Power System Protection
EE454

Lecture ppt. # 4

- **Note:**

  The materials in this presentation are only for the use of students enrolled in this course in the specific campus; these materials are for purposes associated with this course and may not be further disseminated or retained after expiry of the course.

Contents
Lect. File 4 – Mainly **Chapter 4** of PS Relaying


بسم الله الرحمن الرحيم

4

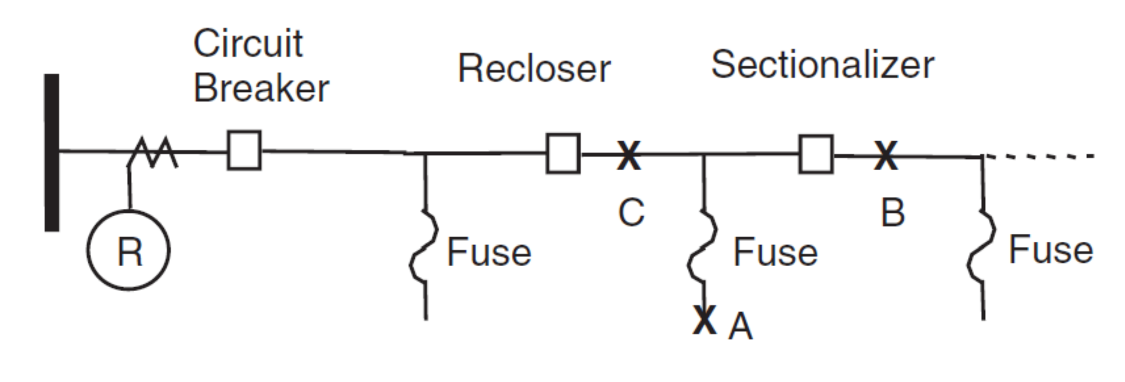
Nonpilot overcurrent protection of transmission lines

In order of ascending cost and complexity,
the protective devices available for transmission line protection are:

1. fuses
2. sectionalizers, reclosers
3. instantaneous overcurrent
4. inverse, time delay, overcurrent
5. directional overcurrent
6. distance
7. pilot.

4.2 Fuses, sectionalizers, reclosers

The subject of fuses, sectionalizers and reclosers should be more properly discussed within the context of the protective requirements of a distribution system since they are that system's primary protective devices.[1]



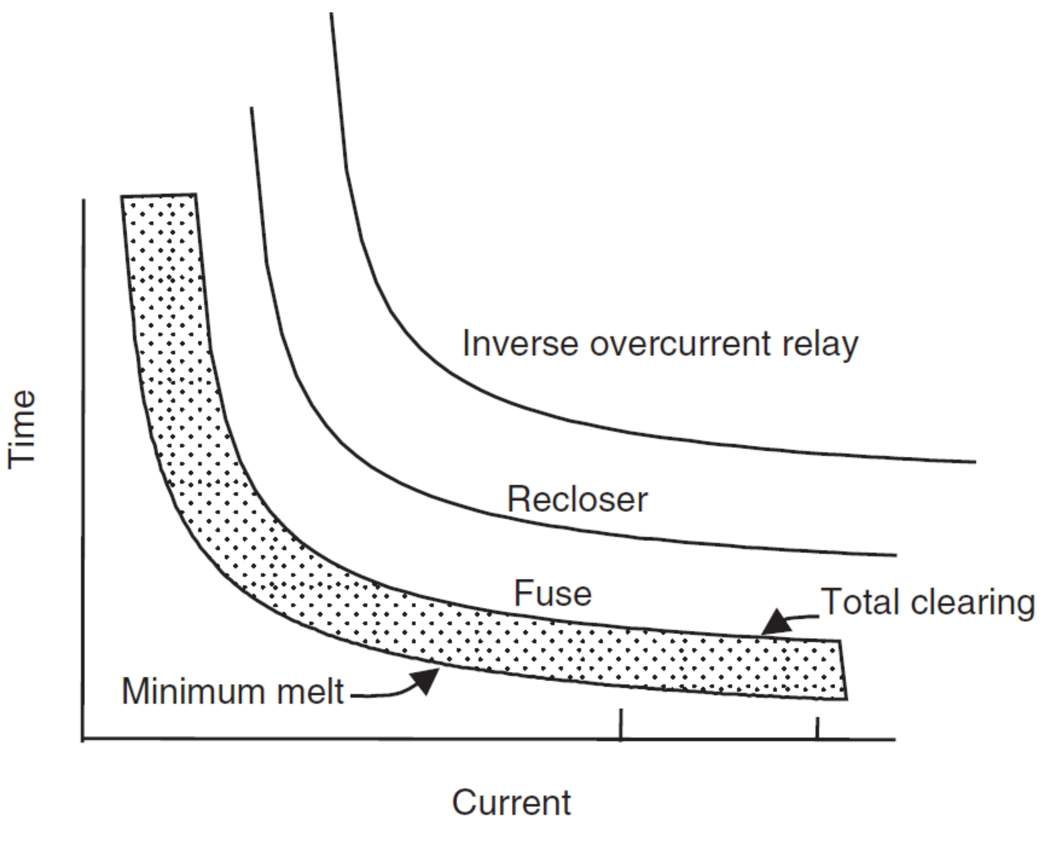


Figure 4.2 Overcurrent device coordination

Fuse

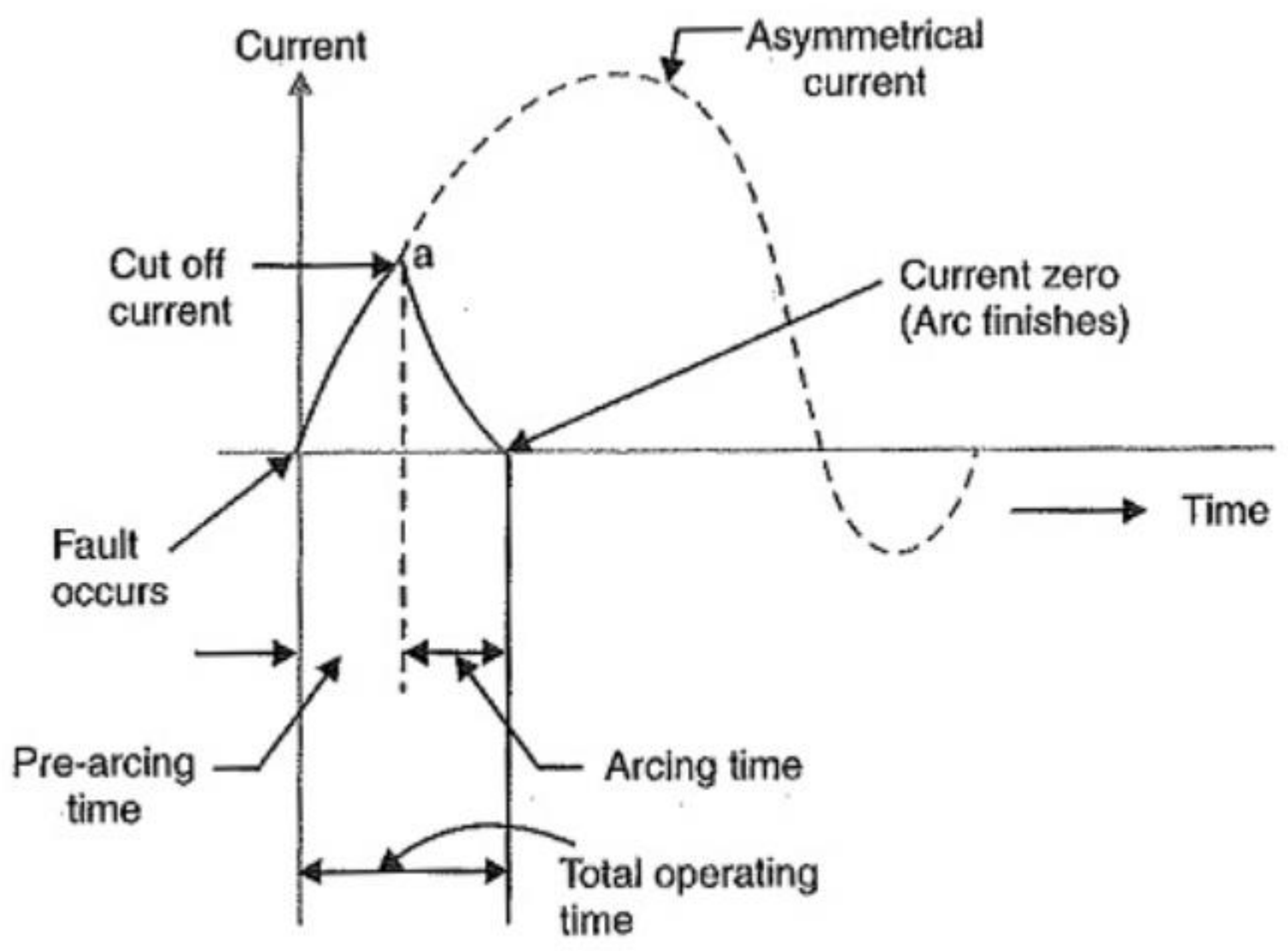


Fig. 20.2

See Ch#2 slides for more details on fuses.

ReCloser

A typical power system recloser is essentially an automatic circuit breaker which can sense fault, break the circuit and then close again for a number of times before being permanently locked out.

Better life.
With electricity.

Reclosers
Technical Data
TD280027EN

Effective July 2017
Supersedes September 2004 (R280-90-8)

COOPER POWER
SERIES

What is a recloser?

A recloser is an automatic, high-voltage electric switch. Like a circuit breaker on household electric lines, it shuts off electric power when trouble occurs, such as a short circuit. Where a household circuit breaker remains shut off until it is manually reset, a recloser automatically tests the electrical line to determine whether the trouble has been removed. And, if the problem was only temporary, the recloser automatically resets itself and restores the electric power.

On high-voltage electric lines, 80 to 90 percent of trouble occurrences are temporary – such as lightning, windblown tree branches or wires, birds, or rodents – and will, by their very nature, remove themselves from the electric line if the power is shut off before permanent damage occurs to the lines.

The recloser senses when trouble occurs and automatically shuts off the power. An instant later (the length of time may be noticeable only as a lightbulb flicker), the recloser turns the power back on, but if the trouble is still present, it shuts it off again. If the trouble is still present after three such tries, the recloser is programmed to consider the problem permanent and it remains off. A power company crew must then repair the problem on the line and reset the recloser to restore power.

Examples of permanent problems include: power lines or other equipment damaged by lightning strikes, fallen tree limbs, or vehicle crashes.

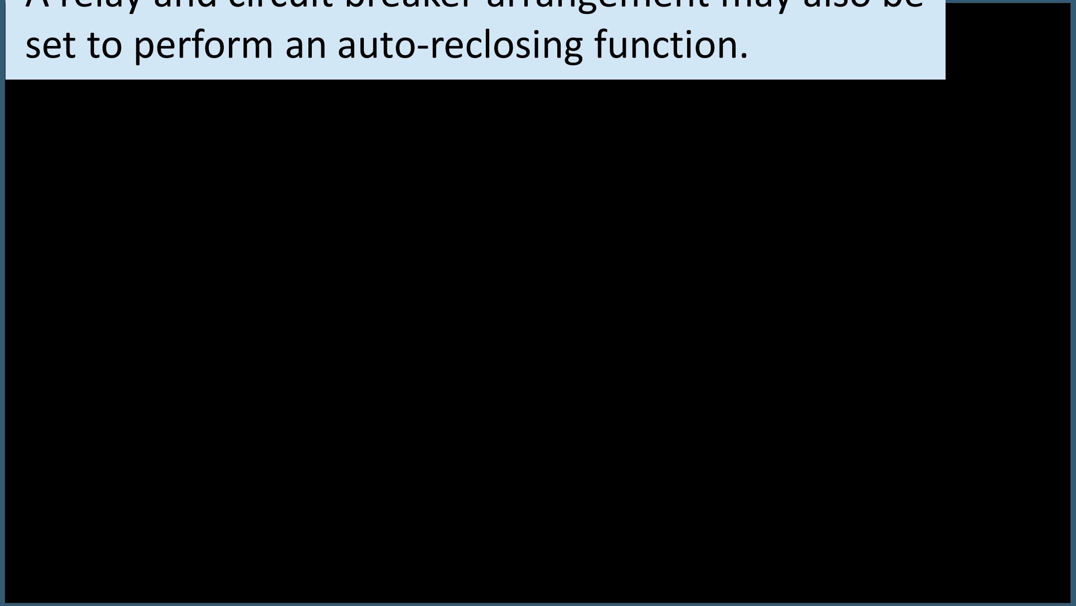
Reclosers save the electric companies considerable time and expense, since they permit power to be restored automatically, after only a flicker or two. And, for outages that require a repair crew, reclosers minimize the outage area and help the crews to quickly locate the problem and restore power. Consumers of electric power– residential, business, industrial, and institutional– are saved from the expense and inconvenience frequent power outages would cause.

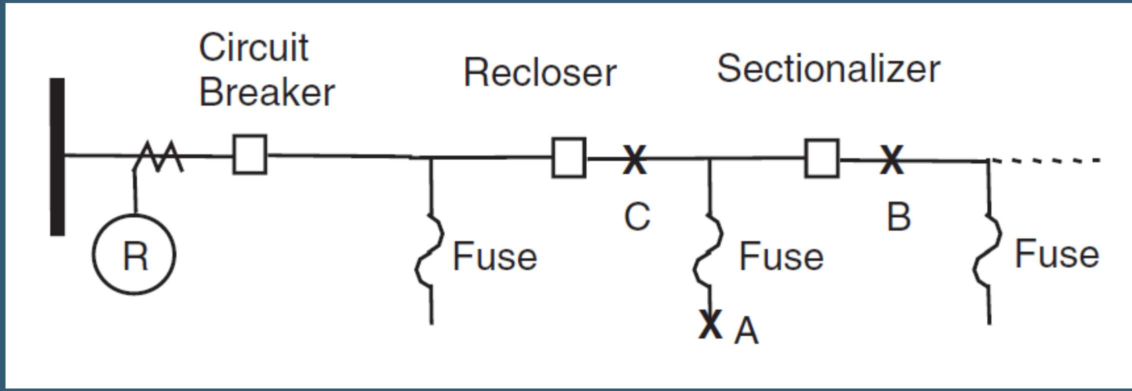
Figure 1. Typical Eaton Cooper Power series single-phase automatic circuit recloser

ReCloser

Arrangement of recloser, sectionalizer and a fuse.

A relay and circuit breaker arrangement may also be set to perform an auto-reclosing function.





Referring to Figure 4.2, a fault at A should be cleared by the branch fuse, leaving service to the main line and to the other branches undisturbed. A fault at B should be cleared by the sectionalizer, but, since the sectionalizer cannot interrupt a fault, the actual clearing is performed by the recloser. The sectionalizer 'sees' the fault current, however, and registers one count. The recloser also sees the fault and trips, de-energizing the line. If the sectionalizer setting is '1' it will now open, allowing the recloser to reclose and restore service to the rest of the system. If the sectionalizer setting is more than '1', e.g. '2', the sectionalizer will not open after the first trip. Instead, the recloser recloses a second time. If the fault is still on, the sectionalizer will see a second count of fault current. The recloser will trip again, allowing the sectionalizer now to open, removing the fault, and the recloser will successfully reclose, restoring service up to the sectionalizer. For a fault at C, the recloser trips and recloses as it is programmed to do. The sectionalizer does not see the fault and does not count.

Normally the tie switch S is open and each station transformer feeds its own load as described above. For a permanent fault at F_1, the sectionalizers or reclosers on the transformer side will open automatically; the line must then be de-energized by opening the downstream breaker and closing switch S, shifting the remaining load to the other transformer. For a transformer fault at F_2, the station breakers (1) and (2) are opened and the entire load can be fed from the other station. The shift from one substation to another affects the magnitude and direction of fault current, and this must be taken into account when applying and setting the line protection devices. Similarly, the use of co-generators on the distribution system introduces another source of energy, independent and remote from the utility's substation, which also affects the magnitude and direction of fault current.

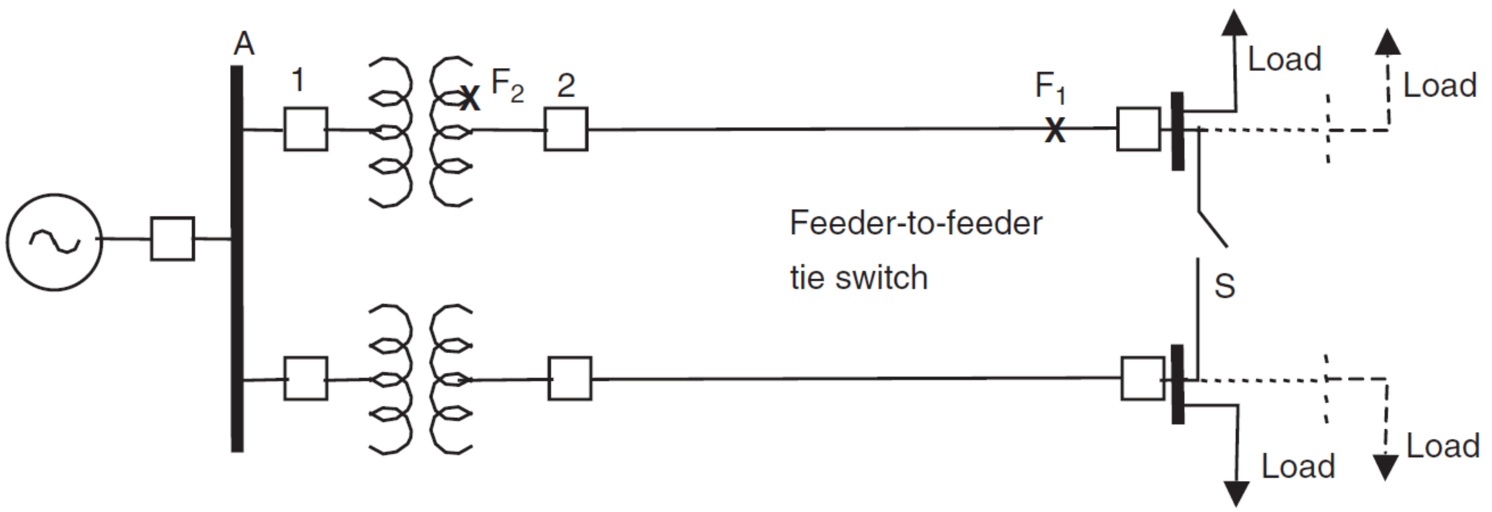


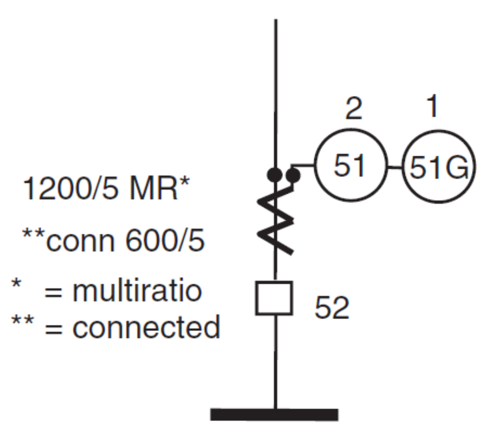
Figure 4.3 Feeder-to-feeder switching

4.3 Inverse, time-delay overcurrent relays

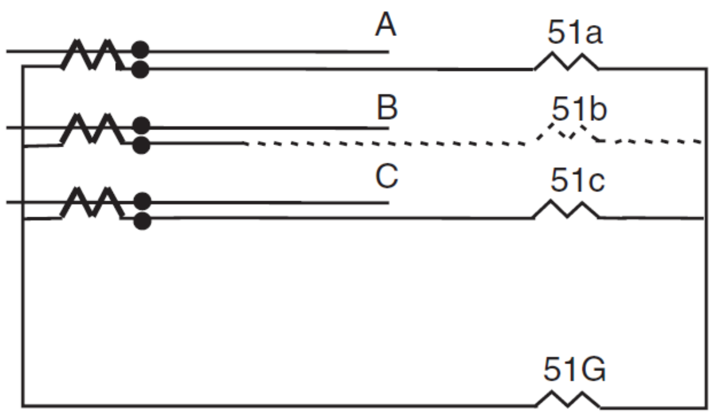
Example 4.1

Given the one-line diagram shown in Figure 4.4(a), show the associated AC and DC connections for two (and three) phase relays and one ground overcurrent relay.

A basic complement of time-delay overcurrent relays would be two phase and one ground relay. This arrangement will protect the equipment for all combinations of phase and ground faults, uses the minimum number of relays, but provides only the minimum of redundancy. Adding the third phase relay provides complete backup protection. Several important design considerations are shown in this example. The conventions and practices used to depict elements of relays and their associated circuits were introduced in sections 2.7 and 2.8. In one-line, elementary, schematic and wiring diagrams, use is made of identifying device function numbers which are shown in Figure 4.4(a), (b) and (c). These numbers are based on a system adopted as standard for automatic switchgear by the IEEE and incorporated in American National Standard ANSI/IEEE C37.2. The system is used in connection diagrams, instruction books and specifications. It provides a readily identifiable reference to the function of a device in a circuit to which additional descriptive numbers or letters can be added to differentiate between similar functions for different devices. A list of most of the commonly used device function numbers is given in Appendix A.



(a) 1-line diagram

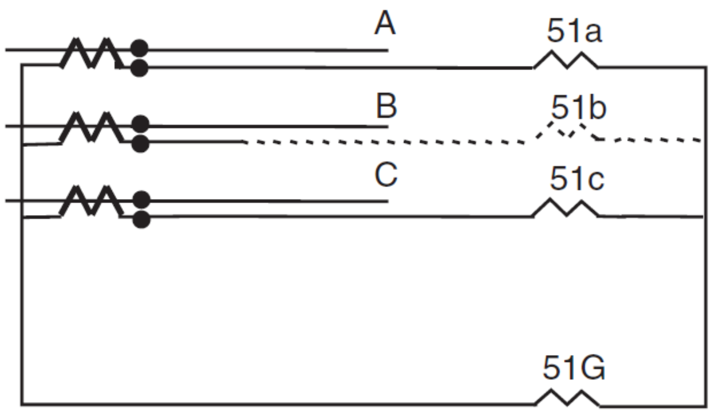


(b) ac circuit

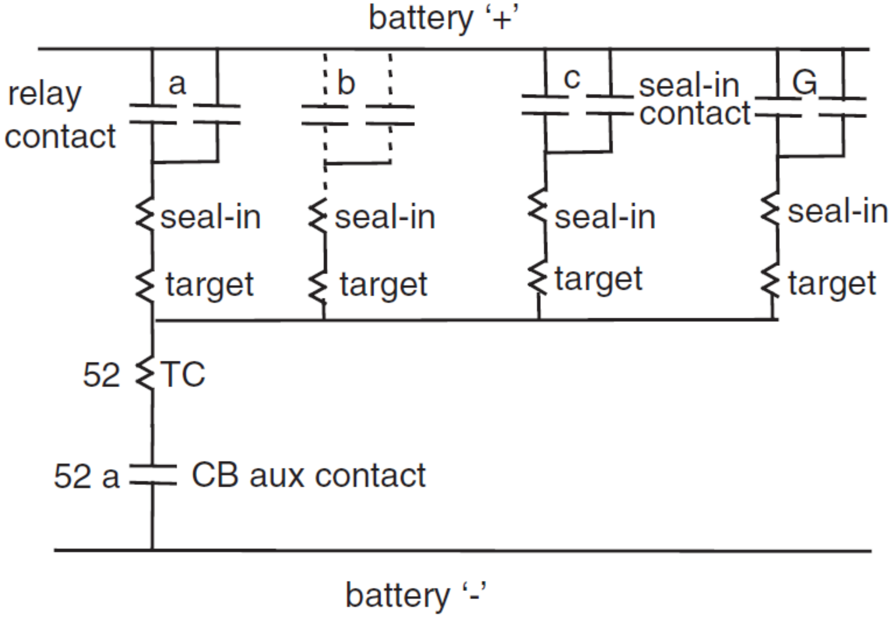
Device Function Numbers

51 = Phase overcurrent relay
e.g. 51a = phase a relay
51G = Ground overcurrent relay
52 = Circuit breaker
52a = Circuit breaker auxiliary “a” switch
52TC = Circuit breaker trip coil

Figure 4.4(a) shows a single-line representation of the three-phase power system showing the number of current transformers, their polarity marks, the fact that it is multiratio (MR), the total number of turns (1200/5), the actual connected ratio (600/5) and the number and type of relays connected to the CTs. On a fully completed one-line diagram there would be comparable notes describing the circuit breaker (52) type and mechanism as well as similar notes for other power equipment. Figure 4.4(b) shows the three-phase secondary AC circuit of the CTs and relays, and Figure 4.4(c) shows the relay DC tripping circuit details. The advantage of the third relay is shown by the dotted line. All faults are covered by at least two relays and so any one relay can be removed for maintenance or calibration leaving the other relay in service. The extra phase relay also provides a degree of redundancy, so that complete protection is still available if any of the relays develop a defect.



(b) ac circuit



(c) dc circuit

Device Function Numbers

51 = Phase overcurrent relay
e.g. 51a = phase a relay
51G = Ground overcurrent relay
52 = Circuit breaker
52a = Circuit breaker auxiliary "a" switch
52TC = Circuit breaker trip coil

From PSP book by Paithankar

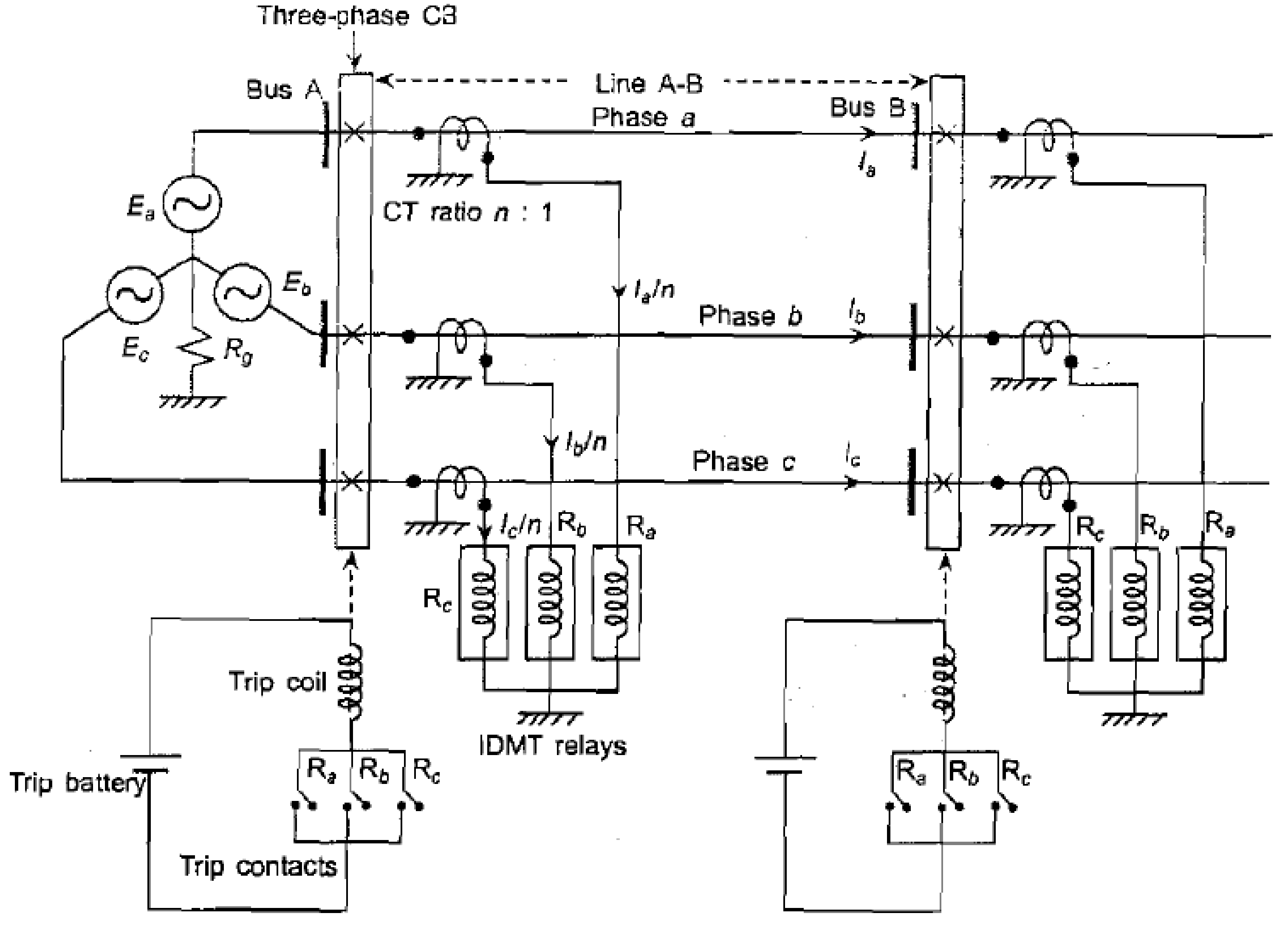


Figure 2.17 OC protection of a three-phase feeder.

Table 2.2 Protection of a three-phase feeder

Fault	*Relays which will operate*	
	Three-phase fault relays of Figure 2.17	*Two-phase fault + one ground fault relay of Figure 2.18*
a-g	R_a	R_a, R_g
b-g	R_b	R_g
c-g	R_c	R_c, R_g
a-b	R_a, R_b	R_a
b-c	R_b, R_c	R_c
c-a	R_c, R_a	R_c, R_a
a-b-g	R_a, R_b	R_a, R_g
b-c-g	R_b, R_c	R_c, R_g
c-a-g	R_a, R_c	R_a, R_c, R_g
a-b-c	R_a, R_b, R_c	R_a, R_c
a-b-c-g	R_a, R_b, R_c	R_a, R_c

From PSP book by Paithankar

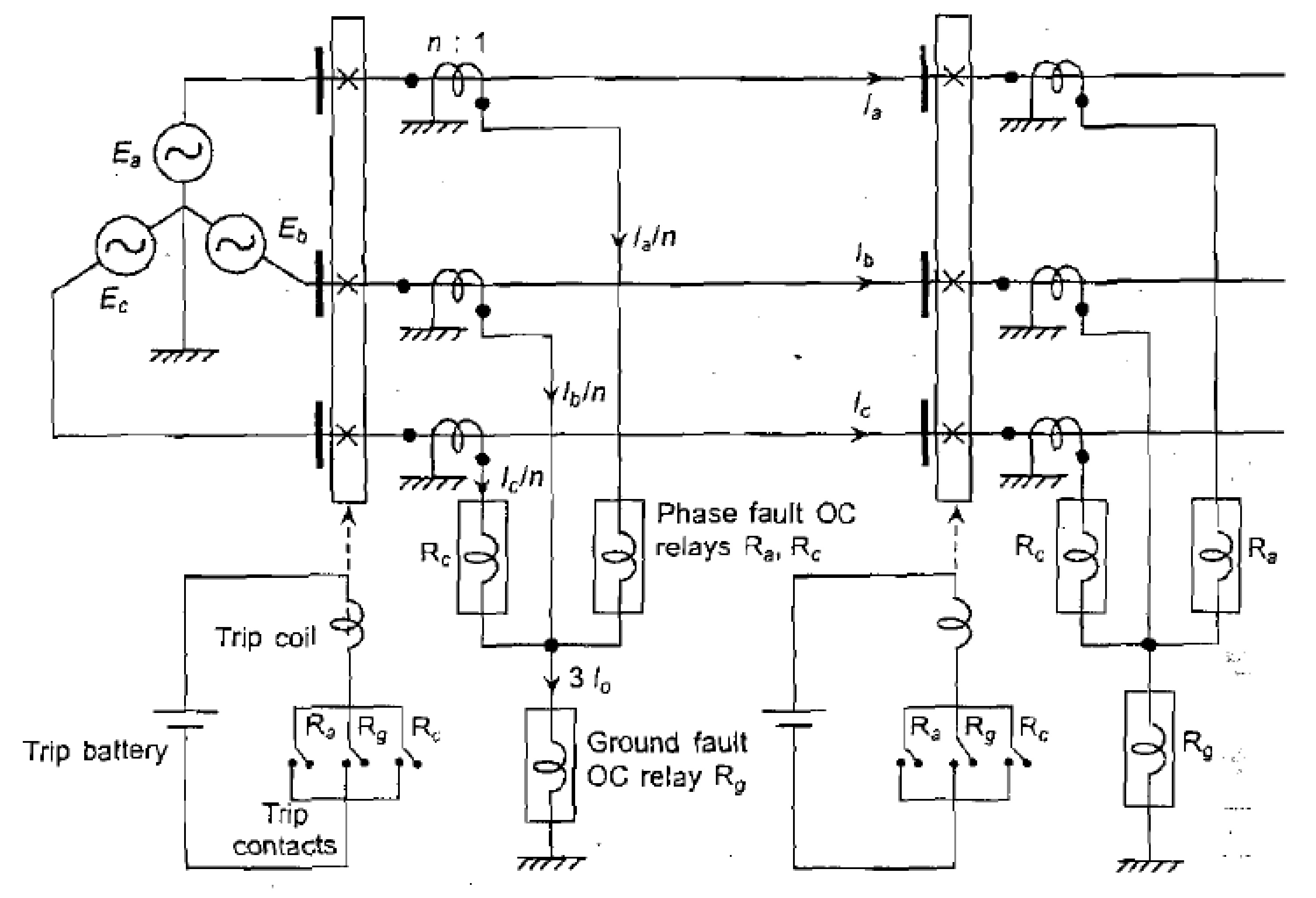


Figure 2.18 Two-phase fault relays and one ground fault relay for OC protection of a three-phase feeder.

Table 2.2 Protection of a three-phase feeder

Fault	Relays which will operate: Three-phase fault relays of Figure 2.17	Relays which will operate: Two-phase fault + one ground fault relay of Figure 2.18
a-g	R_a	R_a, R_g
b-g	R_b	R_g
c-g	R_c	R_c, R_g
a-b	R_a, R_b	R_a
b-c	R_b, R_c	R_c
c-a	R_c, R_a	R_c, R_a
a-b-g	R_a, R_b	R_a, R_g
b-c-g	R_b, R_c	R_c, R_g
c-a-g	R_a, R_c	R_a, R_c, R_g
a-b-c	R_a, R_b, R_c	R_a, R_c
a-b-c-g	R_a, R_b, R_c	R_a, R_c

4.3.2 Setting rules

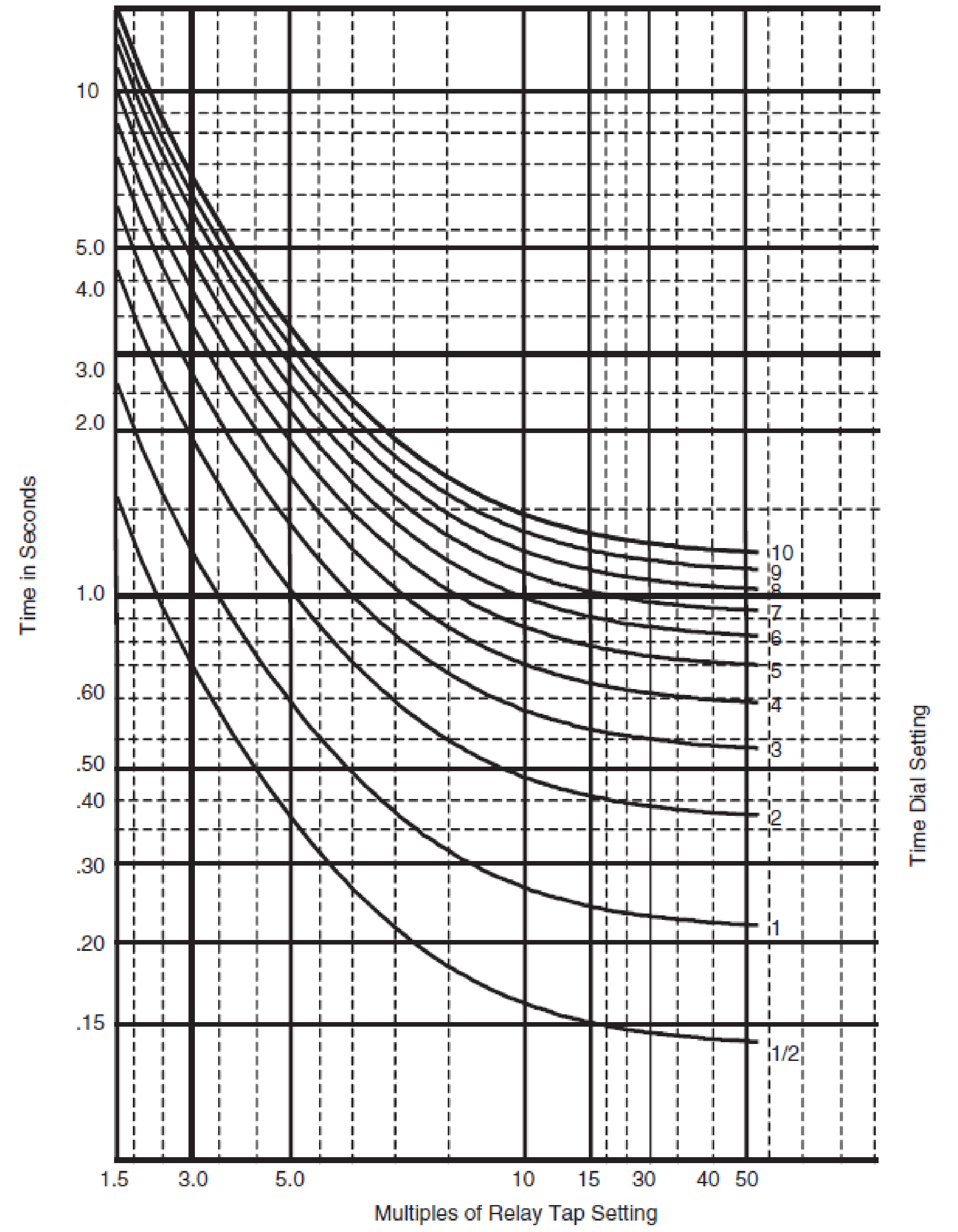
There are two settings that must be applied to all time-delay overcurrent relays: the pickup and the time delay.

Pickup setting

The pickup of a relay (as shown in Figure 2.12) is the minimum value of the operating current, voltage or other input quantity reached by progressive increases of the operating parameter that will cause the relay to reach its completely operated state when started from the reset condition.

Time-delay setting

The dial is marked from a setting of $\frac{1}{2}$ to 10, fastest to slowest operating times respectively.



Example 4.2

Referring to Figure 4.5, determine the operating time for a relay with a 4.0 A pickup, time dial setting of 1.0 and 12.0 A operating current.

The input current of 12 A corresponds to a value of $\frac{12}{4} = 3 \times$ pu. Using this value from the curve and the corresponding curve for the time dial setting of 1.0 gives us an operating time of 1.375 s.

As another example, for a relay with 5.0 A pickup, time dial setting of 2.0 and 15.0 A operating current, the operating current is $3 \times$ pu, and the operating time corresponding to a time dial setting of 2 is 2.25 s.

The operation of the relay is not consistently repeatable when the operating current is only slightly above its pickup setting. In electromechanical relays, the net operating torque is so low at this point that any additional friction or slight errors in calibration may prevent operation. In fact, most manufacturers' curves do not extend below $1.5 \times$ pu. Solid-state or digital relays are more precise, and can be applied with closer tolerances. Nevertheless, it is usual to calibrate the relay at some multiple of pickup (such as $3\times$ or $4\times$) to get consistent results. Similarly, the actual operating time may not correspond exactly to the time dial setting at any given multiple of pickup as given on the manufacturer's curve. The conservative approach is to calibrate the relay with the desired current (converted to $\times$ pu by dividing the operating current in secondary amperes by the pickup current) and to set the required time by small adjustments around the nominal dial setting.

Example 4.3

Referring again to Figure 4.5, determine the time-delay lever setting to achieve an operating time of 1.0 s for a relay set at 10.0 A pickup and an operating current of 50.0 A.

The input current of 50.0 A corresponds to a value of $\frac{50}{10} = 5 \times$ pu. Using this value on the abscissa and the operating time of 1.0 s on the ordinate, the corresponding time dial curve is 2.0.

As another example, consider a relay with a pickup setting of 5.0 A and the same operating time of 1.0 s and fault current of 50 A. The operating current is $\frac{50}{5} = 10 \times$ pu on the abscissa and 1.0 s operating time on the ordinate, corresponding to the curve of a time dial setting of 5.0.

Finally, consider a relay with the same pickup setting of 5.0 A, the same operating time of 1.0 s and an operating current of 35.0 A. The input current is $\frac{35}{5} = 7 \times$ pu which, at an operating time of 1.25 s, corresponds to a time dial setting between the curves labeled 3 and 4. In electromechanical relay design the time dial is a continuous adjustment, so interpolation between two settings is possible, and a setting of 3.5 can be made. However, the exact time should be determined by test calibration. Other relay designs would require different methods of selecting the correct time dial setting.

Example 4.4

Referring to Figure 4.6, determine the CT ratio, pickup and time dial settings for the relay at breaker 1, assuming that no coordination with any other relay is required. Assume that the maximum load is 95 A, minimum fault is 600 A and the maximum fault is 1000 A. Select a CT ratio to give 5.0 A secondary current for maximum load, i.e. $\frac{95}{5} = 19 : 1$. Since this is not a standard CT ratio (refer to Table 3.1), we select the nearest CT ratio of 20 : 1 or 100 : 5. The relay pickup setting should be bracketed by twice the maximum load and one-third of the minimum fault. Using the actual CT ratio, twice maximum load is 190 A divided by 20, or a relay current of 9.5 A.

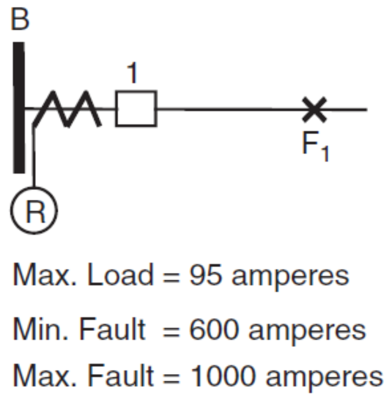


Figure 4.6 Time-delay overcurrent relay setting

Assuming the relay has taps 4.0, 6.0, 8.0, 10.0 and 12.0, we would select the 10.0 A tap, giving a primary current relay pickup of 200 A. Dividing by 95 A load current results in a margin of 2.1 $\times$ pu to prevent false operation (security). The minimum fault is 600 A divided by the relay pickup of 200 A, which gives 3 $\times$ pu to ensure correct operation (dependability). For this configuration no coordination is required, so one can set the time delay at the lowest dial setting (fastest time) of $\frac{1}{2}$.

After learning how to set an OC relay without any coordination with a downstream relay, let us now move to the case where coordination with a downstream relay is required.

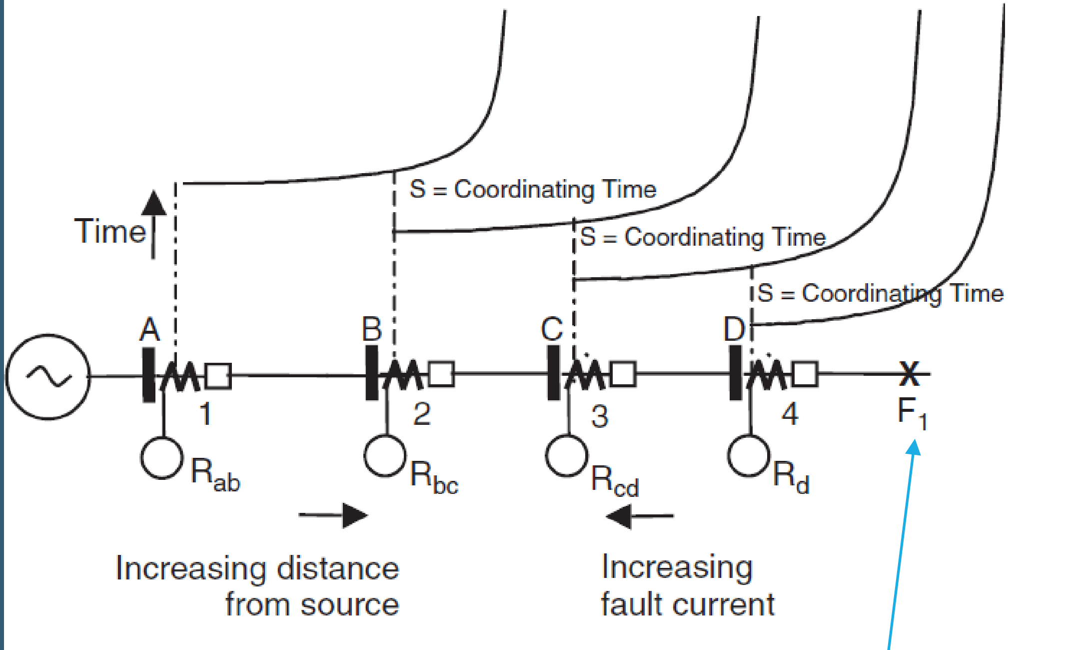


Figure 4.7 Relay coordination principles

F1 is the fault -

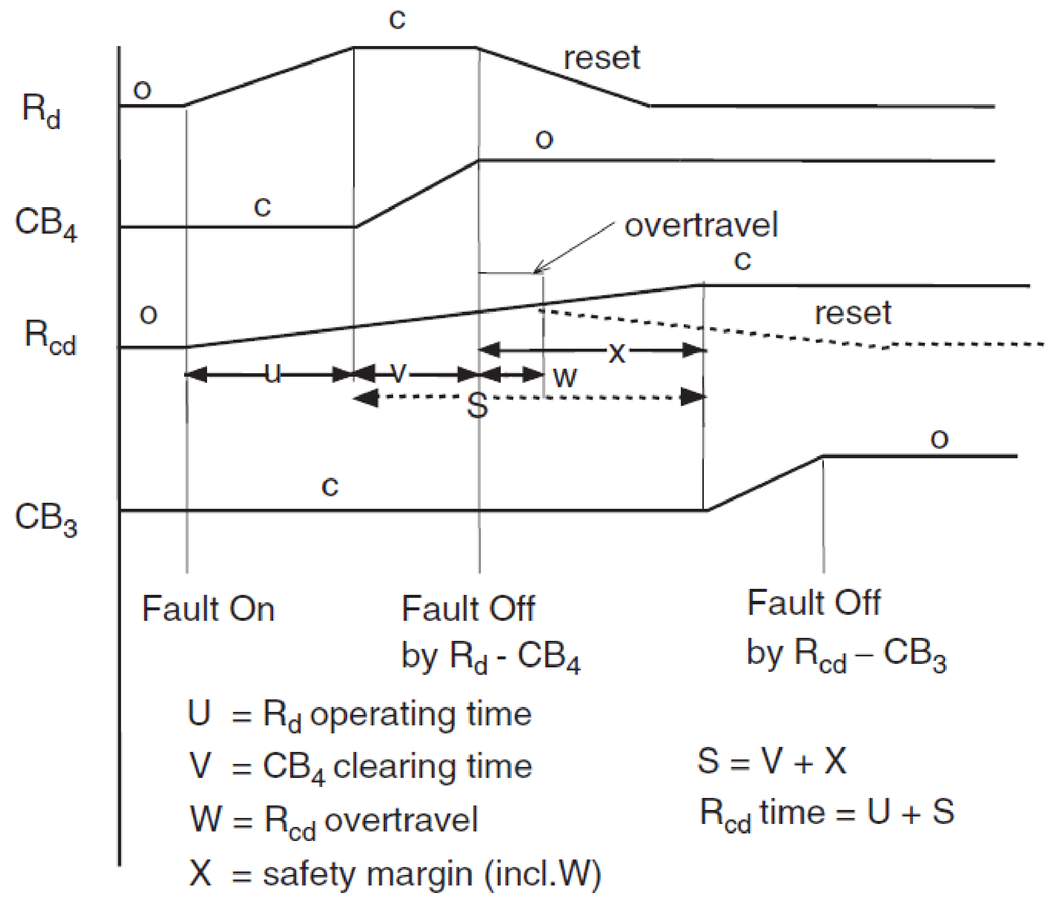


Figure 4.8 Time-delay overcurrent relay coordinating time

It is usual to add 0.3–0.5 s coordinating time to the operating time of R_d which is calculated at its maximum fault. The same fault current is used to determine the operating time of relay R_{cd}.

Example 4.5

Assume we have a radial system with two adjacent line segments as shown in Figure 4.9. The segment farthest from the source is set as shown in Example 4.4. The relay protecting the next line segment closest to the source must protect its own line and, if possible, back up the relays protecting the next line. The pickup should therefore be for the same primary current as the downstream relay and the time setting must coordinate with it. This time setting should be made with maximum current conditions, i.e. assuming a three-phase fault, with maximum generation behind the relay. In a radial system, all relays for which coordination is required must be examined for operation at this same primary current. (Example 4.6 shows how to coordinate relays in a looped system.) When coordination is achieved at maximum current, the shape of the inverse curves, provided they are all of the same family of inverseness, will ensure coordination at all lesser current values.

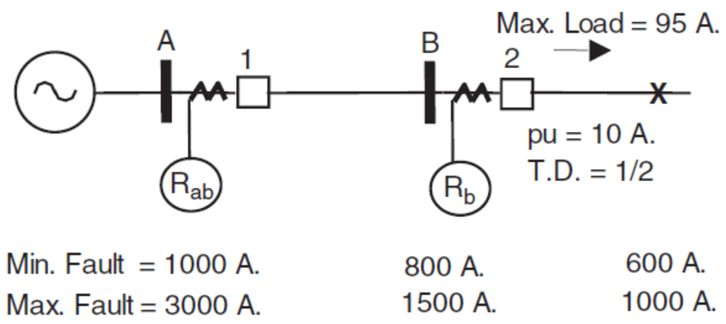


Figure 4.9 Time-delay overcurrent relay setting and coordination

From Example 4.4, the pickup setting of R_b is 10.0 A, and the time dial setting is $\frac{1}{2}$. Theoretically, to ensure that R_{ab} backs up R_b it should be set for the same pickup current, i.e. it sees the same faults, but is set at a slower (higher) time dial.* The operating time of R_b is determined from Figure 4.5 at the maximum fault current at bus B (1500 A) divided by its pickup setting (20×10 A) or $7.5 \times$ pu and the $\frac{1}{2}$ time dial. This is seen to be 0.25 s. Add 0.3 s coordinating time and R_{ab} operating time should be 0.55 s. If we make reference again to Figure 4.5, at the same maximum fault current of 1500 A at bus B and pu of 20×10 A, the multiple of the tap setting is $7.5 \times$ pu and the operating time is 0.55 s. Interpolating between the time dial setting curves of 1 and 2 gives a setting of 1.5. (The actual time dial should be determined by test.)

Example 4.6

Referring to Figure 4.10, there is more current in the relays at current breaker (CB) 5 with all lines in service than there is with line 3–4 out of service (8.33 versus 5.88 A). This helps the coordination between relays at CB 5 and relays at CB 1. With line 3–4 out of service, the infeed is no longer present and the current decreases in the relays at CB 5 (8.33 to 5.88 A) and increases in the relays at CB 1 (4.165 to 5.88 A). This is the critical case for coordination.

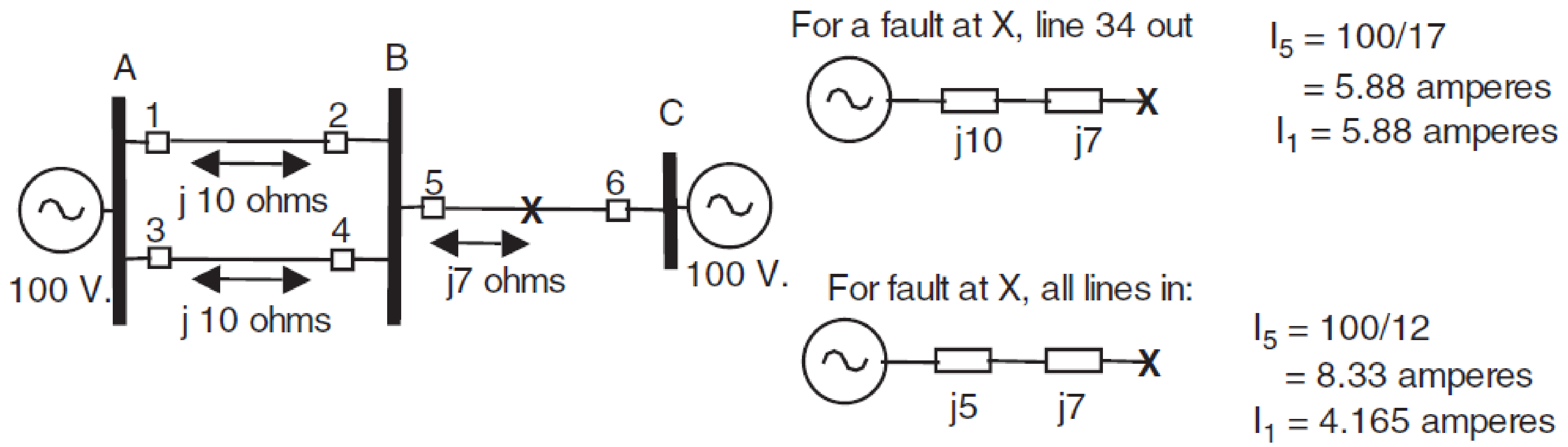


Figure 4.10 Effect of infeed

4.4 Instantaneous overcurrent relays

The relay must be set not to overreach the bus at the remote end of the line and there still must be enough of a difference in the fault current between the near and far end faults to allow a setting for the near-end fault. This will prevent the relay from operating for faults beyond the end of the line and, at the same time, will provide high-speed protection for an appreciable portion of the circuit.

Thus these relays are generally for their own section only and do not provide back-up to the next line section.

4.4.2 Setting rules

It is therefore common to set an instantaneous relay about 125–135 % above the maximum value for which the relay should not operate, and 90 % of the minimum value for which the relay should operate. Solid-state or digital relays can be set closer, e.g. 110 % above the maximum no-go value.

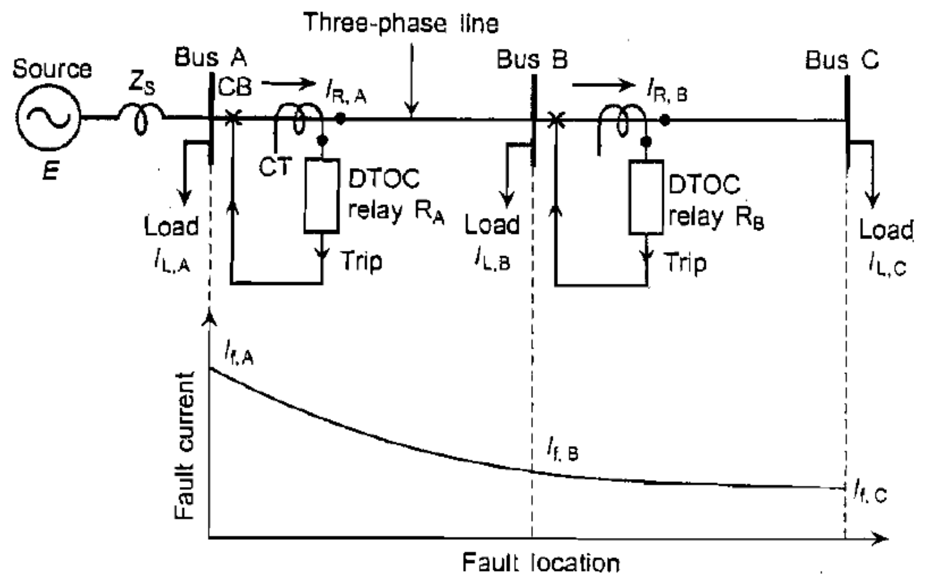


Figure to show concept of decline in fault current – this will be used for setting of inst. OC relay for a certain line section thus provide selectivity between two sections.

Since the instantaneous relay must not see beyond its own line section, the values for which it must operate are very much higher than even emergency loads. Therefore, load is not usually a consideration for the instantaneous relay

there is no need to set an instantaneous overcurrent relay with margins such as 200 % of load and one-third of fault current. However, in addition to the inaccuracies of the relay itself, there is a factor called 'transient overreach' that must be considered. Transient overreach is the tendency of a relay to instantaneously pick up for faults farther away than the setting would indicate. When discussing the parameter T in Chapter 3 (section 3.3), we noted that this factor is related to the time constant of the DC decay of the fault current; the slower the decay, the more overreach is possible. High-voltage transmission systems are more susceptible to transient overreach than lower voltage distribution systems because the latter have a lower X/R ratio in their line impedances. The tendency is also more pronounced in electromagnetic attraction relays than in induction-type relays. Transient overreach is usually only a concern for instantaneous or zone-1 relays. Their reach settings are more critical than backup relays, and backup relays have a time delay which allows the offset to decay. It is therefore common to set an instantaneous relay about 125–135 % above the maximum value for which the relay should not operate, and 90 % of the minimum value for which the relay should operate. Solid-state or digital relays can be set closer, e.g. 110 % above the maximum no-go value.

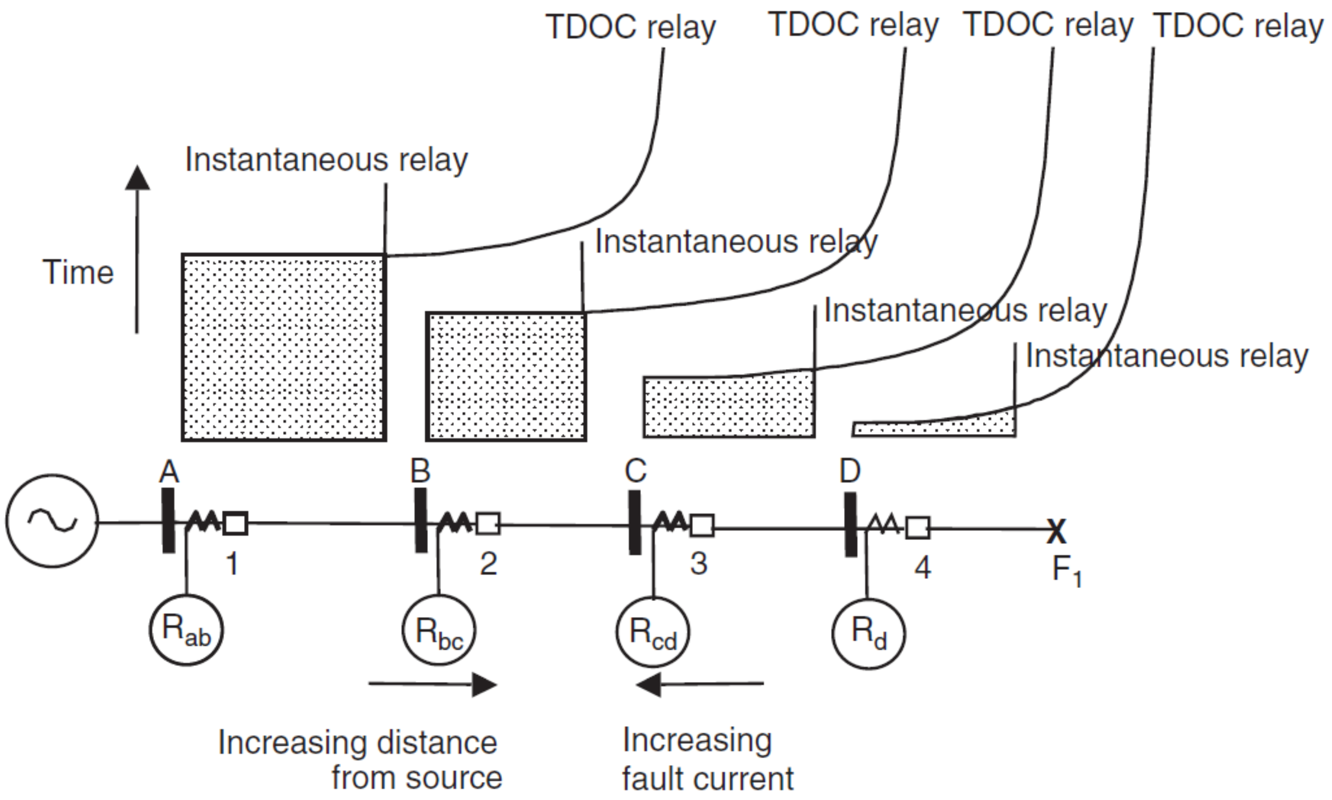


Figure 4.11 Application of instantaneous relays (TDOC, time-delay overcurrent)

This figure apparently gives the concept that use of inst. relays dedicated for a section can provide high speed protection, while at the same time – use of TDOC can give back up to the next section.

Example 4.7

Using Figure 4.9 and the same fault currents of Example 4.5, set the instantaneous relays at buses A and B.

Setting R_b

To avoid overreaching the terminal at the end of the line, R_b should be set at 135 % of the maximum fault at that location, i.e. $R_b = 135\% \times 1000$ A $= 1350$ A. Dividing by the 20 : 1 CT ratio to get relay current, the pickup of R_b is $1350/20 = 67.5$ A.

Check to see how the relay will perform for a minimum fault at bus B. The minimum fault at bus B is 800 A, divided by the relay pickup of 1350 A, giving a multiple of pickup of 0.59: **the relay will not operate.**

Check to see how the relay performs at the maximum current of 1500 A. 1500/1350 gives 1.11:- **barely above pickup.**

This provides very little line protection and an instantaneous relay would not be recommended in this situation.

Setting R_{ab}

Avoid overreaching bus B by setting $R_{ab} = 135\%$ times the maximum current at that bus, i.e. 1.35×1500 A $= 2025$ A.

Check the secondary current by dividing the primary current by the CT ratio: $2025/20 = 101.25$ A. Current over 100 A may cause saturation of the magnetic components and is too high for electromechanical relays. Depending upon the specific design, this current may also be too high for both solid-state and digital relays.

Referring again to Table 3.1, select the next highest standard CT ratio of 40 : 1. The relay current then becomes $2025/40 = 50.63$ A. Depending upon the actual breaker and CT configuration, this change in CT ratio may require that the setting of the time overcurrent relays, e.g. Example 4.5, may have to be recalculated.

Check the performance of the relay at minimum and maximum current at bus A. Pickup at 1000 A is $1000/2025 = 0.49$. **The relay will not pick up.** Pickup at 3000 A, however, is $3000/2025 = 1.48$ and the relay will pick up.

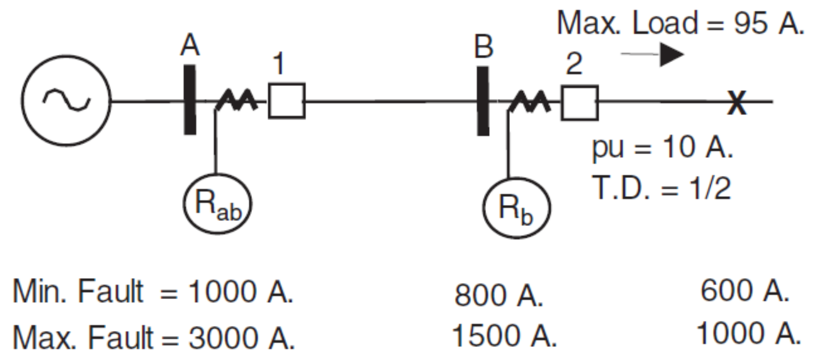
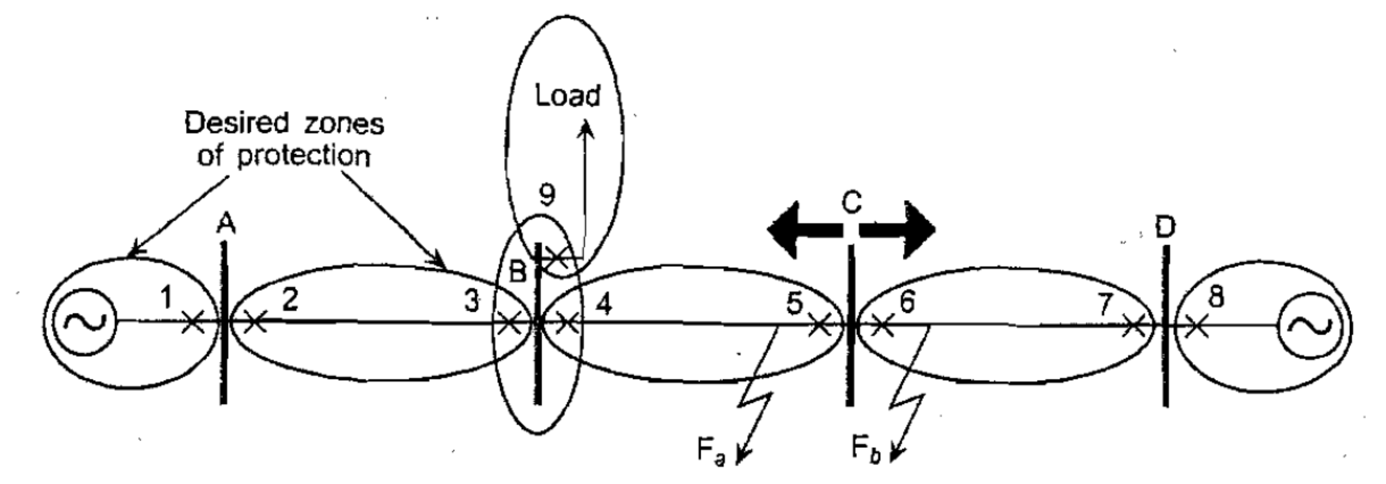


Figure 4.9 Time-delay overcurrent relay setting and coordination

From Paithankar's book

2.9 Directional Over-current Relay



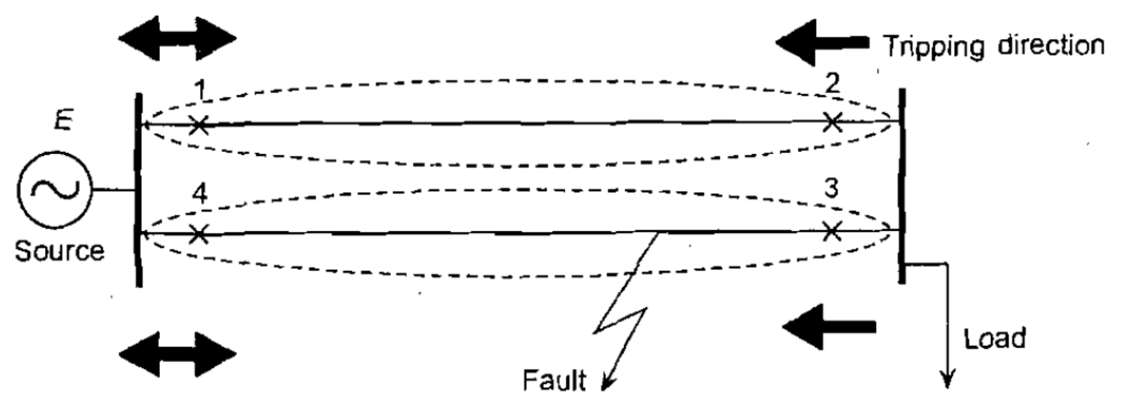
Consider fault F_a. As per the desired zones, only CBs 4 and 5 should trip. However, it can be easily seen that if plain OC relays are used, CBs 3, 4, 5, and 6 will all trip as the fault will be seen by OC relays at these locations. Thus, the desired zones are not generated. The desired relay response is shown in Table 2.3 with respect to faults F_a and F_b.

Table 2.3 Response of OC relays to generate desired zones of protection

Fault	*Direction of fault power flow at bus C as seen from 5*	*Desired response of OC relay at 5*	*Direction of fault power flow at bus C as seen from 6*	*Desired response of OC relay at 6*
F_a	Away from bus C	Trip	Towards bus C	Restrain
F_b	Towards bus C	Restrain	Away from bus C	Trip

From Paithankar’s book

2.9.1 Other Situations Where Directional OC Relays are Necessary

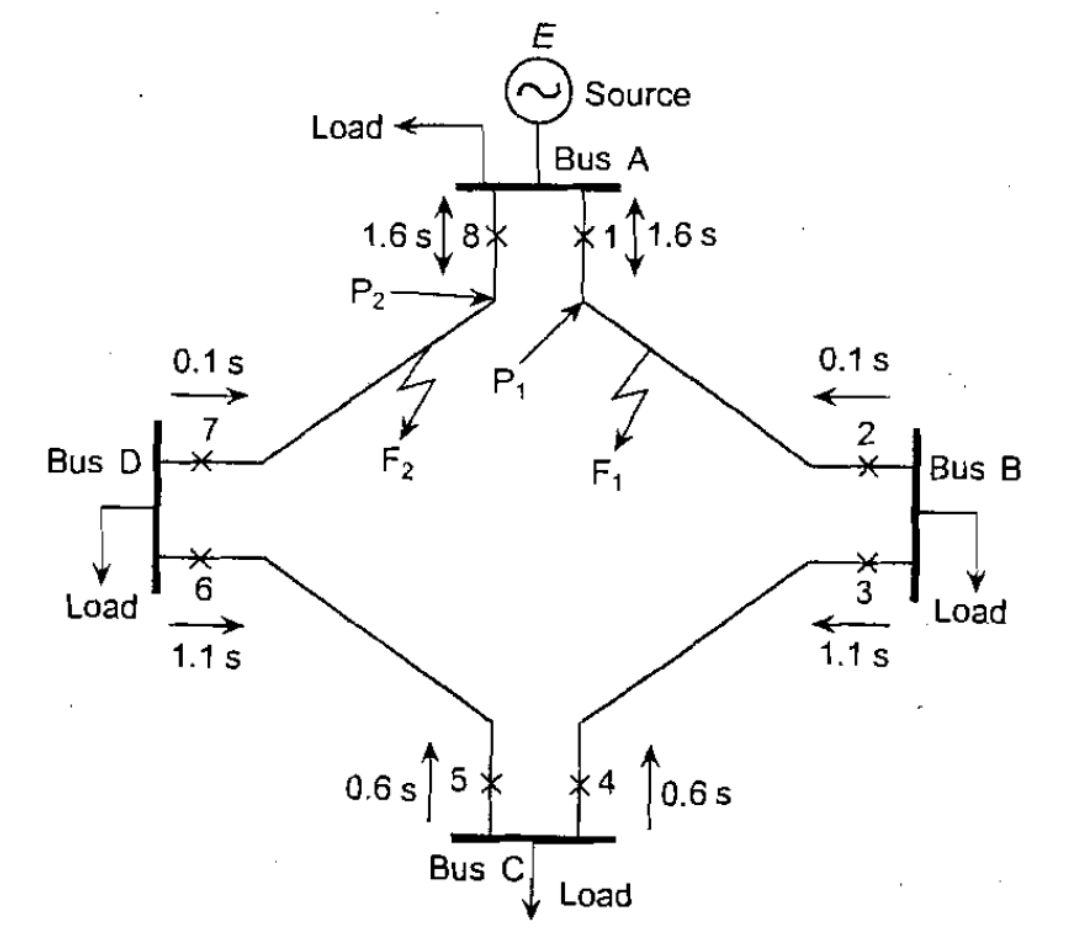


(b) Desired zones and tripping direction of OC relays

It may be noted that directional relays with tripping direction away from the bus will be required at locations ‘2’ and ‘3’ in Figure 2.20. However, at locations ‘1’ and ‘4’, non-directional over-current relays will suffice. Since directional relay units cost more and also need the provision of PTs, they should be used only when absolutely necessary.

From Paithankar's book

Consider the ring main feeder system shown in Figure 2.21. This is another situation where directional supervision of OC relays is called for. It is well known that the ring main feeder allows supply to be maintained to all the loads in spite of fault on any section of the feeder. A fault in any section causes only the CBs associated with that section to trip out, and because of the ring topology, power flows from the alternate path.



From Alstom’s book

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.

9.15.1 Grading of Ring Mains

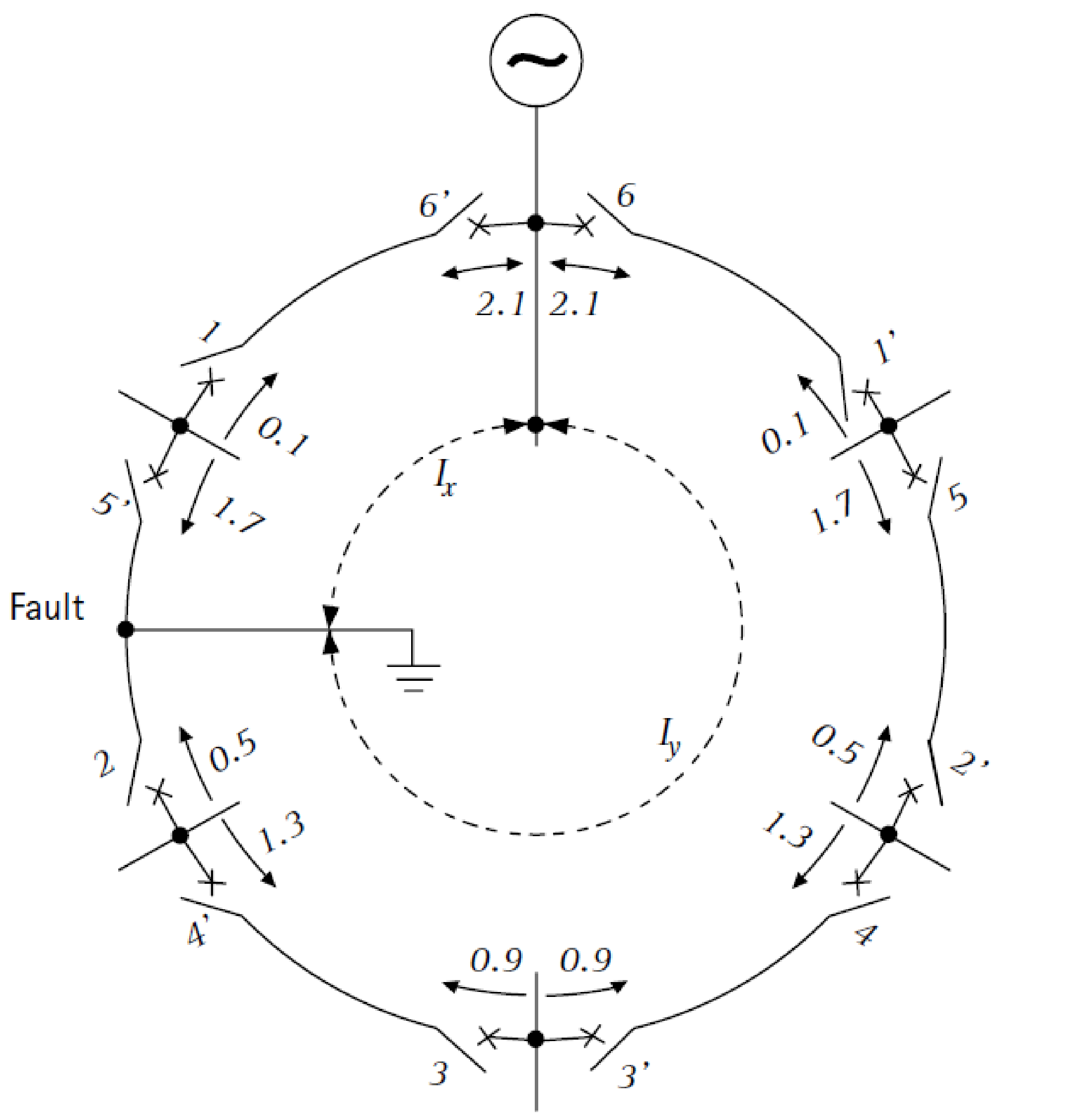
The usual grading procedure for relays in a ring main circuit is to open the ring at the supply point and to grade the relays first clockwise and then anti-clockwise. That is, the relays looking in a clockwise direction around the ring are arranged to operate in the sequence 1-2-3-4-5-6 and the relays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

From Alstom's book

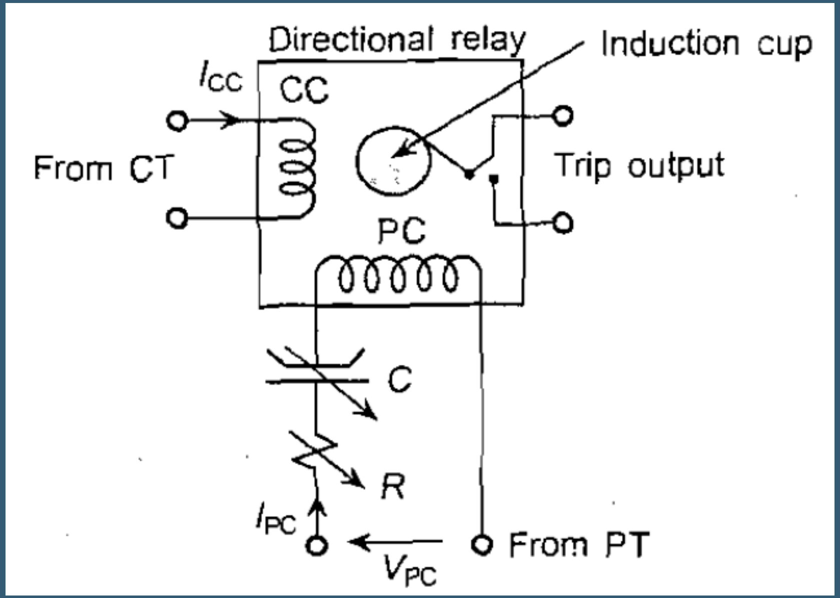
Thus, at each substation in the ring, one set of relays will be made inoperative because of the direction of current flow, and the other set operative. It will also be found that the operating times of the relays that are inoperative are faster than those of the operative relays,

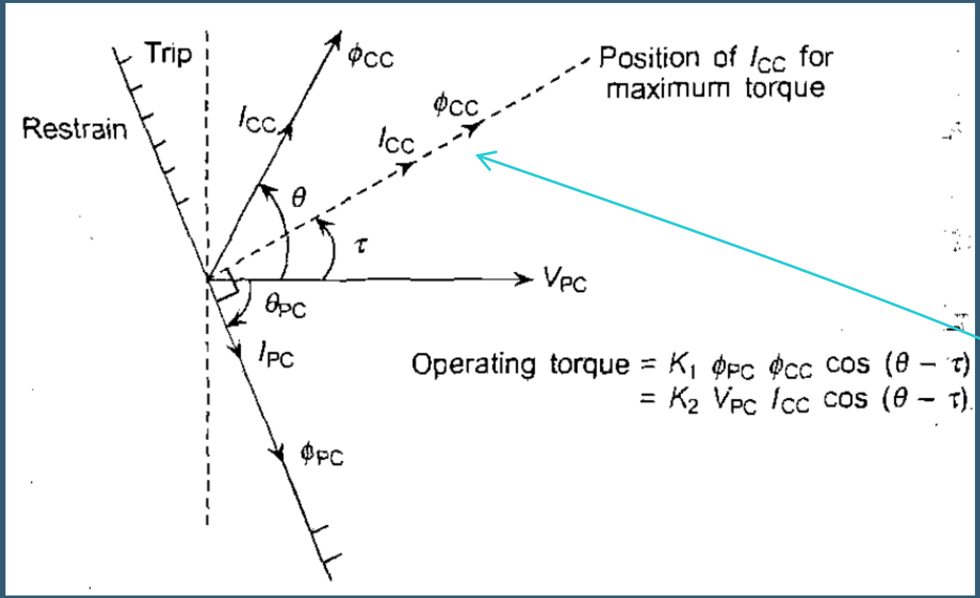
Consequently, the faulted line is the only one to be disconnected from the ring and the power supply is maintained to all the substations.

The purpose of presenting the ring mains system over here is to give another example of necessity of directional protection.



Characteristics of directional relay





V_{PC} is the voltage applied to the pressure coil. The current drawn by the pressure coil I_{PC} lags the voltage by a large angle θ_{PC}.

Now, in a relay based on induction principle, the two fluxes responsible for torque production, ϕ_{PC} and ϕ_{CC} should be shifted in phase by 90°, for them to produce maximum torque.

Also, the torque becomes zero if Icc is in phase or at 180 degrees to IPC – thus variation of Icc angle from 0 to 180 (w.r.t. IPC) gives the +ve torque region i.e. the operating region and vice versa gives the restraining region.

Since the pressure coil is highly inductive, the value of θ_{PC} is of the order of 70° to 80°. This gives MTA of 20° to 10°. However, θ_{PC} and hence τ can be adjusted to any desired value if an external resistance or capacitance is introduced into the pressure coil circuit.

As the currents are in phase with fluxes, hence to achieve max. torque, Icc should be at right angel to IPC – this position of Icc is the MTA line.

τ is the angle of Icc w.r.t Vpc
And it becomes MTA when Icc is at right angle to Ipc.

No - Torque is angle of the MTA line - Theta is the angle of Icc

Polarizing

the ability to differentiate between a fault in one direction or another is obtained by comparing the phase angle of the operating current phasor, which varies directly with the direction of the fault, and some other system parameter that is not dependent on the fault location. This constant parameter is referred to as the polarizing quantity.

2.9.3 Application of Directional Relay to a Three-phase Feeder

In case of application of directional relays to a three-phase feeder, phase faults need to be considered separately from ground faults. There are various possibilities of energizing these relays; hence the various alternatives need to be carefully considered.

The directional relay must meet the following requirements:

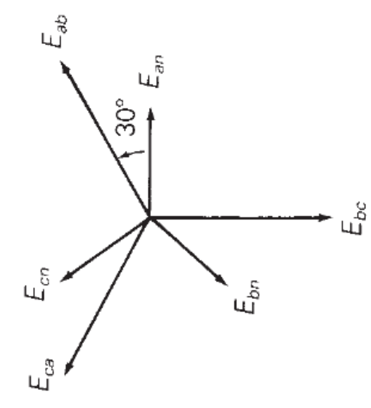
1. The relay must operate for forward faults.
2. The relay must restrain during reverse faults.
3. The relay must not operate during faults other than for which it has been provided, i.e. the relay must not maloperate.

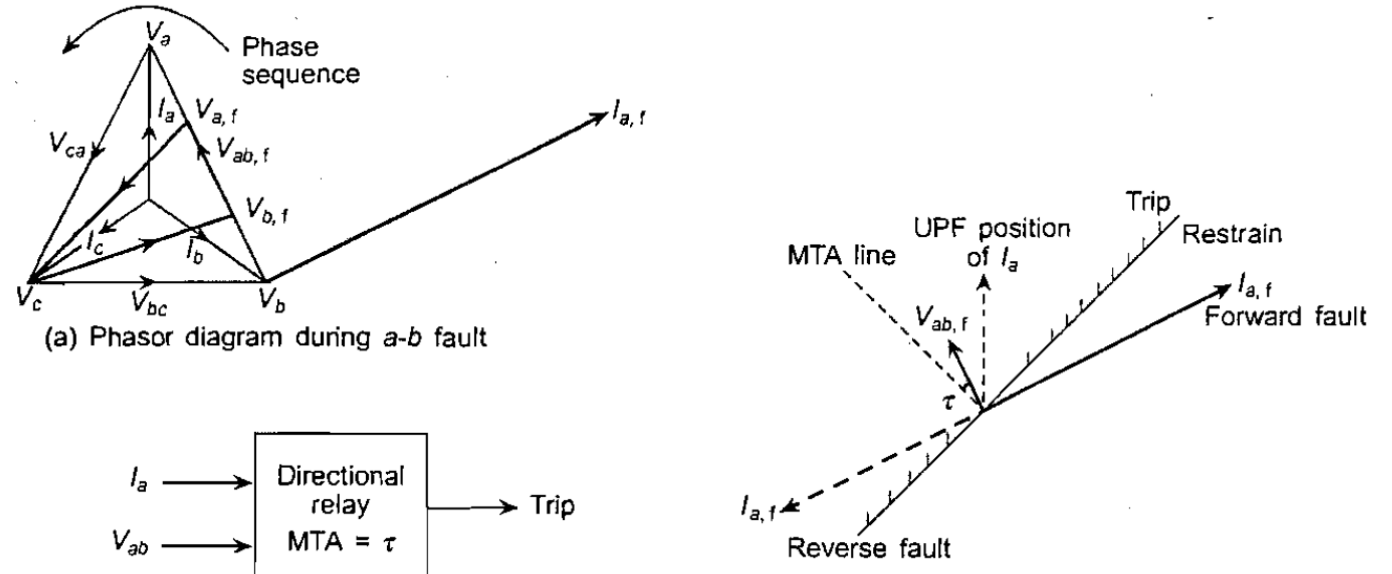
Directional phase fault protection

Figures 2.24 and 2.25 explore the possibility of using voltage V_{ab} and V_{ca} for the pressure coil of the directional relay catering to phase faults involving phase a.

From Figure 2.24, it can be seen that the voltage V_{ab} tends to collapse during a-b fault. Further, the angle between V_{ab} and I_a during fault is substantially large. For the MTA angle shown, the relay does not develop positive torque during forward fault.

The construction of line-line voltage phasors is not apparent, so I am attaching a fig. from PSA by Glover – notice the position of Ean, Ebn and then Eab.





(a) Phasor diagram during a-b fault

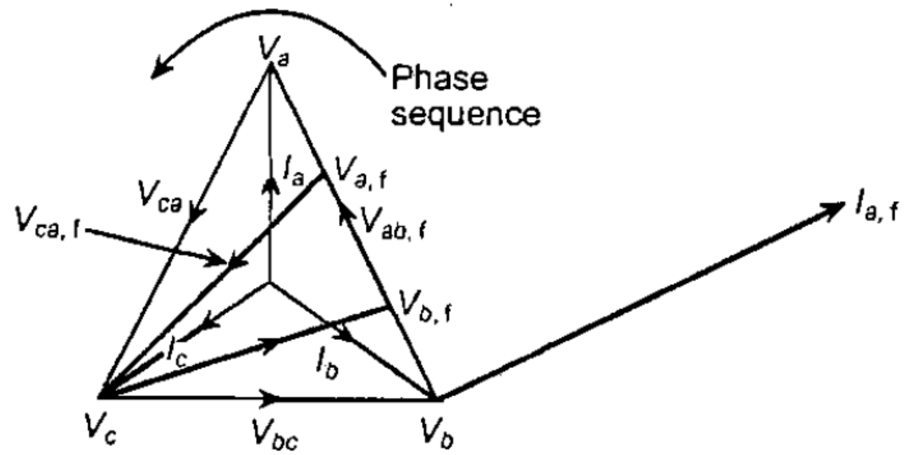
(b) Exploring the possibility of energizing the phase a directional relay with V_{ab}

(c) Phasor relationships during UPF load, forward and reverse fault for phase a directional relay energized by I_a and V_{ab}

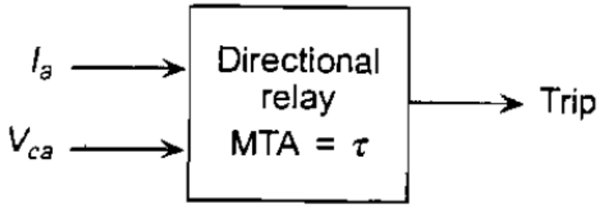
Figure 2.24 Exploring the possibility of energizing the pressure coil of phase a directional relay with voltage V_{ab}.

MTA line is at around 20 degrees to Vab,f – similar to that in the slide explaining concept of MTA with menion of Vpc and Icc.

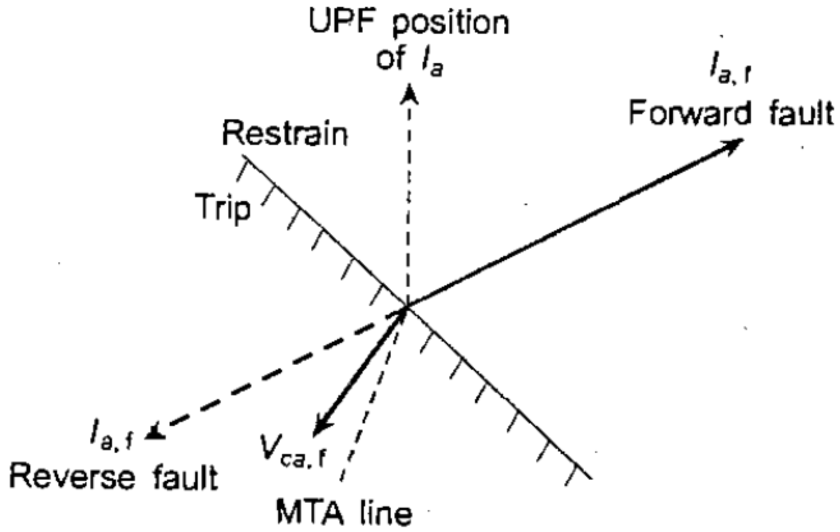
Ia,f should be around the MTA line to give max torque – but instead of being close, Ia,f is not even in the same trip region.



(a) Phasor diagram during *a-b* fault



(b) Exploring the possibility of energizing the phase *a* directional relay with V_{ca}



(c) Phasor relationships during UPF load, forward and reverse fault for phase *a* directional relay energized by I_a and V_{ca}.

Figure 2.25 Exploring the possibility of energizing pressure coil of phase *a* directional relay with voltage V_{ca}.

Figure 2.26 shows that the voltage V_{bc} happens to be the correct choice. Since the unity power factor (UPF) position of I_a leads V_{bc} by 90°, this connection is known as the 90° connection.

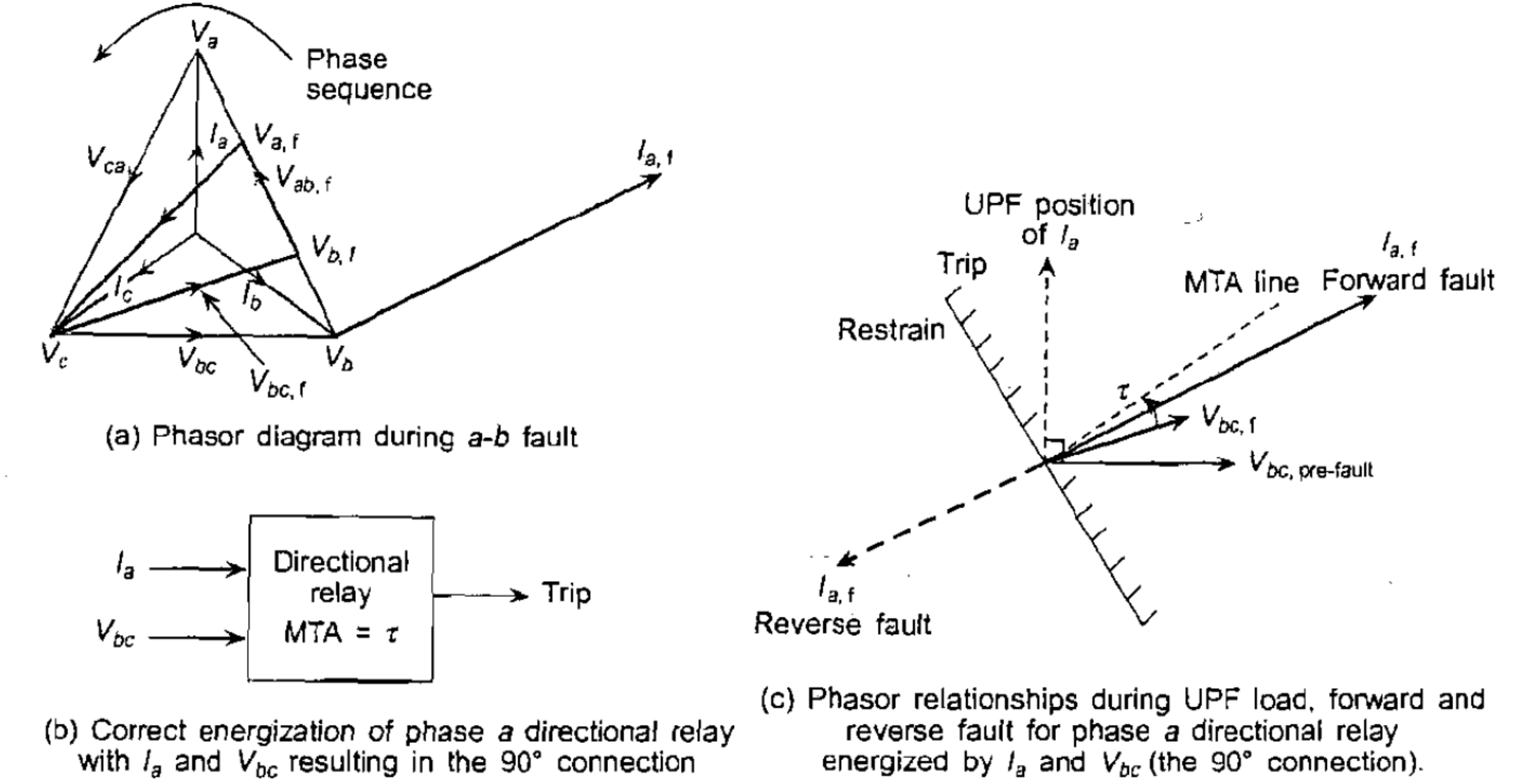


Figure 2.26 Correct energization of directional relay: 90° connection.

The 30° and the 60° connections

As already pointed out there are other possibilities for energizing the voltage coils of directional relays. However, all the possible voltages may not meet the requirement of no maloperations. Hence, the choice has been narrowed down to three. The other two possible voltages, for phase a directional relay, are V_{ac} and $(V_{ac} + V_{bc})$. These are known as the 30° and the 60° connections because of the angular relationship between the unity power factor (UPF) position of I_a and these voltages during the pre-fault condition.

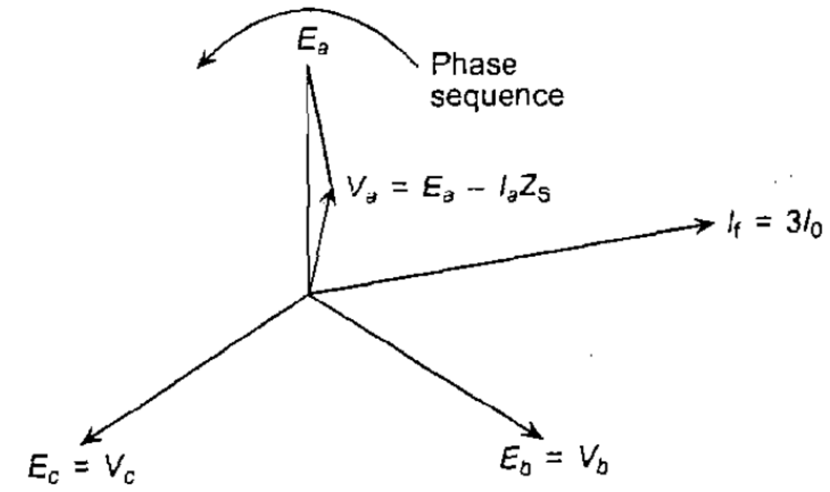
Table 2.4 summarizes various combinations of voltages and currents to be fed to directional phase fault relays catering to phase faults involving the three phases, for the 90°, 30° and 60° connections.

Table 2.4 Summary of phase fault relay excitation

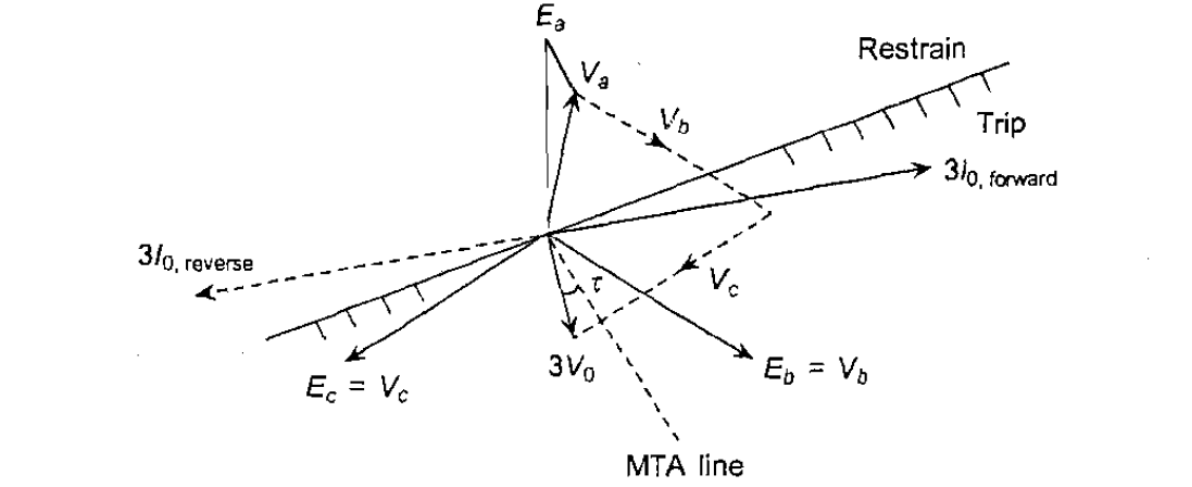
Type of connection	*Phase faults involving phase, a*		*Phase faults involving phase, b*		*Phase faults involving phase, c*	
	Current	*Voltage*	*Current*	*Voltage*	*Current*	*Voltage*
90°	I_a	V_{bc}	I_b	V_{ca}	I_c	V_{ab}
30°	I_a	V_{ac}	I_b	V_{ba}	I_c	V_{cb}
60°	I_a	$V_{ac} + V_{bc}$	I_b	$V_{ba} + V_{ca}$	I_c	$V_{cb} + V_{ab}$

Directional ground fault protection

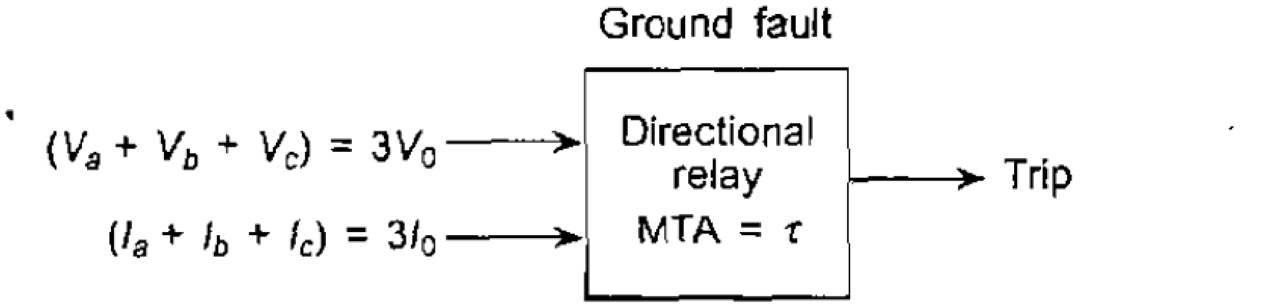
The directional ground fault relay develops correct tripping tendency when fed by the residual current I_0 and residual voltage V_0. This is shown in Figure 2.27.



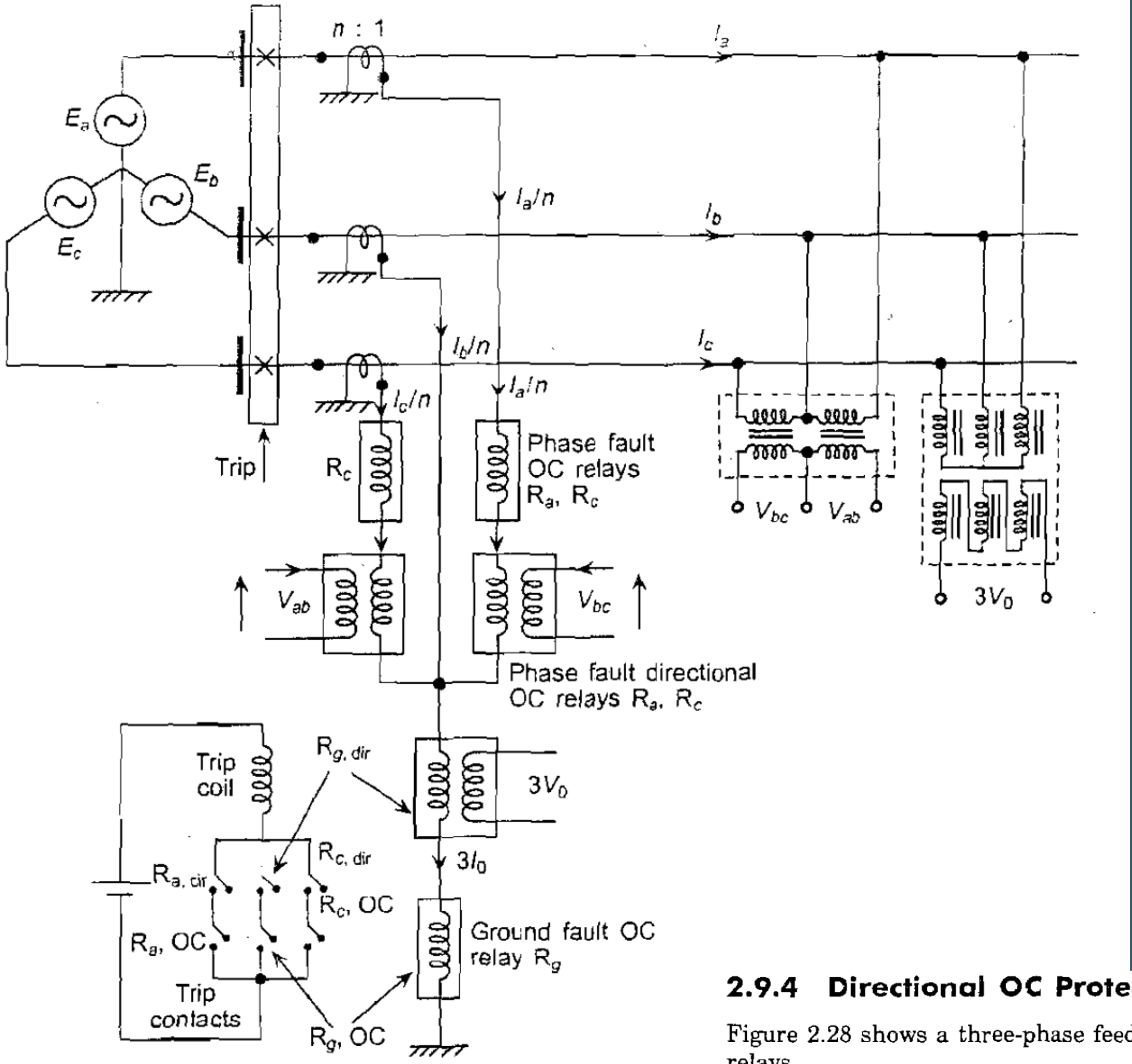
(a) Phasor diagram for *a-g* fault



(b) Phasor relationships between actuating quantities during forward and reverse faults



(c) Directional ground fault relay energized by residual voltage and current



2.9.4 Directional OC Protection of a Three-phase Feeder

Figure 2.28 shows a three-phase feeder protected by directional relays supervised by OC relays.