Electrical network protection

Protection guide

Contents

Presentation 2

Power-system architecture
Selection criteria 4
Examples of architectures 5

Neutral earthing
Five neutral earthing systems 6
Isolated neutral 7
Resistance earthing 8
Low reactance earthing 9
Compensation reactance earthing 10
Solidly earthed neutral 11

Short-circuit currents
Introduction to short-circuits 12
Types of short-circuit 14
Short-circuit across generator terminals 16
Calculation of short-circuit currents 17
Equipment behaviour during short-circuits 18

Sensors
Phase-current sensors (CT) 19
Phase-current sensors (LPCT) 21
Residual-current sensors 22
Voltage transformers (VT) 23

Protection functions
General characteristics 24
List of functions 26
Associated functions 27

Discrimination
Time-based discrimination 28
Current-based discrimination 30
Logic discrimination 31
Directional protection discrimination 32
Differential protection discrimination 33
Combined discrimination 34

Power-system protection
Single-incomer power systems 36
Dual-incomer power systems 38
Open loop power systems 40
Closed loop power systems 41

Busbar protection
Types of faults and protection functions 42

Link (line and cable) protection
Types of faults and protection functions 44

Transformer protection
Types of faults 46
Protection functions 47
Recommended settings 48
Examples of applications 49

Motor protection
Types of faults 50
Protection functions 51
Recommended settings 53
Examples of applications 54

Generator protection
Types of faults 55
Protection functions 56
Recommended settings 58
Examples of applications 59

Capacitor protection
Types of faults 60
Protection functions 61
Recommended settings and examples of applications 62

Appendices
Glossary - Key words and definitions 64
Bibliography 66
Definitions of symbols 67
Index of technical terms 68

Protection units continuously monitor the electrical status of power system components and de-energize them (for instance by tripping a circuit breaker) when they are the site of a serious disturbance such as a short-circuit, insulation fault, etc.
The choice of a protection device is not the result of an isolated study, but rather one of the most important steps in the design of the power system.
Based on an analysis of the behaviour of electrical equipment (motors, transformers, etc.) during faults and the phenomena produced, this guide is intended to facilitate your choice of the most suitable protective devices.

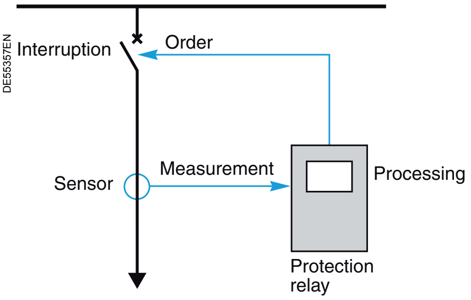


Fig. 1. Protection system.

Introduction

Among their multiple purposes, protection devices:
b contribute to protecting people against electrical hazards,
b avoid damage to equipment (a three-phase short-circuit on medium-voltage busbars can melt up to 50 kg of copper in one second and the temperature at the centre of the arc can exceed 10000 °C),
b limit thermal, dielectric and mechanical stress on equipment,
b maintain stability and service continuity in the power system,
b protect adjacent installations (for example, by reducing induced voltage in adjacent circuits).

In order to attain these objectives, a protection system must be fast, reliable and ensure discrimination.
Protection, however, has its limits because faults must first occur before the protection system can react.
Protection therefore cannot prevent disturbances; it can only limit their effects and their duration. Furthermore, the choice of a protection system is often a technical and economic compromise between the availability and safety of the electrical power supply.

Designing power system protection

The design of protection for a power system can be broken down into two distinct steps:
b definition of the protection system, also called the protection-system study,
b determination of the settings for each protection unit, also called protection coordination or discrimination.

Definition of the protection system

This step includes selection of the protection components and a consistent, overall structure suited to the power system.
The protection system is made up of a string of devices including the following (fig. 1):
b measurement sensors (current and voltage) supplying the data required to detect faults,
b protection relays in charge of continuously monitoring the electrical status of the power system up to and including the formulation and emission of orders to the trip circuit to clear the faulty parts,
b switchgear in charge of clearing faults, such as circuit breakers or combinations of switches or contactors and fuses.

The protection-system study determines the devices to be used to protect against the main faults affecting the power system and the machines:
b phase-to-phase and phase-to-earth short-circuits,
b overloads,
b faults specific to rotating-machines.

The protection-system study must take the following parameters into account:
b power system architecture and size, as well as the various operating modes,
b the neutral-earthing systems,
b the characteristics of current sources and their contributions in the event of a fault,
b the types of loads,
b the need for continuity of service.

Determination of protection-unit settings

Each protection function must be set to ensure the best possible power system operation in all operating modes.
The best settings are the result of complete calculations based on the detailed characteristics of the various elements in the installation.
These calculations are now commonly carried out by specialized software tools that indicate the behaviour of the power system during faults and provide the settings for each protection function.

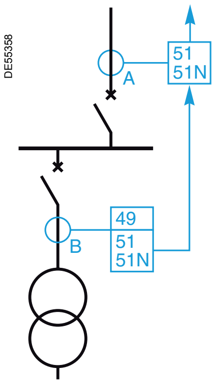


Fig. 1. Protection-system study.

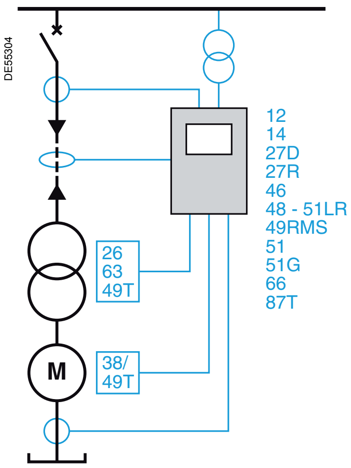


Fig. 2. Example of a motor application.

Contents of this guide

This guide is intended for those in charge of designing protection for power systems.
It comprises two parts:
b part 1, Power-system study,
b part 2, Solutions for each application.

Power-system study

This is a theoretical section presenting the information required to carry out a protection-system study covering the following points:
b power-system architecture - what are the main architectures used in medium-voltage power systems?
b neutral earthing systems - what are the main neutral earthing systems in medium voltage and what are the selection criteria?
b short-circuit currents - what are their characteristics, how are they calculated and how do electrical devices react?
b measurement sensors - how should instrument transformers for current and voltage be used?
b protection functions - what functions do protection units provide and what are their codes (ANSI codes)?
b discrimination of protection devices - what techniques must be used to ensure effective fault clearing?

Precise determination of protection settings is not dealt with in this guide.

Solutions for each application

This section provides practical information on the types of faults encountered in each application:
b power systems,
b busbars,
b lines and cables,
b transformers,
b motors,
b generators,
b capacitors,
and the protection units required for each type of fault, with setting recommendations and application examples.

Selection criteria

Protection of a power system depends on its architecture and the operating mode. This chapter compares typical structures of power systems.

Power-system architecture

The various components of a power system can be arranged in different ways. The complexity of the resulting architecture determines the availability of electrical energy and the cost of the investment.
Selection of an architecture for a given application is therefore based on a trade-off between technical necessities and cost.

Architectures include the following:

- radial systems
  - single-feeder,
  - double-feeder,
  - parallel-feeder,
  - dual supply with double busbars.
- loop systems
  - open loop,
  - closed loop.
- systems with internal power generation
  - normal source generation,
  - replacement source generation.

The table below lists the main characteristics of each architecture for comparison.
Illustrations are provided on the next page.

Architecture	Use	Advantages	Drawbacks
Radial			
Single-feeder radial	Processes not requiring continuous supply E.g. a cement works	Most simple architecture Easy to protect Minimum cost	Low availability Downtime due to faults may be long A single fault interrupts supply to the entire feeder
Double-feeder radial	Continuous processes: steel, petrochemicals	Good continuity of supply Maintenance possible on busbars of main switchboard	Expensive solution Partial operation of busbars during maintenance
Parallel-feeder	Large power systems Future expansion is limited	Good continuity of supply Simple protection	Requires automatic control functions
Double busbars	Processes requiring high continuity of service Processes with major load changes	Good continuity of supply Flexible operation: no-break transfers Flexible maintenance	Expensive solution Requires automatic control functions
Loop systems			
Open loop	Very large power systems Major future expansion Loads concentrated in different zones of a site	Less expensive than closed loop Simple protection	Faulty segment can be isolated during loop reconfiguration Requires automatic control functions
Closed loop	Power system offering high continuity of service Very large power systems Loads concentrated in different zones of a site	Good continuity of supply Does not require automatic control functions	Expensive solution Complex protection system
Internal power generation			
Normal source generation	Industrial process sites producing their own energy E.g. paper plants, steel	Good continuity of supply Cost of energy (energy recovered from process)	Expensive solution
Replacement source (source changeover)	Industrial and commercial sites E.g. hospitals	Good continuity of supply for priority outgoing feeders	Requires automatic control functions

Examples of architectures

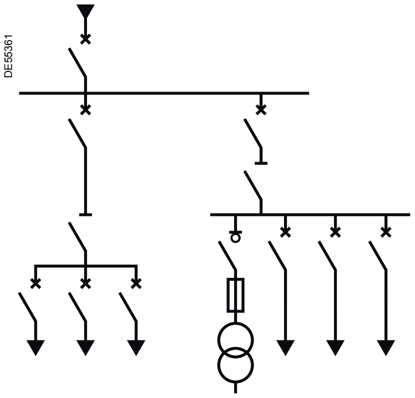
Legend:

NC: normally closed

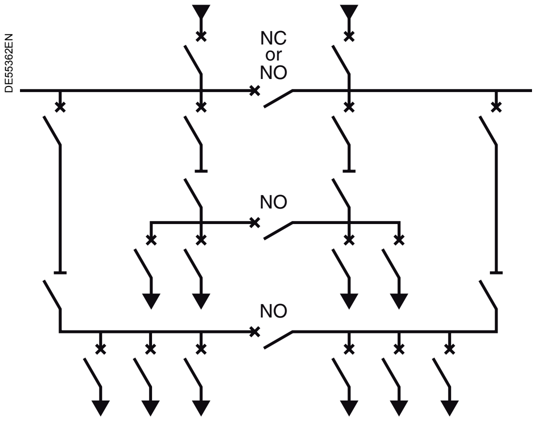
NO: normally open

Unless indicated otherwise, all switchgear is NC.

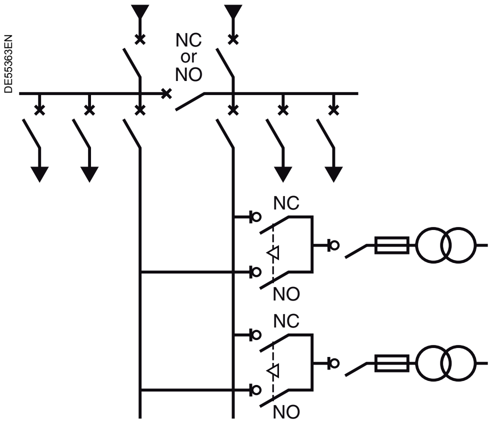
Single-feeder radial



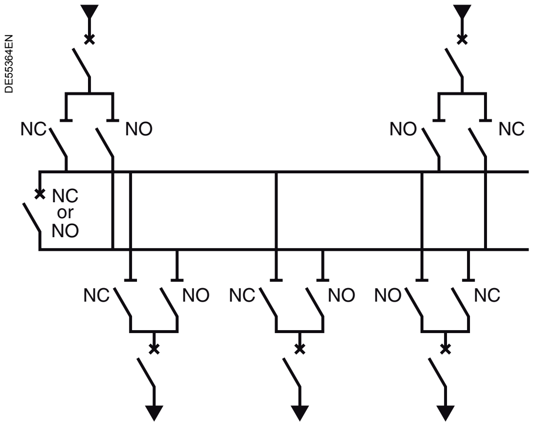
Double-feeder radial



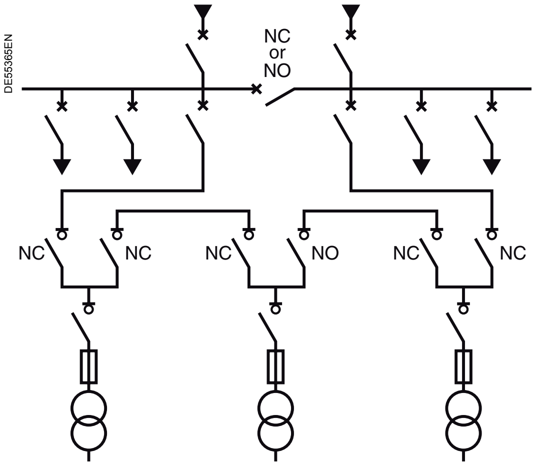
Parallel-feeder



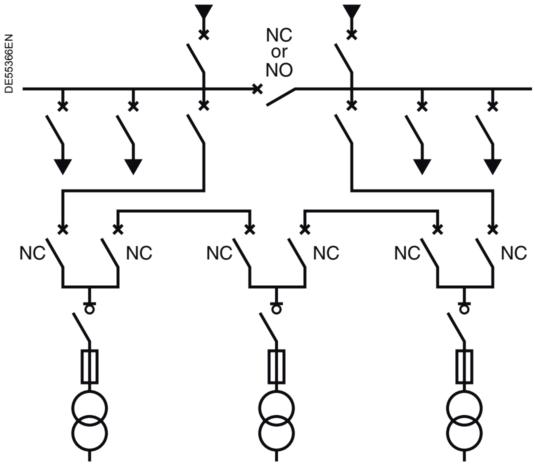
Double busbars



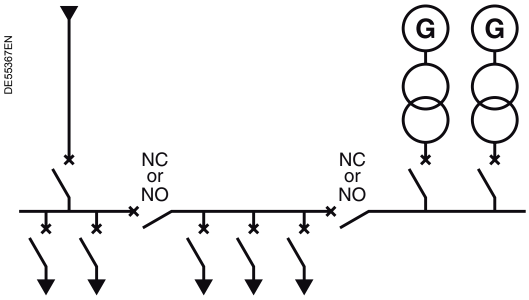
Open loop



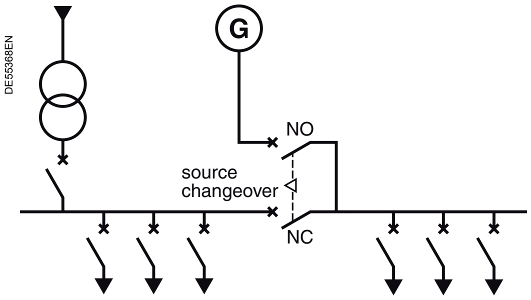
Closed loop



Local normal source generation



Replacement source generation (source changeover)



Five neutral earthing systems

The choice of neutral earthing for MV and HV power systems has long been a topic of heated controversy due to the fact that it is impossible to find a single compromise for the various types of power systems. Acquired experience now allows an appropriate choice to be made according to the specific constraints of each system. This chapter compares the different types of neutral earthing, distinguished by the neutral point connection and the operating technique used.

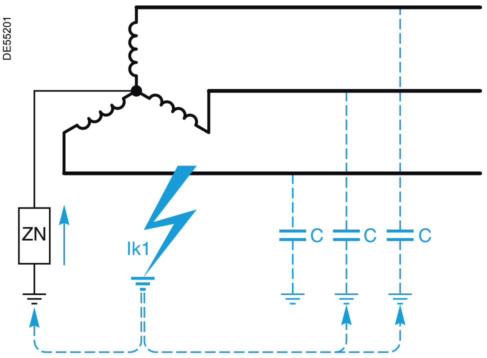


Fig. 1. Equivalent diagram of a power system with an earth fault.

Earthing impedance

The neutral potential can be earthed by five different methods, according to type (capacitive, resistive, inductive) and the value (zero to infinity) of the impedance ZN of the connection between the neutral and earth:

- ZN = ∞: **isolated neutral**, i.e. no intentional earthing connection,
- ZN is related to a **resistance** with a fairly high value,
- ZN is related to a **reactance**, with a generally low value,
- ZN is related to a **compensation reactance**, designed to compensate for the system capacitance,
- ZN = 0: the neutral is **solidly earthed**.

Difficulties and selection criteria

The selection criteria involve many aspects:

- technical considerations (power system function, overvoltages, fault current, etc.),
- operational considerations (continuity of service, maintenance),
- safety,
- cost (capital expenditure and operating expenses),
- local and national practices.

Two of the major technical considerations happen to be contradictory:

Reducing the level of overvoltages
Excessive overvoltages cause the dielectric breakdown of electrical insulating materials, resulting in short-circuits.
Overvoltages are of several origins:

- lightning overvoltage, to which all overhead systems are exposed, up to the user supply point,
- overvoltage within the system caused by switching and critical situations such as resonance,
- overvoltage resulting from an earth fault itself and its elimination.

Reducing earth fault current (Ik1) (fig. 1)
Fault current that is too high produces a whole series of consequences related to the following:

- damage caused by the arc at the fault point; particularly the melting of magnetic circuits in rotating machines,
- thermal withstand of cable shielding,
- size and cost of earthing resistor,
- induction in adjacent telecommunication circuits,
- danger for people created by the rise in potential of exposed conductive parts.

Unfortunately, optimizing one of these requirements is automatically to the disadvantage of the other. Two typical neutral earthing methods accentuate this contrast:

- isolated neutral, which eliminates the flow of earth fault current through the neutral but creates higher overvoltages,
- solidly earthed neutral, which reduces overvoltage to a minimum, but causes high fault current.

As for the operating considerations, according to the neutral earthing method used:

- continued operation may or may not be possible after a persisting first fault,
- the touch voltages are different,
- protection discrimination may be easy or difficult to implement.

An in-between solution is therefore often chosen, i.e. neutral earthing via an impedance.

Summary of neutral earthing characteristics

Characteristics	Neutral earthing				
	isolated	compensated	resistance	reactance	direct
Damping of transient overvoltages	–	+ –	+	+ –	+ +
Limitation of 50 Hz overvoltages	–	–	+	+	+
Limitation of fault currents	+	+ +	+	+	– –
Continuity of service (no tripping required on first fault)	+	+	–	–	–
Easy implementation of protection discrimination	–	– –	+	+	+
No need for qualified personnel	–	–	+	+	+

Legend: *+ good*
– mediocre

Isolated neutral

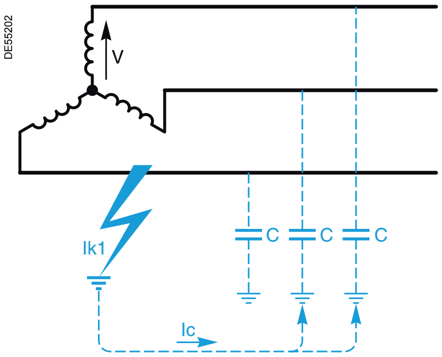


Fig. 1. Capacitive fault current in isolated neutral system.

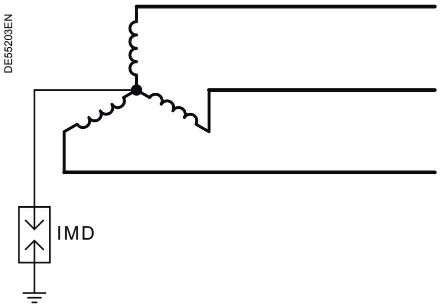


Fig. 2. Insulation monitoring device (IMD).

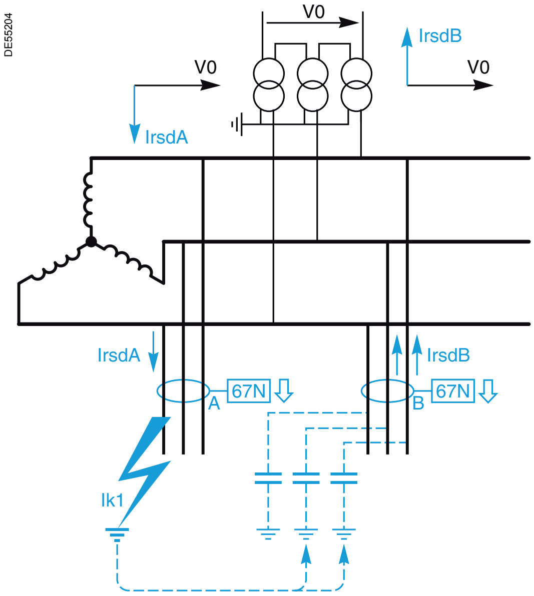


Fig. 3. Detection for directional earth fault protection.

Block diagram

There is no intentional earthing of the neutral point, except for measurement or protection devices.

Operating technique

In this type of power system, a phase-to-earth fault only produces a low current through the phase-to-earth capacitances of the fault-free phases (fig. 1).
It can be shown that **Ik1 = 3 • C • ω • V** where:

- V is the phase-to-neutral voltage,
- C is the phase-to-earth capacitance of a phase,
- ω is the angular frequency of the power system defined as **ω = 2 • π • f**

The fault current Ik1 can remain for a long time, in principle, without causing any damage since it is not more than a few amperes (approximately 2 A per km for a 6 kV single-core cable with a cross-section of 150 mm^2 , XLPE insulation and a capacitance of 0.63 μF/km). Action does not need to be taken to clear this first fault, making this solution advantageous in terms of maintaining service continuity.

However, this entails the following consequences:

- the insulation must be continuously monitored and faults that are not yet cleared must be indicated by **an insulation monitoring device** or by a neutral voltage displacement protection unit (ANSI 59N) (fig. 2),
- subsequent fault tracking requires complex automatic equipment for quick identification of the faulty feeder and also maintenance personnel qualified to operate the equipment,
- if the first fault is not cleared, a second fault occurring on another phase will cause a real two-phase-to-earth short circuit, which will be cleared by the phase protection units.

Advantage

The basic advantage is service continuity since the very low fault current does not cause automatic tripping for the first fault; it is the second fault that requires tripping.

Drawbacks

- The failure to eliminate transient overvoltages through the earth can be a major handicap if the overvoltage is high.
- Also, when one phase is earthed, the others reach a phase-to-phase voltage at power frequency (U = 3 • V) in relation to the earth, and this increases the probability of a second fault. Insulation costs are higher since the phase-to-phase voltage may remain between the phase and earth for a long time with no automatic tripping.
- Insulation monitoring is compulsory, with indication of the first fault.
- A maintenance department with the equipment to quickly track the first insulation fault is required.
- It is difficult to implement protection discrimination for the first fault.
- There are risks of overvoltages created by ferroresonance.

Protection function

The faulty feeder may be detected by a directional earth fault protection unit (ANSI 67N) (fig. 3).
The diagram shows that discrimination is implemented by a comparison of the phase displacement angle between the residual voltage and residual currents, for the faulty feeder and for each fault-free feeder.
The current is measured by a core balance CT and the tripping threshold is set:

- to avoid nuisance tripping,
- lower than the sum of the capacitive currents of all the other feeders.

This makes it difficult for faults to be detected in power systems that are limited in size, consisting of only a few hundreds of meters of cable.

Applications

This solution is often used for industrial power systems (≤ 15 kV) that require service continuity.
It is also used for the public distribution systems in Spain, Italy and Japan.

Resistance earthing

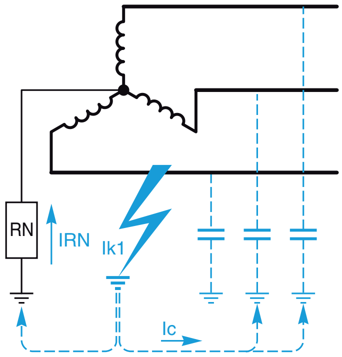


Fig. 1. Earthing with accessible neutral: resistor between neutral and earth.

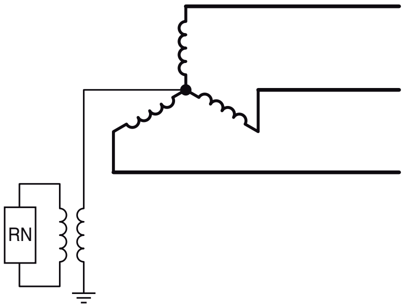
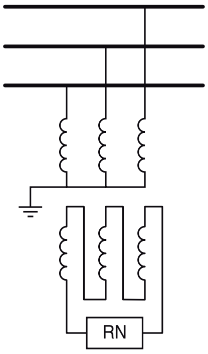
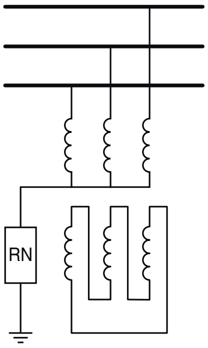


Fig. 2. Earthing with accessible neutral: resistor on single-phase transformer secondary circuit.





Earthing with inaccessible neutral:

Fig. 3. Limiting resistor on secondary circuit.

Fig. 4. Limiting resistor on primary circuit.

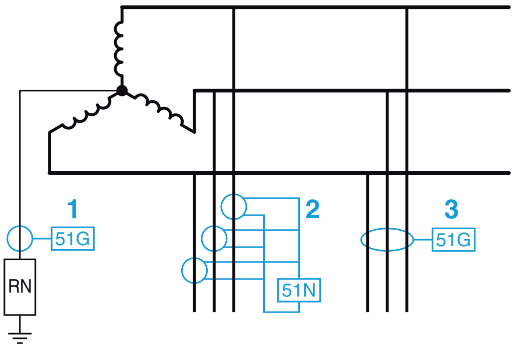


Fig. 5. Earth fault protection solutions.

Block diagram

A resistor is intentionally connected between the neutral point and earth.

Operating technique

In this type of power system, the resistive impedance limits the earth fault current Ik1 and still allows satisfactory evacuation of overvoltages.
However, protection units must be used to automatically clear the first fault. In power systems that supply rotating machines, the resistance is calculated so as to obtain a fault current Ik1 of 15 to 50 A. This low current must however be IRN ≥ 2 Ic (where Ic is the total capacitive current in the power system) to reduce switching surges and allow simple detection.
In distribution power systems, higher values are used (100 to 300 A) since they are easier to detect and allow the evacuation of lightning overvoltages.

Advantages

b This system is a good compromise between low fault current and satisfactory overvoltage evacuation.
b It does not require equipment with phase-to-earth insulation sized for the phase-to-phase voltage.
b The protection units are simple and selective and the current is limited.

Drawbacks

b The service continuity of the faulty feeder is downgraded and earth faults must be cleared as soon as they occur (first fault tripping).
b The higher the voltage and the current limited, the higher the cost of the earthing resistor.

Neutral earthing

b If the neutral point is accessible (star-connected windings with an accessible neutral), the earthing resistor may be connected between the neutral and earth (fig. 1) or via a single-phase transformer with an equivalent resistive load on the secondary winding (fig. 2).
b When the neutral is not accessible (delta-connected winding) or when the protection system study shows that it is appropriate, an artificial neutral point is created using a **zero sequence generator** connected to the busbars; it consists of a special transformer with a very low zero sequence reactance.
v star-delta transformer with solidly earthed primary neutral, and a delta connection including a limiting resistor (LV insulation, therefore the most inexpensive solution) (fig. 3),
v star-delta transformer with limiting resistor (HV insulation) between the primary neutral point and earth, and a closed delta connection (no resistor); this solution is less often used (fig. 4).

Protection functions

To detect a fault current Ik1 that is low, protection functions other than phase overcurrent are required (fig. 5).
These “earth fault” protection functions detect fault current:
b directly in the neutral earthing connection 1,
b or in the power system by the vector sum of the 3 currents measured by:
v 3 current sensors supplying the protection units 2,
v or a core balance CT 3: preferred method since more accurate.

The threshold is set according to the fault current Ik1 calculated without taking into account the source and connection zero sequence impedance in relation to the impedance RN, in compliance with two rules:
b setting > 1.3 times the capacitive current of the power system downstream from the protection unit,
b setting in the range of 10 to 20% of the maximum earth fault current.

In addition, if 3 CTs are used for detection, in view of current technologies, the setting should be within 5 to 30% of the CT rating to account for the uncertainty linked to:
b transient current asymmetry,
b CT saturation,
b scattering of performance.

Applications

Public and industrial MV distribution systems.

Low reactance earthing

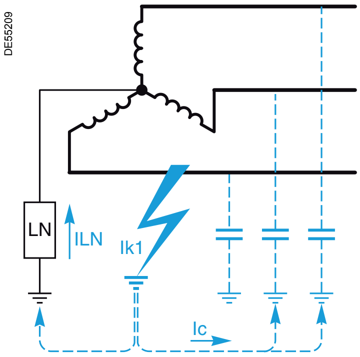


Fig. 1. Earthing with accessible neutral.

Block diagram

A reactor is intentionally connected between the neutral point and earth.
For power system voltages greater than 40 kV, it is preferable to use a reactor rather than a resistor because of the difficulties arising from heat emission in the event of a fault (fig. 1).

Operating technique

In this type of power system, an inductive impedance limits earth fault current Ik1 and still allows satisfactory evacuation of overvoltages. However, protection units must be used to automatically clear the first fault.
To reduce switching surges and allow simple detection, the current IL must be much higher than the total capacitive current of the power system Ic.
In distribution systems, higher values are used (300 to 1000 A) since they are easier to detect and allow the evacuation of lightning overvoltages.

Advantages

- This system limits the amplitude of fault currents.
- Protection discrimination is easy to implement if the limiting current is much greater than the capacitive current in the power system.
- The coil has a low resistance and does not dissipate a large amount of thermal energy; the coil can therefore be reduced in size.
- In high voltage systems, this solution is more cost-effective than resistance earthing.

Drawbacks

- The continuity of service of the faulty feeder is downgraded; earth faults must be cleared as soon as they occur (first fault tripping).
- When earth faults are cleared, high overvoltages may occur due to resonance between the power system capacitance and the reactance.

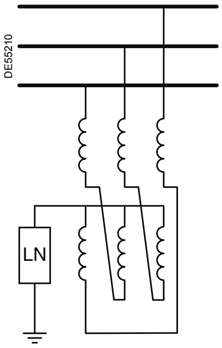


Fig. 2. Earthing with inaccessible neutral.

Neutral earthing

- If the neutral point is accessible (star-connected windings with an accessible neutral), the earthing reactance may be connected between the neutral and earth.
- When the neutral is not accessible (delta-connected winding) or when the protection system study shows that it is appropriate, an artificial neutral point is created by a **neutral point coil** connected to the busbars; it consists of a zigzag coil with an accessible neutral (fig. 2).

The impedance between the two parts of the winding, essentially inductive and low, limits the current to values that remain greater than 100 A.
A limiting resistor may be added between the coil neutral point and earth to reduce the amplitude of the fault current (HV insulation).

Protection functions

- The protection setting is in the range of 10 to 20% of the maximum fault current.
- The protection function is less restrictive than in the case of resistance earthing, especially considering the high value of ILN given that Ic is less than the limited current.

Applications

Public and industrial MV distribution systems (currents of several hundred amperes).

Compensation reactance earthing

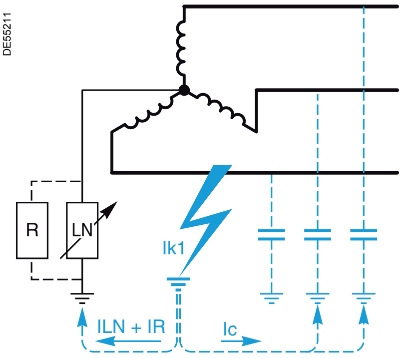


Fig. 1. Earth fault in power system with compensation reactance earthing.

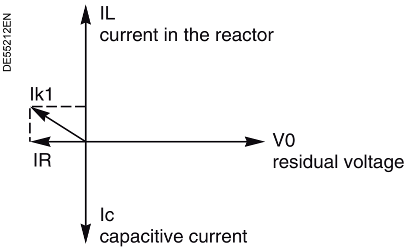


Fig. 2. Vector diagram of currents during an earth fault.

Block diagram

A reactor tuned to the total phase-to-earth capacitance of the power system is inserted between the neutral point and earth so that the fault current is close to zero if an earth fault occurs (fig. 1).

Operating technique

This system is used to compensate for capacitive current in the power system.
The fault current is the sum of the currents flowing through the following circuits:

- reactance earthing circuit,
- fault-free phase capacitances with respect to earth.

The currents compensate for each other since:

- one is inductive (in the earthing circuit),
- the other one is capacitive (in the fault-free phase capacitances).

They therefore add up in opposite phase.
In practice, due to the slight resistance of the coil, there is a low resistive current of a few amperes (fig. 2).

Advantages

- The system reduces fault current, even if the phase-to-earth capacitance is high: spontaneous extinction of non-permanent earth faults.
- The touch voltage is limited at the location of the fault.
- The installation remains in service even in the event of a permanent fault.
- The first fault is indicated by detection of current flowing through the coil.

Drawbacks

- The cost of reactance earthing may be high since the reactance needs to be modified to adapt compensation.
- It is necessary to make sure that the residual current in the power system during the fault is not dangerous for people or equipment.
- There is a high risk of transient overvoltages on the power system.
- Personnel must be present to supervise.
- It is difficult to implement protection discrimination for the first fault.

Protection function

Fault detection is based on the active component of the residual current.
The fault creates residual currents throughout the power system, but the faulty circuit is the only one through which resistive residual current flows.
In addition, the protection units must take into account repetitive self-extinguishing faults (recurrent faults).
When the earthing reactance and power system capacitance are tuned
(**$3\ LN \cdot C \cdot \omega^2 = 1$**)

- fault current is minimal,
- it is a resistive current,
- the fault is self-extinguishing.

The compensation reactance is called an **extinction coil**, or **Petersen coil**.

Application

Public and industrial MV distribution systems with high capacitive current.

Solidly earthed neutral

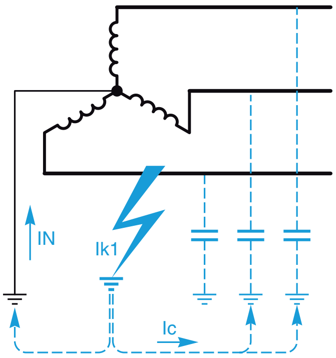


Fig. 1. Earth fault in a solidly earthed neutral power system.

Block diagram

An electrical connection with zero impedance is intentionally set up between the neutral point and earth.

Operating technique

Since the neutral is earthed without any limiting impedance, the phase-to-earth fault current Ik1 is practically a phase-to-neutral short-circuit, and is therefore high (fig. 1). Tripping takes place when the first insulation fault occurs.

Advantages

b This system is ideal for evacuating overvoltages.
b Equipment with insulation sized for phase-to-neutral voltage may be used.
b Specific protection units are not required: the normal phase overcurrent protection units can be used to clear solid earth faults.

Drawbacks

b This system involves all the drawbacks and hazards of high earth fault current: maximum damage and disturbances.
b There is no service continuity on the faulty feeder.
b The danger for personnel is high during the fault since the touch voltages created are high.

Protection function

Impedant faults are detected by a delayed earth fault protection unit (ANSI 51N), set in the range of the rated current.

Applications

b This type of system is not used in European overhead or underground MV power systems, but is prevalent in North American distribution systems. In the North American power systems (overhead systems), other features come into play to justify the choice:
v distributed neutral conductor,
v 3-phase or 2-phase + neutral or phase + neutral distribution,
v use of the neutral conductor as a protective conductor with systematic earthing at each transmission pole.
b This type of system may be used when the short-circuit power of the source is low.

A short-circuit is one of the major incidents affecting power systems.
This chapter describes short-circuits and their effects on power systems and their interaction with equipment.
It also provides a method and the main equations to calculate currents and voltages when short-circuits occur.

Definitions

- A short-circuit is an accidental connection between conductors by a zero (solid short-circuit) or non-zero impedance (impedant short-circuit).
- A short-circuit is referred to as internal if it is located within equipment or external if its occurs on links.
- The duration of a short-circuit is variable. A short-circuit is said to be self-extinguishing if its duration is too short for tripping of the protection devices, transient if cleared following tripping and reclosing of the protection devices and continuous or sustained if it does not disappear following tripping.
- The causes of a short-circuit can be mechanical (a shovel, a branch, an animal), electrical (damaged insulation, overvoltages) or human (operating error) (fig. 1).

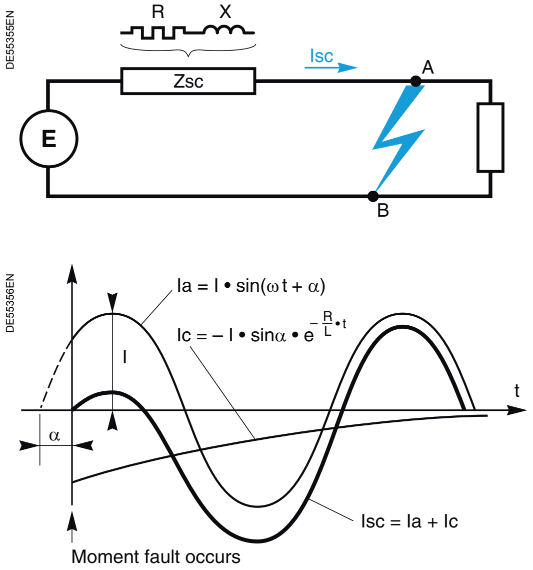


Fig. 1. Graphical representation of a short-circuit current based on an equivalent diagram.

Effects of short-circuit currents

The consequences are often serious, if not dramatic.

- A short-circuit disturbs the power system environment around the fault point by causing a sudden drop in voltage.
- It requires disconnection, through the operation of the protection devices, of a part (often large) of the installation.
- All equipment and connections (cables, lines) subjected to a short-circuit are subjected to high mechanical stress (electrodynamic forces) that can cause breaks and thermal stress that can melt conductors and destroy insulation.
- At the fault point, there is often a high-energy electrical arc, causing very heavy damage that can quickly spread.

Although short-circuits are less and less likely to occur in modern, well-designed, well-operated installations, the serious consequences they can cause are an incentive to implement all possible means to swiftly detect and eliminate them.

The short-circuit current at different points in the power system must be calculated to design the cables, busbars and all switching and protection devices and determine their settings.

Characterization of short-circuits

A number of types of short-circuits can occur in a power system.

- **Three-phase short-circuit**: a fault between the three phases.
This type generally provokes the highest currents (fig. 2).
- **Phase-to-earth short-circuit**: a fault between a phase and earth.
This type is the most frequent (fig. 3).
- **Two-phase short-circuit clear of earth**: a fault between two phases (phase-to-phase voltage). The resulting current is lower than for a three-phase short-circuit, except when the fault is in the immediate vicinity of a generator (fig. 4).
- **Two-phase-to-earth short-circuit**: a fault between two phases and earth (fig. 5).

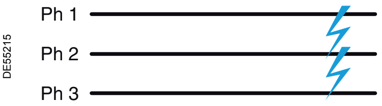


Fig. 2. Three-phase short-circuit (5% of cases).

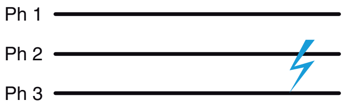


Fig. 4. Two-phase short-circuit clear of earth.

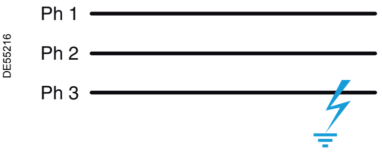


Fig. 3. Phase-to-earth short-circuit (80% of cases).

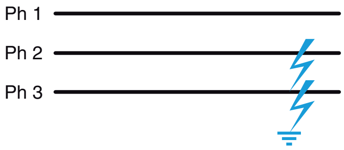


Fig. 5. Two-phase-to-earth short-circuit.

Short-circuit current at a given point in the power system is expressed as the **rms value Ik** (in kA) of its AC component (fig. 6).

The maximum **instantaneous value** that short-circuit current can reach is the **peak value Ip** of the first half cycle. This peak value can be much higher than 2 • Ik because of the damped **DC component IDC** that can be superimposed on the AC component.

This DC component depends on the instantaneous value of the voltage at the start of the short-circuit and on the power system characteristics. The power system is defined by the short-circuit power, according to the equation:

Ssc = 3 • Un • Ik (in MVA).

This theoretical value has no physical reality; it is a practical conventional value comparable to an apparent power rating.

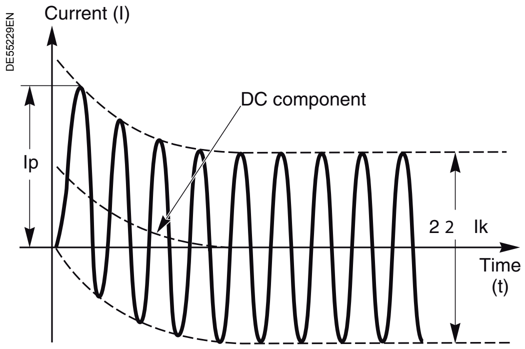


Fig. 6. Typical short-circuit current curve.

Introduction to short-circuits

Symmetrical components

During normal, balanced symmetrical operation, analysis of three-phase systems is similar to that of an equivalent single-phase system, characterized by the phase-to-neutral voltages, phase currents and power system impedances (called cyclical impedances). As soon as a significant dissymmetry appears in the configuration or in power system operation, simplification is no longer possible. It is not possible to establish simple electrical relations in the conductors, using the cyclical impedances.
In this case, the symmetrical-components method is used, which consists of expressing the real system as a superposition of three independent, single-phase power systems, called:

- positive sequence (designated by a subscript 1, e.g. V_1),
- negative sequence (designated by a subscript 2, e.g. V_2),
- zero-sequence (designated by a subscript 0, e.g. V_0).

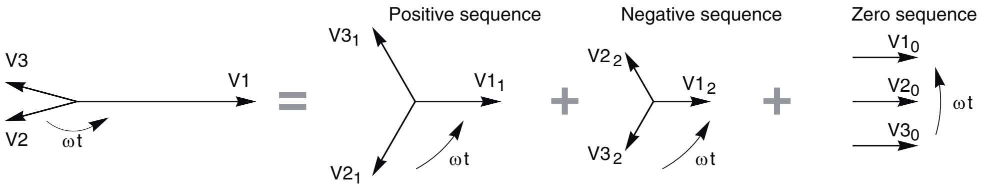
For each system (positive-, negative- and zero-sequence respectively), voltages V_1, V_2, V_0 and currents I_1, I_2, I_0 are related by the impedances Z_1, Z_2, Z_0 of the same system.
The symmetrical impedances are a function of the real impedances, notably the mutual inductances.
The notion of symmetrical components is also applicable to power.

$$\begin{aligned}
\overrightarrow{V1} &= \overrightarrow{V_1} + \overrightarrow{V_2} + \overrightarrow{V_0} \\
\overrightarrow{V2} &= a^2 \bullet \overrightarrow{V_1} + a \bullet \overrightarrow{V_2} + \overrightarrow{V_0} \\
\overrightarrow{V3} &= a \bullet \overrightarrow{V_1} + a^2 \bullet \overrightarrow{V_2} + \overrightarrow{V_0}
\end{aligned}$$

where $a = e^{j \bullet \frac{2\pi}{3}}$

$$\begin{aligned}
\overrightarrow{V_1} &= \frac{1}{3}(\overrightarrow{V1} + a \bullet \overrightarrow{V2} + a^2 \bullet \overrightarrow{V3}) \\
\overrightarrow{V_2} &= \frac{1}{3}(\overrightarrow{V1} + a^2 \bullet \overrightarrow{V2} + a \bullet \overrightarrow{V3}) \\
\overrightarrow{V_0} &= \frac{1}{3}(\overrightarrow{V1} + \overrightarrow{V2} + \overrightarrow{V3})
\end{aligned}$$

where $a = e^{j \bullet \frac{2\pi}{3}}$



Decomposition of a three-phase system into symmetrical components.

Decomposition into symmetrical components is not simply a mathematical technique, it corresponds to the physical reality of the phenomena. It is possible to directly measure the symmetrical components (voltages, currents, impedances) of an unbalanced system.
The positive-, negative- and zero-sequence impedances of an element in the power system are the impedances of the element subjected to voltage systems that are, respectively, positive three-phase, negative three-phase and phase-to-earth on three parallel phases.
Generators produce the positive-sequence component and faults may produce the negative and zero-sequence components.
In the case of motors, the positive-sequence component creates the useful rotating field, whereas the negative-sequence component creates a braking rotating field.
For transformers, an earth fault creates a zero-sequence component that produces a zero-sequence field passing through the tank.

Types of short-circuit

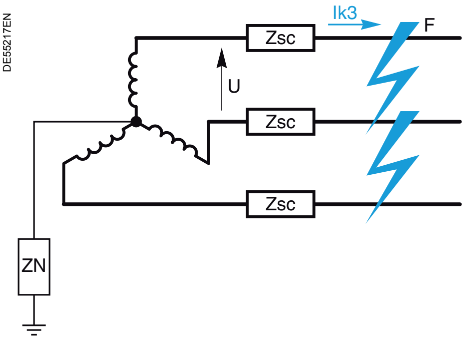


Fig. 1. Three-phase short-circuit.

Three-phase short-circuit between the phase conductors (fig. 1)

The value of the three-phase short-circuit current at a point F within the power system is:

$$\mathbf{Ik3} = \frac{\mathbf{U}}{\sqrt{\mathbf{3}} \bullet \mathbf{Zsc}}$$

where U refers to the phase-to-phase voltage at point F before the fault occurs and Zsc is the equivalent upstream power system impedance as seen from the fault point. In theory, this is a simple calculation; in practice, it is complicated due to the difficulty of calculating Zsc, an impedance equivalent to all the unitary impedances of series and parallel-connected units located upstream from the fault. These impedances are themselves the quadratic sum of reactances and resistances.

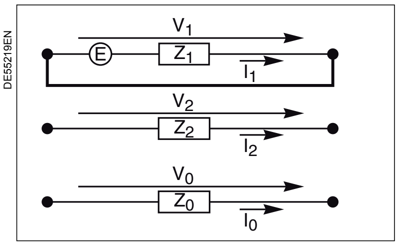
$$\mathbf{Zsc} = \sqrt{\mathbf{R^2} + \mathbf{X^2}}$$

Calculations can be made much simpler by knowing the short-circuit power Ssc at the connection point for utility power. It is possible to deduce the equivalent impedance Za upstream of this point.

$$\mathbf{Za} = \frac{\mathbf{U^2}}{\mathbf{Ssc}} \qquad \mathbf{Isc} = \frac{\mathbf{U}}{\sqrt{\mathbf{3}} \bullet \mathbf{Za}}$$

Similarly, there may not be a single source of voltage, but rather several sources in parallel, in particular, synchronous and asynchronous motors which act as generators when short-circuits occur.
The three-phase short-circuit current is generally the strongest current that can flow in the power system.

$$\mathbf{I_1} = \frac{\mathbf{E}}{\mathbf{Z_1}}$$
$$\mathbf{I_2} = \mathbf{I_0} = \mathbf{0}$$
$$\mathbf{V_1} = \mathbf{V_2} = \mathbf{V_0} = \mathbf{0}$$



Model of a three-phase short-circuit using the symmetrical components.

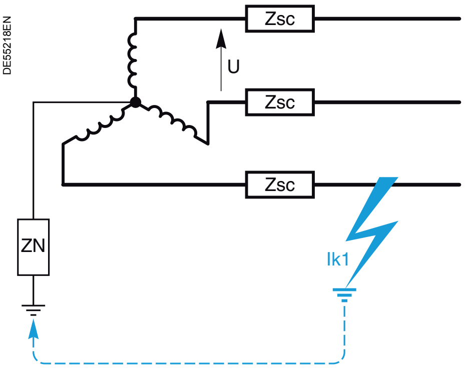


Fig. 2. Phase-to-earth short-circuit.

Single-phase short-circuit between a phase conductor and earth (fig. 2)

The value of this current depends on the impedance ZN between the neutral and earth. This impedance can be virtually nil if the neutral is solidly earthed (in series with the earthing resistance) or, on the contrary, almost infinite if the neutral is isolated (in parallel with the power system phase-to-earth capacitance).

The value of the phase-to-earth fault current is:

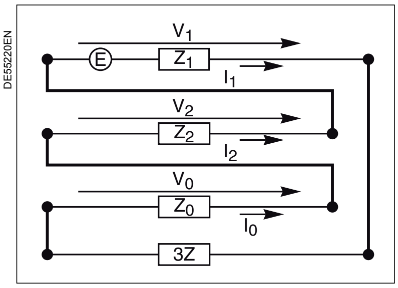
$$\mathbf{Ik1} = \frac{\sqrt{\mathbf{3}} \bullet \mathbf{U}}{(\mathbf{Z_1} + \mathbf{Z_2} + \mathbf{Z_0} + \mathbf{3ZN})}$$

This calculation is required for power systems in which the neutral is earthed by an impedance ZN. It is used to determine the setting of the “earth fault” protection devices which must break the earth-fault current.
If Z_1, Z_2 and Z_0 are negligible with respect to ZN, then:

$$\mathbf{Ik1} = \frac{\mathbf{U}}{\sqrt{\mathbf{3}} \bullet \mathbf{ZN}}$$

This is the case, for example, when Ik1 is limited to 20 A in an MV power system supplied by a high-power transformer (10 MVA).

$$\mathbf{I_1} = \mathbf{I_2} = \mathbf{I_0} = \frac{\mathbf{E}}{\mathbf{Z_1} + \mathbf{Z_2} + \mathbf{Z_0} + \mathbf{3Z}}$$
$$\mathbf{V_1} = \frac{\mathbf{E(Z_2} + \mathbf{Z_0} + \mathbf{3Z)}}{\mathbf{Z_1} + \mathbf{Z_2} + \mathbf{Z_0} + \mathbf{3Z}}$$
$$\mathbf{V_2} = \frac{-\mathbf{Z_2} \bullet \mathbf{E}}{\mathbf{Z_1} + \mathbf{Z_2} + \mathbf{Z_0} + \mathbf{3Z}}$$
$$\mathbf{V_0} = \frac{-\mathbf{Z_0} \bullet \mathbf{E}}{\mathbf{Z_1} + \mathbf{Z_2} + \mathbf{Z_0} + \mathbf{3Z}}$$



Model of a phase-to-earth short-circuit using the symmetrical components.

Types of short-circuit

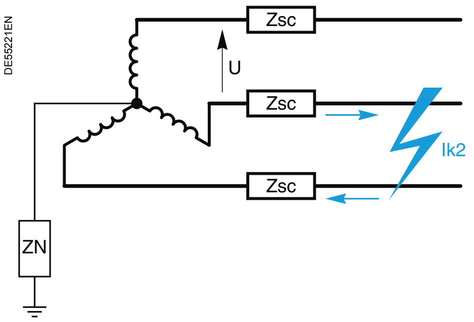


Fig. 1. Two-phase short-circuit clear of earth.

Two-phase short-circuit between phase conductors (fig.1)

The value of the two-phase short-circuit current at a point within the power system is:

$$\mathbf{Ik2} = \frac{\mathbf{U}}{\mathbf{Z_1 + Z_2}}$$

In a power system supplied by a transformer (fault far from the sources), the value of the two-phase short-circuit current at a point within the power system is:

$$\mathbf{Ik2} = \frac{\mathbf{U}}{\mathbf{2 \bullet Zsc}}$$

The two-phase short-circuit current is weaker than three-phase short-circuit current, by a ratio of $\sqrt{3}/2$, i.e. approximately 87%.
If the fault occurs close to a generator ($Z_2 \leq Z_1$), the current can be higher than in a three-phase fault.

$$\mathbf{I_1} = \frac{\mathbf{E}}{\mathbf{Z_1 + Z_2 + Z}}$$

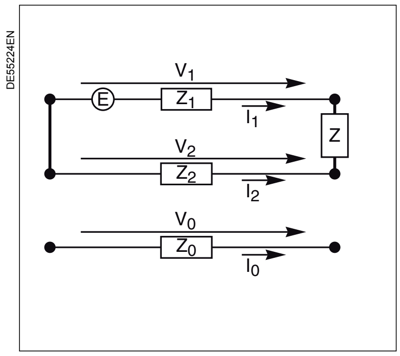
$$\mathbf{I_2} = \frac{\mathbf{-E}}{\mathbf{Z_1 + Z_2 + Z}}$$

$$\mathbf{I_0} = \mathbf{0}$$

$$\mathbf{V_1} = \frac{\mathbf{E(Z_2 + Z)}}{\mathbf{Z_1 + Z_2 + Z}}$$

$$\mathbf{V_2} = \frac{\mathbf{E \bullet Z_2}}{\mathbf{Z_1 + Z_2 + Z}}$$

$$\mathbf{V_0} = \mathbf{0}$$



Model of a two-phase short-circuit using the symmetrical components.

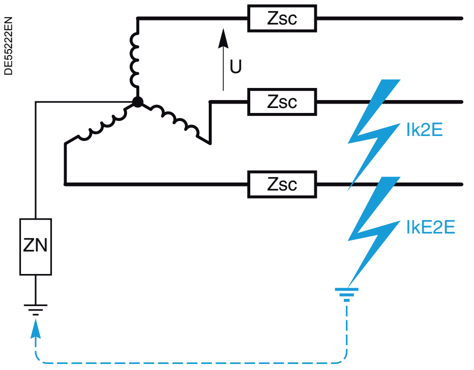


Fig. 2. Two-phase-to-earth short-circuit.

Two-phase short-circuit between two phase conductors and earth (fig. 2)

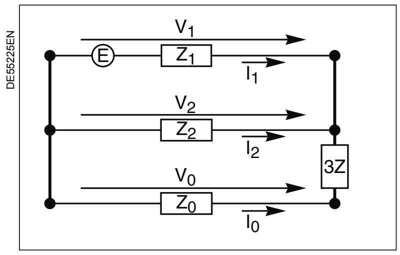
For a solid short-circuit (fault far from the sources), the value of the two-phase-to-earth short-circuit is:

$$\mathbf{IkE2E} = \frac{\mathbf{\sqrt{3} \bullet U}}{\mathbf{(Z_1 + 2Z_0)}}$$

$$\mathbf{I_1} = \frac{\mathbf{E(Z_2 + Z_0 + 3Z)}}{\mathbf{Z_1 \bullet Z_2 + (3Z + Z_0) \bullet (Z_1 + Z_2)}}$$

$$\mathbf{I_2} = \frac{\mathbf{-E(Z_0 + 3Z)}}{\mathbf{Z_1 \bullet Z_2 + (3Z + Z_0) \bullet (Z_1 + Z_2)}}$$

$$\mathbf{I_0} = \frac{\mathbf{-E \bullet Z_2}}{\mathbf{Z_1 \bullet Z_2 + (3Z + Z_0) \bullet (Z_1 + Z_2)}}$$



Model of a two-phase-to-earth short-circuit using the symmetrical components.

Short-circuit across generator terminals

It is more complicated to calculate short-circuit current across the terminals of a synchronous generator than across the terminals of a transformer connected to the power system.

This is because the internal impedance of the machine cannot be considered constant after the start of the fault. It increases progressively and the current becomes weaker, passing through three characteristic stages:

b **subtransient** (approximately 0.01 to 0.1 second), the short-circuit current (rms value of the AC component) is high, 5 to 10 times the rated continuous current.

b **transient** (between 0.1 and 1 second), the short-circuit current drops to between 2 and 6 times the rated current.

b **steady-state**, the short-circuit current drops to between 0.5 and 2 times the rated current.

The given values depend on the power rating of the machine, its excitation mode and, for the steady-state current, on the value of the exciting current, therefore on the load on the machine at the time of the fault.

What is more, the zero-sequence impedance of the AC generators is generally 2 to 3 times lower than their positive-sequence impedance. The phase-to-earth short-circuit current is therefore greater than the three-phase current.

By way of comparison, the steady-state three-phase short-circuit current across the terminals of a transformer ranges between 6 and 20 times the rated current, depending on the power rating.

It can be concluded that short-circuit across generator terminals are difficult to assess, in particular their low, decreasing value makes protection setting difficult.

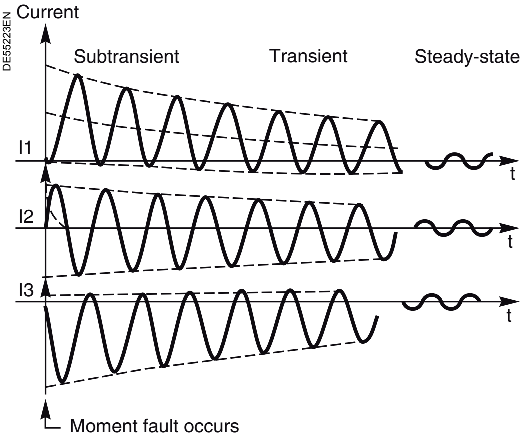


Fig. 1. Typical curves for short-circuit currents across generator terminals.

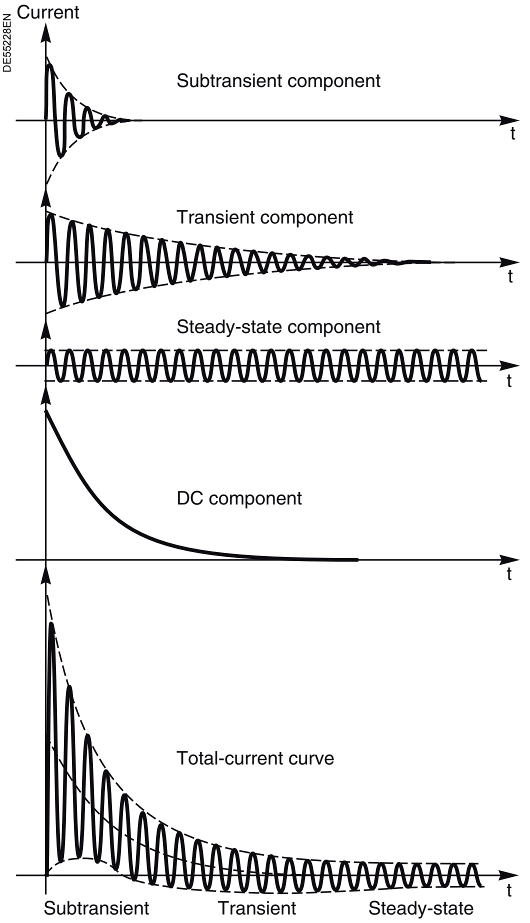


Fig. 2. Decomposition of the short-circuit current.

Calculation of short-circuit currents

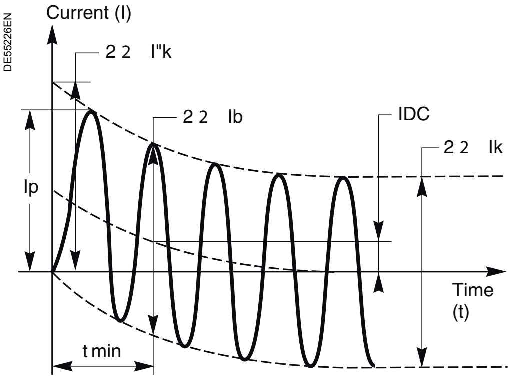


Fig. 1. Graphic representation of short-circuit quantities as per IEC 60909.

Type of short-circuit	I"k
3-phase	$\frac{c \bullet Un}{\sqrt{3} \bullet Z_1}$
2-phase	$\frac{c \bullet Un}{Z_1 + Z_2}$
2-phase-to-earth	$\frac{c \bullet Un \bullet \sqrt{3} \bullet Z_2}{Z_1 \bullet Z_2 + Z_2 \bullet Z_0 + Z_1 \bullet Z_0}$
Phase-to-earth	$\frac{c \bullet Un \bullet \sqrt{3}}{Z_1 + Z_2 + Z_0}$

Short-circuit currents as per IEC 60909 (general situation).

Type of short-circuit	I"k
3-phase	$\frac{c \bullet Un}{\sqrt{3} \bullet Z_1}$
2-phase	$\frac{c \bullet Un}{2 \bullet Z_1}$
2-phase-to-earth	$\frac{c \bullet Un \bullet \sqrt{3}}{Z_1 + 2Z_0}$
Phase-to-earth	$\frac{c \bullet Un \bullet \sqrt{3}}{2Z_1 + Z_0}$

Short-circuit currents as per IEC 60909 (distant faults).

IEC method (standard 60909)

The rules for calculating short-circuit currents in electrical installations are presented in IEC standard 60909, issued in 2001.

The calculation of short-circuit currents at various points in a power system can quickly turn into an arduous task when the installation is complicated.

The use of specialized software accelerates calculations.

This general standard, applicable for all radial and meshed power systems, 50 or 60 Hz and up to 550 kV, is extremely accurate and conservative.

It may be used to handle the different types of solid short-circuit (symmetrical or dissymmetrical) that can occur in an electrical installation:

- three-phase short-circuit (all three phases), generally the type producing the highest currents,
- two-phase short-circuit (between two phases), currents lower than three-phase faults,
- two-phase-to-earth short-circuit (between two phases and earth),
- phase-to-earth short-circuit (between a phase and earth), the most frequent type (80% of all cases).

When a fault occurs, the transient short-circuit current is a function of time and comprises two components (fig. 1):

- an AC component, decreasing to its steady-state value, caused by the various rotating machines and a function of the combination of their time constants,
- a DC component, decreasing to zero, caused by the initiation of the current and a function of the circuit impedances.

Practically speaking, one must define the short-circuit values that are useful in selecting system equipment and the protection system:

- I"k: rms value of the initial symmetrical current,
- Ib: rms value of the symmetrical current interrupted by the switching device when the first pole opens at tmin (minimum delay),
- Ik: rms value of the steady-state symmetrical current,
- Ip: maximum instantaneous value of the current at the first peak,
- IDC: DC value of the current.

These currents are identified by subscripts 3, 2, 2E, 1, depending on the type of short-circuit, respectively three-phase, two-phase clear of earth, two-phase-to-earth, phase-to-earth.

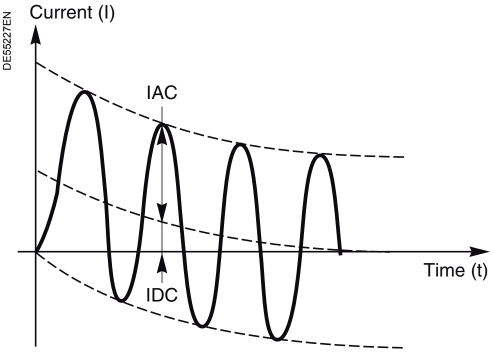
The method, based on the Thevenin superposition theorem and decomposition into symmetrical components, consists in applying to the short-circuit point an equivalent source of voltage in view of determining the current. The calculation takes place in three steps.

- Define the equivalent source of voltage applied to the fault point. It represents the voltage existing just before the fault and is the rated voltage multiplied by a factor taking into account source variations, transformer on-load tap changers and the subtransient behavior of the machines.
- Calculate the impedances, as seen from the fault point, of each branch arriving at this point. For positive and negative-sequence systems, the calculation does not take into account line capacitances and the admittances of parallel, non-rotating loads.
- Once the voltage and impedance values are defined, calculate the characteristic minimum and maximum values of the short-circuit currents.

The various current values at the fault point are calculated using:

- the equations provided,
- a summing law for the currents flowing in the branches connected to the node:
  - I"k, see the equations for I"k in the tables opposite, where voltage factor c is defined by the standard; geometric or algebraic summing,
  - ip = κ • 2 • I"k, where κ is less than 2, depending on the R/X ratio of the positive-sequence impedance for the given branch; peak summing,
  - Ib = μ • q • I"k, where μ and q are less than 1, depending on the generators and motors, and the minimum current interruption delay; algebraic summing,
  - Ik = I"k, when the fault is far from the generator,
  - Ik = λ • Ir, for a generator, where Ir is the rated generator current and λ is a factor depending on its saturation inductance; algebraic summing.

Equipment behaviour during short-circuits



IAC: peak of the periodic component.
IDC: aperiodic component.

Fig. 1. Rated breaking current of a circuit breaker subjected to a short-circuit as per IEC 60056.

Characterization

There are 2 types of system equipment, based on whether or not they react when a fault occurs.

Passive equipment

This category comprises all equipment which, due to its function, must have the capacity to transport both normal current and short-circuit current.
This equipment includes cables, lines, busbars, disconnecting switches, switches, transformers, series reactances and capacitors, instrument transformers.
For this equipment, the capacity to withstand a short-circuit without damage is defined in terms of:

- **electrodynamic withstand** (expressed in kA peak), characterizing mechanical resistance to electrodynamic stress,
- **thermal withstand** (expressed in rms kA for 1 to 5 seconds), characterizing maximum permissible heat rise.

Active equipment

This category comprises the equipment designed to clear short-circuit currents, i.e. circuit breakers and fuses. This property is expressed by the breaking capacity and, if required, the making capacity when a fault occurs.

Breaking capacity (fig. 1)

This basic characteristic of a current interrupting device is the maximum current (in rms kA) it is capable of breaking under the specific conditions defined by the standards; it generally refers to the rms value of the AC component of the short-circuit current. Sometimes, for certain switchgear, the rms value of the sum of the 2 components (AC and DC) is specified, in which case, it is the “asymmetrical current”.
The breaking capacity depends on other factors such as:

- voltage,
- R/X ratio of the interrupted circuit,
- power system natural frequency,
- number of breaks at maximum current, for example the cycle: O - C/O - C/O (O = opening, C = closing),
- device status after the test.

The breaking capacity is a relatively complicated characteristic to define and it therefore comes as no surprise that the same device can be assigned different breaking capacities depending on the standard by which it is defined.

Short-circuit making capacity

In general, this characteristic is implicitly defined by the breaking capacity because a device should be able to close for a current that it can break.
Sometimes, the making capacity needs to be higher, for example for circuit breakers protecting generators.
The making capacity is defined in terms of the kA peak because the first asymmetric peak is the most demanding from an electrodynamic point of view.
For example, according to standard IEC 60056, a circuit breaker used in a 50 Hz power system must be able to handle a peak making current equal to 2.5 times the rms breaking current.

Prospective short-circuit breaking current

Some devices have the capacity to limit the fault current to be interrupted.
Their breaking capacity is defined as the maximum prospective breaking current that would develop during a solid short-circuit across the upstream terminals of the device.

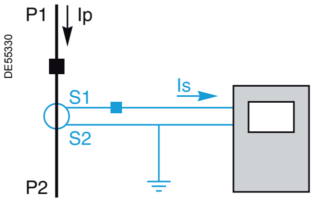
Specific device characteristics

The functions provided by various interrupting devices and their main constraints are presented in the table below.

Device	**Isolation**	**Current switching conditions**		**Main constraints**
		Normal	Fault	
Disconnector	yes	no	no	Longitudinal input/output isolation Earthing switch: short-circuit making capacity
Switch	no	yes	no	Making and breaking of normal load current Short-circuit making capacity With a fuse: short-circuit breaking capacity in fuse no-blow zone
Contactor	no yes, if withdrawable	yes	no	Rated making and breaking capacities Maximum making and breaking capacities Duty and endurance characteristics
Circuit breaker	no yes, if withdrawable	yes	yes	Short-circuit breaking capacity Short-circuit making capacity
Fuse	no	no	yes	Minimum short-circuit breaking capacity Maximum short-circuit breaking capacity

Phase-current sensors (CT)

Protection and measuring devices require data on the electrical rating of the equipment to be protected.
For technical, economic and safety reasons, this data cannot be obtained directly from the high-voltage power supply of the equipment. The following intermediary devices are needed:
b phase-current sensors,
b core balance CTs to measure earth fault currents,
b voltage transformers (VT).
These devices fulfill the following functions:
b reduction of the value to be measured (e.g. 1500/5 A),
b galvanic isolation,
b provision of the power required for data processing and for the protection function itself.



Ip: primary current
Is: secondary current (proportional to Ip and in phase)

Fig. 1. Current transformer.

The role of a phase-current sensor is to provide its secondary winding with a current proportional to the measured primary current. They are used for both measurements and protection.
There are two types of sensors:
b current transformers (CT),
b current transformers with a voltage output (LPCT).

General characteristics (fig. 1)

The current transformer is made up of two circuits, the primary and the secondary, coupled by a magnetic circuit.
When there are a number of turns in the primary circuit, the transformer is of the wound-primary type.
When the primary is a single conductor running through a sensor, the transformer may be of the bar-primary type (integrated primary made up of a copper bar), support type (primary formed by an uninsulated conductor of the installation) or the toroidal type (primary formed by an insulated cable of the installation).

The CTs are characterized by the following values (according to standard IEC 60044)(1).

CT rated insulation level
This is the highest voltage applied to the CT primary.
Note that the primary is at the HV voltage level and that one of the secondary terminals is generally earthed.
Similar to other equipment, the following values are defined:
b maximum1 min. withstand voltage at power frequency,
b maximum impulse withstand voltage.
Example. For a 24 kV rated voltage, the CT must withstand 50 kV for 1 minute at 50 Hz and an impulse voltage of 125 kV.

Rated transformation ratio
It is usually given as the transformation ratio between primary and secondary current Ip/Is.
The rated secondary current is generally 5 A or 1 A.

Accuracy
It is defined by the composite error for the accuracy-limit current.
The accuracy-limit factor is the ratio between the accuracy-limit current and the rated current.
b For class P:
5P10 means 5% error for 10 In and 10P15 means 10% error for 15 In,
5P and 10P are the standard accuracy classes for protection CTs,
5 In, 10 In, 15 In, 20 In are the standard accuracy-limit currents.
b The PR class is defined by the remanence factor, the ratio between the remanent flux and the saturation flux, which must be less than 10%.
5PR and 10PR are the standard accuracy classes for protection CTs.
b Class PX is another way of specifying CT characteristics based on the “knee-point voltage”, the secondary resistance and the magnetizing current (see next page, fig. 1, CT response in saturated state).

Rated output
This is the apparent power in VA that the CT is intended to supply to the secondary circuit at the rated secondary current without causing the errors to exceed the values specified.
It represents the power consumed by all the connected devices and cables.
If a CT is loaded at a power lower than its rated output, its actual accuracy level is higher than the rated accuracy level. Likewise, a CT that is overloaded loses accuracy.

Short time withstand current
Expressed in kA rms, the maximum current permissible for 1 second (Ith) (the secondary being short-circuited) represents the thermal withstand of the CT to overcurrents. The CT must be able to withstand the short-circuit current for the time required to clear it. If the clearing time t is other than 1 sec., the current the CT can withstand is $Ith/\sqrt{t}$
Electrodynamic withstand expressed in kA peak is at least equal to **2.5 • Ith**
Normal values of rated primary currents (in A):
10 - 12.5 - 15 - 20 - 25 - 30 - 40 - 50 - 60 - 75 and multiples or decimal submultiples.

---

(1) Also to be taken into account are elements related to the type of assembly, characteristics of the site (e.g. temperature, etc.), power frequency, etc.

CT response in saturated state

When subjected to a very high primary current, the CT becomes saturated.
The secondary current is no longer proportional to the primary current. The current error which corresponds to the magnetization current increases significantly.

Knee-point voltage (fig. 1)
This is the point on the current transformer magnetization curve at which a 10% increase in voltage E requires a 50% increase in magnetization current Im.

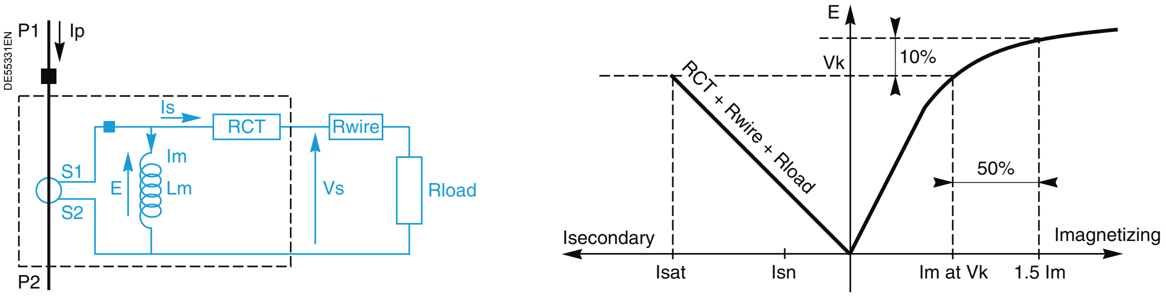


Fig. 1. Equivalent diagram of a CT secondary current...

and CT magnetization curve.

The CT secondary satisfies the equation:
(RCT + Rload + Rwire) • ALF • Isn^2 = constant
where Isn = rated secondary current
ALF = accuracy-limit factor
Isat = ALF • Isn

CT for phase overcurrent protection

For definite-time overcurrent protection, if saturation is not reached at 1.5 times the current setting, operation is ensured no matter how high the fault current (fig. 2).

For IDMT overcurrent protection, saturation must not be reached at 1.5 times the current value corresponding to the maximum in the useful part of the operation curve (fig. 3).

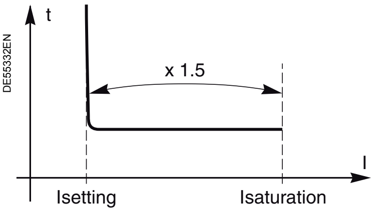


Fig. 2.

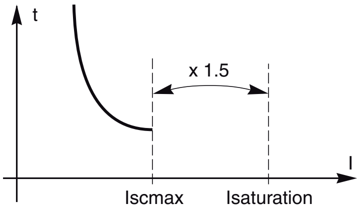


Fig. 3.

CT for differential protection (fig. 4)

The CTs should be specified for each application, according to the operating principle of the protection unit and to the protected component. Refer to the instruction manual of the protection unit.

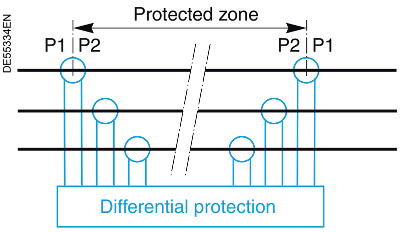


Fig. 4.

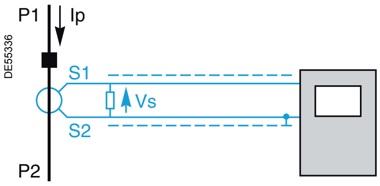


Fig. 1. LPCT-type current sensors.

Low-power current transducers (LPCT) (fig. 1)

These are special voltage-output sensors of the Low-Power Current Transducer (LPCT) type, compliant with standard IEC 60044-8.
LPCTs are used for measurement and protection functions.
They are defined by:

- the rated primary current,
- the rated extended primary current,
- the rated accuracy-limit primary current.

They have a linear output over a wide current range and begin to saturate at levels above the currents to be interrupted.

Example of measurement characteristics as per IEC 60044-8

- Rated primary current Ipn = 100 A
- Rated extended primary current Ipe = 1250 A
- Secondary voltage Vsn = 22.5 mV
- Class 0.5:
  - accuracy 0.5% from 100 A to 1250 A,
  - accuracy 0.75% at 20 A,
  - accuracy 1.5% at 5 A.

Example of protection characteristics as per IEC 60044-8

- Primary current Ipn = 100 A
- Secondary voltage Vsn = 22.5 mV
- Class 5P from 1.25 kA to 40 kA (fig.2).

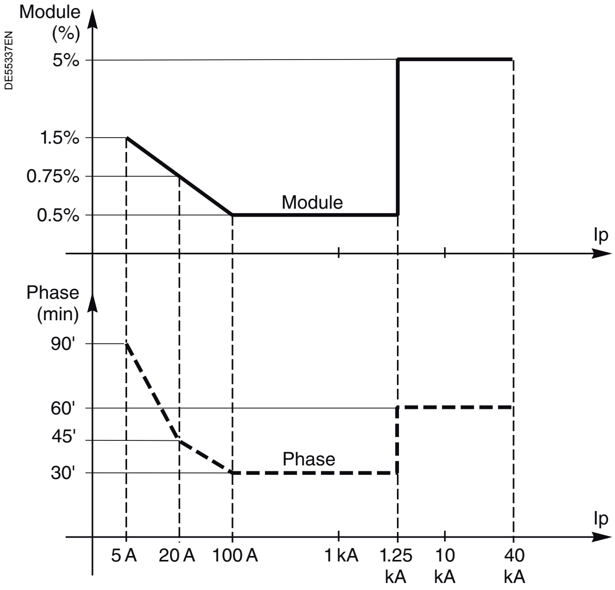


Fig. 2. LPCT accuracy characteristics.

Residual-current sensors

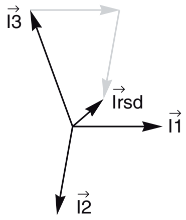


Fig. 1. Definition of residual current.

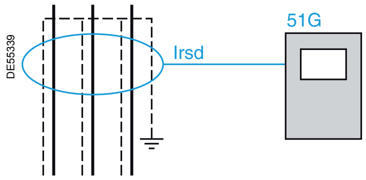
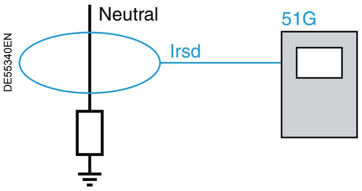
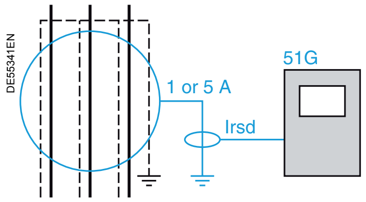
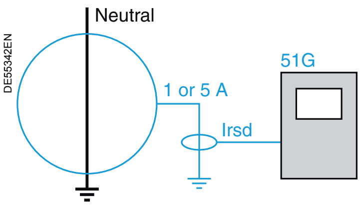
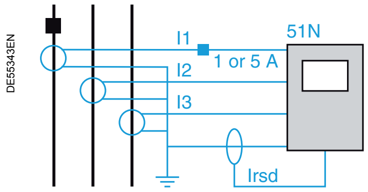
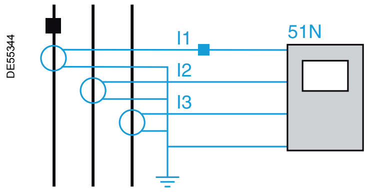
Zero-sequence current - residual current

The residual current characterizing the earth-fault current is equal to the vector sum of the 3 phase currents (fig. 1).
The residual current is equal to three times the zero-sequence current I0.

$$\overrightarrow{Irsd} = 3 \bullet \overrightarrow{I0} = \overrightarrow{I1} + \overrightarrow{I2} + \overrightarrow{I3}$$

Detection of the fault current

Earth-fault current can be detected in a number of ways.

Measurement sensors	Accuracy	Recommended minimum threshold for earth-fault protection	Assembly
Special core balance CT	**+++**	A few amperes	 Direct measurement by special core balance CT connected directly to the protection relay. The CT is installed around the live conductors and directly creates the residual current.  It can also be installed on the accessible neutral to earth link. The result is high measurement accuracy; a very low detection threshold (a few amperes) can be used.
Toroidal CT + interposing ring CT	**++**	10% of InCT (DT) 5% of InCT (IDMT)	 Differential measurement using a classic toroidal CT installed around the live conductors and generating the residual current, plus an interposing ring CT used as an adapter for the protection relay.  The toroidal CT can also be installed on the accessible neutral to earth link with an interposing ring CT. This solution offers good accuracy and flexibility in CT selection.
3 phase CTs + interposing ring CT	**++**	10% of InCT (DT) 5% of InCT (IDMT)	 Measurement of the currents in the three phases with one CT per phase and measurement of the residual current by a special interposing ring CT. Practically speaking, the residual-current threshold must be: b Is0 ≥ 10% InCT (DT protection), b Is0 ≥ 5% InCT (IDMT protection).
3 phase CTs (Irsd calculated by relay)	**+**	No H2 restraint 30% InCT (DT) 10% InCT (IDMT) With H2 restraint 10% InCT (DT) 5% InCT (IDMT)	 Calculation based on measurement of the currents in the three phases with one CT per phase. b The residual current is calculated by the protection relay. b Measurement accuracy is not high (sum of CT errors and saturation characteristics, calculated current). b Installation is easier than in the previous case, but measurement accuracy is lower. Practically speaking, the protection threshold settings must comply with the following rules: b Is0 ≥ 30% InCT for DT protection (10% InCT for a protection relay with H2 restraint), b Is0 ≥ 10% InCT for IDMT protection.

Voltage transformers (VT)

The role of a voltage transformer is to provide its secondary winding with a voltage proportional to that applied to the primary circuit. Voltage transformers are used for both measurements and protection.

Measurement of phase-to-phase voltages

The voltage transformer is made up of two windings, the primary and the secondary, coupled by a magnetic circuit, and connections can be made between phases or between a phase and earth.

Voltage transformers are characterized by the following values:
(publications IEC 60186, IEC 60044-2 and NFC 42-501) (1)
b power frequency, generally 50 or 60 Hz,
b highest primary voltage in the power system,
b rated secondary voltage 100, 100/3 , 110, 110/3 volts depending on the type of connection,
b rated voltage factor used to define the heat-rise characteristics,
b apparent power, in VA, that the voltage transformer can supply to the secondary, without causing errors exceeding its accuracy class, when connected to the rated primary voltage and to its rated load. Note that a VT must never be short-circuited on the secondary, because the power supplied increases and the transformer can be damaged by the resulting heat rise,
b accuracy class defining the guaranteed error limits for the voltage ratio and phase-displacement under the specified power and voltage conditions.

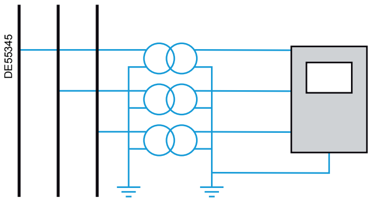


Fig. 1. Star-connected voltage transformers (VT).

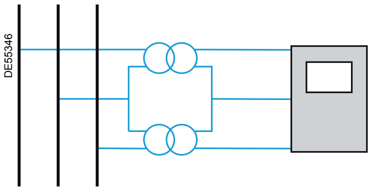


Fig. 2. V-connected voltage transformers (VT).

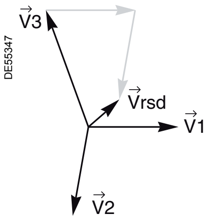


Fig. 3. Definition of residual voltage.

A number of measurement assemblies are possible:
b 3-transformer star assembly (fig. 1)
(requires 1 insulated high-voltage terminal per transformer)

Transformation ratio: $\frac{Un/\sqrt{3}}{100/\sqrt{3}}$ for example

b 2-transformer “V” assembly, (fig. 2)
(requires 2 insulated high-voltage terminals per transformer)
Transformation ratio: $Un/100$ for example

In isolated neutral systems, all phase-neutral VTs sufficiently loaded to avoid the risk of ferromagnetic resonance.

(1) Elements related to the type of assembly, characteristics of the site (e.g. temperature), etc. must also be taken into account.

Measurement of residual voltage

The residual voltage characterizing the neutral-point voltage with respect to earth is equal to the vector sum of the 3 phase-to-earth voltages.
The residual voltage is equal to three times the zero-sequence voltage V0:

$\overrightarrow{Vrsd} = 3 \bullet \overrightarrow{V0} = \overrightarrow{V1} + \overrightarrow{V2} + \overrightarrow{V3}$ (fig. 3)

The occurrence of this voltage signals the existence of an earth fault.
It can be measured or calculated:
b measurement using three voltage transformers whose primaries are star connected and the secondaries, in an open delta arrangement, supply the residual voltage (fig. 4),
b calculation by the relay, using three voltage transformers whose primaries and secondaries are star connected (fig. 5).

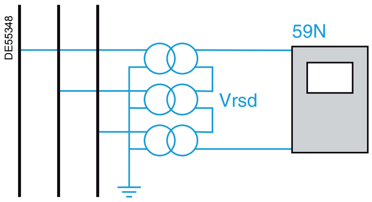


Fig. 4. Direct measurement of residual voltage.

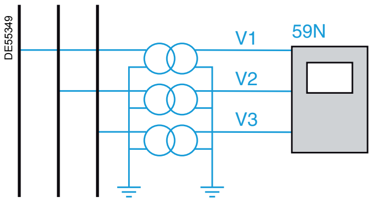


Fig. 5. Calculation of residual voltage.

General characteristics

The protection relays that continuously monitor power system variables include combinations of basic functions to suit the power system components being monitored.

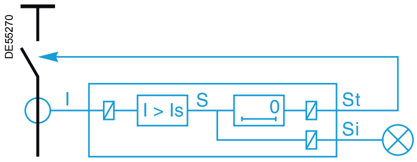


Fig. 1. Relay operating principle.
(example of ANSI 51 phase overcurrent protection relay)

Operation

The relay includes (fig. 1):

- analog measurement input for the variable observed, received from the sensor,
- logic result of measurement processing (noted S),
- instantaneous logic output of the protection function, used for indication, for example (noted Si),
- delayed logic output of the protection function, used to control circuit breaker tripping (noted St).

Characteristics (fig. 2)

The protection function work mode involves characteristic times (IEC 60255-3):

- operating time: this is the time between the application of the characteristic quantity (at twice the threshold setting) and the switching of the output relay (instantaneous output),
- overshoot time: this is the difference between operating time and the maximum time during which the characteristic quantity can be applied with no tripping,
- reset time: this is the time between a sudden decrease in the characteristic quantity and the switching of the output relay.

Note: *other non-standardized terms are commonly found as well, the definitions of which may vary from one manufacturer to another: reclaim time, no response time, instantaneous tripping time, memory time.*

To improve stability, the functions have a drop out/pick up ratio d that is a % of the threshold setting: in the example in figure 3, S goes from 1 to 0 when I = d • Is

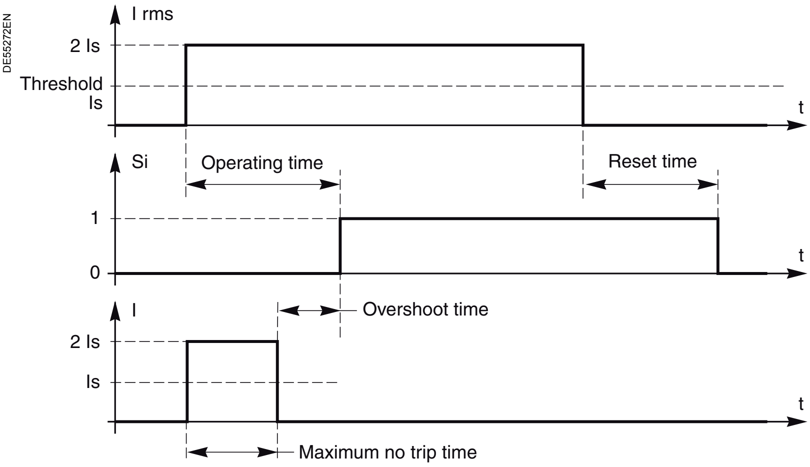


Fig. 2. Protection function characteristic times.

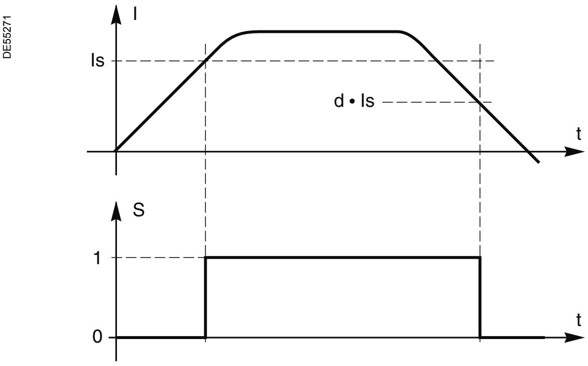


Fig. 3. Drop out/pick up ratio.

Settings

Some protection functions may be set by the user, in particular:
b **tripping set point:** it sets the limit of the observed quantity that actuates the protection function.
b **tripping time:**
v definite time delay (DT)
The example in figure 1, applied to a current relay, shows that above the current threshold Is, the protection tripping time is constant (time delay setting T).

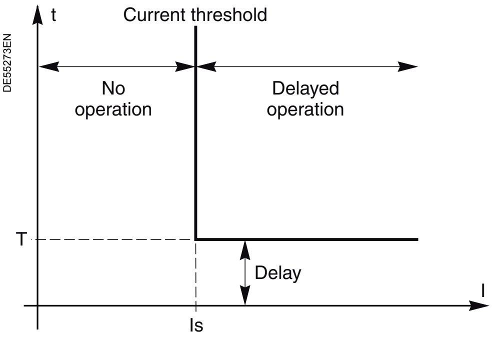


Fig. 1. Definite time tripping principle.

v IDMT delay (IDMT: Inverse Definite Minimum Time)
The example in figure 2, applied to a current relay, shows that above the current threshold Is, the higher the current, the shorter the protection tripping time.

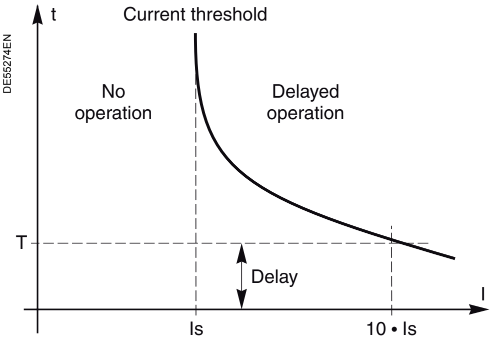


Fig. 2. IDMT tripping principle.

There are several types of curves, determined by equations and defined by the various standardization organizations: for example, the IEC defines the following (fig. 3):
- standard inverse time (SIT),
- very inverse time (VIT),
- extremely inverse time (EIT).

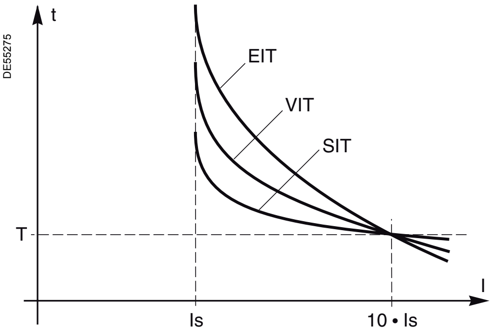


Fig. 3. IDMT tripping curves.

b **timer hold:** adjustable reset time,
b **restraint:** inhibition of tripping according to percentage of second harmonic,
b **time constants** (e.g. thermal overload ANSI 49RMS),
b **characteristic angle** (e.g. directional overcurrent ANSI 67).

List of functions

The main protection functions are listed with a brief definition in the table below.
They are listed in numerical order by ANSI C37.2 code.

ANSI code	Name of function	Definition
12	Overspeed	Detection of rotating machine overspeed
14	Underspeed	Detection of rotating machine underspeed
21	Distance protection	Impedance measurement detection
21B	Underimpedance	Back-up phase-to-phase short-circuit protection for generators
24	Flux control	Overfluxing check
25	Synchro-check	Check before paralleling two parts of the power system
26	Thermostat	Protection against overloads
27	Undervoltage	Protection for control of voltage sags
27D	Positive sequence undervoltage	Protection of motors against operation with insufficient voltage
27R	Remanent undervoltage	Check on the disappearance of voltage sustained by rotating machines after the power supply is disconnected
27TN	Third harmonic undervoltage	Detection of stator winding insulation earth faults (impedant neutral)
32P	Directional active overpower	Protection against active overpower transfer
32Q	Directional reactive overpower	Protection against reactive overpower transfer
37	Phase undercurrent	3-phase protection against undercurrent
37P	Directional active underpower	Protection against active underpower transfer
37Q	Directional reactive underpower	Protection against reactive underpower transfer
38	Bearing temperature monitoring	Protection against overheating of rotating machine bearings
40	Field loss	Protection of synchronous machines against faults or field loss
46	Negative sequence / unbalance	Protection against unbalanced phase current
47	Negative sequence overvoltage	Negative sequence voltage protection and detection of reverse rotation of rotating machines
48 - 51LR	Excessive starting time and locked rotor	Protection of motors against starting with overloads or reduced voltage, and for loads that can block
49	Thermal overload	Protection against overloads
49T	RTDs	Protection against overheating of machine windings
50	Instantaneous phase overcurrent	3-phase protection against short-circuits
50BF	Breaker failure	Checking and protection if the circuit breaker fails to trip after a tripping order
50N or 50G	Instantaneous earth fault	Protection against earth faults: 50N: residual current calculated or measured by 3 CTs 50G: residual current measured directly by a single sensor (CT or core balance CT)
50V	Instantaneous voltage-restrained phase overcurrent	3-phase protection against short-circuits with voltage-dependent threshold
50/27	Inadvertent generator energization	Detection of inadvertent generator energization
51	Delayed phase overcurrent	3-phase protection against overloads and short-circuits
51N or 51G	Delayed earth fault	Protection against earth faults: 51N: residual current calculated or measured by 3 CTs 51G: residual current measured directly by a single sensor (CT or core balance CT)
51V	Delayed voltage-restrained phase overcurrent	3-phase protection against short-circuits with voltage-dependent threshold
59	Overvoltage	Protection against excessive voltage or sufficient voltage detection
59N	Neutral voltage displacement	Insulation fault protection
63	Pressure	Detection of transformer internal faults (gas, pressure)
64REF	Restricted earth fault differential	Earth fault protection for star-connected 3-phase windings with earthed neutral
64G	100% generator stator earth fault	Detection of stator winding insulation earth faults (impedant neutral power systems)
66	Successive starts	Protection function that monitors the number of motor starts
67	Directional phase overcurrent	3-phase short-circuit protection according to current flow direction
67N/67NC	Directional earth fault	Earth fault protection depending on current flow direction (NC: Neutral compensated)
78	Vector shift	Vector shift disconnection protection
78PS	Pole slip	Detection of loss of synchronization of synchronous machines
79	Recloser	Automated device that recloses the circuit breaker after transient line fault tripping
81H	Overfrequency	Protection against abnormally high frequency
81L	Underfrequency	Protection against abnormally low frequency
81R	Rate of change of frequency (ROCOF)	Protection for fast disconnection of two parts of the power system
87B	Busbar differential	3-phase protection against busbar internal faults
87G	Generator differential	3-phase protection against internal faults in AC generators
87L	Line differential	3-phase protection against line internal faults
87M	Motor differential	3-phase protection against internal faults in motors
87T	Transformer differential	3-phase protection against internal faults in transformers

Associated functions

The protection functions are completed by the following:

- *additional control functions,*
- *operation monitoring functions,*
- *operation functions,*
- *indication functions,*
- *metering functions,*
- *diagnosis functions,*
- *communication functions,*

for enhanced operation of power systems. All of these functions may be provided by the same digital protection unit.

Switchgear control

This function controls the different types of switchgear closing and tripping coils.

Trip circuit supervision

This function indicates switchgear trip circuit failures.

Control logic

This function is used to implement logic discrimination by the sending and/or reception of “blocking signals” by different protection units.

Logic functions

These functions perform logic equation operations to generate additional data or orders used for the application.

Operation functions

These functions make operation more convenient for the user.

- Transformer on-load tap changers,
- Reactive energy regulation,
- Fault locator (ANSI 21FL),
- Capacitor bank control,
- Remaining operating time before thermal overload tripping.

Metering functions

These functions provide information required for a good understanding of power system operation.

- Phase current,
- Tripping current,
- Residual current,
- Differential and through currents,
- Current THD (total harmonic distortion),
- Phase-to-neutral and phase-to-phase voltages,
- positive sequence, negative sequence and residual voltages,
- Voltage THD (total harmonic distortion),
- Frequency,
- Active, reactive and apparent power,
- Power factor ($\cos \varphi$),
- Active and reactive energy,
- Peak demand current, active and reactive power,
- Temperature,
- Motor starting time,
- Disturbance recording.

Switchgear diagnosis functions

- Switchgear closing and fault tripping operation counters,
- Operation time,
- Charging time,
- Sensor supervision (VT, CT); this function monitors the voltage or current transformer measurement chain and acts on the related protection functions,
- Cumulative breaking current (kA^2).

Communication functions

These functions are used for the exchange of available data by the different power system components (measurements, states, control orders…).

Time-based discrimination

Protection functions form a consistent system depending on the overall structure of the power distribution system and the neutral earthing arrangement. They should therefore be viewed as a system based on the principle of discrimination, which consists of isolating the faulty part of the power system and only that part as quickly as possible, leaving all the fault-free parts of the power system energized.

Various means can be used to implement discrimination in power system protection:
b time-based discrimination,
b current-based discrimination,
b discrimination by data exchange, referred to as logic discrimination,
b discrimination by the use of directional protection functions,
b discrimination by the use of differential protection functions,
b combined discrimination to ensure better overall performance (technical and economic), or back-up.

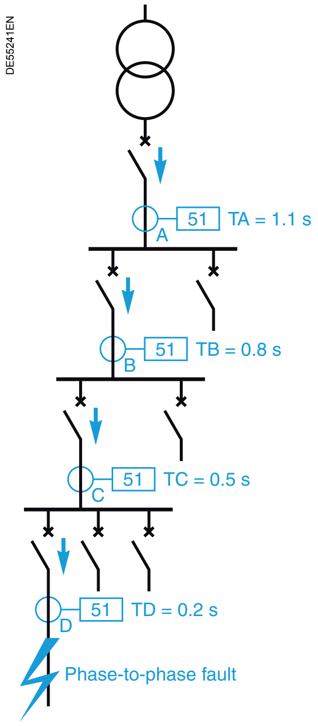


Fig. 1. Time-based discrimination principle.

Principle

Time-based discrimination consists of assigning different time delays to the overcurrent protection units distributed through the power system.
The closer the relay is to the source, the longer the time delay.

Operating mode

The fault shown in the diagram opposite (fig. 1) is detected by all the protection units (at A, B, C, and D). The contacts of delayed protection unit D close faster than those of protection unit C, which themselves close faster than those of protection unit B…
Once circuit breaker D tripped and the fault current has been cleared, protection units A, B and C, which are no longer required, return to the stand-by position.
The difference in operation time ΔT between two successive protection units is the discrimination interval. It takes into account (fig. 2):
b breaking time Tc of the downstream circuit breaker, which includes the breaker response time and the arcing time,
b time delay tolerances dT,
b upstream protection unit overshoot time: tr,
b a safety margin m.

ΔT should therefore satisfy the relation:
$\Delta T \geq Tc + tr + 2dT + m$

Considering present switchgear and relay performances, ΔT is assigned a value of 0.3 s.

Example: Tc = 95 ms, dT = 25 ms, tr = 55 ms; for a 300 ms discrimination interval, the safety margin is 100 ms.

Fig. 2. Breakdown of a discrimination interval.

Advantages

This discrimination system has two advantages:
b it provides its own back-up; for example if protection unit D fails, protection unit C is activated ΔT later,
b it is simple.

Drawbacks

However, when there are a large number of cascading relays, since the protection unit located the furthest upstream has the longest time delay, the fault clearing time becomes prohibitive and incompatible with equipment short-circuit current withstand and external operating necessities (e.g. constraint imposed by utility).

Time-based discrimination

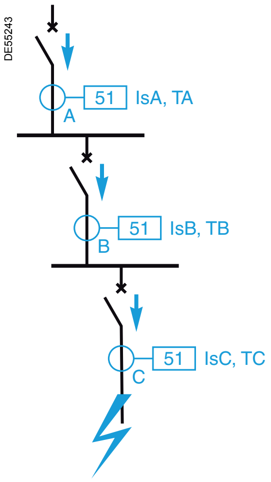


Fig. 1. Radial power system with time-based discrimination.

Application

This principle is used in radial power systems. (fig. 1)

The time delays set for time-based discrimination are activated when the current exceeds the relay settings. The settings must be consistent.
There are two cases, according to the type of time delay used.

Definite time relays (fig. 2)
The conditions to be fulfilled are: IsA > IsB > IsC et TA > TB > TC.
The discrimination interval ∆T is conventionally in the range of 0.3 seconds.

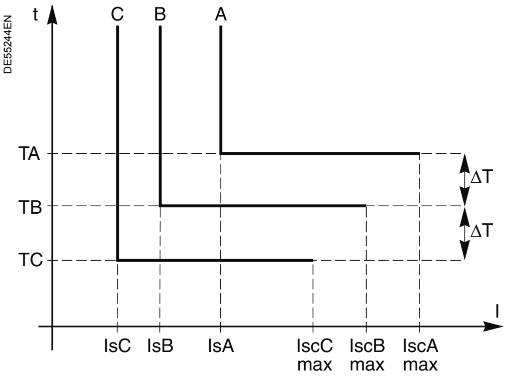


Fig. 2. Time-based discrimination with definite time relays.

IDMT relays (fig. 3)
If the thresholds are set to the rated current In, overload protection is ensured at the same time as short-circuit protection and setting consistency is guaranteed.
InA > InB > InC
IsA = InA, IsB = InB, and IsC = InC
The time delays are set to obtain the discrimination interval ∆T for the maximum current seen by the downstream protection relay. The same family of curves is used to avoid overlapping in a portion of the domain.

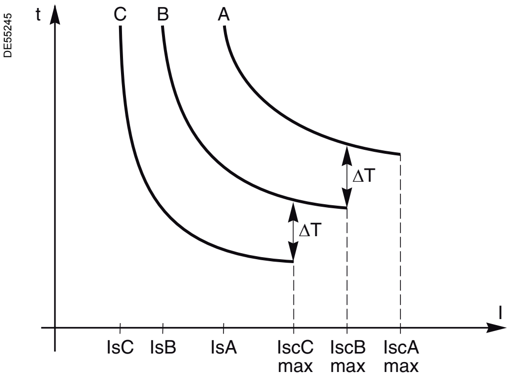


Fig. 3. Time-based discrimination with IDMT relays.

Current-based discrimination

Principle

Current-based discrimination uses the principle that within a power system, the further the fault is from the source, the weaker the fault current is.

Operating mode

A current protection unit is installed at the starting point of each section: the threshold is set to a value lower than the minimum short-circuit current caused by a fault in the monitored section, and higher than the maximum current caused by a fault downstream (outside the monitored area).

Advantages

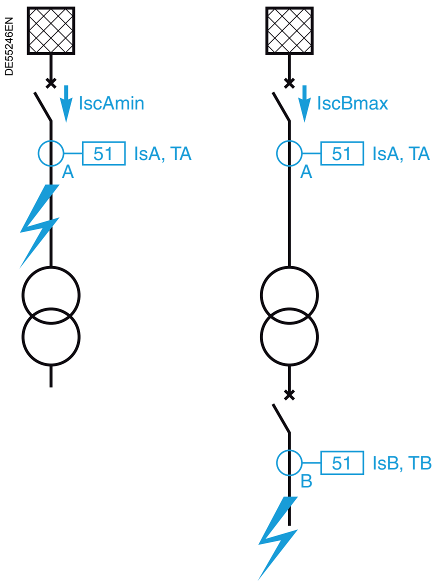
With these settings, each protection device is only activated by faults located immediately downstream, within the monitored zone, and is not sensitive to faults outside that zone.
For sections of lines separated by a transformer, it can be of benefit to use this system since it is simple, cost-effective and quick (tripping with no delay).
An example is given below (fig.1):
IscBmax < IsA < IscAmin
IsA = current setting
IscB on the transformer primary is proportional to the maximum short-circuit current on the secondary.
Time delays TA and TB are independent, and TA may be shorter than TB.

Drawbacks

The upstream protection unit (A) does not provide back-up for the downstream protection unit (B).
In practice, it is difficult to define the settings for two cascading protection units, and still ensure satisfactory discrimination, when there is no notable decrease in current between two adjacent areas. This is the case in medium voltage power systems, except for sections with transformers.

Application

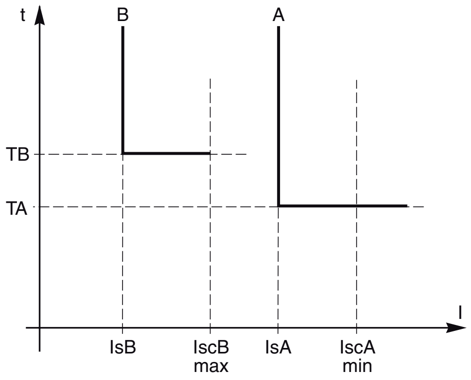
The following example concerns current protection of a transformer between two cable sections.
The overcurrent protection setting Is satisfies the relation:
1.25 IscBmax < IsA < 0.8 IscAmin
Discrimination between the two protection units is ensured.



Condition
IsA < IscAmin

Condition
IsA > IscBmax

Fig. 1. Current-based discrimination operation.



Discrimination curves

Logic discrimination

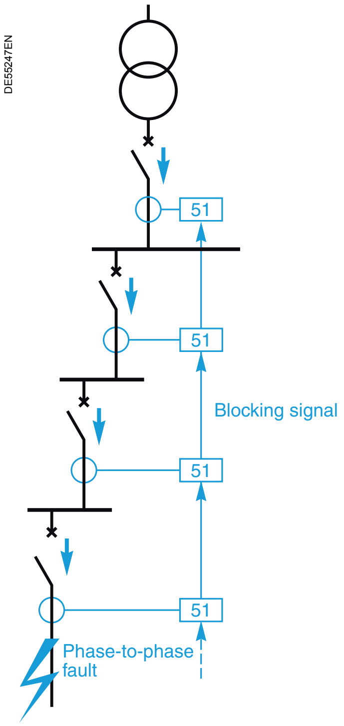


Fig. 1. Logic discrimination principle.

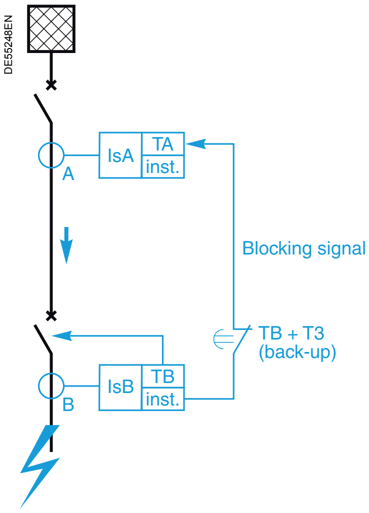


Fig. 2. Logic discrimination operation.

Principle

This system was developed to solve the drawbacks of time-based discrimination.
This principle is used when short fault clearing time is required (fig. 1).

Operating mode

The exchange of logic data between successive protection units eliminates the need for discrimination intervals, and thereby considerably reduces the tripping time of the circuit breakers closest to the source.
In radial power systems, the protection units located upstream from the fault are activated; those downstream are not. The fault point and the circuit breaker to be tripped can therefore be clearly located.
Each protection unit activated by a fault sends:

- a blocking signal to the upstream level (an order to increase the upstream relay time delay),
- a tripping order to the related circuit breaker unless it has already received a blocking signal from the downstream level.

Time-delayed tripping is provided as back-up.

The principle is illustrated in figure 2:

- when a fault appears downstream from B, the protection unit at B blocks the protection unit at A,
- only the protection unit at B triggers tripping after the delay TB, provided it has not received a blocking signal,
- the duration of the blocking signal for the protection unit at A is limited to TB + T3, with T3 ≥ opening and arc extinction time of circuit breaker B (typically 200 ms),
- if circuit breaker B fails to trip, protection unit A gives a tripping order at TB + T3,
- when a fault appears between A and B, protection unit A trips after the delay TA.

Advantages

Tripping time is not related to the location of the fault within the discrimination chain or to the number of protection units in the chain.
This means that discrimination is possible between an upstream protection unit with a short time delay and a downstream unit with a long time delay. For example, a shorter time delay may be used at the source than near the loads.
The system also has back-up designed into it.

Drawbacks

Since logic signals must be transmitted between the different levels of protection units, extra wiring must be installed. This can be a considerable constraint when the protection units are far apart each other, in the case of long links, for example (several hundreds of meters long).
This difficulty may be bypassed by combining functions: logic discrimination in the nearby switchboards and time-based discrimination between zones that are far apart (refer to chapter on combined logic + time-based discrimination).

Application

This principle is often used to protect medium voltage power systems that include radial branches with several levels of discrimination.

Directional protection discrimination

Principle

In a looped power system, in which faults are fed from both ends, it is necessary to use a protection unit that is sensitive to the direction of the flow of fault current in order to locate and clear the fault selectively. This is the role of directional overcurrent protection units.

Operating mode

The protection actions differ according to the direction of the current (figs. 1 and 2), i.e. according to the phase displacement of the current in relation to a reference given by the voltage vector; the relay therefore needs both current and voltage data.
The operating conditions, namely the position of the tripping and no tripping zones, are adapted to fit the power system to be protected (fig. 3).

Example of the use of directional protection units (fig. 4):
Circuit breakers D1 and D2 are equipped with directional protection units that are activated if the current flows from the busbars to the cable.
If a fault occurs at point **1**, it is only detected by the protection unit at D1.
The protection unit at D2 does not detect it, because of the detected current direction.
The D1 circuit breaker trips.
If a fault occurs at point **2**, it is not detected by these protection units and the D1 and D2 circuit breakers remain closed.
Other protection units must be included to protect the busbars.

Advantage

The solution is simple and may be used in a large number of cases.

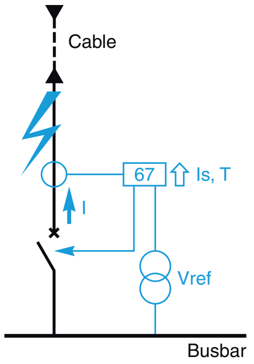
Drawback

Voltage transformers must be used to provide a phase reference to determine the direction of the current.

Application

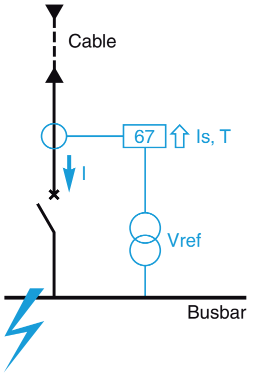
This principle is used to protect parallel incomers and closed loop power systems and also for certain cases of earth fault protection.

DE55249EN



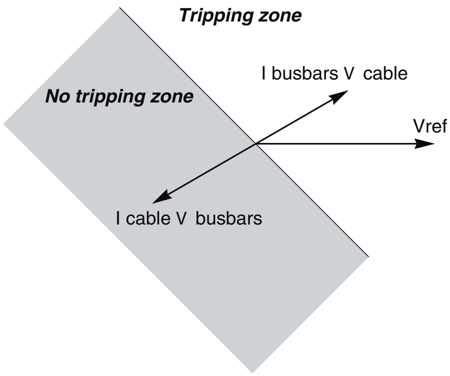
Directional protection principle
Fig. 1. Protection unit active.

DE55250EN



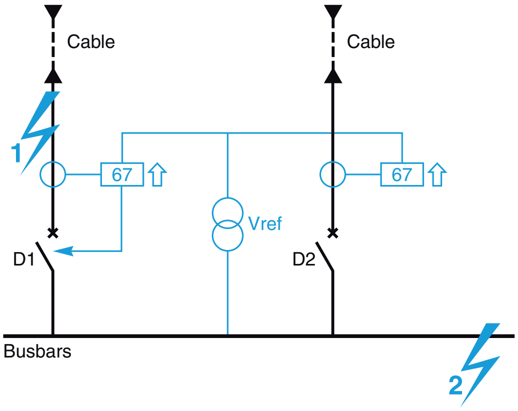
Directional protection principle
Fig. 2. Protection unit not active.

DE55251EN



Directional protection principle
Fig. 3. Detection of current direction.

DE55252EN



Directional protection
Fig. 4. Example of two parallel incomers.

Differential protection discrimination

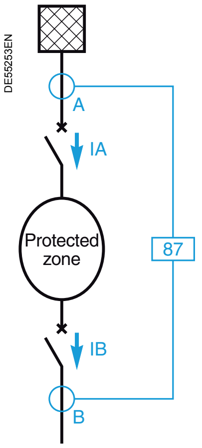


Fig. 1. Differential protection principle.

Principle

These protection units compare the current at the two ends of the monitored section of the power system (fig. 1).

Operating mode

Any amplitude or phase difference between the currents indicates the presence of a fault: The protection units only react to faults within the area they cover and are insensitive to any faults outside that area. This type of protection is therefore selective by nature.
Instantaneous tripping takes place when IA-IB ≠ 0
In order for differential protection to work, it is necessary to use current transformers specifically sized to make the protection units insensitive to other phenomena.

What makes differential protection units stable is that they do not pick up as long as there are no faults in the zone being protected, even if a differential current is detected:

- transformer magnetizing current,
- line capacitive current,
- error current due to saturation of the current sensors.

There are two main principles according to the stabilization mode:

- high impedance differential protection: the relay is series-connected to a stabilization resistor Rs in the differential circuit (figs. 2 and 3),
- percentage-based differential protection: the relay is connected independently to the circuits carrying the currents IA and IB. The difference between the currents IA and IB is determined in the protection unit and the protection stability is obtained by a restraint related to the through current (figs. 4 and 5).

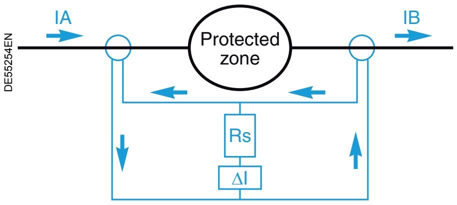


Fig. 2. High impedance differential protection diagram.

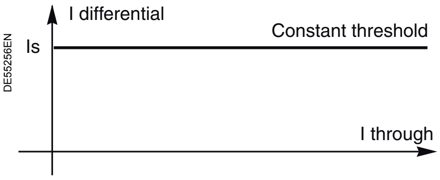


Fig. 3. Stability by resistance.

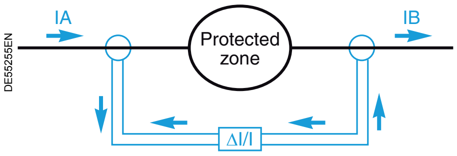


Fig. 4. Percentage-based differential protection diagram.

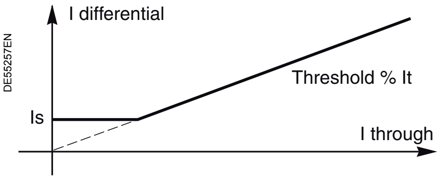


Fig. 5. Stability by restraint.

Advantages

- Protection sensitive to fault current less than the rated current of the protected equipment.
- Zone protection that can trip instantaneously.

Drawbacks

- The cost of the installation is high.
- It takes skill to implement the system.
- An overcurrent back-up function needs to be included.

Comparison of the two principles

- High impedance differential protection:
  - the upstream and downstream CTs must have the same rated currents (primary and secondary),
  - the resistance of the stabilization resistor is chosen to avoid tripping by external faults with a saturated CT and to allow the relay to be supplied by the CT,
  - The relay is relatively simple, but requires the use of stabilization resistors.
- Percentage-based differential protection:
  - can be adapted to fit the equipment to be protected,
  - the relay is relatively more complicated, but is easy to use.

Application

Differential protection may concern all priority high power components: motors, generators, transformers, busbars, cables and lines.

Combined discrimination

Combined discrimination is a combination of basic discrimination functions that provides additional advantages in comparison to individual types of discrimination.
b total discrimination,
b redundancy or back-up.

Several practical examples of applications using combined discrimination are given below:
b current-based + time-based,
b logic + time-based,
b time-based + directional,
b logic + directional,
b differential + time-based.

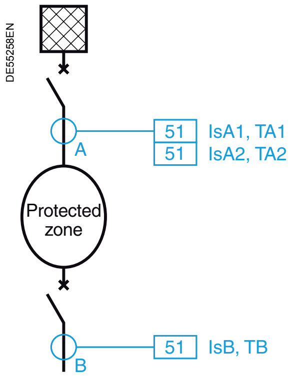
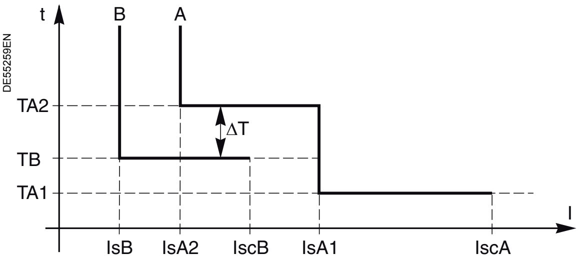


Fig. 1. Current-based + time-based discrimination.

Current-based + time-based discrimination

The example shows an arrangement with both of the following:
b current-based discrimination between A1 and B,
b time-based discrimination between A2 and B.
This provides total discrimination, and the protection unit at A provides back-up for the protection unit at B.



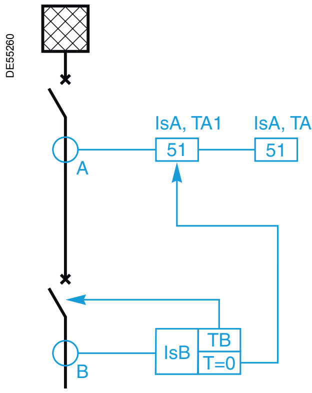
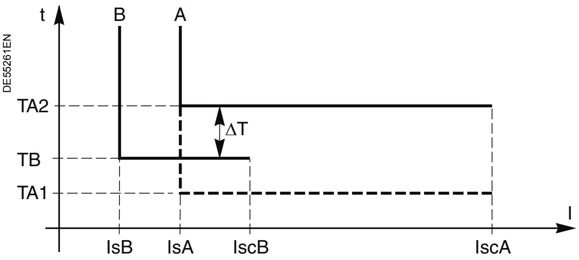


Fig. 2. Logic + back-up time-based discrimination.

Logic + back-up time-based discrimination

The example shows an arrangement with both of the following:
b logic discrimination between A1 and B,
b time-based discrimination between A2 and B.
The A2 protection unit provides back-up for the A1 protection unit, if A1 fails to trip due to a blocking signal fault (permanent blocking signal).



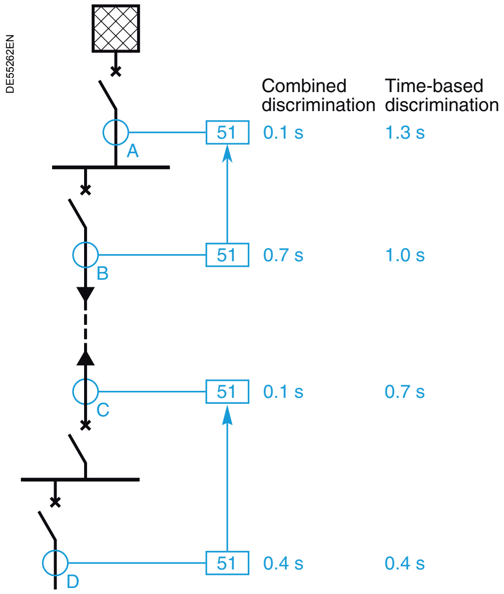


Fig. 3. Comparison of combined (logic + time-based) discrimination and time-based discrimination tripping times.

Logic + time-based discrimination

The example shows an arrangement with both of the following:
b logic discrimination inside a switchboard
(between A and B and between C and D).
b time-based discrimination between two switchboards B and D, with TB = TD + ΔT.
It is not necessary to install a logic signal transmission link between two switchboards that are far apart. The tripping delays are shorter than with time-based discrimination alone (fig. 3).
b back-up time-based discrimination needs to be included at points A and C (refer to the paragraph above).

Combined discrimination

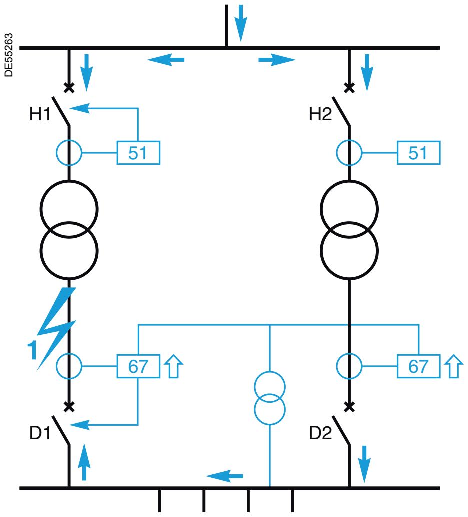


Fig. 1. Time-based + directional discrimination.

Time-based + directional discrimination

D1 and D2 are equipped with short time-delayed directional protection units;
H1 and H2 are equipped with time-delayed overcurrent protection units.
If a fault occurs at point 1, it is only detected by the D1 (directional), H1 and H2 protection units. The protection unit at D2 does not detect it, because of the detected current direction. D1 trips. The H2 protection unit drops out, H1 trips and the faulty section H1-D1 is isolated.

TH1 = TH2
TD1 = TD2
TH = TD + □T

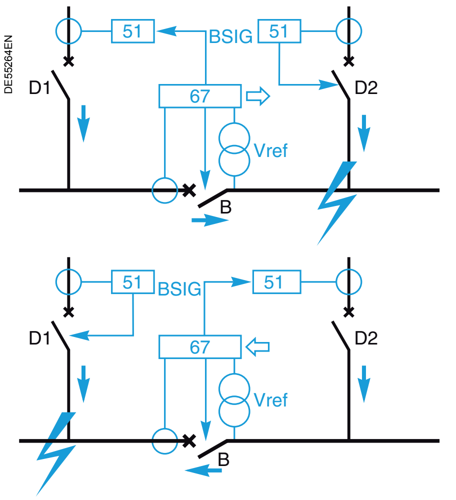


Fig. 2. Logic + directional discrimination.

Logic + directional discrimination

The example shows that the orientation of blocking signals depends on the direction of the current flow.
This principle is used for busbar coupling and closed loops.

Fault at D2 end:
b tripping at D2 and B,
b D1 is blocked by B (BSIG: blocking signal).

Fault at D1 end:
b tripping at D1 and B,
b D2 is blocked by B (BSIG: blocking signal).

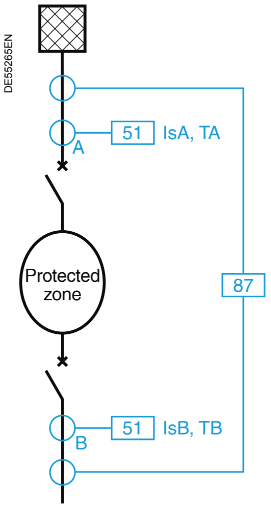


Fig. 3. Differential + time-based discrimination.

Differential + time-based discrimination

The example shows an arrangement with both of the following:
b instantaneous differential protection,
b a phase overcurrent or earth fault protection unit at A as back-up for the differential protection unit,
b a current protection unit at B to protect the downstream zone,
b time-based discrimination between the protection units at A and B, with TA = TB + □T.

This provides back-up for the differential protection function, but double-wound current transformers are sometimes necessary.

Note: time-based discrimination may be replaced by logic discrimination.

Single-incomer power systems

Power-system protection should:
b detect faults,
b isolate the faulty parts of the power system, keeping the fault-free parts in operation.
Protection units are chosen according to the power-system configuration (parallel operation of generators or transformers, loop or radial power system, neutral earthing arrangement…).
Consideration must be given to:
b phase-to-phase fault protection,
b earth fault protection, linked to the neutral earthing arrangement.
The following types of systems will be examined: single-incomer, dual-incomer, open loops and closed loops.

Phase-to-phase faults (fig. 1)

The incomer and feeders are equipped with phase overcurrent protection units (ANSI 51).
Time-based discrimination is used between the incomer protection unit (A) and the feeder protection units (D).

The protection unit at D detects fault **1** on the feeder and trips circuit breaker D after a delay TD.
The protection unit at A detects fault **2** on the busbars and trips after a delay TA.
It also acts as back-up should protection D fail.
Choose: IsA ≥ IsD and TA ≥ TD + ΔT
ΔT: discrimination interval (generally 0.3 s).
The protection unit at D must be selective in relation to the downstream protection units: if the delay required for protection A is too long, logic or combined (logic + time-based) discrimination should be used.

Phase-to-earth faults

Resistance earthing on the transformer (fig.2)
Earth fault protection units (ANSI 51N) are installed on the feeders, incomer and neutral earthing connection.
Time-based discrimination is used between the different protection units.
These units are necessarily different from phase fault protection units since the fault currents are in a different range.

The feeder protection units are set selectively in relation to the incomer protection unit, which is itself set selectively in relation to the neutral earthing protection unit (in accordance with discrimination intervals).
The fault current flows through the capacitances of the fault-free feeders and the earthing resistance.
All the fault-free feeder sensors detect capacitive current.
To prevent inadvertent tripping, the protection unit on each feeder is set higher than the feeder's capacitive current.
b fault at **3**: the D1 circuit breaker is tripped by the protection unit linked to it,
b fault at **4**: the A circuit breaker is tripped by the incomer protection unit,
b fault at **5**: the protection unit on the neutral earthing connection trips circuit breaker H on the transformer primary circuit. (fig. 1).

The protection unit at D must be selective in relation to the downstream protection units: if the delay required for protection A is too long, logic discrimination should be used.
The neutral earthing protection unit at H acts as back-up should the incomer protection unit at A fail to trip.
The incomer protection unit at A acts as back-up should a feeder protection unit at D fail to trip.

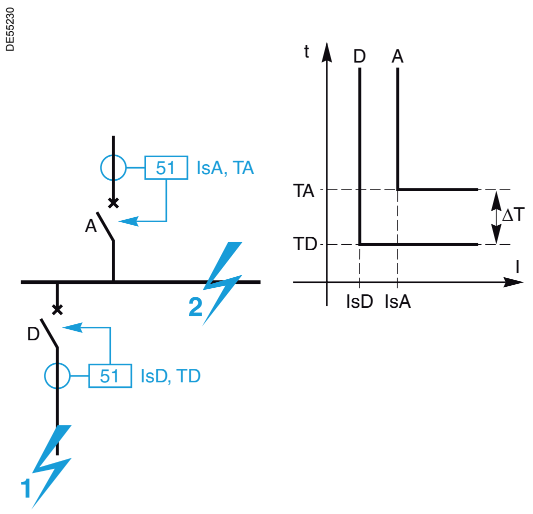


Fig. 1. Phase-to-phase fault protection.

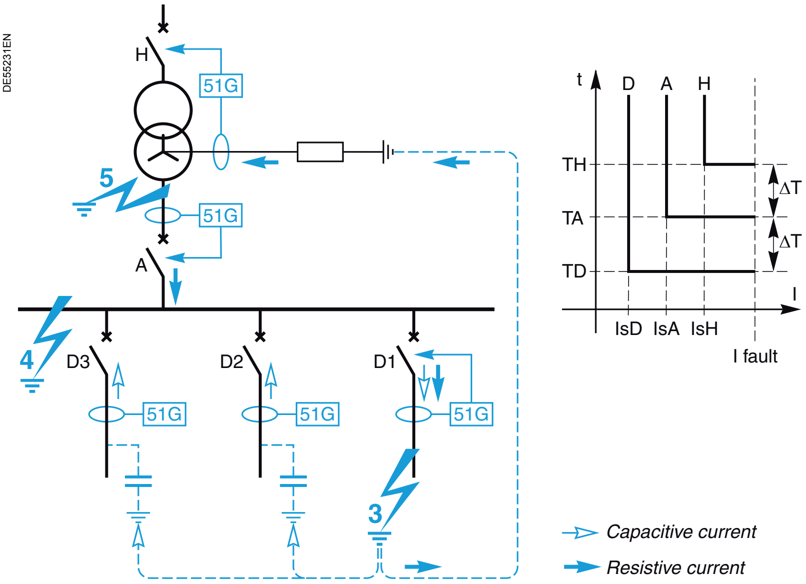


Fig. 2. Phase-to-earth fault protection (resistance-earthed neutral at transformer).

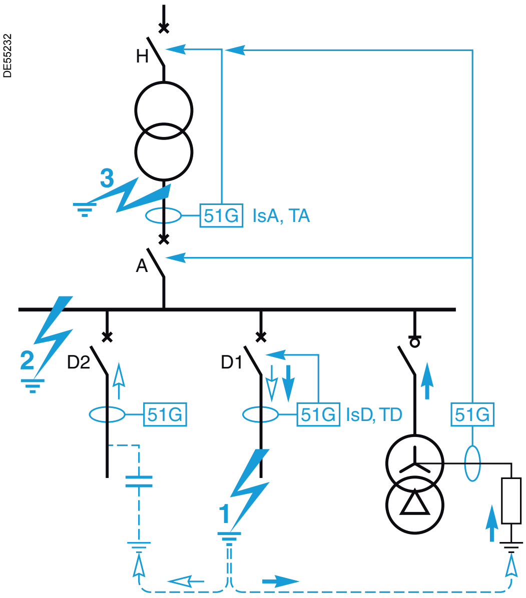


Fig. 1. Phase-to-earth fault protection (resistance-earthed neutral at busbars).

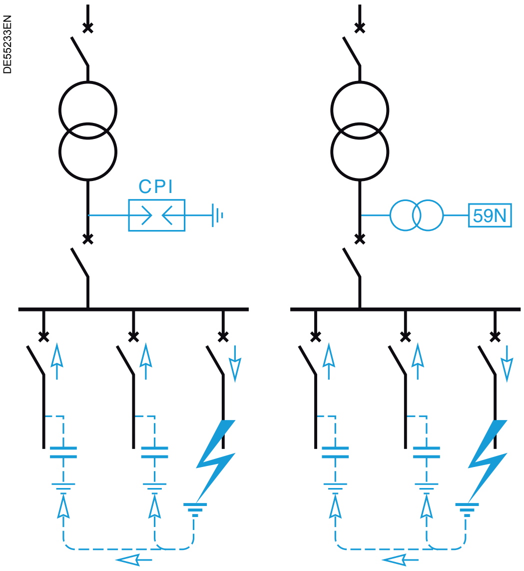


Fig. 2. Phase-to-earth fault protection (isolated neutral).

Phase-to-earth faults (cont'd)

Resistance-earthed neutral at busbars (fig. 1)
A zero sequence generator is used for resistance-earthing.
Earth fault protection units (ANSI 51G) are installed on the feeders, incomer and zero sequence generator.
Time-based discrimination is used between the different protection units.
The feeder protection units and incomer protection unit are set selectively in relation to the earthing impedance protection unit. As in the previous case, the protection unit on each feeder is set higher than the feeder's capacitive current.
In the event of a fault on feeder 1, only the D1 feeder circuit breaker trips.
In the event of fault on the busbars 2, only the protection unit on the earthing connection detects the fault. It trips circuit breaker A.
In the event of fault on the transformer secondary circuit 3, the incomer protection units detects the fault. It trips circuit breaker H.
Note: when circuit breaker A is open, the transformer secondary circuit neutral is isolated. It may be necessary to protect it by a neutral voltage displacement measurement (ANSI 59N).

The zero sequence generator protection unit acts as back-up should the incomer protection unit at A or a feeder protection unit at D fail to trip.
If the condition IsD > 1.3 Ic cannot be satisfied for a feeder, a directional earth fault protection unit may be used to discriminate between fault current and capacitive current.

Reactance-earthed neutral
The same procedure is used as for resistance-earthing at the transformer or busbars.

Isolated neutral (fig. 2)
A fault, regardless of its location, produces current which flows through the capacitance of the fault-free feeders.
In industrial power systems, this current is generally weak (a few amperes), allowing operations to carry on while the fault is being tracked.
Time-based discrimination is used between the different protection units.
The fault is detected by an insulation monitoring device or a neutral voltage displacement protection unit (ANSI 59N).
When the total capacitive current of a power system is high (in the range of ten amperes), additional measures must be taken to quickly clear the fault.
Directional earth fault protection can be used to selectively trip the fault feeder.

Solidly earthed neutral
This is similar to resistance-earthing at the transformer, but the capacitive currents are negligible compared to the fault current, so the protection function is simpler to implement.

Compensated neutral
The power system is earthed at the transformer. Faults are detected by a specific directional earth fault protection unit (ANSI 67NC), which monitors the active residual current and recognizes faults during their initial transient phase.

Dual-incomer power systems

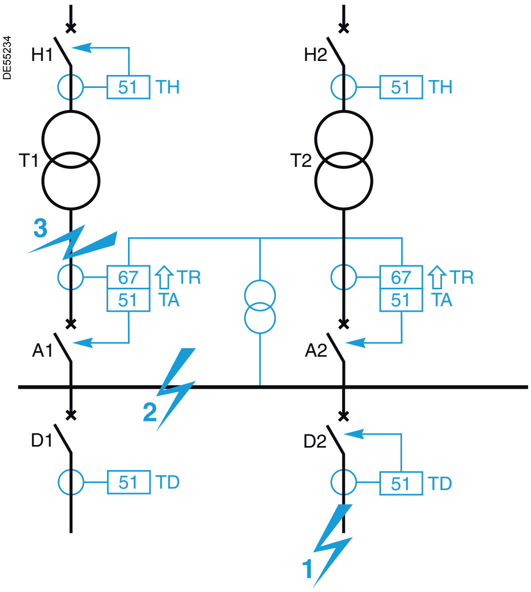


Fig. 1. Phase-to-phase fault protection.

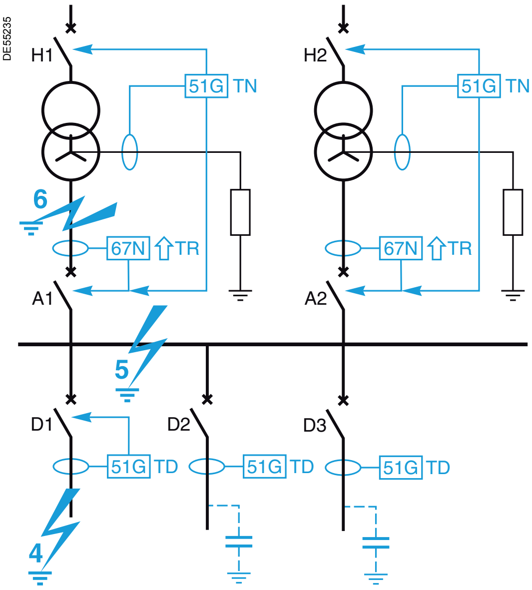


Fig. 2. Phase-to-earth fault protection (resistance-earthed neutral at the transformer).

Phase-to-phase faults (fig. 1)

Power system with two transformer incomers or two line incomers

The feeders are equipped with phase overcurrent protection units with delays set to TD.

The two incomers A1 and A2 are equipped with phase overcurrent protection units (ANSI 51) set selectively in relation to the feeders, i.e.

$TA \geq TD + \Delta T$.

They are also equipped with directional protection units (ANSI 67) with delays set at $TR < TA - \Delta T$.

Time-based discrimination is used between the incomer A protection units and feeder D protection units.

Current-based discrimination is used between the power supply H protection units and incomer A protection units.

This means that a fault at 1 is cleared by the tripping of D2 after a delay TD.

A fault at 2 is cleared by the tripping of A1 and A2 with a delay of TA (the directional protection units do not detect the fault).

A fault at 3 is detected by the A1 directional protection unit which trips at the time TR, allowing continued operation of the fault-free part of the power system.

However, the fault at 3 is still fed by T1. At the time $TH \geq TA + \Delta T$, H1 is tripped by the phase overcurrent protection unit linked to it.

Phase-to-earth faults (fig. 2)

Resistance-earthed neutral at incomer transformers

Earth fault protection units (ANSI 51G) are installed on the feeders and set higher than the corresponding capacitive currents, with delays of TD.

Directional earth fault protection units (ANSI 67N) are installed on incomers A1 and A2, with time delays of TR.

Earth fault protection units (ANSI 51G) are installed on the earthing connections and set higher than the incomer and feeder protection units, with time delays such that $TN \geq TD + \Delta T$.

Time-based discrimination is used between the different protection units.

This means that a fault at 4 is cleared by the tripping of D1.

A fault at 5 is cleared by the tripping of A1, A2, H1 and H2 by the protection units located on the neutral earthing connections of the 2 transformers.

A fault at 6 is detected by the A1 directional protection unit which trips at the time TR, allowing continued operation of the fault-free part of the power system.

However, the fault at 6 continues to be supplied up to the time TN at which the protection unit on the corresponding transformer earthing connection trips the H1 circuit breaker.

Resistance-earthed neutral at the busbars

A zero sequence generator is used for resistance-earthing.

Earth fault protection units are installed on the feeders, incomers and zero sequence generator.

Time-based discrimination is used between the different protection units.

The system operates in the same way as in single-incomer power systems.

Isolated neutral

The system operates in the same way as in single-incomer power systems.

Solidly earthed neutral

This is similar to resistance-earthing, but the phase-to-earth current is higher and reaches the phase-to-phase current level.

Compensated neutral

Only one earthing coil is in service at a given time to ensure power system capacitance matching; this is similar to single-incomer power systems.

Dual-incomer power systems

Additional protection functions

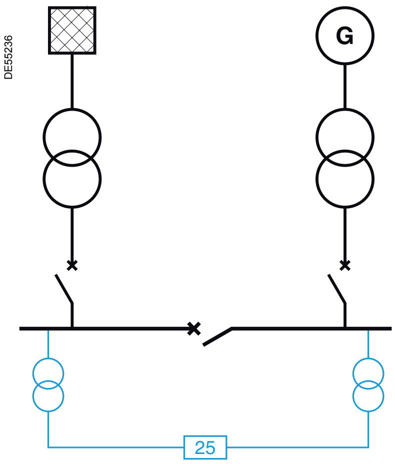


Fig. 1. Power system coupling protection.

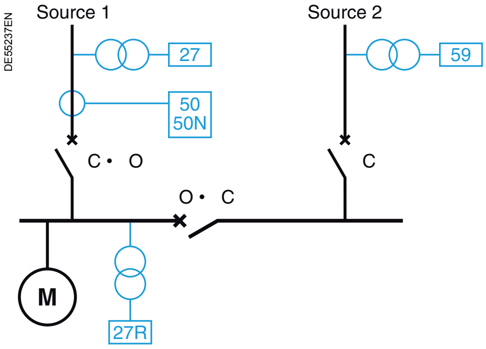


Fig. 2. Automatic source transfer.

Coupling (fig. 1)
The synchro-check function (ANSI 25) is used to check that the circuits to be connected have voltage amplitude, phase and frequency differences within acceptable limits to allow closing of the coupling circuit breaker.

Decoupling
When electrical installations are supplied by the utility and an independent power source, interference between the two sources as a result of events such as a utility failure or earth faults should be avoided. The consequences include voltage and frequency fluctuations and current and power exchanges between the different circuits. Protection functions are often advocated or imposed in the distributors' technical guides.
There are several methods of decoupling two sources:
b monitoring of the active power direction and protection by a reverse power protection relay (ANSI 32P),
b monitoring of voltage amplitude and under or overvoltage protection (ANSI 27 or 59),
b monitoring of frequencies and underfrequency (ANSI 81L) or overfrequency (ANSI 81H) protection,
b protection against phase shifts caused by faults (ANSI 78),
b monitoring of frequency variations and ROCOF (rate of change of frequency) protection (ANSI 81R) with respect to a threshold. This protection function is faster than the frequency protection functions and more stable than phase shift protection.

Automatic source transfer (fig. 2)
The system in figure 2 shows an installation with two busbars normally supplied by two sources with the coupling open (2/3 configuration).
If source 1 is lost, the power system is reconfigured. Source 1 is opened and the coupling is closed; this automatic source transfer takes place according to a procedure:
b initialization of the transfer by the detection of undervoltage (ANSI 27) on source 1 resulting in opening of the source 1 circuit breaker: Us = 70% Un,
b inhibition of transfer if a fault is detected downstream from source 1 by an overcurrent protection unit (ANSI 50 and 50N),
b enabling of transfer after the disappearance of voltage sustained by rotating machines is checked by the remanent undervoltage protection unit (ANSI 27R):
Us = 25% Un,
b enabling of transfer after verification that there is sufficient voltage (ANSI 59) on source 2 and closing of coupling circuit breaker: Us = 85% Un.

Open loop power systems

In distribution systems that include substations supplied in open loops, protection is provided at the head of the loop.

The power system is operated as an open loop and protection is provided at the ends of the loops, which are equipped with circuit breakers (fig. 1).

The switching devices used on the substations are switches.

Faults cause power outages.

Phase overcurrent and earth fault protection units (ANSI 51 and 51N) are installed on the circuit breakers at the head of each loop.

A fault occurring in a cable that connects 2 substations may trip either of these circuit breakers depending on the position of the loop opening.

The protection is often completed by an automated device that:

- clears the fault (with the power off) by opening the devices located at the ends of the faulty cable, after the faulty cable has been located by the fault detector,
- closes the circuit breaker that has tripped at the head of the loop,
- closes the device that ensured the normal opening of the loop in order to restore power to the fault-free downstream half of the loop.

The power system can be put back into its initial operating state after the faulty circuit has been repaired.

The outage may last from a few seconds to a few minutes depending on whether the loop is reconfigured automatically or manually.

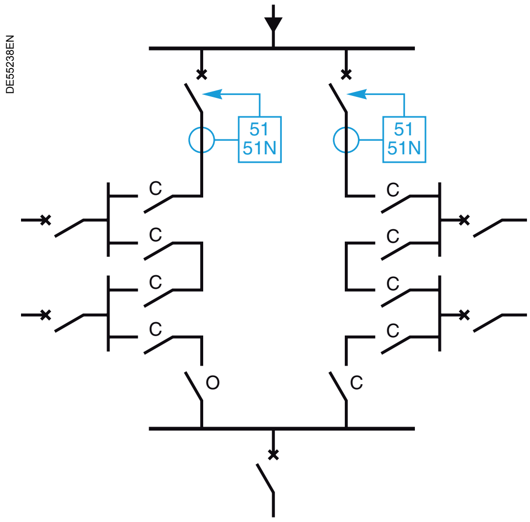


Fig. 1. Open loop protection principle.

Closed loop power systems

In distribution systems that include substations supplied in closed loops, protection is provided for different sections.

The power system may be operated in closed loops, with each section protected by circuit breakers at the ends of the section. Most faults do not cause power outages. Various protection solutions may be used.

Differential protection (fig. 1)
Each cable is equipped with a line differential protection unit (ANSI 87L) and each substation is equipped with a busbar differential protection unit (ANSI 87B).
This type of protection is very quick.
If the neutral is resistance-earthed, the sensitivity of the differential protection units must cover phase-to-earth faults.

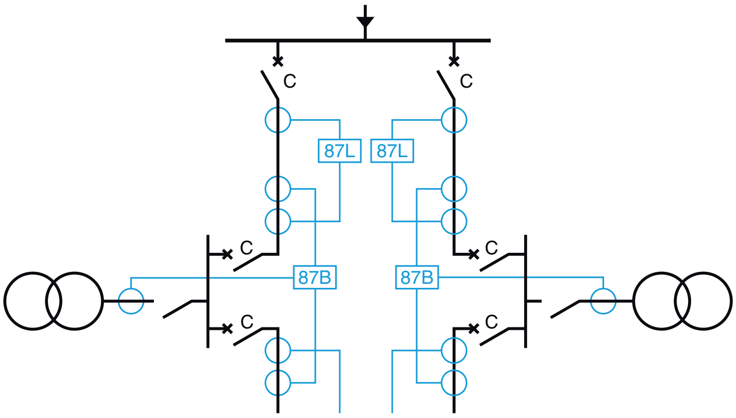


Fig. 1. Closed loop differential protection.

Overcurrent protection and directional logic discrimination (fig. 2)
The circuit breakers in the loop are equipped with overcurrent and directional protection units. Logic discrimination is used to clear faults as quickly as possible.
A fault in the loop activates:
b all the protection units if the loop is closed,
b all the protection units upstream from the fault when the loop is open.
Each protection unit sends a blocking signal to one of the adjacent units in the loop, according to the data transmitted by the directional protection unit.
Protection units that do not receive a blocking signal trip with a minimum delay that is not dependent on the fault's position in the loop:
b the fault is cleared by two circuit breakers, one on either side of the fault if the loop is closed, and all the switchboards remain energized,
b the fault is cleared by the upstream circuit breaker if the loop is open.
This solution is a comprehensive one since it protects cables and busbars.
It is fast, selective and includes back-up protection.

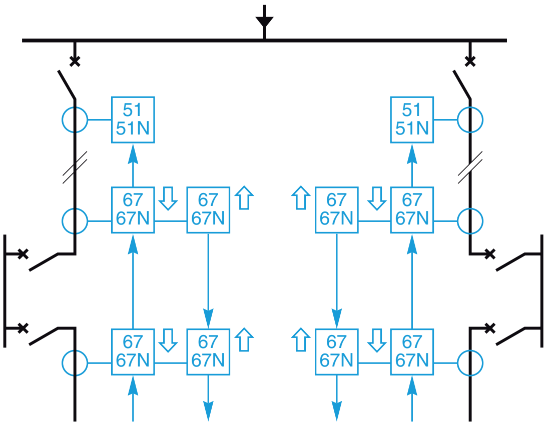


Fig. 2. Loop overcurrent protection and directional logic discrimination.

Types of faults and protection functions

Busbars are electrical power dispatching nodes that generally have more than two ends.
Specific busbar protection may be provided in a variety of ways, using basic functions.

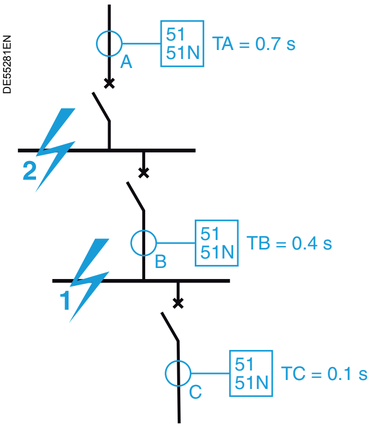


Fig. 1. Time-based discrimination.

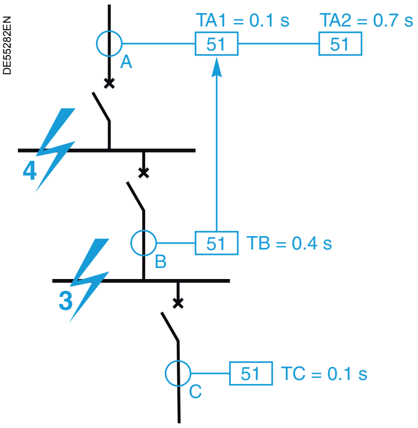


Fig. 2. Logic discrimination.

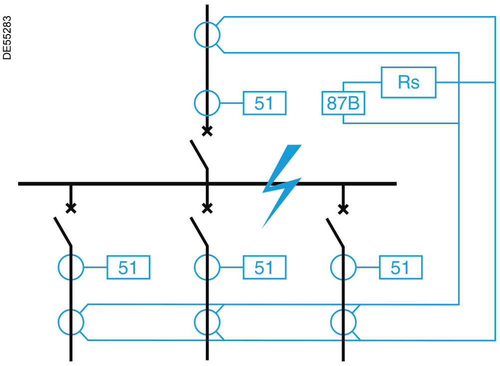


Fig. 3. Differential protection.

Phase-to-phase and phase-to-earth faults

Overcurrent protection

The use of time-based discrimination with the overcurrent (ANSI 51) and earth fault (ANSI 51N) protection functions may quickly result in excessive fault clearing time due to the number of levels of discrimination.

In the example (fig. 1), protection unit B trips in 0.4 s when there is a busbar fault at point 1; when a busbar fault occurs at point 2, protection unit A trips in 0.7 s, since the discrimination interval is set to 0.3 s.

The use of logic discrimination (fig. 2) with overcurrent protection provides a simple solution for busbar protection.

A fault at point 3 is detected by protection unit B, which sends a blocking signal to protection unit A.

Protection unit B trips after 0.4 s.

However, a fault at point 4 is only detected by protection unit A, which trips after 0.1 s; with backup protection provided if necessary in 0.7 s.

Differential protection

Differential protection (ANSI 87B) is based on the vector sum of the current entering and leaving the busbars for each phase. When the busbars are fault-free, the sum is equal to zero, but when there is a fault on the busbars, the sum is not zero and the busbar supply circuit breakers are tripped.

This type of protection is sensitive, fast and selective.

b With percentage-based, low impedance differential protection, the difference is calculated directly in the relay. The threshold setting is proportional to the through current and CTs with different ratios may be used. However, the system becomes complicated when the number of inputs increases.

b With high impedance differential protection (fig. 3), the difference is calculated in the cables, and a stabilization resistor is installed in the differential circuit. The CTs are sized to account for saturation according to a rule given by the protection relay manufacturer. The threshold setting is approximately 0.5 CT In and it is necessary to use CTs with the same ratings.

Load shedding function

The load shedding function is used when a shortage of available power in comparison to the load demand causes an abnormal drop in voltage and frequency: certain consumer loads are disconnected according to a preset scenario, called a load shedding plan, in order to recover the required power balance.
Different load shedding criteria may be chosen:

- undervoltage (ANSI 27),
- underfrequency (ANSI 81L),
- rate of change of frequency (ANSI 81R).

Breaker failure

The breaker failure function (ANSI 50BF) provides backup when a faulty breaker fails to trip after it has been sent a trip order: the adjacent incoming circuit breakers are tripped.
The example (fig. 1) shows that when a fault occurs at point 1 and the breaker that has been sent the trip order fails, the breaker failure protection function is faster than action by upstream protection time-based discrimination: 0.6 s instead of 0.7 s.

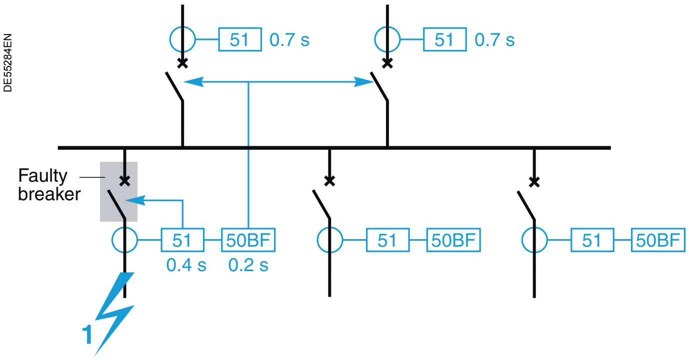


Fig. 1. Breaker failure.

Types of faults and protection functions

The term "link" refers to components designed to convey electrical power between two points that are several meters to several kilometers apart: links are generally overhead lines with bare conductors or cables with insulated conductors.

A specific type of protection is required for links.

Thermal overload

Protection against overheating due to overload currents in conductors under steady state conditions is provided by the thermal overload protection function (ANSI 49RMS), which estimates temperature buildup according to the current measurement.

Phase-to-phase short circuits

b Phase overcurrent protection (ANSI 51) may be used to clear the fault, the time delay being set to provide discrimination.
A distant 2-phase fault creates a low level of overcurrent and an unbalance; a negative sequence / unbalance protection function (ANSI 46) is used to complete the basic protection function (fig. 1).
b To reduce fault clearance time, a percentage-based differential protection function (ANSI 87L) may be used. It is activated when the differential current is equal to more than a certain percentage of the through current. There is a relay at either end of the link and information is exchanged by the relays via a pilot (fig. 2).

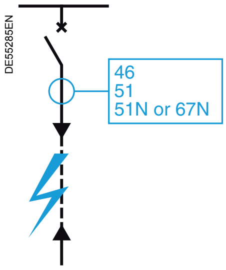


Fig. 1. Link protection by overcurrent relay.

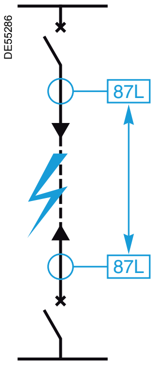


Fig. 2. Link protection by differential relays.

Phase-to-earth short circuits

Time-delayed overcurrent protection (ANSI 51N) may be used to clear faults with a high degree of accuracy (fig. 1).
For long feeders though, with high capacitive current, the directional earth fault protection function (ANSI 67N) allows the current threshold to be set lower than the capacitive current in the cable as long as system earthing is via a resistive neutral.

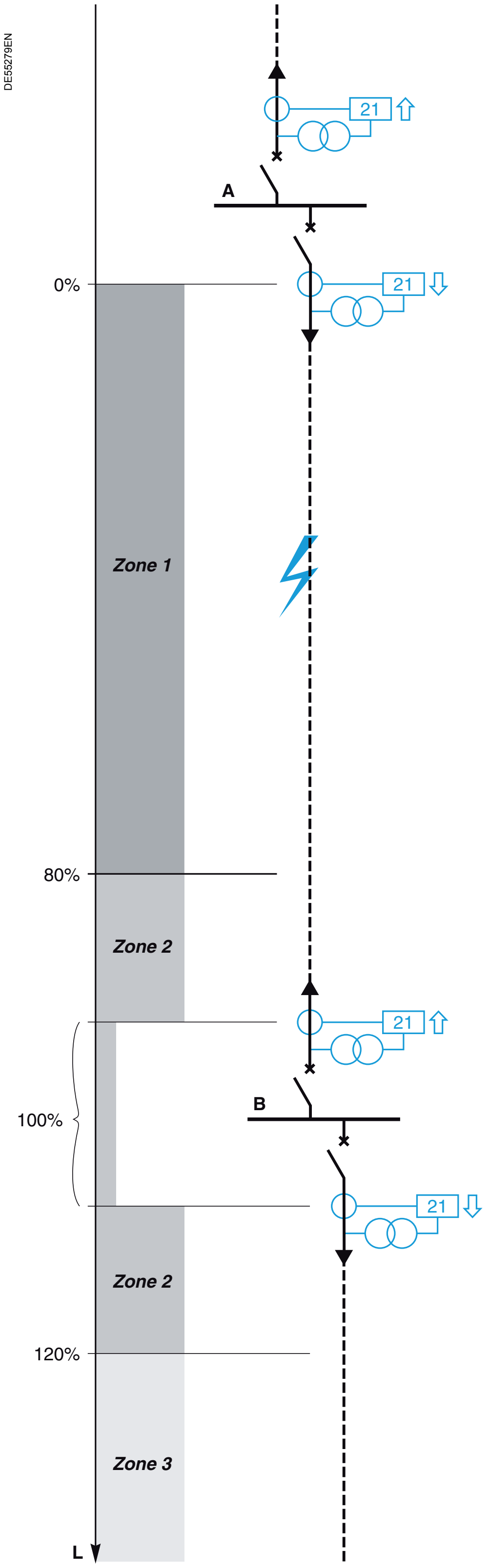


Fig. 1. Distance protection principle.

Distance protection

Distance protection (ANSI 21) against faults affecting line or cable sections is used in meshed power systems (parallel links, several sources).
It is selective and fast, without requiring time-based discrimination. Sensitivity depends on the short-circuit power and the load. It is difficult to implement when the type of link is not the same throughout (overhead line + cable).
It operates according to the following principle:

- measurement of an impedance proportional to the distance from the measurement point to the fault,
- delimitation of impedance zones which represent line sections of different lengths (fig. 1),
- tripping by zone with time delay.

The example in figure 2 shows the following for the protection unit at point A in line section AB:

- an impedance circle at 80% of the length of the line (zone 1), inside which tripping is instantaneous,
- an impedance band between 80% and 120% of the length of the line (zone 2), in which tripping is delayed (200 ms),
- an impedance circle at 120% of the length of the line (zone 3), outside which there is long-time delayed backup tripping of protection unit B outside AB,
- an impedance circle at 120% downstream to provide backup for downstream protection,
- When there is communication between the protection units at the ends, tripping can take place instantaneously between 0 and 100%.

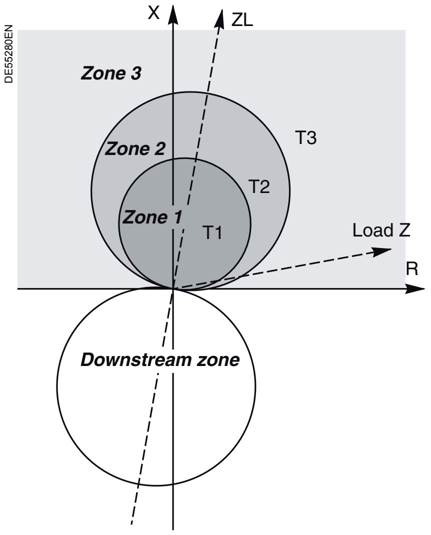


Fig. 2. Impedance circles.

Recloser

The recloser function (ANSI 79) is designed to clear transient and semi-permanent faults on overhead lines and limit down time as much as possible. The recloser function automatically generates circuit breaker reclosing orders to resupply overhead lines after a fault. This is done in several steps:

- tripping when the fault appears to de-energize the circuit,
- time delay required for insulation recovery in the location of the fault,
- resupply of the circuit by reclosing.

Reclosing is activated by the link protection units.
The recloser may be single-phase and/or 3-phase, and may comprise one or more consecutive reclosing cycles.

Types of faults

The transformer is a particularly important power system component.
Transformers requires effective protection against all faults liable to damage them, whether of internal or external origin.
The choice of a protection unit is often based on technical and cost considerations related to the power rating.

The main faults that can affect transformers are:
- overloads,
- short-circuits,
- frame faults.

Overloads

Overloads may be caused by an increase in the number of loads supplied simultaneously or by an increase in the power drawn by one or more loads.
Overloads result in overcurrent of long duration, causing a rise in temperature that is detrimental to the preservation of insulation and to the service life of the transformer.

Short-circuits

Short-circuits can occur inside or outside the transformer.

Internal short-circuits: faults between different phase conductors or faults between turns of the same winding. The fault arc damages the transformer winding and can cause fire. In oil transformers, the arc causes the emission of decomposition gas. If the fault is slight, a small amount of gas is emitted and the accumulation of gas can become dangerous.
A violent short-circuit can cause major damage liable to destroy the winding and also the tank frame by the spread of burning oil.

External short-circuits: phase-to-phase faults in the downstream connections. The downstream short-circuit current creates electrodynamic stress in the transformer that is liable to have a mechanical effect on the windings and lead to an internal fault.

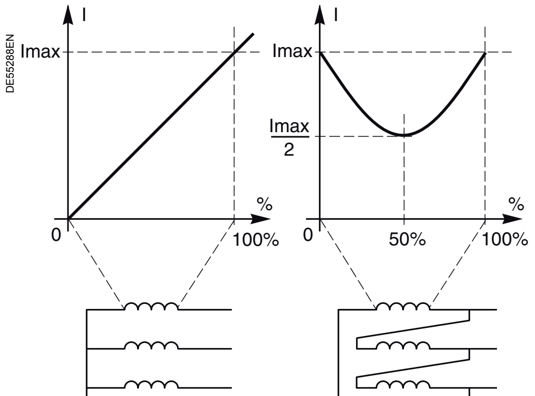


Fig. 1 *Fig. 2*

Fault current according to the position of the fault in the winding.

Frame faults

Frame faults are internal faults. They may occur between the winding and the tank frame or between the winding and the magnetic core.
They cause gas emission in oil transformers. Like internal short-circuits, they can cause transformer damage and fire. The amplitude of the fault current depends on the upstream and downstream neutral earthing arrangements, and also on the position of the fault in the winding:
- in star connected arrangements (fig. 1), the frame fault current varies between 0 and the maximum value depending on whether the fault is at the neutral or phase end of the winding.
- in delta connected arrangements (fig. 2), the frame current varies between 50 and 100% of the maximum value depending on whether the fault is in the middle or at the end of the winding.

Information on transformer operation

Transformer energizing (fig. 3)
Transformer energizing creates a transient peak inrush current that may reach 20 times the rated current with time constants of 0.1 to 0.7 seconds. This phenomenon is due to saturation of the magnetic circuit which produces a high magnetizing current. The peak current is at its highest when energizing takes place as the voltage goes through zero and there is maximum remanent induction on the same phase. The waveform contains a substantial amount of 2nd harmonics.
This phenomenon is part of normal power system operation and should not be detected as a fault by the protection units, which should let the peak energizing current through.

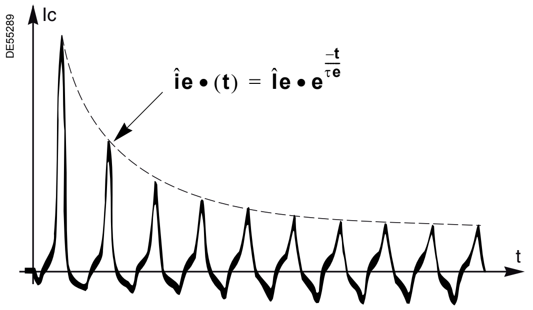


Fig. 3. Transformer energizing.
Ie: inrush current envelope
τe: time constant

Overfluxing
Transformer operation at a voltage or frequency that is too low creates excessive magnetizing current and leads to deformation of the current by a substantial amount of 5th harmonics.

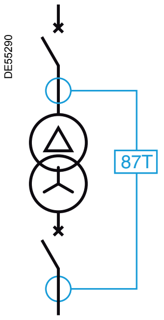


Fig. 1. Transformer differential protection.

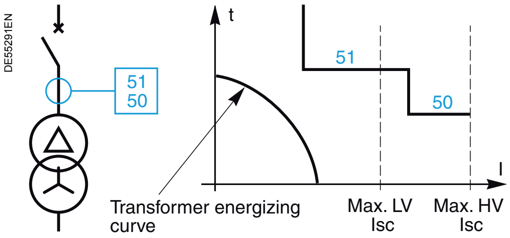


Fig. 2. Transformer overcurrent protection.

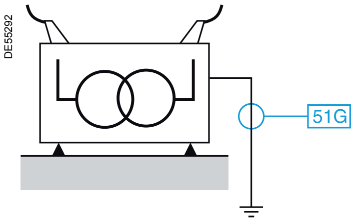


Fig. 3. Transformer tank frame fault protection.

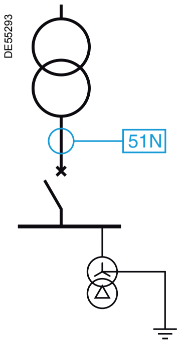


Fig. 4. Earth fault protection.

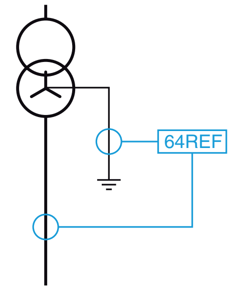


Fig. 5. Restricted earth fault protection.

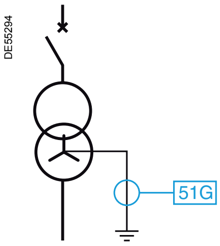


Fig. 6. Neutral point earth protection.

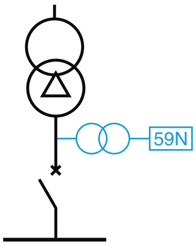


Fig. 7. Neutral voltage displacement protection.

Overloads

Overcurrent of long duration may be detected by a definite time or IDMT delayed overcurrent protection unit (ANSI 51) that provides discrimination with respect to the secondary protection units.
The dielectric temperature is monitored (ANSI 26) for transformers with liquid insulation and the winding temperature is monitored (ANSI 49T) for dry type transformers.
Thermal overload protection (ANSI 49RMS) is used for more sensitive monitoring of temperature rise: heat rise is determined by simulation of the release of heat according to the current and thermal inertia of the transformer.
For MV/LV transformers, overloads may be detected on the low voltage side by the long time trip function of the main LV circuit breaker.

Short-circuits

Several protection functions may be implemented.
b For oil transformers, devices that are sensitive to gas emission or oil movement (ANSI 63) caused by short-circuits between turns of the same phase or phase-to-phase short-circuits:
v Buchholz relays for free breathing HV/HV transformers,
v gas and pressure detectors for hermetically sealed HV/LV transformers.
b Transformer differential protection (ANSI 87T) (fig. 1) which provides fast protection against phase-to-phase faults. It is sensitive and used for vital high power transformers. To avoid nuisance tripping, the 2nd harmonic of the differential current is measured to detect transformer energizing (H2 restraint) and the 5th harmonic is measured to detect overfluxing (H5 restraint).
The use of this protection function with neural network technology provides the advantages of simple setting and stability.
b An instantaneous overcurrent protection unit (ANSI 50) (fig. 2) linked to the circuit breaker located on the transformer primary circuit provides protection against violent short-circuits. The current threshold is set higher than the current due to short-circuits on the secondary winding, thereby ensuring current-based discrimination.
b HV fuses can be used to protect transformers with low kVA ratings.

Frame faults

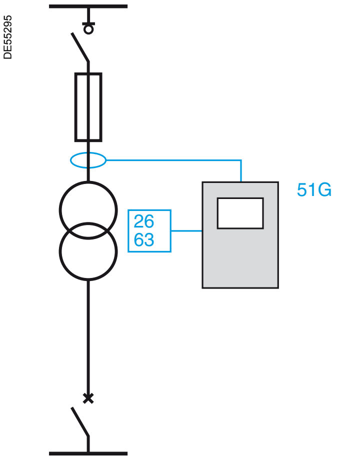
b Tank frame fault (fig. 3)
This slightly delayed overcurrent protection unit (ANSI 51G), installed on the transformer frame earthing connection (if the setting is compatible with the neutral earthing arrangement), is a simple, effective solution for internal winding-to-frame faults. In order for it to be used, the transformer must be isolated from the earth. This protection function is selective: it is only sensitive to transformer frame faults on the primary and secondary sides.

Another solution consists of using earth fault protection:
b earth fault protection (ANSI 51N) located on the upstream power system for frame faults that affect the transformer primary circuit.
b earth fault protection (ANSI 51N) located on the incomer of the switchboard being supplied, if the neutral of the downstream power system is earthed on the busbars (fig. 4).
These protection functions are selective: they are only sensitive to phase-to-earth faults situated in the transformer or on the upstream and downstream connections.
b restricted earth fault protection (ANSI 64REF) if the downstream power system neutral is earthed at the transformer (fig. 5). This is a differential protection function that detects the difference between residual currents measured at the neutral earthing point and at the three-phase output of the transformer.
b neutral point earth protection (ANSI 51G) if the downstream power system is earthed at the transformer (fig. 6).
b neutral voltage displacement protection (ANSI 59N) may be used if the downstream power system neutral is isolated from the earth (fig. 7).

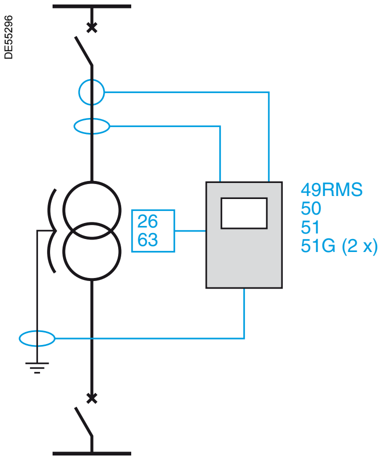
Recommended settings

Faults	Appropriate protection function	ANSI code	Setting information
Overloads			
	Dielectric temperature monitoring (transformers with liquid insulation)	**26**	Alarm at 95°C; tripping at 100°C
	Winding temperature monitoring (dry type transformers)	**49T**	Alarm at 150°C; tripping at 160°C
	Thermal overload	**49 RMS**	Alarm threshold = 100% of thermal capacity used Tripping threshold = 120% of thermal capacity used Time constant in the 10 to 30 minute range
	Low voltage circuit breaker		Threshold ≥ In
Short-circuits			
	Fuses		Choice of rating according to appropriate method for switchgear concerned
	Instantaneous overcurrent	**50**	High threshold > downstream Isc
	Definite time overcurrent	**51**	Low threshold < 5 In Delay ≥ downstream T + 0.3 seconds
	IDMT overcurrent	**51**	IDMT low threshold, selective with downstream, approximately 3 In
	Percentage-based differential	**87T**	Slope = 15% + setting range Min. threshold 30%
	Buchholz or gas and pressure detection	**63**	logic
Earth faults			
	Tank frame overcurrent	**51G**	Threshold > 20 A, delay 0.1 seconds
	Earth fault	**51N/51G**	Threshold ≤ 20% of maximum earth fault current and > 10% of CT rating (with 3CTs and H2 restraint) Delay 0.1 seconds if earthing is on the power system Time delay according to discrimination if earthing is on the transformer
	Restricted earth fault differential	**64REF**	Threshold 10% of In, no delay
	Neutral point earth fault	**51G**	Threshold < permanent limitation resistance current
	Neutral voltage displacement	**59N**	Threshold approximately 10% of residual overvoltage
Overfluxing			
	Flux control	**24**	Threshold > 1.05 Un/fn Delay: constant time, 1 hour

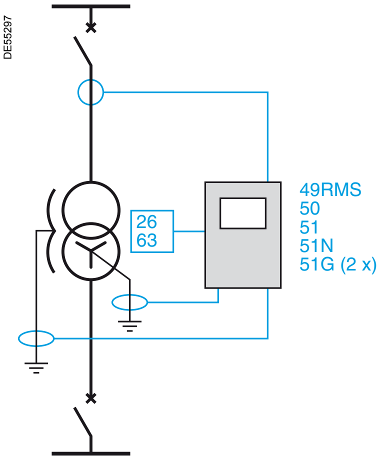
Examples of applications



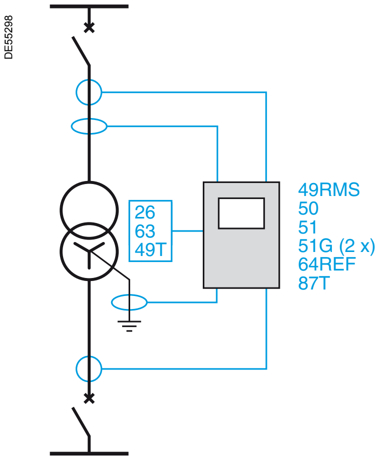
Low rated HV/LV transformer
Fuse protection



High-rated HV/LV transformer
Circuit breaker protection



Low-rated HV/HV transformer



High-rated HV/HV transformer

Types of faults

Motors are the interface between electrical and mechanical equipment. They are connected to the machines they drive and are therefore exposed to the same environment.
Motors may be subjected to internal mechanical stress due to their moving parts. A single faulty motor can disrupt an entire production process. Modern motors have optimized characteristics which make them unsuitable for operation other than according to their rated characteristics. This means that they are relatively fragile electrical loads that need to be carefully protected.
There are asynchronous motors (mainly squirrel-cage motors or wound-rotor motors) and synchronous motors (motors with DC rotor excitation).
Questions concerning synchronous motors are the same as those that concern asynchronous motors plus those that concern generators.

Motors are affected by:
b faults related to the driven loads,
b power supply faults,
b motor internal faults.

Faults related to the driven loads

Overloads
If the power drawn is greater than the rated power, there is overcurrent in the motor and an increase in losses, causing a rise in temperature.
Excessive starting time and frequency of starts
Motor starting creates substantial overcurrents which are only admissible for short durations. If a motor starts too frequently or if starting takes too long due to insufficient motor torque compared to load torque, overheating is inevitable and must be avoided.
Blocking
Rotation suddenly stops due to blocking of the driven mechanism. The motor draws the starting current and stays blocked at zero speed. There is no more ventilation and overheating occurs very quickly.
Loss of load
Loss of pump priming or a break in load coupling causes no-load operation of the motor, which does not directly harm the motor. However, the pump itself is quickly damaged.

Power supply faults

Loss of supply
This causes motors to operate as generators when the inertia of the driven load is high.
Voltage sag
This reduces motor torque and speed: the slow-down causes increased current and losses. Abnormal overheating therefore occurs.
Unbalance
3-phase power supply may be unbalanced for the following reasons:
b the power source (transformer or AC generator) does not supply symmetrical 3-phase voltage,
b all the other consumers together do not constitute a symmetrical load and this unbalances the power supply system,
b the motor is powered by two phases after a fuse has blown on one phase,
b The phase order is reversed, changing the direction of motor rotation.
Power supply unbalance creates negative sequence current which causes very high losses and quick rotor overheating.
When the voltage is re-supplied after a motor power failure, the motor sustains remanent voltage that may lead to overcurrent when the motor starts again or even a mechanical break in transmission.

Motor internal faults

Phase-to-phase short-circuits
These faults vary in strength according to where they occur in the coil and they cause serious damage.
Stator frame fault
The amplitude of the fault current depends on the power system neutral earthing arrangement and the position of the fault within the coil.
Phase-to-phase short-circuits and stator frame faults require motor rewinding, and frame faults can also irreparably damage the magnetic circuit.
Rotor frame faults (for wound-rotor motors)
Rotor insulation breakdown can cause a short-circuit between turns and produce a current that creates local overheating.
Overheating of bearings due to wear or faulty lubrication.
Field loss
This fault affects synchronous motors; motor operation is asynchronous and the rotor undergoes considerable overheating since it is not designed accordingly.
Pole slip
This fault also affects synchronous motors, which may lose synchronism for different reasons:
b mechanical: sudden load variation,
b electrical: power supply system fault or field loss.

Overloads

Overloads may be monitored the following:
b IDMT overcurrent protection (ANSI 51),
b thermal overload protection (ANSI 49RMS), which involves overheating due to current,
b RTD temperature monitoring (ANSI 49T).

Excessive starting time and locked rotor

The same function provides both types of protection (ANSI 48-51LR).
For excessive starting time protection, an instantaneous current threshold is set below the value of the starting current and activated after a delay that begins when the motor is energized; the delay is set longer than the normal starting time.
Locked rotor protection is activated outside starting periods by current above a threshold, after a delay.

Successive starts

The successive starts protection function (ANSI 66) is based on the number of starts within a given interval of time or on the time between starts.

Loss of pump priming

This is detected by a definite time undercurrent protection unit (ANSI 37) which is reset when the current is nil (when the motor stops).

Speed variation

Additional protection may be provided by the direct measurement of rotation speed by mechanical detection on the machine shaft.
The underspeed protection function (ANSI 14) detects slow-downs or zero speed resulting from mechanical overloads or locked rotors.
The overspeed protection function (ANSI 12) detects racing when the motor is driven by the load, or a loss of synchronization for synchronous motors.

Loss of supply

Loss of supply is detected by a directional active power protection unit (ANSI 32P).

Voltage sag

This is monitored by a delayed positive sequence undervoltage protection unit (ANSI 27D).
The voltage threshold and delay are set to allow discrimination with the power system’s short-circuit protection units and to tolerate normal voltage sags such as those that occur during motor starting. The same protection function may be shared by several motors in the switchboard.

Unbalance

Protection is provided by the detection of negative sequence current by an IDMT or definite time protection unit (ANSI 46).
The phase rotation direction is detected by the measurement of negative sequence overvoltage (ANSI 47).

Resupply

Motor remanence is detected by a remanent undervoltage protection unit (ANSI 27R) which enables resupply when the voltage drops below a certain voltage threshold.

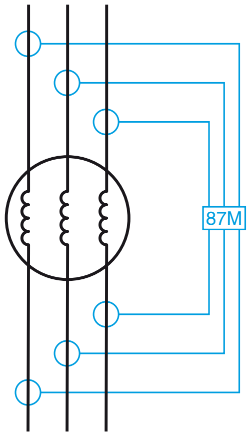


Fig. 1. Phase-to-phase short-circuit.
Differential protection (ANSI 87M)

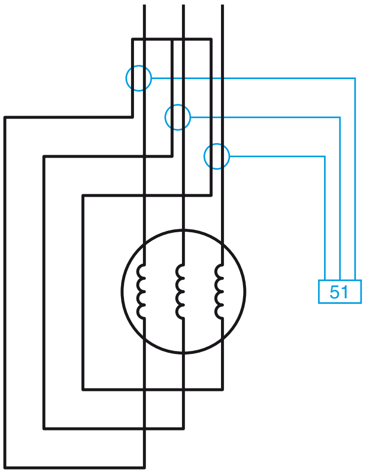


Fig. 2. Phase-to-phase short-circuit.
Autodifferential overcurrent protection (ANSI 51)

Phase-to-phase short circuits

They are detected by a delayed overcurrent protection unit (ANSI 50 and 51).
The current threshold is set higher than the starting current and a very short delay is applied to prevent the protection unit from tripping on transient inrush currents.
When the corresponding breaking device is a contactor, it is associated with fuses which ensure short-circuit protection.
For large motors, a high impedance or percentage-based differential protection system (ANSI 87M) is used (fig. 1).
As an alternative, by appropriate adaptation of the connections on the neutral side and by the use of 3 summing current transformers, a simple overcurrent protection unit (ANSI 51) can be used to provide sensitive, stable detection of internal faults (fig.2).

Stator frame fault

The type of protection depends on the neutral earthing arrangement. High sensitivity is required to limit damage to the magnetic circuit.
If the neutral is solidly earthed or impedance-earthed, a delayed residual overcurrent protection unit (ANSI 51N/51G) may be used to protect the main windings.
In isolated neutral arrangements, a neutral voltage displacement protection unit (ANSI 59N) may be used to detect neutral voltage displacement. If the motor feeder is capacitive (long cable), a directional earth fault protection unit (ANSI 67N) is used.

Rotor frame fault

An insulation monitoring device with AC or DC current injection detects winding insulation faults.

Overheating of bearings

The bearing temperature is measured by RTDs (ANSI 38).

Field loss

For synchronous motors: refer to the chapter on generators.

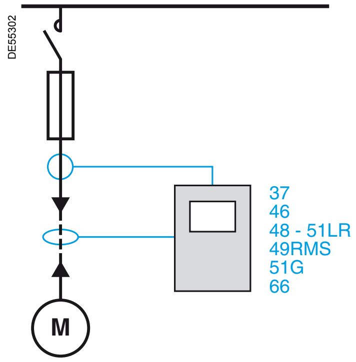
Pole slip

For synchronous motors: refer to the chapter on generators.

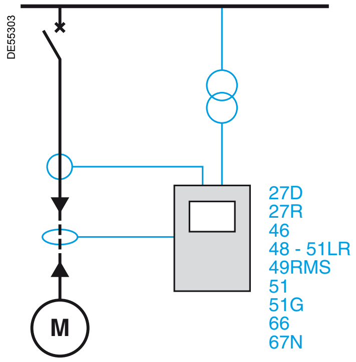
Recommended settings

Faults	Appropriate protection function		ANSI code	Setting information
Faults related to the driven loads				
Overloads	IDMT overcurrent		**50/51**	Setting that enables starting
	Thermal overload		**49RMS**	According to motor operating characteristics (time constant in the range of 10 to 20 minutes)
	RTDs		**49T**	Depends on the thermal class of the motor
Excessive starting time	Delayed current threshold		**48**	Threshold in the 2.5 In range Delay: starting time + a few seconds
Locked rotor	Delayed current threshold		**51LR**	Threshold: 2.5 In Delay: 0.5 to 1 second
Successive starts	Counting of number of starts		**66**	According to motor manufacturer
Loss of load	Phase undercurrent		**37**	Threshold in the range of 70% of drawn current Delay: 1 second
Speed variation	Mechanical detection of overspeed, underspeed		**12, 14**	Threshold ± 5% of rated speed Delay of a few seconds
Power supply faults				
Loss of supply	Directional active overpower		**32P**	Threshold 5% of Sn Delay: 1 second
Voltage sag	Positive sequence undervoltage		**27D**	Threshold from 0.75 to 0.80 Un Delay in the 1 second range
Unbalance	Negative sequence / unbalance		**46**	b Definite time Is1 = 20% In, delay = starting time + a few seconds Is2 = 40% In, delay 0.5 seconds b IDMT Is = 10% In, tripping time at 0.3 In > starting time
Rotation direction	Phase rotation direction		**47**	Negative sequence voltage threshold at 40% of Un
Resupply	Remanent undervoltage		**27R**	Threshold < 20 to 25% of Un Delay in the 0.1 second range
Internal motor faults				
Phase-to-phase short circuits	Fuses			Rating that allows consecutive starts
	Definite time overcurrent		**50/51**	Threshold > 1.2 starting I, delay in the 0.1 second range (DT)
	Differential protection		**87M**	Slope 50%, threshold 5 to 15% of In, no delay
Stator frame fault	Earthed neutral	Earth fault	**51N/51G**	10% of maximum earth fault current Delay in the 0.1 second range (DT)
	Isolated neutral	*Power system with low capacitance* Neutral voltage displacement	**59N**	Threshold = 30% of Vn
		High capacitance Directional earth fault	**67N**	Minimum threshold according to sensor
Rotor frame fault	Insulation monitoring device			
Overheating of bearings	Temperature measurement		**38**	According to manufacturer's instructions
Specific synchronous motor faults				
Field loss	Directional reactive overpower		**32Q**	Threshold 30% of Sn Delay: 1 second
	Underimpedance		**40**	Same as for generator
Pole slip	Loss of synchronization		**78PS**	Same as for generator

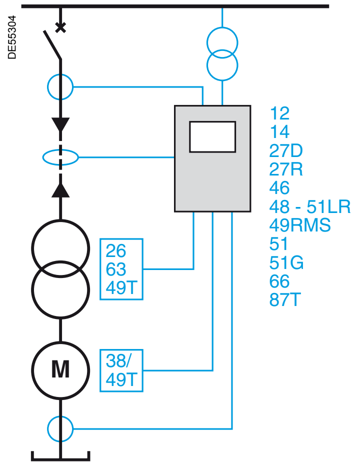
Examples of applications



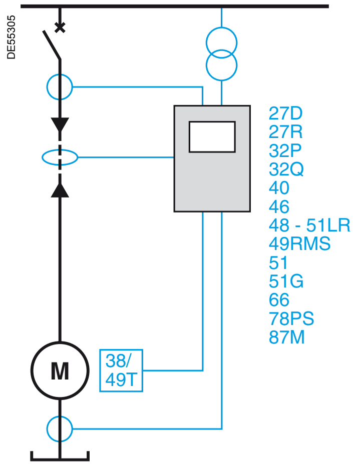
Asynchronous motor controlled by fuse and contactor
Example: 100 kW pump



Asynchronous motor controlled by circuit breaker
Example: 250 kW fan



Motor-transformer unit: asynchronous motor/transformer
Example: 1 MW crusher



Priority synchronous motor
Example: 2 MW compressor

Types of faults

Generator operation can be altered by both faults within the machine and disturbances occurring in the power system to which it is connected.

A generator protection system therefore has a dual objective: to protect the machine and protect the power system.

The generators referred to here are synchronous machines (AC generators).

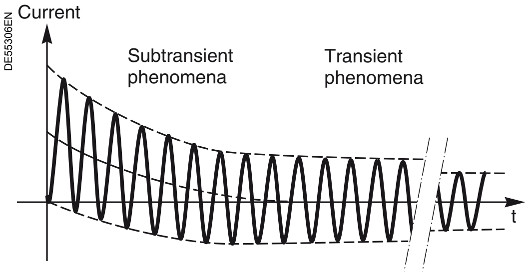


Fig. 1. Short circuit currents across generator terminals.

Faults such as overloads, unbalance and internal phase-to-phase faults are the same type for generators and motors.
Only faults specifically related to generators are described below.

External phase-to-phase short-circuits

When a short circuit occurs in a power system close to a generator, the fault current looks like the current shown in figure 1.
The maximum short-circuit current should be calculated taking into account the machine’s substransient impedance X"d.
The short-circuit current detected by a protection unit with a very short time delay (about 100 ms) should be calculated taking into account the machine's transient impedance X'd.
The short-circuit current in steady state conditions should be calculated taking into account the synchronous impedance X.
It is low, generally less than the generator’s rated current.
Voltage regulators can often keep it higher than the rated current (2 or 3 times higher) for a few seconds.

Internal phase-to-frame faults

This is the same type of fault as for motors and the effects depend on the neutral earthing arrangement used. There is a difference however in comparison to motors in that generators can be decoupled from the power system during start-up and shutdown and also in test or stand-by mode. The neutral earthing arrangement may differ according to whether the generator is connected or disconnected and the protection functions should be suitable for both cases.

Field loss

When a generator coupled with a power system loses its field, it becomes desynchronized with respect to the power system. It then operates asynchronously, at a slight overspeed, and it draws reactive power.
This causes stator overheating since the reactive current may be high and rotor overheating since the rotor is not sized for the induced currents.

Loss of synchronism

The loss of generator synchronization occurs when balanced steady state operation is disrupted by strong disturbances: for example, when a short-circuit in the power system causes a drop in the electrical power supplied by the generator and the generator accelerates, still driven by the prime mover.

Operation as a motor

When a generator is driven like a motor by the power system (to which it is connected), it applies mechanical energy to the shaft and this can cause wear and damage to the prime mover.

Voltage and frequency variations

Voltage and frequency variations under steady state conditions are due to regulator malfunctions and cause the following problems:
b frequencies that are too high cause motor overheating,
b frequencies that are too low cause motor power loss,
b frequency variations cause motor speed variations, that may cause mechanical damage and malfunctioning of electronic devices,
b voltage that is too high puts stress on the insulation of all parts of the power system, causes magnetic circuit overheating and damages sensitive loads,
b voltages that are too low cause torque loss and an increase in current and motor overheating,
b voltage fluctuations cause motor torque variations resulting in flicker (flickering of light sources).

Generator management

Normal generator management may be disturbed:
b inadvertent energization when the normal starting sequence is not complied with: the generator, shut down but coupled to the power system, runs like a motor and may damage the prime mover,
b power management: when there are several parallel sources, the number of sources must be adapted to suit the power drawn by the loads; there is also the case of islanded operation of an installation with its own power generation.

Overloads

The overload protection functions for generators are the same as those for motors:

- IDMT overcurrent (ANSI 51),
- thermal overload (ANSI 49RMS),
- RTD temperature monitoring (ANSI 49T).

Unbalance

Protection is ensured, the same as for motors, by IDMT or definite time negative sequence current detection (ANSI 46).

External phase-to-phase short-circuits (in the power system)

- As the value of short-circuit current decreases over time to approximately the rated current, if not lower, in steady state conditions, simple current detection may be insufficient.
This type of fault can be detected effectively by a voltage-restrained overcurrent protection device (ANSI 51V), the threshold of which increases with the voltage (fig. 1). Operation is delayed.
- When the machine is equipped with a system that maintains the short-circuit at about 3 In, the use of a phase overcurrent protection unit (ANSI 51) is recommended.
- Another solution consists of using a delayed underimpedance protection unit (ANSI 21G), which may also provide back-up (ANSI 21B) for the overcurrent protection unit.

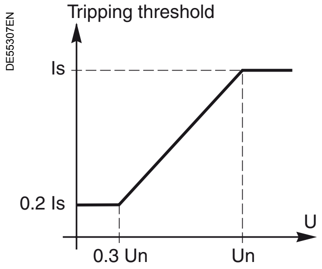


Fig. 1. Voltage restrained overcurrent protection threshold.

Internal phase-to-phase short-circuits (in the stator)

- High impedance or percentage-based differential protection (ANSI 87G) provides a sensitive, quick solution.
- If the generator is operating in parallel with another source, a directional phase overcurrent protection unit (ANSI 67) can detect internal faults.
- In certain cases, particularly for generators with low power ratings compared to the power system to which they are connected , internal phase-to-phase short-circuit protection may be provided as follows (fig. 2):
  - instantaneous overcurrent protection (A), validated when the generator circuit breaker is open, with current sensors on the neutral point side, set lower than the rated current,
  - instantaneous overcurrent protection (B), with current sensors on the circuit breaker side, set higher than the generator short-circuit current.

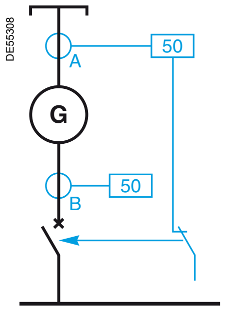


Fig. 2. AC generator coupled with other sources.

Stator frame fault

- If the neutral is earthed at the generator neutral point, earth fault protection (ANSI 51G) or restricted earth fault protection (ANSI 64REF) is used.
- If the neutral is earthed within the power system rather than at the generator neutral point, a stator frame fault is detected by:
  - an earth fault protection unit on the generator circuit breaker when the generator is coupled to the power system,
  - by an insulation monitoring device for isolated neutral arrangements when the generator is decoupled from the power system.
- If the neutral is impedant at the generator neutral point, 100% stator frame fault protection (ANSI 64G) is used. This protection combines two functions:
  - neutral voltage displacement, which protects 80% of the windings (ANSI 59N)
  - third harmonic (H3) neutral point undervoltage, which protects the 20% of the windings on the neutral side (ANSI 27TN).
- If the neutral is isolated, frame fault protection is provided by an insulation monitoring device. This device operates either by detecting residual voltage (ANSI 59N) or by injecting DC current between the neutral and earth. If this device exists on the power system, it monitors the generator when it is coupled; a special generator device, validated by the open position of the generator circuit breaker being in the open position, is needed to monitor insulation when the generator is uncoupled.

Rotor frame fault

When the excitation current circuit is accessible, frame faults are monitored by an insulation monitoring device.

Field loss

Field loss is detected either by a delayed reactive overpower protection unit (ANSI 32Q) for high power rating systems or by an underimpedance protection unit (ANSI 40) for “islanded” power systems with generators, or by direct monitoring of the excitation circuit if it is accessible (ANSI 40DC).

Loss of synchronization

Protection against the loss of synchronization is provided by a specific pole slip protection function (ANSI 78PS); the pole slip measurement principle is based on either an estimate of machine instability according to the equal-area criterion, or by the detection of active power swings (fig. 1); an overspeed protection unit (ANSI 12) may be used as back-up.

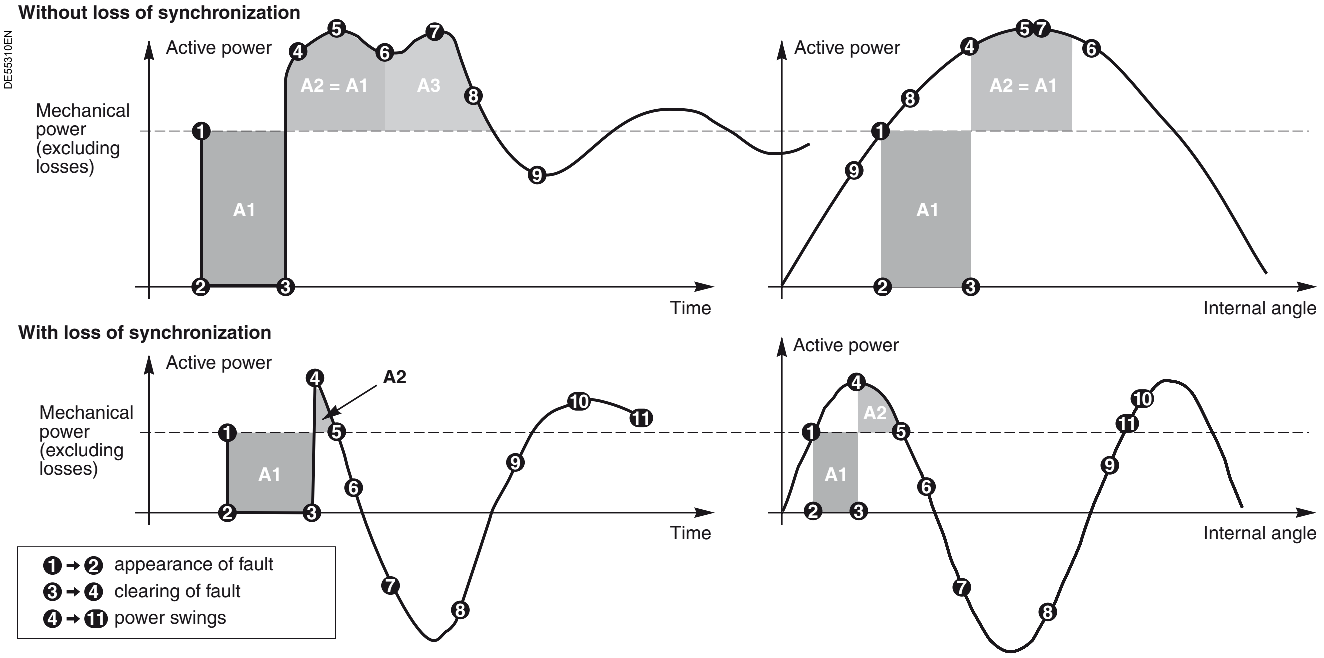


Fig. 1. Active power flows in a generator following a short-circuit.

Operation as a motor

This is detected by a relay that detects reverse active power (ANSI 32P) drawn by the generator.

Voltage and frequency variations

Voltage variations are monitored by an overvoltage-undervoltage protection unit (ANSI 59 and 27) and frequency variations by an overfrequency-underfrequency protection unit (ANSI 81H and 81L).

The protection units are delayed since the phenomena do not require instantaneous action and because the power system protection units and voltage and speed controllers must be allowed time to react.

The flux control function (ANSI 24) can detect overfluxing.

Inadvertent energization

The starting of generators according to a normal sequence is monitored by the inadvertent energization protection function (ANSI 50/27). This protection involves the simultaneous use of:

b an instantaneous overcurrent function and an undervoltage protection function,

b the undervoltage protection function is delayed to avoid unwanted 3-phase fault tripping, and there is another delay to allow generator starting without the presence of current before coupling.

Power management

The distribution of active power flows can be managed appropriately by the use of directional active underpower protection units (ANSI 37P), which provide adequate control of source and load circuit breaker tripping (example in fig. 2).

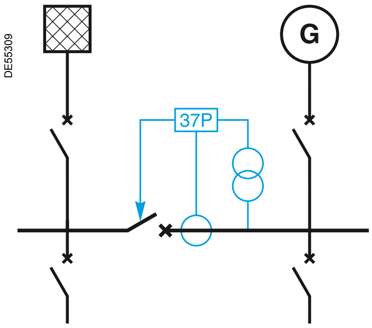
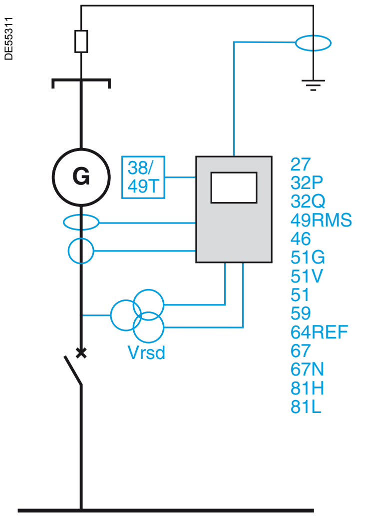


Fig. 2. Independent operation of an installation with its own generating unit.

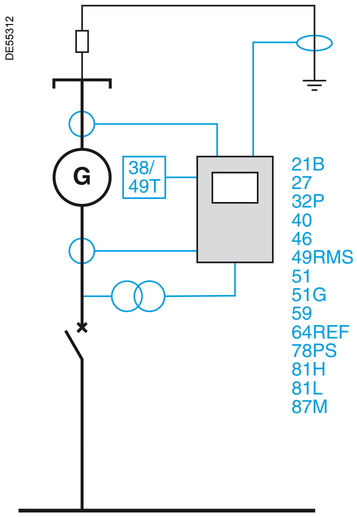
Recommended settings

Faults	Appropriate protection function		ANSI code	Setting information
Prime mover related faults				
Overloads	Overcurrent		**51**	In threshold, IDMT curve
	Thermal overload		**49RMS**	According to the generator operating characteristics: maximum thermal capacity used 115 to 120%
	RTDs		**49T**	Depends on the thermal class of the generator
Operation as a motor	Directional active overpower		**32P**	Threshold 5% of Sn (turbine) to 20% of Sn (diesel) Delay of a few seconds
Speed variation	Mechanical detection of overspeed, underspeed		**12, 14**	Threshold ± 5% of rated speed Delay of a few seconds
Power supply system faults				
External short-circuits	With current maintained at 3 In	Overcurrent	**51**	Threshold 2 In Delay for discrimination with downstream protection
	Without current maintained at 3 In	Voltage-restrained overcurrent	**51V**	Threshold 1.2 In Delay for discrimination with downstream protection
		Underimpedance (back-up)	**21B**	About 0.3 Zn Delay for discrimination with downstream protection
Inadvertent energization	Inadvertent energization		**50/27**	Current threshold = 10% of generator In Voltage threshold = 80% of Un Inhibit time after voltage sag = 5 seconds Minimum current appearance time after voltage appearance = 250 ms
Generator internal faults and generator control				
Phase-to-phase short circuits	High impedance differential		**87G**	Threshold 5 to 15% of In No delay
	Percentage-based differential		**87G**	Slope 50%, threshold 5 to 15% of In No delay
	Directional phase overcurrent		**67**	Threshold In Delay according to discrimination with the other sources
Unbalance	Negative sequence / unbalance		**46**	Threshold 15% of In Delay of a few seconds
Stator frame fault	If neutral is earthed at generator stator	Earth fault	**51G**	Threshold = 10% of maximum earth fault current Delay for discrimination with downstream protection
		Restricted earth fault differential	**64REF**	Threshold 10% of In No delay
	If neutral is impedant at generator stator	100% stator frame fault	**64G/59N**	Vrsd threshold = 30% of Vn Delay of 5 seconds
			64G/27TN	Adaptive threshold = 15% of 3rd harmonic Vrsd
	If neutral is earthed within the power system	Earth fault on generator circuit breaker side	**51N/51G**	Threshold 10 to 20% of maximum earth fault current Delay in the 0.1 second range
		Neutral voltage displacement if the generator is decoupled	**59N**	Vrsd threshold = 30% of Vn Delay of a few seconds
	If neutral is isolated	Neutral voltage displacement	**59N**	Vrsd threshold = 30% of Vn Delay of a few seconds
Rotor frame fault	Insulation monitoring device			
Field loss	Directional reactive overpower		**32Q**	Threshold 30% of Sn Delay of a few seconds
	Impedance measurement		**40**	Xa = 0.15 Zn, Xb =1.15 Zn, Xc = 2.35 Zn Zn circle delay: 0.1 second Xd circle delay: discrimination with downstream protection
Pole slip	Loss of synchronization		**78PS**	Equal-area criterion: delay of 0.3 seconds Power-swing criterion: 2 revolutions, 10 seconds between 2 power swings
Voltage regulation	Overvoltage		**59**	Threshold 110% of Un Delay of a few seconds
	Undervoltage		**27**	Threshold 80% of Un Delay of a few seconds
Frequency regulation	Overfrequency		**81H**	Threshold + 2 Hz of rated frequency
	Underfrequency		**81L**	Threshold - 2 Hz of rated frequency
Overheating of bearings	RTDs		**38**	According to manufacturer’s specifications
Power management	Directional active underpower		**37P**	According to the application

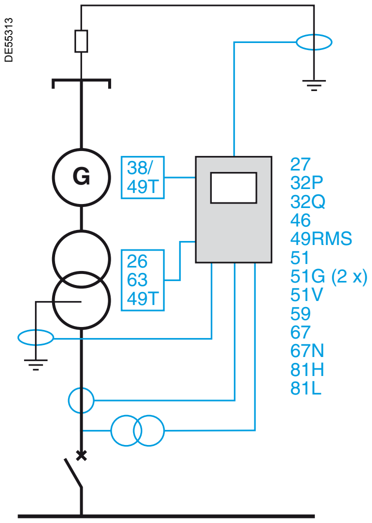
Examples of applications



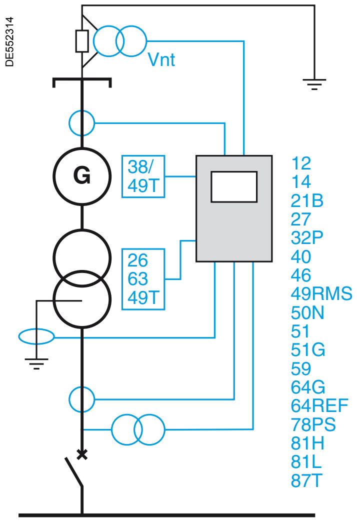
Low power generator



Medium power generator



Low power generator-transformer



Medium power generator-transformer

Types of faults

Capacitor banks are used to compensate for reactive energy drawn by power system loads and occasionally in filters to reduce harmonic voltage. Their role is to improve the quality of the power system.
They may be connected in star, delta and double star arrangements, depending on the level of voltage and the total rated power of the loads.
A capacitor comes in the form of a case with insulating terminals on top. It comprises individual capacitors (fig. 1) which have limited maximum permissible voltages (e.g. 2250 V) and are mounted in groups:
b in series to obtain the required voltage withstand,
b in parallel to obtain the desired power rating.
There are 2 types of capacitor banks:
b without internal protection,
b with internal protection where a fuse is added for each individual capacitor.

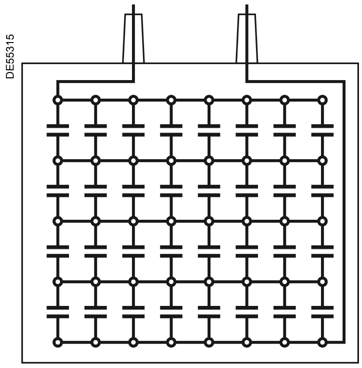


Fig. 1. Capacitor bank.

The main faults which are liable to affect capacitor banks are:
b overloads,
b short-circuits,
b frame faults,
b short-circuit of an individual capacitor.

Overloads

An overload is due to continuous or temporary overcurrent:
b continuous overcurrent due to:
v an increase in the supply voltage,
v the flow of harmonic current due to the presence of non-linear loads such as static converters (rectifiers, variable speed drives), arc furnaces, etc.,
b temporary overcurrent due to energizing of a capacitor bank step.
Overloads result in overheating which has an adverse effect on dielectric withstand and leads to premature capacitor aging.

Short-circuits

A short-circuit is an internal or external fault between live conductors, phase-to-phase (delta connection of capacitors) or phase-to-neutral (star connection).
The appearance of gas in the gas-tight case of the capacitor creates overpressure which may lead to the opening of the case and leakage of the dielectric.

Frame faults

A frame fault is an internal fault between a live capacitor component and the frame made up of the metal case that is earthed for safety purposes.
The fault current amplitude depends on the neutral earthing arrangement and on the type of connection (star or delta).
Similar to an internal short-circuit, the appearance of gas in the gas-tight case of the capacitor creates overpressure which may lead to the opening of the case and leakage of the dielectric.

Short-circuit of an individual capacitor

Dielectric breakdown of an individual capacitor results in a short-circuit.
Without internal protection, the parallel-wired individual capacitors are shunted by the faulty unit:
b capacitor impedance is modified,
b the applied voltage is distributed to one less group in the series,
b each group is subjected to greater stress, which may result in further, cascading breakdowns, until a full short-circuit.
Figure 2 shows the situation where group 2 is shunted following breakdown of an individual capacitor.
With internal protection, blowing of the related internal fuse clears the faulty individual capacitor:
b the capacitor remains fault-free,
b its impedance is modified accordingly.
Figure 3 shows the situation where the individual capacitor in group 2 is cleared by its internal fuse and group 2 remains in service.

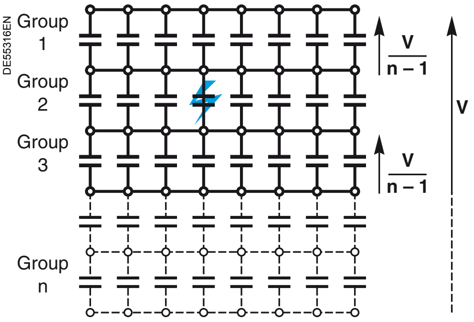


Fig. 2. Capacitor bank without internal fuses.

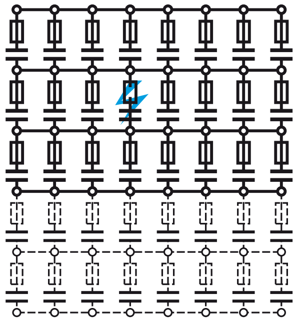


Fig. 3. Capacitor bank with internal fuses.

Protection functions

Capacitors should not be energized unless they have been discharged.
Re-energizing must be time-delayed in order to avoid transient overvoltages.
A 10-minute time delay allows for sufficient natural discharging.
Fast discharge inductors may be used to reduce discharging time.

Overloads

b Extended overcurrents due to increases in the supply voltage can be avoided by overvoltage protection (ANSI 59) that monitors the power-system voltage. This protection may cover the capacitor itself or a larger part of the power system. Given that the capacitor can generally accommodate a voltage of 110% of its rated voltage for 12 hours a day, this type of protection is not always necessary.

b Extended overcurrents due to the flow of harmonic current are detected by an overload protection of one the following types:

v thermal overload (ANSI 49RMS),

v time-delayed overcurrent (ANSI 51), provided it takes harmonic frequencies into account.

b The amplitude of short overcurrents due to the energizing of a capacitor bank step is limited by mounting impulse inductors in series with each step.

Short-circuits

Short-circuits are detected by time-delayed overcurrent protection (ANSI 51). Current and time-delay settings make it possible to operate with the maximum permissible load current as well as close and switch capacitor bank steps.

Frame faults

This type of protection depends on the neutral earthing arrangement.
If the neutral is earthed, time-delayed earth fault protection (ANSI 51G) is used.

Capacitor component short-circuit

Fault detection is based on the modification of the impedance created:

b by short-circuiting the component for capacitors with no internal protection,

b by clearing the faulty individual capacitor for capacitors with internal fuses.

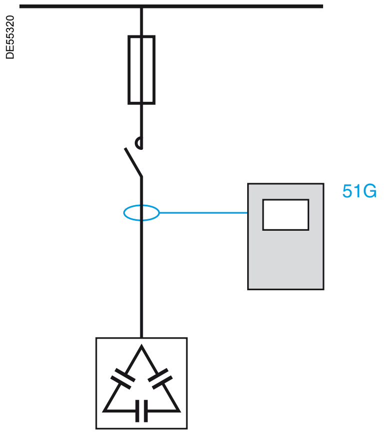
When the capacitor bank is double star-connected, the unbalance created by the change in impedance in one of the stars causes current to flow in the connection between the neutral points. This unbalance is detected by a time-delayed sensitive overcurrent protection device (ANSI 51).

Recommended settings and examples of applications

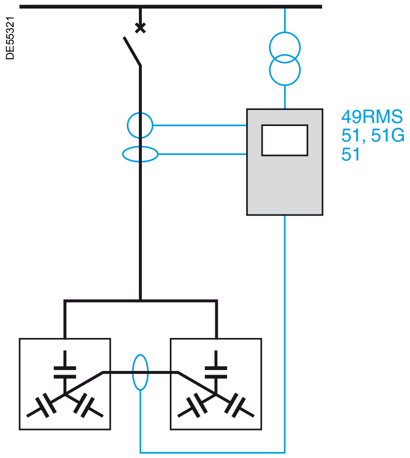
Recommended settings

Faults	Suitable protection functions	ANSI code	Setting information
Overloads	Overvoltage	**59**	Threshold ≤ 110% Un
	Thermal overload	**49 RMS**	Threshold ≤ 1.3 In Time constant in the 10-minute range
	Time-delayed overcurrent	**51**	Threshold ≤ 1.3 In, IDMT curve
Short-circuits	Time-delayed overcurrent	**51**	Threshold approximately 10 In Time delay approximately 0.1 s (DT)
Frame faults	Time-delayed earth fault	**51N/51G**	Threshold ≤ 20% I maximum earth fault Threshold ≥ 10% CT rating is supplied by 3 CTs, with H2 restraint Time delay approximately 0.1 s (DT)
Capacitor component short-circuit	Time-delayed overcurrent	**51**	Threshold approx. 1 A, depending on the application Time delay approximately 1 s (DT)

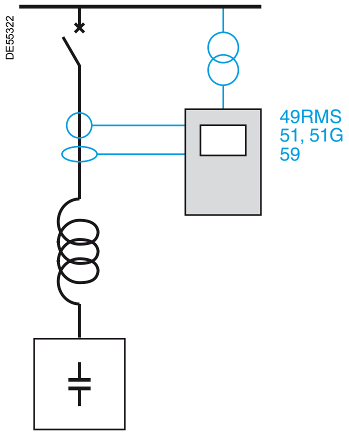
Examples of applications



Delta compensation



Double-star compensation



Filtering assembly

Glossary
Key words and definitions

Key words	Definitions
Active power in MW	The part of the apparent power that can be converted into mechanical or thermal power.
Aperiodic component	Average value (that drops to zero) of the upper and lower envelopes of a current during energization or the initiation of a short-circuit.
Apparent power in MVA	Power in MVA drawn by the loads in a power system.
Blocking signal	Order sent to an upstream protection device by a device that has detected a fault.
Breaking capacity	Maximum current that a breaking device is capable of interrupting under prescribed conditions.
Compensated neutral	The power system is earthed via a reactor tuned to the phase-to-earth capacitances.
Compensation coil (Petersen coil)	Neutral earthing reactor tuned to the phase-to-earth capacitances.
Core balance CT	Current sensor used to measure the residual current by summing the magnetic fields.
Cos φ	Cosine of the angle between the fundamental components of the current and voltage.
Coupling	Operation whereby a source or part of a power system is connected to a power system already in operation when the necessary conditions are fulfilled.
Current sensor	Device used to obtain a value related to the current.
Current-based discrimination	Discrimination system based on the fact that the closer the fault is located to the source, the stronger the fault current.
Decoupling	Operation whereby a source or part of a power system is disconnected from a power system.
Definite-time delay	Time delay before device tripping that does not depend on the measured current.
Discrimination	Capacity of a set of protection devices to distinguish between conditions where a given protection device must operate and those where it must not.
Dynamic stability	Capacity of a power system to return to normal operation following a sudden disturbance.
Feeder	Cables arriving from a set of busbars and supplying one or more loads or substations.
Harmonics	Series of sinusoidal signals whose frequencies are multiples of the fundamental frequency.
IDMT delay	Variable time delay before device tripping that is inversely dependent upon the measured current.
IEC 60909	International standard dealing with the calculation of short-circuit currents in three-phase power systems.
Impedant neutral	The power system is earthed via a resistance or a low reactance.
Incomer	A line supplying energy from a source to the busbars of a substation.
Inrush current	Transient current that occurs when a load is connected to a power system. For inductive loads, it comprises an aperiodic component.
Insulation monitoring device (IMD)	In an isolated neutral system, device that verifies the absence of a fault.
Isolated neutral	The power-system neutral is not earthed except for high-impedance connections to protection or measurement devices.
Load reconnection	Restoration of supply to loads that have been shed, when normal power system operating conditions have been re-established.
Load shedding	Disconnection of non-priority loads from the power system when normal power system operating conditions no longer exist.
Logic discrimination	Discrimination system in which any protection device detecting a fault sends a “no-trip” order (blocking signal) to the upstream protection device. The upstream protection trips a circuit breaker only if it did not receive a blocking signal from the downstream device.
Making capacity	Maximum current that a breaking device is capable of making under prescribed conditions. It is at least equal to the breaking capacity.
Neutral earthing	Method by which the power system neutral is connected to earth.
Non-linear load	Load drawing a current with a waveform that is not identical to that of the voltage. Current variations are not proportional to the voltage variations.
Overload	Overcurrent lasting a long time and affecting one of the elements in the power system.

Glossary
Key words and definitions

Key words	Definitions
Polarization voltage	In a directional phase protection function, the phase-to-phase voltage value in quadrature with the current for cos φ = 1. In a directional earth-fault protection function, it is the residual voltage.
Power factor	Ratio between the active power and the apparent power. For sinusoidal signals, the power factor is equal to cos φ.
Power system	Set of electrical-power production and consumption centres interconnected by various types of conductors.
Protection settings	Protection function settings determined by the protection-system study.
Protection system	Set of devices and their settings used to protect power systems and their components against the main faults.
Protection-system study	Rational selection of all the protection devices for a power system, taking into account its structure and neutral earthing system.
Rate of change of frequency (ROCOF)	Protection used for rapid decoupling of a source supplying a power system in the event of a fault.
Reactive power in Mvar	The part of the apparent power that supplies the magnetic circuits of electrical machines or that is generated by capacitors or the stray capacitance of the links.
Recloser	Automatic device that recloses a circuit breaker that has tripped on a fault.
Residual current	Sum of the instantaneous line currents in a polyphase power system.
Residual voltage	Sum of the instantaneous phase-to-earth voltages in a polyphase power system.
Restricted earth fault protection	Protection of a three-phase winding with earthed neutral against phase-to-earth faults.
Short-circuit	Accidental contact between conductors or between a conductor and earth.
Short-circuit power	Theoretical power in MVA that a power system can supply. It is calculated on the basis of the rated power system voltage and the short-circuit current.
Solidly earthed neutral	The power-system neutral is earthed via a connection with zero impedance.
Source transfer	Operation whereby a power system is disconnected from one source and connected to another. The sources may or may not be parallel connected.
Subtransient	Period lasting between 0 and 100 ms following the appearance of a fault.
Symmetrical components	Three independent single-phase systems (positive sequence, negative sequence and zero sequence) superimposed to describe any real system.
System reconfiguration	Operation, following an incident, involving switching of circuit breakers and switches to resupply power system loads.
Time delay	Intentional delay in the operation of a protection device.
Time-based discrimination	Discrimination system in which protection devices detecting a fault are organized to operate one after the other. The protection device closest to the source has the longest time delay.
Total harmonic distortion	Ratio of the rms value of the harmonics to that of the fundamental.
Transient	Period lasting between 100 ms and 1 second following the appearance of a fault.
Tripping threshold	Value of the monitored parameter that trips operation of the protection device.
Voltage sensor	Device used to obtain a value related to the voltage.
Zero-sequence generator	Three-phase transformer used to create a neutral point in a power system for neutral earthing.

Bibliography

Types of documents	Titles
Standards	b IEC 60050 international electrotechnical vocabulary b IEC 60044 current transformers b IEC 60186 voltage transformers b IEC 60255 electrical relays b IEC 60909 calculation of short-circuit currents in three-phase AC systems b IEEE C37.2 standard electrical power system device function numbers and contact designations
Schneider Electric documentation	b MV design guide b Protection of power systems (Published by Hermès) b MV partner b Cahier technique publications v N° 2 Protection of electrical distribution networks by the logic-selectivity system v N° 18 Analysis of three-phase networks under transient conditions using symmetrical components v N° 62 Neutral earthing in an industrial HV network v N° 113 Protection of machines and industrial HV networks v N° 158 Calculation of short-circuit currents v N° 169 HV industrial network design v N° 174 Protection of industrial and tertiary MV networks v N° 181 Directional protection equipment v N° 189 Switching and protecting MV capacitor banks v N° 192 Protection of MV/LV substation transformers v N° 194 Current transformers: how to specify them v N° 195 Current transformers: specification errors and solutions b Schneider Electric site: http://www.schneider-electric.com b Sepam protection-relay site: http://www.sepamrelay.com b Sepam catalogues
General	b Les techniques de l'ingénieur (Engineering techniques) b Guide de l'ingénierie électrique (Electrical engineering handbook) (Lavoisier)

Definitions of symbols

Symbol	Definition
ALF	accuracy-limit factor
C	capacitance of a phase with respect to earth
CT	current transformer
D	feeder circuit breaker
Δt	difference between the operating times of two protection devices
dT	tolerance of time delays
E	phase-to-neutral voltage of the equivalent single-phase diagram
f	power frequency
I"k	initial symmetrical short-circuit current
I_0	zero-sequence component of current
I_1	positive-sequence component of current
I_2	negative-sequence component of current
I1	phase 1 current
I2	phase 2 current
I3	phase 3 current
Ib	symmetrical short-circuit current interrupted when the first pole separates
Ic	capacitive current
IDC	decreasing aperiodic component of the short-circuit current
Ik	continuous short-circuit current
Ik1	continuous phase-to-earth short-circuit current
Ik2	two-phase short-circuit current
Ik3	three-phase short-circuit current
ILN	current flowing in the neutral earthing reactor
Im	magnetizing current
IMD	insulation monitoring device
In	rated current of an electrical component
IN	current flowing in the solidly earthed neutral-point circuit
InCT	rated current of a current transformer
Ip	peak value of short-circuit current
IpCT	primary current in a current transformer
IRN	circuit flowing in the neutral earthing resistor
Irsd	residual current
Is	current threshold setting
Isat	saturation current in a current transformer
Isc	short-circuit current
Iscmax	the highest short-circuit current
IsCT	secondary current in a current transformer
Ith	maximum permissible current for 1 s
LN	neutral-point earthing reactance
LPCT	low-power current transformer
m	safety margin
MALT	earthing

Symbol	Definition
NPC	neutral point coil
Ph1	phase 1
Ph2	phase 2
Ph3	phase 3
R	resistance
RCT	winding resistance in a current transformer
RN	neutral-point earthing resistance
Rs	stabilization resistance in a differential circuit
Ssc	short-circuit power
T	tripping time delay
Td	tripping time
THD	total harmonic distortion
Tmin	circuit breaker breaking time (minimum time before separation of 1st pole)
tr	protection overshoot time
U	phase-to-phase voltage
Un	rated phase-to-phase voltage
Us	phase-to-phase voltage threshold
V	phase-to-neutral voltage
V_0	zero-sequence component of voltage
V_1	positive-sequence component of voltage
V_2	negative-sequence component of voltage
V1	phase 1 phase-to-neutral voltage
V2	phase 2 phase-to-neutral voltage
V3	phase 3 phase-to-neutral voltage
Vk	knee-point voltage
Vn	rated phase-to-neutral voltage
Vrsd	residual voltage
Vs	phase-to-neutral voltage threshold
VT	voltage transformer
X	reactance
Xd	synchronous reactance
X'd	transient reactance
X"d	subtransient reactance
Z_0	zero-sequence impedance
Z_1	positive-sequence impedance
Z_2	negative-sequence impedance
Za	equivalent impedance
Zn	apparent rated impedance (transformer, capacitor, motor, generator)
ZN	impedance between the neutral point and earth
Zsc	short-circuit impedance

Index of technical terms

A
aperiodic component 18

B
blocking signal 27, 31, 34, 35, 41, 42
breaking capacity 18
busbars 4, 5, 33

C
cable 18, 33, 41, 44, 45
capacitor 18, 27, 60, 61, 62
capacitor bank 27
characteristic angle 25
circuit breaker 17, 18, 27, 36–43, 45
circuit-breaker failure 43
coil
    extinction 10
    neutral point 9
    Petersen 10
contactor 2, 18, 52, 54
core balance CT 7, 8, 22, 26
coupling 35, 39, 46, 57
current
    residual 10, 22
    short-circuit 12–19, 28, 30
current sensors 19-22, 33

D
decoupling 19, 26, 39
differential protection
    busbars 26
    generator 26
    high impedance 33, 58
    line 26
    motor 26
    percentage-based 48, 58
    restricted earth fault 26, 47, 48, 56, 58
    transformer 26
discrimination
    combined 34, 36
    current-based 30, 34, 47
    differential 35
    directional 35
    logic 34, 35, 36
    time-based 28, 29, 31, 34, 35, 38

E
earthing 6–11

F
fault, characterization 12, 18
fuse 18, 47, 50, 52, 60

G
generator 14–17, 33, 55–59

H
harmonics 46, 47, 56, 58, 60

I
IEC 60909 17

L
line 18, 33, 44, 45
load shedding 43
LPCT 19, 21

M
making capacity 18
motor
    asynchronous 14, 50, 54, 55
    synchronous 14, 50, 53, 54

N
neutral
    compensated 6, 26, 37, 38
    impedant 26, 56, 58
    isolated 6, 7, 23
    solidly earthed 11, 37, 38
neutral earthing 6-11
neutral point 6–11, 37, 47, 48, 52, 56

O
overfluxing 47
overload 44, 47, 51, 56, 61
overvoltage 6–12, 61

P
power
    active 27, 39, 51, 53, 57, 58
    apparent 19, 23
    rated output 19
    reactive 53, 55, 57, 58
    short-circuit 11, 12, 45
power system
    architecture 3, 4, 5
    loop 4, 5, 32, 35, 40, 41
    radial 4, 5, 29, 31, 36
power factor 27
protection
    100% generator stator 26
    busbars 42, 43
    capacitor 60–62
    circuit breaker failure 26
    differential 20, 26, 33, 35, 41, 42, 44, 47, 52, 53, 56
    directional active overpower 26
    directional active underpower 26, 58
    directional reactive overpower 26, 53, 58
    directional reactive underpower 26
    distance 26, 45
    excessive starting time and locked rotor 26, 51
    field loss 26, 50, 52, 53, 55, 57, 58
    generator 55–59
    inadvertent generator energization 26
    links 44, 45
    motor 50–54
    negative sequence / unbalance protection 26, 44, 53, 58
    negative sequence overvoltage 26

Index of technical terms

- neutral voltage displacement 26, 48, 53, 58
- overcurrent
  - delayed earth fault 11, 26, 44, 61, 62
  - delayed phase 26, 47, 52, 62
  - delayed voltage-restrained phase 26, 56
  - directional earth fault 7, 26, 37, 44, 52, 53
  - directional phase 26, 56, 58
  - earth fault 36, 37, 38, 40, 42, 48, 53, 56, 58
  - instantaneous earth-fault 26
  - instantaneous phase 26, 47, 48
  - instantaneous voltage-restrained phase 26
  - phase 20, 36, 38, 40, 44, 56
- overfluxing 26, 48, 57
- overfrequency 26, 58
- overspeed 26, 53, 58
- overvoltage 26, 37, 47, 58, 62
- phase undercurrent 26, 53
- pole slip 26, 50-58
- positive sequence undervoltage 26, 51, 53
- power system 36–41
- pressure 26, 47, 48
- rate of change of frequency (rocof) 26, 39, 43
- recloser 26, 45
- remanent undervoltage 26, 51, 53
- residual undervoltage (third harmonic) 26, 56, 58
- RTD 26, 51, 53, 56, 58
- successive starts 26
- synchro-check 26, 39
- temperature monitoring 26
- thermal image 26, 44, 47, 51, 53, 56, 58, 61, 62
- thermostat 26
- transformer 46–49
- underfrequency 26, 58
- underimpedance 26, 53, 56, 57, 58
- underspeed 26, 53, 58
- undervoltage 26, 57, 58
- vector shift 26

protection coordination 2
protection relays 22, 24, 42
protection settings 14
protection system study 2, 3, 8, 9

R

rate of change of frequency 26, 39, 43
recloser 26, 45
residual voltage 7, 23, 37, 47, 52, 56
restraint
- current 33
- H2 (second harmonic) 22, 25, 47, 48, 62
- H5 (fifth harmonic) 47
- voltage 26, 56, 58

restricted earth fault 26, 47, 48, 56, 58

S

saturation
- of a CT 8, 19, 20, 22, 33, 42
- of a transformer 46

short-circuit
- phase-to-earth 12, 14, 17
- phase-to-phase 12, 14, 17, 44, 47, 52, 56
- three-phase 12, 14, 17
- two-phase 15, 17
- two-phase clear of earth 12
- two-phase-to-earth 7, 12, 15, 17

source transfer 39
subtransient 16, 17, 55
switch 2, 18, 40
symmetrical components 13, 14, 15, 17

T

temperature 27, 47, 51, 52
time
- operation 24, 28
- overshoot 24, 28
- reset 24, 25
- timer hold 25
- tripping 24, 25, 31, 34, 53

time delay
- definite 25
- IDMT 25

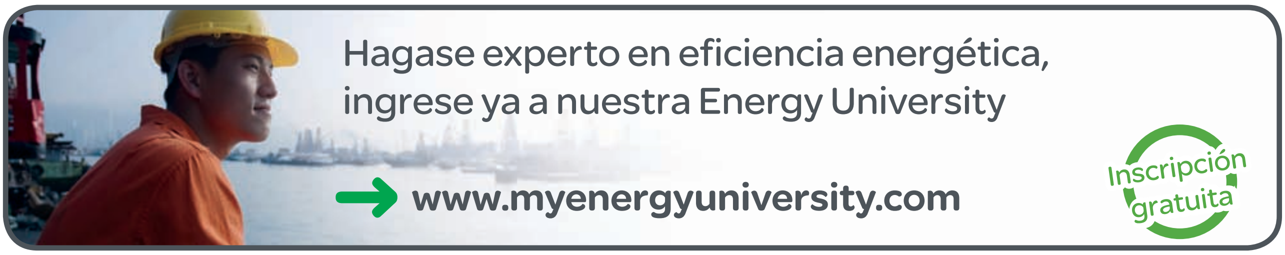
total harmonic distortion 27
transformation ratio 23
transformer
- current 19, 21, 27, 33, 35, 52
- voltage 19, 23, 27, 32

transformer energization 46
transient 6, 7, 10, 16, 46, 55
tripping threshold 7, 25, 48

Z

zero-sequence generator 8, 37, 38

Make the most of your energy



Schneider Electric de Colombia S.A.

Centro de Atención Clientes
Bogotá: 4269733 Resto del Pais: 01900 33 12345
cacschneider@co.schneider-electric.com
www.schneider-electric.com.co

Schneider Electric de Colombia S.A.
Principal BOGOTÁ D.C., Carrera 102 A No. 25 D - 40
Tel.:57 (1) 4269700
Fax: 57 (1) 4269740 - 57 (1) 4269738

Agencia Antioquia
MEDELLÍN Calle 10 Sur No. 50FF - 28 Of. 309
Tel.: 57 (4) 3616730 - 57 (4) 3621191
Fax: 57 (4) 2856568

Agencia Costa Norte
BARRANQUILLA Calle 77B No. 57 - 141 Of. 309
Tel.: 57 (5) 3530465 - 57 (5) 3530468 - 57 (5) 3530447
Fax. 57 (5) 3530429

Agencia Eje Cafetero
MANIZALES Carrera 23 No. 63 - 15 Oficina 804
Edificio El Castillo
Tel.: 57 (6) 8853660 Fax: 57 (6) 8973435

Agencia Occidente
CALI Calle 19 Norte No. 2N - 29 Edificio Torre de Cali
Piso 36 Of. 3601-A Tel.: 57 (2) 6536414 - 57 (2) 6536515
57 (2) 6536539 Fax: 57 (2) 6536540

Agencia Oriente
BUCARAMANGA Carrera 28 No. 41 - 19
Tel.: 57 (7) 6343169 Fax. 57 (7) 6450762

♻ Impreso con tintas a base de aceite vegetal, papel sin cloro, material reciclable.