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Switchgear

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Contents

'Switchgear' is a term used to refer to combinations of switching devices and their interconnection with associated control, protective and measurement systems. It facilitates the interconnection of different parts of an electricity supply network by means of cable or overhead-line connections in order to allow the control of the flow of electricity within that network. Switchgear is also designed to be capable of safely clearing any fault which may occur on any part of the electricity network in order to protect the network itself, connected equipment and operational personnel. It also provides the facility, by means of disconnectors, for segregating parts of the network and, with the application of earth switches, allows safe access for maintenance or repair to component parts of the electricity supply network. Switchgear connected into an electricity supply network via transformers, overhead lines and/or cables, together with its mounting structures, housings, protective fencing and ancillary equipment and connections is referred to as a 'substation'.

These terms generally apply to switchgear of all voltage ratings ranging from, for example, supplies to domestic consumers at say 240 V with nominal short-circuit currents of up to 16 kA, to equipment used on major transmission networks at say 420 kV or higher with short-circuit currents of typically 55 kA. Switchgear may also be used for direct connection of main generators having rated short-circuit currents of typically 200 kA at 24 kV with normal rated load currents of 24 kA.

Switchgear is used to provide supplies to major items of plant such as motors, arc furnaces, reactors, capacitors or other machinery as well as supplies to commercial, industrial and domestic consumers. In doing so it must also provide for the safe operation of connected items of plant and limit the effects on connected equipment of transient overvoltage phenomena caused, for example, by lightning or other surges generated by operation of the switching devices themselves. In order to perform these varied functions, switching devices used within switchgear assemblies have evolved in different ways to suit particular applications. They may be mounted separately in an outdoor fenced area and be interconnected by means of air-insulated bus-bars, this arrangement generally being referred to as an 'open-type substation'. Alternatively, they may be coupled together by the switchgear manufacturer to form an assembly within a metal enclosure. The insulating media may comprise combinations of air, solid insulating material, insulating oil, bitumen compound or, with more recent equipment, an inert dielectric gas known as sulphur hexafluoride (SF_6).

The major components of the switchgear are described in the following sections.

34.1 Circuit-switching devices

34.1.1 Disconnectors (isolators)

A disconnector is a device comprising movable contacts capable of being mechanically closed to form an electrical circuit to other equipment or of being mechanically opened to physically disconnect one part of the electrical network from an adjacent part and at the same time providing an isolating distance. This provides circuit segregation for operational purposes or, with appropriate earthing equipment and application of safety procedures, provides facilities to allow work to be safely undertaken on disconnected and earthed primary electrical equipment.

Disconnectors are generally hand operated but may have power operating mechanisms if remote operational facilities are required. Disconnector moving contact systems are generally slow in operation as a disconnector is not intended to interrupt circuit currents. It will, however, be required to interrupt the small capacitive current flowing in the associated disconnected equipment. When air-insulated disconnectors are operated a short duration 'buzz' is generally heard when this capacitive current is interrupted. High-frequency currents are generated during such an operation. These can result in primary circuit overvoltages, which in turn can be coupled into earthed circuits or secondary connected equipment resulting in electromagnetic interference. In its closed position a disconnector must be capable of carrying the full rated load current of the associated circuit and of safely withstanding the rated short-circuit current of the system for the maximum circuit-breaker clearance time which may be between 1 and 3 s.

Disconnection may be achieved in metal-enclosed switchgear of voltage ratings typically up to 36 kV by physical withdrawal of the circuit-breaker either horizontally or vertically. No separate disconnector as such is provided, as the separation of the plug in contacts of the circuit-breaker provides an isolating distance. Earthed metallic shutters are commonly provided to segregate both sides of the circuit, but this is not an essential requirement for a disconnector. For higher voltage metal-enclosed equipment or for open-type substations separate disconnectors are used. Depending on the substation electrical layout, disconnectors are generally provided to isolate either side of each circuit-breaker and all circuits connecting into a substation. In addition, they are generally used on overhead rural distribution networks to segregate parts of the network in the event of a faulted section.

Disconnectors can take a number of different physical forms depending on particular applications and substation layout. Typical arrangements are shown in *Figure 34.1*.

The isolating distance of a disconnector is generally visible, but this is not an essential requirement. With open-type equipment, visible indication is readily achieved, but with metal-enclosed equipments windows may be provided. These may induce additional problems. Very many disconnectors are in use which do not provide visual indication of the isolating gap and with this type of equipment the operator must be able to rely fully on the external operation indicators accurately representing the positions of the main contacts.

34.1.2 Switches

A switch is a mechanical switching device that, unlike a disconnector, is capable of closing against, and interrupting, circuit load currents. In its closed position it must be capable of carrying the rated short-circuit current of the system for the rated time, i.e. 1–3 s. An additional optional design feature is the ability to close satisfactorily against the rated short-circuit current of the system. A switch is not capable of breaking short-circuit currents. A further optional design feature is the ability to close and open satisfactorily against specified overload conditions as may occur, for example, when switching motor circuits.

In view of the need to make and break specified circuit conditions, consistency of operation is an essential requirement. As direct manual operation cannot achieve this, power operation is necessary. Power operation of the switch is invariably achieved by the use of a spring operating mechanism whereby the spring is compressed during the

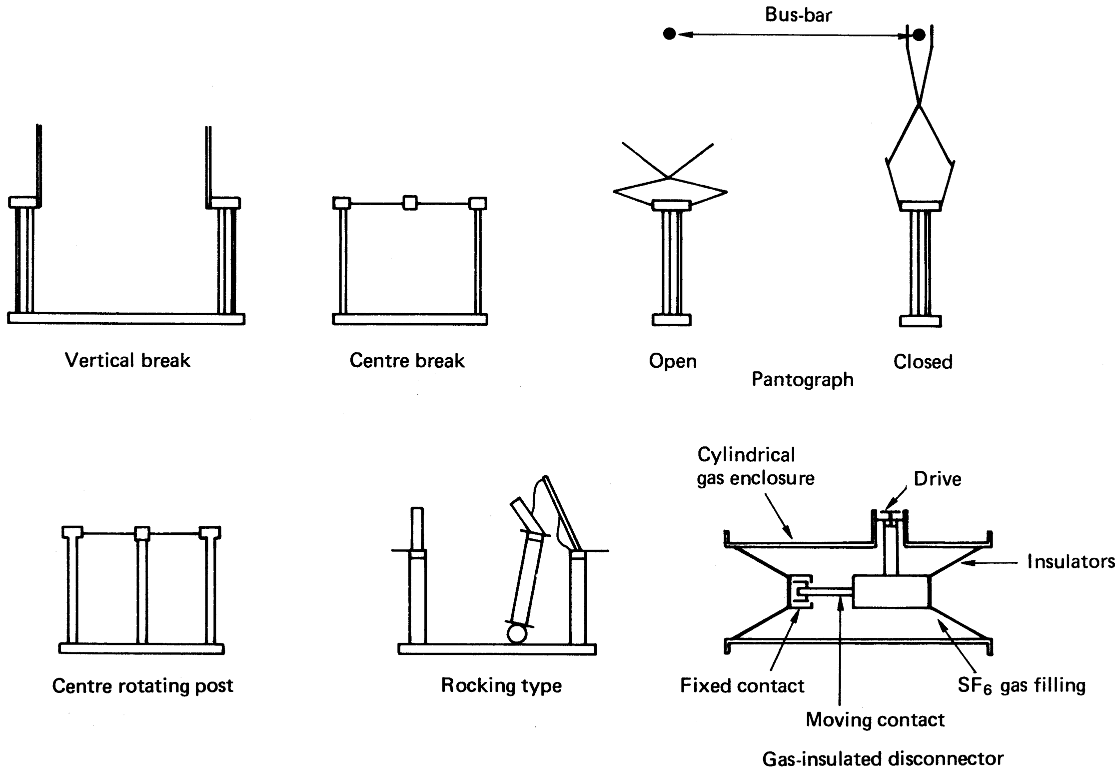

Figure 34.1 Typical disconnector arrangements

early part of the operation by manual means and then travels over centre to release its stored energy to operate the moving contact system independently of the operator. Switches normally are either air or oil insulated, with more recent designs being SF_6 insulated and they usually have some rudimentary method of controlling the arc during a breaking operation. Although the major application of switches is in low-voltage networks they are also widely used on distribution networks at voltages of up to about 20 kV. Use at higher voltages is minimal and at transmission voltages very few current designs exist and these have very limited specific applications.

34.1.3 Switch disconnectors

A switch disconnector is a switch which in its open position provides the isolating facilities required of a disconnector. Interlocking and padlocking facilities are generally provided. In LV applications switch disconnectors are not always employed, whereas at higher voltages switch disconnectors are almost invariably employed. The oil switch and SF_6 switch shown in *Figure 34.2* normally provide an isolating distance and are thus defined as switch disconnectors.

For open-type equipment at distribution voltages a switch may be built into a disconnector. This usually comprises an air-insulated interrupter as shown in *Figure 34.3*. Such a switch disconnector provides the facility for switching a downstream length of overhead line without the need to de-energise the whole of the line as would be required for a disconnector.

Switch disconnectors were also commonly used at transmission voltages some years ago but they now show little economic advantage over the use of a circuit-breaker and their application has declined. A typical 420 kV switch disconnector is shown in *Figure 34.4*.

34.1.4 Earth switches

An earth switch is not a switch as described in Section 34.1.2 because it does not have to make or break load current. An earth switch is a mechanical switching device used to connect the disconnected and de-energised primary conductors of a circuit to earth and to allow work to be undertaken on the earthed part of the circuit. An earth switch does not have to be capable of making or breaking current on its contacts and, consequently, earth switches are usually dependent manual operated. In its closed position it must be capable of carrying the rated short-circuit current of the system for the rated time. This requirement is necessary to safeguard against the circuit being inadvertently re-energised at its remote end. Earth switches are usually interlocked by mechanical or electrical means with the associated disconnector such that they can only be operated to apply an earth to the system when that part of the system has been de-energised and isolated. However, when applying an earth to an outgoing circuit comprising a cable or overhead line, interlocking with the remote end of the circuit is not feasible and safety instructions and permits must be relied upon. These may not always be foolproof and some authorities insist that line-end and cable-end earth switches must, in addition, be capable of safely closing onto an energised circuit. Such earth switches are generally referred to as 'fault-making earth switches' and power-operated mechanisms are an essential requirement.

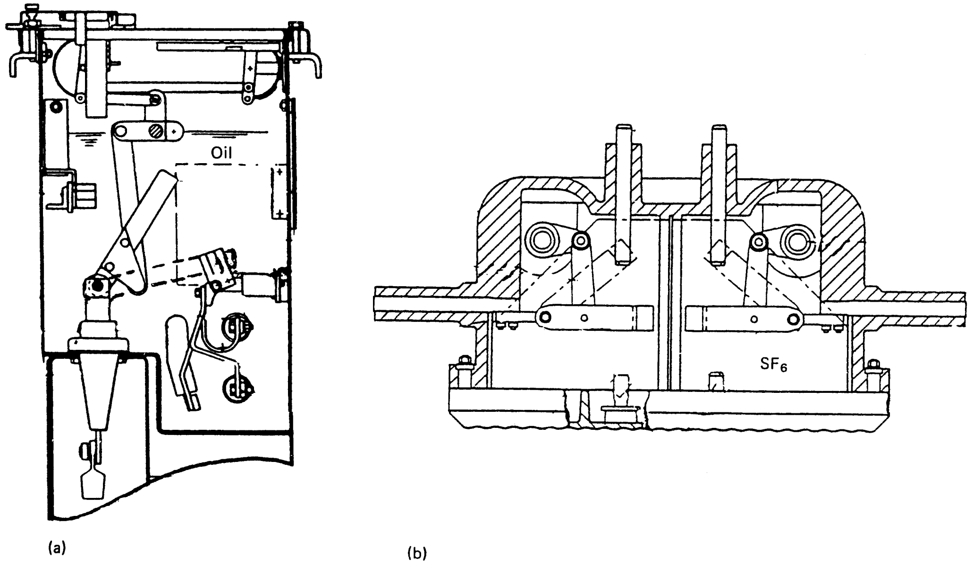

Figure 34.2 Arrangement of (a) an oil switch and (b) an SF_6 switch disconnectors

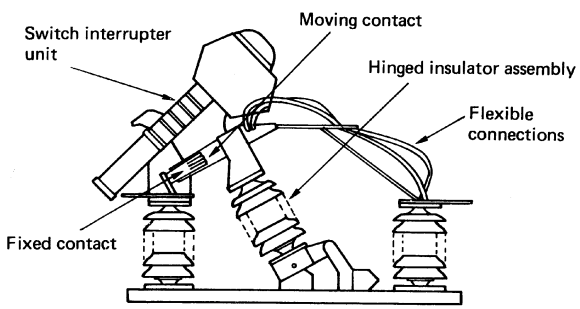

Figure 34.3 Pole-mounted switch disconnector

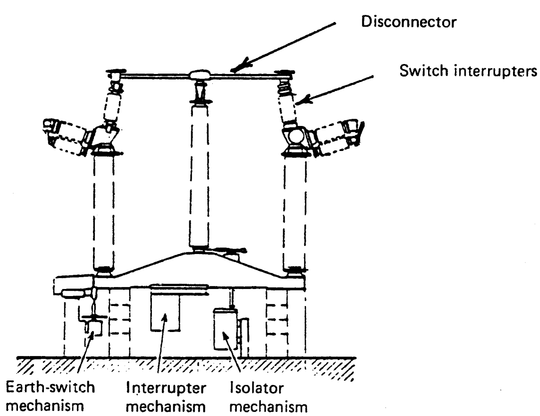

Figure 34.4 A 420 kV switch disconnector

At low voltages earth switches are seldom applied, as circuits can readily be tested to check whether they are live. Once proven to be de-energised, temporary earth connections can then be fitted. At distribution voltages many accidents have occurred over the years with operators inadvertently applying an earth to a live circuit and current practice is for fault-making earth switches to be provided for all applications. At transmission voltages, where instruction and permit systems can more readily be relied upon, and particularly for open-type substations where visible isolation is readily available, non-fault-making earth switches are nearly always used. For gas-insulated earth switches at transmission voltages where isolating distances may not be readily visible, the practice of using the safer fault-making earth switch is now becoming more common.

34.1.5 Fuses

A fuse is a 'one-shot' device capable of carrying the rated load current of the circuit in which it is situated, defined circuit overload conditions for predetermined times and of clearing overcurrents or short-circuit currents associated with faults which may occur on the system. Once operated on short-circuit, the fuse link, a component part of a fuse, must be replaced. (A fuse comprises all the parts which form the complete device and incorporates terminations for connecting into a circuit.)

A fuse is a thermally operated device. It comprises some form of conductor which, when subjected to predetermined currents for predetermined times, melts or blows to clear the circuit. The simplest form of fuse link comprises a wire held between terminations in air.

34.1.5.1 Rewirable fuses

For LV applications a wire fuse is generally described as a 're-wirable' or 'semi-enclosed' fuse. These are commonly used in domestic applications for protecting radial and ring circuits, their main advantage being that they are readily repairable by the layman, providing appropriate fuse wire is available. However, they can readily be abused. Their rated short-circuit breaking capacity is low, typically 2–3 kA at 240 V, although some designs may achieve a rating of 10 kA. As they break in air they require the passage of a current zero in order to clear, hence the total let-through energy of such a fuse is high and the 'downstream' circuit must be designed to cater for this passage of short-circuit current and associated energy. In addition, the fuse holder, which contains the wire fuse element tends to carbonise with repeated fault operations and the fuse may eventually fail to clear. A further shortcoming is that for the fuse to operate, the fuse element must reach a temperature which will cause it to melt; depending on the element material, this may be of the order of 1000°C or more. Also, for long-duration overloads over-heating may well occur.

Notwithstanding these potential limitations re-wirable LV fuses are very economical and are still widely used in domestic applications, although latterly the tendency has been to use the inherently better performance of the cartridge fuse or miniature circuit-breaker.

Re-wirable fuses are also used at distribution voltages up to 33 kV, but in some countries they may be used at even higher voltages. Such a re-wirable fuse is generally referred to as an expulsion fuse. This comprises a fuse element, i.e. that part of the fuse designed to melt when the fuse operates, which is generally enclosed within a small insulated tube. Each end of the element has a flexible tail for connecting to the terminals of the fuse carrier. The fuse carrier also generally comprises an insulating tube through which the fuse element is inserted. The fuse element is then held under tension by spring-loaded contacts into which the fuse carrier is fitted. These contacts are secured to the fuse base which comprises one or more insulators and a metallic base for installation on to an overhead-line pole.

The assembly, as described, is placed up a pole and connected onto the overhead line. It operates in atmospheric air and may be subjected to all types of weather conditions. When the fuse operates the fuse-carrier assembly usually hinges about its bottom contact and drops down, thus providing a visible indication of operation. Such a fuse assembly may also be designed to provide isolating facilities and thus can be used as a disconnection point.

When an expulsion fuse operates an arc is formed at the appropriate point of the fuse element, gases are produced from the small insulated tube surrounding the element; for small overloads these gases may be sufficient to build up pressure to extinguish the arc. For higher overloads or short-circuit currents the rapid pressure build up will cause the inner tube to burst and gases will then be generated by the arc impinging on the inner wall of the fuse-carrier tube. When sufficient pressure is built up the arc is extinguished and this pressure expels the ends of the fuse element. During such an operation a loud detonation or bang will be heard and hot ionised gases will be expelled from both ends of the fuse-carrier tube. A typical expulsion fuse is shown diagrammatically in *Figure 34.5*.

Like the semi-enclosed LV fuse, the expulsion fuse also requires the passage of a zero current in order to clear and thus the let-through energy is high. This results in the breaking capacity being relatively low, typically 8 kA at 12 kV. Expulsion fuses are very economical devices and are particularly effective at protecting overhead-line spur connections. However, replacement of an operated expulsion fuse can be costly in terms of the manpower required to be sent to the appropriate location. The problem can be alleviated to a large extent by the use of an electronically operated sectionalising link which fits into an expulsion fuse base. The link differentiates between transient and permanent faults and operates to isolate a permanently faulted circuit during the open period of the feeding auto-reclosing circuit-breaker.

34.1.5.2 *Current-limiting fuses*

The most widely used type of fuse for industrial applications is the current-limiting cartridge fuse. The main advantage of a cartridge fuse over the re-wireable fuses described is that they are perhaps the most effective circuit-protecting device available in that they will operate very rapidly during

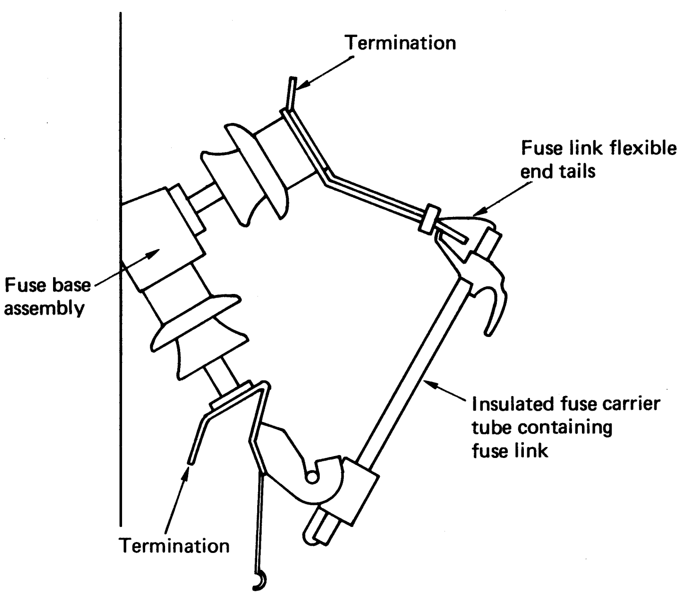

Figure 34.5 Typical expulsion fuse

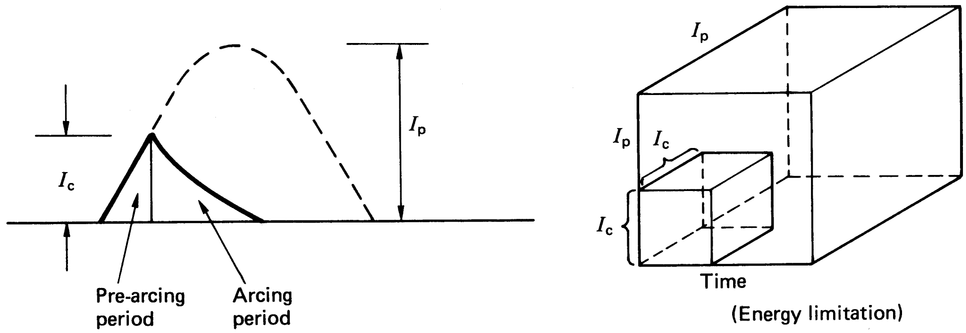

Figure 34.6 Fuse cut-off current

the initial part of the power frequency short-circuit current to clear the current at a low level before it reaches its peak value. Such a phenomenon is referred to as 'cut-off' and is shown in *Figure 34.6*

In consequence, the downstream circuit will never see the full short-circuit current of the system and economies in circuit design can be achieved. A further advantage of this rapid cut-off of current is that energy fed through to the faulted point is also considerably limited; this is shown diagramatically in *Figure 34.6*.

A cartridge fuse exhibiting these properties is known as a 'current-limiting fuse'. Current-limiting fuses are generally available from LV up to about 72.5 kV. Their major application in HV distribution being for voltages in the range 10–20 kV. Typical short-circuit breaking currents at LV are normally up to 80 kA and in the HV range up to 20 kA. However, short-circuit ratings as high as 200 kA at 415 V can be achieved and recent development of a HV fuse at 200 kA, 20 kV has been successfully achieved. In general interruption of high short-circuit currents does not constitute a difficult problem to a current-limiting fuse since the current and resultant energy is kept to a very low level by the phenomenon of cut-off.

The construction of LV fuses is somewhat different from HV fuses, but both operate in a similar manner. The current-limiting fuse is always in the form of a cartridge comprising a specially designed and proportioned element or number of parallel elements enclosed within an insulating barrel, usually of a ceramic material. The barrel is fitted with end caps to which the fuse elements are attached, additional end caps may then be fitted to carry the terminations for connecting to the fuse holder. Before the outer caps are fitted the inner assembly of fuse link is filled with fine-grained silica sand. The general construction of a typical LV fuse link is shown in *Figure 34.7*.

The fuse element may take a number of different forms, but the basic design criterion is to achieve melting of the element at defined points to create a number of arcs in series along the length of the fuse element. Restrictions are incorporated in the element to ensure a greater current density at these points and, for high short-circuit currents, there is little time for heat to dissipate along the length of the element and the element thus melts at these restrictions. An arc is formed at each point and energy is removed from the arc by the fine granules of sand which melt and fuse together to form a glass-like substance known as 'fulgurite'. The rate of extraction of energy must be greater than the rate of build up of energy in order for the arc to be extinguished. In practice this process is very rapid and will only last for some 2–3 ms or less and it is this phenomenon which gives the cartridge fuse its rapid current-limiting capabilities. Typical fuse-element forms are shown in *Figure 34.8*.

The fuse-element material is generally silver, but copper is now widely employed for LV applications.

In order to avoid overheating problems as might occur with small, long-duration overcurrents, the fuse element

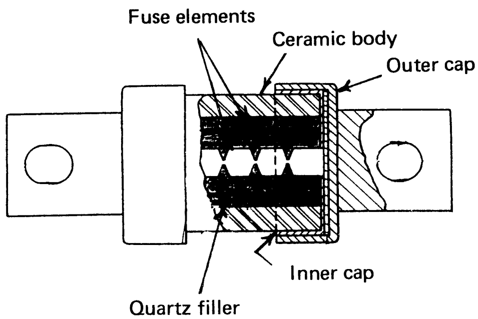

Figure 34.7 Construction of a typical LV fuse link

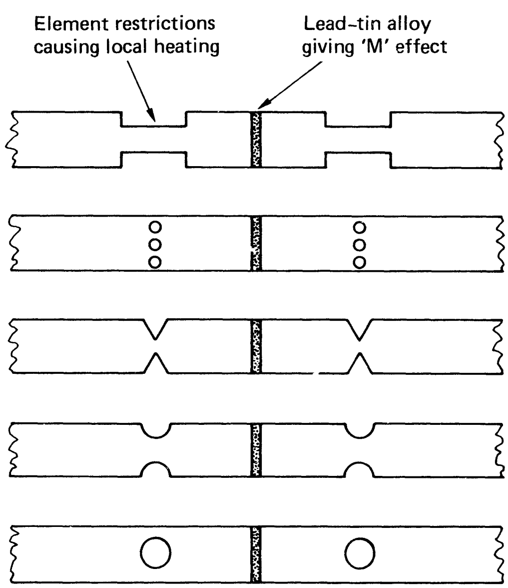

Figure 34.8 Typical fuse-element forms

often employs a small deposit of low-melting-point alloy at some point across its width. The alloy solder deposit causes an eutectic effect whereby the melting point of the base material is considerably reduced, e.g. from 960°C for silver to about 230°C for the alloy. This is often referred to as the 'M' or 'Metcalf' effect.

For HV current-limiting fuses it is necessary to employ a significantly longer fuse element comprising a larger number of restrictions along its length. A greater number of arcs in series must be generated in order to produce a back-e.m.f. capable of overcoming the applied voltage to ensure arc extinction. A typical 11 kV fuse link may require an element length of approximately 1 m. Clearly, a fuse link of this length would be impracticable and costly. The problem is overcome by winding the fuse element or elements in a spiral form around an inner ceramic star core support. This enables the element of an 11 kV fuse to be accommodated in a fuse barrel length of some 250 mm. Since the spacing between adjacent sections of the spirally wound elements must be sufficient to ensure that flashover does not occur across this gap, only a limited number of parallel elements can be employed. This limits the normal current rating to typically 80 A for a fuse link of some 250 mm length and 50 mm diameter. Higher current ratings at the same voltage can be achieved by increasing the barrel length, a typical length being 350 mm for which ratings of some 125 A may be achieved at 11 kV. Even higher current ratings can be achieved by connecting a number of fuse links in parallel. This requires more space, becomes more costly and is seldom applied at HV

A typical HV fuse construction is shown in *Figure 34.9*.

A further feature of a HV current-limiting fuse is that it can generally be fitted with a fuse-striker device which ejects when the fuse operates. The striker can be used as an indication device or, more generally, to cause an associated switch to trip so that for single-phase faults all three phases can be disconnected by operation of the striker activated switch. This approach prevents two phasing of HV circuits and alleviates consequential problems that might occur for example on three-phase motors.

Striker assemblies are of two basic types, being either activated by an explosive charge or compressed spring. The former is generally used within the UK where three-phase tripping is a requirement. This tends to necessitate the larger output of an explosively operated striker. Where indication or three-phase tripping is not required or where very light loaded switch trip mechanisms are used the lower energy spring-operated striker can be applied. Spring-activated strikers are commonly used in continental European fuse designs. Both types of striker are operated by a very thin fuse wire running the length of the fuse, generally located within the centre section of the star core assembly.

The striker wire may only require a few amperes to operate. When it does so it activates and ignites the gunpowder charge in the explosive design of striker or allows the release of the precharged spring in the spring striker assembly. Once the striker has operated to cause an associated switch to trip it must not be possible to reclose the switch until the operated fuse has been replaced. Thus a fundamental requirement is that it must not be possible to push the operated striker back into its housing. This is normally achieved by employing a ratchet-type serration on the striker pin which engages with a flat spring washer.

Typical explosive and spring-operated striker assemblies are shown in *Figure 34.10*.

With a HV fuse link it may not be possible to generate sufficient arc energy and consequent back-e.m.f. when operating under very low overload conditions to ensure that clearance will be achieved. It is thus common for HV fuses to have a specific minimum breaking capacity below which fuse operation cannot be guaranteed. Some other form of circuit-overload-protection device should be employed to cater for long-term overcurrents which may be of values between the fuse rated current and the fuse minimum breaking current. Such a type of fuse is referred to as a 'back-up' fuse and the fuse manufacturer will specify its minimum breaking current so that the user can ensure that coordination is achieved throughout the required operating range of the circuit-protecting devices.

HV fuses having very low minimum breaking currents can be produced, and are referred to as 'general-purpose' fuses. By definition, a general-purpose fuse is one that will operate at all values of short-circuit current or overload current down to a value of current which will cause the fuse to operate in 1 h. Even such fuses may have limitations in attempting to clear values of overload current between the rated current and the 1 h melting current. In consequence, there are now designs available which will clear all values of current to which the fuse may be subjected, even values below the rated current, if for example the fuse link is situated in a very high temperature environment. Such a fuse link is generally referred to as a 'full range' fuse link.

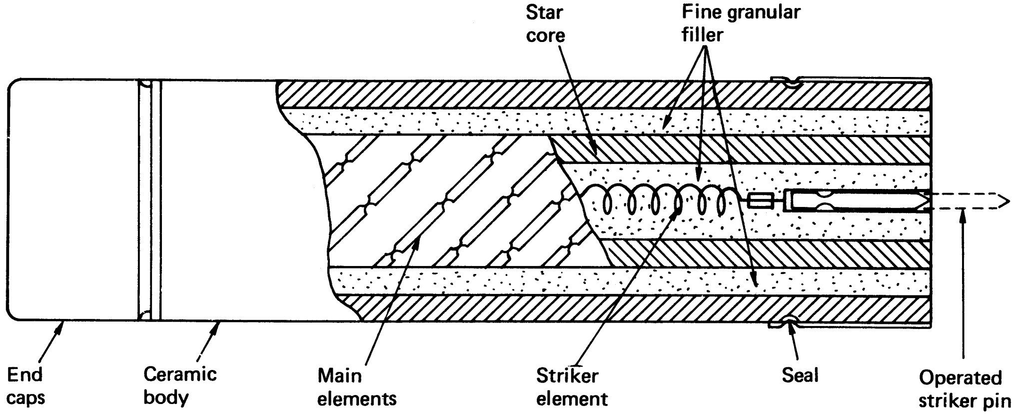

Figure 34.9 HV fuse construction

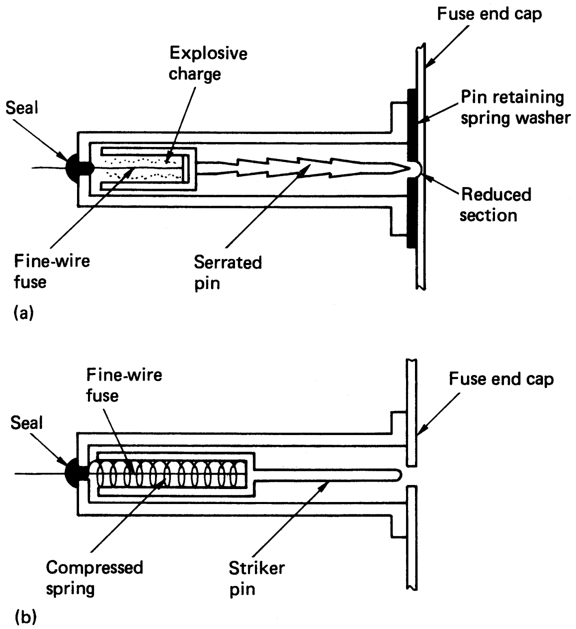

Figure 34.10 Typical explosive (a), and spring-operated (b), strikers

However, means of adequately verifying the performance of such a fuse is still under discussion within the appropriate international standards committees.

34.1.5.3 Fuse characteristics

A fuse exhibits a number of different performance characteristics of which the user needs to be familiar in order to ensure its correct application. The main advantage of a current-limiting fuse link is, as described, its ability to limit very rapidly the flow of fault current. Hence, in order to ensure adequate 'downstream' circuit design, it is necessary to know its cut-off current performance. This will vary depending on the current rating of the fuse and the value of prospective short-circuit current. A typical fuse cut-off characteristic is shown in *Figure 34.11*.

As the prospective short circuit is decreased for a given fuse rating, the proportional value of cut-off current to prospective peak current will increase until such a time as the cut-off current equates to the peak prospective current. Below this value of prospective current the fuse link will no longer exhibit cut-off.

A further important characteristic for 'downstream' circuit design is the total let through energy of the fuse link.

However, since energy is dependent on the total circuit resistance, an additional quantity is normally referred to, this being the 'joule integral', i.e. the square of the current over a given time interval:

$$I^2t = \int_{t_0}^{t_1} i^2\,\mathrm{d}t$$

Specific values are quoted for each fuse rating and these are given as I^2t. The values generally quoted are pre-arcing time I^2t, i.e. the I^2t integral over the pre-arcing time of the fuse, and the arcing I^2t, i.e. the I^2t integral over the arcing period of the fuse. The sum of these two characteristics is referred

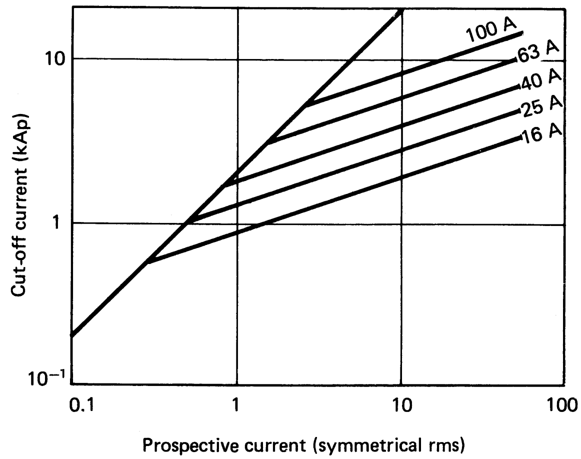

Figure 34.11 Cut-off characteristics

to as the 'total operating I^2t'. Typical I^2t characteristics are shown in *Figure 34.12*.

The total operating I^2t is important in designing the 'down-stream' circuit because its energy-handling capability must be in excess of this. Also, in order to achieve discrimination it is important to ensure that the total operating I^2t of the 'down-stream' fuse does not exceed the pre-arcing I^2t of the main fuse.

The I^2t characteristics are important parameters when assessing the circuit performance under high values of short-circuit current. With values of short-circuit current below the value which will cause the fuse to exhibit cut-off, it is then necessary to examine the fuse characteristics for these lower values of current. These characteristics are known as time–current characteristics and are usually presented in graphical form on log–log paper. Typical time–current characteristic zones are shown in *Figure 34.13*.

Each manufacturer's time–current characteristics will differ slightly for a given current rating, depending on the specific design features used. Thus specific time–current

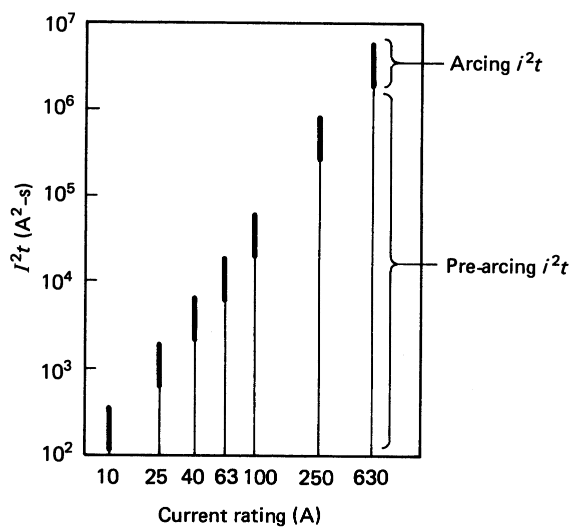

Figure 34.12 I^2t characteristics

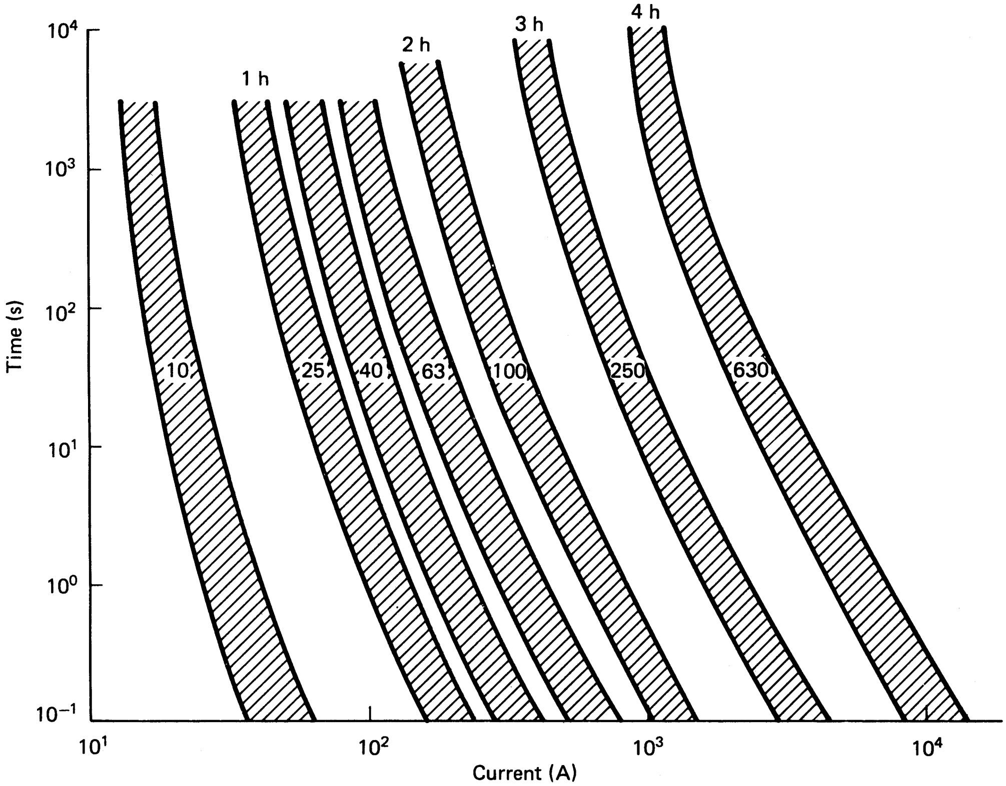

Figure 34.13 Time–current characteristic zones

characteristics cannot be used as the basis for circuit design as the designer may wish to be able to employ any particular manufacturer's fuse link. In order to overcome this problem, time–current characteristic bands are specified for LV fuse current ratings in the appropriate international fuse specifications.

34.1.5.4 Fuse applications

From examination of the fuse characteristics, it is evident that fuses are suitable for very many applications. Fuse designs have evolved around idealised characteristics for the protection of specific circuits. For example, recent changes within the international committees dealing with wiring regulations now require a close degree of protection of downstream cable circuits and protection against electric shock. The new regulations call for a discrimination ratio between major and minor fuses of 1.6 : 1. This requirement is met by modern LV fuses based on pre-arcing I^2t at a time of 10 ms.

Many fuses are used to protect motor circuits. With this application it is imperative that the fuse does not operate with the current surge present when starting a motor. For direct on-line starting this may require a possible current of six times the motor full-load current for some 10 s. For motor protection a steep time–current characteristic is desirable such that the fuse will clear quickly for high values of short-circuit current. For overload, these characteristics would not be ideal and it is common practice for separate overload protection to be provided. Such a characteristic is shown in *Figure 34.14*.

The motor fuse characteristics would not be ideal for protection of a transformer circuit where the fuse must be able to withstand the transformer in-rush current, typically $10 \times I_{FL}$ for 0.1 s. It must also quickly clear faults within the transformer circuit and may have to discriminate with fuses on the LV side of the transformer. A shallow-sloped characteristic is more ideal (see *Figure 34.15*).

For HV fuses there are now separate international specifications covering both motor- and transformer-protection requirements. Specially developed LV fuses are available for protecting semiconductor devices. These must have a low I^2t let-through, low cut-off current and very low overvoltage on operation. In order to achieve the low I^2t such fuses tend to run very hot and the 'M' effect is generally not applied. They are not suitable for use in enclosed fuse holders and must be mounted so as to allow adequate air circulation. They generally have substantial terminations to assist in heat dissipation.

34.1.6 Fuse switches

A fuse switch is a switch which is connected in series with a fuse or, more precisely, the fuse is mounted on the moving contact system of a specially designed switch. An alternative device, a switch fuse, has the switch electrically connected to a series fuse to form a composite unit. This arrangement has disadvantages in that when changing a fuse the electrical circuit to which it is connected may still be live. Furthermore, if the switch is connected to the live side of the circuit the switch may not be capable of closing against

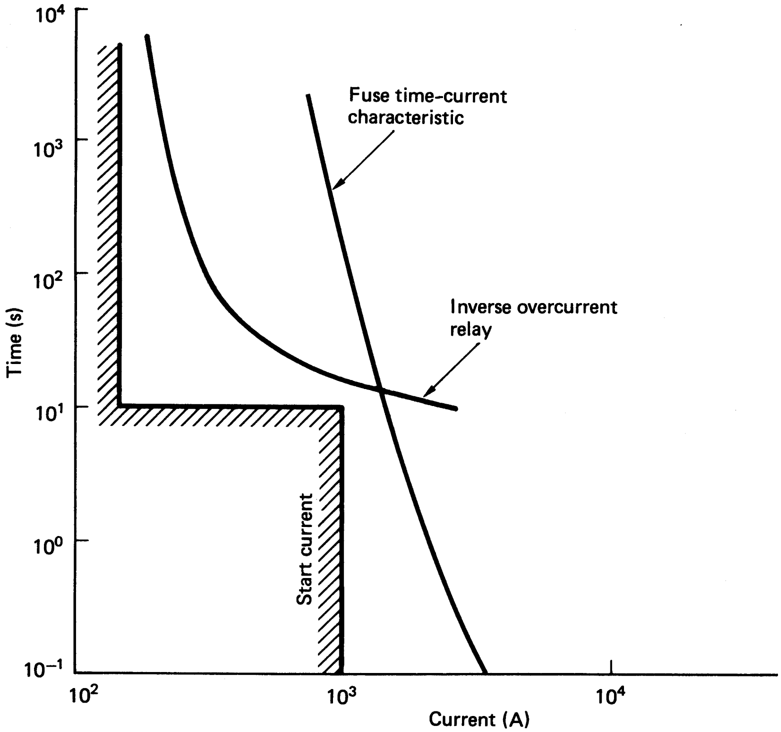

Figure 34.14 Motor starting fuse characteristics

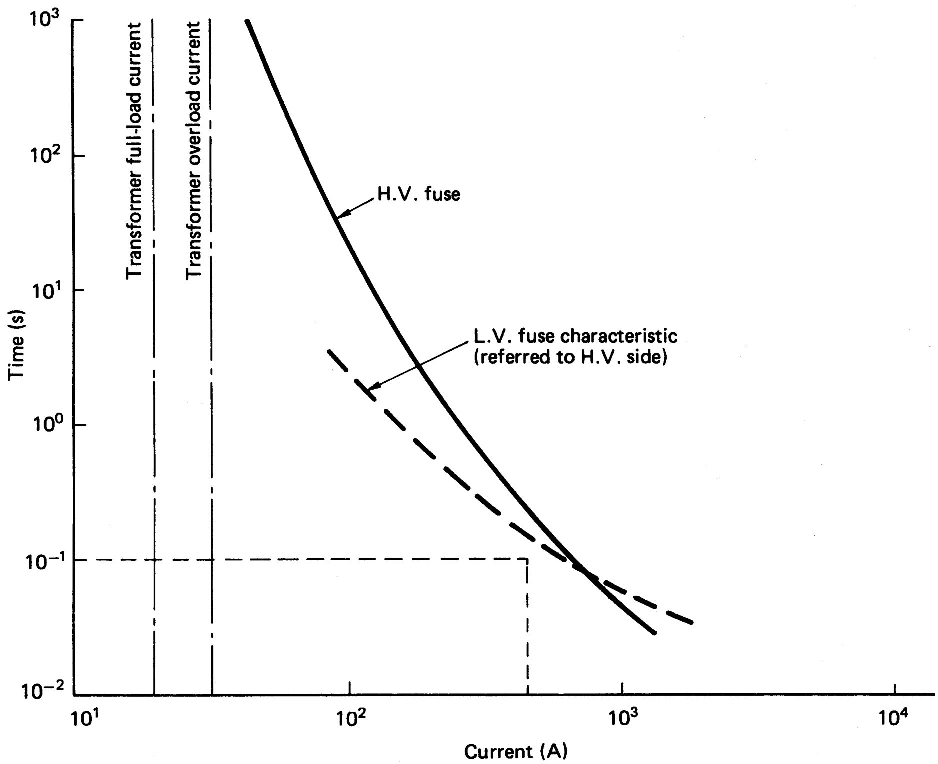

Figure 34.15 Transformer fuse characteristics

a fault between the switch and fuse. A fuse switch is inherently a safer device and is now widely used.

The advantage of the fuse switch is that it is an economical switching device that can safely make and break, by means of the fuse, short-circuit currents that may occur on the 'down-stream' system. Fuse switches are usually manually operated by means of an over-centre spring-operating mechanism which ensures a consistent and adequate opening and closing speed.

Fuse switches are perhaps the most commonly encountered mechanical switching device on industrial switchboards using three-phase LV circuits. A typical LV fuse switch is shown in *Figure 34.16*.

HV fuse switches operating at voltages of up to some 20 kV are widely employed on urban secondary distribution networks. In such an application three-phase operation of the fuse switch is necessary for any single-phase fuse operation and this is achieved by means of the fuse striker pin (see Section 34.1.5.2) operating the HV switch-trip bar. In addition, co-ordination is applied between the switch and fuse to ensure that for currents below the minimum breaking current, for a back-up fuse, the switch will trip satisfactorily, by fuse-striker operation, to clear an overloaded circuit. HV fuse switches use fuses mounted either in air or under oil, the latter being the more widespread application. When a fuse is mounted under oil the fuse design must incorporate appropriate sealing to ensure that oil does not enter the fuse body as this may result in fuse maloperation. A cross-section of an oil-filled fuse switch is shown in *Figure 34.17*.

34.1.7 Contactors

A contactor is capable of performing much the same switching duty as a switch and may also be capable of closing against a downstream short circuit when protected by an appropriate fuse. Its main difference is that it is capable of performing very frequent switching operations such as may occur, for example, with industrial processes where frequent stops and starts are required. In consequence it is necessary that it is capable of being remotely operated and, therefore, a spring-operated mechanism, for example, is unsuitable. The majority of contactor designs use a solenoid operating mechanism. This may be a continuously energised coil which holds the contactor closed, i.e. 'electrically held', or a short-time rated coil which closes the contactor via a mechanical operating mechanism and causes the mechanism to latch to hold the contactor in the closed position, i.e. a 'latched contactor'. Opening of a latched contactor requires the provision of a trip coil to operate a trip bar to release the latched mechanism. Most contactor-operating coils are energised from the source of supply; on loss of supply, all electrically held contactors would open and, unless appropriate protection were provided, would re-close on reinstatement of supply. For many industrial processes

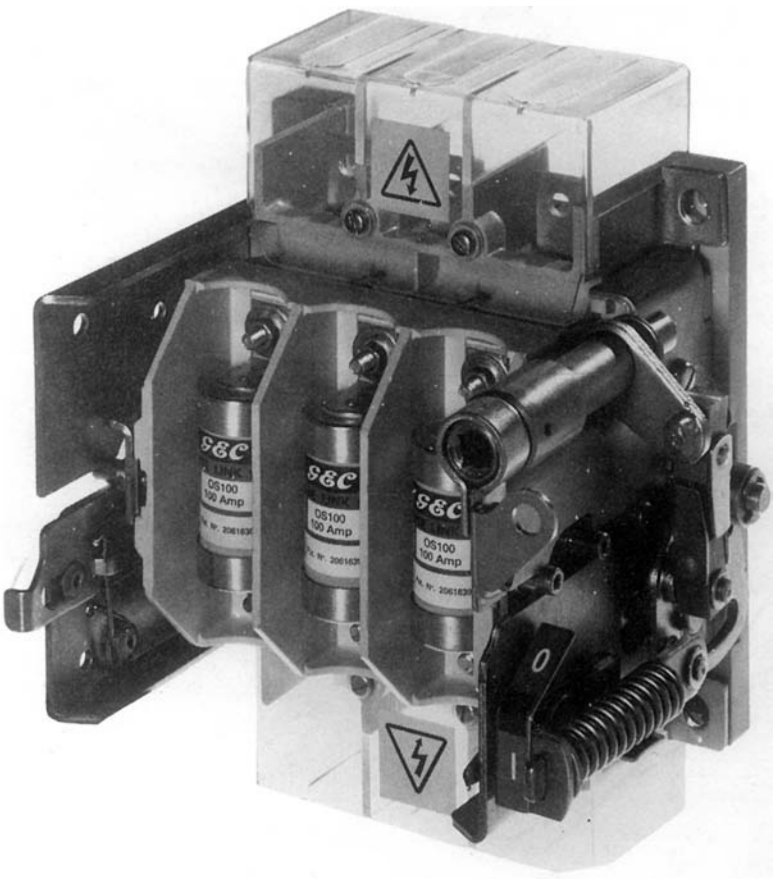

Figure 34.16 L.v. fuse switch

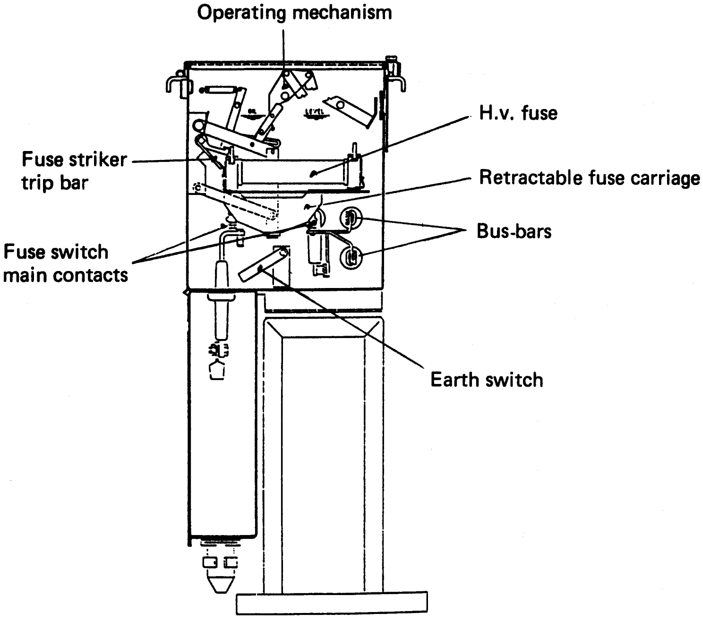

Figure 34.17 Cross-section of an oil-filled fuse switch

this feature may prove to be unsatisfactory, in which case latched contactors would be used.

A contactor, like a switch, needs to break inductive load currents and in order to achieve this within compact dimensions some form of arc control system is employed. This usually comprises a number of parallel disposed metallic plates separated by small gaps into which the arc is forced. These plates cause a number of separate arcs to be formed and at the same time they cool and extract energy from the arc to achieve arc extinction.

Early designs of contactors comprised a large open-clapper-type single-break construction. These have now largely been replaced by more modern, compact and economic double-break block construction contactors.

34.1.8 Circuit-breakers

A circuit-breaker is a more sophisticated mechanical switching device in that, in addition to making and breaking load and overload currents of the circuit, it is also capable of both making and breaking the full-rated short-circuit current of the system.

In order to break the full short-circuit current of the system, very sophisticated arc control mechanisms have been evolved over the years. The techniques of arc extinction were developed originally on a trial-and-error basis, and were considered to be more of an art than a science. However, with modern knowledge and experience, interrupter performance can more readily be predicted using advanced theory and computer techniques. Nevertheless, it is still necessary to perform actual short-circuit tests to verify the performance of a circuit-breaker.

In order to be able to clear a faulted circuit some means of detection of the fault is necessary and that information must be transferred into a signal to cause tripping of the circuit-breaker. For LV systems direct-acting overload coils may be employed or more sophisticated relays used. For HV systems it is necessary to ensure that the tripping signal is at LV, i.e. it must safely be segregated from the HV system. This is achieved by the use of current and voltage transformers. The output from these devices is fed into appropriate relays which operate under predetermined conditions to cause their contacts to make and energise the circuit-breaker tripping circuit.

Tripping supplies are usually obtained from continuously charged batteries operating at a nominal 125 V d.c. The most common method of satisfactorily achieving low tripping energy is to use mechanically held or latched operating mechanisms. This type of mechanism requires some form of prestored energy which can be released when required to cause the mechanism linkages to operate to close the circuit-breaker. Once the circuit-breaker has been closed and the stored energy dissipated, the mechanism must hold the circuit-breaker in the closed position by virtue of its interconnecting linkages, usually by some form of mechanical latching. The mechanism can then only be released to open the circuit-breaker by operation of a low energy trip bar operated from a trip coil plunger.

The most common circuit-breaker operating mechanism is the spring charged mechanism whereby the springs are charged either manually by means of a detachable spring charging handle or by means of an electric motor and geared drive system. The latter offers the advantage of remote charging. The charged springs can then be released by means of a small solenoid coil to close the circuit-breaker. An alternative closing energy source may be derived from a large solenoid coil but, whilst again this offers the facility for remote closing, it has the disadvantage of requiring a large d.c. supply.

This supply can either be fed from substation batteries or from a rectified supply derived from a voltage transformer. Either source of d.c. supply can be expensive and the motor rechargeable spring is now more widely employed.

For lower fault rated circuit-breakers the over-centre spring-operating mechanism, as used in most switches, is sometimes employed. Higher fault rated circuit-breakers, particularly at transmission system voltages, use either pneumatic or hydraulically operated mechanisms. These may take a number of different forms. For example, compressed air may be used to close a conventional mechanical operating mechanism to achieve mechanical latching with tripping being achieved by release of the latched linkages. Alternatively, the compressed air may be released through a series sequence of valves to operate a piston which in turn operates through direct mechanical linkages to the circuit-breaker contacts. A further alternative is where the compressed air is used directly to operate the circuit-breaker contacts.

Similarly with hydraulic mechanisms, a hydraulic pump may be used as a method of remotely charging the operating mechanism spring. This arrangement is seldom employed nowadays. Alternatively, the hydraulic system itself may be used to transmit the drive via a piston to operate the circuit-breaker moving contacts directly. With such an arrangement the stored energy required to operate the circuit-breaker is derived from an accumulator. This comprises a cylinder with a central 'floating' piston, one side of the cylinder being filled with a suitable compressed gas, usually nitrogen, and the other side of the cylinder being filled with hydraulic oil which is connected to the hydraulic pump. The pump operates to pressurise the system, the stored energy being contained within the pressurised nitrogen compartment of the accumulator. A series sequence of valves is then used to allow the stored energy to be released, via the hydraulic pipework to operate a piston to close the circuit-breaker.

Circuit-breakers have evolved in a number of different ways to suit particular applications and use a number of different arc interruption techniques. The types of circuit-breaker typically encountered are described in the following sections.

34.1.8.1 Miniature circuit-breakers

Miniature circuit-breakers are only used at LV, mainly in domestic or light-industrial or commercial applications. In general they are used in the same applications as semi-enclosed or cartridge fuses and offer an alternative for protecting radial or ring circuits. They are usually only single-phase devices and have a typical rated load current range of up to 100 A with a maximum short-circuit rating of 16 kA at 240 V. Manually operated over-centre spring-operating mechanisms are used. Miniature circuit-breakers usually employ a series overload coil for rapid short-circuit tripping and a bimetallic element for tripping on overloads. All miniature circuit-breakers operate on the air-break principle where an arc formed between the main contacts is forced, by means of an arc runner, and the magnetic effects of the short-circuit currents, into metallic arc splitter plates. These cause a number of series arcs to be formed and at the same time extract energy from the arc and cool it to achieve arc extinction. With some designs of miniature circuit-breaker this arc interruption process can be so rapid that current cut-off can be achieved in much the same way as described for a current-limiting fuse. The principle of a typical miniature circuit-breaker is shown in *Figure 34.18*.

Miniature circuit-breakers do not, however, provide rapid operation for low values of earth leakage current. Modern day wiring regulations require that very rapid operation is achieved in the event of an earth fault to minimise the dangers from electrocution. This requires operation for earth fault currents as low as 30 mA in a time of some 2–3 ms.

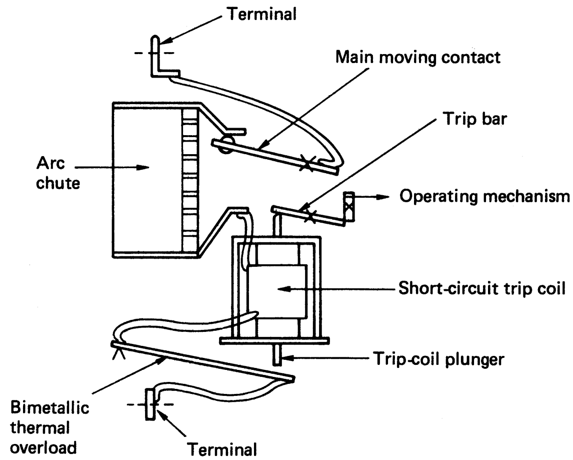

Figure 34.18 Principle of miniature circuit-breaker

A variation on the basic construction of the miniature circuit-breaker is used to achieve this requirement. Such a device is commonly known as an 'earth-leakage circuit-breaker', although the correct terminology is 'residual-current device'. Tripping at such low values of earth leakage current is achieved by passing both the feed and return conductors through an integral current transformer. Under normal conditions the resultant flux in the current-transformer core is zero. Under earth-fault conditions the feeding and return currents will not be of the same value and the current difference causes a flux to be generated within the current transformer core producing an output voltage at its secondary winding terminals which is used to energise the tripping circuit of the residual-current device.

Residual-current devices may be permanently wired into an installation or used as plug-in devices to protect domestic electrical appliances.

One feature of the miniature circuit-breaker and residual-current device is that their contacts are not maintainable and after a limited number of operations replacement of the device may be necessary. However, in practice, this is seldom a significant limitation and eroded contacts can usually be detected by overheating causing nuisance tripping of the device.

34.1.8.2 Moulded-case circuit-breakers

Moulded-case circuit-breakers are also only used for LV applications. They are basically an upgraded version of the miniature circuit-breaker and are invariably three-phase devices. They have typical current ratings ranging from 100 to 2500 A and may have rated short-circuit ratings up to 50 kA at 415 V. Some designs also exhibit cut-off similar to the current-limiting fuse and all are provided with inherent short-circuit and thermal overload protection devices. They may also be provided with earth-leakage protection.

There are two categories of short-circuit performance: P1 and P2. Category P1 requires the circuit-breaker to be capable of performing two short-circuit operations, an open (O), operation followed by a close/open (CO) operation. Subsequent to this duty the circuit-breaker may not be capable of performing its normal requirements and should be replaced. Category P2 requires the circuit-breaker to perform a further CO duty and subsequent to this test there must be no reduction in its current carrying performance.

In applying moulded-case circuit-breakers care must be taken to ascertain the circuit prospective short-circuit level and probable frequency of occurrence of faults. For circuits where the frequency of faults is high a category-P1 moulded-case circuit-breaker is likely to be inadequate.

Whilst some designs offer facilities for contact maintenance others do not, in which case erosion of contacts will only be detected by nuisance tripping resulting from overheating.

As the name implies, moulded-case circuit-breakers are invariably completely enclosed in a premoulded casing. There is usually an on/off operating toggle on the front of the unit with the three-phase terminals at the top and bottom of the unit. As for the miniature circuit-breaker, an over-centre spring-operating mechanism is usually employed.

Moulded-case circuit-breakers are generally used in similar applications to fuse switches, i.e. protection of large three-phase LV loads and for motor-starting applications. They do not, however, have the facility for remote or frequent operation and cannot be used to replace a contactor where frequent starting is likely to be a requirement. A typical moulded-case circuit-breaker is shown in *Figure 34.19*.

34.1.8.3 Air circuit-breakers

An air circuit-breaker uses atmospheric air as its interrupting medium. The arc is drawn between its contacts and extended via arc runners on to an arc chute where it is presented with a large cooling surface of arc splitter plates. These break the arc into a number of series arcs, the principle being to increase the resistance of the arc and extract energy from it via the metallic splitter in much the same way as described for LV switches, contactors and miniature circuit-breakers. A typical arc chute is shown in *Figure 34.20*.

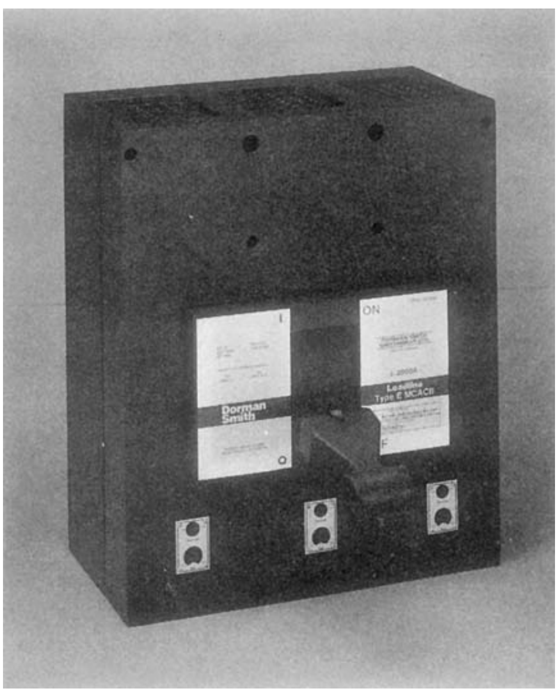

Figure 34.19 A typical moulded-case circuit-breaker

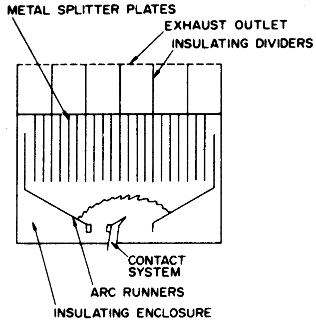

Figure 34.20 Arc chute interrupter used for air circuit-breakers

Free-air circuit-breakers are used for LV applications and HV applications up to some 20 kV. They can have very high rated currents of typically up to 4000 A and very high short-circuit interrupting capabilities of typically up to 90 kA at 12 kV. Their main application at LV is where an onerous performance is required in terms of load, number of operations and fault level. Mainly due to economic considerations, moulded-case circuit-breakers have replaced many LV applications where previously air circuit-breakers were used but where high performance, maintainability and long-term reliability are essential requirements air circuit-breakers are still used. A typical application is in generating-station LV auxiliary supplies.

The main application of HV air circuit-breakers has been in applications where the exclusion of flammable materials is a fundamental requirement. Again a typical application being generating-station HV auxiliary supplies. Such large high-rated air circuit-breakers are, however, extremely costly and their use is now tending to diminish in favour of high performance vacuum or SF_6 circuit-breakers.

A further application of air circuit-breakers is for use with d.c. supplies, this method of interruption still being the most suitable for d.c. circuits. D.c. circuit-breakers are widely used in traction applications where ratings of up to some 3 kV may be employed.

34.1.8.4 Air-blast circuit-breakers

Air-blast circuit-breakers use a blast of compressed air at a pressure of 25–75 bar which is directed across the arc path to cool and remove the ionised gas. Air-blast circuit-breakers are fast in interruption, which occurs usually at the first or second zero current, and arc lengths are short. The compressed air needs to be stored locally at the circuit-breaker within its own air receiver. Subsequent to operation the compressed air local storage needs to be replenished from a compressor system. This is usually a central system feeding all circuit-breakers via a suitable ring-main network.

Air-blast circuit-breakers are of two basic types, one where the interrupter contacts reclose subsequent to the blast of air, usually referred to as a 'sequentially isolated circuit-breaker' and the other where the interrupter contacts remain in the open position after the passage of the air blast and are continually pressurised to maintain the dielectric strength. This latter type is referred to as a 'pressurised-head circuit-breaker'.

With the sequentially isolated type, air is admitted via a blast valve at the bottom of the vertical support insulator. A high pressure ceramic blast tube is necessary to transfer this blast of air up to the main interrupter contacts to cause them to open against a return spring. This type of circuit-breaker also incorporates a free air disconnector in series with its interrupters. During the period in which the circuit-breaker contacts are held open by the blast of air and, after arc extinction, the disconnector is automatically operated to open the circuit. Once the sequential disconnector is fully open the main blast valve recloses to cause the main contacts to reclose under their own return spring pressure. For closing, the circuit is made on to the contacts of the sequential disconnector. These contacts must be very robust as they must close against the full short-circuit current of the system.

Sequentially operated air-blast circuit-breakers are used typically at voltages of up to 420 kV. Their main application is at transmission voltages. Their application at distribution voltage is minimal. Ratings of 50 kA at 420 kV with normal current ratings of 4 kA are possible. The interrupting capability per interrupter is limited and it is necessary to employ a number of series interrupters per phase, 12 breaks being typical at 420 kV. It is necessary to ensure that the interrupting duty is shared equally across each break and parallel capacitors or resistors are often employed for this purpose. Sequentially operated air-blast circuit-breakers invariably employ pneumatic operating mechanisms.

With pressurised-head circuit-breakers the arc is extinguished in much the same way as for the sequentially operated air-blast circuit-breaker. The main difference is that this type employs a main operating valve on the exhaust side of the interrupter such that once interruption is complete the open contact system is pressurised, at the full pressure of the compressed-air system, to maintain the dielectric strength across the open contacts. The contacts are held open permanently whilst the circuit-breaker is in its 'open' position. Interrupter contacts are generally driven mechanically via insulated pull rods from the main mechanical operating mechanism normally operated from a compressed-air-driven piston. The circuit-breaker is usually held closed by mechanical latching of the mechanism and opened by operation of a mechanical release trip bar, although some designs employ a compressed-air mechanism which is held open or closed by pneumatically operated valves.

Whilst the pressurised-head circuit-breaker alleviates the need for sequential isolation its main advantage is that, because the pressurised air is already at the interrupter contacts, very rapid arc extinction can be achieved, typical total break times being of the order of 40 ms. Such fast operation is necessary in order to ensure stability of the supply system when subjected to major faults. The very severe duties encountered often require the application of an interrupter in parallel to the main interrupter. When the main interrupter opens a resistor is then inserted in series with the parallel interrupter. This has the effect of damping the very severe transient overvoltage that might arise on circuit interruption, thus ensuring satisfactory fault clearance.

Such circuit-breakers may be used up to 800 kV with fault currents of some 80 kA or more. A number of series interrupter heads is necessary to achieve this rating—at 420 kV, for example, 10 or 12 interrupter heads may be required per phase. In addition to the resistor interrupters, parallel capacitors are also necessary to ensure equal voltage distribution across the interrupter heads during operation.

One phase of a typical pressurised-head air-blast circuit-breaker is shown in *Figure 34.21*. Such circuit-breakers are both mechanically and electrically very complicated and are very costly. Nevertheless, until the advent of SF_6 circuit-breakers, they were the only satisfactory means of interrupting very high values of fault current at the highest system voltages.

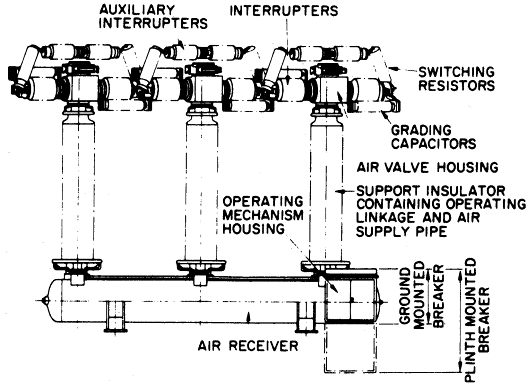

Figure 34.21 One phase of a pressurised-head air-blast circuit-breaker

Since all air-blast circuit-breakers expend, in a very short period of time, a large quantity of compressed air, they are very noisy in operation. To overcome this problem it is common to fit silencers to the exhaust systems of the circuit-breaker. The application of a silencer will reduce the noise level from approximately 120 to 90 dB.

Since the action of all air-blast circuit-breakers is dependent on arc extinction by a blast of compressed air, consistent fault-clearance times are achieved which are independent of the value of current interrupted.

34.1.8.5 Oil circuit-breakers

Oil circuit-breakers were the earliest devices used for satisfactorily achieving arc interruption. It was found that when an arc is drawn in hydrocarbon oil the arc energy decomposes the oil to form hydrogen (80%), acetylene (22%), methane (5%) and ethylene (3%), and the arc takes place in a bubble of gas surrounded by cooler insulating oil. The effect is that energy is extracted from the arc by chemical decomposition of the oil. Arc cooling is achieved mainly by the hydrogen gas which has a high thermal diffusion ratio; the surrounding oil also cools the arc plasma and the oil itself has a high dielectric strength when it flows into the arc path at zero current. Its good insulation properties also allow electrical clearances to be minimised.

The chief disadvantage of oil is that it is flammable. When expelled gases, formed due to decomposition of the oil on arc formation, mix with air these can be ignited as a result of a circuit-breaker maloperation to cause an explosion. For these reasons oil circuit-breakers are not used in generating stations where fire hazards are of paramount importance.

Early designs of oil circuit-breakers were of the plain-break design where contacts separated in oil without any specific means of controlling the arc. Performance was rather unpredictable, particularly under single-phase operating conditions and when drawing long inductive low-current arcs. For these reasons many plain-break circuit-breakers have now been withdrawn from service.

The problem was resolved in the late 1930s when the arcing process was controlled within an arc-control device. This device has the effect of constricting the arc, allowing a high pressure to be built up, which in turn assists in arc extinction. The gas, formed by the decomposition of the oil by the arc, is expelled through vents in the side of the arc-control device, allowing cool oil to flow across the arc path and cause rapid arc extinction (*Figure 34.22*).

Careful design of the arc-control device is necessary to allow the arc-interruption features to operate effectively. Each manufacturer has their own design of arc control device. All oil circuit-breakers now employ some form of arc-control device.

There are two basic forms of oil circuit-breaker: the bulk-oil circuit-breaker and the low-oil-content circuit-breaker. Both are widely applied with the former being traditionally used in the USA and the UK and the latter in Continental Europe.

The bulk-oil circuit-breaker comprises an earthed tank which contains the contacts and arc-control system. Connections are taken into and out of the tank by means of through-bushing insulators.

Operating mechanisms are external to the tank with drive linkage to the moving contacts taken via an oil-tight seal. For voltages up to 72.5 kV all three phases are contained in a common tank; above this voltage separate phase isolated tanks are usually employed. Up to 72.5 kV single-break contact systems per phase are used, although the major application uses double-break contact systems per phase.

Above 72.5 kV multibreak contact systems are necessary with six series breaks being used at 300 kV. Parallel resistors are usually employed to ensure equal voltage sharing across the breaks. Above 300 kV bulk-oil circuit-breakers become dimensionally unsatisfactory and uneconomical and are seldom employed.

Low-oil-content, or live tank minimum oil, circuit-breakers have only sufficient oil to surround the contact and arc control device and use phase segregated insulated enclosures. The main advantage of this design is that less oil is used and compact, economical designs can be achieved. The main disadvantage is that the small quantity of oil used per interrupter can soon become contaminated with carbon under frequent fault operations and the dielectric withstand capabilities across the oil and oil/insulator interface can deteriorate. More frequent maintenance is thus required than for an equivalent rated bulk-oil circuit-breaker. Low-oil-content circuit-breakers offer a convenient form of construction for transmission voltage open type switchgear in that the interrupters can be contained within a vertical hollow porcelain insulator and the assembly can be mounted on a support insulator.

Multiple interrupters can be connected in series using a modular construction to achieve short-circuit ratings of some 50 kA at 420 kV.

With dead-tank bulk-oil circuit-breakers, current transformers can be placed around the circuit-breaker entry bushings to provide an economical mounting arrangement. With low-oil-content circuit-breakers separate current transformers are required which must contain their own primary insulation. When current transformers are required on both sides of the circuit-breaker the low-oil-content concept can become a more costly arrangement than a dead-tank bulk-oil circuit-breaker with integral current transformers.

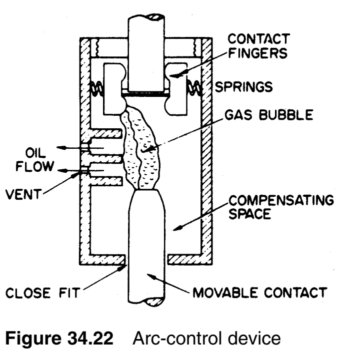

Figure 34.22 Arc-control device

34.1.8.6 SF_6 circuit-breakers

Virtually all current designs of circuit-breaker for use at transmission voltages now use sulphur hexafluoride (SF_6) gas both as an arc-interrupting and a dielectric medium. At distribution voltages SF_6 designs of circuit-breaker are also used, but here the market is still shared with vacuum and bulk-oil circuit-breaker alternatives.

Three basic types of SF_6 interrupter are commonly employed. The gas-blast interrupter, the puffer interrupter and the rotating-arc interrupter.

The gas-blast interrupter tends to have a higher performance capability than the other interrupters and is more commonly applied to transmission circuit-breakers. All gas-blast interrupters cause a flow of pre-pressurised gas across or along the opening circuit-breaker contacts. These interrupters may take a number of forms. Early designs used a store of high-pressure SF_6 gas kept separate from the main SF_6 used for dielectric purposes. On opening of contacts a valve operates to allow the flow of the high-pressure gas around the contacts to extinguish the arc. The gas is then re-compressed following an opening operation. Such a two-pressure system was used on early designs of SF_6 circuit-breaker. However, it has the disadvantage that the high-pressure gas, typically stored at some 15 bar gauge, liquefies at normal ambient temperatures and it is then necessary to apply heaters to the gas in the high pressure storage cylinder to ensure that it is retained in its gaseous state. Heater failure would require the circuit-breaker to be removed from service until the heater could be reinstated. In addition, the provision of a high pressure storage chamber makes the two-pressure circuit-breaker very expensive.

The problem was resolved by the development of the 'puffer' circuit-breaker. Here the gas is compressed during the initial part of the opening stroke and prior to separation of the circuit-breaker arcing contacts. This requires the circuit-breaker to have a long operating stroke and a powerful operating mechanism to precompress the gas. Nevertheless, it is this arrangement that is most commonly used on transmission SF_6 circuit-breakers. There are a number of variations of the puffer principle which determine the way in which the gas flows around the opening arcing contacts. These may be referred to as 'mono-blast', 'partial duo-blast' or 'duo-blast'. A typical partial duo-blast interrupter is shown in *Figure 34.23*.

Attempts have been made to overcome the necessity for the provision of a large powerful operating mechanism on puffer circuit-breakers by using the heat of the arc itself to pressurise the surrounding gas and induce arc extinction. This principle is commonly referred to as the 'self-pressurisation interrupter'. Whilst clearance at high values of fault current can readily be achieved, it is usually still necessary to apply a small piston to assist in arc extinction at very low values of fault current. This design of circuit-breaker is commonly used in distribution circuits and is now being employed in circuit-breakers for use at transmission voltages.

A further alternative, widely used at distribution voltages, is the use of the rotating-arc principle. Here the arc is induced to rotate very rapidly under the influence of magnetic fields set up by a series coil inserted into the current

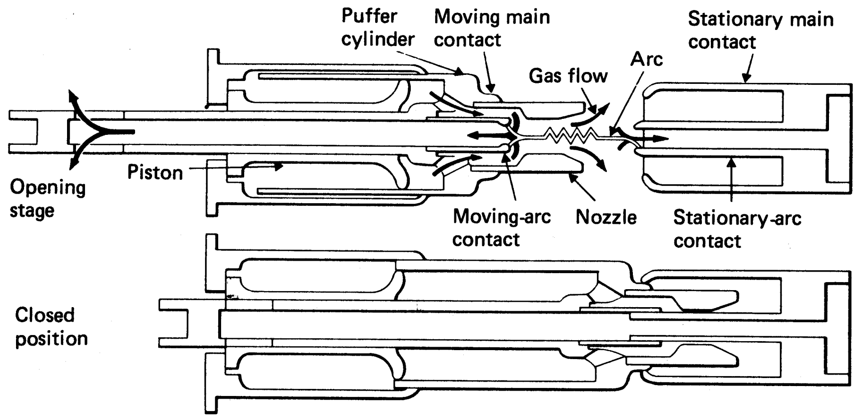

Figure 34.23 A typical partial duo-blast SF_6 interrupter

path during the opening of the circuit-breaker contacts. Very rapid movement of the arc causes a flow of cool SF_6 gas across the arc to achieve arc extinction.

The rotating-arc principle is shown in *Figure 34.24*. With this design more economical operating mechanisms can be achieved but, unlike the puffer circuit-breaker, the arc duration is largely dependent on the size of current being interrupted.

At transmission voltages, SF_6 circuit-breakers mainly use either pneumatic, hydraulic or spring operating mechanisms, whilst at distribution voltages spring operating mechanisms are now invariably used.

With SF_6 circuit-breakers it is imperative to ensure a leak-proof assembly. The number of enclosure joints needs to be kept to an absolute minimum and the main drive for the circuit-breaker moving-contact system should preferably be taken through only one point in the enclosure. Either rotary or axial drives may be used, but special provisions must be made to ensure adequate gas sealing. Maximum gas-leakage rates are typically specified as being not greater than 1% per annum in order to ensure adequate gas retention within the anticipated maintenance periods of the circuit-breaker.

Low-gas-density alarms are usually fitted to give indication of loss of gas and, in the event of rapid loss of gas, circuit-breaker immediate tripping or trip lockout systems are usually employed.

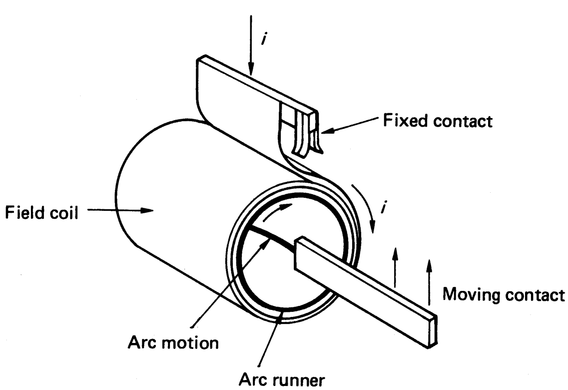

Figure 34.24 One type of SF_6 rotating-arc principle

The development of the SF_6 interrupter has been such that the interrupter capability has increased rapidly and it is now common practice to use only two interrupters per phase for a typical circuit-breaker rating of 55 kA three-phase at 420 kV. A single interrupter can achieve a typical rating of 40 kA at 420 kV.

The transient recovery voltage withstand capabilities are such that parallel resistor interrupters, as used on air-blast circuit-breakers, are not required. All that is necessary is simple capacitive voltage grading across both interrupters to ensure uniform sharing. Comparison with an equivalent air-blast circuit-breaker shows that the number of interrupters at 420 kV has been reduced from 10 to 2, parallel resistor interrupters and high pressure ceramic blast tubes are no longer required because standard porcelain insulators can satisfactorily operate at the SF_6 gas pressures required for interruption. This considerably reduces the number and complexity of components used and has enabled significant cost reductions to be achieved in the application of transmission switchgear.

34.1.8.7 Vacuum circuit-breakers

The possible use of vacuum as an interrupting medium has been studied since the 1920s. The major difficulty has been to produce a sealed device capable of retaining the full vacuum over an anticipated life span of some 25 years. It was not until commercially available high integrity vacuum devices, such as cathode-ray tubes, appeared that suitable techniques for ensuring, adequate sealing evolved. This then opened up the way for vacuum interrupters which became available in the late 1950s. Early designs were costly to produce and could not compete economically with the then widely used oil circuit-breakers. It was not until the late 1960s that mass produced economical designs became readily available.

In a vacuum interrupter, as the vacuum chamber is evacuated and the available ionisable molecules are reduced, the dielectric strength for a given gap rapidly increases. Pressures of some 10^{-8} T are typically used in vacuum interrupters. Pressures up to some 10^{-4} T would be satisfactory, but above this value ionisable atoms become available and the dielectric strength rapidly reduces to give the typical Paschan voltage–vacuum breakdown characteristic. Thus, at the end of the life of a vacuum interrupter, a pressure of some 10^{-4} T is still necessary. A typical contact gap in

11 kV vacuum interrupters would be some 15 mm. A major advantage of a vacuum circuit-breaker is that the very small contact travel required and the low mass of contacts have enabled very economical low output operating mechanisms to be used.

Very careful choice of contact material is necessary for vacuum interrupters. At high-current interruption, metal vapours are produced which assist in arc extinction and, therefore, for long contact life a hard contact material is the ideal choice. However, under low-current interruption conditions, hard contacts produce very little metallic vapour and very rapid arc extinction and 'chopping' of the current waveform results, which can produce high overvoltages. A softer contact material is better for low-current interruption, but erodes too rapidly at high currents. Contact material therefore must be a compromise between these two extremes and contact designs have evolved to ensure that the arc is kept in motion to minimise contact erosion. Important contact material criteria are vapour pressure, electrical conductivity, heat conductivity and melting point. Commonly used contact materials are copper–bismuth or copper–chrome alloys. Since the arc burns in an ionised metal vapour this vapour must condense on arc extinction and a vapour shield is usually provided for this purpose. This prevents the vapour from depositing on the insulating envelope and reducing its dielectric withstand capabilities. The shield also protects the envelope from thermal shock.

At or near zero current the arc extinguishes, vapour production ceases and very rapid re-combination and de-ionisation of the metal vapour occurs. The metal vapour products are deposited on the shield thus ensuring the clean conditions necessary for withstanding transient recovery voltage across the open contacts.

Means must be provided to allow moving-contact travel within the vacuum envelope. This is usually achieved by the provision of a stainless-steel bellows assembly. Design, construction and quality-control checks of the bellows are vitally important to ensure long term vacuum integrity.

Vacuum interrupters, by virtue of their construction, are single-phase devices. They are usually mounted in air in a three-phase circuit-breaker with air and solid insulation between phases. The maximum voltage rating of a vacuum interrupter is some 36 kV and maximum short-circuit currents may, in extreme cases, be as high as 100 kA, with rated currents of up to 4000 A.

The main use of vacuum interrupters is in circuit-breakers for use on distribution systems. More recently, with the higher ratings now achievable and for economic reasons, they are also being used in generating station auxiliary supply applications instead of free-air circuit-breakers. Vacuum circuit-breakers are seldom used at transmission system voltages as their maximum voltage limitation would require a large number of series connected interrupters which would be uneconomical.

The vacuum interrupter can also be used, in a much lighter construction, as a contactor for motor switching applications at voltages of up to 12 kV. A typical vacuum interrupter construction is shown in *Figure 34.25*.

34.2 Materials

34.2.1 Insulating materials

Many insulating materials are used in switchgear, they may be required just to provide insulation or to provide insulation and mechanical support, or to provide insulation and also assist in the arc interruption process. Where this happens some disassociation occurs and chemical recombination may be required.

They must also be capable, in addition, of withstanding temperature variations which may occur in service under both normal load and fault conditions. Under the latter they must withstand the extreme mechanical and electromagnetic forces that might result and sometimes also extreme pressure rises.

With insulation systems exposed to the atmosphere they must also be designed to withstand all anticipated environmental conditions of extreme temperature, rapid temperature changes, ice, snow, sun, wind, severe rain, solar radiation and lightning. All insulation systems must be designed to withstand transient overvoltages associated with lightning, switching surges and power frequency overvoltages. In some cases they may also experience d.c. trapped charges on circuit de-energisation or possibly d.c. with superimposed a.c. voltage.

Insulation systems must thus withstand many varied criteria and often with simultaneous combined phenomena, in addition, they must perform satisfactorily for many years with minimum of maintenance.

For outdoor insulation of overhead lines at transmission voltages for example, glass insulators have been commonly used, glazed porcelain insulators are also occasionally used. Whilst porcelain insulators are somewhat more expensive

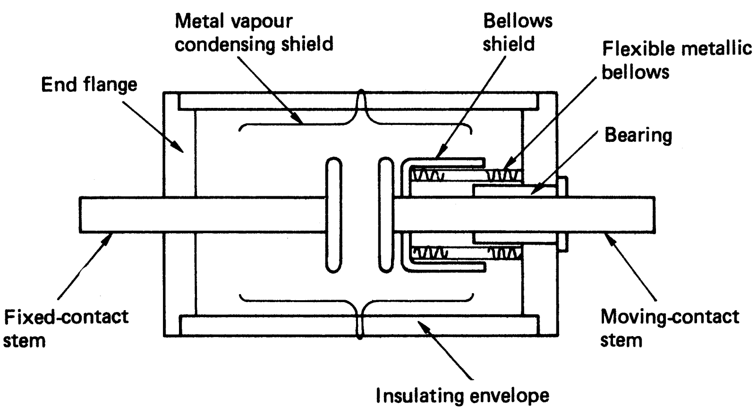

Figure 34.25 Cross-section of a vacuum interrupter

than glass insulators they generally show improved performance under polluted conditions. Porcelain insulators are widely used for distribution overhead lines and have almost universally been used for exposed terminations of substation equipment. In more recent years polymeric overhead line insulators have been used, these usually being in the form of EPDM or silicone rubber. Their performance is somewhat more complex than both porcelain and glass and very careful design is necessary. In addition, the composition of polymers is very critical and minor changes of constituents can cause significant performance changes.

Epoxy resin polymers have occasionally been used for outdoor insulation although these tend to deteriorate from solar radiation. Epoxy resin insulators are widely used in switchgear applications not exposed to external atmospheric conditions. These resins can be readily moulded to form complex insulator shapes which may not be possible with many other insulating materials. Such insulators have both exceptionally good dielectric and mechanical strength. Epoxy resin insulators will be encountered in most types of distribution switchgear and in gas insulated switchgear at transmission voltages.

A more economic form of insulation which is widely used in low-voltage switchgear is commonly referred to as dough moulding. This is a mixed polymer that rapidly sets at high temperature and pressure and is usually impregnated with numerous glass fibre strands to provide increased mechanical strength. Its mechanical and dielectric performance is usually inferior to epoxy resin systems and it is rarely found in distribution or transmission switchgear.

A further form of insulator which has been used for many years in switchgear is known as the 'Synthetic Resin Bonded Paper' insulator, often referred to as SRBP. This can only be used for straight insulators as may be required for example for circuit breaker bushings. The basic constituent is a thin, flat, electrical quality paper, commonly known as 'Kraft' paper. The paper, on a roll, is cut to the required length and then wound onto a mandrel, at the same time, a special electrical grade varnish is allowed to run in between the layers of paper. The mandrel may either be a metallic tube or in the form of a copper rod. Stress control throughout the section of insulator is important, this is usually achieved by winding in very thin aluminum foils known as stress control shields.The length of these shields tends to reduce from the HV conductor to the external earthed electrode to ensure uniform stressing both across the insulator section and along it's length. On completion of winding the assembly is placed in an oven, often under vacuum, to allow the varnish to cure. The final insulator is mechanically very strong. Such a form of insulator is commonly used where an HV conductor has to pass through an earthed electrode i.e. a circuit breaker tank. The atmospheric side of the insulator is usually enclosed in a porcelain housing to protect it from the environment. The annular gap between the SRBP insulator and inner porcelain wall is filled with high quality insulating oil.

A somewhat similar form of insulator is referred to as the 'Oil Impregnated Paper' insulator, commonly known as OIP. This form of insulator is usually utilised where more complex insulation profiles may be required. The same type of paper as used for SRBP insulators is employed, but in a narrower strip form, such that it may be wound either by machine or by hand, over a complex profile. In some cases a crepe paper is used to give greater flexibility where even more complex profiles are required. Aluminum foils are also embedded for stress control purposes. On completion of winding the insulated assembly is placed in a vacuum chamber with gradual increasing temperature to remove both moisture and air which will be trapped within the winding. Finally, high grade insulating oil is slowly introduced into the chamber to fully impregnate the paper. Once impregnated in its final assembly the oil should not be removed otherwise moisture and air might be re-introduced and re-processing would again be required. OIP insulation is commonly used as the insulation system for transmission system current and electromagnetic voltage transformers.

Where insulated screens may be required, for example between the phases in air insulated distribution switchgear, these may be of either bakelised paper form, made in flat rigid sheets in a similar manner as described for SRBP bushings, or in the compressed fibre board form which comprises bonded layers of oil impregnated fibrous paper. Compressed fibre board has the advantage that it can be bent to form enclosures. Such bent assemblies of compressed fibre board are usually found, as insulating barriers, within the tanks of bulk oil circuit breakers.

A further form of solid insulating material which is commonly used for insulated mechanical drive rods within switchgear is compressed and impregnated plywood, the impregnation again being with a high grade electrical varnish. This material has a high breaking strength under both tensile and compressive loading.

For transmission circuit breakers where a much higher mechanical loading is required the drive rods usually take the form of wound, epoxy impregnated, fibreglass matting, either wound as a tube or a rod. Metallic end fittings can usually be attached either by crimping or by epoxy bonding.

For cable terminations to distribution switchgear bitumen compound has been used for many years to provide the main insulation between phases and to earth. This material has a low affinity to moisture and becomes fluid at temperatures of around 120°C such that when heated it can readily be poured into the cable box and sets hard on cooling. Care is necessary however to use the appropriate grade of compound as shrinkage, embrittlement and cracking may occur to produce voids which may latter result in dielectric breakdown. Bitumen compound is also commonly found in current transformer chambers of distribution switchgear.

In more recent years, heat shrinkable polymers have been used for insulation of cable terminations. The application process is somewhat critical as entrapped air can lead to dielectric failure. Correct stress control is also vitally important. As cable jointing is, by necessity, a site function, it is important that site personnel are appropriately trained in the techniques and that appropriate Quality Control procedures are applied.

Insulating mineral oil has been used for many years as a dielectric media and also as an arc interrupting media in oil circuit breakers. It is usually of a Napthenic or Parafinic base dependent upon its source. Both have been used successfully in switchgear but in more recent years parafinic based oils have been more widely used due to, limitations of supply of napthanic oils.

One disadvantage of insulating oils is that they absorb moisture which can lead to dielectric degradation. Hence it is necessary to ensure that moisture entry is severely limited by equipment design. A further major disadvantage is that oils are flammable and, dependent upon class, have flash points varying between 95°C and 140°C. When disassociated due to arcing, hydrogen is formed and under equipment failure conditions the hydrogen can ignite to result in severe explosion and subsequent oil fire. Whilst the failure rate of oil filled switchgear is extremely low, the number of equipment's in service is very large (some hundreds of thousands of equipment's in the UK alone). Unfortunately failures and explosions do occasionally occur. It is for this reason that the application of oil filled switchgear has significantly diminished in recent years in favour of SF_6 insulated equipments.

In order to eliminate fire risks, synthetic insulating oils have been previously used, these were generically referred to as 'Askerals', these were based on polychlorinated biphenyls (PCBs). These have no flash point and are considered non-flammable. However, they are hardly bio-degradable and accumulate along the food chain, for this reason their production was banned in Europe in 1985. Strict regulations now apply to their use and most have in fact now been eliminated from service. Over the last 20 years considerable work has ensued on the production of less flammable liquids, the main alternatives are silicone and ester liquids, these are expensive and other performance parameters are limited. They are not generally used in switchgear.

Over the last 30 years or so the use of sulfur hexafluoride (SF_6) as an insulating and interrupting medium has slowly increased whereby today it has virtually replaced the use of oil in modern designs of switchgear.

Pure SF_6 is odourless and non-toxic but will not support life. It is 4.7 times heavier than air and tends to accumulate in low areas with the possibility of causing drowning. It has unique features which are particularly suited to its application in switchgear. It has a high electron attachment coefficient which allows it to have a high dielectric withstand characteristic. Its alternating voltage withstand characteristic at 0.9 bar(g) is comparable with that of insulating oil. A further advantage is that its arc voltage characteristic is low, hence the arc energy removal requirements are low. When subjected to the extremely high temperatures associated with arcing it tends to fragment into numerous constituent gases some of which are toxic, however, these recombine very quickly as the temperature falls and dielectric strength rapidly recovers. This process can occur in microseconds to allow several fault interruptions in quick succession. Solid arc products may be produced, these comprise mainly metal fluorides and sulphides, these are acidic and must not be inhaled. The gas performance is not impaired by the presence of these solids provided that it is maintained in a very dry state. At typical operating pressures of 4.5 bar(g) at 20°C SF_6 will remain in its gaseous form down to about −40°C, below this temperature it will liquefy and the equipment's performance may be impaired.

SF_6 is a very stable gas and if released into the atmosphere it may take over 3000 years to dissociate. It also has a high reflective index in the infrared spectrum which means it contributes to greenhouse warming. In fact it is the worst known greenhouse gas but at present the quantity in the outer atmosphere is small and its contribution to greenhouse warming is negligible. Nevertheless, it must no longer be deliberately released into the atmosphere and leakage and handling losses must be minimised. Contaminated gas can readily be re-processed to restore it to a state whereby it can safely be reused. It can also be safely disposed of at the end of its useful life.

34.2.2 Contact materials

Low-voltage high current contacts are used in LV distribution switchgear. They are usually of the bolted form or are intended to open and close to provide either circuit isolation, load interruption, motor switching duties or fault interruption.

Bolted contacts used to connect bus-bars for example are usually of silver or tin plated copper. The silver or tin plating being used to inhibit long term oxidation of pure copper contacts. Usually more than one fixing device is employed to minimise the possibility of a loose contact which could lead to over-heating or failure. The contact must also be capable of withstanding short circuit through current in the event of a system fault. A typical fault withstand capability being 43 kA for three seconds.

Disconnectors may be provided to facilitate a circuit open point, these are switched with the load removed such that their contacts have only to interrupt a few milliamperes. They are infrequently switched and copper contacts are usually silver plated to prevent oxidation of the copper surfaces. Switches or switch disconnector contacts have to break load current and may have to close against the system short circuit current. Such switches may be operated relatively frequently and contacts are generally unplated as the wiping action during closing or opening generally cleans the contacts and tends to remove any oxide formation. When fault closing is required pure copper contacts may well weld due to the softness of the copper. Such contacts usually contain a hardening additive within the copper, typically additives are beryllium or tungsten. For low-voltage circuit breaker applications where high fault current breaking is required the point of arc root during interruption must be of a very hard material and typically tungsten tips are welded to the ends of the contact fingers. It is important that the arc transfers to the contact tip and does not root on the normal current carrying surface of the contacts, failure would rapidly result if this should occur, i.e. the normal current carrying surfaces of the closed contacts should not be eroded as a result of fault interruption.

Circuit breakers at distribution voltages usually employ copper contacts with a hardening agent to prevent either cold welding in the normally closed position and high current welding resulting from the passage of through fault current. Copper/tungsten contact tips are invariably employed for arc rooting during short circuit interruption. Such contacts may be of the rod and multi-finger type, wedge and multi-parallel finger type or butt type contact.

Distribution switchgear bus-bar contacts are usually of multi-fixing point silver plated copper joints. Sometimes however, for lower rated current circuits, aluminum bus-bars may be employed. Jointing aluminum however requires more care than for copper as aluminum readily oxidises and it is necessary to wire brush joint surfaces with a stainless steel wire brush with a layer of grease applied to prevent re-oxidation. The joint is usually made with the application of a fine layer of jointing grease. Where aluminum bus-bars are used in outdoor substations it is necessary also to apply a proprietary jointing compound to inhibit moisture ingress.

For transmission circuit breakers similar contact materials are used but the copper contact fingers may have an additional additive, e.g. molybdenum, to provide spring resilience. In view of the generally higher current ratings of transmission circuit breakers cylindrical type contacts are often used to minimise the skin effects induced by the very high current.

For gas insulated switchgear (GIS) aluminum tubular bus-bars are invariably used. This is to provide a large diameter to minimise the surface dielectric stresses. Copper surfaces may be embedded onto the aluminum tube where bus-bars are jointed.

34.3 Primary-circuit-protection devices

Primary-circuit-protection devices are necessary to ensure that any system malfunction is quickly detected and steps taken to minimise its consequences. The main primary-circuit-protection devices encountered are current transformers, voltage transformers and surge arresters.

34.3.1 Current transformers

A current transformer is a current transducer that will give a current signal directly proportional in magnitude and phase to the current flowing in the primary circuit. It also has another very important function in that the signal it produces must be at earth potential relative to the HV conductor. The primary circuit of the current transformer must be insulated to the same level of integrity as the primary insulation of the system. For current transformers used on HV systems the primary-circuit insulation represents a very large proportion of the cost of the transformer.

The current transformer is the only current transducer widely used in HV networks. Recent developments of fibre-optic HV current transducers show promise but high cost and questionable reliability have limited their application. There is little doubt, however, that future current transducers will use fibre-optic technology.

A current transformer, as its name implies, is a transformer. It is almost invariably in the form of a ring-type core around which is wound a secondary winding.

The primary winding usually consists of a straight bar through the centre of the core which forms one turn of the primary winding. For low primary currents, typically below 100 A, multiturn primary windings consisting of two or more turns may be used in order to achieve sufficient ampere-turns output to operate the secondary connected equipment. For use at distribution voltages the core and secondary winding, together with the secondary terminations, are usually placed over a straight HV conductor bushing insulator which forms the segregation between the HV conductor and earth. An earthed screen is usually provided on the outer surface of the bushing and the current transformers are placed over this earth screen to ensure the limitation of HV partial discharge activity in the air gap between the bushing and the current-transformer winding. Current transformer secondary windings are generally connected to electromagnetic relays. These tend to require a high operating input which necessitates high-output (typically 15 V-A) current transformers. More modern protection is of the solid-state form and requires a much lower operating signal, thus enabling current-transformer designs and costs to be reduced. The secondary windings of current transformers tend to be rated at either 1 or 5 A, although other ratings are used at times.

Where long secondary connections are required between the transformer and the relay, 1 A secondary windings are advantageous in reducing the lead burden. Cold-rolled silicon-iron is usually used as the core material for protective current transformers but, where high-accuracy metering requirement is necessary, a very high grade alloy steel is used which is commonly referred to as 'Mumetal'.

For use at higher transmission voltages it is necessary to build integral insulation into the current transformer between HV conductors and secondary windings. This insulation is nearly always in the form of oil-impregnated paper, although SF_6 gas is occasionally used. The cost of providing the pressurised SF_6 gas enclosure usually makes SF_6 insulated current transformers uneconomical.

There are two basic forms of construction of transmission voltage oil-impregnated-paper insulated current transformers: the live-tank and dead-tank forms.

In the live-tank form the core and winding are placed at the same level as the primary conductor which passes through the centre of the assembly. The core and windings clearly need to be at earth potential. They are usually enclosed in some form of metallic housing which has a long vertical metallic tube through which the secondary winding leads pass to the base level. This housing and vertical metallic tube then have very many layers of paper wrapped around them to form the main primary insulation. Aluminium foil stress-control layers are wound in between the paper layers to ensure a uniform stress distribution from earth potential at the bottom end of the assembly to line potential at the top end.

The insulated current transformer assembly is then placed within an insulator housing having a metallic top assembly through which a primary conductor is passed. This conductor is electrically connected to the top assembly on one side and insulated on the other to prevent a current transformer short-circuited turn.

Before assembling the top cover, the whole transformer assembly is placed under vacuum for several days to ensure thorough extraction of moisture from the paper. The assembly is then filled under vacuum with a high grade insulating oil to prevent the formation of air bubbles. After filling the transformer to the top it is sealed. Some form of expansion assembly is incorporated to allow for expansion and contraction of the oil within its sealed compartment. This may comprise a bellows assembly or sealed nitrogen cushion. The current transformer may also incorporate an oil-level indicator to allow checking for loss of oil and a gas-detection system to allow monitoring for the production of gaseous products resulting from partial dielectric breakdown.

In the dead-tank version the current transformer core and windings are placed at the bottom, earth, end of the assembly and the insulation between the primary and secondary is in this case placed around the HV primary conductor rather than core and winding assembly. The centre section of the insulated HV primary conductor at which the core and windings are placed must be at earth potential. The HV primary conductor insulation must be graded on either side of the core and windings. Aluminium-foil wraps are inserted between the paper layers to provide the necessary grading from earth potential at the centre section to line potential at either end. To enable the HV primary conductor assembly to be accommodated in a vertical insulator, the assembly is bent in a 'hairpin' fashion. The insulated paper is in fact wound on to a conductor already formed to this hairpin shape. The legs of this insulated assembly are then opened up to allow the core and windings to be slipped over.

The completed assembly is vacuum processed and oil filled in a similar manner to that described for the live-tank current transformer.

Both live-tank and dead-tank forms of construction are very widely used. Both constructions are shown in *Figure 34.26*.

34.3.2 Voltage transformers

Voltage transformers are also, as the name implies, voltage transducers giving an accurate representation in magnitude and phase of the voltage of the primary conductors. They also require insulation to segregate the primary and secondary circuits. At transmission voltages they are always single-phase assemblies, whereas at distribution voltages they may be three-phase or single-phase assemblies. At distribution voltages the primary winding is always star connected with its neutral point generally insulated and unearthed.

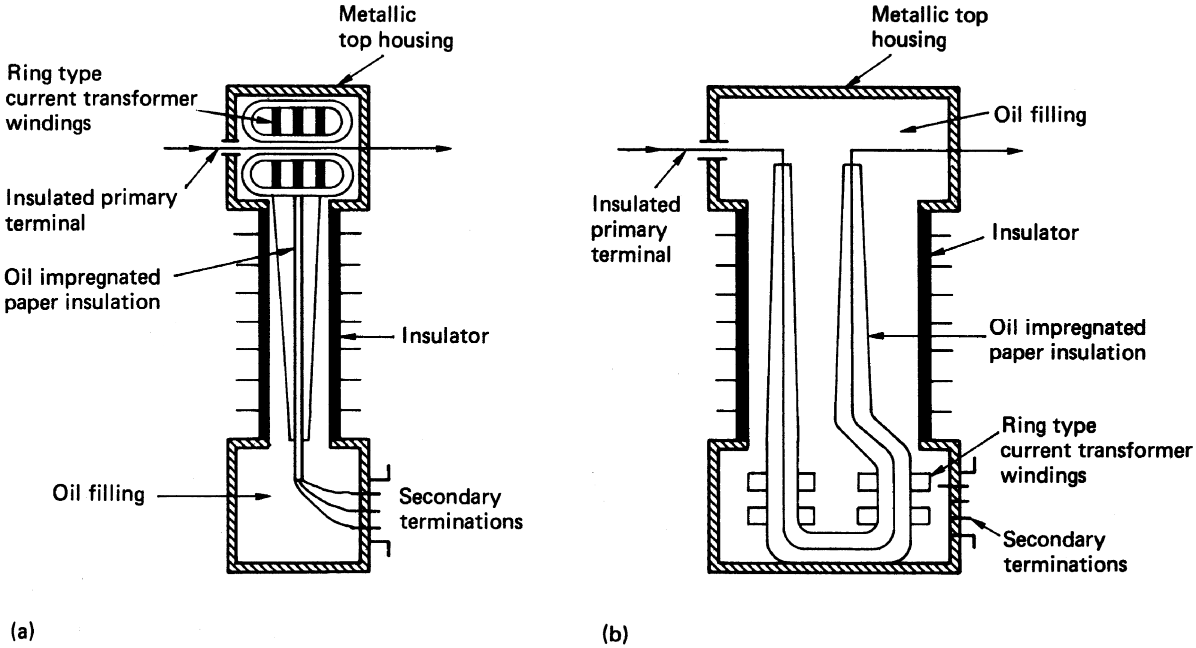

Figure 34.26 Cross-section of (a) live-tank and (b) dead-tank current transformers

The secondary windings are usually connected in a star arrangement to provide a standard phase-to-phase secondary voltage of 110 V, the individual phase secondary windings being rated at 63.5 V.

For certain applications a further secondary winding is sometimes provided which is connected in open delta. Under normal balanced voltage conditions the voltage across the open delta is zero. However, for earth-fault conditions balance will no longer be achieved and a voltage will occur across the open-delta winding. A three-phase residual voltage transformer uses a five-limb core to allow the zero sequence resultant flux to circulate. Such a system is generally used for residual earth-fault protection.

Three-phase assemblies at distribution voltage traditionally were of the oil-filled construction. More recent designs of three-phase voltage transformer employ a dry type cast epoxy resin insulated assembly enclosed in a metallic tank. Three single-phase cast epoxy insulated voltage transformers may also be mounted within an enclosure and connected to form a three-phase assembly.

Designs of electromagnetic voltage transformer usually employ an earthed electrical shield between the HV and the secondary winding. In the event of an HV breakdown, fault currents will flow to earth via the shield rather than through the secondary winding. A further useful feature of the shield is that it prevents h.f. coupling between primary and secondary windings as h.f. coupling in secondary windings and circuits could cause maloperation of secondary connected equipment. Such high frequencies may, for example, be generated by disconnector operation.

At distribution voltages, voltage transformer HV windings are usually protected by means of fuses to limit the energy that is fed into a faulted voltage transformer to prevent possible external disruption of it.

At transmission voltages, early designs of voltage transformers were also of the electromagnetic construction with the core and winding built in a conventional transformer manner and enclosed within a large oil-filled tank at earth potential. The HV connection was taken into the transformer via a large external bushing. Whilst some of these designs are still in service and are reliable, in the rare event of failure a large amount of energy would be expended within the transformer tank.

Since it is impracticable to protect such voltage transformers with fuses, to alleviate the problem a gas-detection device is usually fitted which will trip the associated circuit-breaker in the event of rapid build up of gas.

Electromagnetic voltage transformers for use at transmission voltages are also very costly and a more inherently reliable and economical device was developed which is referred to as a 'capacitor-voltage transformer'. This concept uses one or more HV capacitor assemblies, each of which is enclosed within its own porcelain housing. The individual units are mounted on top of each other to form a series assembly of HV capacitors. The complete assembly is usually mounted on an earthed tank which encloses a further capacitor and an electromagnetic transformer/reactor assembly. The bottom capacitor forms the lower leg of a capacitor divider assembly and a voltage signal (typically 12–25 kV) is taken from the interface of the HV and LV capacitors. This signal is then fed via a reactor to a transformer which has a secondary winding giving an output of 63.5 V at the system rated voltage. The secondary winding may have tappings to enable correct setting and thus minimise the voltage-ratio error.

The reactor also usually has tappings to allow for minimum setting of the phase-angle error. The LV capacitor is usually of a large value, typically 20 000 or 30 000 pF. The value of the reactance connected to this capacitor is such as to allow resonance to occur at the required system frequency, e.g. 50 or 60 Hz. This arrangement allows a significantly larger secondary output to be taken from the capacitor-voltage transformer than would be available if it were purely a capacitor divider. Ratings of 200 V-A can readily be achieved by this means. Capacitor-voltage transformers are tuned devices and their accuracy and output will fall considerably at frequencies other than the tuned frequency.

Maloperation of a capacitor-voltage transformer is usually detected by variation in secondary output voltage and explosive failures are extremely rare. Unless a very high value of HV capacitor is used, external moisture or pollution contamination on the insulation can cause variations in the HV field around the insulator which will result in slight variations in output. These variations are of little significance for capacitor-voltage transformers used for protective purposes, but for high accuracy tariff metering such variations can be significant.

For these reasons capacitor-voltage transformers are seldom suitable for use in high accuracy tariff metering applications and it has been necessary to revert to the electromagnetic transformer for these applications. Early designs used a cascade arrangement of separately connected transformers in order to reduce physical size and to alleviate the consequences of dielectric breakdown. These arrangements have been used at both 420 and 300 kV and comprise three separate electromagnetic units vertically mounted on top of each other and enclosed within a large-diameter oil-filled insulator assembly. Cascade electromagnetic voltage transformers have proved to be very reliable, but are also extremely costly. Where large numbers of high-accuracy voltage transformers are required, for example at interconnections between adjacent electricity supply companies, then the cascade voltage transformer is no longer economical and it has been necessary to revert to a single electromagnetic unit enclosed within its own porcelain housing.

Because of the considerable reduction in output achieved by the use of solid state secondary equipment, smaller electromagnetic units can now be used. These designs nevertheless still comprise paper-insulated oil-filled units and are prone to the dielectric-breakdown problems of the earlier designs. Very careful design and strict manufacturing quality-control procedures are necessary to ensure the long-term integrity required of these equipments. It is still normal practice for gas-detection alarms to be provided which may also offer the facility for circuit-breaker tripping on sudden build up of gas.

34.3.3 Combined-instrument transformers

Where high-accuracy instrument transformers are required to be fitted retrospectively, space limitations in existing substations often present significant problems. The situation has been alleviated by the combination of both a current transformer and an electromagnetic voltage transformer into a common insulator housing. These devices are referred to as 'combined instrument transformers'. They are used at transmission voltages up to some 300 kV, but for higher voltages where very limited numbers would be required they are not economically viable and separate units are still used.

Figure 34.27 shows typical arrangements of a capacitor-voltage transformer, cascade electromagnetic voltage transformer and combined-instrument transformer.

34.3.4 Surge arresters

Electricity supply networks extensively use overhead lines to transmit the power from generating stations to major load centres. These allow interconnection of different parts of the system and, in rural networks, supply isolated consumers. All of these overhead-line circuits are prone to atmospheric disturbances. These may be physical in nature (i.e. wind, rain, snow, ice and pollution) or electrical (as may occur during lightning activity). Should an overhead-line circuit be struck by lightning the overvoltage surge generated on the line may be of the order of megavolts. This surge will travel down the line, possibly causing flashovers en route, and its magnitude and shape will be attenuated by the electrical parameters of the line. When it arrives at the terminations of electrical equipment it may cause the equipment to flashover externally or fail internally. The surge will be triangular in wave shape having a steep wavefront with a rate of rise of possibly up to 3 MV/μs and a long duration tail of typically 20–200 μs.

In addition, transient overvoltages can be generated by the switching devices themselves. These will also be triangular in shape but with a much less steep wavefront (250 μs) and much longer wave tail (2500 μs) than the lightning surge. Switching surges can also result in dielectric failure of connected electrical equipment. It is thus necessary to

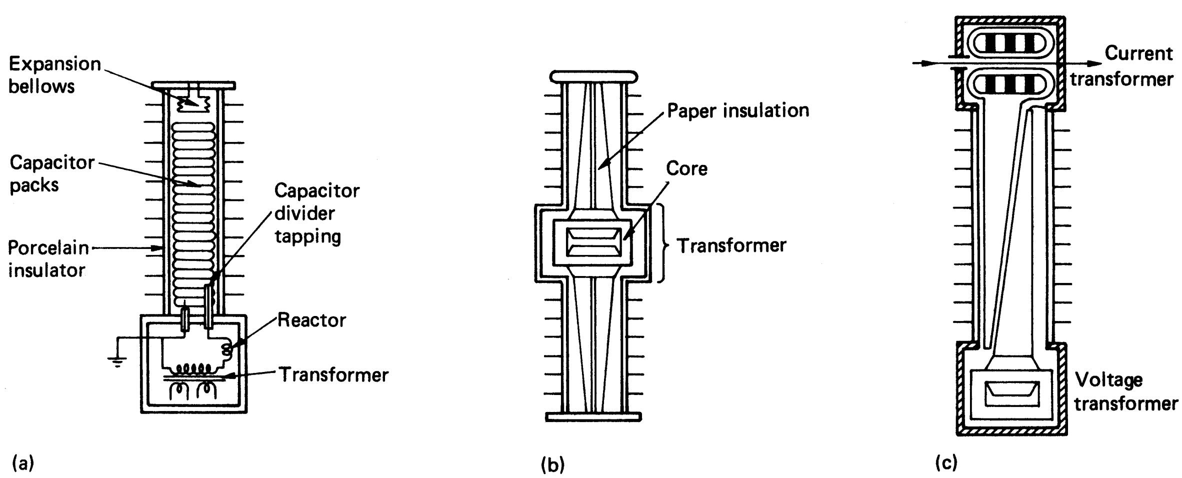

Figure 34.27 Arrangement of (a) capacitor-voltage transformer, (b) cascade electromagnetic voltage transformer, and (c) combined-instrument transformer

protect electrical equipment against these transient overvoltages. This is normally achieved by application of a surge diverter or, more correctly, surge arrester. The surge arrester is a device which is electrically connected between the conductor and earth and in close proximity to the equipment that it is to protect. Under normal power frequency conditions the current which flows to earth is negligible, but under transient overvoltage conditions it will detect the change in voltage magnitude and divert the surge to earth. Surge currents may be as high as 100 kA or more and of a few tens of microseconds in duration. Once the surge has passed, the surge arrester will very quickly reinstate itself to immediately withstand the power frequency system voltage and prevent power frequency fault current flow. The duration of the passage of surge current is so short that the system protection does not operate to cause circuit-breaker tripping.

Rod gaps are sometimes provided across insulators, or electrical apparatus also to divert the surge to earth but, in doing so, cause power frequency fault current to flow and result in circuit-breaker tripping.

Surge arresters provide the required characteristics by the use of non-linear resistor blocks which have a high resistance at LV and a very low resistance at HV Traditionally, silicon carbide blocks have been used as being the most suitable non-linear resistor material. However, they suffer from the disadvantage that even at LV a significant current will still flow which will lead to overheating and eventual failure. This problem was resolved by incorporating a number of series gaps in the arrester. The capacitance of these gaps causes insignificant current to flow through the blocks under normal voltage conditions and thus alleviates overheating problems. For transient overvoltages, the series gaps will break down and the resistor blocks will effectively be switched into circuit. These gaps will quickly reinstate after the passage of surge current.

Many lightning strikes comprise multiple strokes which occur within a few milliseconds of each other. For example, a low-probability strike might comprise six strokes within 100 ms. The application of each transient overvoltage to the terminals of the surge arrester will require the dissipation of a large amount of energy which will result in heating of the silicon carbide blocks. The arrester, however, must be capable of dissipating multiple lightning strokes without deterioration and the resistor blocks must be sized accordingly. The disadvantage of the silicon carbide gapped arrester is that, in order to overcome the high leakage current problems, series gaps are required and these make the arrester large and costly. Nevertheless, these arresters can readily withstand temporary power frequency overvoltages for long periods of time since the series gaps are unlikely to operate.

The problem of size, complexity and cost of the silicon carbide gapped arrester has been resolved in recent years by the development of the zinc oxide arrester. These arresters use resistor blocks manufactured from zinc oxide and a combination of a number of other additives and have the advantage that their resistance is such that, at normal operating voltages, only a milliampere or so of leakage current will flow. They have a sharp knee point at higher voltages which rapidly allows the flow of high current resulting in the very rapid dissipation of the surge.

A comparison of the characteristics of silicon carbide and zinc oxide resistor blocks is given in *Figure 34.28*.

Since the leakage current for zinc oxide blocks is very low, series gaps are no longer required. In addition, the zinc oxide blocks are physically smaller for a given rating. This technology has allowed the rapid development of very

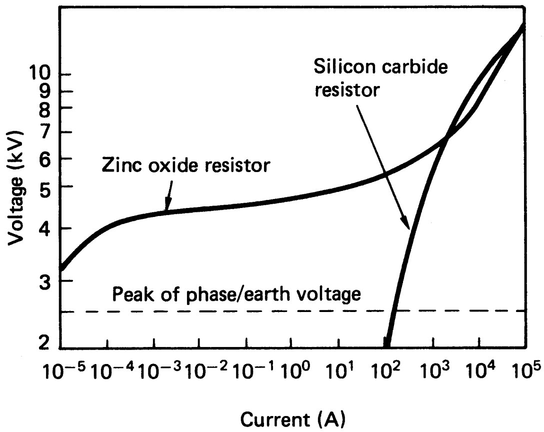

Figure 34.28 Comparison of (a) silicon carbide and (b) zinc oxide resistor characteristics

economical high-performance designs of surge arrester and the virtual elimination of silicon carbide designs.

A further innovation has been the recent introduction of a polymeric housed, rather than a porcelain housed, arrester. This has significantly increased the mechanical strength of the arrester and elimination of the problem of shattered porcelain in the event of arrester internal failure. A typical porcelain housed silicon carbide gapped arrester and a polymeric house of zinc oxide arrester construction for the same voltage rating are shown in *Figure 34.29*.

34.4 LV switchgear

34.4.1 Fuse cut-outs

'Fuse cut-out' is a term commonly applied to the equipment placed at the interface between the supply authority system and a domestic consumer's system. It comprises facilities for terminating the main incoming cable, for incorporating a fuse link and for terminating outgoing conductors to the supply authority's meter. Since the consumer may have physical access to this equipment, safety is of paramount importance. All live connections must be enclosed to prevent danger and fuse holders containing the fuse links are sealed within the cut-out assembly.

Many thousands of these units are installed by the supply authorities and reliability is of paramount importance. Elaborate specifications and extensive type testing are necessary to ensure the suitability of the device. The cut-out must be rated for the consumer's load which is normally supplied from a single-phase circuit typically having current ratings of up to 100 A.

For higher loads three-phase assemblies must be supplied. The consumer's load can vary rapidly over short periods of time and the cut-out must be designed and tested under a very large number of repetitive cyclic loading conditions in order to ensure that long-term deterioration is unlikely to occur.

The fuse cut-out must also be capable of clearing a short-circuit across its terminals. This may be of the order of 16 kA at 240 V. The main purpose of the cut-out is to protect the supply authority's circuits in the event of malfunction of the consumer's installation. However, in performing this function it will also limit the energy fed into

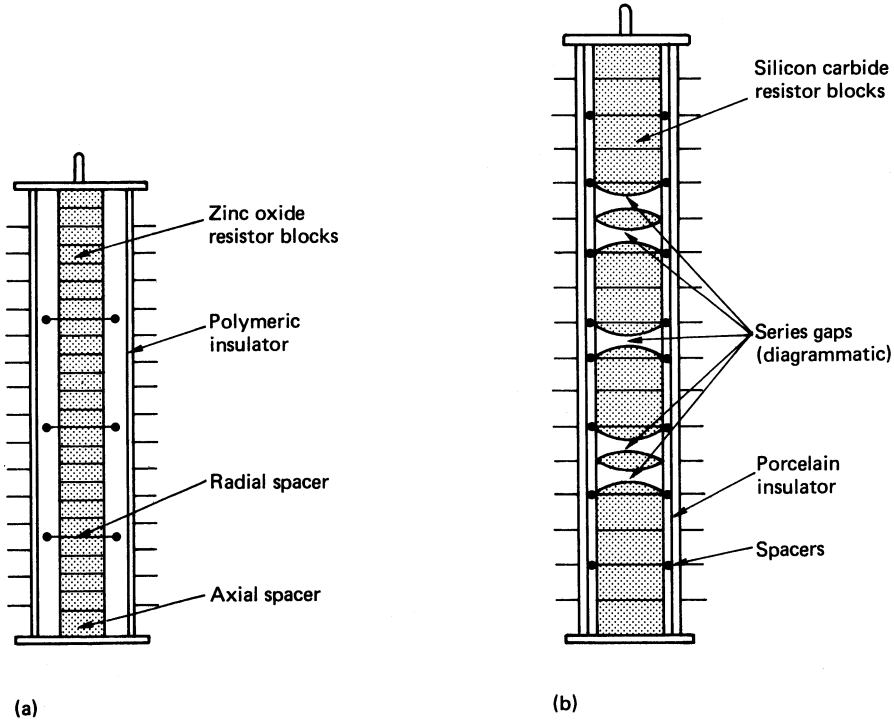

Figure 34.29 Construction of silicon carbide and zinc oxide surge arresters

a consumer's faulted equipment. Removal of the cut-out fuse links will provide physical isolation between the supply authority's and consumer's equipment to allow work to be safely undertaken on the consumer's installation. As the cut-out fuse holders are sealed within their base their removal can only be undertaken by the supply authority.

A typical three-phase domestic fuse cut-out is shown in *Figure 34.30*.

34.4.2 LV fuse cabinets

For commercial or light-industrial consumers the connected loads are in excess of those that can be provided by the domestic fuse cut-out. Three-phase loads are generally required with possible current ratings of up to 1600 A at 415 V. Multiple circuit loads may also be required. These are usually provided by means of a LV fuse cabinet supplied directly from a HV transformer having ratings typically of up to 1000 kVA.

Fuse cabinets may be bolted directly to the LV terminals of the transformer. They comprise an incoming directly connected circuit from the transformer to three single-phase manually operated disconnectors. These disconnectors then control and supply each phase of a main three-phase bus-bar system from which up to five outgoing circuits can be taken. Each phase of the outgoing circuit is protected by a bus-bar-mounted LV fuse with terminations for the outgoing circuit cables provided on the outgoing fixed contacts on the fuse.

Fuse cabinets are generally of weatherproof construction suitable for installation outdoors. They are incorporated within the supply authority's substations and only authorised personnel can gain access. Since live manual fuse replacement may be necessary special training and

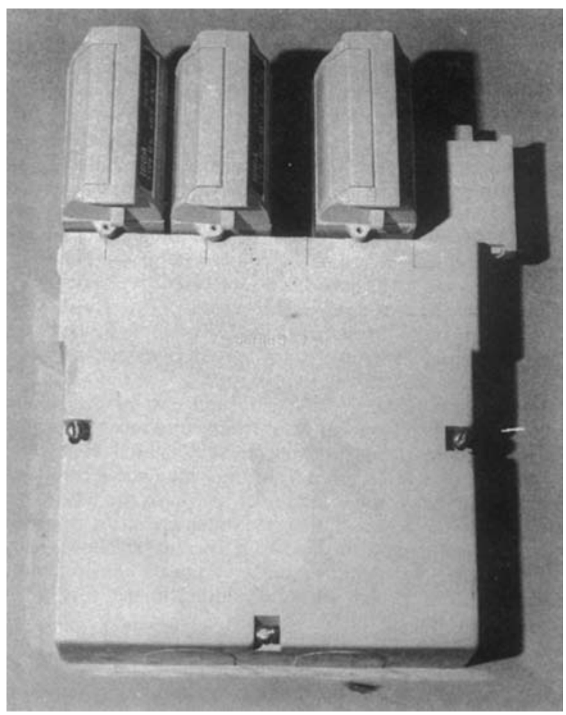

Figure 34.30 Domestic fuse cut-out

Figure 34.31 LV fuse cabinet

equipment is provided for authorised operators. Short-circuit ratings may be up to 43 kA at 415 V three-phase.

Figure 34.31 shows a typical LV fuse cabinet.

34.4.3 LV switchboards

For LV supplies to large commercial and industrial consumers a LV switchboard is often used whereby the incoming circuit-breaker is owned by the supply authority and is connected by cables to the LV of a suitable transformer. The incoming circuit-breaker will then feed on to a bus-bar system from which the load circuits can be fed. The load circuits may be protected by moulded-case circuit-breakers or fuse switches. The equipments are generally built into a metal-enclosed housing which provides glanding for terminating outgoing circuit cables. Similar switchboards are also used for LV distribution applications in large industrial complexes.

Various configurations of switchgear can be applied depending on the equipment importance. For example, all bus-bars, bus-bar tee-off connections, and circuit-protecting equipments may be enclosed in a common metal-enclosed housing. This arrangement has the disadvantage that any one faulted component within the switchboard will allow the fault to spread to other equipments within the switchboard such that for a major fault the complete switchboard could be rendered inoperative. For high-integrity switchboards, where reliability of supply is of utmost importance, metallic segregation is provided whereby the incoming circuit-breaker will be in its own metal-enclosed compartment as will the bus-bars and bus-bar feeder circuits, the outgoing feeder equipment and the cable terminations, thus preventing the spread of a fault from any one compartment to adjacent compartments. This latter construction is normally applied to high integrity industrial equipments such as may be used, for example, within generating stations. The switchboard can also incorporate combinations of fuse switches and contactors to form motor starter assemblies. A high-integrity LV switchboard is shown diagrammatically in *Figure 34.32*.

34.5 HV secondary distribution switchgear

34.5.1 Urban networks

Supplies to large numbers of consumers in urban conurbations are usually taken from a primary switchboard at between 10 and 20 kV. The switchboard usually comprises two sections of bus-bar with a central, normally open, bus-section circuit-breaker. The supplies are taken from a circuit-breaker on one section of the bus-bar via a ring cable circuit to a circuit-breaker on the adjacent section of bus-bar. The ring circuit may be some kilometres in length and secondary distribution substations can be situated at various points around the ring. The ring may be normally run open at some suitable point along its length.

The secondary distribution substation comprises a HV cable connected switchgear unit normally referred to as a ring-main unit, a HV/LV transformer having typical ratings up to 1000 kVA and a LV fuse cabinet of the type described in Section 34.3.2. The ring-main unit may be physically mounted on the HV terminals of the transformer with the LV fuse cabinet mounted on its LV terminals to form a complete transportable secondary distribution substation. Alternatively, the three items of equipment may be separately mounted and all cable connected. Secondary distribution substations are normally of weatherproof construction and used in outdoor environments. Such a substation is usually protected from the public by means of suitable fencing. The equipments may also be housed in a weatherproof, vandal-resistant housing in which case individual items of equipment may not be weatherproofed.

Very many thousands of secondary substations of the type described are in service and have, over a long period of time, given economical and reliable performance. The ring-main unit usually comprises two manually operated ring switches and a centrally disposed tee-off fuse switch, also manually operated. In addition to the ring switch, fault-making earth switches and suitable cable test facilities may be built into the cable side of each switch to allow the cable to be safely earthed, repaired if necessary, and re-tested. The ring switches, earth switches and test facilities may incorporate interlocking and padlocking facilities to prevent an operator from undertaking an incorrect switching sequence.

As described in Section 34.2, switches are not fault-breaking devices. However, there have in the past been occasions when a switch has inadvertently been closed on to a fault and the operator's reaction, on realising his error, is immediately to attempt to open the switch. In order to prevent this happening most switches now have a delay incorporated such that, subsequent to closing, the switch cannot be opened for a period of at least 3 s. This allows time for the protection at the primary substation to operate to trip the associated circuit-breaker to clear the fault.

The tee-off fuse switch may also incorporate a fault-making earth switch on its HV terminations as a safety precaution against possible LV back-feeds.

Careful selection of the fuse rating in the fuse switch is necessary as the fuse needs to fulfil a number of functions. It must operate to clear a fault within the HV winding of the transformer and in the HV cable circuit to the transformer.

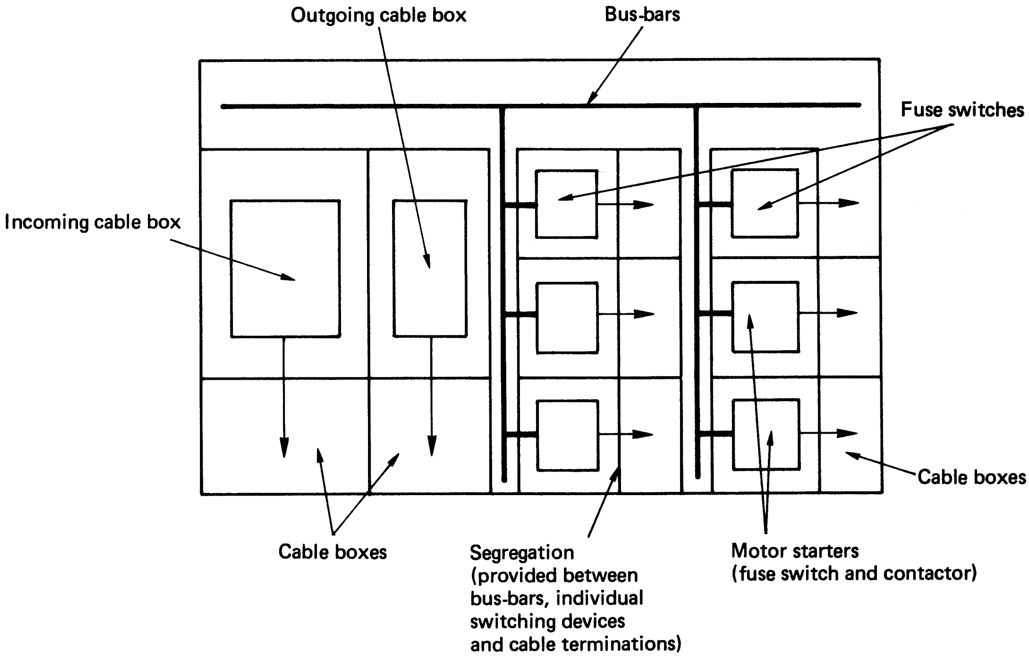

Figure 34.32 Construction of a high-integrity LV switchboard

It must be sized to discriminate with the LV fuses such that it does not operate for a downstream LV fault and it also must discriminate with the HV ring feeder circuit-breaker protection. It must not operate on transformer in-rush current and it must be sized to carry the rated current of the transformer or overload current of the transformer, which may be up to 150% of the transformer rating, for limited periods of time. It must also not deteriorate with age.

Most currently used designs of ring-main unit are oil-filled and use fuses under oil, although some may have fuses mounted in air.

SF_6 insulated designs of ring-main unit are now becoming available, their main advantage being the limited fire hazard in the event of a fault. However, they are relatively costly to produce since the enclosure must be gas tight. Relays or pressure gauges may be incorporated to give an indication of loss of gas pressure. HV fuses cannot be readily accommodated within the SF_6 insulated chambers and are usually mounted in air. Some manufacturers now use suitably rated vacuum or SF_6 circuit-breakers in place of the tee-off fuse switch. Whilst SF_6 insulated ring-main units can be made weatherproof for outdoor use, the general tendency now is to place them within a weather-protected housing. *Figure 34.33* shows an SF_6 insulated ring-main unit installed within a housing.

Modern safety legislation now requires equipment to be designed such that, even in the event of maloperation, it will present no danger to an operator. It is becoming common practice for new designs of equipment to be tested with a deliberately connected internal fault in order to demonstrate that any arcing products which may be expelled are directed away from where an operator may be standing whilst performing his normal duties. This is particularly pertinent for manually operated ring-main units.

Operating mechanisms which can be controlled remotely are available and provide the possibility for remote switching. However, pilot cable connections are seldom available for secondary distribution substations and this provision together with remote operational facilities can add significantly to the cost of a secondary distribution network where fault ratings are invariably low.

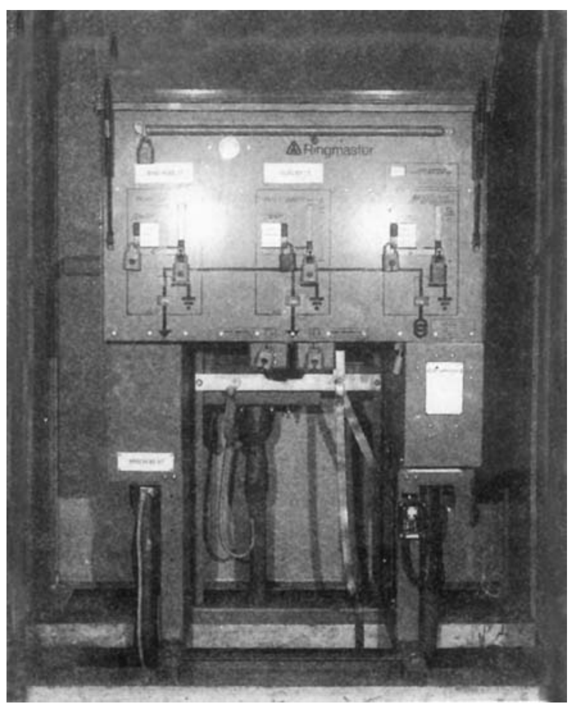

Figure 34.33 SF_6 insulated ring-main unit

34.5.2 Rural networks

Rural networks are usually fed from overhead-line systems operating at voltages of 10–36 kV. They may entail line lengths of some tens of kilometres which may only be lightly loaded.

The lines are fed from a primary switchboard and may comprise either a ring formation or radial network. The disposition of the load may be such that ring networks are not geographically practicable and the majority of circuits are radial with tee-off branches to consumers. The tee-off circuits traditionally have been protected by pole-mounted three-phase or single-phase expulsion fuse assemblies or, more recently, by automatic pole-mounted sectionalisers (see Section 34.1.5.1). The main line circuit is usually protected by a circuit-breaker incorporating an auto-reclosing facility.

Many overhead-line faults are transient in nature due, for example, to wind activity or lightning. The circuit-breaker will trip on fault initiation and the fault will then clear to allow the circuit-breaker to re-close automatically. Three or more reclosures may be permitted before it is assumed that the fault is permanent in nature when the circuit-breaker will then remain open. Under these conditions the whole of the overhead-line circuit will be out of commission with all consumers off supply until the faulted section can be located and repaired.

This situation can be alleviated by the use of pole-mounted auto-reclosing circuit-breakers, normally referred to as 'auto-reclosers', situated at suitable positions along the overhead line. The protection settings and number of permissible reclosures to lock-out can be pre-set such that only consumers downstream of a faulted section will be affected. Early auto-reclosers were operated by a falling-weight mechanism which needed to be re-charged subsequent to completion of a predetermined number of reclosures. More modern designs use solenoid coils operated directly from the HV feeding supply.

Auto-reclosers were traditionally oil-filled devices, but more recently SF_6 auto-reclosers have been available. A typical SF_6 auto-recloser is shown in *Figure 34.34*.

Sometimes a pole-mounted switch, often referred to as a 'sectionaliser' is used in conjunction with auto-reclosers, to allow manual reinstatement of circuits.

Rural consumers tend to suffer more and longer outages than urban consumers since the overhead line is more vulnerable to faults and longer distances are involved in operator travel to locate and repair the faulted section.

Where ring circuits can be employed, these offer the advantage of possible automation whereby a faulted section of line can automatically be isolated and all remaining sections up to the faulted section automatically reinstated. Signalling can be incorporated to allow the control engineer to direct the personnel directly to the circuit. Such systems are now technically viable and in use in some countries, but financial viability needs to be demonstrated.

34.6 HV primary distribution switchgear

HV primary switchgear feeding urban systems usually comprises cable-connected metal-enclosed switchboards housed within a brick-built substation. For feeding rural systems it may be in the form of open-type switchgear equipments, interconnected by air-insulated bus-bars, feeding overhead-line circuits. The metal-enclosed switchboard comprises disconnectors, bulk oil, SF_6 or vacuum circuit-breakers connected to a common bus-bar system and feeding via current transformers and voltage transformers on to a cable network. The bus-bars, circuit- breakers, current-transformer chambers and cable-box terminations may each be segregated within metal enclosures. Such equipment is referred to as being 'metal clad'. Live components within the enclosures may be air insulated or, more generally, insulated with solid material, usually cast epoxy resin, although more recently many different forms of cast resin materials have become available to the designer.

Figure 34.34 Pole mounted SF_6 auto-reclosing circuit-breaker

Bus-bars are usually segregated into two or more sections which can be coupled together by means of a bus-section circuit-breaker. A double bus-bar system may be provided for important installations where outages from a possible bus-bar fault cannot be tolerated. However, switchgear reliability is such that double bus-bar arrangements are now seldom employed at distribution-system voltages.

Outdoor substations at distribution voltages usually employ dead-tank oil, SF_6 or vacuum circuit-breakers incorporating ring type current-transformers around their bushings.

Manually operated disconnectors are usually employed. They are interconnected by copper or aluminium tubular bus-bars which are air insulated and supported on post insulators. The live equipment is mounted at a height of some 2 m above ground level to allow safe personnel access. Surge arresters may be employed at overhead-line entries into the substation.

34.7 HV transmission switchgear

HV transmission switchgear is used within substations to control the flow of large quantities of electric power within an electrical network. It may operate at rated voltages of 145–800 kV, with normal load currents of up to 4 kA and short-circuit currents of up to 80 kA.

The switchgear may be connected in the substation in various arrangements, the most common being the double bus-bar arrangement. Other commonly found alternatives are 1½ switch or mesh-connected arrangements. These are shown diagrammatically in *Figure 34.35*.

The switchgear may be of the open-type air-insulated construction basically similar to that described for open-type distribution switchgear or it may also be in the metal-enclosed form. The metal-enclosed form is a relatively recent innovation made possible by the use of SF_6 gas and is now widely employed, it is generally referred to as 'gas-insulated switchgear'. All live parts to earth are insulated with SF_6 and circuit-breakers also use it as their interrupting medium. Typical clearances between live parts and earth for 420 kV equipments might be some 250 mm which allows very compact substations to be built. A gas-insulated-switchgear substation, for example, may occupy only one-fifth of the ground area of an open-type substation. It will also have a low physical profile and is ideal for installation in urban networks where land availability and space is at a premium. Gas-insulated switchgear usually consists of phase-isolated assemblies at 420 kV and above but below this voltage the three phases may be housed in a common SF_6 enclosure. Cable compartments, bus-bars, disconnectors and circuit-breakers are generally segregated within their own gas enclosures. A typical 145 kV gas-insulated substation is shown in *Figure 34.36*.

In view of the very small electrical clearances involved between live conductors and earth, internal cleanliness is of utmost importance. For example, a small particle of a few millimetres in length can induce dielectric breakdown. Strict quality-control and inspection procedures are necessary during assembly. Such particles can induce partial discharge activity and most users now require monitoring for this activity in order to alleviate the consequences of dielectric breakdown. Partial discharges within gas-insulated switchgear excite resonances within the chambers. These resonances can be detected by the use of integral capacitive couplers and by examination of the frequency spectrum which may be generated. They are typically of the order of 1000 MHz. This recently developed technique is referred to as the 'ultra-high frequency partial discharge technique'.

34.8 Generator switchgear

It had long been the desire to be able to switch generator circuits directly at generator voltage, but circuit-breaker technology and testing techniques had not developed sufficiently to allow this. This situation changed some years ago and a few manufacturers now produce generator circuit-breakers capable of switching and clearing faults on the

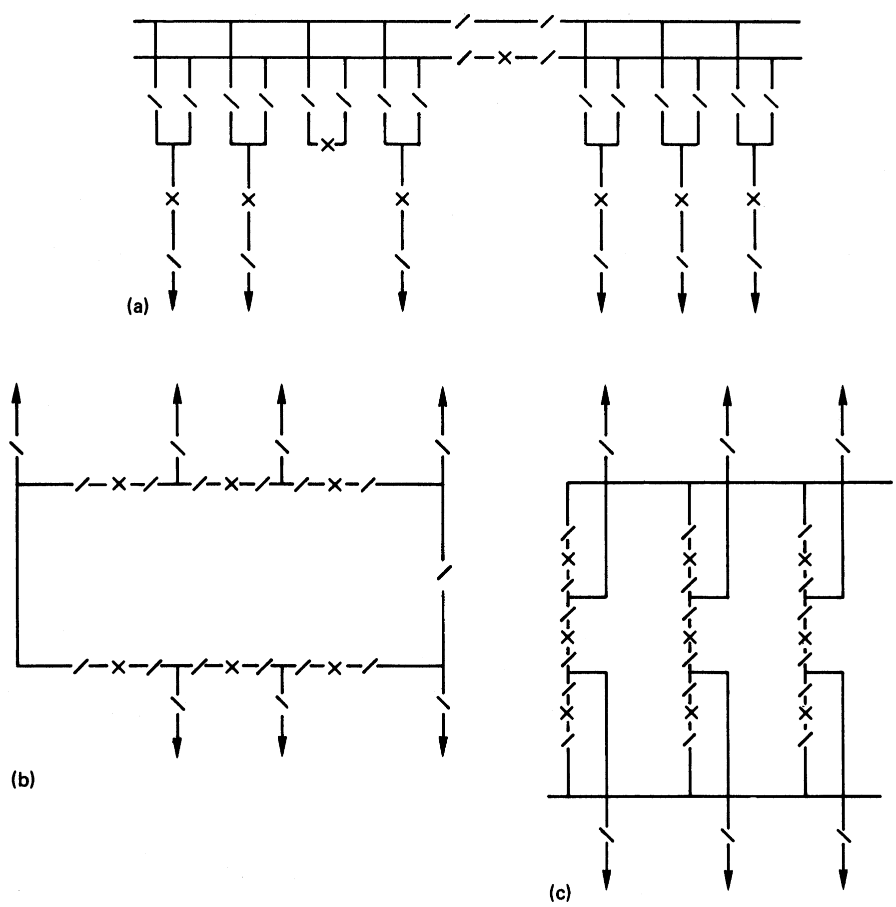

Figure 34.35 Typical substation arrangements: (a) double bus-bar; (b) mesh; (c) 1½; circuit-breaker

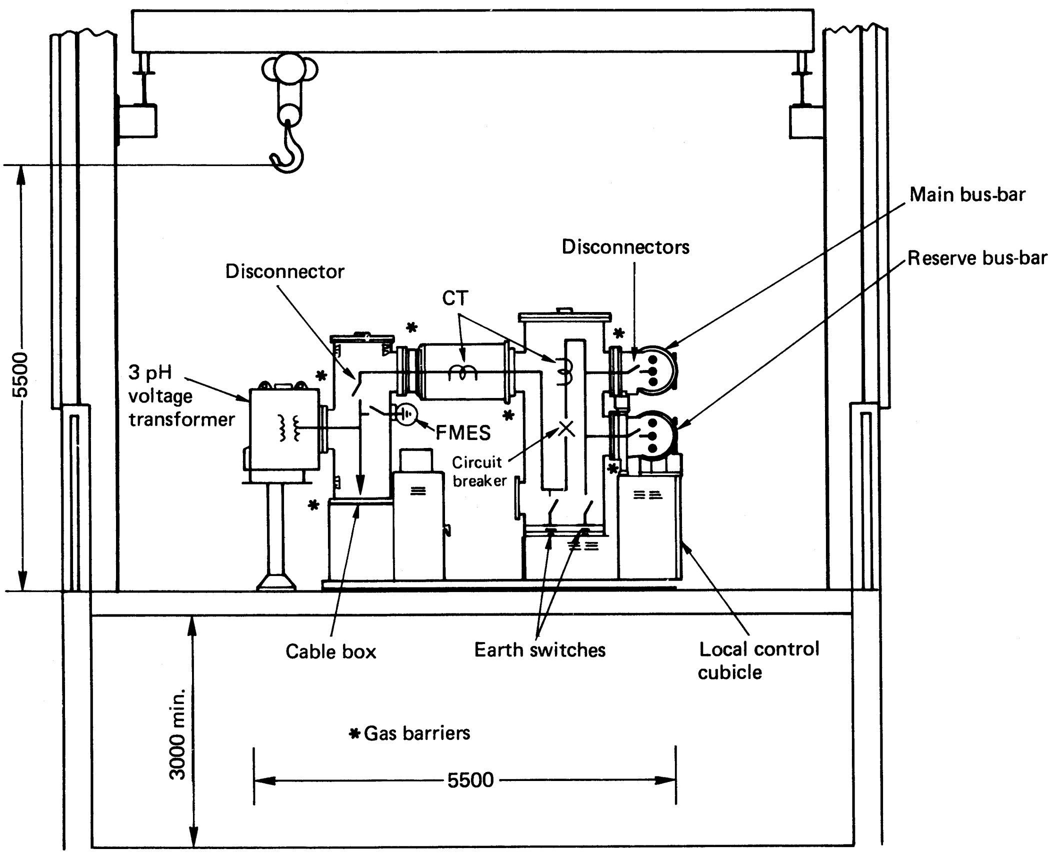

Figure 34.36 A 145 kV gas-insulated-switchgear substation. (FMES, fault making earth switch)

largest of generator circuits. Typical ratings may be 200 kA at 24 kV with rated load currents of 24 kA.

Early designs of generator circuit-breaker used air-blast technology, but more recent designs use SF_6 technology. The cross-section of a typical generator circuit-breaker is shown in *Figure 34.37*.

34.9 Switching conditions

Switching equipment must clearly be suitable for switching normal and, where required, abnormal conditions of the circuit in which it is situated. All circuits consist of series/parallel arrangements of resistance, reactance and capacitance and during switching these components will produce resonances of different forms. The switching equipments must therefore be capable of safely withstanding these resonant conditions during the switching operation. The switching conditions described in the following sections are regularly encountered.

34.9.1 Normal switching conditions

34.9.1.1 Shunt capacitor bank switching

When switching a shunt capacitor bank the load is purely capacitive. The source side of the circuit-breaker will include bus-bar capacitance to earth, this being small compared with the load capacitance, and series reactance. Since the capacitive current will be small compared with the circuit-breaker's rated short-circuit current, clearance of this current will often occur at the first available zero current. At this point of clearance a 1 pU charge will be left on the load-side capacitance. The source-side power frequency voltage will then swing to its opposite polarity to create a voltage across the opening circuit-breaker contacts of 2 pU. The circuit-breaker contact gap may be insufficient to withstand this voltage and breakdown across the gap might occur.

Thus the energy stored in the load capacitor is discharged to the bus-bar shunt capacitance and series inductance to cause a high-frequency oscillation. Large currents will flow across the opening contact gap and damage to arc control devices may occur. The term 're-ignition' is applied if this breakdown occurs within 0.25 cycles of arc extinction and 're-strike' if it occurs subsequent to this.

Circuit-breakers suitable for switching shunt capacitor circuits ideally should be designed and proven by test to be re-strike free.

34.9.1.2 Overhead-line and cable switching

Both overhead-line and cable switching conditions present problems similar to those of capacitor switching.

In the case of the overhead line there will be distributed capacitance between the phases, and to earth along the line,

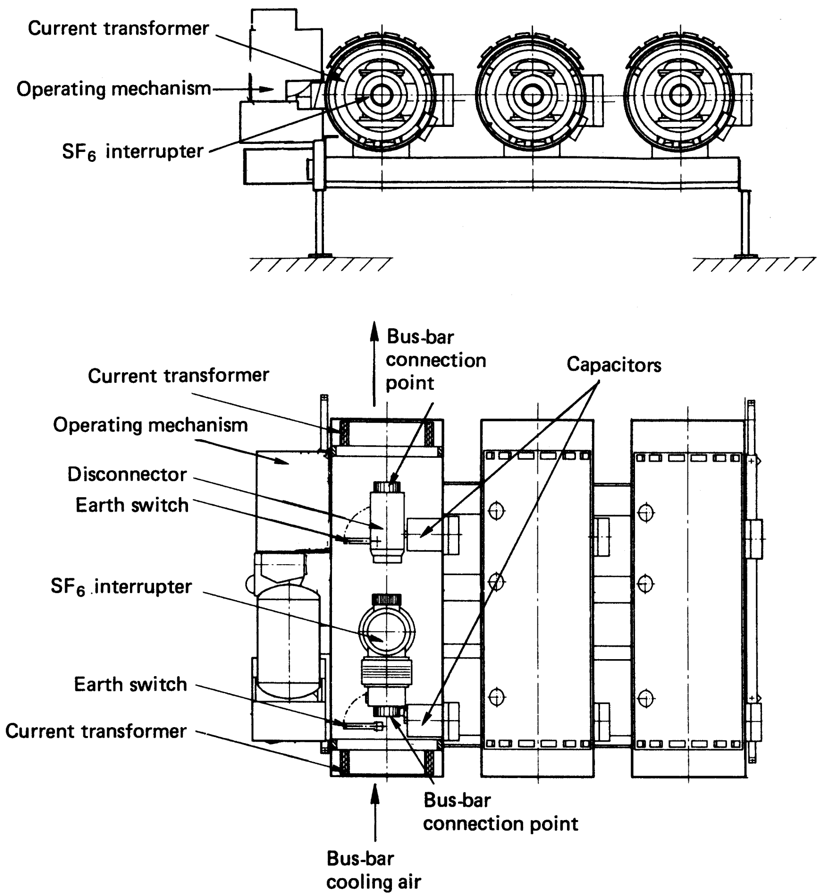

Figure 34.37 Cross-section of a typical generator circuit-breaker

interspersed with distributed line inductance. The load current is again small and its interruption is probable at the first available current zero. This will leave a charge on the line which may result in a travelling wave propagating along the line to the far end where it will reflect and return to the circuit-breaker.

The wave is generally attenuated when it reaches the circuit-breaker, but the circuit-breaker contact gap may be insufficient to withstand the voltage now appearing across its contacts and a re-ignition or re-strike may occur. Overhead-line switching may be a regular switching condition for a circuit-breaker and international specifications now require a circuit-breaker intended for overhead-line switching duties to be re-strike free.

A further problem may occur when switching an overhead line which is terminated at an unloaded transformer. The combination of line capacitance and transformer reactance then may cause high-frequency oscillations with phase to earth overvoltages in excess of 3.0 pU. Overhead-line switching regimes usually prohibit the switching of such circuits. If remote-end switching is necessary the overvoltage at the transformer can be limited by the application of surge arresters, but these would need to be rated to be capable of dissipating the energy associated with this switching condition.

With cable switching, the condition is similar to overhead-line switching except that capacitance values significantly higher than those associated with the overhead line will be encountered.

34.9.1.3 Transformer magnetising current switching

The arc-extinction methods described in Section 34.1.8 for circuit-breakers indicate that circuit-breakers generally clear on cessation of flow of current, i.e. at a natural zero current. When interrupting very low values of current this may not always be the case and the arc-extinction mechanisms may force the arc to extinguish before the current reaches its natural zero. This phenomenon is referred to as 'current chopping'. Since the voltage appearing across the circuit is proportional to the rate of change of current times and inductance of the circuit, very high overvoltages may occur as a result of current chopping. This phenomenon occurs when switching low inductive currents, as for example may occur when switching the magnetising current of a transformer. The transient voltage will in fact oscillate at a frequency determined by the transformer magnetising inductance and winding capacitance. The oscillation will be damped by eddy and current hysteresis losses in the transformer. Overvoltages of the order of 3 pU may be generated.

Whilst vacuum circuit-breakers are particularly good at rapidly extinguishing low values of current, current chopping can occur when used for switching inductive currents such as transformers or motors.

34.9.1.4 Shunt-reactor switching

Shunt reactors are often used to compensate for the capacitance of lightly loaded lines. They may be frequently switched depending on the line-loading regimes. Shunt-reactor switching presents onerous switching conditions for a circuit-breaker and frequent maintenance may be necessary. At transmission voltages, shunt-reactor currents may be of the order of 400–600 A. The associated circuit-breaker will thus have to switch a very large reactive current with little parallel capacitance on the load side and very steep rates of rise of transient recovery voltage may result across the opening circuit-breaker contacts. These may cause multiple re-ignitions and, depending on the circuit-breaker type, may cause long arc lengths and arc durations. The dielectric withstand properties of the interrupter may rapidly deteriorate under these switching conditions.

34.9.1.5 Series-reactor switching

Series reactors are sometimes used to limit the short-circuit fault capacity between two connected sections of a supply system. Should a fault occur on the circuit side of the reactor this would cause a relatively high-frequency transient on the reactor side of the circuit-breaker and a low-frequency oscillation on the bus-bar side. A double frequency recovery voltage will thus appear across the opening contacts of the circuit-breaker and may result in a very high rate of rise of transient recovery voltage being imposed as the circuit-breaker contacts are opening. Thus circuit-breakers for series-reactor switching duties need to be tested for these specific conditions.

34.9.1.6 Disconnector switching

Whilst disconnectors generally have only to switch the small capacitive currents associated with a section of bus-bar between the disconnector and circuit-breaker, this can cause certain problems. Firstly, the disconnector must be capable of satisfactorily switching the maximum value of capacitive current likely to be encountered without causing contact or dielectric deterioration.

Secondly, the contacts of a disconnector are generally slow in operation and, when switching very low values of capacitive current, very many re-ignitions may occur. These will result in very high-frequency transients propagating along the bus-bar and may result in overvoltages of the order of 2.6 pU. The disconnected section of bus-bar may be left with a d.c. trapped charge which, in gas-insulated switchgear, may remain for some weeks. If, however, an electromagnetic voltage transformer is connected to the disconnected section of bus-bar, the trapped charge may dissipate through the primary winding of the voltage transformer and, depending on the relative circuit parameters, overheating or physical damage to the voltage transformer may occur.

When synchronising generators, a disconnector may be used to energise a short section of bus-bar from the generator circuit to an open synchronising circuit-breaker with the generator already excited to system voltage. If the open circuit-breaker has capacitive voltage grading, the voltage of the bus-bar between the open circuit-breaker and open disconnector may be very close to the system voltage since capacitance to earth will be small. This means that the open disconnector contacts have, on one side, a voltage fed from the system which is close to the system voltage, and on the generator side a voltage close to the system voltage fed from the generator. The generator frequency will not align with system frequency and the voltage across the disconnector contacts can rise to 2 pU. As the contacts close the contact gap may flashover at this 2 pU voltage which will leave a d.c. trapped charge superimposed on the a.c. voltage on the section of bus-bar between circuit-breaker and disconnector. The voltage across the disconnector contacts then may rise to as high as 3.5 pU.

The three disconnector switching conditions described above need to be proven by test, and international specifications covering these requirements are in preparation.

Disconnectors are also commonly used to transfer load current from one bus-bar to an adjacent parallel connected bus-bar. Under these conditions the disconnector may have to make and break full-load current with a voltage across its contacts equal to the impedance drop around the parallel circuit. Whilst this may only be some tens of volts, contact burning can result. Disconnectors require to be designed such that this type of operation does not adversely affect the dielectric properties of an open disconnector.

International specifications now call for disconnectors to be proven for switching this condition.

34.9.1.7 Earth switch/switching

Since earth switches are only applied to a de-energised circuit they should not, under normal conditions, be required to make or break current. However, when an overhead line is taken out of service and where work is required on the line, it is necessary to earth the line at both ends. In the case of a double circuit overhead line with one circuit earthed, the earthed line will have currents induced into it by means of magnetic coupling from the adjacent loaded line and inductive currents will circulate around the closed loop of the earthed line. The first earth switch to open will then have to break this inductive current which, at 420 kV, may be of some hundreds of amperes and the voltage appearing across the earth switch contacts may also rise to a few kilovolts. With the line then earthed at one end only, a current to earth will be induced in the line equal to the capacitive current flowing between the two parallel lines. When the second earth switch opens it will have to clear this capacitive current, which again for 420 kV may be some tens of amperes, but the voltage across the open contacts may now increase to some tens of kilovolts.

New international specifications will incorporate tests to verify earth-switch performance when operating under these conditions.

34.9.2 Abnormal switching conditions

The main difference of a circuit-breaker compared with other mechanical switching devices is its ability to satisfactorily clear abnormal circuit conditions as may occur, for example, when a short-circuit occurs on the downstream side of the circuit-breaker. Under these conditions the circuit is mainly inductive and the short-circuit current lags the system voltage by almost 90°. This means that when the current passes through a zero point the voltage across the opening circuit-breaker contacts is at or near its peak value. The arc-extinguishing process must therefore be such as to ensure that, at a suitable current zero, sufficient dielectric strength has built up to withstand this peak voltage. For an air-blast or gas-blast SF_6 circuit-breaker this will usually occur at, or before, the second available current zero. For oil circuit-breakers several current zeros may pass before arc extinction occurs. Unfortunately the process is more complicated than that described since during the arcing period the voltage across the circuit-breaker contacts is small and, at clearance, it must change from this small value to the peak of the system voltage in a very short period of time. In doing so the voltage across the contacts will tend to rise to twice the peak voltage which will set the downstream circuit into a damped oscillation at its natural frequency. This transient voltage is known as the 'transient recovery voltage'. For a given circuit the value of the fault current will depend on the impedance of the circuit up to the point of a fault, and fault currents will clearly be lower for longer distance faults. This means that a greater length of the circuit will be available to resonate on fault clearance. This has the general effect that the rate of rise in the transient recovery voltage, and its peak value, tend to be higher for lower values of fault current. This situation is covered in international specifications by calling for short-circuit tests at 100%, 60%, 30% and 10% of the circuit-breaker current with the transient recovery voltage parameters being specified for each value of short-circuit test current.

An additional complication arises where the ratio of inductance to resistance can be high, for example, for faults close to transformer terminals. This causes the a.c. current to contain a large decaying d.c. component of current. When the circuit-breaker contacts open, this decaying d.c. current may not have reached zero and the circuit-breaker will be required to clear an a.c. current off-set from the zero line. This is referred to as an 'asymmetrical short-circuit current'. This has the effect that, depending on the circuit-breaker type, clearance, for example at a minor loop of current, might be less onerous than clearance at a major loop of current. Again international specifications detail precise parameters to be met by a circuit-breaker when clearing these conditions.

A similar situation might arise when a circuit-breaker is required to close against a short-circuit when the system reactance to resistance ratio (X/R) is high. A large d.c. current in the initial part of the a.c. current wave may occur and the d.c. current peak may, in theory, reach $2\times\sqrt{2}\ I_{\mathrm{rms}}$. For typical X/R ratios the peak current is, in practice, nearer to $1.8\times\sqrt{2}\ I_{\mathrm{rms}}$ and it is this value which the circuit-breaker must satisfactorily close against. As large mechanical forces will result from the electromagnetic effects of the peak short-circuit current, the circuit-breaker operating mechanism must have sufficient energy to overcome these forces.

As described previously for disconnectors, a circuit-breaker may be required to close, and open, under conditions where it ties together two large power systems the frequencies of which may differ by up to 180° prior to circuit-breaker closure or during opening. Under these conditions the current that flows may be of the order of 25% of the rated short-circuit current of the system, but the recovery voltage across the circuit-breaker contacts may, in the extreme, be as high as 3 pU.

A further onerous condition may occur for a fault a short distance along an overhead line whereby the line impedance is such as to reduce the short-circuit current to some 75–95% of its rated value. This is termed a 'short-line fault condition'. At a current zero the voltage on the line-side terminal of the circuit-breaker is equal to the impedance drop along the faulted section of line. When the circuit-breaker opens to clear the fault this impedance voltage drop will cause a transient voltage to propagate up and down the short section of faulted line. This will result in a decaying 'saw tooth' wave on the line side of the circuit-breaker. The voltage across the circuit-breaker contacts will be the sum of this line-side voltage and the source-side power frequency voltage. This will result in a very steep rate-of-rise of the initial part of the transient recovery voltage wave thus presenting a very onerous clearance condition for the circuit-breaker. Again specifications require transmission circuit-breakers to be tested for this condition.

34.10 Switchgear testing

During short-circuit fault clearance an interrupter of a circuit-breaker will be required to dissipate a very large amount of energy. For example, higher rated circuit-breakers may be required to safely dissipate, over a very short period of time, something in excess of 1000 MW. The circuit-breaker must be capable of satisfactorily performing such a rated short-circuit duty at least three times, without danger to operators, or without danger to the system. Whilst present day theory can significantly assist in the development of interrupter design, it can still not satisfactorily ensure the safe operation of the complete circuit-breaker. It is thus necessary for the circuit-breaker performance to be proven under very specific short-circuit test conditions in order to verify its safe performance.

Whilst tests can be, and sometimes are, performed on actual systems, the system parameters cannot readily be modified to achieve the required test conditions. In addition, such testing may induce significant risk to system operation and is rarely undertaken nowadays.

Short-circuit testing is thus performed in specially designed short-circuit testing stations. These may entail the use of 1–4 large, specially designed, generators for producing the necessary output. The supply to the generator is usually disconnected immediately prior to the application of a short-circuit and a large flywheel may be attached to the generator shaft to maintain its inertia. The output of the generators may be paralleled to produce the necessary short-circuit ratings and they may also be connected via transformers so that a wide variation of test settings can be achieved. Reactors, resistors or capacitors may be added to both the source and load sides of the circuit-breaker in order to ensure the achievement of the specified test parameters. Such short-circuit testing is generally referred to as 'direct testing' and may be either single phase or three phase. For distribution circuit-breakers, for example, three-phase direct testing can nearly always be achieved. However, for large circuit-breakers the output of the short-circuit test station may be insufficient to allow direct testing of the complete three-phase circuit-breaker. Under these conditions a section or 'unit' of a circuit-breaker may be tested, i.e. one interrupter of a two-interrupter circuit-breaker. Test parameters on this 'unit' must be such as to reproduce the worst conditions that would apply to the interrupter when the circuit-breaker was operating to clear the specified three-phase fault condition. This method of testing is referred to as 'unit testing'.

Even with unit testing, however, the output of the short-circuit testing station may still be insufficient to meet the specified short-circuit levels. It is then necessary to revert to a more recently developed method of short-circuit testing known as 'synthetic testing'. With synthetic testing the current is still obtained from a short-circuit generator, but the recovery voltage is obtained from a separate supply circuit and is injected across the opening circuit-breaker contacts at an appropriate current zero. The recovery voltage circuit usually comprises a large precharged capacitor bank assembly which is switched, at the precise moment in time, via a combined inductance, capacitance and resistance network to produce the correct transient recovery peak voltage and frequency. Synthetic unit testing is now the standard method used for testing large transmission circuit-breakers.

International specifications have been produced which detail precise test requirements and methods of tests covering all the normally required short-circuit test conditions for circuit-breakers.

In addition to short-circuit testing there are other 'type tests' to which a circuit-breaker must be subjected in order to demonstrate its performance. These comprise a mechanical endurance test, generally of 1000 operations without maintenance, a temperature-rise test at rated current, a HV test and, for outdoor circuit-breakers, an environmental test.

The HV tests verify the dielectric performance of the circuit-breakers and generally comprise a power frequency overvoltage test, a lightning impulse voltage test, to simulate the effects of a lightning strike, and for higher voltage transmission circuit-breakers a switching surge on the system.

A further test is usually performed at a specified power frequency overvoltage to check for any partial dielectric-breakdown activity that might be occurring in faulted insulation. This is referred to as a 'partial discharge test'.

Environmental testing on outdoor circuit-breakers entails subjecting the circuit-breaker to cyclic variations in ambient temperature, from its maximum working temperature of, say, 35°C to its minimum working temperature of, say, −25°C. It may also entail the application and verification of mechanical operations at various points during the temperature cycling and of checks for leakage of insulant.

The above tests are usually performed as type tests on one equipment of a specific design and are intended to demonstrate the suitability of that design of equipment.

Further works tests must be performed on production equipment and these are referred to as 'routine tests'. These usually comprise a power frequency overvoltage test, measurement of resistance of primary circuits and a mechanical operations test. Similar tests are generally repeated once equipment has been erected on the site. Site tests would, in addition, include primary circuit injection tests to verify circuit-breaker operation via protective relays.

Whilst clear and precise erection instructions are necessary for all switchgear equipments this is particularly important for gas-insulated switchgear where even very small particles may, for example, induce dielectric breakdown. Site quality-control checks are of paramount importance and many users of gas-insulated switchgear now require the measurement of partial discharge activity as a site commissioning test and some also require on-line monitoring for partial discharge activity as an essential operational criterion.

34.11 Diagnostic monitoring

The concept of using maintenance-free switchgear whereby maintenance would not be required during the lifetime of the equipment is an ideal user objective. Indeed, with modern SF_6 switchgear, this ideal objective is now becoming more of a reality. On the other hand, current legislation may require equipments to be regularly maintained to be in a serviceable condition and, therefore, there is a need to be able to verify that equipment remains in a serviceable state without the need for physical dismantling. The application of techniques to monitor externally the internal state of equipment can reveal many incipient problems and such diagnostic monitoring techniques are currently being developed and applied. Continuous on-line monitoring and self-diagnosis using fibre-optic technology is now becoming a practical reality. Parameters that can be readily monitored are, for example, contact speed, contact engagement, moving system damping, circuit-breaker operating times, summated interrupted fault current, operating mechanism pressures/times, conductor temperatures, dielectric gas pressures, liquid levels and, for gas-insulated switchgear, partial discharge activity. In addition, system-fault currents and associated voltages can now readily be recorded and these data, in conjunction with the above on-line monitoring, can assist in ascertaining the internal condition of a circuit-breaker.

34.12 Electromagnetic compatibility

'Electromagnetic compatibility' refers to the susceptibility of electrical equipment to any electromagnetic interference phenomena to which it might be subjected as well as to electro-magnetic interference signals which the equipment itself may emit. Levels are currently being specified for maximum emissions from electrical equipment and also for levels of interference below which the equipment would not be affected. Switchgear equipment will be required to comply with the criteria.

Such interference phenomena may be caused, for example, by lightning, switching surges, high-frequency-discharge activity, voltage dips, signalling on lines, harmonics, and superimposed d.c. on an a.c. system. Some of the phenomena may be generated by the switchgear itself and may cause malfunction of associated electrical equipment, e.g. alarm circuits and relays. Typical phenomena in a metal-enclosed gas-insulated-switchgear substation may, for example, be disconnector induced transient overvoltages, these may be coupled either by conduction or by radiation into secondary connections and other associated equipments causing flashover or dielectric breakdown. It is then necessary for steps to be taken to limit the coupling of these signals. Typical steps might, for example, be: the provision of an earth screen between HV and LV windings of voltage transformers; short direct earth connections to a high-frequency earth mat; the use of screened secondary cables with the screening earthed at both ends of the cable; cables should be run together, preferably within a trench and parallel with main earth connection; and flow and return conductors should be within the same screened cable.

With ever-increasing use of modern electronic equipments this subject is gaining significant importance to the extent that in some countries not only are limiting values specified but legislation is being introduced to make compliance mandatory.

34.13 Future developments

In the last ten years or so since deregulation the Electrical Power Industry has been through major re-organisational changes. In the main, the way in which electricity is produced, transported and delivered to customers is much the same as it has always been. There is one significant change however, and that is the advent of combined cycle power plants which can be located nearer to load centres, within very short time scales, at lower costs and with reduced emissions compared with conventional coal fired plants. All of this minimises the requirements for transmission. If this trend continues, as it is likely to, then the way in which transmission systems operate will significantly change. In addition, there is also a trend for more and more generation to be embedded in the distribution systems so the way in which they operate will also significantly change. These factors mean that the requirements for switchgear will also have to adapt to the changing power systems. For distribution systems the switchgear will need to be re-locatable such that as new systems evolve it can be positioned to the most appropriate system node. It will also have to cater for power flows in both directions which means that protection systems will need to be modified. The switchgear should have improved reliability, require the minimum of maintenance and be capable of complete operation from a remote source. It must also be cost effective and in fact, may be leased to the utility and operated by an independent owner.

Similarly transmission switchgear will follow the system trends and many of the functions described for distribution switchgear will also be required.

Fortunately, many new technology developments are becoming available. There is a major breakthrough in polymers, for example, these can now be designed on a computer to formulate the appropriate molecular structure to meet the performance requirements. Similarly, there are major developments in magnetic materials, both conducting and insulating ceramics, superconductivity and solid state thyristors such that conventional power transformers may become a thing of the past. Developments in hard materials utilising diamond technology and carbon C60 will undoubtedly assist in the practical development of current limiting/solid state/superconducting circuit breakers. Already prototype equipment's are being developed and the concept of switchgear equipment's embodying all these new technologies, together with fundamental changes in the ways electricity is produced and provided to the customer presents many new and exciting challenges for younger engineers.

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