves. Table 9.1(b) gives the mathematical description of these characteristics and Figure 9.4(b) shows the curves standardised to a time dial setting of 1.0.

9.5 COMBINED I.D.M.T. AND HIGH SET INSTANTANEOUS OVERCURRENT RELAYS

A high-set instantaneous element can be used where the source impedance is small in comparison with the protected circuit impedance. This makes a reduction in the tripping time at high fault levels possible. It also improves the overall system grading by allowing the 'discriminating curves' behind the high set instantaneous elements to be lowered.

As shown in Figure 9.6, one of the advantages of the high set instantaneous elements is to reduce the operating time of the circuit protection by the shaded area below the 'discriminating curves'. If the source impedance remains constant, it is then possible to achieve high-speed protection over a large section of the protected circuit. The rapid fault clearance time achieved helps to minimise damage at the fault location. Figure 9.6 also illustrates a further important advantage gained by the use of high set instantaneous elements. Grading with the relay immediately behind the relay that has the instantaneous elements enabled is carried out at the current setting of the instantaneous elements and not at the maximum fault level. For example, in Figure 9.6, relay R_2 is graded with relay R_3 at 500A and not 1100A, allowing relay R_2 to be set with a TMS of 0.15 instead of 0.2 while maintaining a grading margin between relays of 0.4s. Similarly, relay R_1 is graded with R_2 at 1400A and not at 2300A.



I.D.M.T. Relay settings
R_1 set at 500A 0.125 TMS
R_2 set at 125A 0.15 TMS
R_3 set at 62.5A 0.10 TMS

High set instantaneous relay settings
R_1 set at 300A
R_2 set at 1400A
R_3 set at 500A

Figure 9.6: Characteristics of combined IDMT and high-set instantaneous overcurrent relays

9.5.1 Transient Overreach

The *reach* of a relay is that part of the system protected by the relay if a fault occurs. A relay that operates for a fault that lies beyond the intended zone of protection is said to overreach.

When using instantaneous overcurrent elements, care must be exercised in choosing the settings to prevent them operating for faults beyond the protected section. The initial current due to a d.c. offset in the current wave may be greater than the relay pick-up value and cause it to operate. This may occur even though the steady state r.m.s. value of the fault current for a fault at a point beyond the required reach point may be less than the relay setting. This phenomenon is called transient overreach, and is defined as:

$$\%\ transient\ overreach = \frac{I_1 - I_2}{I_2} \times 100\%$$

...Equation 9.1

where:

I_1 = *r.m.s steady-state relay pick-up current*

I_2 = *steady state r.m.s. current which when fully offset just causes relay pick-up*

When applied to power transformers, the high set instantaneous overcurrent elements must be set above the maximum through fault current than the power transformer can supply for a fault across its LV terminals, in order to maintain discrimination with the relays on the LV side of the transformer.

9.6 VERY INVERSE (VI) OVERCURRENT RELAYS

Very inverse overcurrent relays are particularly suitable if there is a substantial reduction of fault current as the distance from the power source increases, i.e. there is a substantial increase in fault impedance. The VI operating characteristic is such that the operating time is approximately doubled for reduction in current from 7 to 4 times the relay current setting. This permits the use of the same time multiplier setting for several relays in series.

Figure 9.7 provides a comparison of the SI and VI curves for a relay. The VI curve is much steeper and therefore the operation increases much faster for the same reduction in current compared to the SI curve. This enables the requisite grading margin to be obtained with a lower TMS for the same setting current, and hence the tripping time at source can be minimised.

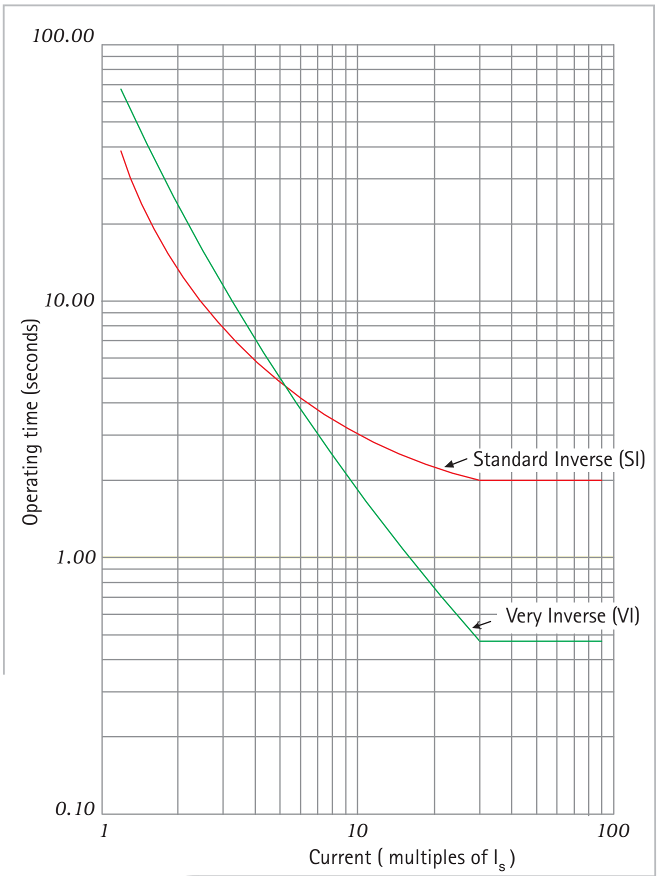


Figure 9.7: Comparison of SI and VI relay characteristics

9.7 EXTREMELY INVERSE (EI) OVERCURRENT RELAYS

With this characteristic, the operation time is approximately inversely proportional to the square of the applied current. This makes it suitable for the protection of distribution feeder circuits in which the feeder is subjected to peak currents on switching in, as would be the case on a power circuit supplying refrigerators, pumps, water heaters and so on, which remain connected even after a prolonged interruption of supply. The long time operating characteristic of the extremely inverse relay at normal peak load values of current also makes this relay particularly suitable for grading with fuses. Figure 9.8 shows typical curves to illustrate this. It can be seen that use of the EI characteristic gives a satisfactory grading margin, but use of the VI or SI characteristics at the same settings does not. Another application of this relay is in conjunction with auto-reclosers in low voltage distribution circuits. The majority of faults are transient in nature and unnecessary blowing and replacing of the fuses present in final circuits of such a system can be avoided if the auto-reclosers are set to operate before the fuse blows. If the fault persists, the auto-recloser locks itself in the closed position after one opening and the fuse blows to isolate the fault.

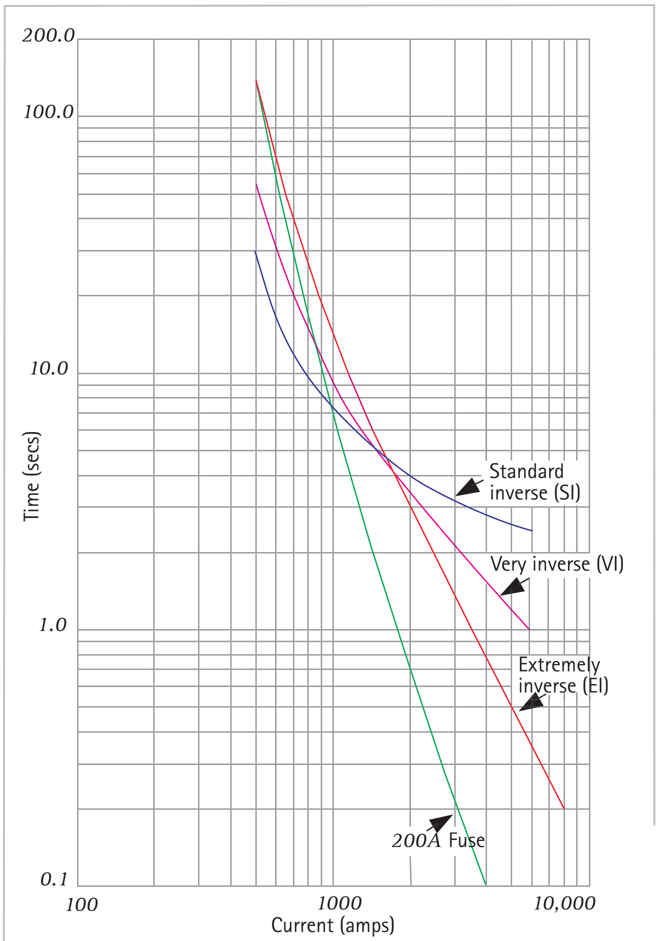


Figure 9.8: Comparison of relay and fuse characteristics

9.8 OTHER RELAY CHARACTERISTICS

User definable curves may be provided on some types of digital or numerical relays. The general principle is that the user enters a series of current/time co-ordinates that are stored in the memory of the relay. Interpolation between points is used to provide a smooth trip characteristic. Such a feature, if available, may be used in special cases if none of the standard tripping characteristics is suitable. However, grading of upstream protection may become more difficult, and it is necessary to ensure that the curve is properly documented, along with the reasons for use. Since the standard curves provided cover most cases with adequate tripping times, and most equipment is designed with standard protection curves in mind, the need to utilise this form of protection is relatively rare.

Digital and numerical relays may also include pre-defined logic schemes utilising digital (relay) I/O provided in the relay to implement standard schemes such as CB failure and trip circuit supervision. This saves the provision of separate relay or PLC (Programmable Logic Controller) hardware to perform these functions.

9.9 INDEPENDENT (DEFINITE) TIME OVERCURRENT RELAYS

Overcurrent relays are normally also provided with elements having independent or definite time characteristics. These characteristics provide a ready means of co-ordinating several relays in series in situations in which the system fault current varies very widely due to changes in source impedance, as there is no change in time with the variation of fault current. The time/current characteristics of this curve are shown in Figure 9.9, together with those of the standard I.D.M.T. characteristic, to indicate that lower operating times are achieved by the inverse relay at the higher values of fault current, whereas the definite time relay has lower operating times at the lower current values.

Vertical lines T_1, T_2, T_3, and T_4 indicate the reduction in operating times achieved by the inverse relay at high fault levels.

9.10 RELAY CURRENT SETTING

An overcurrent relay has a minimum operating current, known as the current setting of the relay. The current setting must be chosen so that the relay does not operate for the maximum load current in the circuit being protected, but does operate for a current equal or greater to the minimum expected fault current. Although by using a current setting that is only just above the maximum load current in the circuit a certain degree of protection against overloads as well as faults may be provided, the main function of overcurrent protection is to isolate primary system faults and not to provide overload protection. In general, the current setting will be selected to be above the maximum short time rated current of the circuit involved. Since all relays have hysteresis in their current settings, the setting must be sufficiently high to allow the relay to reset when the rated current of the circuit is being carried. The amount of hysteresis in the current setting is denoted by the pick-up/drop-off ratio of a relay – the value for a modern relay is typically 0.95. Thus, a relay minimum current

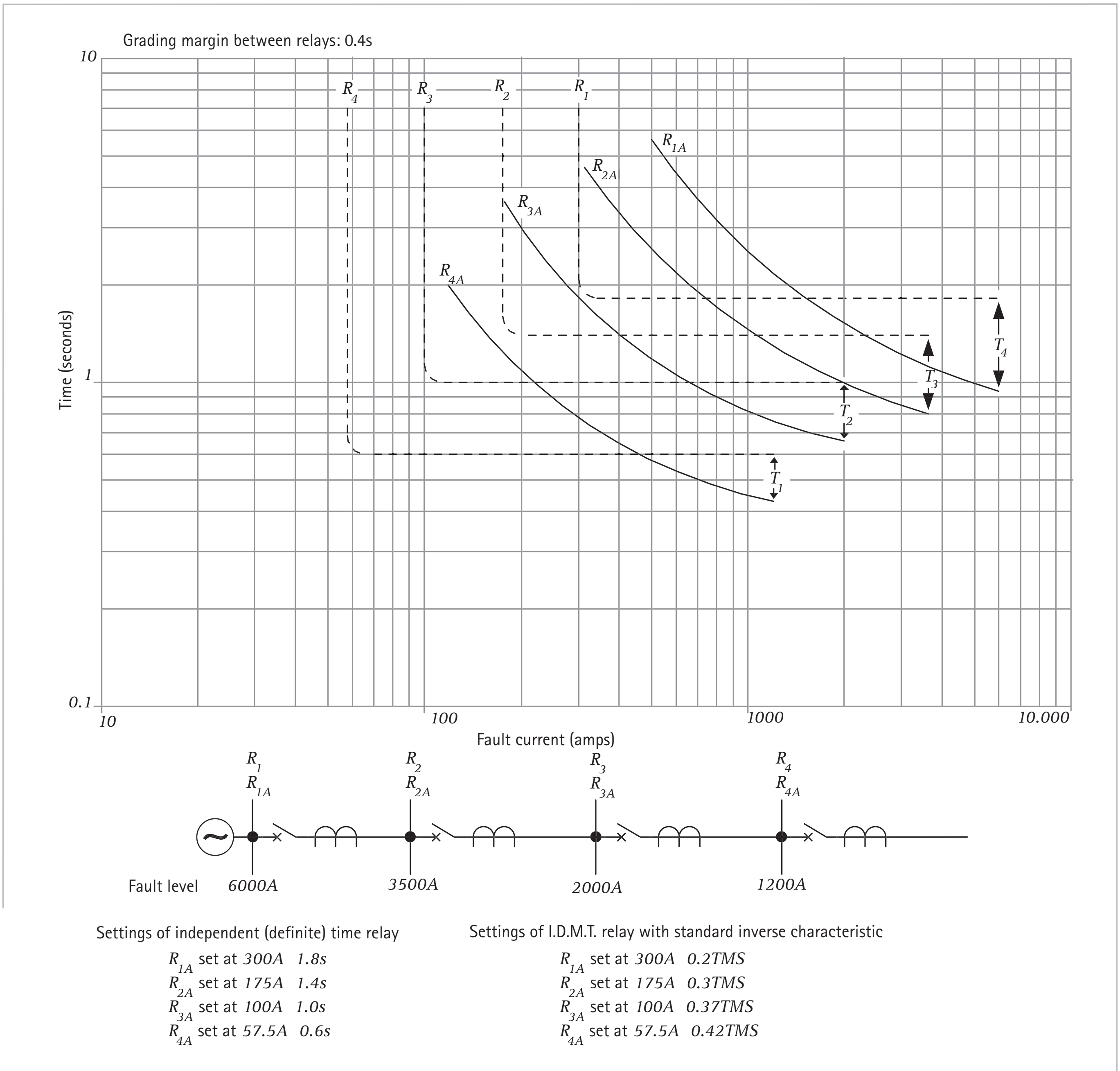


Figure 9.9: Comparison of definite time and standard I.D.M.T. relay

setting of at least 1.05 times the short-time rated current of the circuit is likely to be required.

9.11 RELAY TIME GRADING MARGIN

The time interval that must be allowed between the operation of two adjacent relays in order to achieve correct discrimination between them is called the *grading margin*. If a grading margin is not provided, or is insufficient, more than one relay will operate for a fault, leading to difficulties in determining the location of the fault and unnecessary loss of supply to some consumers.

The grading margin depends on a number of factors:

i. the fault current interrupting time of the circuit breaker

ii. relay timing errors

iii. the overshoot time of the relay

iv. CT errors

v. final margin on completion of operation

Factors (ii) and (iii) above depend to a certain extent on the relay technology used – an electromechanical relay, for instance, will have a larger overshoot time than a numerical relay.

Grading is initially carried out for the maximum fault level at the relaying point under consideration, but a check is also made that the required grading margin exists for all current levels between relay pick-up current and maximum fault level.

9.11.1 Circuit Breaker Interrupting Time

The circuit breaker interrupting the fault must have completely interrupted the current before the discriminating relay ceases to be energised. The time taken is dependent on the type of circuit breaker used and the fault current to be interrupted. Manufacturers normally provide the fault interrupting time at rated interrupting capacity and this value is invariably used in the calculation of grading margin.

9.11.2 Relay Timing Error

All relays have errors in their timing compared to the ideal characteristic as defined in IEC 60255. For a relay specified to IEC 60255, a relay error index is quoted that determines the maximum timing error of the relay. The timing error must be taken into account when determining the grading margin.

9.11.3 Overshoot

When the relay is de-energised, operation may continue for a little longer until any stored energy has been dissipated. For example, an induction disc relay will have stored kinetic energy in the motion of the disc; static relay circuits may have energy stored in capacitors. Relay design is directed to minimising and absorbing these energies, but some allowance is usually necessary.

The overshoot time is defined as the difference between the operating time of a relay at a specified value of input current and the maximum duration of input current, which when suddenly reduced below the relay operating level, is insufficient to cause relay operation.

9.11.4 CT Errors

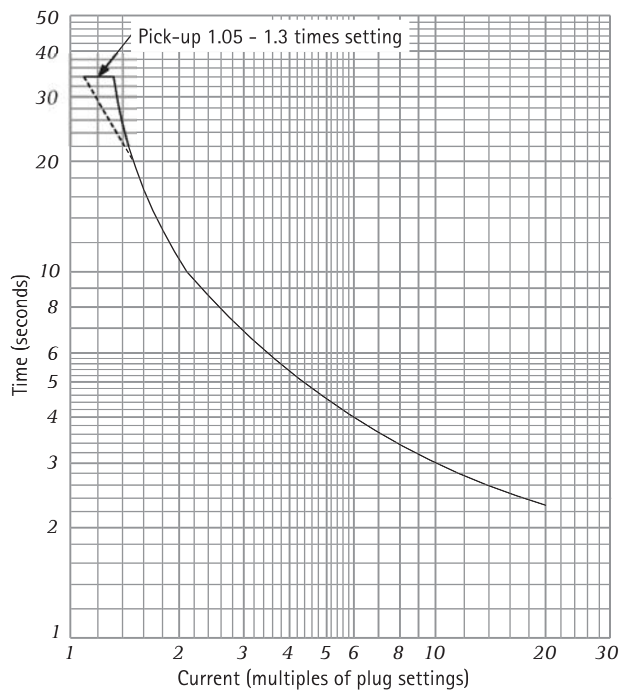
Current transformers have phase and ratio errors due to the exciting current required to magnetise their cores. The result is that the CT secondary current is not an identical scaled replica of the primary current. This leads to errors in the operation of relays, especially in the time of operation. CT errors are not relevant when independent definite-time delay overcurrent relays are being considered.

9.11.5 Final Margin

After the above allowances have been made, the discriminating relay must just fail to complete its operation. Some extra allowance, or safety margin, is required to ensure that relay operation does not occur.

9.11.6 Overall Accuracy

The overall limits of accuracy according to IEC 60255-4 for an IDMT relay with standard inverse characteristic are shown in Figure 9.10.



Time/Current characteristic allowable limit

At 2 times setting	2.5 x Declared error
At 5 times setting	1.5 x Declared error
At 10 times setting	1.0 x Declared error
At 20 times setting	1.0 x Declared error

Figure 9.10: Typical limits of accuracy from IEC 60255-4 for an inverse definite minimum time overcurrent relay

9.12 RECOMMENDED GRADING INTERVALS

The following sections give the recommended overall grading margins for between different protection devices.

9.12.1 Grading: Relay to Relay

The total interval required to cover the above items depends on the operating speed of the circuit breakers and the relay performance. At one time 0.5s was a normal grading margin. With faster modern circuit breakers and a lower relay overshoot time, 0.4s is reasonable, while under the best conditions even lower intervals may be practical.

The use of a fixed grading margin is popular, but it may be better to calculate the required value for each relay location. This more precise margin comprises a fixed time, covering circuit breaker fault interrupting time, relay overshoot time and a safety margin, plus a variable time that allows for relay and CT errors. Table 9.2 gives typical relay errors according to the technology used.

It should be noted that use of a fixed grading margin is only appropriate at high fault levels that lead to short relay operating times. At lower fault current levels, with longer operating times, the permitted error specified in IEC 60255 (7.5% of operating time) may exceed the fixed grading margin, resulting in the possibility that the relay fails to grade correctly while remaining within specification. This requires consideration when considering the grading margin at low fault current levels.

A practical solution for determining the optimum grading margin is to assume that the relay nearer to the fault has a maximum possible timing error of +2E, where E is the basic timing error. To this total effective error for the relay, a further 10% should be added for the overall current transformer error.

	Relay Technology			
	Electro-mechanical	Static	Digital	Numerical
Typical basic timing error (%)	7.5	5	5	5
Overshoot time (s)	0.05	0.03	0.02	0.02
Safety margin (s)	0.1	0.05	0.03	0.03
Typical overall grading margin - relay to relay(s)	0.4	0.35	0.3	0.3

Table 9.2: Typical relay timing errors - standard IDMT relays

A suitable minimum grading time interval, t', may be calculated as follows:

$$t' = \left[\frac{2E_R + E_{CT}}{100} \right] t + t_{CB} + t_o + t_s \text{ seconds}$$

...Equation 9.2

where:

E_r = relay timing error (IEC 60255-4)
E_{ct} = allowance for CT ratio error (%)
t = operating time of relay nearer fault (s)
t_{CB} = CB interrupting time (s)
t_o = relay overshoot time (s)
t_s = safety margin (s)

If, for example $t=0.5s$, the time interval for an electromechanical relay tripping a conventional circuit breaker would be 0.375s, whereas, at the lower extreme, for a static relay tripping a vacuum circuit breaker, the interval could be as low as 0.24s.

When the overcurrent relays have independent definite time delay characteristics, it is not necessary to include the allowance for CT error. Hence:

$$t' = \left[\frac{2E_R}{100} \right] t + t_{CB} + t_o + t_s \text{ seconds}$$

...Equation 9.3

Calculation of specific grading times for each relay can often be tedious when performing a protection grading calculation on a power system. Table 9.2 also gives practical grading times at high fault current levels between overcurrent relays for different technologies. Where relays of different technologies are used, the time appropriate to the technology of the downstream relay should be used.

9.12.2 Grading: Fuse to Fuse

The operating time of a fuse is a function of both the pre-arcing and arcing time of the fusing element, which follows an I^2t law. So, to achieve proper co-ordination between two fuses in series, it is necessary to ensure that the total I^2t taken by the smaller fuse is not greater than the pre-arcing I^2t value of the larger fuse. It has been established by tests that satisfactory grading between the two fuses will generally be achieved if the current rating ratio between them is greater than two.

9.12.3 Grading: Fuse to Relay

For grading inverse time relays with fuses, the basic approach is to ensure whenever possible that the relay backs up the fuse and not vice versa. If the fuse is upstream of the relay, it is very difficult to maintain correct discrimination at high values of fault current because of the fast operation of the fuse.

The relay characteristic best suited for this co-ordination with fuses is normally the extremely inverse (EI) characteristic as it follows a similar I^2t characteristic. To ensure satisfactory co-ordination between relay and fuse, the primary current setting of the relay should be approximately three times the current rating of the fuse. The grading margin for proper co-ordination, when expressed as a fixed quantity, should not be less than 0.4s or, when expressed as a variable quantity, should have a minimum value of:

$$t' = 0.4t + 0.15 \text{ seconds}$$

...Equation 9.4

where t is the nominal operating time of fuse.

Section 9.20.1 gives an example of fuse to relay grading.

9.13 CALCULATION OF PHASE FAULT OVERCURRENT RELAY SETTINGS

The correct co-ordination of overcurrent relays in a power system requires the calculation of the estimated relay settings in terms of both current and time.

The resultant settings are then traditionally plotted in suitable log/log format to show pictorially that a suitable grading margin exists between the relays at adjacent substations. Plotting may be done by hand, but nowadays is more commonly achieved using suitable software.

The information required at each relaying point to allow a relay setting calculation to proceed is given in Section 9.2. The principal relay data may be tabulated in a table similar to that shown in Table 9.3, if only to assist in record keeping.

Location	Fault Current (A)		Maximun Load Current (A)	CT Ratio	Relay Current Setting		Relay Time Multiplier Setting
	Maximun	Minimun			Per Cent	Primary Current (A)	

Table 9.3: Typical relay data table

It is usual to plot all time/current characteristics to a common voltage/MVA base on log/log scales. The plot includes all relays in a single path, starting with the relay nearest the load and finishing with the relay nearest the source of supply.

A separate plot is required for each independent path, and the settings of any relays that lie on multiple paths must be carefully considered to ensure that the final setting is appropriate for all conditions. Earth faults are considered separately from phase faults and require separate plots.

After relay settings have been finalised, they are entered in a table. One such table is shown in Table 9.3. This also assists in record keeping and during commissioning of the relays at site.

9.13.1 Independent (definite) Time Relays

The selection of settings for independent (definite) time relays presents little difficulty. The overcurrent elements must be given settings that are lower, by a reasonable margin, than the fault current that is likely to flow to a fault at the remote end of the system up to which back-up protection is required, with the minimum plant in service.

The settings must be high enough to avoid relay operation with the maximum probable load, a suitable margin being allowed for large motor starting currents or transformer inrush transients.

Time settings will be chosen to allow suitable grading margins, as discussed in Section 9.12.

9.13.2 Inverse Time Relays

When the power system consists of a series of short sections of cable, so that the total line impedance is low, the value of fault current will be controlled principally by the impedance of transformers or other fixed plant and will not vary greatly with the location of the fault. In such cases, it may be possible to grade the inverse time relays in very much the same way as definite time relays. However, when the prospective fault current varies substantially with the location of the fault, it is possible to make use of this fact by employing both current and time grading to improve the overall performance of the relay.

The procedure begins by selection of the appropriate relay characteristics. Current settings are then chosen, with finally the time multiplier settings to give appropriate grading margins between relays. Otherwise, the procedure is similar to that for definite time delay relays. An example of a relay setting study is given in Section 9.20.1.

9.14 DIRECTIONAL PHASE FAULT OVERCURRENT RELAYS

When fault current can flow in both directions through the relay location, it may be necessary to make the response of the relay directional by the introduction of a directional control facility. The facility is provided by use of additional voltage inputs to the relay.

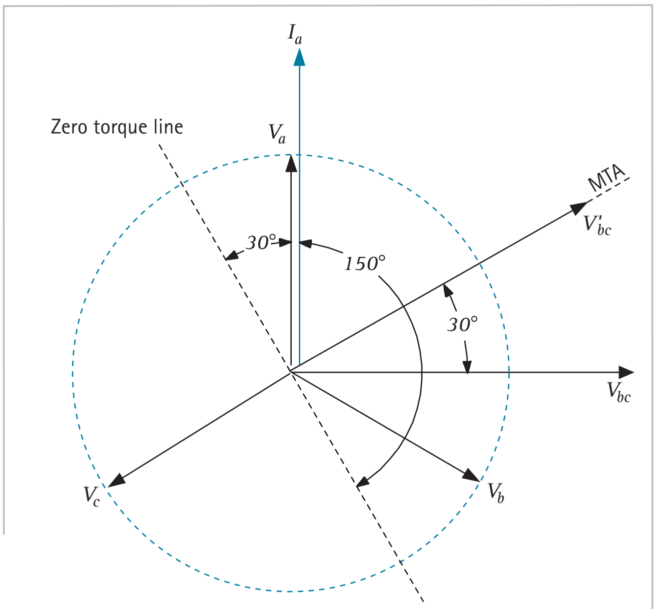
9.14.1 Relay Connections

There are many possibilities for a suitable connection of voltage and current inputs. The various connections are dependent on the phase angle, at unity system power factor, by which the current and voltage applied to the relay are displaced. Reference [9.1] details all of the connections that have been used. However, only very few are used in current practice and these are described below.

In a digital or numerical relay, the phase displacements are realised by the use of software, while electromechanical and static relays generally obtain the required phase displacements by suitable connection of the input quantities to the relay. The history of the topic results in the relay connections being defined as if they were obtained by suitable connection of the input quantities, irrespective of the actual method used.

9.14.2 90° Relay Quadrature Connection

This is the standard connection for static, digital or numerical relays. Depending on the angle by which the applied voltage is shifted to produce maximum relay sensitivity (the Relay Characteristic Angle, or RCA) two types are available.



A phase element connected I_a V_{bc}

B phase element connected I_b V_{ca}

C phase element connected I_c V_{ab}

Figure 9.11: Vector diagram for the 90°-30° connection (phase A element)

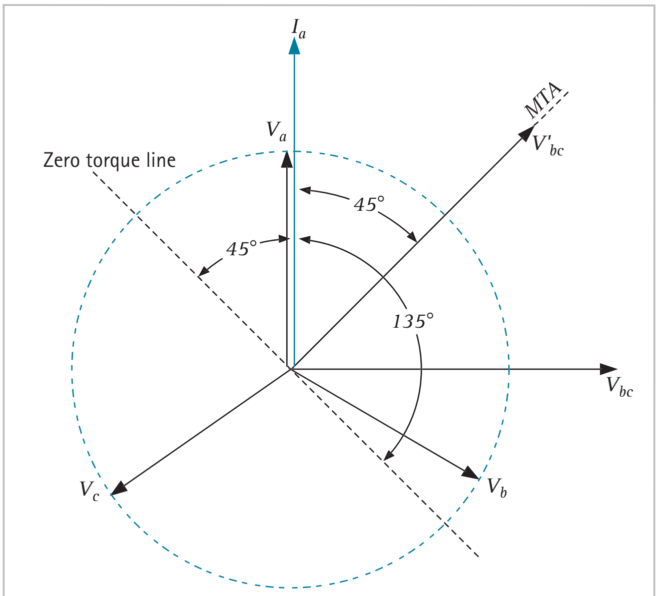
9.14.2.1 90°-30° characteristic (30° RCA)

The A phase relay element is supplied with I_a current and V_{bc} voltage displaced by 30° in an anti-clockwise direction. In this case, the relay maximum sensitivity is produced when the current lags the system phase to neutral voltage by 60°. This connection gives a correct directional tripping zone over the current range of 30° leading to 150° lagging; see Figure 9.11. The relay sensitivity at unity power factor is 50% of the relay maximum sensitivity and 86.6% at zero power factor lagging. This characteristic is recommended when the relay is used for the protection of plain feeders with the zero sequence source behind the relaying point.

9.14.2.2 90°-45° characteristic (45° RCA)

The A phase relay element is supplied with current I_a and voltage V_{bc} displaced by 45° in an anti-clockwise direction. The relay maximum sensitivity is produced when the current lags the system phase to neutral voltage by 45°. This connection gives a correct directional tripping zone over the current range of 45° leading to 135° lagging. The relay sensitivity at unity power factor is 70.7% of the maximum torque and the same at zero power factor lagging; see Figure 9.12.

This connection is recommended for the protection of transformer feeders or feeders that have a zero sequence source in front of the relay. It is essential in the case of parallel transformers or transformer feeders, in order to ensure correct relay operation for faults beyond the star/delta transformer. This connection should also be used whenever single-phase directional relays are applied to a circuit where a current distribution of the form 2-1-1 may arise.



A phase element connected I_a V_{bc}

B phase element connected I_b V_{ca}

C phase element connected I_c V_{ab}

Figure 9.12: Vector diagram for the 90°-45° connection (phase A element)

For a digital or numerical relay, it is common to allow user-selection of the RCA angle within a wide range.

Theoretically, three fault conditions can cause maloperation of the directional element:

i. a phase-phase-ground fault on a plain feeder

ii. a phase-ground fault on a transformer feeder with the zero sequence source in front of the relay

iii. a phase-phase fault on a power transformer with the relay looking into the delta winding of the transformer

It should be remembered, however, that the conditions assumed above to establish the maximum angular displacement between the current and voltage quantities at the relay are such that, in practice, the magnitude of the current input to the relay would be insufficient to cause the overcurrent element to operate. It can be shown analytically that the possibility of maloperation with the 90°-45° connection is, for all practical purposes, non-existent.

9.14.3 Application of Directional Relays

If non-unit, non-directional relays are applied to parallel feeders having a single generating source, any faults that might occur on any one line will, regardless of the relay settings used, isolate both lines and completely disconnect the power supply. With this type of system configuration, it is necessary to apply directional relays at the receiving end and to grade them with the non-directional relays at the sending end, to ensure correct discriminative operation of the relays during line faults. This is done by setting the directional relays R_1' and R_2' in Figure 9.13 with their directional elements looking into the protected line, and giving them lower time and current settings than relays R_1 and R_2. The usual practice is to set relays R_1' and R_2' to 50% of the normal full load of the protected circuit and 0.1TMS, but care must be taken to ensure that the continuous thermal rating of the relays of twice rated current is not exceeded. An example calculation is given in Section 9.20.3

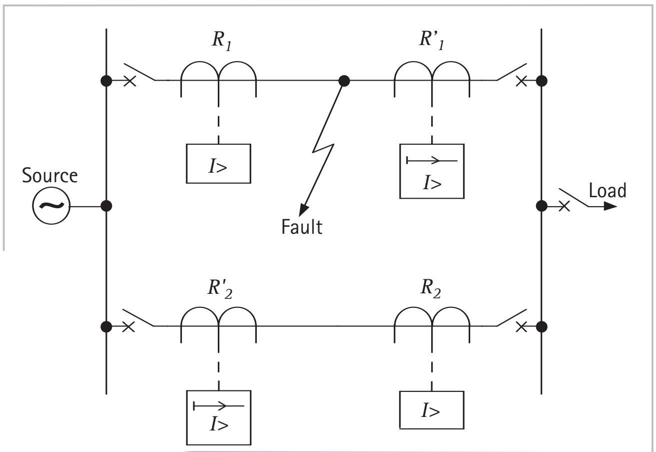


Figure 9.13: Directional relays applied to parallel feeders

9.15 RING MAINS

A particularly common arrangement within distribution networks is the Ring Main. The primary reason for its use is to maintain supplies to consumers in case of fault conditions occurring on the interconnecting feeders. A typical ring main with associated overcurrent protection is shown in Figure 9.14. Current may flow in either direction through the various relay locations, and therefore directional overcurrent relays are applied.

In the case of a ring main fed at one point only, the settings of the relays at the supply end and at the mid-point substation are identical. They can therefore be made non-directional, if, in the latter case, the relays are located on the same feeder, that is, one at each end of the feeder.

It is interesting to note that when the number of feeders round the ring is an even number, the two relays with the same operating time are at the same substation. They will therefore have to be directional. When the number of feeders is an odd number, the two relays with the same operating time are at different substations and therefore do not need to be directional. It may also be noted that, at intermediate substations, whenever the operating time of the relays at each substation are different, the difference between their operating times is never less than the grading margin, so the relay with the longer operating time can be non-directional. With modern numerical relays, a directional facility is often available for little or no extra cost, so that it may be simpler in practice to apply directional relays at all locations. Also, in the event of an additional feeder being added subsequently, the relays that can be non-directional need to be re-determined and will not necessarily be the same – giving rise to problems of changing a non-directional relay for a directional one. If a VT was not provided originally, this may be very difficult to install at a later date.

9.15.1 Grading of Ring Mains

The usual grading procedure for relays in a ring main circuit is to open the ring at the supply point and to grade the relays first clockwise and then anti-clockwise. That is, the relays looking in a clockwise direction around the ring are arranged to operate in the sequence 1-2-3-4-5-6 and the relays looking in the anti-clockwise direction are arranged to operate in the sequence 1'-2'-3'-4'-5'-6', as shown in Figure 9.14.

The arrows associated with the relaying points indicate the direction of current flow that will cause the relay to operate. A double-headed arrow is used to indicate a non-directional relay, such as those at the supply point where the power can flow only in one direction. A single-headed arrow is used to indicate a directional

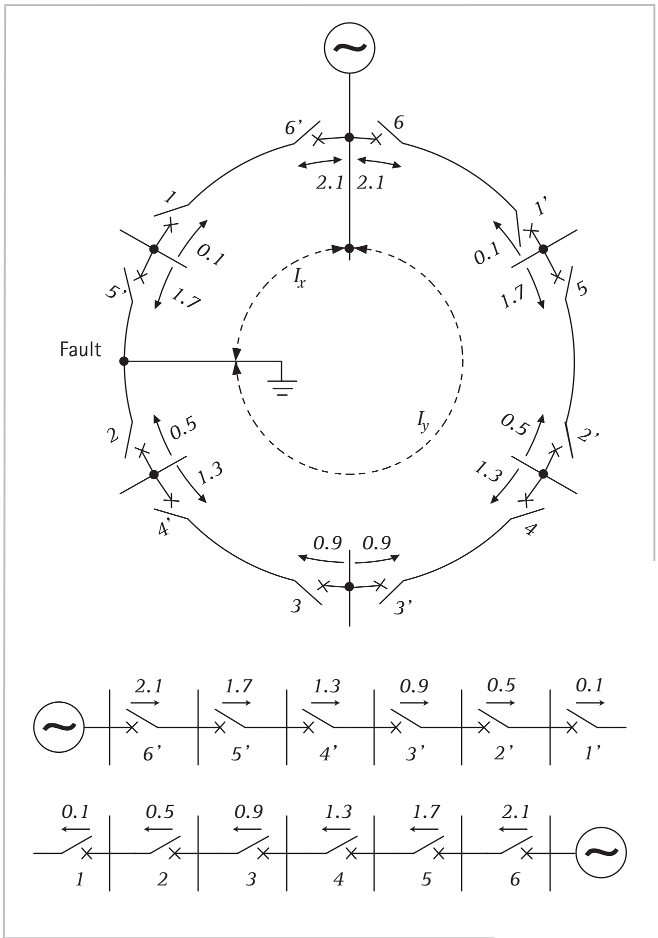


Figure 9.14: Grading of ring mains

relay, such as those at intermediate substations around the ring where the power can flow in either direction. The directional relays are set in accordance with the invariable rule, applicable to all forms of directional protection, that the current in the system must flow from the substation busbars into the protected line in order that the relays may operate.

Disconnection of the faulted line is carried out according to time and fault current direction. As in any parallel system, the fault current has two parallel paths and divides itself in the inverse ratio of their impedances. Thus, at each substation in the ring, one set of relays will be made inoperative because of the direction of current flow, and the other set operative. It will also be found that the operating times of the relays that are inoperative are faster than those of the operative relays, with the exception of the mid-point substation, where the operating times of relays 3 and 3' happen to be the same.

The relays that are operative are graded downwards towards the fault and the last to be affected by the fault operates first. This applies to both paths to the fault. Consequently, the faulted line is the only one to be disconnected from the ring and the power supply is maintained to all the substations.

When two or more power sources feed into a ring main, time graded overcurrent protection is difficult to apply and full discrimination may not be possible. With two sources of supply, two solutions are possible. The first is to open the ring at one of the supply points, whichever is more convenient, by means of a suitable high set instantaneous overcurrent relay. The ring is then graded as in the case of a single infeed. The second method is to treat the section of the ring between the two supply points as a continuous bus separate from the ring and to protect it with a unit protection system, and then proceed to grade the ring as in the case of a single infeed. Section 9.20.4 provides a worked example of ring main grading.

9.16 EARTH FAULT PROTECTION

In the foregoing description, attention has been principally directed towards phase fault overcurrent protection. More sensitive protection against earth faults can be obtained by using a relay that responds only to the residual current of the system, since a residual component exists only when fault current flows to earth. The earth-fault relay is therefore completely unaffected by load currents, whether balanced or not, and can be given a setting which is limited only by the design of the equipment and the presence of unbalanced leakage or capacitance currents to earth. This is an important consideration if settings of only a few percent of system rating are considered, since leakage currents may produce a residual quantity of this order.

On the whole, the low settings permissible for earth-fault relays are very useful, as earth faults are not only by far the most frequent of all faults, but may be limited in magnitude by the neutral earthing impedance, or by earth contact resistance.

The residual component is extracted by connecting the line current transformers in parallel as shown in Figure 9.15. The simple connection shown in Figure 9.15(a) can be extended by connecting overcurrent elements in the individual phase leads, as illustrated in Figure 9.15(b), and inserting the earth-fault relay between the star points of the relay group and the current transformers.

Phase fault overcurrent relays are often provided on only two phases since these will detect any interphase fault; the connections to the earth-fault relay are unaffected by this consideration. The arrangement is illustrated in Figure 9.15(c).

The typical settings for earth-fault relays are 30%-40% of the full-load current or minimum earth-fault current on the part of the system being protected. However, account may have to be taken of the variation of setting with relay burden as described in Section 9.16.1 below. If greater sensitivity than this is required, one of the methods described in Section 9.16.3 for obtaining sensitive earth-fault protection must be used.

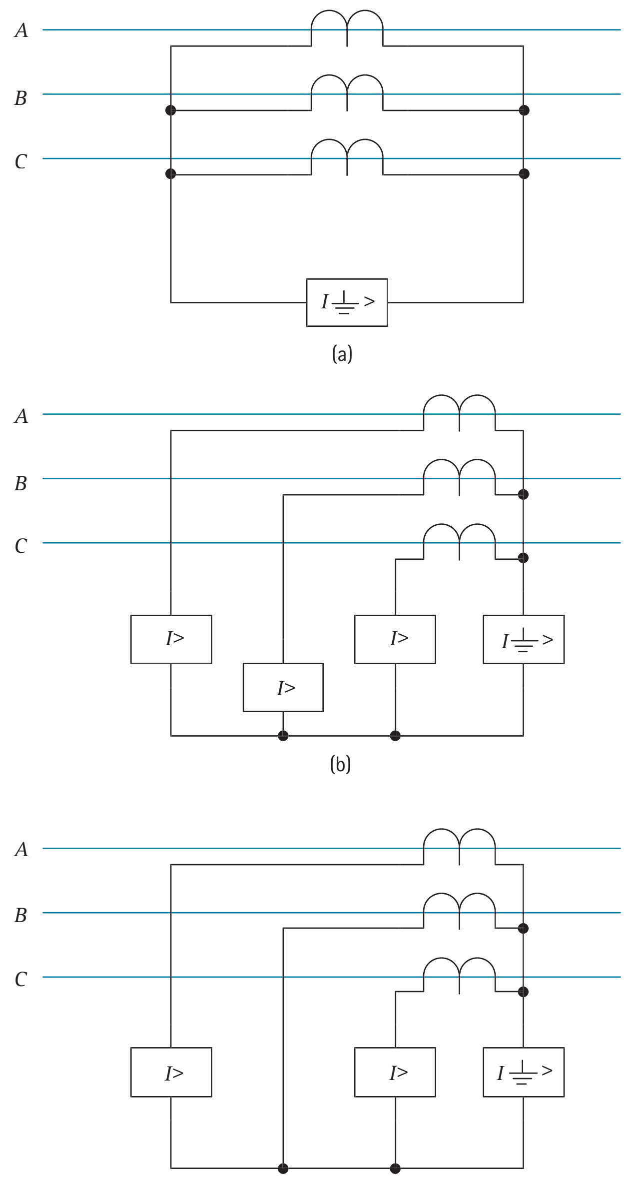


Figure 9.15: Residual connection of current transformers to earth-fault relays

9.16.1 Effective Setting of Earth-Fault Relays

The primary setting of an overcurrent relay can usually be taken as the relay setting multiplied by the CT ratio. The CT can be assumed to maintain a sufficiently accurate ratio so that, expressed as a percentage of rated current, the primary setting will be directly proportional to the relay setting. However, this may not be true for an earth-fault relay. The performance varies according to the relay technology used.

9.16.1.1 Static, digital and numerical relays

When static, digital or numerical relays are used the relatively low value and limited variation of the relay burden over the relay setting range results in the above statement holding true. The variation of input burden with current should be checked to ensure that the variation is sufficiently small. If not, substantial errors may occur, and the setting procedure will have to follow that for electromechanical relays.

9.16.1.2 Electromechanical relays

When using an electromechanical relay, the earth-fault element generally will be similar to the phase elements. It will have a similar VA consumption at setting, but will impose a far higher burden at nominal or rated current, because of its lower setting. For example, a relay with a setting of 20% will have an impedance of 25 times that of a similar element with a setting of 100%. Very frequently, this burden will exceed the rated burden of the current transformers. It might be thought that correspondingly larger current transformers should be used, but this is considered to be unnecessary. The current transformers that handle the phase burdens can operate the earth fault relay and the increased errors can easily be allowed for.

Not only is the exciting current of the energising current transformer proportionately high due to the large burden of the earth-fault relay, but the voltage drop on this relay is impressed on the other current transformers of the paralleled group, whether they are carrying primary current or not. The total exciting current is therefore the product of the magnetising loss in one CT and the number of current transformers in parallel. The summated magnetising loss can be appreciable in comparison with the operating current of the relay, and in extreme cases where the setting current is low or the current transformers are of low performance, may even exceed the output to the relay. The 'effective setting current' in secondary terms is the sum of the relay setting current and the total excitation loss. Strictly speaking, the effective setting is the vector sum of the relay setting current and the total exciting current, but the arithmetic sum is near enough, because of the similarity of power factors. It is instructive to calculate the effective setting for a range of setting values of a relay, a process that is set out in Table 9.4, with the results illustrated in Figure 9.16.

The effect of the relatively high relay impedance and the summation of CT excitation losses in the residual circuit is augmented still further by the fact that, at setting, the flux density in the current transformers corresponds to the bottom bend of the excitation characteristic. The exciting impedance under this condition is relatively low, causing the ratio error to be high. The current transformer actually improves in performance with increased primary current, while the relay impedance decreases until, with an input current several times greater than the primary setting, the multiple of setting current in the relay is appreciably higher than the multiple of primary setting current which is applied to the primary circuit. This causes the relay operating time to be shorter than might be expected.

At still higher input currents, the CT performance falls off until finally the output current ceases to increase substantially. Beyond this value of input current, operation is further complicated by distortion of the output current waveform.

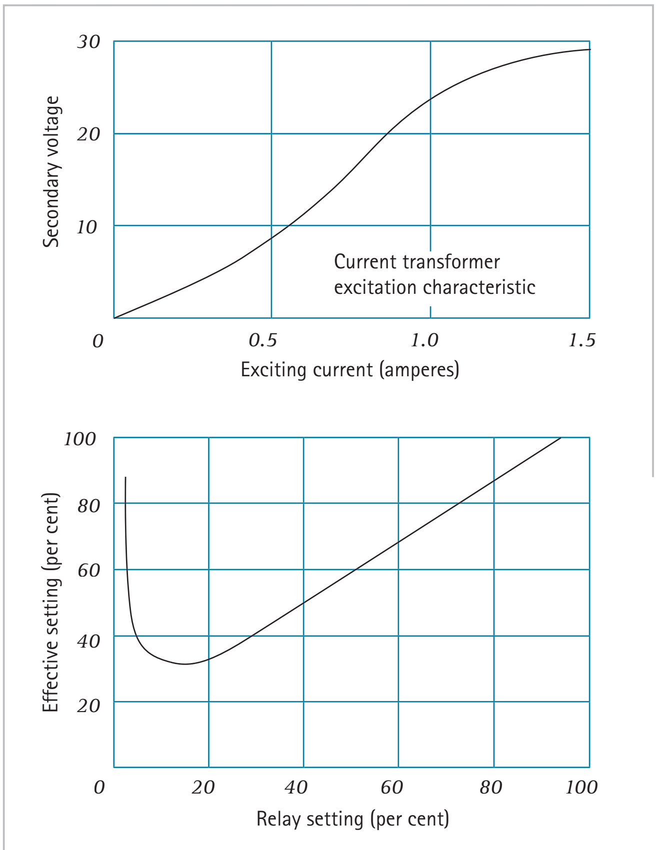


Figure 9.16: Effective setting of earth-fault relay

Relay Plug Setting %	Relay Plug Setting Current (A)	Coil voltage at Setting (V)	Exciting Current I_e	Effective Setting Current (A)	Effective Setting %
5	0.25	12	0.583	2	40
10	0.5	6	0.405	1.715	34.3
15	0.75	4	0.3	1.65	33
20	1	3	0.27	1.81	36
40	2	1.5	0.17	2.51	50
60	3	1	0.12	3.36	67
80	4	0.75	0.1	4.3	86
100	5	0.6	0.08	5.24	105

Table 9.4: Calculation of effective settings

9.16.2 Time Grading of Earth-Fault Relays

The time grading of earth-fault relays can be arranged in the same manner as for phase fault relays. The time/primary current characteristic for electro-mechanical relays cannot be kept proportionate to the relay characteristic with anything like the accuracy that is possible for phase fault relays. As shown above, the ratio error of the current transformers at relay setting current may be very high. It is clear that time grading of electromechanical earth-fault relays is not such a simple matter as the procedure adopted for phase relays in Table 9.3. Either the above factors must be taken into account with the errors calculated for each current level, making the process much more tedious, or longer grading margins must be allowed. However, for other types of relay, the procedure adopted for phase fault relays can be used.

9.16.3 Sensitive Earth-Fault Protection

LV systems are not normally earthed through an impedance, due to the resulting overvoltages that may occur and consequential safety implications. HV systems may be designed to accommodate such overvoltages, but not the majority of LV systems.

However, it is quite common to earth HV systems through an impedance that limits the earth-fault current. Further, in some countries, the resistivity of the earth path may be very high due to the nature of the ground itself (e.g. desert or rock). A fault to earth not involving earth conductors may result in the flow of only a small current, insufficient to operate a normal protection system. A similar difficulty also arises in the case of broken line conductors, which, after falling on to hedges or dry metalled roads, remain energised because of the low leakage current, and therefore present a danger to life.

To overcome the problem, it is necessary to provide an earth-fault protection system with a setting that is considerably lower than the normal line protection. This presents no difficulty to a modern digital or numerical relay. However, older electromechanical or static relays may present difficulties due to the high effective burden they may present to the CT.

The required sensitivity cannot normally be provided by means of conventional CT's. A core balance current transformer (CBCT) will normally be used. The CBCT is a current transformer mounted around all three phase (and neutral if present) conductors so that the CT secondary current is proportional to the residual (i.e. earth) current. Such a CT can be made to have any convenient ratio suitable for operating a sensitive earth-fault relay element. By use of such techniques, earth fault settings down to 10% of the current rating of the circuit to be protected can be obtained.

Care must be taken to position a CBCT correctly in a cable circuit. If the cable sheath is earthed, the earth connection from the cable gland/sheath junction must be taken through the CBCT primary to ensure that phase-sheath faults are detected. Figure 9.17 shows the correct and incorrect methods. With the incorrect method, the fault current in the sheath is not seen as an unbalance current and hence relay operation does not occur.

The normal residual current that may flow during healthy conditions limits the application of non-directional sensitive earth-fault protection. Such residual effects can occur due to unbalanced leakage or capacitance in the system.

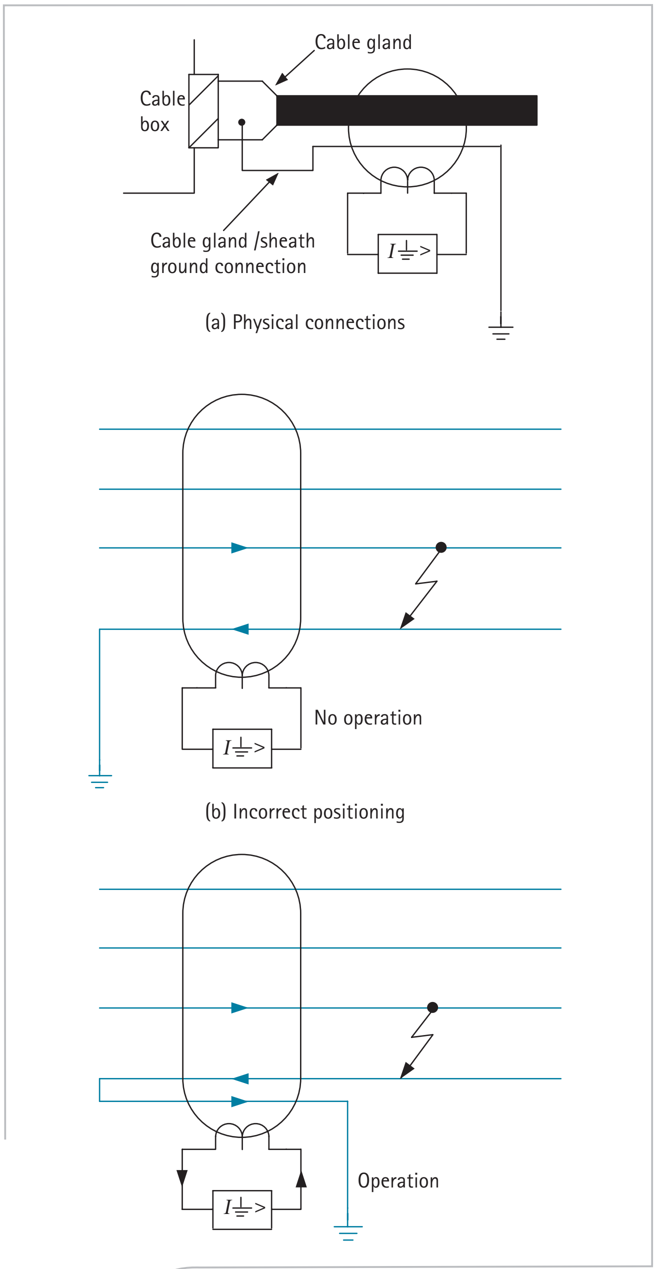


Figure 9.17: Positioning of core balance current transformers

9.17 DIRECTIONAL EARTH-FAULT OVERCURRENT PROTECTION

Directional earth-fault overcurrent may need to be applied in the following situations:

i. for earth-fault protection where the overcurrent protection is by directional relays

ii. in insulated-earth networks

iii. in Petersen coil earthed networks

iv. where the sensitivity of sensitive earth-fault protection is insufficient – use of a directional earth-fault relay may provide greater sensitivity

The relay elements previously described as phase fault elements respond to the flow of earth fault current, and it is important that their directional response be correct for this condition. If a special earth fault element is provided as described in Section 9.16 (which will normally be the case), a related directional element is needed.

9.17.1 Relay Connections

The residual current is extracted as shown in Figure 9.15. Since this current may be derived from any phase, in order to obtain a directional response it is necessary to obtain an appropriate quantity to polarise the relay. In digital or numerical relays there are usually two choices provided.

9.17.1.1 Residual voltage

A suitable quantity is the residual voltage of the system. This is the vector sum of the individual phase voltages. If the secondary windings of a three-phase, five limb voltage transformer or three single-phase units are connected in broken delta, the voltage developed across its terminals will be the vector sum of the phase to ground voltages and hence the residual voltage of the system, as illustrated in Figure 9.18.

The primary star point of the VT must be earthed. However, a three-phase, three limb VT is not suitable, as there is no path for the residual magnetic flux.

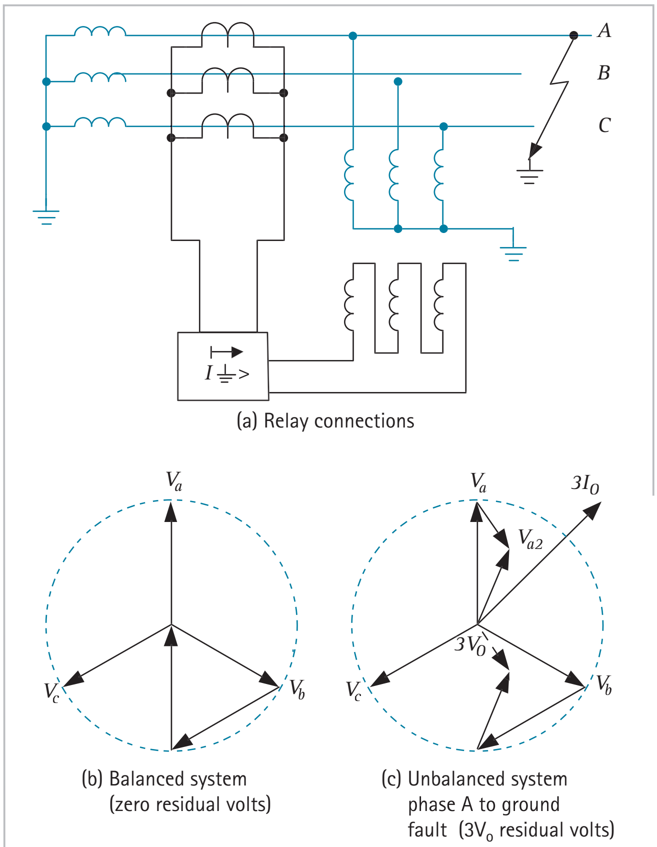


Figure 9.18: Voltage polarised directional earth fault relay

When the main voltage transformer associated with the high voltage system is not provided with a broken delta secondary winding to polarise the directional earth fault relay, it is permissible to use three single-phase interposing voltage transformers. Their primary windings are connected in star and their secondary windings are connected in broken delta. For satisfactory operation, however, it is necessary to ensure that the main voltage transformers are of a suitable construction to reproduce the residual voltage and that the star point of the primary winding is solidly earthed. In addition, the star point of the primary windings of the interposing voltage transformers must be connected to the star point of the secondary windings of the main voltage transformers.

The residual voltage will be zero for balanced phase voltages. For simple earth-fault conditions, it will be equal to the depression of the faulted phase voltage. In all cases the residual voltage is equal to three times the zero sequence voltage drop on the source impedance and is therefore displaced from the residual current by the characteristic angle of the source impedance. The residual quantities are applied to the directional element of the earth-fault relay.

The residual current is phase offset from the residual voltage and hence angle adjustment is required. Typically, the current will lag the polarising voltage. The method of system earthing also affects the Relay Characteristic Angle (RCA), and the following settings are usual:

i. resistance-earthed system: 0° RCA

ii. distribution system, solidly-earthed: -45° RCA

iii. transmission system, solidly-earthed: -60° RCA

The different settings for distribution and transmission systems arise from the different X/R ratios found in these systems.

9.17.1.2 Negative sequence current

The residual voltage at any point in the system may be insufficient to polarise a directional relay, or the voltage transformers available may not satisfy the conditions for providing residual voltage. In these circumstances, negative sequence current can be used as the polarising quantity. The fault direction is determined by comparison of the negative sequence voltage with the negative sequence current. The RCA must be set based on the angle of the negative phase sequence source voltage.

9.18 EARTH-FAULT PROTECTION ON INSULATED NETWORKS

Occasionally, a power system is run completely insulated from earth. The advantage of this is that a single phase-earth fault on the system does not cause any earth fault current to flow, and so the whole system remains operational. The system must be designed to withstand high transient and steady-state overvoltages however, so its use is generally restricted to low and medium voltage systems.

It is vital that detection of a single phase-earth fault is achieved, so that the fault can be traced and rectified. While system operation is unaffected for this condition, the occurrence of a second earth fault allows substantial currents to flow.

The absence of earth-fault current for a single phase-earth fault clearly presents some difficulties in fault detection. Two methods are available using modern relays.

9.18.1 Residual Voltage

When a single phase-earth fault occurs, the healthy phase voltages rise by a factor of √3 and the three phase voltages no longer have a phasor sum of zero. Hence, a residual voltage element can be used to detect the fault. However, the method does not provide any discrimination, as the unbalanced voltage occurs on the whole of the affected section of the system. One advantage of this method is that no CT's are required, as voltage is being measured. However, the requirements for the VT's as given in Section 9.17.1.1 apply.

Grading is a problem with this method, since all relays in the affected section will see the fault. It may be possible to use definite-time grading, but in general, it is not possible to provide fully discriminative protection using this technique.

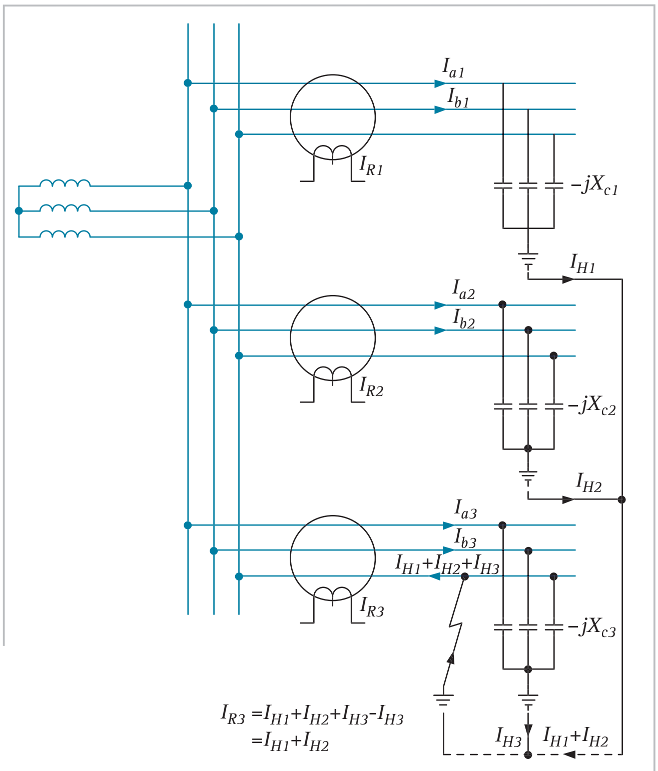


Figure 9.19: Current distribution in an insulated system with a C phase –earth fault

9.18.2 Sensitive Earth Fault

This method is principally applied to MV systems, as it relies on detection of the imbalance in the per-phase charging currents that occurs.

Figure 9.19 illustrates the situation that occurs when a single phase-earth fault is present. The relays on the healthy feeders see the unbalance in charging currents for their own feeders. The relay in the faulted feeder sees the charging currents in the rest of the system, with the current of its' own feeders cancelled out. Figure 9.20 shows the phasor diagram.

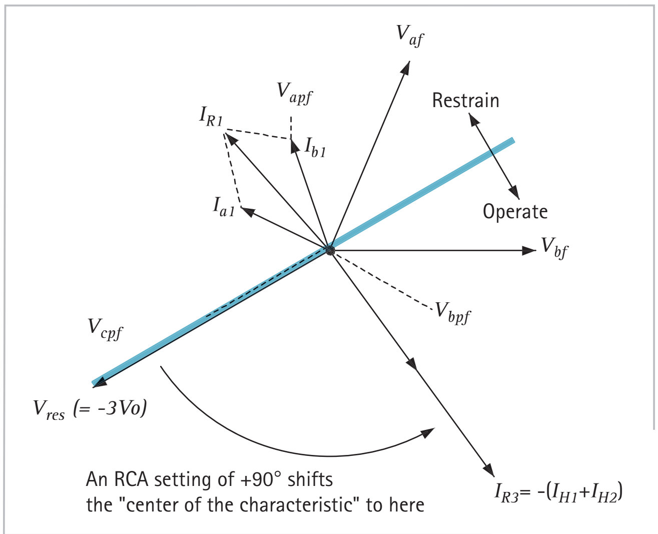


Figure 9.20: Phasor diagram for insulated system with C phase-earth fault

Use of Core Balance CT's is essential. With reference to Figure 9.20, the unbalance current on the healthy feeders lags the residual voltage by 90°. The charging currents on these feeders will be √3 times the normal value, as the phase-earth voltages have risen by this amount. The magnitude of the residual current is therefore three times the steady-state charging current per phase. As the residual currents on the healthy and faulted feeders are in antiphase, use of a directional earth fault relay can provide the discrimination required.

The polarising quantity used is the residual voltage. By shifting this by 90°, the residual current seen by the relay on the faulted feeder lies within the 'operate' region of the directional characteristic, while the residual currents on the healthy feeders lie within the 'restrain' region. Thus, the RCA required is 90°. The relay setting has to lie between one and three times the per-phase charging current.

This may be calculated at the design stage, but confirmation by means of tests on-site is usual. A single phase-earth fault is deliberately applied and the resulting currents noted, a process made easier in a modern digital or numeric relay by the measurement facilities provided. As noted earlier, application of such a fault for a short period does not involve any disruption to the network, or fault currents, but the duration should be as short as possible to guard against a second such fault occurring.

It is also possible to dispense with the directional element if the relay can be set at a current value that lies between the charging current on the feeder to be protected and the charging current of the rest of the system.

9.19 EARTH FAULT PROTECTION ON PETERSEN COIL EARTHED NETWORKS

Petersen Coil earthing is a special case of high impedance earthing. The network is earthed via a reactor, whose reactance is made nominally equal to the total system capacitance to earth. Under this condition, a single phase-earth fault does not result in any earth fault current in steady-state conditions. The effect is therefore similar to having an insulated system. The effectiveness of the method is dependent on the accuracy of tuning of the reactance value – changes in system capacitance (due to system configuration changes for instance) require changes to the coil reactance. In practice, perfect matching of the coil reactance to the system capacitance is difficult to achieve, so that a small earth fault current will flow. Petersen Coil earthed systems are commonly found in areas where the system consists mainly of rural overhead lines, and are particularly beneficial in locations subject to a high incidence of transient faults.

To understand how to correctly apply earth fault protection to such systems, system behaviour under earth fault conditions must first be understood.

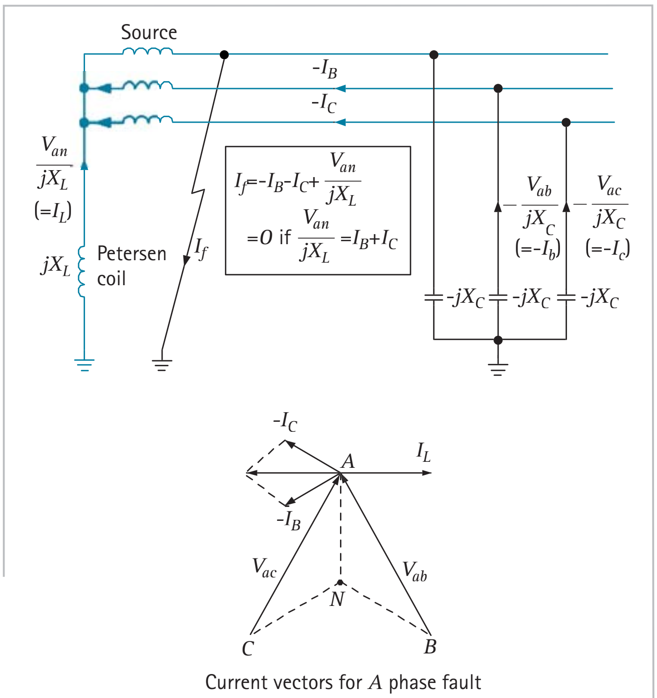


Figure 9.21: Earth fault in Petersen Coil earthed system

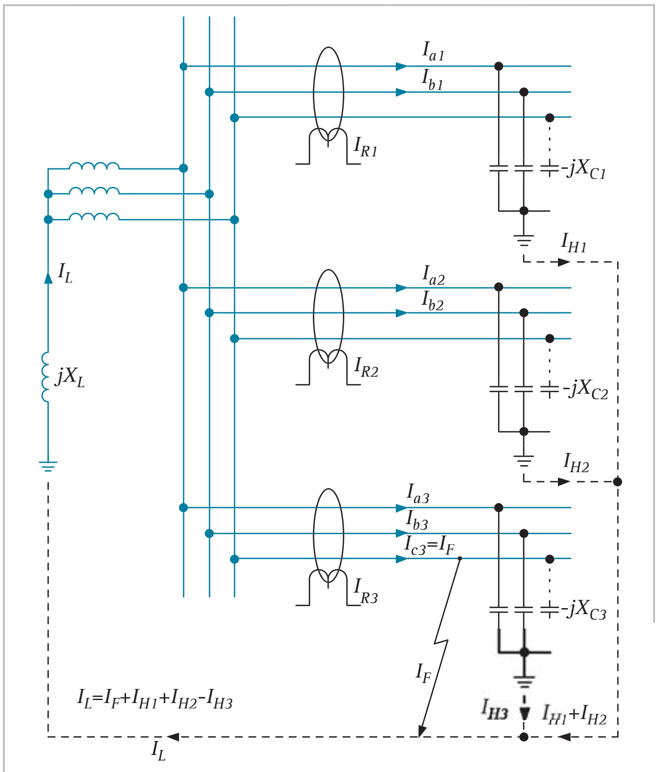


Figure 9.22: Distribution of currents during a C phase-earth fault – radial distribution system

Figure 9.21 illustrates a simple network earthed through a Petersen Coil. The equations clearly show that, if the reactor is correctly tuned, no earth fault current will flow.

Figure 9.22 shows a radial distribution system earthed using a Petersen Coil. One feeder has a phase-earth fault on phase C. Figure 9.23 shows the resulting phasor diagrams, assuming that no resistance is present.

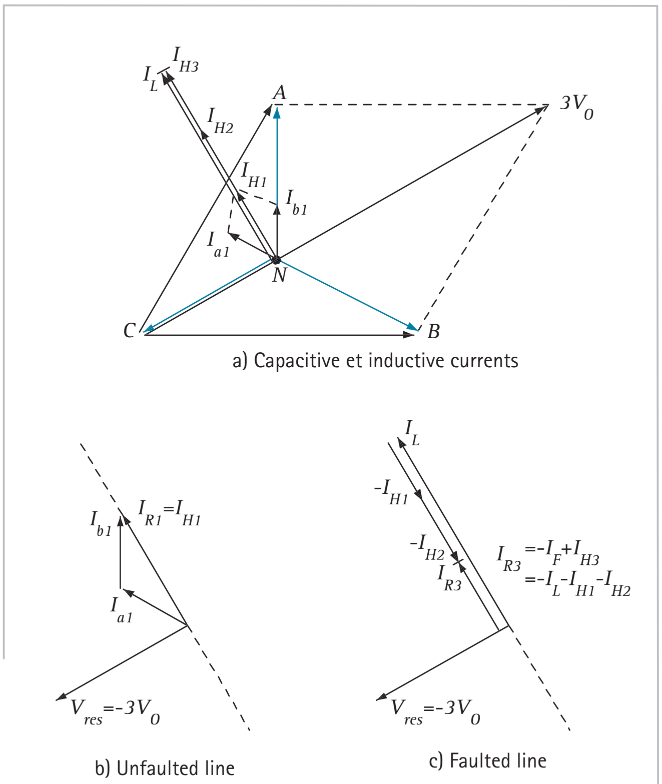


Figure 9.23: C phase-earth fault in Petersen Coil earthed network: theoretical case –no resistance present in X_L or X_C

In Figure 9.23(a), it can be seen that the fault causes the healthy phase voltages to rise by a factor of √3 and the charging currents lead the voltages by 90°.

Using a CBCT, the unbalance currents seen on the healthy feeders can be seen to be a simple vector addition of I_{a1} and I_{b1}, and this lies at exactly 90° lagging to the residual voltage (Figure 9.23(b)). The magnitude of the residual current I_{R1} is equal to three times the steady-state charging current per phase. On the faulted feeder, the residual current is equal to I_L-I_{H1}-I_{H2}, as shown in Figure 9.23(c) and more clearly by the zero sequence network of Figure 9.24.

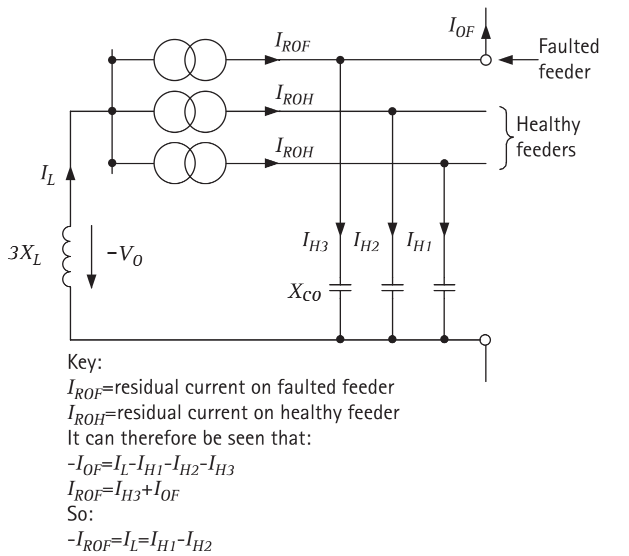


Figure 9.24: Zero sequence network showing residual currents

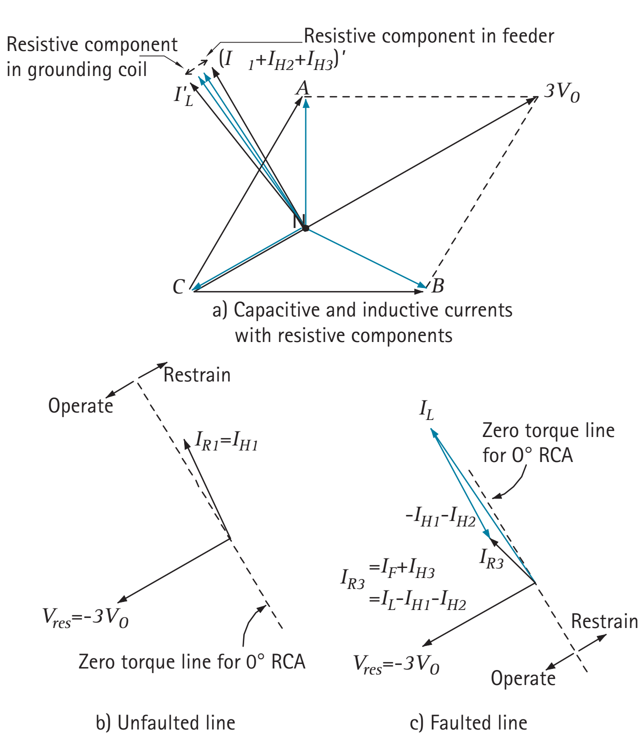


Figure 9.25: C phase-earth fault in Petersen Coil earthed network: practical case with resistance present in X_L or X_C

However, in practical cases, resistance is present and Figure 9.25 shows the resulting phasor diagrams. If the residual voltage V_{res} is used as the polarising voltage, the residual current is phase shifted by an angle less than 90° on the faulted feeder and greater than 90° on the healthy feeders.

Hence a directional relay can be used, and with an RCA of 0°, the healthy feeder residual current will fall in the 'restrain' area of the relay characteristic while the faulted feeder residual current falls in the 'operate' area.

Often, a resistance is deliberately inserted in parallel with the Petersen Coil to ensure a measurable earth fault current and increase the angular difference between the residual signals to aid relay application.

Having established that a directional relay can be used, two possibilities exist for the type of protection element that can be applied – sensitive earth fault and zero sequence wattmetric.

9.19.1 Sensitive Earth Fault Protection

To apply this form of protection, the relay must meet two requirements:

a. current measurement setting capable of being set to very low values

b. an RCA of 0°, and capable of fine adjustment around this value

The sensitive current element is required because of the very low current that may flow – so settings of less than 0.5% of rated current may be required. However, as compensation by the Petersen Coil may not be perfect, low levels of steady-state earth-fault current will flow and increase the residual current seen by the relay. An often used setting value is the per phase charging current of the circuit being protected.

Fine tuning of the RCA is also required about the 0° setting, to compensate for coil and feeder resistances and the performance of the CT used. In practice, these adjustments are best carried out on site through deliberate application of faults and recording of the resulting currents.

9.19.2 Sensitive Wattmetric Protection

It can be seen in Figure 9.25 that a small angular difference exists between the spill current on the healthy and faulted feeders. Figure 9.26 illustrates how this angular difference gives rise to active components of current which are in antiphase to each other.

Consequently, the active components of zero sequence power will also lie in similar planes and a relay capable of detecting active power can make a discriminatory

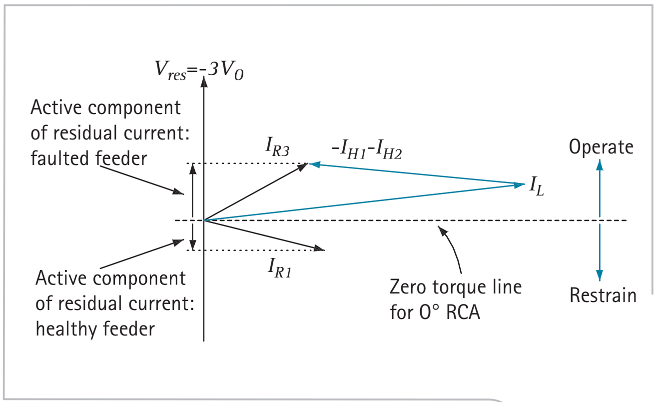


Figure 9.26: Resistive components of spill current

Figure 9.27: MiCOM P140

decision. If the wattmetric component of zero sequence power is detected in the forward direction, it indicates a fault on that feeder, while a power in the reverse direction indicates a fault elsewhere on the system. This method of protection is more popular than the sensitive earth fault method, and can provide greater security against false operation due to spurious CBCT output under non-earth fault conditions.

Wattmetric power is calculated in practice using residual quantities instead of zero sequence ones. The resulting values are therefore nine times the zero sequence quantities as the residual values of current and voltage are each three times the corresponding zero sequence values. The equation used is:

$$V_{res} \times I_{res} \times \cos(\varphi - \varphi_c)$$

$$= 9 \times V_0 \times I_0 \times \cos(\varphi - \varphi_c) \quad \text{...Equation 9.5}$$

where:

V_{res} = *residual voltage*

I_{res} = *residual current*

V_o = *zero sequence voltage*

I_o = *zero sequence current*

ϕ = *angle between* V_{res} *and* I_{res}

ϕ_c = *relay characteristic angle setting*

The current and RCA settings are as for a sensitive earth fault relay.

9.20 EXAMPLES OF TIME AND CURRENT GRADING

This section provides details of the time/current grading of some example networks, to illustrate the process of relay setting calculations and relay grading. They are based on the use of a modern numerical overcurrent relay illustrated in Figure 9.27, with setting data taken from this relay.

9.20.1 Relay Phase Fault Setting Example – IDMT Relays/Fuses

Consider the system shown in Figure 9.28.

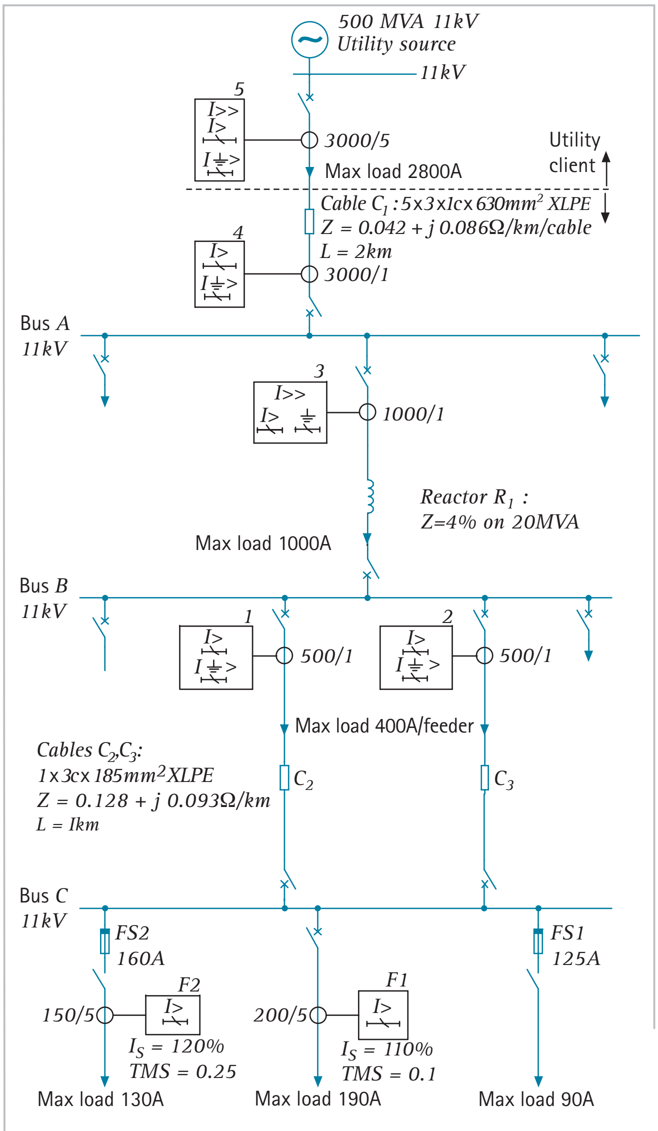


Figure 9.28: IDMT relay grading example

The problem is to calculate appropriate relay settings for relays *1-5* inclusive. Because the example is concerned with grading, considerations such as bus-zone protection, and CT knee-point voltage requirements, etc., are not dealt with. All curves are plotted to an 11kV base. The contactors in series with fuses *FS1/FS2* have a maximum breaking capacity of 3kA, and relay *F2* has been set to ensure that the fuse operates prior to the contactor for currents in excess of this value. CT's for relays *F1*, *F2* and *5* are existing CT's with 5A secondaries, while the remaining CT's are new with 1A secondaries. Relay *5* is the property of the supply utility, and is required to be set using an SI characteristic in order to ensure grading with upstream relays.

9.20.1.1 Impedance Calculations

All impedances must first be referred to a common base, taken as 500MVA, as follows:

Reactor R_1

$$Z_{R1}=\frac{4\times500}{20}=100\%$$

Cable C_1

$$Z_{C1}=\frac{0.096}{5}\times2=0.038\Omega$$

On 500MVA base,

$$Z_{C1}=\frac{0.038\times100\times500}{(11)^2}$$

$$=15.7\%$$

Cables C_2,C_3

$$Z_{C2},\ Z_{C3}=0.158\ \Omega$$

On 500MVA base,

$$Z_{C2},Z_{C3}=\frac{0.158\times100\times500}{(11)^2}$$

$$=65.3\%$$

Source Impedance (500MVA base)

$$Z_S=\frac{500}{500}\times100\%$$

$$=100\%$$

9.20.1.2 Fault Levels

The fault levels are calculated as follows:

(i) At bus C

For 2 feeders,

$$Fault\ Level=\frac{500\times100}{Z_{R1}+Z_S+Z_{C1}+Z_{C2}/2}MVA$$

$$=10.6\ kA\ on\ 11kV\ base$$

For a single feeder, fault level = 178MVA

= 9.33kA

(ii) At bus B

$$Fault\ Level=\frac{500\times100}{Z_S+Z_{C1}+Z_{R1}}MVA$$

$$=232MVA$$

$$=12.2kA$$

(iii) At bus A

$$Fault\ Level=\frac{500\times100}{Z_S+Z_{C1}}MVA$$

$$=432MVA$$

$$=22.7kA$$

(iv) Source

$$Fault\ Level=500MVA$$

$$=26.3kA$$

9.20.1.3 CT ratio selection

This requires consideration not only of the maximum load current, but also of the maximum secondary current under fault conditions.

CT secondaries are generally rated to carry a short-term current equal to 100 x rated secondary current. Therefore, a check is required that none of the new CT secondaries has a current of more than 100A when maximum fault current is flowing in the primary. Using the calculated fault currents, this condition is satisfied, so modifications to the CT ratios are not required.

9.20.1.4 Relay overcurrent settings – Relays 1/2

These relays perform overcurrent protection of the cable feeders, Busbar *C* and backup-protection to relays *F1*, *F2* and their associated fuses *FS1* and *FS2*. The settings for Relays *1* and *2* will be identical, so calculations will only be performed for Relay *1*. Consider first the current setting of the relay.

Relay *1* must be able to reset at a current of 400A – the rating of the feeder. The relay has a drop-off/pick-up ratio of 0.95, so the relay current setting must not be less than 400/0.95, or 421A. A suitable setting that is greater than this value is 450A. However, Section 9.12.3 also recommends that the current setting should be three times the largest fuse rating (i.e. 3 x 160A, the rating of the largest fuse on the outgoing circuits from Busbar *C*), leading to a current setting of 480A, or 96% of relay rated primary current. Note that in this application of relays to a distribution system, the question of maximum and minimum fault levels are probably not relevant as the difference between maximum and minimum fault levels will be very small. However in other applications where significant differences between maximum and minimum fault levels exist, it is essential to ensure that the selection of a current setting that is greater than full load current does not result in the relay failing to operate under minimum fault current conditions. Such a situation may arise for example in a self-contained power system with its own generation. Minimum generation may be represented by the presence of a single generator and the difference between minimum fault level and maximum load level may make the choice of relay current settings difficult.

The grading margin now has to be considered. For simplicity, a fixed grading margin of 0.3s between relays is used in the calculations, in accordance with Table 9.2. Between fuse and relay, Equation 9.4 is applied, and with fuse *FS2* pre-arcing time of 0.01s (from Figure 9.29), the grading margin is 0.154s.

Consider first the IDMT overcurrent protection. Select the EI characteristic, as fuses exist downstream, to ensure grading. The relay must discriminate with the longest operating time between relays *F1*, *F2* and fuse *FS2* (being the largest fuse) at the maximum fault level seen by relays *1* and *2*. The maximum fault current seen by relay *1* for a fault at Busbar *C* occurs when only one of cables C_2, C_3 is in service. This is because the whole of the fault current then flows through the feeder that is in service. With two feeders in service, although the fault level at Busbar *C* is higher, each relay only sees half of the total fault current, which is less than the fault current with a single feeder in service. With EI characteristics used for relays *F1* and *F2*, the operating time for relay *F1* is 0.02s at TMS=0.1 because the fault current is greater than 20 times relay setting, at which point the EI characteristic becomes definite time (Figure 9.4) and 0.05s for relay *F2* (TMS=0.25).

Hence select relay 1 operating time $=0.3+0.05=0.35s$, to ensure grading with relay *F2* at a fault current of 9.33kA.

With a primary setting of 480A, a fault current of 9.33kA represents

9330/480 = 19.44 times setting

Thus relay *1* operating time at TMS=1.0 is 0.21s. The required TMS setting is given by the formula:

$$TMS=\frac{operation\ time\ required}{Actual\ op.\ time\ required\ at\ TMS=1.0}$$

$$\therefore\ TMS=\frac{0.35}{0.21}=1.66$$

This value of TMS is outside the settable range of the relay (maximum setting 1.2). Therefore, changes must be made to the relay current setting in order to bring the value of TMS required into the range available, provided this does not result in the inability of the relay to operate at the minimum fault level.

By re-arrangement of the formula for the EI characteristic:

$$I_{sr1f}=\sqrt{\frac{80}{t}+1}$$

where

t is the required operation time (s)

I_{sr1f} = *setting of relay at fault current*

Hence, with $t = 0.35$,

$I_{sr1f} = 15.16$

or, $I_{sr1}=\frac{9330}{15.16}=615.4A$

$$I_{sr1}=\frac{616}{500}=1.232$$

Use 1.24 = 620A nearest available value

At a TMS of 1.0, operation time at 9330A

$$=\frac{80}{\left(\frac{9330}{620}\right)^2-1}=0.355$$

Hence, required TMS

$$=\frac{0.35}{0.355}=0.99$$

for convenience, use a TMS of 1.0, slightly greater than the required value.

From the grading curves of Figure 9.29, it can be seen that there are no grading problems with fuse *FS1* or relays *F1* and *F2*.

9.20.1.5 Relay overcurrent settings - Relay 3

This relay provides overcurrent protection for reactor R_1, and backup overcurrent protection for cables C_2 and C_3. The overcurrent protection also provides busbar protection for Busbar *B*.

Again, the EI characteristic is used to ensure grading with relays *1* and *2*. The maximum load current is 1000A. Relay *3* current setting is therefore

$$I_{sr3}>\frac{feeder\ flc}{CT\ primary\ current\times 0.95}$$

Substituting values,

$I_{sr3}>1052A$

Use a setting of 106% or 1060A, nearest available setting above 1052A.

Relay *3* has to grade with relays *1/2* under two conditions:

1. for a fault just beyond relays *1* and *2* where the fault current will be the busbar fault current of 12.2kA

2. for a fault at Bus *C* where the fault current seen by

either relay *1* or *2* will be half the total Bus *C* fault current of 10.6kA, i.e. 5.3kA

Examining first condition 1. With a current setting of 620A, a TMS of 1.0 and a fault current of 12.2kA, relay *1* will operate in 0.21s. Using a grading interval of 0.3s, relay *3* must therefore operate in

$$0.3 + 0.21 = 0.51\text{s}$$

at a fault current of 12.2kA.

12.2kA represents 12200/1060 = 11.51 times setting for relay *3* and thus the time multiplier setting of relay *3* should be 0.84 to give an operating time of 0.51s at 11.51 times setting.

Consider now condition 2. With settings of 620A and TMS of 1.0 and a fault current of 5.3kA, relay *1* will operate in 1.11s. Using a grading interval of 0.3s, relay *3* must therefore operate in

$$0.3 + 1.11 = 1.41\text{s}$$

at a fault current of 5.3kA.

5.3kA represents 5300/1060 = 5 times setting for relay *3*, and thus the time multiplier setting of relay *3* should be 0.33 to give an operating time of 1.11s at 5 times setting. Thus condition 1 represents the worst case and the time multiplier setting of relay *3* should be set at 0.84. In practice, a value of 0.85 is used as the nearest available setting on the relay.

Relay *3* also has an instantaneous element. This is set such that it will not operate for the maximum through-fault current seen by the relay, a setting of 130% of this value being satisfactory. The setting is therefore:

$$1.3 \text{x} 12.2kA$$

$$=15.86kA$$

This is equal to a current setting of 14.96 times the setting of relay *3*.

9.20.1.6 Relay 4

This must grade with relay *3* and relay *5*. The supply authority requires that relay *5* use an SI characteristic to ensure grading with relays further upstream, so the SI characteristic will be used for relay *4* also. Relay *4* must grade with relay *3* at Bus *A* maximum fault level of 22.7kA. However with the use of an instantaneous high set element for relay *3*, the actual grading point becomes the point at which the high set setting of relay *3* operates, i.e. 15.86kA. At this current, the operation time of relay *3* is

$$\frac{80}{(14.96)^2 - 1} \times 0.85s = 0.305s$$

Thus, relay *4* required operating time is

0.305 + 0.3 = 0.605s at a fault level of 15.86kA.

Relay *4* current setting must be at least

$$\frac{2800}{3000 \times 0.95} = 98\%$$

For convenience, use a value of 100% (=3000A). Thus relay *4* must operate in 0.605s at 15860/3000 = 5.29 times setting. Thus select a time multiplier setting of 0.15, giving a relay operating time of 0.62s for a normal inverse type characteristic.

At this stage, it is instructive to review the grading curves, which are shown in Figure 9.29(a). While it can be seen that there are no grading problems between the fuses and relays *1/2*, and between relays *F1/2* and relays *1/2*, it is clear that relay *3* and relay *4* do not grade over the whole range of fault current. This is a consequence of the change in characteristic for relay *4* to SI from the EI characteristic of relay *3* to ensure grading of relay *4* with relay *5*. The solution is to increase the TMS setting of relay *4* until correct grading is achieved. The alternative is to increase the current setting, but this is undesirable unless the limit of the TMS setting is reached, because the current setting should always be as low as possible to help ensure positive operation of the relay and provide overload protection. Trial and error is often used, but suitable software can speed the task – for instance it is not difficult to construct a spreadsheet with the fuse/relay operation times and grading margins calculated. Satisfactory grading can be found for relay *4* setting values of:

$$I_{st4} = 1.0 \text{ or } 3000A$$

$$TMS = 0.275$$

At 22.7kA, the operation time of relay *4* is 0.93s. The revised grading curves are shown in Figure 9.29(b).

9.20.1.7 Relay 5

Relay *5* must grade with relay *4* at a fault current of 22.7kA. At this fault current, relay *4* operates in 0.93s and thus relay *5* must operate in

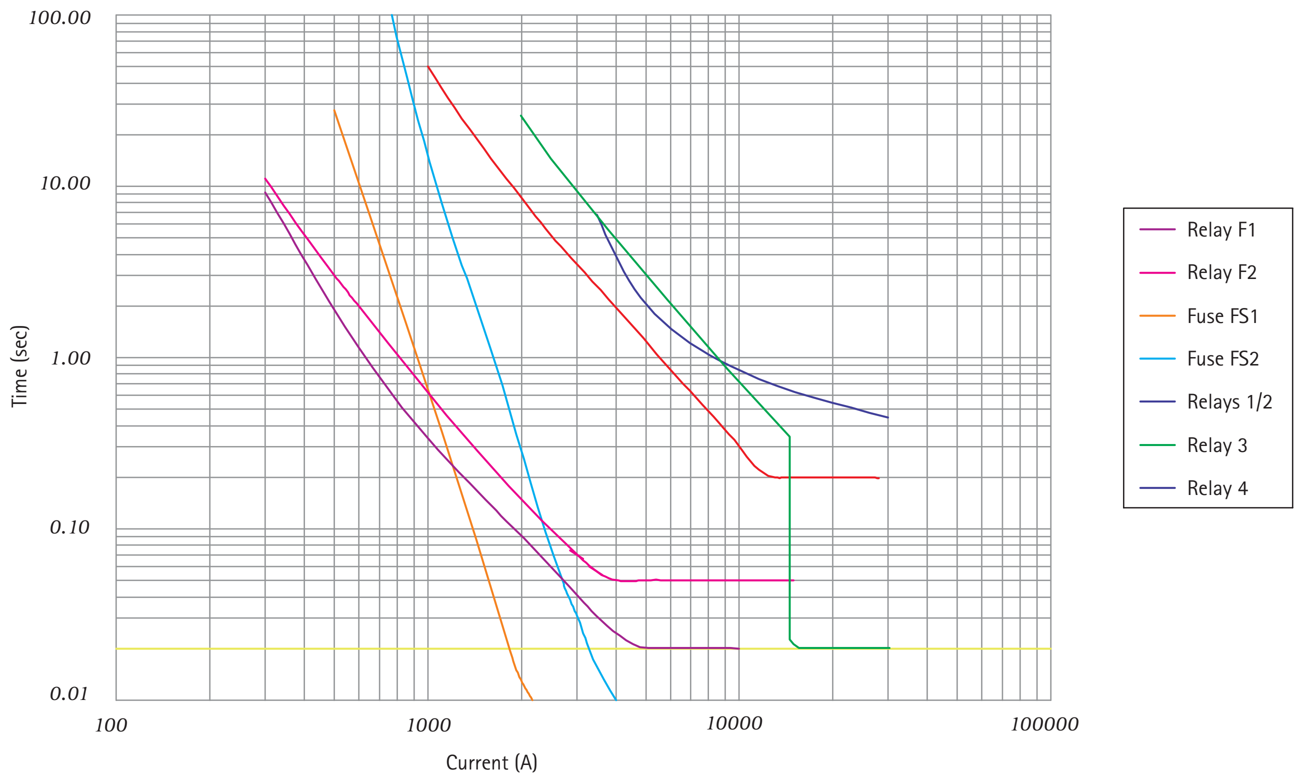
0.3 + 0.93 = 1.23s at 22.7kA.

A current setting of 110% of relay *4* current setting (i.e. 110% or 3300A) is chosen to ensure relay *4* picks up prior to relay *5*. Thus 22.7kA represents 6.88 times the setting of relay *5*. Relay *5* must grade with relay *4* at a fault current of 22.7kA, where the required operation time is 1.23s. At a TMS of 1.0, relay *5* operation time is

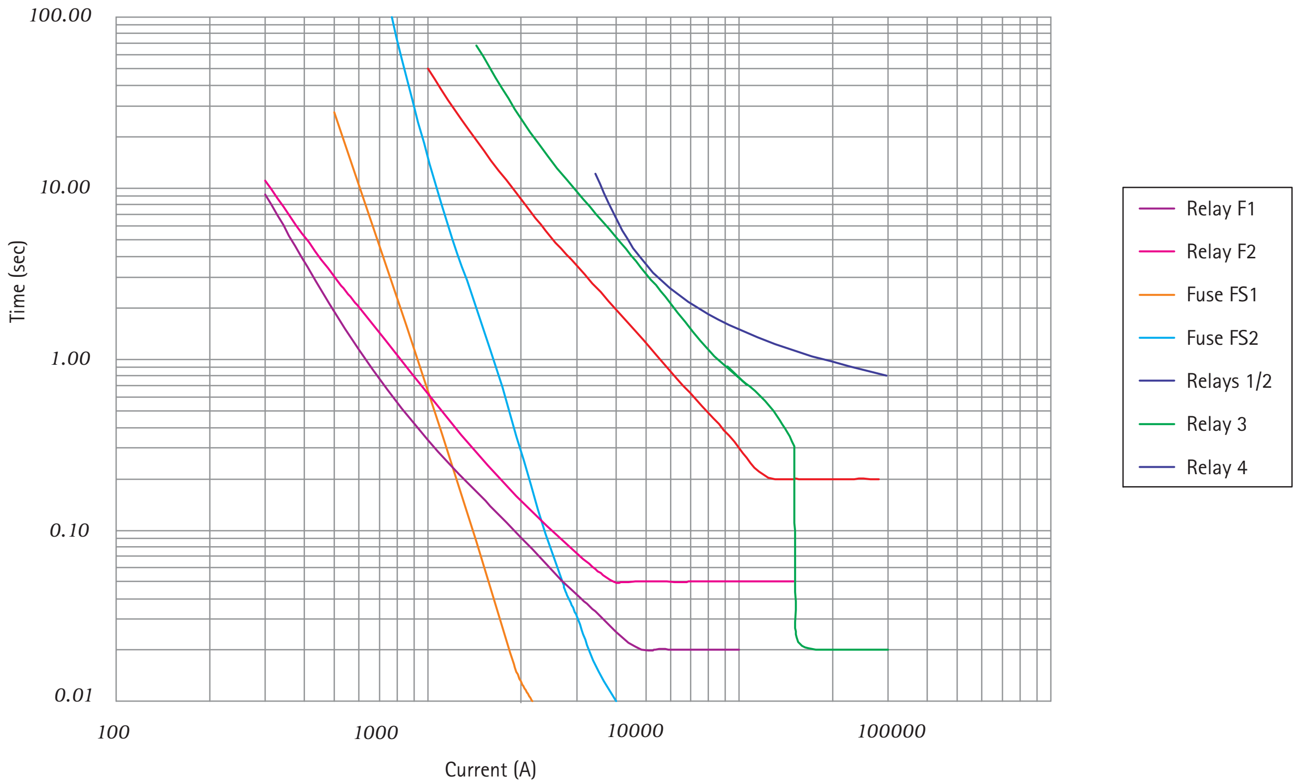
$$\frac{0.14}{(6.88)^{0.02} - 1} = 3.56\ s$$

Therefore, the required TMS is $1.23/3.56 = 0.345$, use 0.35 nearest available value.

The protection grading curves that result are shown in Figure 9.30 and the setting values in Table 9.5. Grading is now satisfactory.



(a) Initial grading curves



(b) Revised initial grading curves

Figure 9.29: Initial relay grading curves – overcurrent relay example

In situations where one of the relays to be graded is provided by a third party, it is common for the settings of the relay to be specified and this may lead to a lack of co-ordination between this relay and others (usually those downstream). Negotiation is then required to try and achieve acceptable settings, but it is often the case that no change to the settings of the relay provided by the third party is allowed. A lack of co-ordination between relays then has to be accepted over at least part of the range of fault currents.

Relay/ Fuse	Load current (A)	Max Fault Current kA	CT Ratio	Fuse Rating	Relay Settings: Charac- teristic	Current Setting: Primary Amps	Current Setting: Per Cent	TMS
F1	190	10.6	200/5		EI	100	100	0.1
F2	130	10.6	150/5		EI	150	120	0.25
FS1	90	10.6	-	125A				
FS2	130	10.6	-	160A		-	-	-
1	400	12.2	500/1		EI	620	124	1
2	400	12.2	500/1		EI	620	124	1
3	1000	22.7	1000/1		EI	1060	106	0.85
					Instant.	15860	14.96	-
4	3000	22.7	3000/1		SI	3000	100	0.275
5	3000	26.25	3000/5		SI	3300	110	0.35

Table 9.5: Relay settings for overcurrent relay example

9.20.2 Relay Earth-Fault Settings

The procedure for setting the earth-fault elements is identical to that for the overcurrent elements, except that zero sequence impedances must be used if available and different from positive sequence impedances in order to calculate fault levels. However, such impedances are frequently not available, or known only approximately and the phase fault current levels have to be used. Note that earth fault levels can be higher than phase fault levels if the system contains multiple earth points, or if earth fault levels are considered on the star side of a delta/star transformer when the star winding is solidly earthed.

On the circuit with fuse $F2$, low-level earth faults may not be of sufficient magnitude to blow the fuse.

Attempting to grade the earth fault element of the upstream relay with fuse $F2$ will not be possible. Similarly, relays $F1$ and $F2$ have phase fault settings that do not provide effective protection against earth faults. The remedy would be to modify the downstream protection, but such considerations lie outside the scope of this example. In general therefore, the earth fault elements of relays upstream of circuits with only phase fault protection (i.e. relays with only phase fault elements or fuses) will have to be set with a compromise that they will detect downstream earth faults but will not provide a discriminative trip. This illustrates the practical point that it is rare in anything other than a very simple network to achieve satisfactory grading for all faults throughout the network.

In the example of Figure 9.27, it is likely that the difference in fault levels between phase to phase and phase to earth faults will be very small and thus the only function of earth fault elements is to detect and isolate low level earth faults not seen by the phase fault

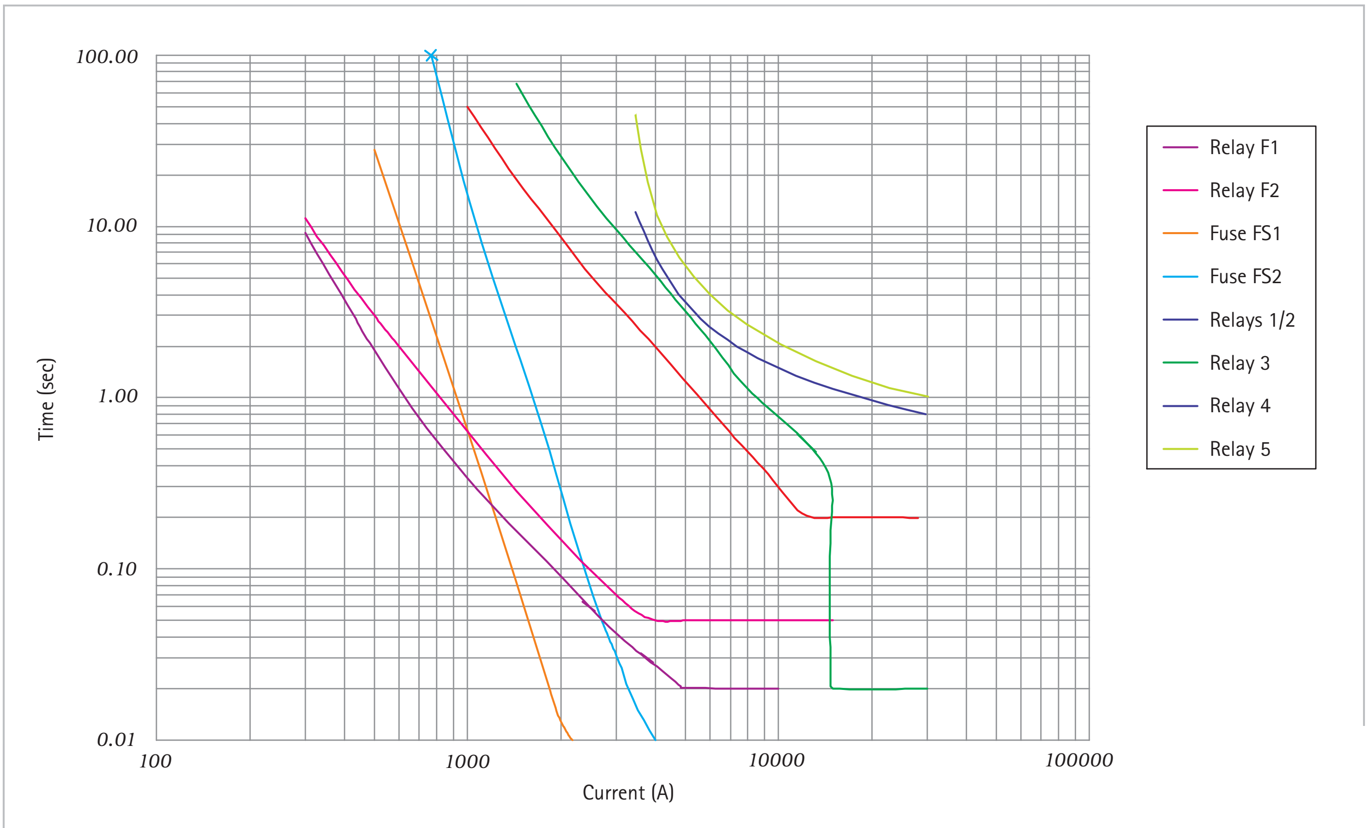


Figure 9.30: Final relay grading curves for overcurrent relay example

elements. Following the guidelines of Section 9.16, relays *1/2* can use a current setting of 30% (150A) and a TMS of 0.2, using the EI characteristic. Grading of relays *3/4/5* follows the same procedure as described for the phase-fault elements of these relays.

9.20.3 Protection of Parallel Feeders

Figure 9.31(a) shows two parallel transformer feeders forming part of a supply circuit. Impedances are as given in the diagram.

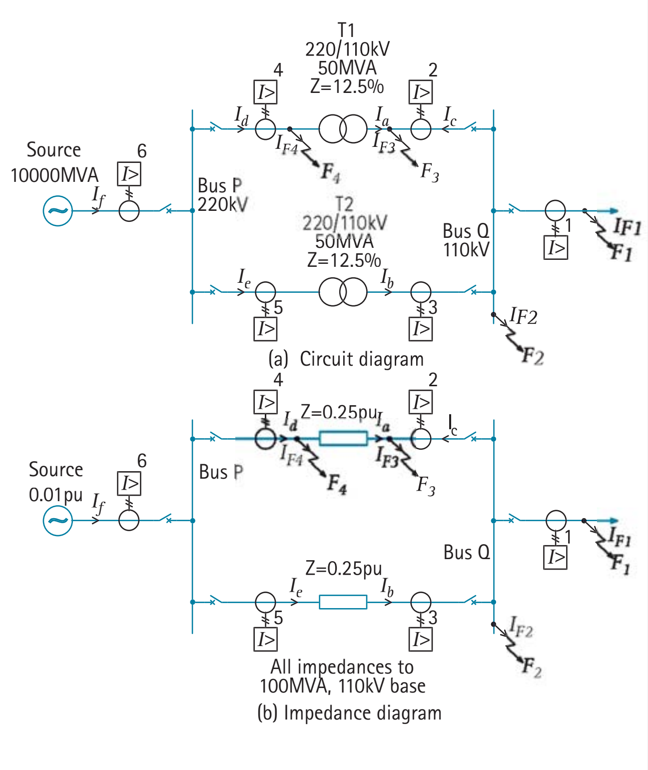


Figure 9.31: System diagram: Parallel feeder example

The example shows that unless relays *2* and *3* are made directional, they will maloperate for a fault at *F3*. Also shown is how to calculate appropriate relay settings for all six relays to ensure satisfactory protection for faults at locations *F1-F4*.

Figure 9.31(b) shows the impedance diagram, to 100MVA, 110kV base. The fault currents for faults with various system configurations are shown in Table 9.6.

Fault Position	System Config.	Currents (A) Fault	I_a	I_b	I_c	I_d	I_e	I_f
F1	2 fdrs	3888	1944	1944	0	972	972	1944
F1/F2	1 fdr	2019	2019	0	0	1009	0	1009
F2	2 fdrs	3888	1944	1944	0	972	972	1944
F3	2 fdrs	3888	1944	1944	1944	972	972	1944
F4	1 fdr	26243	0	0	0	26243	0	26243

Table 9.6: Fault currents for parallel feeder example

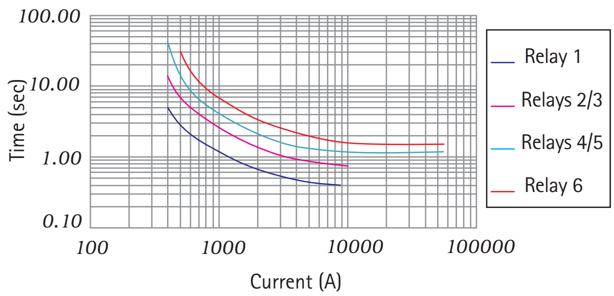
If relays *2* and *3* are non-directional, then, using SI relay characteristics for all relays, grading of the relays is dictated by the following:

a) fault at location *F1*, with 2 feeders in service

b) fault at location *F4*, with one feeder in service

Relay	CT Primary	Current setting	TMS	Characteristic
1	300	1	0.2	SI
2	300	1.1	0.3	SI
3	300	1.1	0.3	SI
4	300	0.61	0.425	SI
5	300	0.61	0.425	SI
6	300	0.7	0.7	SI

(a) Relay settings - non-directional relays



(b) Relay grading curves - non-directional relays

Figure 9.32: Relay grading for parallel feeder example – non-directional relays

The settings shown in Figure 9.32(a) can be arrived at, with the relay operation times shown in Figure 9.32(b). It is clear that for a fault at *F3* with both transformer feeders in service, relay *3* operates at the same time as relay *2* and results in total disconnection of Bus Q and all consumers supplied solely from it. This is undesirable – the advantages of duplicated 100% rated transformers have been lost.

By making relays *2* and *3* directional as shown in Figure 9.33(a), lower settings for these relays can be adopted – they can be set as low as reasonably practical but normally a current setting of about 50% of feeder full load current is used, with a TMS of 0.1. Grading rules can be established as follows:

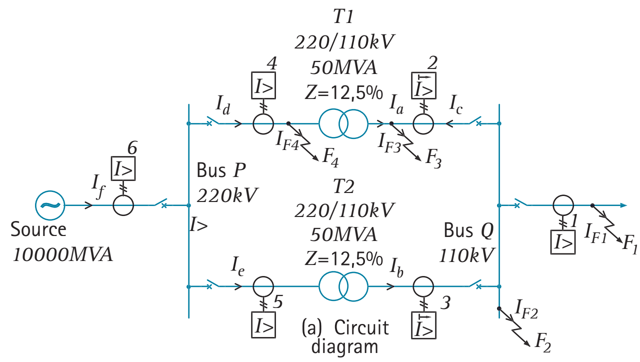
a. relay *4* is graded with relay *1* for faults at location *F1* with one transformer feeder in service

b. relay *4* is graded with relay *3* for faults at location *F3* with two transformer feeders in service

c. relay *6* grades with relay *4* for faults at *F4*

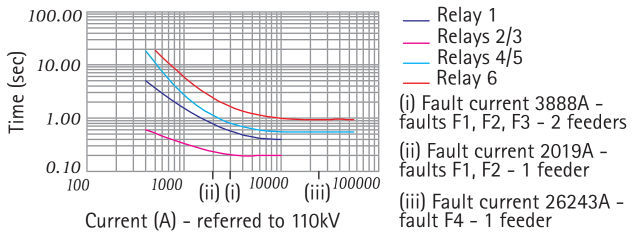
d. relay *6* also has to grade with relay *4* for faults at *F1* with both transformer feeders in service – relay *6* sees the total fault current but relay *4* only 50% of this current.

Normal rules about calculating current setting values of relays in series apply. The settings and resulting operation times are given in Figure 9.33(b) and(c) respectively.



Relay	CT Primary	Current setting	TMS	Characteristic
1	300	1	0.2	SI
2	300	0.42	0.1	SI
3	300	0.42	0.1	SI
4	300	0.6	0.275	SI
5	300	0.6	0.275	SI
6	300	0.7	0.475	SI

(b) Relay settings



(c) Relay characteristics

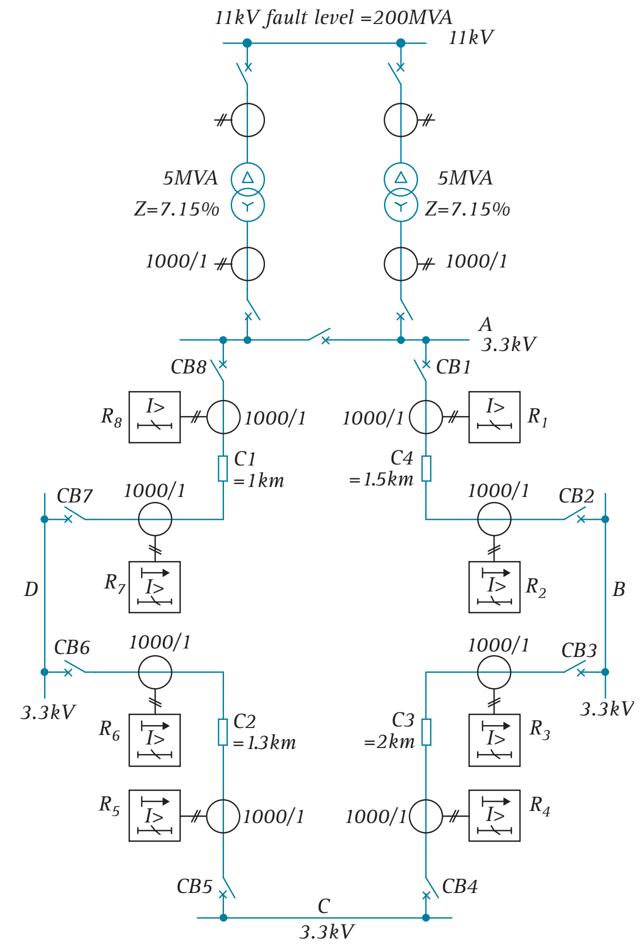
Figure 9.33: Relay grading for parallel feeder example – directional relays

In practice, a complete protection study would include instantaneous elements on the primary side of the transformers and analysis of the situation with only one transformer in service. These have been omitted from this example, as the purpose is to illustrate the principles of parallel feeder protection in a simple fashion.

9.20.4 Grading of a Ring Main

Figure 9.34 shows a simple ring main, with a single infeed at Bus A and three load busbars. Settings for the directional relays $R2$-$R7$ and non-directional relays $R1/R8$ are required. Maximum load current in the ring is 785A (maximum continuous current with one transformer out of service), so 1000/1A CT's are chosen. The relay considered is a MiCOM P140 series.

The first step is to establish the maximum fault current at each relay location. Assuming a fault at Bus B (the actual location is not important), two possible configurations of the ring have to be considered, firstly a closed ring and secondly an open ring. For convenience, the ring will be considered to be open at $CB1$ ($CB8$ is the other possibility to be considered, but the conclusion will be the same).



All cables are 3 x 1c x 1200mm², Al conductor, Z = 0.09 Ω/km
VT's omitted for clarity

Figure 9.34: Ring main grading example – circuit diagram

Figure 9.35 shows the impedance diagram for these two cases.

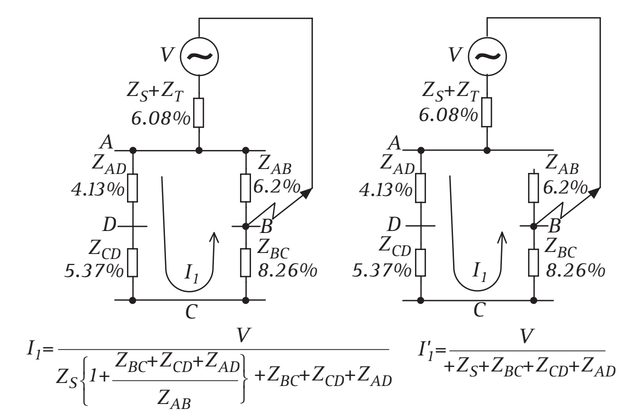


Figure 9.35: Impedance diagrams with ring open

Three-phase fault currents I_1 and I'_1 can be calculated as 2.13kA and 3.67kA respectively, so that the worst case is with the ring open (this can also be seen from consideration of the impedance relationships, without the necessity of performing the calculation).

Clockwise		Anticlockwise	
Open Point CB8		Open Point CB1	
Bus	Fault Current kA	Bus	Fault Current kA
D	7.124	B	3.665
C	4.259	C	5.615
B	3.376	D	8.568

Table 9.7: Fault current tabulation with ring open

Table 9.7 shows the fault currents at each bus for open points at $CB1$ and $CB8$.

For grading of the relays, consider relays looking in a clockwise direction round the ring, i.e. relays $R1/R3/R5/R7$.

9.20.4.1 Relay R7

Load current cannot flow from Bus D to Bus A since Bus A is the only source. Hence low relay current and TMS settings can be chosen to ensure a rapid fault clearance time. These can be chosen arbitrarily, so long as they are above the cable charging current and within the relay setting characteristics. Select a relay current setting of 0.8 (i.e. 800A CT primary current) and TMS of 0.05. This ensures that the other relays will not pick up under conditions of normal load current. At a fault current of 3376A, relay operating time on the SI characteristic is

$$0.05 \times \left[\frac{0.14}{(4.22)^{0.02} - 1} \right] s$$

$$= 0.24s$$

9.20.4.2 Relay R5

This relay must grade with relay $R7$ at 3376A and have a minimum operation time of 0.54s. Relay $R5$ current setting must be at least 110% of relay $R7$ to prevent unwanted pickup, so select relay $R5$ current setting of 0.88 (i.e. 880A CT primary current).

Relay $R5$ operating time at $TMS = 1.0$

$$= \left[\frac{0.14}{(3.84)^{0.02} - 1} \right] s = 5.14s$$

Hence, relay $R5$ TMS $= \dfrac{0.54}{5.14} = 5.14s$

Use nearest settable value of TMS of 0.125.

Bus	Relay	Relay Charact-eristic	CT Ratio	Max Load Current (A)	Max Fault Current (A) (3.3kV base)	Current Setting p.u.	TMS
D	R7	SI	1000/1	874	3376	0.8	0.05
C	R5	SI	1000/1	874	4259	0.88	0.125
B	R3	SI	1000/1	874	7124	0.97	0.2
A	R1	SI	1000/1	874	14387	1.07	0.275
A	R8	SI	1000/1	874	14387	1.07	0.3
D	R6	SI	1000/1	874	8568	0.97	0.2
C	R4	SI	1000/1	874	5615	0.88	0.125
B	R2	SI	1000/1	874	3665	0.8	0.05

Table 9.8: Ring main example relay settings

Table 9.8 summarises the relay settings, while Figure 9.36 illustrates the relay grading curves.

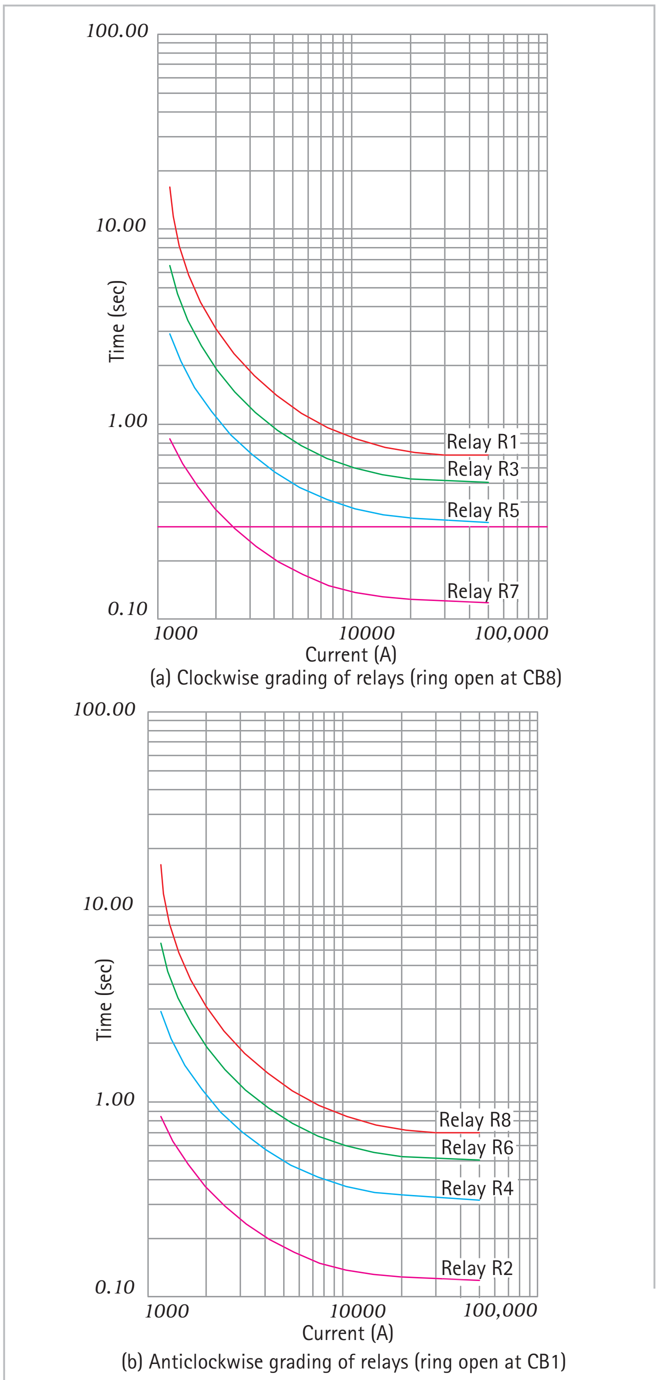


Figure 9.36: Ring main example – relay grading curves

9.21 REFERENCES

9.1. *Directional Element Connections for Phase Relays.* W.K Sonnemann, Transactions A.I.E.E. 1950.