# B3

# Industrial & Commercial Power System Protection

## Network Protection & Automation Guide

Life Is On | Schneider Electric

Chapter

# B3

# Industrial & Commercial Power System Protection

# 1. Introduction

As industrial and commercial operations processes and plants have become more complex and extensive (Figure B3.1), the requirement for improved reliability of electrical power supplies has also increased. The potential costs of outage time following a failure of the power supply to a plant have risen dramatically as well. The introduction of automation techniques into industry and commerce has naturally led to a demand for the deployment of more power system automation, to improve reliability and efficiency.

The protection and control of industrial power supply systems must be given careful attention. Many of the techniques that have been evolved for EHV power systems may be applied to lower voltage systems also, but typically on a reduced scale. However, industrial systems have many special problems that have warranted individual attention and the development of specific solutions.

Many industrial plants have their own generation installed. Sometimes it is for emergency use only, feeding a limited number of busbars and with limited capacity. This arrangement is often adopted to ensure safe shutdown of process plant and personnel safety. In other plants, the nature of the process allows production of a substantial quantity of electricity, perhaps allowing export of any surplus to the public supply system – at either sub-transmission or distribution voltage levels. Plants that run generation in parallel with the public supply distribution network are often referred to as co-generation or embedded generation. Special protection arrangements may be demanded for the point of connection between the private and public Utility plant see Chapter [C8: Generator and Generator-Transformer Protection] for further details).

Industrial systems typically comprise numerous cable feeders and transformers. Chapter [C7: Transformer and Transformer-Feeder Protection] covers the protection of transformers and Chapters [C1: Overcurrent Protection for Phase and Earth Faults] and [C2: Line Differential Protection], the protection of feeders.

**Figure B3.1:**
**Large modern industrial plant**

# 2. Busbar arrangement

The arrangement of the busbar system is obviously very important, and it can be quite complex for some very large industrial systems. However, in most systems a single busbar divided into sections by a bus-section circuit breaker is common, as illustrated in Figure B3.2. Main and standby drives for a particular item of process equipment will be fed from different sections of the switchboard, or sometimes from different switchboards.

The main power system design criterion is that single outages on the electrical network within the plant will not cause loss of both the main and standby drives simultaneously. Considering a medium sized industrial supply system as shown in Figure B3.3, with duplicated supplies and transformers. Certain important loads are segregated and fed from 'Essential Services Board(s)' or 'Emergency Boards' distributed throughout the plant. This enables maximum utilisation of the standby generator facility.

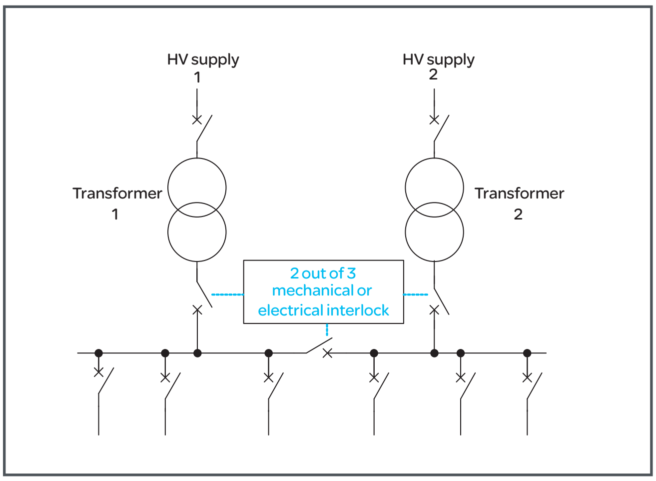


**Figure B3.2:**
**Typical switchboard configuration for an industrial plant**

# 2. Busbar arrangement



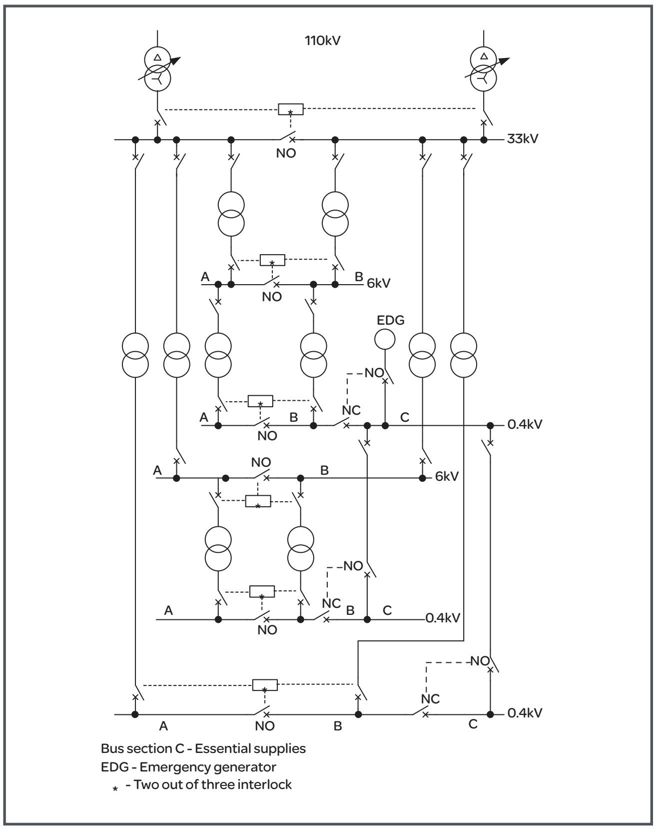


**Figure B3.3:**
**Typical industrial power system**

A standby generator is usually of the turbo-charged diesel-driven type. On detection of loss of incoming supply at any switchboard with an emergency section, the generator is automatically started. The appropriate circuit breakers will close once the generating set is up to speed and rated voltage to restore supply to the Essential Services sections of the switchboards affected, provided that the normal incoming supply is absent - for a typical diesel generator set, the emergency supply would be available within 10-20 seconds from the start sequence command being issued.

The Essential Services Boards are used to feed equipment that is essential for the safe shut down, limited operation or preservation of the plant and for the safety of personnel.

This will cover process drives essential for safe shutdown, venting systems, UPS loads feeding emergency lighting, process control computers, etc. The emergency generator may range in size from a single unit rated 20-30kW in a small plant up to several units of 2-10MW rating in a large oil refinery or similar plant. Large financial trading institutions may also have standby power requirements of several MW to maintain computer services.

# 3. Discrimination

Protection equipment works in conjunction with switchgear. For a typical industrial system, feeders and plant will be protected mainly by circuit breakers of various types and by fused contactors. Circuit breakers will have their associated overcurrent and earth fault relays. A contactor may also be equipped with a protection device (e.g. motor protection), but associated fuses are provided to break fault currents in excess of the contactor interrupting capability. The rating of fuses and selection of relay settings is carried out to ensure that discrimination is achieved – i.e. the ability to select and isolate only the faulty part of the system.

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# 4. HRC fuses

The protection device nearest to the actual point of power utilisation is most likely to be a fuse or a system of fuses and it is important that consideration is given to the correct application of this important device.

The HRC fuse is a key fault clearance device for protection in industrial and commercial installations, whether mounted in a distribution fuseboard or as part of a contactor or fuse-switch. The latter is regarded as a vital part of LV circuit protection, combining safe circuit making and breaking with an isolating capability achieved in conjunction with the reliable short-circuit protection of the HRC fuse. Fuses combine the characteristics of economy and reliability; factors that are most important in industrial applications.

HRC fuses remain consistent and stable in their breaking characteristics in service without calibration and maintenance. This is one of the most significant factors for maintaining fault clearance discrimination. Lack of discrimination through incorrect fuse grading will result in unnecessary disconnection of supplies, but if both the major and minor fuses are HRC devices of proper design and manufacture, this need not endanger personnel or cables associated with the plant.

### 4.1 Fuse characteristics

The time required for melting the fusible element depends on the magnitude of current. This time is known as the 'pre-arcing' time of the fuse. Vaporisation of the element occurs on melting and there is fusion between the vapour and the filling powder leading to rapid arc extinction.

Fuses have a valuable characteristic known as 'cut-off', illustrated in Figure B3.4. When an unprotected circuit is subjected to a short circuit fault, the r.m.s. current rises towards a 'prospective' (or maximum) value. The fuse usually interrupts the short circuit current before it can reach the prospective value, in the first quarter to half cycle of the short circuit. The rising current is interrupted by the melting of the fusible element, subsequently dying away to zero during the arcing period.

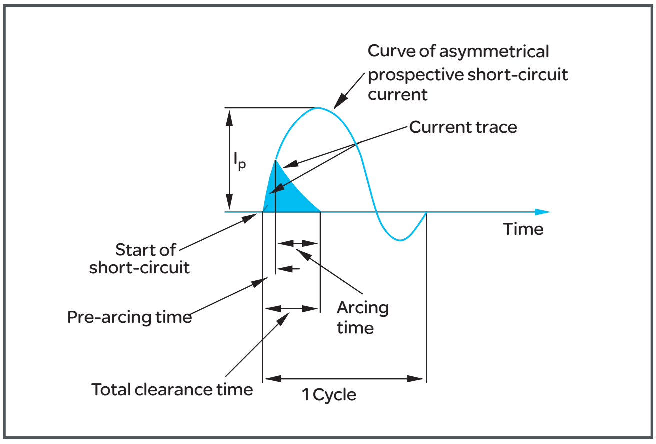


**Figure B3.4:**
**HRC fuse cut-off feature**

Since the electromagnetic forces on busbars and connections carrying short circuit current are related to the square of the current, it will be appreciated that 'cut-off' significantly reduces the mechanical forces produced by the fault current and which may distort the busbars and connections if not correctly rated. A typical example of 'cut-off' current characteristics is illustrated in Figure B3.5.

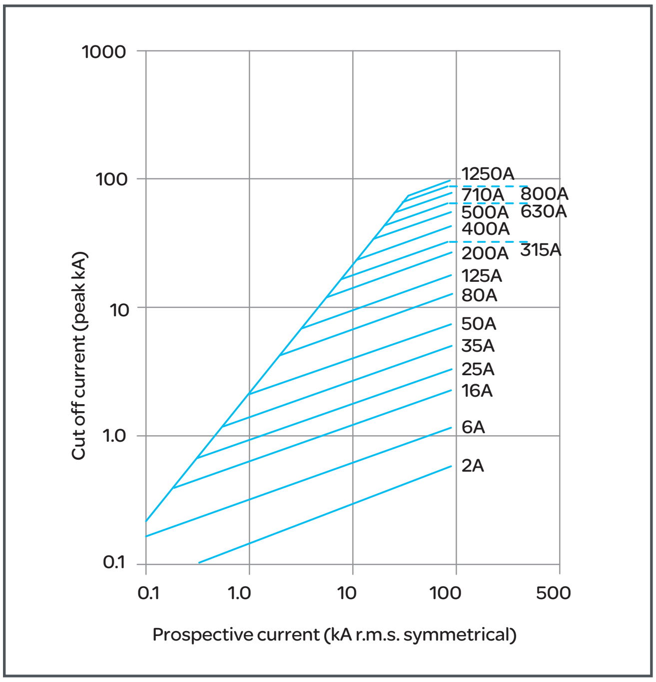


**Figure B3.5:**
**Typical fuse cut-off current characteristics**

It is possible to use this characteristic during the design stage of a project to utilise equipment with a lower fault withstand rating downstream of the fuse, than would be the case if 'cut-off' was ignored. This may save on costs, but appropriate documentation and maintenance controls are required to ensure that only replacement fuses of very similar characteristics are used throughout the lifetime of the plant concerned – otherwise a safety hazard may arise.

### 4.2 Discrimination between fuses

Fuses are often connected in series electrically and it is essential that they should be able to discriminate with each other at all current levels. Discrimination is obtained when the larger ('major') fuse remains unaffected by fault currents that are cleared by the smaller ('minor') fuse.

The fuse operating time can be considered in two parts:

**a.** the time taken for fault current to melt the element, known as the 'pre-arcing time'

**b.** the time taken by the arc produced inside the fuse to extinguish and isolate the circuit, known as the 'arcing time'

# 4. HRC fuses



The total energy dissipated in a fuse during its operation consists of 'pre-arcing energy' and 'arc energy'. The values are usually expressed in terms of $I^2t$, where $I$ is the current passing through the fuse and $t$ is the time in seconds. Expressing the quantities in this manner provides an assessment of the heating effect that the fuse imposes on associated equipment during its operation under fault conditions.

To obtain positive discrimination between fuses, the total $I^2t$ value of the minor fuse must not exceed the pre-arcing $I^2t$ value of the major fuse. In practice, this means that the major fuse will have to have a rating significantly higher than that of the minor fuse, and this may give rise to problems of discrimination. Typically, the major fuse must have a rating of at least 160% of the minor fuse for discrimination to be obtained.

### 4.3 Protection of cables by fuses

PVC cable is allowed to be loaded to its full nominal rating only if it has 'close excess current protection'. This degree of protection can be given by means of a fuse link having a 'fusing factor' not exceeding 1.5, where:

$$\text{Fusing factor} = \frac{Minimum\ Fusing\ Current}{Current\ Rating}$$

Cables constructed using other insulating materials (e.g. paper, XLPE) have no special requirements in this respect.

### 4.4 Effect of ambient temperature

High ambient temperatures can influence the capability of HRC fuses. Most fuses are suitable for use in ambient temperatures up to 35 °C, but for some fuse ratings, derating may be necessary at higher ambient temperatures. Manufacturers' published literature should be consulted for the de-rating factor to be applied.

### 4.5 Protection of motors

The manufacturers' literature should also be consulted when fuses are to be applied to motor circuits. In this application, the fuse provides short circuit protection but must be selected to withstand the starting current (possibly up to 8 times full load current) and also carry the normal full load current continuously without deterioration. Tables of recommended fuse sizes for both 'direct on line' and 'assisted start' motor applications are usually given. Examples of protection using fuses are given in Section 12.1.

# 5. Industrial circuit breakers

Some parts of an industrial power system are most effectively protected by HRC fuses, but the replacement of blown fuse links can be particularly inconvenient in others. In these locations, circuit breakers are used instead, the requirement being for the breaker to interrupt the maximum possible fault current successfully without damage to itself. In addition to fault current interruption, the breaker must quickly disperse the resulting ionised gas away from the breaker contacts, to prevent re-striking of the arc, and away from other live parts of equipment to prevent breakdown. The breaker, its cable or busbar connections, and the breaker housing, must all be constructed to withstand the mechanical forces resulting from the magnetic fields and internal arc gas pressure produced by the highest levels of fault current to be encountered.

The types of circuit breaker most frequently encountered in industrial systems are described in the following sections.

### 5.1 Miniature Circuit Breakers (MCBs)

MCBs are small circuit breakers, both in physical size but more importantly, in ratings. The basic single pole unit is a small, manually closed, electrically or manually opened switch housed in a moulded plastic casing. They are suitable for use on 230V a.c. single-phase/400V a.c. three-phase systems and for d.c. auxiliary supply systems, with current ratings of up to 125A. Contained within each unit is a thermal element, in which a bimetal strip will trip the switch when excessive current passes through it. This element operates with a predetermined inverse-time/current characteristic. Higher currents, typically those exceeding 3-10 times rated current, trip the circuit breaker without intentional delay by actuating a magnetic trip overcurrent element. The operating time characteristics of MCBs are not adjustable. European Standard EN 60898-2 defines the instantaneous trip characteristics, while the manufacturer can define the inverse time thermal trip characteristic. Therefore, a typical tripping characteristic does not exist. The maximum a.c. breaking current permitted by the standard is 25kA.

Single-pole units may be coupled mechanically in groups to form 2, 3 or 4 pole units, when required, by assembly on to a rail in a distribution board. The available ratings make MCBs suitable for industrial, commercial or domestic applications,

# 5. Industrial circuit breakers

for protecting equipment such as cables, lighting and heating circuits, and also for the control and protection of low power motor circuits. They may be used instead of fuses on individual circuits, and they are usually 'backed-up' by a device of higher fault interrupting capacity.

Various accessory units, such as isolators, timers, and undervoltage or shunt trip release units, may be combined with an MCB to suit the particular circuit to be controlled and protected. When personnel or fire protection is required, a residual current device (RCD) may be combined with the MCB. The RCD contains a miniature core balance current transformer that embraces all of the phase and neutral conductors to provide sensitivity to earth faults within a typical range of 0.05% to 1.5% of rated current, dependent on the RCD selected. The core balance CT energises a common magnetic trip actuator for the MCB assembly.

It is also possible to obtain current-limiting MCBs. These types open prior to the prospective fault current being reached, and therefore have similar properties to HRC fuses. It is claimed that the extra initial cost is outweighed by lifetime savings in replacement costs after a fault has occurred, plus the advantage of providing improved protection against electric shock if an RCD is used. As a result of the increased safety provided by MCBs fitted with an RCD device, they are tending to replace fuses, especially in new installations.

### 5.2 Moulded Case Circuit Breakers (MCCBs)

These circuit breakers are broadly similar to MCBs but have the following important differences:

**a.** the maximum ratings are higher, with voltage ratings up to 1000V a.c./1200V d.c. Current ratings of 2.5kA continuous/180kA r.m.s break are possible, dependent upon power factor

**b.** the breakers are larger, commensurate with the level of ratings. Although available as single, double or triple pole units, the multiple pole units have a common housing for all the poles. Where fitted, the switch for the neutral circuit is usually a separate device, coupled to the multi-pole MCCB

**c.** the operating levels of the magnetic and thermal protection elements may be adjustable, particularly in the larger MCCBs

**d.** because of their higher ratings, MCCBs are usually positioned in the power distribution system nearer to the power source than the MCBs

**e.** the appropriate European specification is EN 60947-2

Care must be taken in the short-circuit ratings of MCCBs. MCCBs are given two breaking capacities, the higher of which is its ultimate breaking capacity. The significance of this is that after breaking such a current, the MCCB may not be fit for continued use. The lower, or service, short circuit breaking capacity permits continued use without further detailed examination of the device. The standard permits a service breaking capacity of as little as 25% of the ultimate breaking capacity. While there is no objection to the use of MCCBs to break short-circuit currents between the service and ultimate values, the inspection required after such a trip reduces the usefulness of the device in such circumstances. It is also clearly difficult to determine if the magnitude of the fault current was in excess of the service rating.

The time-delay characteristics of the magnetic or thermal timed trip, together with the necessity for, or size of, a back-up device varies with make and size of breaker. Some MCCBs are fitted with microprocessor-controlled programmable trip characteristics offering a wide range of such characteristics. Time–delayed overcurrent characteristics may not be the same as the standard characteristics for dependent-time protection stated in IEC 60255-3. Hence, discrimination with other protection must be considered carefully.

There can be problems where two or more MCBs or MCCBs are electrically in series, as obtaining selectivity between them may be difficult. There may be a requirement that the major device should have a rating of k times the minor device to allow discrimination, in a similar manner to fuses – the manufacturer should be consulted as to value of k. Careful examination of manufacturers' literature is always required at the design stage to determine any such limitations that may be imposed by particular makes and types of MCCBs. An example of co-ordination between MCCBs, fuses and relays is given in Section 12.2.

### 5.3 Air Circuit Breakers (ACBs)

Air circuit breakers are frequently encountered on industrial systems rated at 3.3kV and below. Modern LV ACBs are available in current ratings of up to 6.3kA with maximum breaking capacities in the range of 85kA-120kA r.m.s., depending on system voltage.

This type of breaker operates on the principle that the arc produced when the main contacts open is controlled by directing it into an arc chute. Here, the arc resistance is increased and hence the current reduced to the point where the circuit voltage cannot maintain the arc and the current reduces to zero. To assist in the quenching of low current arcs, an air cylinder may be fitted to each pole to direct a blast of air across the contact faces as the breaker opens, so reducing contact erosion.

Air circuit breakers for industrial use are usually withdrawable and are constructed with a flush front plate making them ideal for inclusion together with fuse switches and MCBs/MCCBs in modular multi-tier distribution switchboards, so maximising the number of circuits within a given floor area.

Older types using a manual or dependent manual closing mechanism are regarded as being a safety hazard. This arises under conditions of closing the CB when a fault exists on the circuit being controlled. During the close-trip operation, there is a danger of egress of the arc from the casing of the CB, with a consequent risk of injury to the operator. Such types may be required to be replaced with modern equivalents. ACBs are normally fitted with integral overcurrent protection, thus avoiding the need for separate protection devices. However, the operating time characteristics of the integral protection are often designed to make discrimination with MCBs/MCCBs/fuses easier and so they may not be in accordance with the standard dependent time characteristics given in IEC 60255-3. Therefore, problems in co-ordination with discrete protection relays may still arise, but modern numerical relays have more flexible characteristics to alleviate such difficulties. ACBs will also have facilities for accepting an external trip signal, and this can be used in conjunction with an external relay if desired. Figure B3.6 illustrates the typical tripping characteristics available.

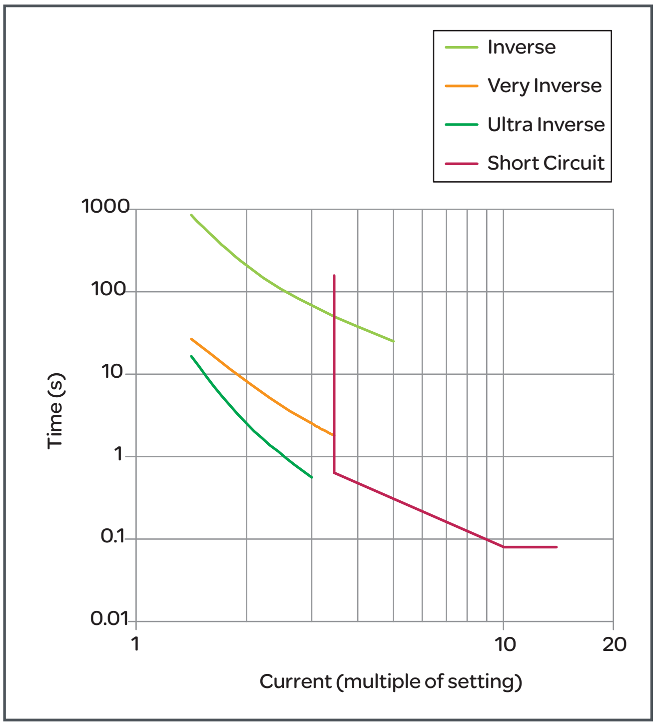


**Figure B3.6:**
**Typical tripping characteristics of an ACB**

### 5.4 Oil Circuit Breakers (OCBs)

Oil circuit breakers have been very popular for many years for industrial supply systems at voltages of 3.3kV and above. They are found in both 'bulk oil' and 'minimum oil' types, the only significant difference being the volume of oil in the tank.

In this type of breaker, the main contacts are housed in an oil-filled tank, with the oil acting as the both the insulation and the arc-quenching medium. The arc produced during contact separation under fault conditions causes dissociation of the hydrocarbon insulating oil into hydrogen and carbon. The hydrogen extinguishes the arc. The carbon produced mixes with the oil. As the carbon is conductive, the oil must be changed after a prescribed number of fault clearances, when the degree of contamination reaches an unacceptable level.

Because of the fire risk involved with oil, precautions such as the construction of fire/blast walls may have to be taken when OCBs are installed.

### 5.5 Vacuum Circuit Breakers (VCBs)

Since the introduction of vacuum switching technology in the 1960's, Vacuum switchgear has all but replaced Air Circuit Breaker (ACBs) and Oil Circuit Breaker (OCBs) at medium voltage levels.

Vacuum switchgear is rated for fault level up to 63kA with continuous ratings of greater than 5000A.

The vacuum interrupter is a compact, inherently reliable and maintenance free device with an expected life of more than 10,000 operations and is capable of interrupting full fault currents up to 100 times.

These characteristics have resulted in a dramatic reduction in switchgear maintenance compared to ACBs or OCBs and are used in a wide range of applications, including Distribution networks and medium to large industry.

The reduction in maintenance requirements and smaller dimensions have allowed the configuration of switchgear to be adapted from the conventional withdrawable pattern to a fixed pattern Air Insulated Switchgear (AIS, See Fig B3.7). Fixed pattern switchgear is generally more compact, easier to install and has simpler operation.

**Figure B3.7:**
**Typical air insulated vacuum contactor switchgear**

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# 5. Industrial circuit breakers

The fixed pattern is also available in a gas insulated configuration (GIS) where the Vacuum Interrupter and main current carrying parts are insulated with SF6 gas. This further enhances the compact nature of the design. Typically 36kV GIS has similar dimensions to 12kV AIS (See Figure B3.8).

**Figure B3.8:**
**Typical gas insulated vacuum contactor switchgear**

Gas Insulated Switchgear is normally found in higher voltage applications. i.e. 24kV and above.

A variation of vacuum switchgear is the vacuum contactor. This device has a limited fault interrupting rating and is used in conjunction with High Rupturing Capacity (HRC) fuses, The contactor has a very high operating duty – up to 1 million operations, and is typically used to switch MV motors.

### 5.6 SF6 circuit breakers

Circuit breakers using SF6 gas as the arc-quenching medium are also available and in some countries and for some applications are preferred. Generally these have similar ratings to those of vacuum switchgear and in some cases can be incorporated into the same cubicle as vacuum circuit breakers.

### 5.7 Improved safety

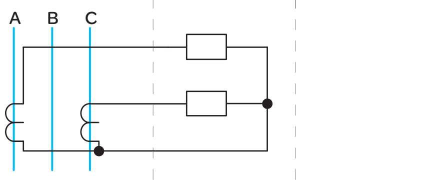
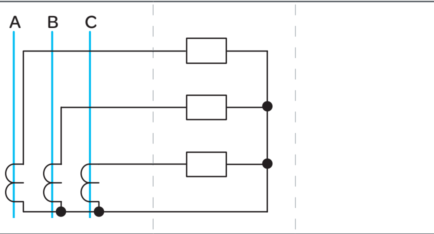
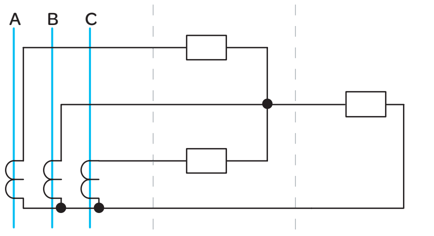
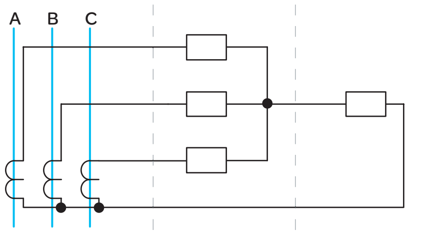
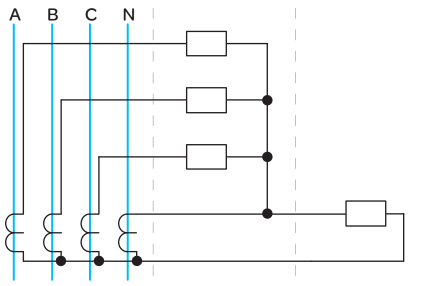
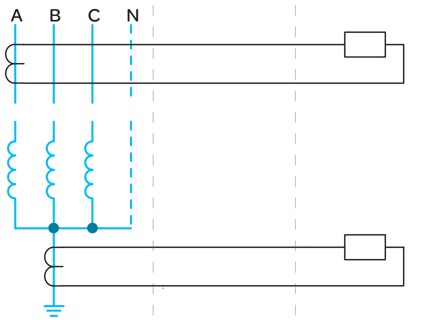
Changes in International Standards have resulted in improvements to operator safety. One area is Internal Arc (Arc Flash) protection. Many switchgear designs have passive protection 'built in' and are capable of controlling the effects of an internal arc fault even at the highest fault levels available.

To supplement this, or to improve the performance of existing switchgear, active solutions, which detect the occurrence of an arc fault and then initiate the disconnection of the supply, are available in conjunction with protection relay systems. For more details on arc protection solutions please refer to Chapter [C11: Arc Protection].

# 6. Protection relays

When the circuit breaker itself does not have integral protection, then a suitable external relay will have to be provided. For an industrial system, the most common protection relays are time- delayed overcurrent and earth fault relays. Chapter [C1: Overcurrent Protection for Phase and Earth Faults] provides details of the application of overcurrent relays.

Traditionally, for three wire systems, overcurrent relays have often been applied to two phases only for relay element economy. Even with modern multi-element relay designs, economy is still a consideration in terms of the number of analogue current inputs that have to be provided. Two overcurrent elements will detect any interphase fault, so it is conventional to apply two elements on the same phases at all relay locations. The phase CT residual current connections for an earth fault relay element are unaffected by this convention. Figure B3.9 illustrates the possible relay connections and limitations on settings.

| | CT connections | Phase elements | Residual current elements | System | Type of fault | Notes |
|---|---|---|---|---|---|---|
| (a) |  | | | 3Ph. 3w | Ph. - Ph. | Petersen coil and unearthed systems |
| (b) |  | | | 3Ph. 3w | (a) Ph. - Ph.<br>(b) Ph. - E* | * Earth-fault protection only if earth-fault current is not less than twice primary operating current |
| (c) | | | | 3Ph. 4w | (a) Ph. - Ph.<br>(b) Ph. - E*<br>(c) Ph. - N | |
| (d) |  | | | 3Ph. 3w | (a) Ph. - Ph.<br>(b) Ph. - E | Phase elements must be in same phases at all stations. Earth-fault settings may be less than full load |
| (e) |  | | | 3Ph. 3w | (a) Ph. - Ph.<br>(b) Ph. - E | Earth-fault settings may be less than full load |
| (f) | | | | 3Ph. 4w | (a) Ph. - Ph.<br>(b) Ph. - E<br>(c) Ph. - N | Earth-fault settings may be less than full load, but must be greater than largest Ph. - N load |
| (g) |  | | | 3Ph. 4w | (a) Ph. - Ph.<br>(b) Ph. - E<br>(c) Ph. - N | Earth-fault settings may be less than full load |
| (h) |  | | | 3Ph. 3w<br>or<br>3Ph. 4w | Ph. - E | Earth-fault settings may be less than full load |

Ph. = phase ; w = wire ; E = earth ; N = neutral

**Figure B3.9:**
**Overcurrent and earth fault relay connections**

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# 7. Co-ordination problems

There are a number of problems that commonly occur in industrial and commercial networks that are covered in the following sections.

### 7.1. Earth fault protection with residually-connected CTs

For four-wire systems, the residual connection of three phase CTs to an earth fault relay element will offer earth fault protection, but the earth fault relay element must be set above the highest single- phase load current to avoid nuisance tripping. Harmonic currents (which may sum in the neutral conductor) may also result in spurious tripping. The earth fault relay element will also respond to a phase-neutral fault for the phase that is not covered by an overcurrent element where only two overcurrent elements are applied. Where it is required that the earth fault protection should respond only to earth fault current, the protection element must be residually connected to three phase CTs and to a neutral CT or to a core-balance CT. In this case, overcurrent protection must be applied to all three phases to ensure that all phase-neutral faults will be detected by overcurrent protection. Placing a CT in the neutral earthing connection to drive an earth fault relay provides earth fault protection at the source of supply for a 4-wire system. If the neutral CT is omitted, neutral current is seen by the relay as earth fault current and the relay setting would have to be increased to prevent tripping under normal load conditions.

When an earth fault relay is driven from residually connected CTs, the relay current and time settings must be such that that the protection will be stable during the passage of transient CT spill current through the relay. Such spill current can flow in the event of transient, asymmetric CT saturation during the passage of offset fault current, inrush current or motor starting current. The risk of such nuisance tripping is greater with the deployment of low impedance electronic relays rather than electromechanical earth CBCT connection for four-wire system fault relays which presented significant relay circuit impedance. Energising a relay from a core balance type CT generally enables more sensitive settings to be obtained without the risk of nuisance tripping with residually connected phase CTs. When this method is applied to a four-wire system, it is essential that both the phase and neutral conductors are passed through the core balance CT aperture. For a 3-wire system, care must be taken with the arrangement of the cable sheath, otherwise cable faults involving the sheath may not result in relay operation (Figure B3.10).

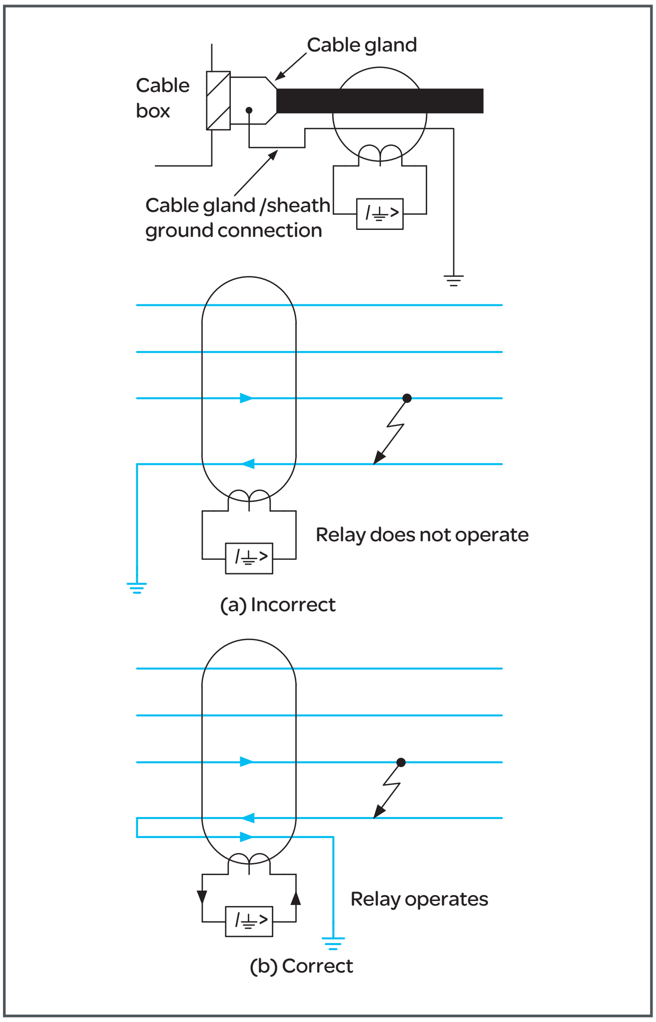


**Figure B3.10:**
**CBCT connection for four-wire system**

### 7.2 Four-wire dual-fed substations

The co-ordination of earth fault relays protecting four-wire systems requires special consideration in the case of low voltage, dual-fed installations. Horcher [Ref B3.1: Overcurrent Relay Co-ordination for Double Ended Substations] has suggested various methods of achieving optimum co-ordination. Problems in achieving optimum protection for common configurations are described below.

#### *7.2.1 Use of 3-pole CBs*

When both neutrals are earthed at the transformers and all circuit breakers are of the 3-pole type, the neutral busbar in the switchgear creates a double neutral to earth connection, as shown in Figure B3.11. In the event of an uncleared feeder earth fault or busbar earth fault, with both the incoming supply breakers closed and the bus section breaker open, the earth fault current will divide between the two earth connections. Earth fault relay $R_{E2}$ may operate, tripping the supply to the healthy section of the switchboard as well as relay $R_{E1}$ tripping the supply to the faulted section.

If only one incoming supply breaker is closed, the earth fault relay on the energised side will see only a proportion of the fault current flowing in the neutral busbar. This not only significantly increases the relay operating time but also reduces its sensitivity to low-level earth faults.

# 7. Co-ordination problems



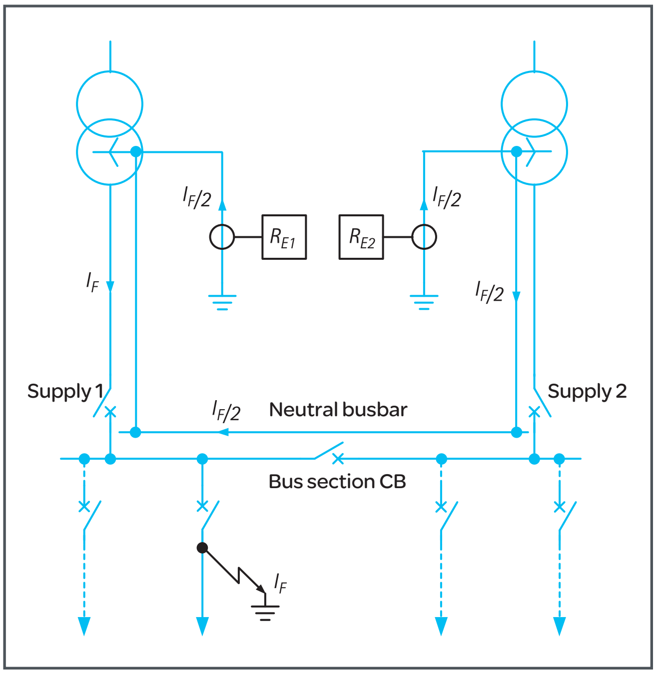


**Figure B3.11:**
**Dual fed four-wire systems: use of 3-pole CBs**

The solution to this problem is to utilise 4-pole CBs that switch the neutral as well as the three phases. Then there is only a single earth fault path and relay operation is not compromised.

### *7.2.2 Use of single earth electrode*

A configuration sometimes adopted with four-wire dual-fed substations where only a 3-pole bus section CB is used is to use a single earth electrode connected to the mid-point of the neutral busbar in the switchgear, as shown in Figure B3.12.

When operating with both incoming main circuit breakers and the bus section breaker closed, the bus section breaker must be opened first should an earth fault occur, in order to achieve discrimination. The co-ordination time between the earth fault relays $R_F$ and $R_E$ should be established at fault level $F_2$ for a substation with both incoming supply breakers and bus section breaker closed.

When the substation is operated with the bus section switch closed and either one or both of the incoming supply breakers closed, it is possible for unbalanced neutral busbar load current caused by single phase loading to operate relay $R_{S1}$ and/or $R_{S2}$ and inadvertently trip the incoming breaker. Interlocking the trip circuit of each $R_S$ relay with normally closed auxiliary contacts on the bus section breaker can prevent this.

However, should an earth fault occur on one side of the busbar when relays $R_S$ are already operated, it is possible for a contact race to occur. When the bus section breaker opens, its break contact may close before the $R_S$ relay trip contact on the healthy side can open (reset). Raising the pick-up level of relays $R_{S1}$ and $R_{S2}$ above the maximum unbalanced neutral current may prevent the tripping of both supply breakers in this case. However, the best solution is to use 4-pole circuit breakers, and independently earth both sides of the busbar.

If, during a busbar earth fault or uncleared feeder earth fault, the bus section breaker fails to open when required, the interlocking break auxiliary contact will also be inoperative. This will prevent relays $R_{S1}$ and $R_{S2}$ from operating and providing back-up protection, with the result that the fault must be cleared eventually by slower phase overcurrent relays. An alternative method of obtaining back-up protection could be to connect a second relay $R'_E$ , in series with relay $R_E$ , having an operation time set longer than that of relays $R_{S1}$ and $R_{S2}$ . But since the additional relay must be arranged to trip both of the incoming supply breakers, back-up protection would be obtained but busbar selectivity would be lost.

An example of protection of a typical dual-fed switchboard is given in Section 12.3.

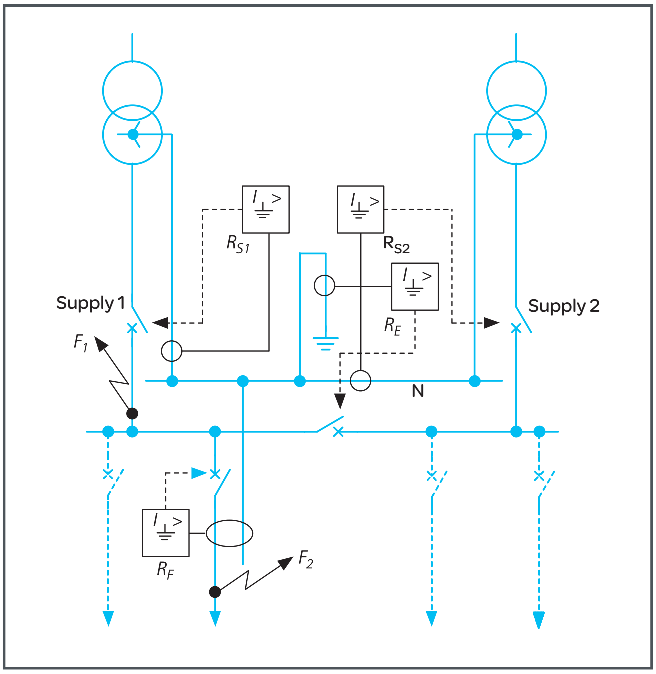


**Figure B3.12:**
**Dual fed four-wire systems: use of single point neutral earthing**

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# 8. Fault current contribution from induction motors

When an industrial system contains motor loads, the motors will contribute fault current for a short time. They contribute to the total fault current via the following mechanism.

When an induction motor is running, a flux, generated by the stator winding, rotates at synchronous speed and interacts with the rotor. If a large reduction in the stator voltage occurs for any reason, the flux in the motor cannot change instantaneously and the mechanical inertia of the machine will tend to inhibit speed reduction over the first few cycles of fault duration. The trapped flux in the rotor generates a stator voltage equal initially to the back e.m.f. induced in the stator before the fault and decaying according to the $X/R$ ratio of the associated flux and current paths. The induction motor therefore acts as a generator, resulting in a contribution of current having both a.c. and d.c. components decaying exponentially. Typical 50Hz motor a.c. time constants lie in the range 10ms-60ms for LV motors and 60-200ms for HV motors. This motor contribution has often been neglected in the calculation of fault levels.

Industrial systems usually contain a large component of motor load, so this approach is incorrect. The contribution from motors to the total fault current may well be a significant fraction of the total in systems having a large component of motor load. Standards relating to fault level calculations, such as IEC 60909, require the effect of motor contribution to be included where appropriate. They detail the conditions under which this should be done, and the calculation method to be used. Guidance is provided on typical motor fault current contribution for both HV and LV motors if the required data is not known. Therefore, it is now relatively easy, using appropriate calculation software, to determine the magnitude and duration of the motor contribution, so enabling a more accurate assessment of the fault level for:

**a.** discrimination in relay co-ordination

**b.** determination of the required switchgear/busbar fault rating

For protection calculations, motor fault level contribution is not an issue that is generally is important. In industrial networks, fault clearance time is often assumed to occur at 5 cycles after fault occurrence, and at this time, the motor fault level contribution is much less than just after fault occurrence. In rare cases, it may have to be taken into consideration for correct time grading for through-fault protection considerations, and in the calculation of peak voltage for high-impedance differential protection schemes.

It is more important to take motor contribution into account when considering the fault rating of equipment (busbars, cables, switchgear, etc.). In general, the initial a.c. component of current from a motor at the instant of fault is of similar magnitude to the direct-on-line starting current of the motor. For LV motors, 5xFLC is often assumed as the typical fault current contribution (after taking into account the effect of motor cable impedance), with 5.5xFLC for HV motors, unless it is known that low starting current HV motors are used. It is also accepted that similar motors connected to a busbar can be lumped together as one equivalent motor.

In doing so, motor rated speed may need to be taken into consideration, as 2 or 4 pole motors have a longer fault current decay than motors with a greater number of poles. The kVA rating of the single equivalent motor is taken as the sum of the kVA ratings of the individual motors considered. It is still possible for motor contribution to be neglected in cases where the motor load on a busbar is small in comparison to the total load (again IEC 60909 provides guidance in this respect). However, large LV motor loads and all HV motors should be considered when calculating fault levels.

# 9. Automatic changeover systems



Induction motors are often used to drive critical loads. In some industrial applications, such as those involving the pumping of fluids and gases, this has led to the need for a power supply control scheme in which motor and other loads are transferred automatically on loss of the normal supply to an alternative supply. A quick changeover, enabling the motor load to be re-accelerated, reduces the possibility of a process trip occurring. Such schemes are commonly applied for large generating units to transfer unit loads from the unit transformer to the station supply/start-up transformer.

When the normal supply fails, induction motors that remain connected to the busbar slow down and the trapped rotor flux generates a residual voltage that decays exponentially. All motors connected to a busbar will tend to decelerate at the same rate when the supply is lost if they remain connected to the busbar. This is because the motors will exchange energy between themselves, so that they tend to stay 'synchronised' to each other. As a result, the residual voltages of all the motors decay at nearly the same rate. The magnitude of this voltage and its phase displacement with respect to the healthy alternative supply voltage is a function of time and the speed of the motors. The angular displacement between the residual motor voltage and the incoming voltage will be 180° at some instant. If the healthy alternative supply is switched on to motors which are running down under these conditions, very high inrush currents may result, producing stresses which could be of sufficient magnitude to cause mechanical damage, as well as a severe dip in the alternative supply voltage.

Two methods of automatic transfer are used:

**a.** in-phase transfer system

**b.** residual voltage system

The in-phase transfer method is illustrated in Figure B3.13(a). Normal and standby feeders from the same power source are used.

Phase angle measurement is used to sense the relative phase angle between the standby feeder voltage and the motor busbar voltage. When the voltages are approximately in phase, or just prior to this condition through prediction, a high-speed circuit breaker is used to complete the transfer. This method is restricted to large high inertia drives where the gradual run down characteristic upon loss of normal feeder supply can be predicted accurately.

Figure B3.13(b) illustrates the residual voltage method, which is more common, especially in the petrochemical industry.

Two feeders are used, supplying two busbar sections connected by a normally open bus section breaker. Each feeder is capable of carrying the total busbar load. Each bus section voltage is monitored and loss of supply on either section causes the relevant incomer CB to open. Provided there are no protection operations to indicate the presence of a busbar fault, the bus section breaker is closed automatically to restore the supply to the unpowered section of busbar after the residual voltage generated by the motors running down on that section has fallen to a an acceptable level. This is between 25% and 40%, of nominal voltage, dependent on the characteristics of the power system. The choice of residual voltage setting will influence the re-acceleration current after the bus section breaker closes. For example, a setting of 25% may be expected to result in an inrush current of around 125% of the starting current at full voltage. Alternatively, a time delay could be used as a substitute for residual voltage measurement, which would be set with knowledge of the plant to ensure that the residual voltage would have decayed sufficiently before transfer is initiated.

The protection relay settings for the switchboard must take account of the total load current and the voltage dip during the re- acceleration period in order to avoid spurious tripping during this time. This time can be several seconds where large inertia HV drives are involved.

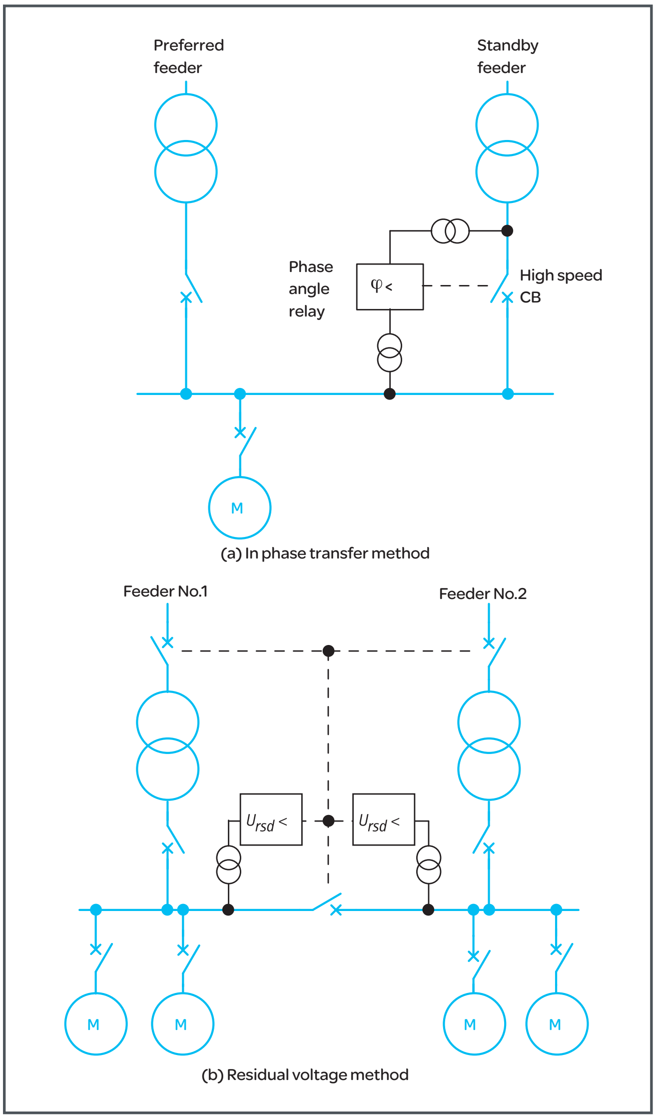


**Figure B3.13: Auto-transfer systems**

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# 10. Voltage and phase reversal protection

Voltage relays have been widely used in industrial power supply systems. The principle purposes are to detect undervoltage and/or overvoltage conditions at switchboards to disconnect supplies before damage can be caused from these conditions or to provide interlocking checks. Prolonged overvoltage may cause damage to voltage-sensitive equipment (e.g. electronics), while undervoltage may cause excessive current to be drawn by motor loads. Motors are provided with thermal overload protection to prevent damage with excessive current, but undervoltage protection is commonly applied to disconnect motors after a prolonged voltage dip. With a voltage dip caused by a source system fault, a group of motors could decelerate to such a degree that their aggregate re-acceleration currents might keep the recovery voltage depressed to a level where the machines might stall. Modern numerical motor protection relays typically incorporate voltage protection functions, thus removing the need for discrete undervoltage relays for this purpose. See Chapter [C.9: A.C. Motor Protection]. Older installations may still utilise discrete undervoltage relays, but the setting criteria remain the same.

Reverse phase sequence voltage protection should be applied where it may be dangerous for a motor to be started with rotation in the opposite direction to that intended. Incorrect rotation due to reverse phase sequence might be set up following some error after power system maintenance or repairs, e.g. to a supply cable. Older motor control boards might have been fitted with discrete relays to detect this condition. Modern motor protection relays may incorporate this function. If reverse phase sequence is detected, motor starting can be blocked. If reverse phase sequence voltage protection is not provided, the high-set negative phase sequence current protection in the relay would quickly detect the condition once the starting device is closed – but initial reverse rotation of the motor could not be prevented.

# 11. Power factor correction and protection of capacitors

Loads such as induction motors draw significant reactive power from the supply system, and a poor overall power factor may result. The flow of reactive power increases the voltage-drops through series reactances such as transformers and reactors, it uses up some of the current carrying capacity of power system plant and it increases the resistive losses in the power system.

To offset the losses and restrictions in plant capacity they incur and to assist with voltage regulation, Utilities usually apply tariff penalties to large industrial or commercial customers for running their plant at excessively low power factor. The customer is thereby induced to improve the power factor of his system and it may be cost-effective to install fixed or variable power factor correction equipment to raise or regulate the plant power factor to an acceptable level.

Shunt capacitors are often used to improve power factor. The basis for compensation is illustrated in Figure B3.14, where $\angle\varphi_1$ represents the uncorrected power factor angle and $\angle\varphi_2$ the angle relating to the desired power factor, after correction.

The following may be deduced from this vector diagram:

**a.** Uncorrected power factor = $\dfrac{kW}{kVA_1} = \cos\angle\varphi_1$

**b.** Corrected power factor = $\dfrac{kW}{kVA_2} = \cos\angle\varphi_2$

**c.** Reduction in $kVA = kVA_1 - kVA_2$

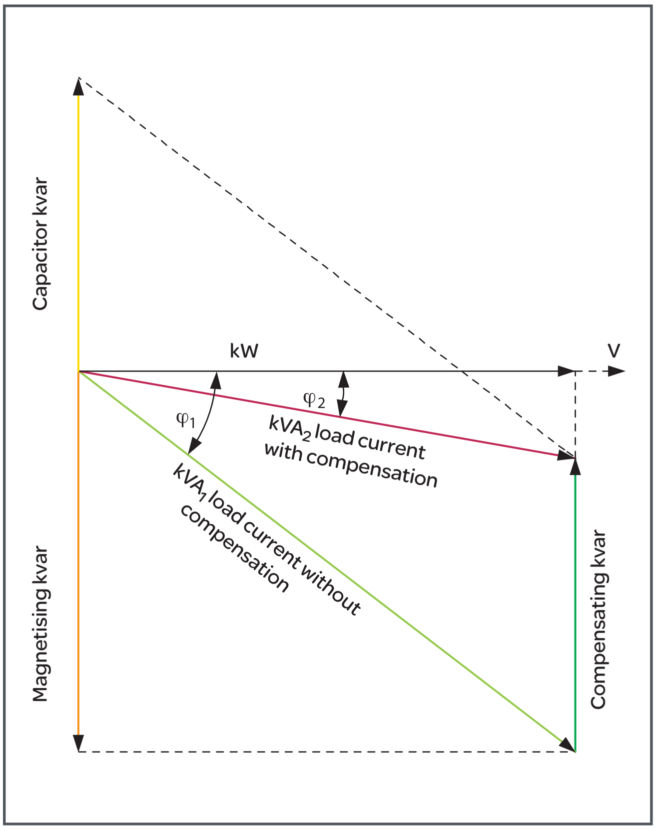


**Figure B3.14:**
**Power factor correction principle**

# 11. Power factor correction and protection of capacitors



If the kW load and uncorrected power factors are known, then the capacitor rating in kvar to achieve a given degree of correction may be calculated from:

Capacitor $kvar = kW \times (tan\angle\varphi_1 - tan\angle\varphi_2)$

A spreadsheet can easily be constructed to calculate the required amount of compensation to achieve a desired power factor.

### 11.1 Capacitor control

Where the plant load or the plant power factor varies considerably, it is necessary to control the power factor correction, since over-correction will result in excessive system voltage and unnecessary losses. In a few industrial systems, capacitors are switched in manually when required, but automatic controllers are standard practice. A controller provides automatic power factor correction, by comparing the running power factor with the target value. Based on the available groupings, an appropriate amount of capacitance is switched in or out to maintain an optimum average power factor. The controller is fitted with a 'loss of voltage' relay element to ensure that all selected capacitors are disconnected instantaneously if there is a supply voltage interruption. When the supply voltage is restored, the capacitors are reconnected progressively as the plant starts up. To ensure that capacitor groups degrade at roughly the same rate, the controller usually rotates selection or randomly selects groups of the same size in order to even out the connected time. The provision of overvoltage protection to trip the capacitor bank is also desirable in some applications. This would be to prevent a severe system overvoltage if the power factor correction (PFC) controller fails to take fast corrective action.

The design of PFC installations must recognise that many industrial loads generate harmonic voltages, with the result that the PFC capacitors may sink significant harmonic currents. A harmonic study may be necessary to determine the capacitor thermal ratings or whether series filters are required.

### 11.2 Motor power factor correction

When dealing with power factor correction of motor loads, group correction is not always the most economical method. Some industrial consumers apply capacitors to selected motor substations rather than applying all of the correction at the main incoming substation busbars. Sometimes, power factor correction may even be applied to individual motors, resulting in optimum power factor being obtained under all conditions of aggregate motor load. In some instances, better motor starting may also result, from the improvement in the voltage regulation due to the capacitor. Motor capacitors are often six-terminal units, and a capacitor may be conveniently connected directly across each motor phase winding.

Capacitor sizing is important, such that a leading power factor does not occur under any load condition. If excess capacitance is applied to a motor, it may be possible for self-excitation to occur when the motor is switched off or suffers a supply failure. This can result in the production of a high voltage or in mechanical damage if there is a sudden restoration of supply. Since most star/delta or auto-transformer starters other than the 'Korndorffer' types involve a transitional break in supply, it is generally recommended that the capacitor rating should not exceed 85% of the motor magnetising reactive power.

### 11.3 Capacitor protection

When considering protection for capacitors, allowance should be made for the transient inrush current occurring on switch-on, since this can reach peak values of around 20 times normal current. Switchgear for use with capacitors is usually de-rated considerably to allow for this. Inrush currents may be limited by a resistor in series with each capacitor or bank of capacitors.

Protection equipment is required to prevent rupture of the capacitor due to an internal fault and also to protect the cables and associated equipment from damage in case of a capacitor failure. If fuse protection is contemplated for a three-phase capacitor, HRC fuses should be employed with a current rating of not less than 1.5 times the rated capacitor current.

Medium voltage capacitor banks can be protected by the scheme shown in Figure B3.15. Since harmonics increase capacitor current, the relay will respond more correctly if it does not have in-built tuning for harmonic rejection.

Double star capacitor banks are employed at medium voltage. As shown in Figure B3.16, a current transformer in the inter star-point connection can be used to drive a protection relay to detect the out-of-balance currents that will flow when capacitor elements become short-circuited or open-circuited. The relay will have adjustable current settings, and it might contain a bias circuit, fed from an external voltage transformer, that can be adjusted to compensate for steady-state spill current in the inter star-point connection.

Some industrial loads such as arc furnaces involve large inductive components and correction is often applied using very large high voltage capacitors in various configurations.

Another high voltage capacitor configuration is the 'split phase' arrangement where the elements making up each phase of the capacitor are split into two parallel paths. Figure B3.17 shows two possible connection methods for the relay. A differential relay can be applied with a current transformer for each parallel branch, comparing the currents in the split phases. Alternatively an overcurrent relay can be applied with a current transformer in the bridge link, where normally no current should flow. Both relays use sensitive current settings but also adjustable compensation for the unbalance currents arising from initial capacitor mismatch.

The difference of current through the split phases or the increase of the current through the bridge link indicates a defect of a single capacitor unit 'can' where the amount of additional current is directly dependent on the can dimensions.

# 11. Power factor correction and protection of capacitors

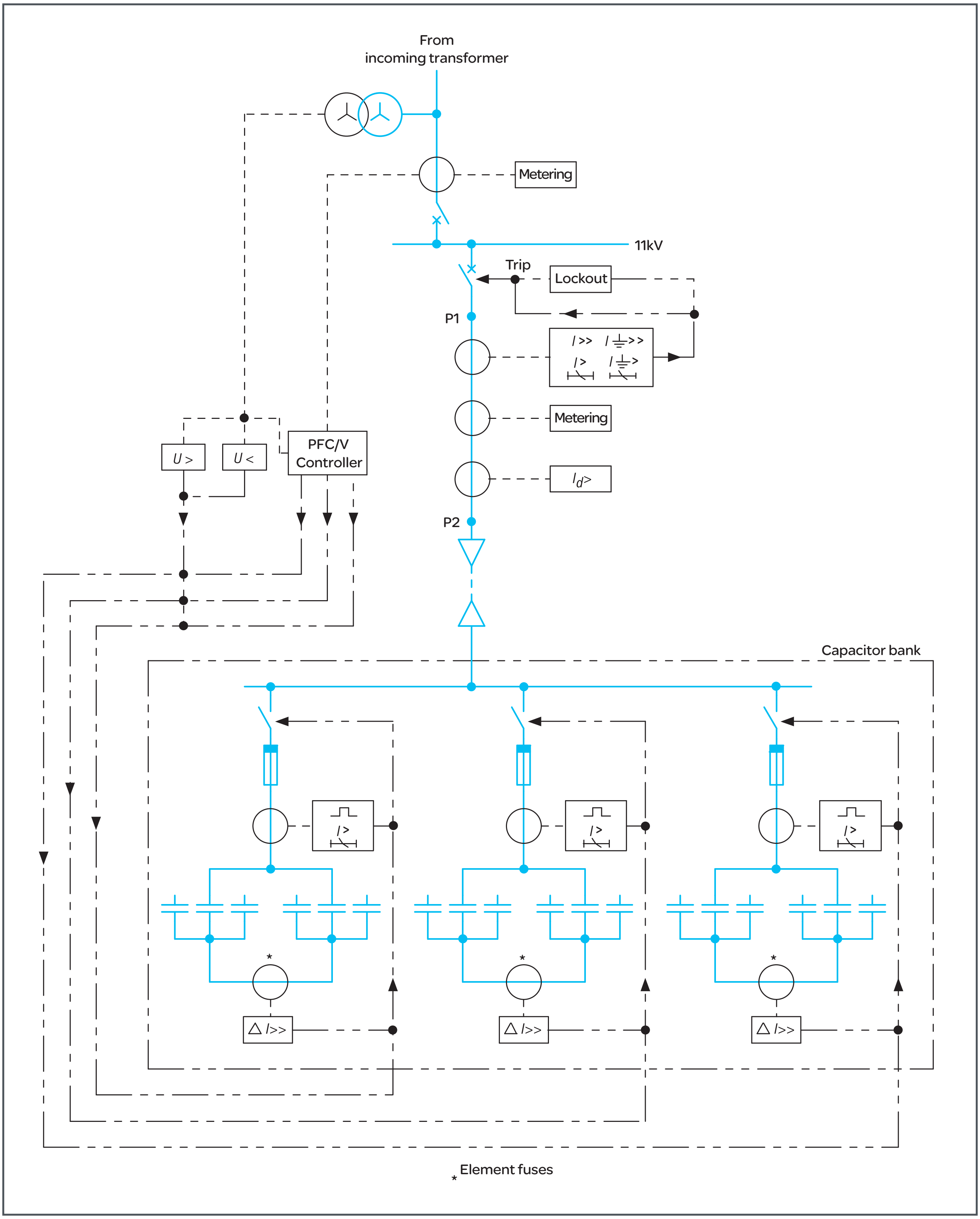


**Figure B3.15:**
**Protection of capacitor banks**

# 11. Power factor correction and protection of capacitors



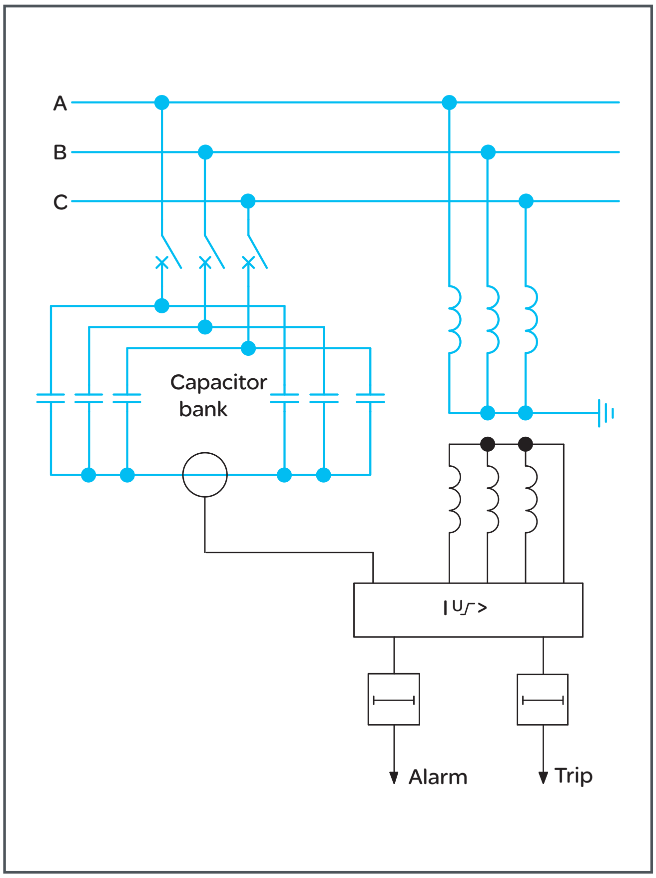


**Figure B3.16:**
**Protection of double star capacitor banks without and with grounded starpoint**

The usual aim is to get an alarm if one of the cans is defective and to trip the bank if a second can becomes defective. It is possible to deduce which can is defective from the phase relationships of the current and hence help to reduce repair time.

Capacitor units shall be suitable for continuous operation at an r.m.s. current of 1,30 times the current that occurs at rated sinusoidal voltage and rated frequency. In order to prevent thermal damage under load conditions a protection with a 1st order thermal model using the maximum phase current r.m.s. value is typical. Optionally this can be biased by measured ambient (coolant) temperature. Depending on the design/size of the capacitor bank, a dedicated overload protection may be required for current limiting reactors connected in series.

The usual design of capacitor banks allows a continuous sinusoidal voltage of 110% of rated nominal voltage at nominal frequency, in line with normal operation limits of power systems. So by design, the rated voltage of a capacitor bank would be chosen as 121 kV for a 110 kV nominal system.

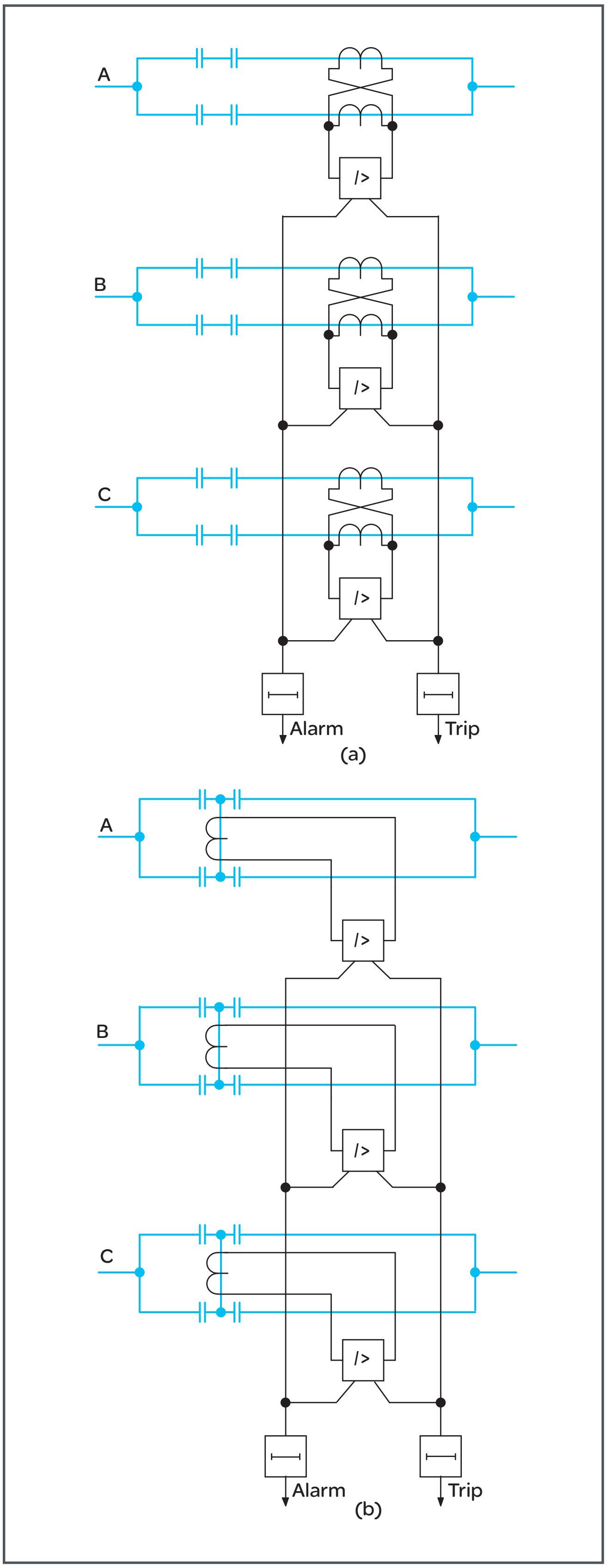


**Figure B3.17:**
**Differential protection of split phase capacitor banks**

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# 11. Power factor correction and protection of capacitors

A short-time overvoltage is permitted where duration naturally gets shorter with higher voltage. This results in an inverse-time characteristic per IEC 60871-1 or ANSI/IEEE 37.99, as shown in Figure B3.18. Accordingly, overvoltage protection should consist of a high set definite time delayed and inverse timed element. Due to the “memory effect” of capacitances, a reset characteristic should also be considered to prevent damage from repetitive overvoltages.

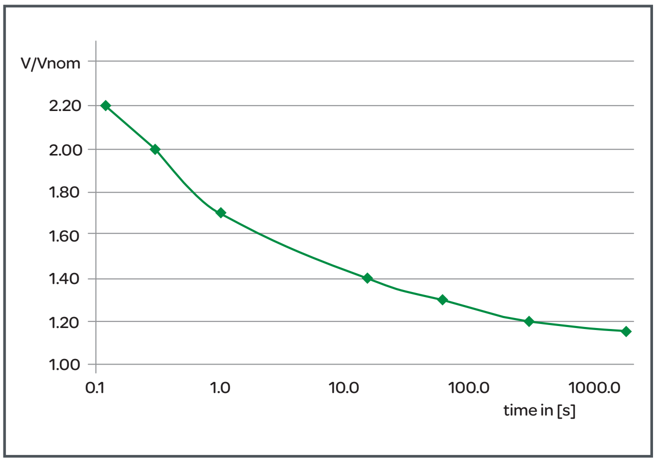


**Figure B3.18:**
**Capacitor bank overvoltage characteristic**

As voltage across the capacitor bank is usually not directly accessible through voltage transformers, the voltage is evaluated by integration of the phase currents:

$$v = \frac{1}{c} \int i \, dt$$

Voltage protection requires coordination with nearby generators. Capacitor banks should be disconnected to reduce system overvoltage prior to operation of generator under-excitation protection.

Time-staged tripping of capacitor banks is recommended if banks are installed nearby (the same or neighbouring substation). This is done to avoid simultaneous tripping that might result in a sudden loss of capacitance, which may provoke a subsequent critical undervoltage situation in the power system.

The residual voltage of a capacitor bank prior to energisation shall not exceed 10 % of its rated voltage to minimise the voltage transients when switching due to the network impedances. For this purpose resistors are connected in parallel to the capacitors and designed to internally discharge them when becoming disconnected from the power grid. The resistors are sized to ensure that the capacitor residual voltage occurs within 5 minutes. Therefore after switching off the capacitor bank a suitably long (re-)close blocking time should be provided in the capacitor control and/or protection circuit.

In this section, examples of the topics dealt with in the Chapter are considered.

### 12.1 Fuse co-ordination

An example of the application of fuses is based on the arrangement in Figure B3.19(a). This shows an unsatisfactory scheme with commonly encountered shortcomings. It can be seen that fuses $B$, $C$ and $D$ will discriminate with fuse $A$, but the 400A sub-circuit fuse $E$ may not discriminate, with the 500A sub-circuit fuse $D$ at higher levels of fault current.

The solution, illustrated in Figure B3.19(b), is to feed the 400A circuit direct from the busbars.

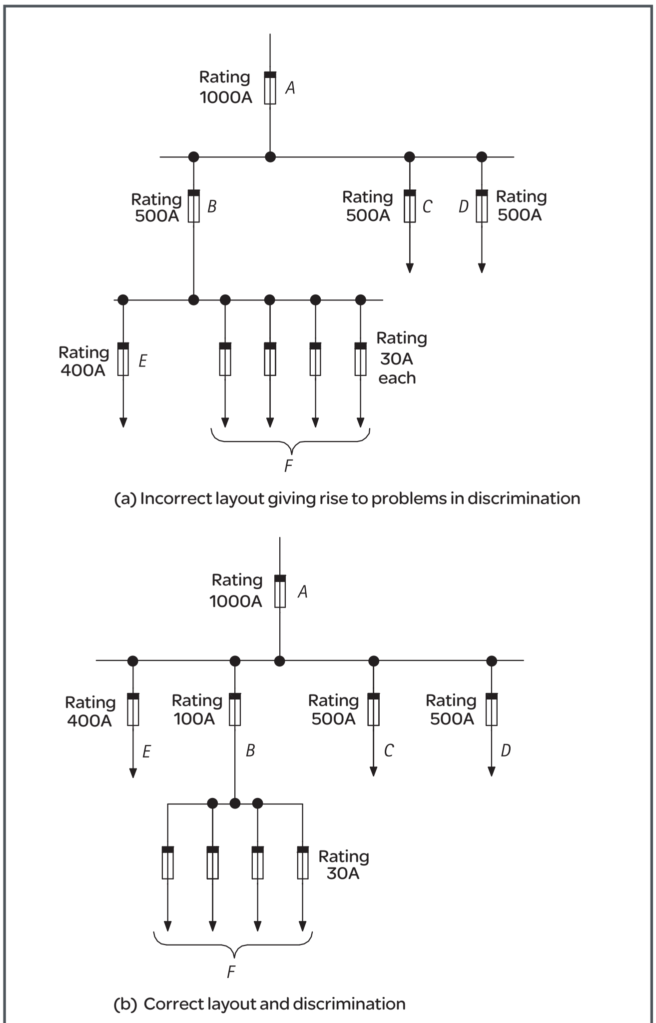


**Figure B3.19:**
**Fuse protection: effect of layout on discrimination**

The sub-circuit fuse $D$ may now have its rating reduced from 500A to a value, of say 100A, appropriate to the remaining sub-circuit. This arrangement now provides a discriminating fuse distribution scheme satisfactory for an industrial system.

However, there are industrial applications where discrimination is a secondary factor. In the application shown in Figure B3.20, a contactor having a fault rating of 20kA controls the load in one sub-circuit. A fuse rating of 630A is selected for the minor fuse in the contactor circuit to give protection within the through-fault capacity of the contactor.

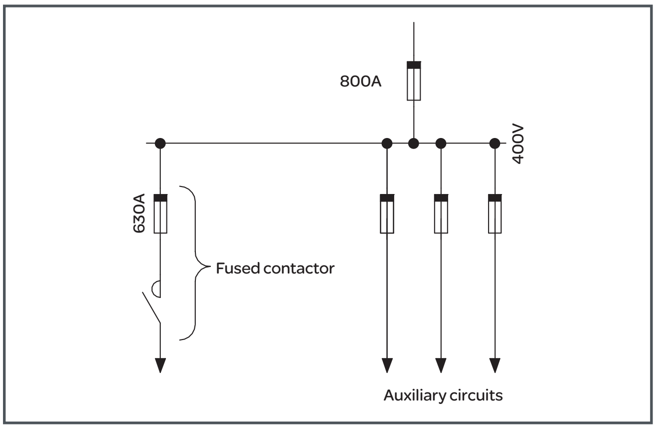


**Figure B3.20:**
**Example of back-up protection**

The major fuse of 800A is chosen as the minimum rating that is greater than the total load current on the switchboard. Discrimination between the two fuses is not obtained, as the pre-arcing $I^2t$ of the 800A fuse is less than the total $I^2t$ of the 630A fuse. Therefore, the major fuse will blow as well as the minor one, for most faults so that all other loads fed from the switchboard will be lost. This may be acceptable in some cases. In most cases, however, loss of the complete switchboard for a fault on a single outgoing circuit will not be acceptable, and the design will have to be revised.

### 12.2 Grading of fuses/MCCBs/overcurrent relays

An example of an application involving a moulded case circuit breaker, fuse and a protection relay is shown in Figure B3.21. A 1MVA 3.3kV/400V transformer feeds the LV board via a circuit breaker, which is equipped with a MiCOM P141 numerical relay having a setting range of 8-400% of rated current and fed from 2000/1A CTs.

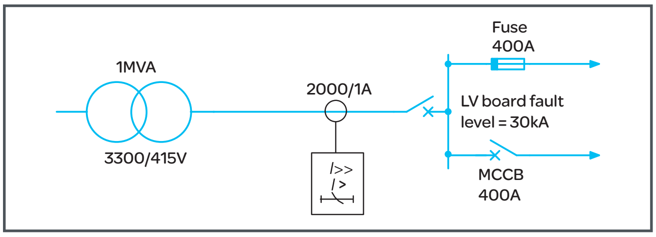


**Figure B3.21:**
**Network diagram for protection co-ordination example – fuse/MCCB/relay**

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# 12. Examples

Discrimination is required between the relay and both the fuse and MCCB up to the 40kA fault rating of the board. To begin with, the time/current characteristics of both the 400A fuse and the MCCB are plotted in Figure B3.22.

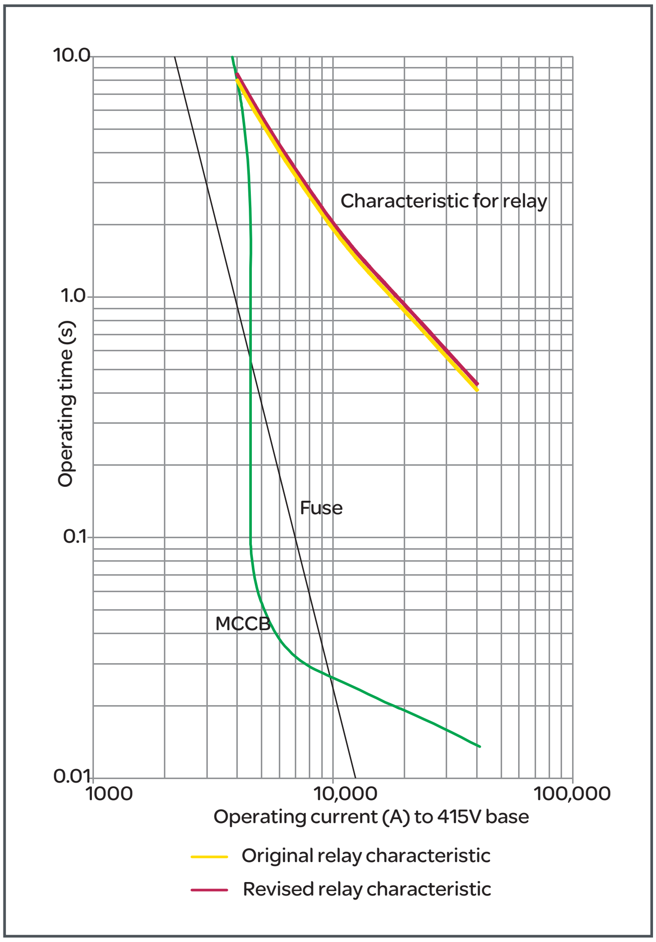



**Figure B3.22:**
**Grading curves for Fuse/MCCB/relay grading example**

### *12.2.1 Determination of relay current setting*

The relay current setting chosen must not be less than the full load current level and must have enough margin to allow the relay to reset with full load current flowing. The latter may be determined from the transformer rating:

$$FLC = \frac{kVA}{kV \times \sqrt{3}}$$

$$= \frac{1000}{0.4 \times \sqrt{3}} = 1443A$$

With the CT ratio of 2000/1A and a relay reset ratio of 95% of the nominal current setting, a current setting of at least 80% would be satisfactory, to avoid tripping and/or failure to reset with the transformer carrying full load current. However, choice of a value at the lower end of this current setting range would move the relay characteristic towards that of the MCCB and discrimination may be lost at low fault currents. It is therefore prudent to select initially a relay current setting of 100%.

### *12.2.2 Relay characteristic and time multiplier selection*

An EI characteristic is selected for the relay to ensure discrimination with the fuse (see Chapter [C1: Overcurrent Protection for Phase and Earth Faults] for details). From Figure B3.20, it may be seen that at the fault level of 40kA the fuse will operate in less than 0.01s and the MCCB operates in approximately 0.014s. Using a fixed grading margin of 0.4s, the required relay operating time becomes 0.4 + 0.014 = 0.414s. With a CT ratio of 2000/1A, a relay current setting of 100%, and a relay TMS setting of 1.0, the extremely inverse curve gives a relay operating time of 0.2s at a fault current of 40kA. This is too fast to give adequate discrimination and indicates that the EI curve is too severe for this application. Turning to the VI relay characteristic, the relay operation time is found to be 0.71s at a TMS of 1.0. To obtain the required relay operating time of 0.414s:

$$TMS\ setting = \frac{0.414}{0.71}$$

$$= 0.583$$

Use a TMS of 0.6, nearest available setting.

The use of a different form of inverse time characteristic makes it advisable to check discrimination at the lower current levels also at this stage. At a fault current of 4kA, the relay will operate in 8.1s, which does not give discrimination with the MCCB. A relay operation time of 8.3s is required. To overcome this, the relay characteristic needs to be moved away from the MCCB characteristic, a change that may be achieved by using a TMS of 0.625. The revised relay characteristic is also shown in Figure B3.22.

## 12.3 Protection of a dual-fed substation

As an example of how numerical protection relays can be used in an industrial system, consider the typical large industrial substation of Figure B3.23. Two 1.6MVA, 11/0.4kV transformers feed a busbar whose bus-section CB is normally open. The LV system is solidly earthed. The largest outgoing feeder is to a motor rated 160kW, 193kVA, and a starting current of 7 x FLC.

The transformer impedance is to IEC standards. The LV switchgear and bus bars are fault rated at 50kA r.m.s. To simplify the analysis, only the phase-fault LV protection is considered.

### *12.3.1 General considerations*

Analysis of many substations configured as in Figure B3.23 shows that the maximum fault level and feeder load current are obtained with the bus-section circuit breaker closed and one of the infeeding CBs open. This applies so long as the switchboard has a significant amount of motor load. The contribution of motor load to the fault level at the switchboard is usually larger than that from a single infeeding transformer, as the transformer restricts the amount of fault current infeed from the primary side. The three-phase break fault level at the switchboard under these conditions is assumed to be 40kA r.m.s.

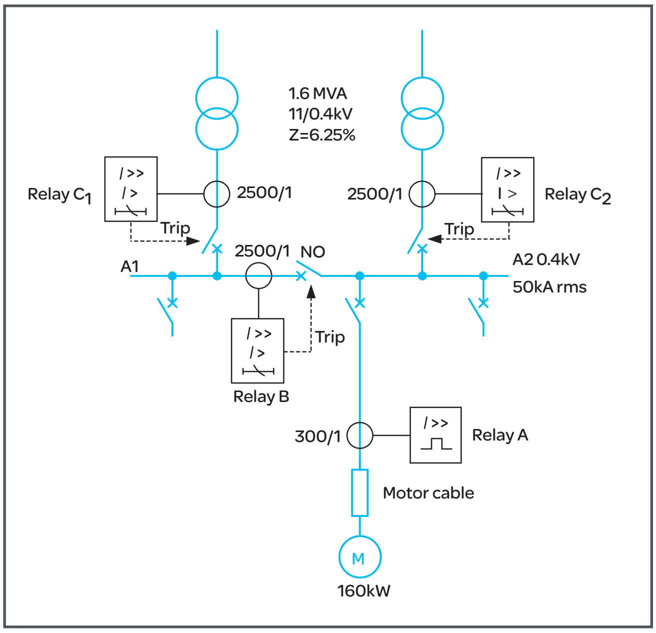



**Figure B3.23:**
**Relay grading example for dual-fed switchboard**

Relays $C$ are not required to have directional characteristics see Chapter [C1: Overcurrent Protection for Phase and Earth Faults, Section 14.3] as all three circuit breakers are only closed momentarily during transfer from a single infeeding transformer to a two infeeding transformers configuration. This transfer is normally an automated sequence, and the chance of a fault occurring during the short period (of the order of 1s) when all three CBs are closed is taken to be negligibly small. Similarly, although this configuration gives the largest fault level at the switchboard, it is not considered from either a switchboard fault rating or protection viewpoint.

It is assumed that modern numerical relays are used. For simplicity, a fixed grading margin of 0.3s is used.

### *12.3.2 Motor protection relay settings*

From the motor characteristics given, the overcurrent relay settings (Relay $A$) can be found using the guidelines set out in Chapter [C9: A.C. Motor Protection] as:

**a.** Thermal element:

current setting: 300A

time constant: 20 mins

**b.** Instantaneous element:

current setting: 2.32kA

These are the only settings relevant to the upstream relays.

### *12.3.3 Relay B settings*

Relay $B$ settings are derived from consideration of the loading and fault levels with the bus-section breaker between busbars $A1$ and $A2$ closed. No information is given about the load split between the two busbars, but it can be assumed in the absence of definitive information that each busbar is capable of supplying the total load of 1.6MVA. With fixed tap transformers, the bus voltage may fall to 95% of nominal under these conditions, leading to a load current of 2430A. The IDMT current setting must be greater than this, to avoid relay operation on normal load currents and (ideally) with aggregate starting/re-acceleration currents. If the entire load on the busbar was motor load, an aggregate starting current in excess of 13kA would occur, but a current setting of this order would be excessively high and lead to grading problems further upstream. It is unlikely that the entire load is motor load (though this does occur, especially where a supply voltage of 690V is chosen for motors – an increasingly common practice) or that all motors are started simultaneously (but simultaneous re-acceleration may well occur).

What is essential is that relay $B$ does not issue a trip command under these circumstances – i.e. the relay current/time characteristic is in excess of the current/time characteristic of the worst-case starting/re-acceleration condition. It is therefore assumed that 50% of the total bus load is motor load, with an average starting current of 600% of full load current (= 6930A), and that re-acceleration takes 3s. A current setting of 3000A is therefore initially used. The SI characteristic is used for grading the relay, as co-ordination with fuses is not required. The TMS is required to be set to grade with the thermal protection of relay $A$ under 'cold' conditions, as this gives the longest operation time of Relay $A$, and the re-acceleration conditions. A TMS value of 0.41 is found to provide satisfactory grading, being dictated by the motor starting/ re-acceleration transient. Adjustment of both current and TMS settings may be required depending on the exact re-acceleration conditions. Note that lower current and TMS settings could be used if motor starting/re-acceleration did not need to be considered.

The high-set setting needs to be above the full load current and motor starting/re-acceleration transient current, but less than the fault current by a suitable margin. A setting of 12.5kA is initially selected. A time delay of 0.3s has to used to ensure grading with relay $A$ at high fault current levels; both relays $A$ and $B$ may see a current in excess of 25kA for faults on the cable side of the CB feeding the 160kW motor. The relay curves are illustrated in Figure B3.24.

B3

# 12. Examples

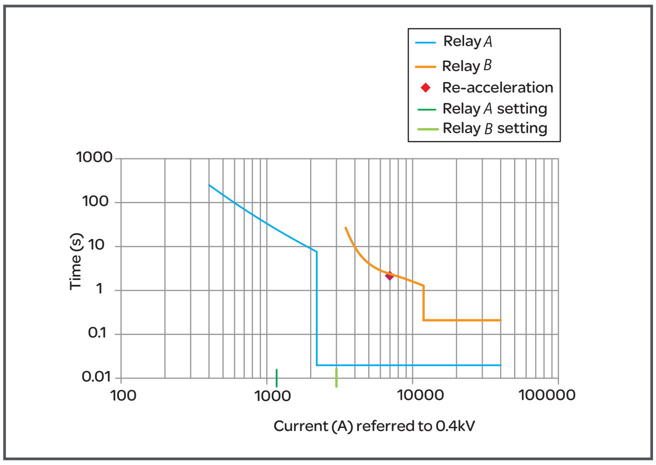



**Figure B3.24:**
**Grading of relays A and B**

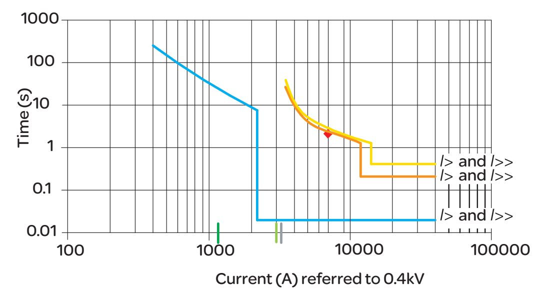
### *12.3.4 Relays C settings*

The setting of the IDMT element of relays $C_1$ and $C_2$ has to be suitable for protecting the busbar while grading with relay $B$. The limiting condition is grading with relay $B$, as this gives the longest operation time for relays $C$.

The current setting has to be above that for relay $B$ to achieve full co-ordination, and a value of 3250A is suitable. The TMS setting using the SI characteristic is chosen to grade with that of relay $B$ at a current of 12.5kA (relay $B$ instantaneous setting), and is found to be 0.45. The high-set element must grade with that of relay $B$, so a time delay of 0.62sec is required. The current setting must be higher than that of relay $B$, so use a value of 15kA. The final relay grading curves and settings are illustrated in Figure B3.25.

| | Parameter | Value | Parameter | Value | Parameter | Value | Parameter | Value |
|---|---|---|---|---|---|---|---|---|
| Relay A | Ith | 300A | Time const | 1200s | I>> | 2320A | $t_{dinst}$ | 0 |
| Relay B | I> | 2500A | TMS | 0.175 | I>> | 12500A | $t_{dinst}$ | 0.32s |
| Relay C | I> | 2750A | TMS | 0.25 | I>> | 15000 | $t_{dinst}$ | 0.62s |

(a) Relay settings




(b) Grading curves

**Figure B3.25:**
**Final relay grading curves**

### *12.3.5 Comments on grading*

While the above grading may appear satisfactory, the protection on the primary side of the transformer has not been considered. IDMT protection at this point will have to grade with relays $C$ and with the through-fault short-time withstand curves of the transformer and cabling. This may result in excessively long operation times. Even if the operation time at the 11kV level is satisfactory, there is probably a Utility infeed to consider, which will involve a further set of relays and another stage of time grading, and the fault clearance time at the utility infeed will almost certainly be excessive. One solution is to accept a total loss of supply to the 0.4kV bus under conditions of a single infeed and bus section CB closed. This is achieved by setting relays $C$ such that grading with relay $B$ does not occur at all current levels, or omitting relay $B$ from the protection scheme. The argument for this is that network operation policy is to ensure loss of supply to both sections of the switchboard does not occur for single contingencies. As single infeed operation is not normal, a contingency (whether fault or maintenance) has already occurred, so that a further fault causing total loss of supply to the switchboard through tripping of one of relays $B$ is a second contingency. Total loss of supply is therefore acceptable. The alternative is to accept a lack of discrimination at some point on the system, as already noted in Chapter [C1: Overcurrent Protection for Phase and Earth Faults]. Another solution is to employ partial differential protection to remove the need for Relay $A$, but this is seldom used. The strategy adopted will depend on the individual circumstances.

# 13. References



**[B3.1] Overcurrent Relay Co-ordination for Double Ended Substations**

George R Horcher
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