Applications for
SIPROTEC Protection Relays

2005

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Contents

Protection of Combined Cable and Overhead Lines

1. Distance protection with auto-reclosure on mixed lines

On mixed lines with cables and overhead lines the distance zone signals can be used with a distance protection relay 7SA6 to distinguish to a certain extent between cable and overhead line faults. Mixed lines mean that part of the protected line is designed – within the same grading zone – as a cable section and the other part of that line as an overhead line section. The auto-reclosure function is only useful on the overhead section of the line. The section of the line to be protected must be selected accordingly in the grading. The auto-reclosure function can be blocked (in the event of a fault in the cable section) by interconnection by means of the user-programmable logic functions (CFC) in the DIGSI parameterization and configuration tool.

2. System configuration

According to the system configuration in the distance zones Z1, Z2, Z3 and Z5 with their line impedances (impedances of the line as *R* and *X* values, resistance values and reactance values) the line sections are graded as usual in the distance protection relay SIPROTEC 7SA6. Zone Z1B serves above all for the automatic reclosing function and for switching functions (e.g. "manual close"). Zone Z4 is used to measure and select the cable or overhead line part of the line to be protected.

Zone Z1B can also be used for fast disconnection of the line to be protected when closing onto a fault, in addition to application in conjunction with the auto-reclosure function. The protection must trip fast if, when closing onto the line to be protected, the feeder at the remote end is e.g. still earthed. The 7SA6 also provides the "high-current – instantaneous tripping" function for this protection as an alternative. Both applications are described here.

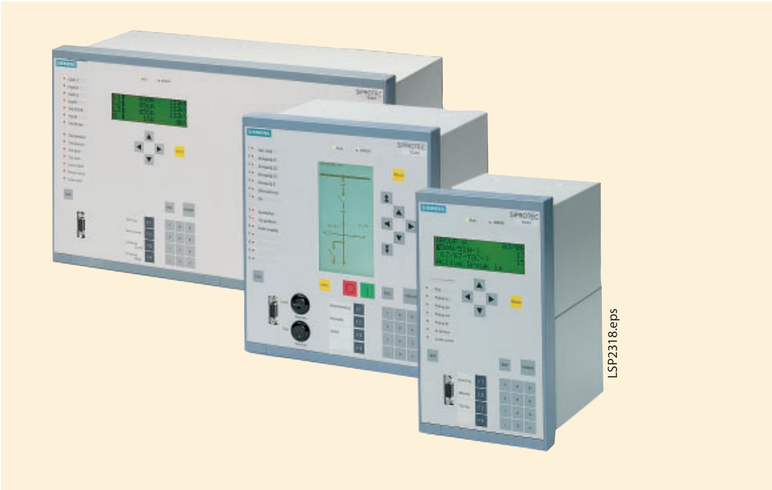


Fig. 1 SIPROTEC 7SA6 distance protection

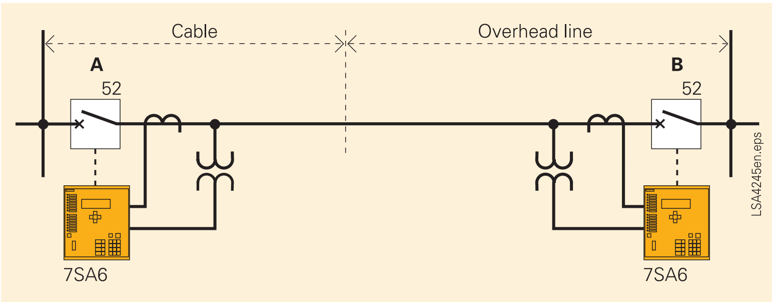


Fig. 2 Protection of combined cable and overhead lines

The application is described on the basis of a line <A-B> with two SIPROTEC 7SA6 distance protection relays.

A solution for the protection relay at location "A" is described in the following. Here the line sections of the mixed line are selected with the distance zones Z1B and Z4.

The protection relay at location "B" can be set for auto-reclosure on mixed lines either

- by the distance zone Z1B and the high-current instantaneous tripping or
- alternatively with grading of zones Z1B and Z4.

■ 3. Settings in the configuration with DIGSI

First the following settings must be made in the configuration matrix in the parameter set for the 7SA6, for configuration in DIGSI.

Configuration matrix (group: "Auto-reclosure" or "General distance protection"

a) FNo. 2703 – ">Block auto-reclose function" configured to "Source CFC"

b) FNo. 3747 – "Distance pickup Z1B, loop L1E" configured to "Target CFC"

c) FNo. 3748 – "Distance pickup Z1B, loop L2E" configured to "Target CFC"

d) FNo. 3749 – "Distance pickup Z1B, loop L3E" configured to "Target CFC"

e) FNo. 3750 – "Distance pickup Z1B, loop L12" configured to "Target CFC"

f) FNo. 3751 – "Distance pickup Z1B, loop L23" configured to "Target CFC"

g) FNo. 3752 – "Distance pickup Z1B, loop L31" configured to "Target CFC"

h) FNo. 3759 – "Distance pickup Z4" configured to "Target CFC"

Parameterization: (parameter group A, distance protection – polygon, zone 4)
Parameter 1335 "T4 DELAY"

The tripping time for zone 4 (parameter 1335 = T4) must be set to infinite (T4 = ∞) because this zone is only used for selecting the cable or overhead line part of the line. Zone 4 should only signal a pickup in this application. Tripping in this zone is irrelevant. This function is particularly important for the single-pole auto-reclosure function because the tripping then takes place exclusively via zone Z1B.

■ 4. Creating the logic flowcharts

All that need now be done is to create, link and translate the appropriate logic diagrams in the CFC in DIGSI. The "fast" PLC task (PLC0) is used as a run level in the CFC.

The individual logic functions and the effect on the protected zone are described below.

Appropriate allocations must be performed (with the execution of an auto-reclosure function) for the described line <A – B> in both distance protection relays, to detect the zone of the overhead line.

4.1 Control of auto-reclosure in the 7SA6 for protection relay A

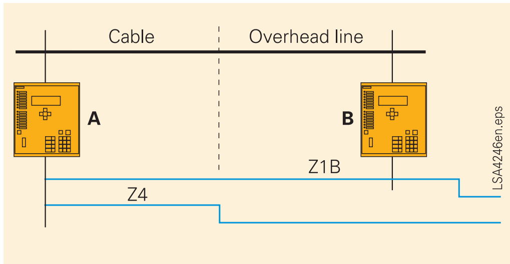


Fig. 3 Control of the auto-reclosure for protection relay A

7SA6 – protection relay A:

The setting values of zone Z4 correspond to the grading with the *R* and *X* values of the cable section. Zone Z1B is designed as usual for about 120 % of the line length. Since no auto-reclosure is to be performed in the cable section, the overhead line section is selected in zone Z1B by a CFC plan. With the result of the CFC plan (FNo. 2703: ">AR block.") auto-reclosure can be blocked in the event of a fault in the cable section (zone Z4) (see Fig. 4).

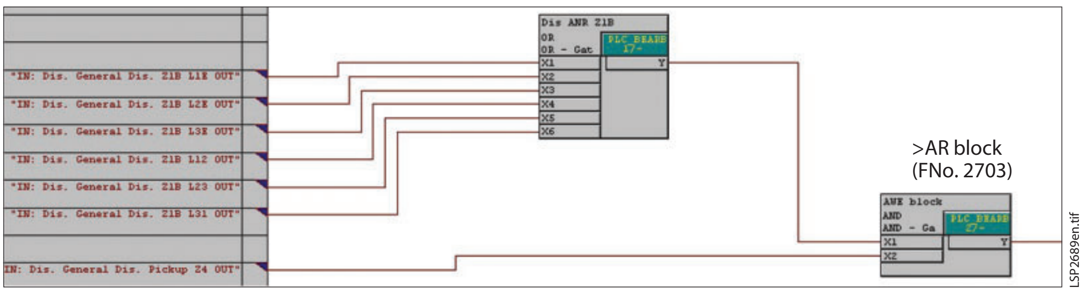


Fig. 4 CFC plan for protection relay A

4.2 Control of auto-reclosure in the 7SA6 for protection relay B

4.2.1 Version 1

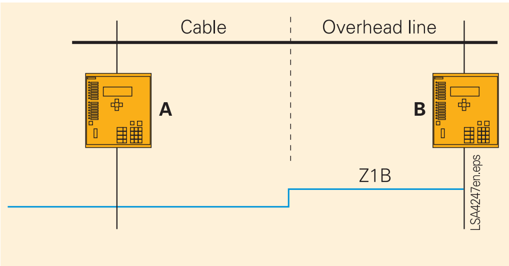


Fig. 5 Distance protection with zone Z1B and the instantaneous high-current tripping

7SA6 – protection relay B:

The setting values of zone Z1B correspond to the grading with the *R* and *X* values of the overhead line on which the auto-reclosure function is to be performed. The instantaneous "high-current tripping" function is used in 7SA6 for instantaneous tripping when closing onto a fault, to completely protect the <A – B> line.

The task of the *instantaneous high-current element (instantaneous high-current switch-onto-fault)* is to perform tripping immediately and without delay when a feeder is closed onto a high-current short-circuit. It serves primarily as fast-acting protection when connecting an earthed feeder, but can also become effective (settable) with every closing – including auto-reclosure. The connection of the line is reported to the protection by the "detection of the circuit-breaker position" (parameter 1134).

In order to make use of the instantaneous high-current tripping, the function must have been enabled in the relay scope configuration. The value of the short-circuit current which leads to pickup of the instantaneous tripping function is set as '*I*>>>' value (parameter 2404). The value must be high enough to avoid the protection tripping (whatever the circumstances) in the event of a line overload or current increase – e.g. as a result of a brief interruption on a parallel line.

At least 2.5 times the rated current of the line is recommended as a pickup value for the instantaneous high-current tripping.

4.2.2 Version 2

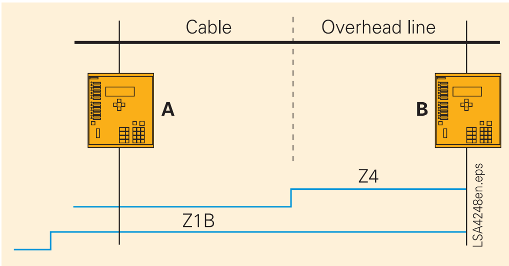


Fig. 6 Distance protection with grading of the zones Z1B and Z4

7SA6 – protection relay B:

The setting values of zone Z4 correspond to the grading with the *R* and *X* values of the overhead line. Zone Z1B is designed as usual for about 120 % of the line length. Since no auto-reclosure is to be performed in the cable section, the overhead line section is selected in zone Z1B with a CFC plan. With the result of the CFC plan (FNo. 2703: ">AR block.") automatic reclosing is blocked in the event of a fault in the cable section. This means that an auto-reclosure is only performed in the case of pickup of the protection in zones Z1B and Z4 (see Fig. 7).

5. Summary:

By division into two distance protection zones (Z1B and Z4), selection of the cable and overhead line sections for double-end feeding in the event of a fault is substantially simplified. In the practical application the auto-reclosure function can only be performed restricted to the overhead line. A fault in the cable section leads immediately to a final TRIP command.

As shown, special requirements (such as selection of the faulty line section) can be implemented easily and at low cost with the CFC logic in the SIPROTEC distance protection.

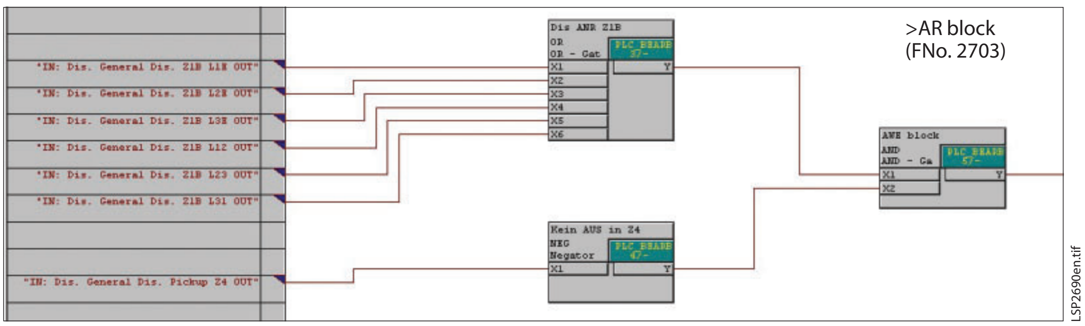


Fig. 7 CFC plan for protection relay B

Redundant Supply with Bus Coupler

Automatic switchover of incoming supply with SIPROTEC 7SJ62

1. Introduction

Liberalized energy markets are demanding new solutions for the operation of electrical systems. This publication describes an application in which the availability of power supply of a switchgear or plant can be improved considerably by switching over from a faulty to a redundant incoming supply. The influence of external system faults is minimized decisively by fast disconnection of faulty system parts and switchover from a faulty to a trouble-free infeed. These automation tasks can be accomplished today with modern SIPROTEC protection relays without the need for further equipment.

2. Influential variables of system availability

"Power Quality" covers all the properties of an electrical power supply. Power quality can be further subdivided into "voltage quality and system reliability" as shown in Fig. 2. The latter is closely linked with an "adequate" power supply and the security of the supply. Only the system reliability is looked at in detail below.

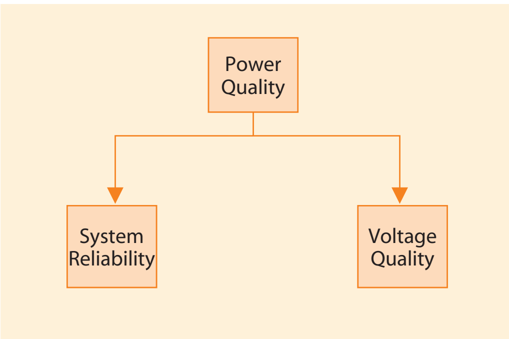


Fig. 2 Subdivision of Power Quality

Fig. 1 SIVACON 400 V, with 7SJ62-protected and controlled circuit-breakers

The reliability of an electrical system is determined by a number of factors. These include the reliability of every single item of equipment, the kind and method of connection of the equipment, i.e. the system topology, the properties of the protection relays, the remote control equipment, the dimensioning of the equipment, the method of operation including troubleshooting, and the system load capacity. The most frequently applied qualitative criterion in power system planning is (n-1), with which a system can be checked for sufficient redundancy.

It requires that the system must be able to survive failure of any item of equipment without impermissible restriction of its function. The (n-1) criterion is a pragmatic and easy-to-handle basis for decision but has the disadvantage that the supply reliability cannot be quantified. Frequency, duration and scope of interruptions in the supply are not measured, with the result that it is not possible (for example) to distinguish between different (n-1)-safe system variants in terms of reliability. Quantitative methods of system reliability analysis allow further evaluation of planning and operating variants supplementary to the qualitative methods. The supply quality is quantified by suitable parameters and thus enables a comparative assessment of different (n-1) reliable planning and operation variants (for example). This allows a specific estimate of the costs and benefits of individual solutions in system planning and operation.

Switchover with redundant incoming feeders means investment. However, by considering the behavior in case of outages of equipment, the system topology, the protection concepts, the system capacity utilization (supply and loads) and the method of operation, even more reliable and safe system operation can be ensured. The aim is overall system reliability, expressed in terms of a high degree of supply availability for special customers with sensitive processes. Closer analyses by way of the load cycle of individual feeders or transformer stations –as well as permanent rationalization measures in operation of the power systems –also call for a higher degree of automation in all power system sections.

2.1 Transient voltage sags and outages

The most frequent cause of system faults and internal voltage sags or outages (total failures) is a lightning strike. As Fig. 3 shows, the system fault may be in the transmission system or in the distribution system.
Usually there is no total blackout but the remaining residual voltage is greater than 70 %.

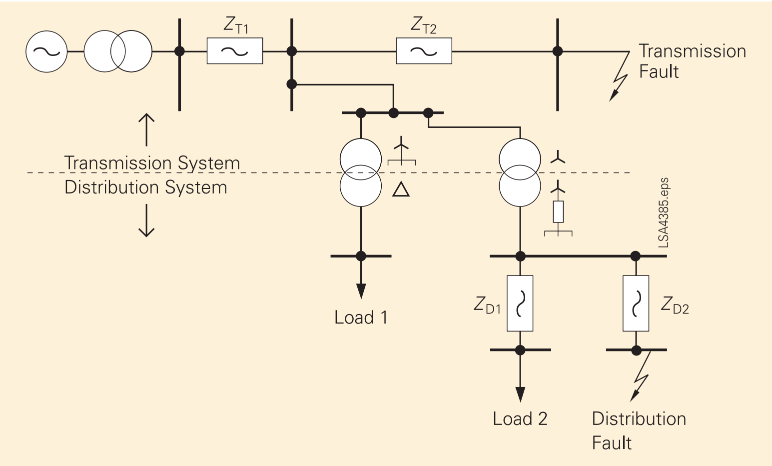


Fig. 3 Possible locations of system faults

The economic damage caused by sags or outages is immense (Fig. 4). The following Fig. 5 shows computer loads can fail already when the system amplitude deviates from its rating for less than one period. This so-called ITI/CBEMA curve is used worldwide as a reference for the sensitivity of other load types too, because the appropriate manufacturer data are often unavailable. The difficulty in protecting a highly automated factory is largely attributable to the large number of loads and the degree of networking of these loads.

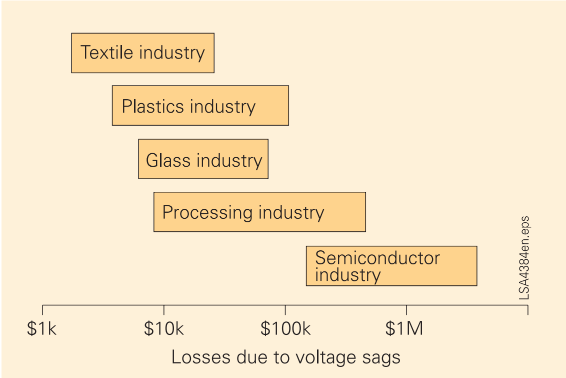


Fig. 4 Typical failure costs per voltage sags

3. Functional principle and aim of automatic switchover

A traditional method for a utility to solve its power quality problems is information from customers about supply limitations suffered. With the multifunction protection relays presented below it is possible to find solutions for protecting whole areas from outages by means of protection relays with integrated automatic functions.

Automatic switchover is suitable for disconnecting an endangered supply and quickly bringing in a redundant, secure supply with the aid of an alternative incoming feeder. A fault is detected by an undervoltage detection function. Using a directional overcurrent detection function, it can be decided whether the fault is external or internal. In the event of an external fault, switchover to the alternative incoming feeder takes place. However, if the fault is internal there is no switchover, with the intention that the fault can be cleared by available circuit-breakers.

Switchover to the alternative incoming feeder or the coupling of separated networks only takes place instantaneously when both separated networks are synchronized. Otherwise it waits until synchro- nicity between the two separated networks is established or the voltage has dropped to such an extent that safe connection is possible. However this is only on condition that the two incoming feeders are not impaired in their voltage quality by the same system fault, such that switchover provides no protection against load shedding.

In the case of rapid system decoupling (opening the circuit-breaker in the faulty incoming feeder) it can be assumed that the fault current has a higher displacement than in normal switching. This should be taken into account in the choice of circuit-breakers. The system configuration and the specific requirements regarding switching time must therefore be analyzed before choosing the suitable rapid switchover.

The following typical applications are particularly conceivable:

1. Switchover from one redundant incoming feeder to the next to protect loads from voltage outages
2. System decoupling in the event of a fault on the load side and therefore prevention of the fault from affecting other loads.

3.1 Practical principle

The SIPROTEC relays attend to full protection of the incoming feeders by means of directional overcurrent-time protection.

Configuration instructions for protection of the incoming feeders are not dealt with in detail here.

Automatic switchover is implemented by at least two autarchic SIPROTEC 4 relays (e.g. 7SJ62) which can be adapted individually to the design and basic conditions applying in a customer specification, in combination with the existing switchgear.

The following switchover possibilities can be distinguished here:

- Overlap switchover
  Both circuit-breakers are actuated almost simultaneously
- Rapid switchover
  Circuit-breaker 1 is opened and circuit-breaker 2 closed as long as the voltage is below ΔU – motor rundown behavior is taken into account
- Slow switchover
  Motors must have run down, or else be switched back on as from a certain residual voltage, the reason being high start-up current of the motor groups; this possibility should be rare.

3.2 Description

The desired configuration can be selected as "normal operation" with the preselector switch S100. The selected circuit-breaker remains defined as "normally OPEN". This open circuit-breaker is considered as a backup in the event of a fault which can then supply the faulty, disconnected busbar section with energy again. Each circuit-breaker operates autarchically and is controlled by one single multifunction relay.

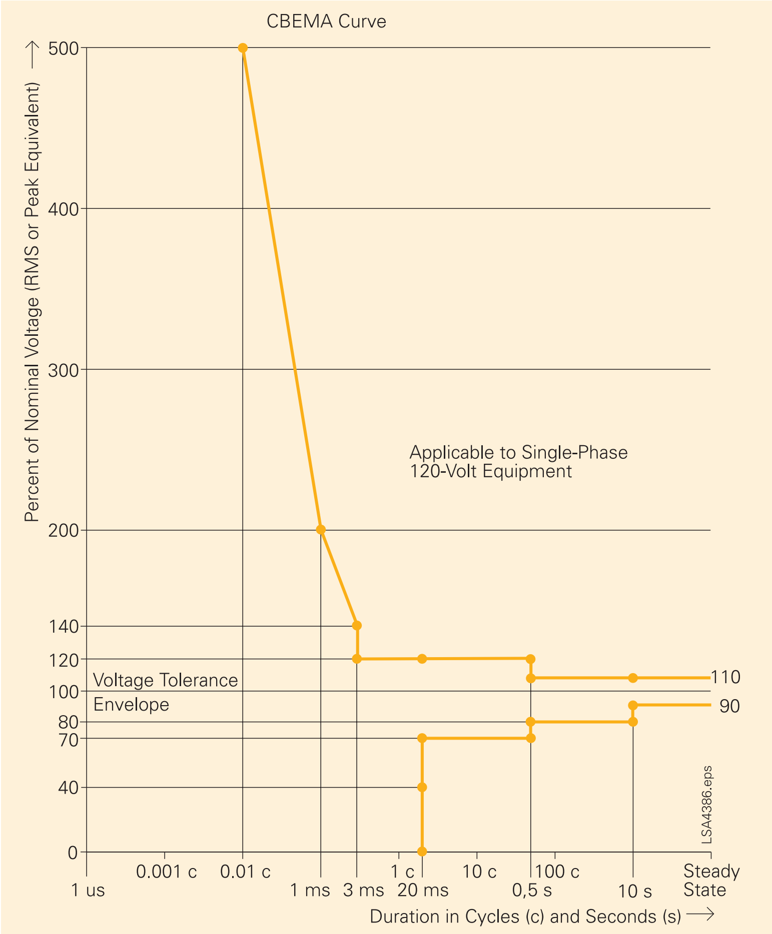


Fig. 5 ITI/CBEMA curve

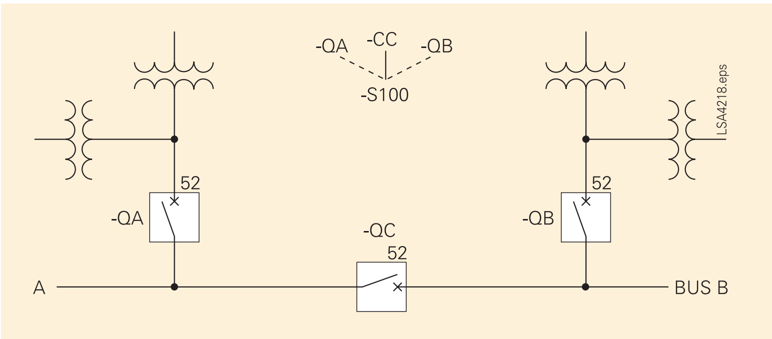


Fig. 6 Bay layout

The relays are interconnected by binary signal communication between the binary inputs and outputs. In this way every relay can communicate with the other two relays and exchange information about circuit-breaker position and protection functions.

Therefore it is possible to create self-controlling automatism also allowing manual control from the outside. When connecting, the synchro-check can be performed by the multifunction relays (7SJ64) themselves or by a separate synchro-check device.

a) In the event of undervoltage and breaker failure from subordinate feeders or from the parallel incoming supply, the circuit-breakers are tripped individually by any protective pickup.

b) If the protection has picked up due to a fault outside the switchgear or plant, or the supply voltage drops although there is no short-circuit/earth fault, the parallel incoming feeder is granted release (release of infeed B) to close.

c) If the disconnector is closed in the trouble-free incoming feeder and the parallel supply is released (2 releases), the circuit-breaker is closed, either at synchronicity or if there is no voltage on the busbar. Disconnection of the faulty incoming feeder and switch-in of the substitute incoming feeder can be coordinated by the timer T1 (overlap time).

By setting the post-fault time with timer T2, the maximum permissible time interval is specified which may pass between connection and the last satisfied synchronization condition.

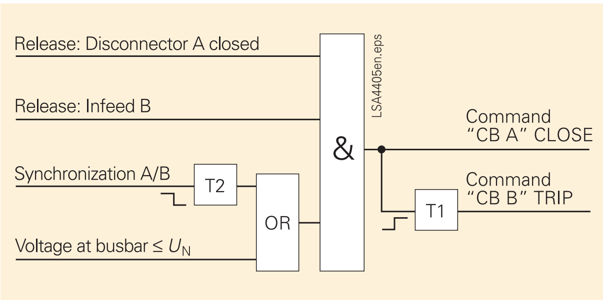


Fig. 7 Logic example for input field A

d) If the circuit-breaker in the faulty incoming feeder has not opened properly, the circuit-breaker in the substitute incoming feeder will be reclosed by the breaker failure protection.

This configuration was installed in the plant of a petrochemical industry customer and has been operating reliably since 2002.

The principle has proven so reliable that it is used in all the busbars there, from the 400 V switchgear through 6.6 kV right up to the 33 kV level.

Fig. 8 Air-insulated switchgear 8BK, 6.6 kV, with 7SJ63-protected and controlled circuit-breakers

4. Summary

Multifunction relays which also assume control and protection duties for the switchgear or plant are highly attractive due to their greater flexibility. There is considerable interest in solutions for protection against outages that would otherwise bring whole factories to a standstill. Therefore this solution has the potential for use in both the low and the medium-voltage sector.

Automatic switchover based exclusively on SIPROTEC 4 relays represents an attractive alternative to existing products in terms of both investment volume and engineering effort. The necessary functions are available. The integrated logic can be used to great advantage for the parameterization (by means of a CFC logic editor) of automatic switchover in the relays.

Coordination of Inverse-Time Overcurrent Relays with Fuses

1. Introduction

The duty of protection equipment is to allow overload currents that occur during operation, yet to prevent impermissible loading of lines and equipment. To avoid damages in the case of short-circuits the relevant equipment must be tripped in the shortest possible time. On the other hand only as few feeders or loads as possible should be disconnected from supply.
The protection relays available in the power system must recognize the fault, perform tripping themselves or give trip commands for the relevant switching device.
The protection relays must be set to ensure selective tripping. Absolute selectivity is not always assured. "Selectivity" means that the series-connected protection relay nearest the fault first trips the faulted line. Other protection relays (further upstream) recognize the fault but trip only after a delay (backup protection).

In the following the use of HV HRC fuses (high-voltage-high-rupturing capacity) and inverse-time overcurrent-time protection relays (as well as their interaction) will be described. See Fig. 1.

2. Protective equipment

2.1 HV HRC fuses

The high-voltage-high-rupturing capacity fuse is a protective device suited for non-recurring shutdown in medium-voltage switchgear, in which the current is interrupted by the melting of a fusible element embedded in sand.

HV HRC fuses are used for short-circuit protection in medium-voltage switchgear up to 20 kV. Used upstream of transformers, capacitors and cable feeders, they protect equipment and system components from the dynamic and thermal effects of high short-circuit currents by shutting them down as they arise.

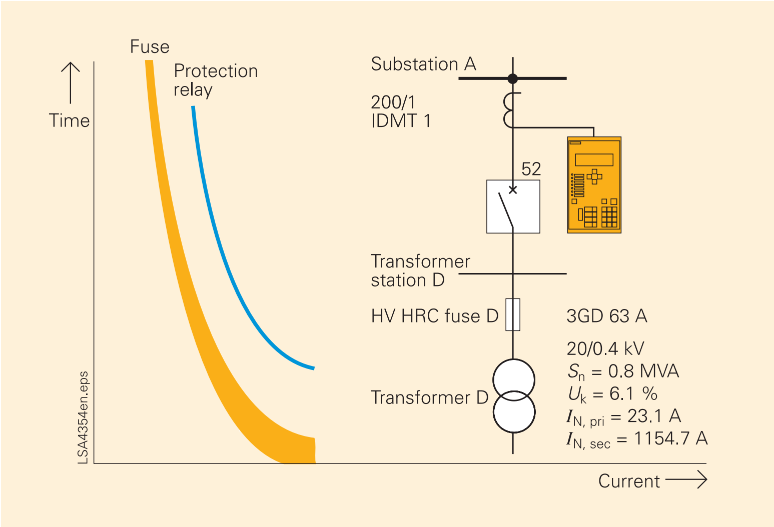


Fig. 1 Block diagram

However, they are not used as overload protection because they can only trip reliably as from their minimum breaking current. For most HV HRC fuse links the lowest breaking current is $I_{min} = 2.5$ to $3 \times I_N$.

With currents between I_N and I_{min} HV HRC fuses cannot operate.

When choosing HV HRC fuse-links, stressing of the fuse from earth-fault current or residual current must be considered.

HV HRC fuse-links are installed with high-voltage fuse-bases in the switchgear. They can also be installed in the built-on units of the switch disconnectors provided. By combining switch disconnector and HV HRC fuse, the I_N to I_{min} current which is critical to the fuse can also be reliably broken. The switch is tripped by the fuse's striker and disconnects the overload current in the three phases. Some typical breaking characteristics are shown in Fig. 2.

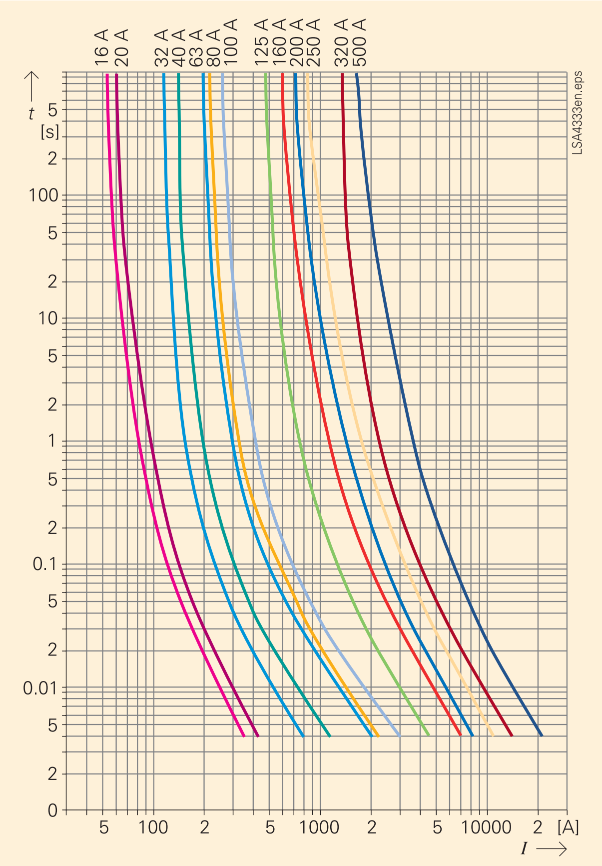


Fig. 2
Breaking characteristics of HV HRC fuses

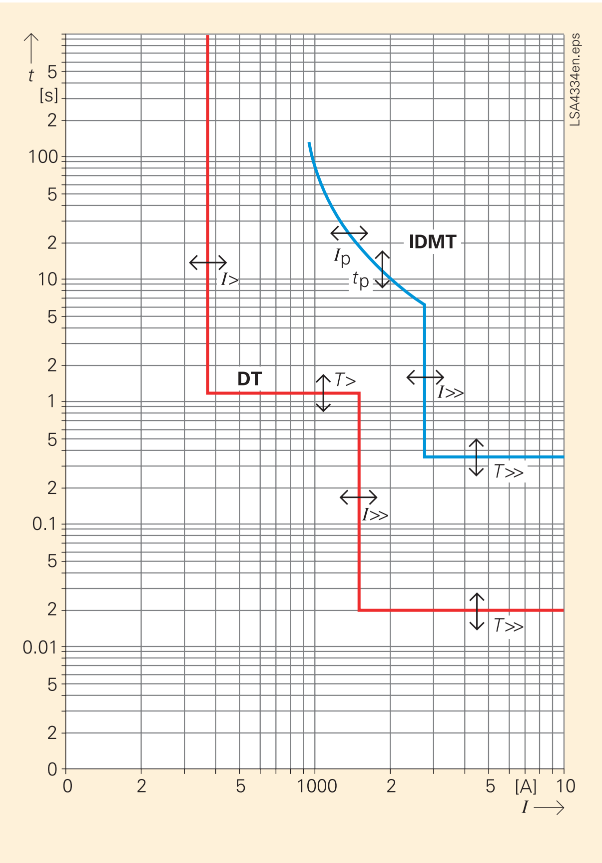


Fig. 3
Definite and inverse-time characteristics

2.2 Inverse-time overcurrent protection

Overcurrent protection is the main function of the 7SJ6 product range. It can be activated separately for phase and earth-fault currents.
The I>> high-set overcurrent stage and the I> overcurrent stage always work with definite tripping time.
In the I_p inverse-time overcurrent stage, the tripping time depends on the magnitude of the short-circuit current.

Fig. 3 shows the basic characteristics of definite and inverse-time overcurrent protection.

For inverse-time overcurrent functions (I_p stages) various tripping characteristics can be set.

- Normal inverse (NI)
- Very inverse (VI)
- Extremely inverse (EI)
- Long time inverse (LI)

All characteristics are described by the formulae below. At the same time, there are also distinctions as follows:

	IEC/BS	ANSI
NI	$t = \frac{0.14}{(I/I_p)^{0.02}-1} \cdot T_p$	$t = \left(\frac{8.9341}{(I/I_p)^{2.0938}-1} + 0.17966\right) \cdot D$
VI	$t = \frac{13.5}{(I/I_p)-1} \cdot T_p$	$t = \left(\frac{3.922}{(I/I_p)^{2}-1} + 0.0982\right) \cdot D$
EI	$t = \frac{80}{(I/I_p)^{2}-1} \cdot T_p$	$t = \left(\frac{5.64}{(I/I_p)^{2}-1} + 0.02434\right) \cdot D$
LI	$t = \frac{120}{(I/I_p)-1} \cdot T_p$	$t = \left(\frac{5.6143}{(I/I_p)-1} + 2.18592\right) \cdot D$
	t = Tripping time T_p = Setting value of the time multiplier I = Fault current I_p = Setting value of the current	

Table 1 IEC/BS and ANSI

The general IEC/BS characteristic is shown in Fig. 4 and that of ANSI in Fig. 5

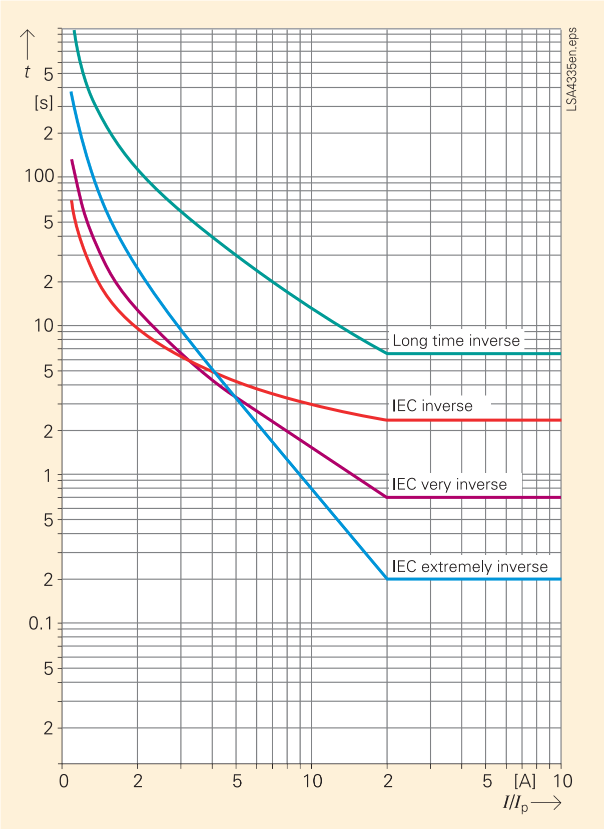


Fig. 4 IEC/BS characteristics

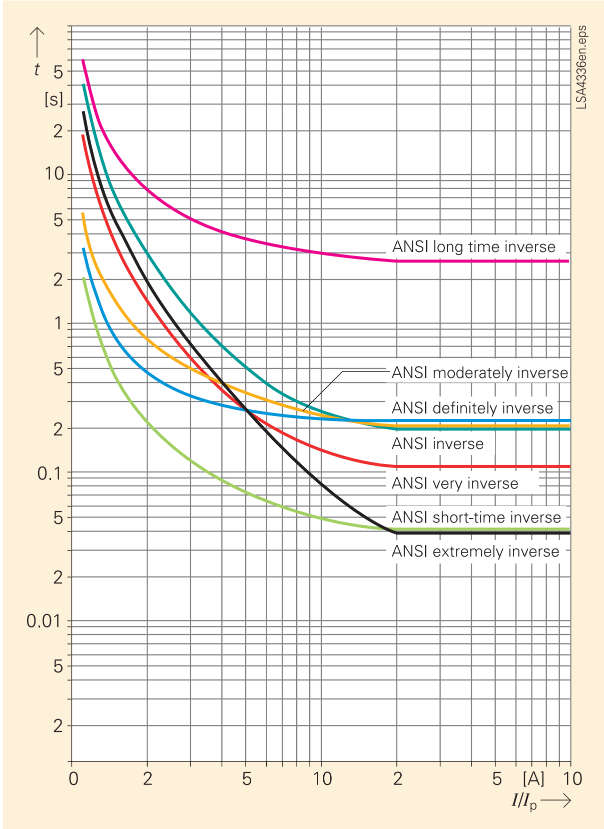


Fig. 5 ANSI characteristics

■ 3. Network circuit and protection concept

The topology of a distribution system should be as simple and clear as possible and ensure a reliable supply.

Individual transformer stations are supplied by ring cables. An example of a ring cable system is shown in Fig. 6.
In order that a fault does not cause the whole ring with all stations to fail, an "open" operating method is the standard. In this example, transformers are protected on the low voltage (LV) side with HV HRC fuses and the ring cable itself with an overcurrent-time relay.

3.1 Calculating the relevant system currents

The full load current and short-circuit strength are the selection criteria for the cable to be used. The transformer rated currents must not deviate too much from the rated currents of the cables used. The maximum and minimum short-circuit currents (3, 2, 1 phase) appearing in this power system section must be calculated before the parameters of the relays can be set. LV-side short-circuit currents must also be taken into account here. It is advisable to use programs such as SIGRADE (Siemens Grading Program) to calculate the short-circuit currents.
For further information please visit us at: www.siemens.com/systemplanning

■ 4. Selection and setting of protective components

The HV HRC fuses are selected using tables that take into account transformer power (S_n), short-circuit voltage (U_{sc}) and rated voltage on the HV side. Using the short-circuit currents detected, a proposal can be worked out for selective protection setting of the inverse-time overcurrent functions:

- I_p must be set above the permissible rated current of the cable (around 1.5 x I_N cable)
- I>> should not trip in the case of a fault on the low-voltage side
- In the case of a max. short-circuit current in the MV system, there must be an interval of at least 100 ms between the tripping characteristic of the HV HRC fuse and the inverse-time characteristic. The time multiplier T_p must be set to get this safe grading time.

It must be borne in mind that the value of the time multiplier T_p (in 7SJ6 from 0.05 to 3.2 seconds) does not correspond to the genuine tripping time of the characteristic. Rather, the inverse-time characteristic can be shifted in parallel in the time axis by this value.

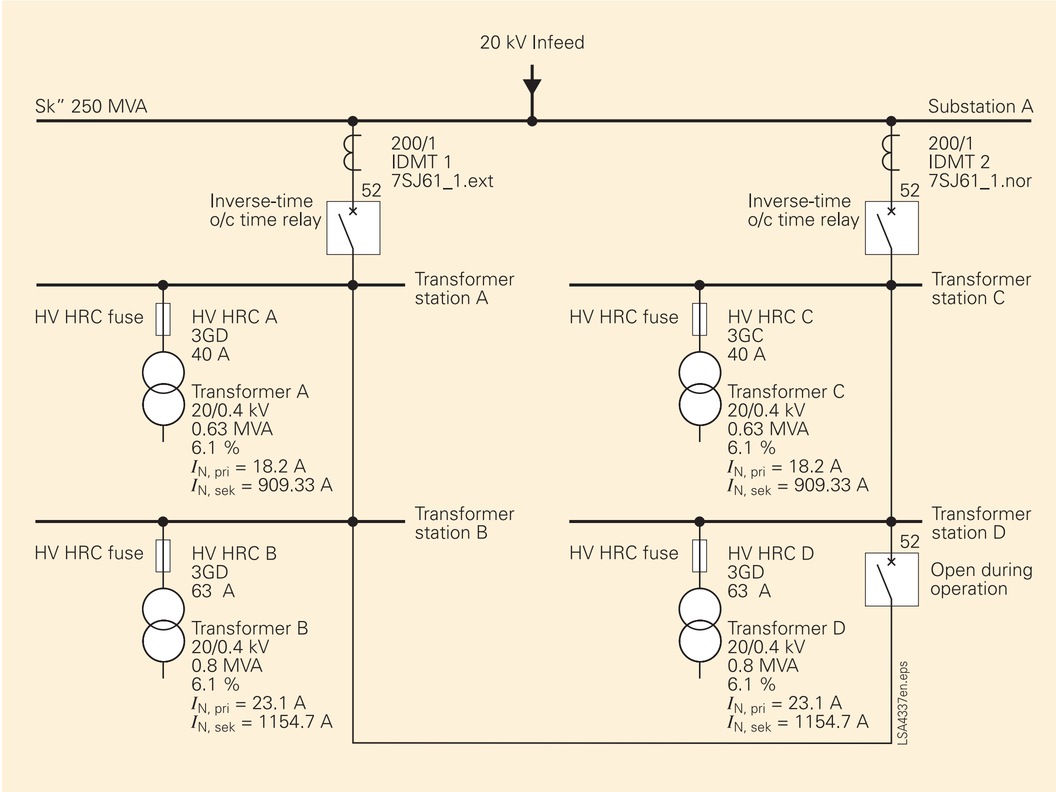


Fig. 6 Example of a 20 kV ring distribution system

■ *5. Proof of selective tripping*

As mentioned earlier, selectivity means only the protection relay closest to the faulty system section trips. Protection equipment connected (upstream) in series must register the fault but only trip after a delay period. Typically, proof of selective tripping is shown in a current-time-diagram with double logarithm scale. Programs like SIGRADE are also used for this.
For the power system sections in question, typical or critical time grading diagrams are selected.

Each protection relay has its own name, which describes the installation location. The same power system and protective elements shown in more than one time grading diagram have the same name.

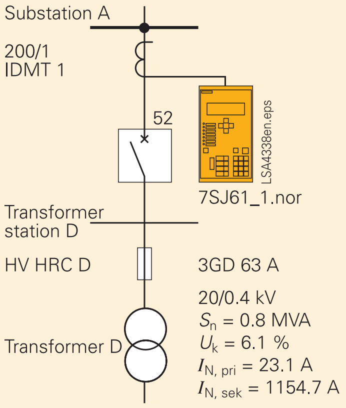
The color of the name in the time grading path (left side of the diagram) matches the color of the set characteristic (in the time grading diagram on the right) in the current-time-diagram. On the left side, in addition to the single-line circuit diagram (time-grading path) for each protection relay, the type name, the setting range and the set values are given.

In addition to the characteristics of the protection relay, the current-time-diagram shows the short-circuit current ranges plotted with minimum and maximum values as bandwidth (values from the short-circuit calculation). These short-circuit current bands always end on the voltage current scale. The right-hand characteristic in a band is the maximum short-circuit current (3 phase), calculated (here in green) from the incoming elements (generators, transformers, etc). The left-hand characteristic shows the minimum short-circuit current (1 or 2 phase) which is calculated on the basis of the impedances of the elements in the power system up to the location of the fault.

Band 1 (Transf. D Pr) shows the bandwidth of the 20 kV power system;
band 2 (Transf. D Sec) shows that of the 0.4 kV power system.
The above-mentioned bands are contained in the time-grading diagrams (Figs. 7 to 11).

■ *6. Grading of overcurrent-time relay and HV HRC fuse*

As an example of the power system shown in Fig. 6, in 3 time sequence diagrams the most usual characteristics (NI, VI, EI) of the inverse-time overcurrent protection are shown with the corresponding HV HRC fuses characteristic. The overcurrent-time relay 1, HV HRC fuse D and transformer D are selected from the circuit diagram.



Setting range	Setting
$I_p = 0.1 – 4$ A $T_p = 0.05 – 3.2$ s	$I_p = 1.8$ A $T_p = 0.05$ s
$I_{p\_mi} = 2.3$ kA $I_{s\_mi} = 15.8$ kA	$I_{p\_ma} = 7.8$ kA $I_{s\_ma} = 18.2$ kA

Overcurrent-time relay with "Normal Inverse" (NI) setting

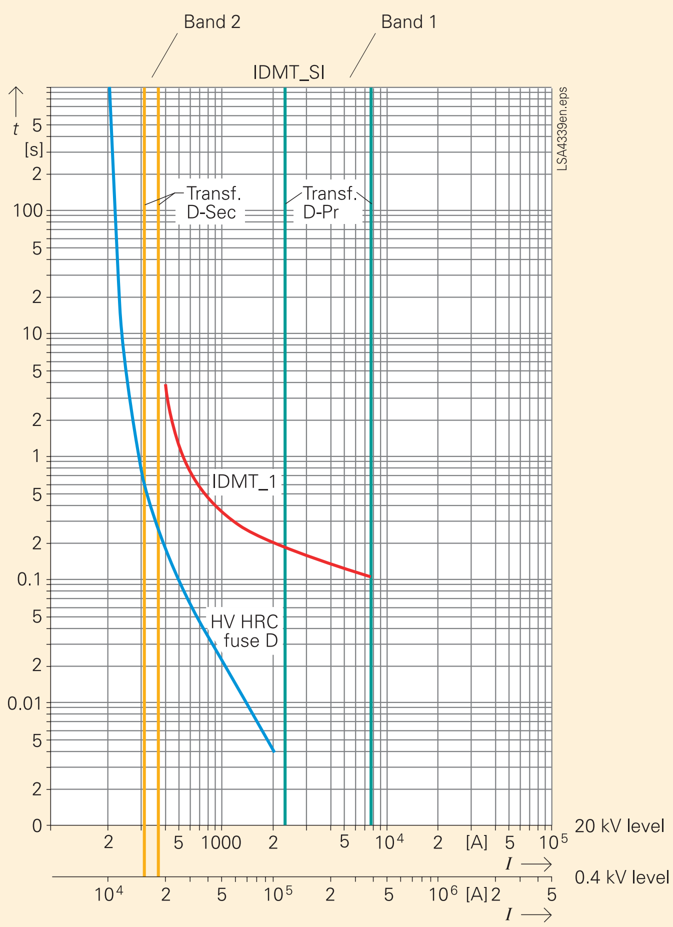
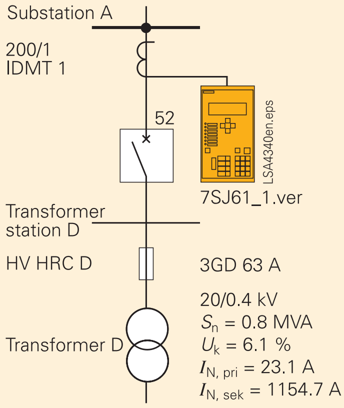


Fig. 7 Time-grading diagram, inverse-time NI



	Setting range	Setting
IDMT 1	I_p = 0.1 – 4 A T_p = 0.05 – 3.2 s	I_p = 1.8 A T_p = 0.15 s
Transformer D	I_{p_mi} = 2.3 kA I_{s_mi} = 15.8 kA	I_{p_ma} = 7.8 kA I_{s_ma} = 18.2 kA

Overcurrent-time relay with "Very Inverse" (VI) setting

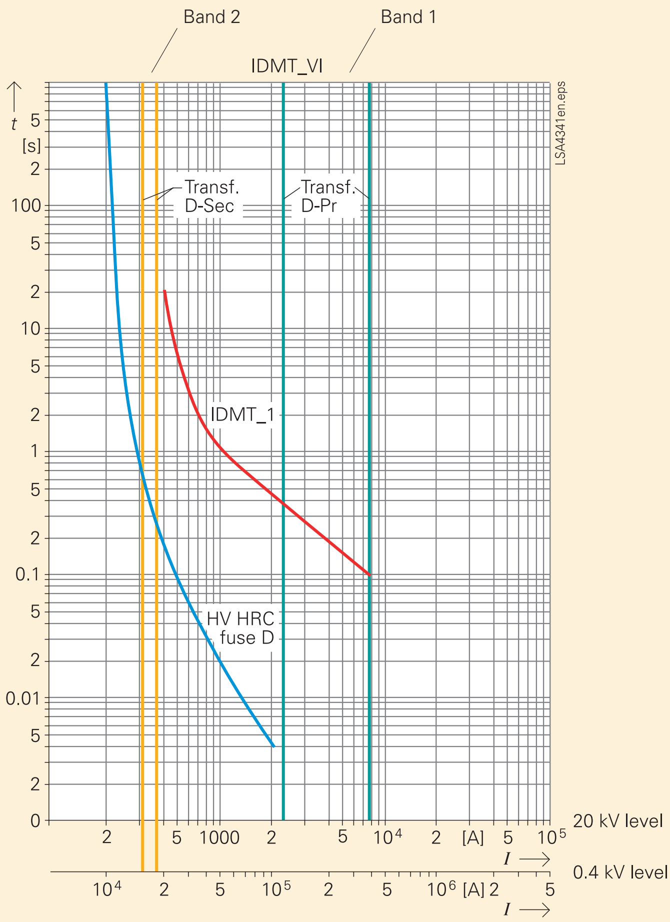
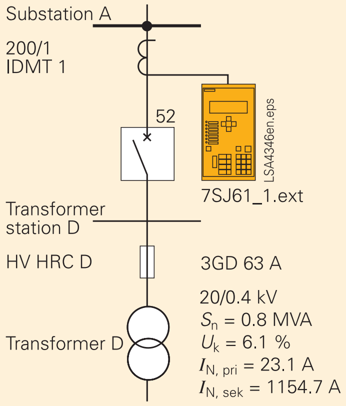


Fig. 8 Time-grading diagram, inverse-time VI



	Setting range	Setting
	$I_p = 0.1 - 4$ A $T_p = 0.05 - 3.2$ s	$I_p = 1.8$ A $T_p = 0.45$ s
	$I_{p\_mi} = 2.3$ kA $I_{s\_mi} = 15.8$ kA	$I_{p\_ma} = 7.8$ kA $I_{s\_ma} = 18.2$ kA

Overcurrent-time relay with "Extremely Inverse" (EI) setting

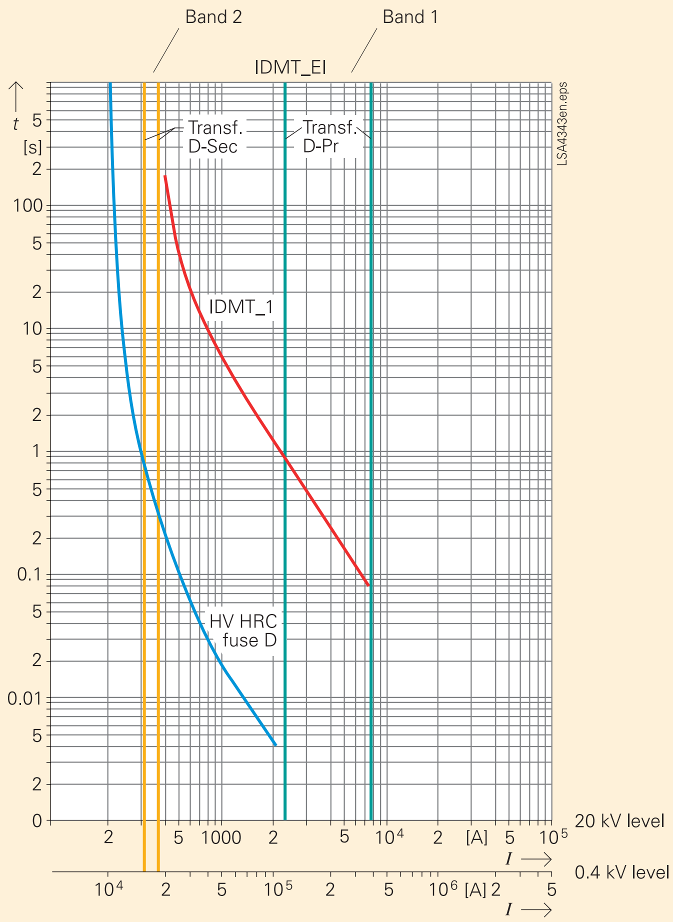
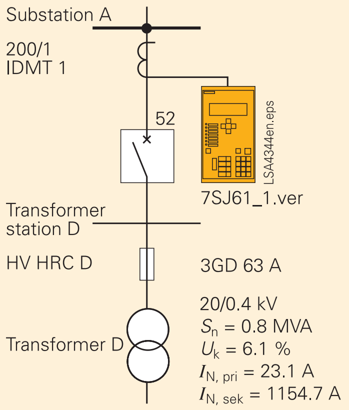


Fig. 9 Time-grading diagram, inverse-time EI

	Setting range	Setting
Substation A, 200/1, IDMT 1, 7SJ61_1.ver	I_p = 0.1 – 4 A T_p = 0.05 – 3.2 s	I_p = 1.8 A T_p = 0.05 s
Transformer D, 20/0.4 kV	I_{p_mi} = 2.3 kA I_{s_mi} = 15.8 kA	I_{p_ma} = 7.8 kA I_{s_ma} = 18.2 kA



Overcurrent-time relay with VI setting, with same setting as NI

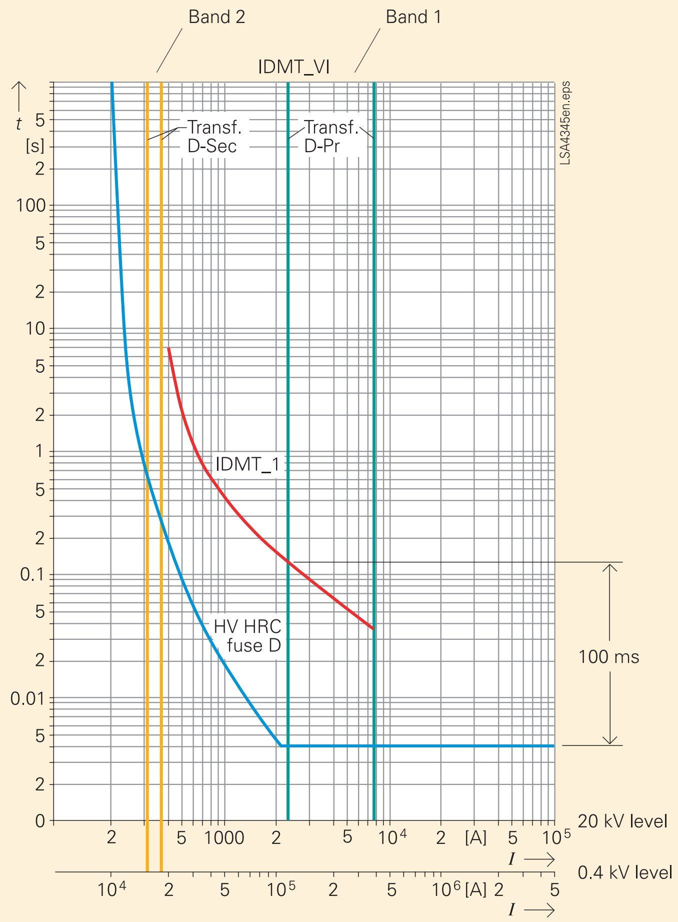
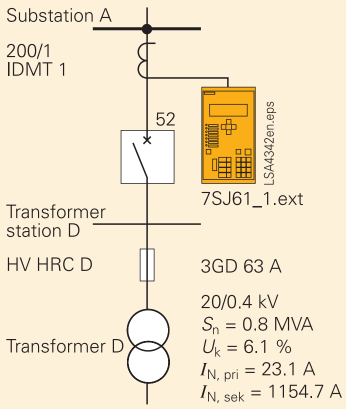


Fig. 10
Time-grading diagram, very inverse, with setting like normal inverse

	Setting range	Setting
	$I_p = 0.1 – 4$ A $T_p = 0.05 – 3.2$ s	$I_p = 1.8$ A $T_p = 0.05$ s
	$I_{p\_mi} = 2.3$ kA $I_{s\_mi} = 15.8$ kA	$I_{p\_ma} = 7.8$ kA $I_{s\_ma} = 18.2$ kA



Overcurrent-time relay with EI setting, with same setting as NI

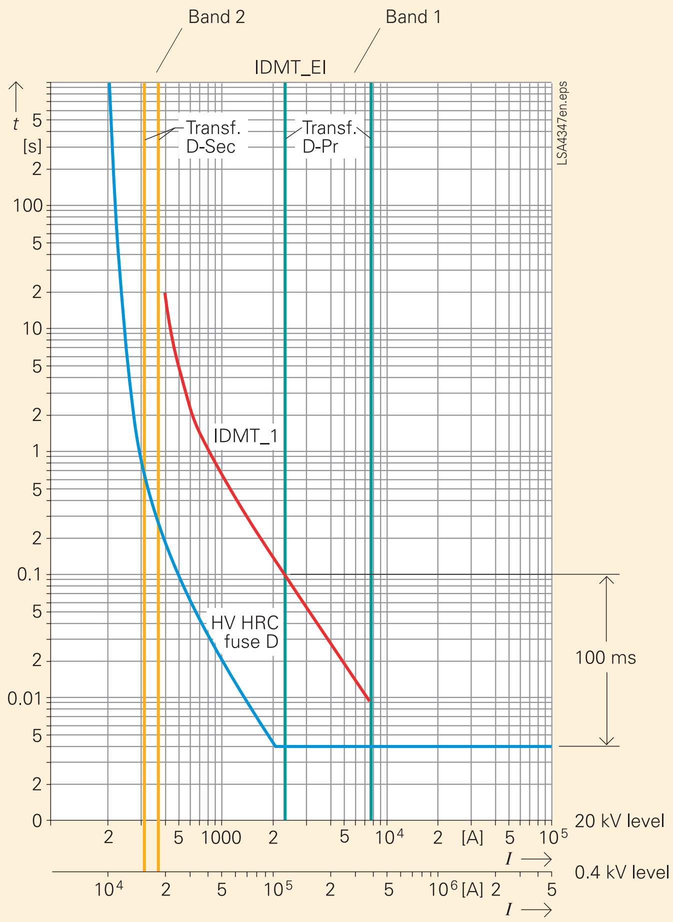


Fig. 11
Time-grading diagram, extremely inverse, with setting like normal inverse

For the transformer considered (20/0.4 kV, S_n = 0.8 MVA, U_k = 6.1 %), a 63 A HV HRC fuse is selected according to the above-mentioned selection tables.

In order to maintain selectivity, the target trip time is approx. 100 ms for the overcurrent-time relay setting in the various characteristics with maximum short-circuit current on the 20 kV side. Under the same short-circuit conditions the HV HRC fuse trips in approx. 1 ms.

By setting the I_p appropriately, the maximum fault on the LV side does not lead to pickup of the overcurrent-time relay. As can be seen in Fig. 10 the characteristic begins on the right, next to the maximum short-circuit current (brown, vertical lines). The following setting values should be used to achieve a safe grading time of 100 ms between all types of o/c inverse-time characteristics (NI, VI, EI) and the characteristic of the fuse.

Fig.	I_p x I_N	T_p (s)	Characteristics
7	1.8	0.05	Normal inverse (NI)
8	1.8	0.15	Very inverse (VI)
9	1.8	0.45	Extremely inverse (EI)

Table 2

When comparing the three figures it is clear that the area between the HV HRC and inverse-time characteristics is smallest for the setting NI. Therefore the NI setting must be preferred in this example.

In order to explain the difference in the characteristics more clearly, two diagrams are shown with the characteristics VI and EI with the same setting values as NI.

Very inverse (VI)	Extremely inverse (EI)
I_p = 1.8	I_p = 1.8
T_p = 0.05	T_p = 0.05
See Fig. 10	See Fig. 11

Table 3

Conclusion

The steeper the slope of the characteristic the lower the tripping time with maximum fault current. The safe grading time from the HV HRC characteristic becomes smaller. The coordination shown here of the protection devices is only part of the power system and must be adapted to the concept of the overall power system with all protection relays.

Note:
In this example there was no setting of I>>, because the inverse-time characteristics themselves trip in the ≤ 0.2 s range in the event of the maximum or minimum 20 kV side fault.

7. Summary

This application example demonstrates the engineering effort necessary to achieve a selective time grading.

Real power systems are more complex and equipped with various protection relays. Whatever the circumstances, it is necessary to know the operating mode of the power system (parallel, generator, meshing, spur lines etc) as well as to calculate the rated and short-circuit currents. It is worth the effort for the protection engineer because the objective is to lose only the faulty part of the power system.

SIGRADE software effectively supports grading calculations. Power system planning and time grading calculation is also offered by Siemens.

8. References

Günther Seip: Elektrische Installationstechnik

Siemens: Manual for Totally Integrated Power

Catalog HG12: HV HRC Fuses

SIGRADE Software V3.2

Manual 7SJ61: Multifunctional Protective Relay with Bay Controller 7SJ61

Medium-Voltage Protection with Auto-Reclosure and Control

1. Introduction

An important protection criterion in medium-voltage applications is overcurrent-time protection. Hardware redundancy can be dispensed with in favor of lower-cost solutions, thanks to numerical technology and the high reliability of the SIPROTEC 4 protection relays. The SIPROTEC 4 protection relays also allow functions which go beyond the basic scope of protection:

- Unbalanced load (negative-sequence) protection, motor protection functions, circuit-breaker failure protection,...
- Other voltage-dependent protection functions such as voltage protection, directional overcurrent protection
- Auto-reclosure
- Control, including interlocking
- Integration in a control system

This enables all the requirements in the feeder to be met with a single relay. Scalable, flexible hardware allows simple adaptation to any application.

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Fig. 1 SIPROTEC medium-voltage protection

2. Protection concept

2.1 Overcurrent-time protection

The task of overcurrent-time protection is to detect the feeder currents, in order to initiate tripping by the circuit-breaker in the event of overcurrent. Selectivity is achieved here by current grading or time grading. The phase currents I_{L1}, I_{L2} and I_{L3} and the earth current I_E serve as measuring variables here. (Non-directional) overcurrent-time protection is used in medium-voltage power systems with single-end infeed or as backup protection in high-voltage applications.

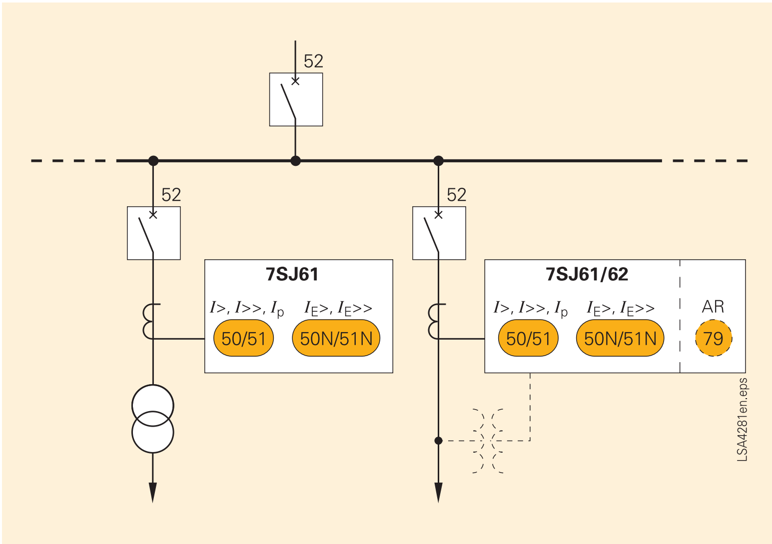


Fig. 2 Block diagram

2.1.1 Grading and selectivity

The aim of every protective setting is to achieve selectivity, i.e. the protection relay closest to the fault location trips the CB; all the others detect the fault but do not switch off or at least only after a delay. This ensures backup protection if "regular" protection fails.

There are basically two criteria for achieving selectivity:

- Time
  Here a protection relay initiates tripping immediately or with an adjustable delay time. Since the power system fault is usually detected by a number of protection relays in the power system, the protection relay with the shortest delay time initiates tripping. The delay times in the individual protection relays are defined such that the short-circuit is cleared by the protection relay closest to the fault.

This type of grading is normally used for cable and overhead power line systems.

- Current
  Another grading criterion may be the magnitude of the short-circuit current itself. Since the size of the short-circuit current cannot be determined exactly in pure line or cable systems, this method is used for grading of transformers. The transformer limits the short-circuit current resulting in different magnitudes of short-circuit current on the high and low-voltage side.
  This behavior is utilized to achieve selectivity in tripping, as is attained in time grading.

The flexibility of SIPROTEC 4 overcurrent-time protection relays allows a mixture of these two criteria and therefore helps to achieve optimum supply security.

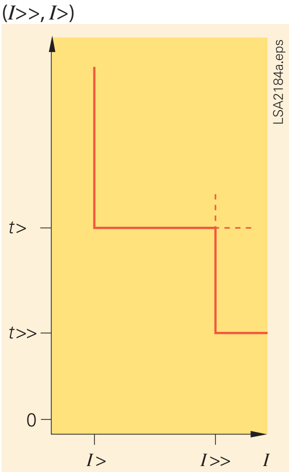
2.1.2 Definite-time overcurrent protection

Definite-time overcurrent protection is the main characteristic used in Europe (except in countries with a British influence). Delay times are assigned to several current pickup thresholds.

I>> pickup value (high short-circuit current)
t>> (short delay time)

I> pickup value (low short-circuit current),
t> (delay time)

Fig. 2
2-stage definite-time overcurrent characteristic (*I*>>, *I*>)



2.1.3 Inverse-time overcurrent protection

The inverse-time characteristic is widely used in countries with a British and American influence. Here the delay time is dependent on the current detected.

Inverse-time overcurrent protection characteristics according to IEC 60255

IEC 60255-3 defines four characteristics which differ in their slope.

Inverse
Very Inverse
Extremely Inverse
Long Inverse

The calculation formulae and the corresponding characteristics are shown below by way of comparison.

Inverse $$t = \frac{0.14}{\left(I/I_p\right)^{0.02} - 1} \cdot T_p$$

Very inverse $$t = \frac{13.5}{\left(I/I_p\right) - 1} \cdot T_p$$

Extremely inverse $$t = \frac{80}{\left(I/I_p\right)^{2} - 1} \cdot T_p$$

Long inverse $$t = \frac{120}{\left(I/I_p\right) - 1} \cdot T_p$$

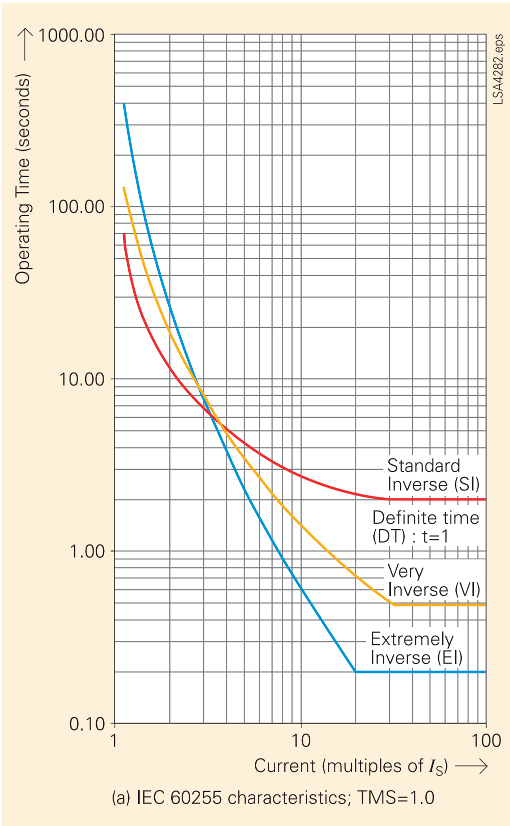


Fig. 3 Comparison of inverse-time overcurrent protection characteristics

The corresponding characteristic is selected dependent on the overall grading coordination chart. However, the inverse characteristic is sufficient for most applications.

Inverse-time overcurrent protection characteristics according to ANSI/IEEE

Characteristics are also defined by ANSI/IEEE similar to those according to IEC 60255. For further details about these, see the application example on "Coordination of Inverse-Time Overcurrent Relays with Fuses". The ANSI characteristics are also available as standard in all SIPROTEC 4 overcurrent-time protection relays.

2.1.4 User-defined characteristics

Numerical protection relays like SIPROTEC 4 also allow the user to freely define characteristics, and therefore enable maximum flexibility. This means ease of adaptation to existing protection concepts, e.g. when renewing the protection, even for special applications.

2.1.5 Combined characteristics

SIPROTEC 4 overcurrent-time protection allows the advantages of definite and inverse-time overcurrent protection to be combined. On the one hand, with the high-set current stage *I*>>, the tripping time with high short-circuit currents can be reduced in comparison with inverse-time overcurrent protection characteristics, and on the other hand the grading can be adapted optimally to the characteristic of the HV HRC fuses with inverse-time overcurrent protection characteristic.

2.1.6 Sensitivity

The earth current can be measured or calculated in addition to the phase currents. Independent protection stages for phase-to-earth faults are also available in the SIPROTEC 4. As a result, sensitivity below the rated current is achieved for such a fault.

2.2 Auto-reclosure

Auto-reclosure is only used on overhead lines, because the chances of success are relatively slight in the event of faults in a cable network. About 85% of reclosures are successful on overhead lines, which contributes greatly to a reduction in power system downtimes.

Important parameters for reclosure are:

Dead time
Lockout (blocking) time
Single or three-pole
Single or multishot

Normally only one single three-pole reclosure is performed for medium-voltage applications. Dead times between 0.3 and 0.6 s usually suffice for adequate de-ionization of the flashover distance and thus a successful reclosure.

The lockout times (time up to next reclosure) are chosen so that protection relays affected by the power system fault have reliably reset. In the past this led to relatively long lockout times (approximately 30 s) due to the dropout time of mechanical protection relays. This is not necessary in numerical protection relays. Shorter lockout times can therefore reduce the number of final disconnections (unsuccessful reclosures), for example during thunderstorms.

In the past separate relays were used for protection and automatic reclosure. The initiation for this was given by parallel wiring with the protection relay. In SIPROTEC 4 relays the auto-reclosure function can be integrated in the protection relay; there is no need for any additional relay and wiring.

2.3 Control

There is a noticeable worldwide trend towards automation, even in medium-voltage power systems. SIPROTEC 4 protection relays provide the conditions for controlling the feeder both locally and remotely by telecontrol/station control and protection systems. This is supported by the appropriate control elements on the relay and various serial interfaces. See Chapter 4 for further information.

■ 3. Settings

The determining of the most important setting parameters is explained in this chapter by means of a typical application.

3.1 Overcurrent-time protection

The setting of the overcurrent stages is defined by the grading coordination chart of the overall network. Current grading is possible for the "transformer" protection object; only time grading can usually be applied for overhead lines/cables.

3.1.1 High-set current stage I>>

The high-set current stage *I*>> is set under the address 1202 and the corresponding delay T *I*>> under 1203. It is normally used for current grading at high impedances such as are encountered in transformers, motors or generators. Setting is such that it picks up for short-circuits reaching into this impedance range.

Example:
Transformer in the infeed of a busbar with the following data:

Rated apparent power	S_{NT} = 4 MVA
Short-circuit voltage	U_k = 10 %
Primary rated voltage	U_{N1} = 33 kV
Secondary rated voltage	U_{N2} = 11 kV
Vector group	Dy 5
Neutral	earthed
Short-circuit power on 33 kV side	250 MVA

The following short-circuit currents can be calculated from these data:

3-pole, high-voltage side short-circuit
I''_{SC3} = 4389 A

3-pole, low-voltage side short-circuit
$I''_{SC3,\,11}$ = 2100 A

on the high-voltage side flow
$I''_{SC3,33}$ = 700 A

rated current of the transformer HV
$I_{NT,\,33}$ = 70 A (high-voltage side)

rated current of the transformer LV
$I_{NT,\,11}$ = 211 A (low-voltage side)

current transformer (high-voltage side)
$I_{NW,\,33}$ = 100 A / 1 A

current transformer (low-voltage side)
$I_{NW,\,11}$ = 300 A / 1 A

Due to the setting value of the high-set current stage *I*>>

$$I{>>}/I_N > \frac{1}{U_{k\,\text{Transfo}}} \cdot \frac{I_{N\,\text{Transfo}}}{I_{N\,\text{CT}}}$$

the following setting on the protection relay:

The high-set current stage *I*> must be set higher than the maximum short-circuit current detected on the high-voltage side in the event of a fault on the low-voltage side. In order to attain a sufficient noise ratio even at fluctuating short-circuit power, a setting of

$I{>>}/I_N = 10$, i.e. $I{>>} = 1000$ A

is selected.

Increased inrush current surges are disarmed by the delay times (parameter 1203 T *I*>>) provided their fundamental component exceeds the setting value. The set time is a purely additional time delay which does not include the operating time.

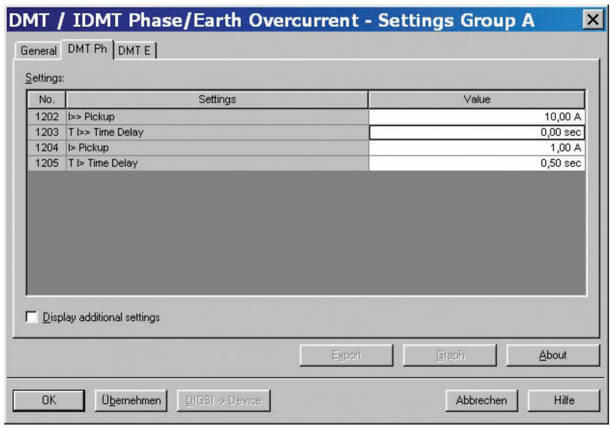


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Fig. 4 DIGSI parameter sheet, definite-time overcurrent protection phase

3.1.2 Overcurrent stage I>

The maximum operating current occurring is significant for the setting of the overcurrent stage *I*>. Pickup by overload must be ruled out because the relay works as a short-circuit protection with correspondingly short operating times in this mode and not as overload protection. It is therefore set for lines at about 20 % and for transformers and motors at about 40 % above the maximum (over) load to be expected. The delay to be set (parameter 1205 T*I*>) is given by the grading coordination chart created for the power system.

The set time is a purely additional time delay which does not include the operating time (measuring time). The delay can be set to ∞. The stage then does not trip after pickup but the pickup is signaled. If the *I*> stage is not needed at all, the pickup threshold *I*> is set to ∞. Then there is neither pickup indication nor tripping.

According to the above example this gives a calculated setting value of

$$I> = 1.4 \cdot I_{NT,\,33} = 1.4 \cdot 70\ \text{A} = 100\ \text{A} = 1.0 \cdot I_{NW,\,33}$$

3.1.3 Inverse-time overcurrent protection stages I_p

It must be taken into account when selecting an inverse-time overcurrent characteristic that a factor of approximately 1.1 is already incorporated between the pickup value and the setting value. This means that pickup only takes place when a current 1.1 times the setting value flows. The current value is set under address 1207 **Ip**. The maximum operating current occurring is significant for the setting.

Pickup by overload must be ruled out because the relay works as a short-circuit protection with appropriately short command times in this mode and not as overload protection. The corresponding time multiplier is accessible under address 1208 T **Ip** (51 TIME DIAL) when selecting an IEC characteristic, and under address 1209 51 TIME DIAL when selecting an ANSI characteristic. This must be coordinated with the grading coordination chart of the power system.

The time multiplier can be set to ∞. Then the stage does not trip after pickup but the pickup is signaled. If the I_p stage is not needed at all, address 1201 DMT/IDMT PHASE = DTM only (FCT 50/51) is selected in the configuration of the protection functions.

3.1.4 Earth current stages

I_E>> (earth)
The high-set current stage I_E>> is set under address 1302 (50 N-2 PICKUP) and the corresponding delay T I_E>> under 1030 (50 N-2 DELAY). Similar considerations apply for the setting, as previously described, for the phase currents.

I_E> (earth) or I_{Ep}
The minimum occuring earth fault current is mainly decisive for the setting of the overcurrent stage I_E> or I_{Ep}. If great inrush currents are to be expected when using the protection relay on transformers or motors, an inrush restraint can be used in 7SJ62/63/64 for the overcurrent stage I_E> or I_{Ep}. This is switched on or off for both phase and earth current together under address 2201 INRUSH REST.

The time delay to be set (parameter 1305 T I_E>/ 50 N-1 DELAY or 1308 T /I_{Ep}/51N TIME DIAL) is given by the grading coordination chart created for the power system, whereby a separate grading coordination chart with shorter delay times is often possible for earth currents in the earthed power system.

3.2 Auto-reclosure

The integrated auto-reclosure function can be used for performing reclosures on overhead lines. This can be initiated by every overcurrent stage and other protection functions. External initiation via binary inputs is also possible. In this way the reclosing function can be adapted individually to the respective application without external wiring.

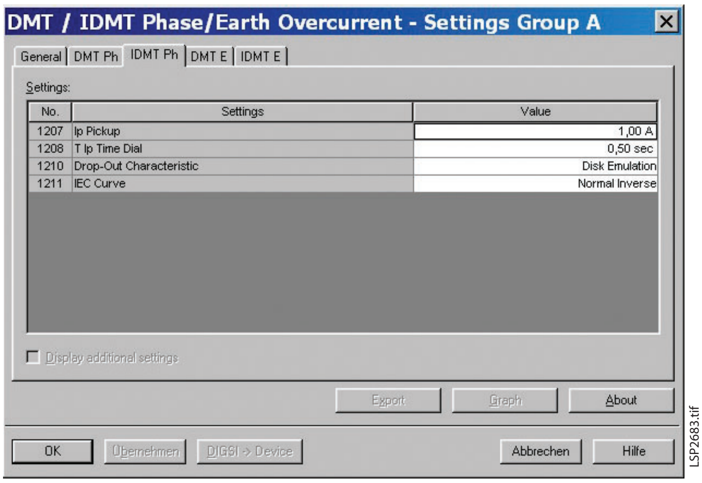

Fig. 5 DIGSI parameter sheet, inverse time overcurrent protection phase

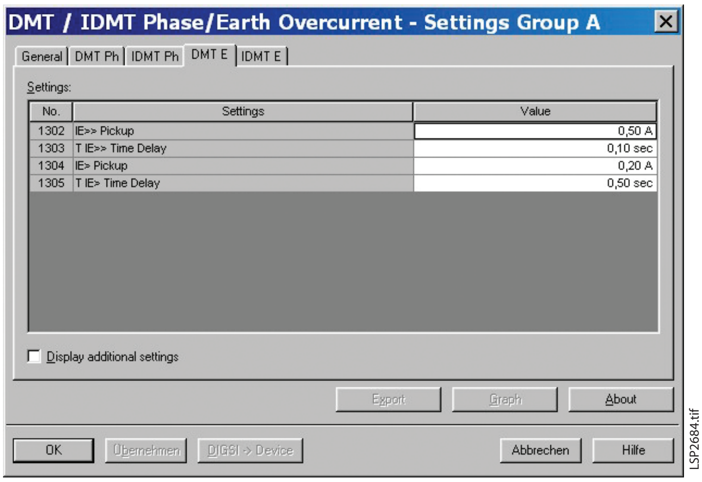

Fig. 6 DIGSI parameter sheet, definite time overcurrent earth protection

A description for setting the most important reclosure parameters follows:

7105 Time restraint:

The blocking time TIME RESTRAINT (address 7105) is the time span following successful reclosure after which the power system fault is considered cleared. Generally, a few seconds are enough. In regions with frequent thunderstorms a short lockout time is recommendable, to reduce the danger of final disconnection due to lightning strikes in rapid succession or cable flashover. The default selection is 3 s.

7117 Action time

The action time checks the time between the pickup of a relay and the trip command of a protection function parameterized as a starter, in ready (but not yet running) auto-reclosure.
If a trip command is received from a protection function parameterized as a starter within the action time, auto-reclosure is initiated. If this time is outside the parameterized value of T-ACTION (address 7117), auto-reclosure is blocked dynamically. With inverse-time characteristics the release time is determined essentially by the fault location and the fault resistance. With the help of the action time, no reclosure is performed in the event of very remote or high-resistance faults with a long tripping time.
Presetting of ∞ always initiates a reclosure.

7135 Number of reclosure attempts, earth
7136 Number of reclosure attempts, phase

The number of reclosures can be set separately for the programs "Phase" (address 7136, NUMBER RC PHASE/# OF RCL. PH) and "Earth" (address 7135 NUMBER RC EARTH/# OF RCL. GND). The presetting for both parameters is 1 (one); one reclosure cycle is therefore executed.

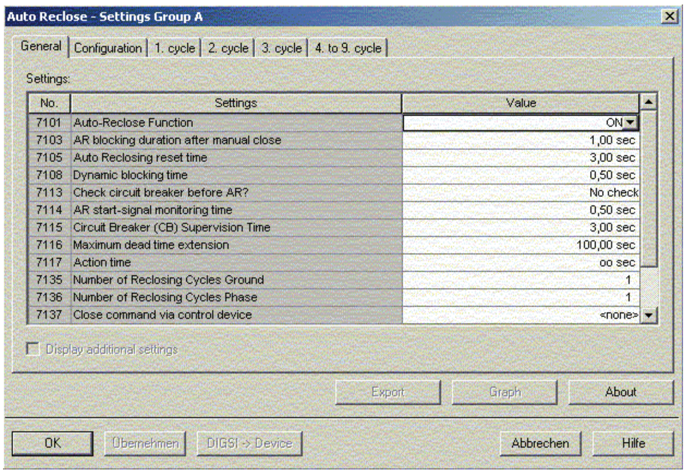

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Fig. 7 DIGSI parameter sheet, auto-reclosure (general)

The "configuration sheet" defines which of the protection stages starts the reclosure. For each of the stages it can be decided whether this stage starts the reclosure, does not start it or blocks it out.

7127 Dead time 1: ph
7128 Dead time 1: G

The parameters 7127 and 7128 define the length of the dead times of the 1st cycle. The time defined by the parameter is started upon opening the circuit-breaker (if auxiliary contacts are allocated) or upon reset after the trip command.

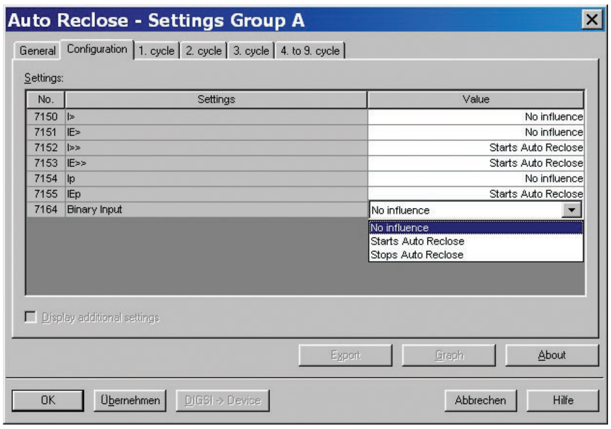

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Fig. 8 DIGSI parameter sheet, auto-reclosure configuration

The dead time before the 1st reclosure for the reclosure program "Phase" (phase-to-phase fault) is set in address 7127 DEADTIME 1:PH; for the reclosure program "Earth" (single phase-to-earth fault) it is set in address 7128 DEADTIME 1:G.
The duration of the dead time should relate to the type of application. For longer lines the time should be long enough for the short-circuit arc to extinguish and de-ionize the ambient air, to allow successful reclosure (usually 0.9 s to 1.5 s). The stability of the power system has priority in the case of lines fed from several ends. Since the disconnected line cannot develop any synchronizing forces, often only a short dead time is permissible. Normal values are between 0.3 s and 0.6 s. Longer dead periods are usually allowed in radial systems. The default is 0.5 s.

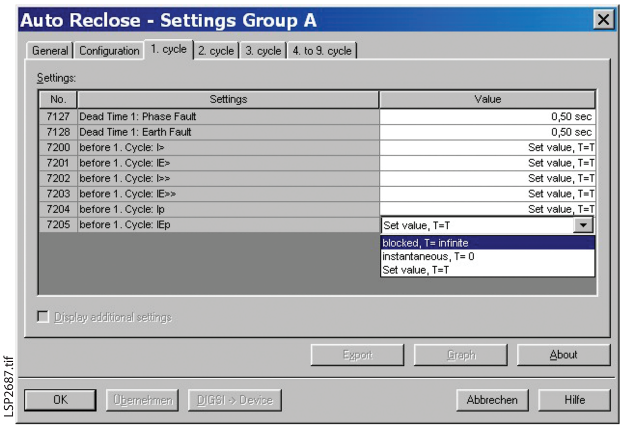

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Fig. 9 DIGSI parameter sheet, auto-reclosure (1st reclosure cycle)

4. Further functions

As already described in Chapter 2, a number of additional functions can be configured in the SIPROTEC 4 relays. Apart from further protection functions, these also include control tasks for the feeder. All SIPROTEC 4 relays (e.g. 7SJ61 and 7SJ62) have 4 freely assignable function keys F1 to F4 which simplify frequently required operations. These function keys can take the user directly to the display window for measured values, or to fault event logs for example. If the relay is also to be used for feeder control, these keys can be used for controlling the circuit-breaker. The key F1 then selects the ON command for example, key F2 the OFF command and key F3 executes the selected command (two-stage command output).

Fig. 10 Front view 7SJ61 or 7SJ62

The 7SJ63 also has a graphic display on which the individual feeder mimic diagram can be shown. Separate ON/OFF control buttons ensure safe and reliable local control. An integrated, freely programmable interlock logic prevents switching errors.

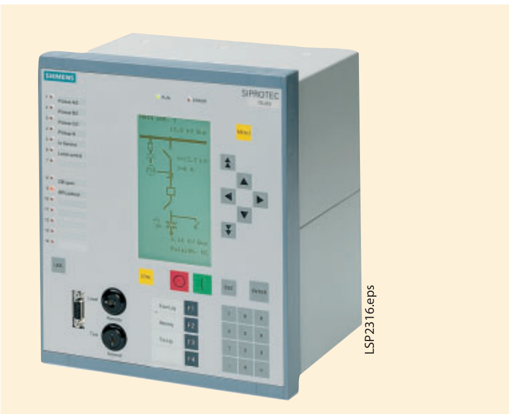


Fig. 11 Front view 7SJ63

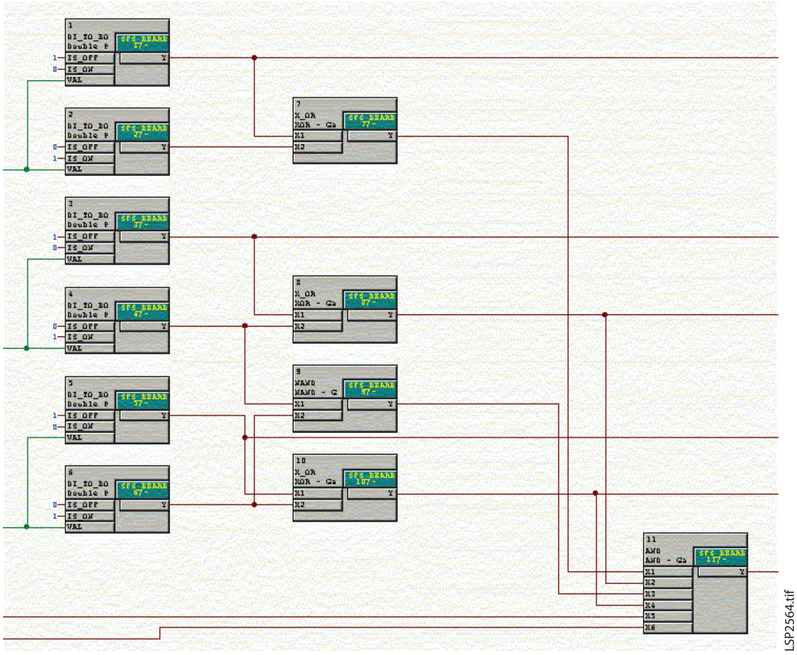


Fig. 12 Example of interlock logic

The switching authority (local/remote) can be changed and the interlock check overridden by two key-operated switches.

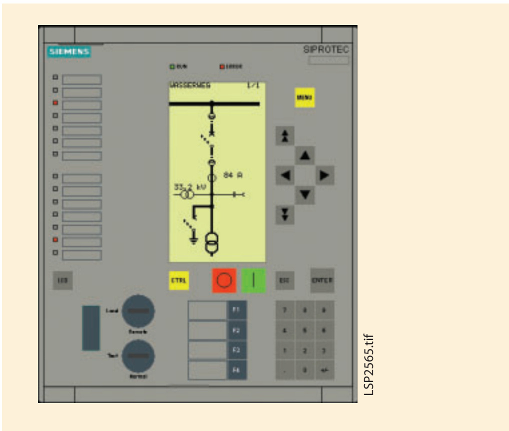


Fig. 13 Front view, key-operated switch with customer-specific feeder mimic diagram

5. Connection examples

5.1 Current and voltage transformers

Connection of the protection relays to the switchgear depends on the number of switching objects (circuit-breakers, disconnectors) and current and voltage transformers. Normally at least three current transformers are available per feeder which are connected to the protection relay as follows.

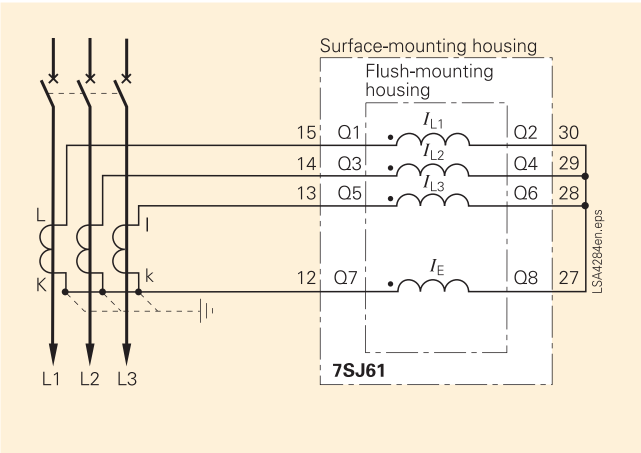
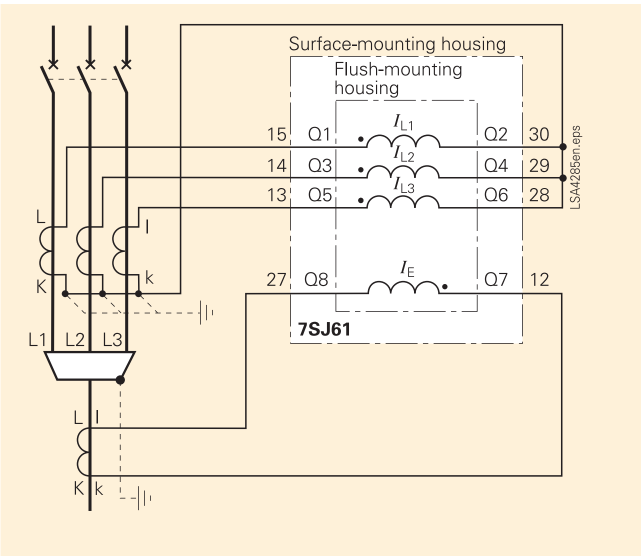


Fig. 14 Transformer connection to three current transformers

In some systems, also the earth current is measured by a core-balance current transformer. This can be connected to the protection relay separately. A core-balance current transformer achieves greater accuracy (sensitivity) for low earth currents.



Important: The cable shield must be earthed on the cable side!

Note: Reversing the current polarity (address 0201) also reverses the polarity of the current input I_E

Fig. 15 Transformer connection to three current transformers and core-balance CT

If voltages are also available (from the feeder or as a busbar measurement), these can be connected on 7SJ62/63/64 and then also enable voltage-dependent protection functions (directional overcurrent protection, voltage protection, frequency protection, ...).

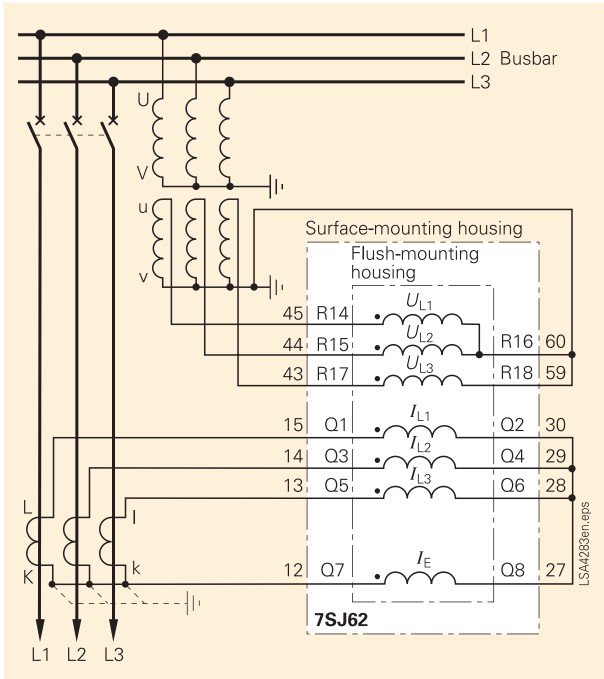


Fig. 16 Transformer connection to three current and three voltage transformers

5.2 Input/output periphery

In addition to the current transformers (and if required to the voltage transformers too), at least the TRIP command has to be wired to the circuit-breaker. The standard allocation supports this by practice-oriented preassignment.

Preassignment of the inputs and outputs in the 7SJ610:

Binary inputs

BI1	Block definite/inverse time overcurrent protection
BI2	LED reset
BI3	Display lighting on

Binary outputs (command relays)

BO1	TRIP command
BO2	Reclosure command
BO3	Reclosure command
BO4	MV monitoring

LEDs

LED1	TRIP command
LED2	PICKUP L1
LED3	PICKUP L2
LED4	PICKUP L3
LED5	PICKUP E
LED6	MV monitoring
LED7	Not used

The assignment can be changed and the protection parameters set conveniently with the DIGSI 4 operating program. The parameterizat- ion data can then be saved and copied conveniently as a basis for further feeders.

6. Summary

SIPROTEC 4 protection relays are suitable for almost any application due to their modular hardware structure and the flexible scope of functions. A suitable relay with the necessary scope can be selected in line with requirements. Factory parameterization is oriented to typical applications and can often be adopted with only small modifications. In the parameter setting with DIGSI, all unnecessary parameters are hidden so that clarity is much improved.

The retrofitting of serial interfaces for subsequent integration into a substation control and protection system is also possible locally, which reduces downtimes to a minimum. The functional scope can also be changed later by "downloading" a new order number.

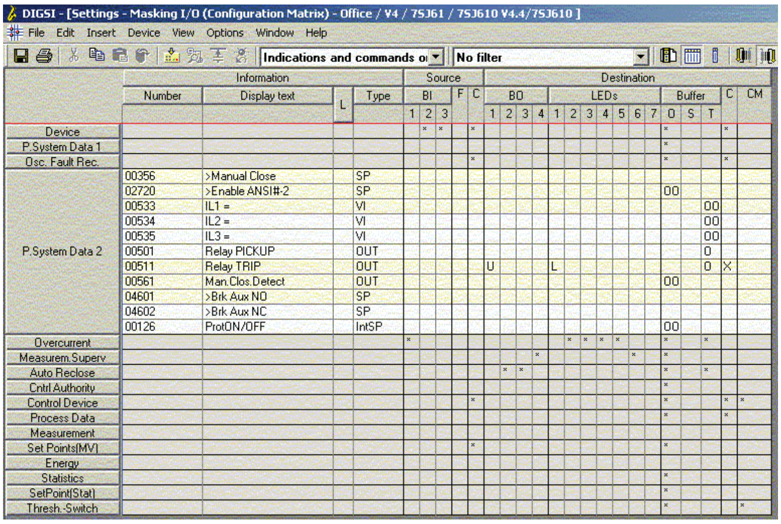


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Fig. 17 Configuration matrix

Differential Protection of Cables up to 12 km via Pilot Wires (Relay Type: 7SD600)

■ 1. Introduction

Line differential protection systems make it possible to protect cables or overhead lines selectively and as fast as possible in the event of a short-circuit. The application domain of the SIPROTEC 7SD600 described here is predominantly in the medium-voltage sector if either the tripping times of graded overcurrent-time protection relays become too great, or if distance protection relays are no longer able to guarantee the desired selectivity.

■ 2. Protection concept

The 7SD600 digital differential protection relay provides short-circuit protection for cables and overhead lines in power supply systems, independent of the system star-point configuration. It works according to the conventional 2-conductors principle. Here, the phase currents at the two line-ends are –with the help of summation current transformers –added up to one summation current. These are then transformed by voltage dividers into proportional voltages, which are fed with reversed polarity to two pilot wires. The resultant voltage difference finally produces a current, which represents the determinant tripping magnitude for both relays. Because of its rigorous local selectivity (the protection range is limited by current transformers at both ends of the line), differential protection is generally applied as an instantaneous main protection since no other protection can disconnect the line more quickly and selectively.

2.1 Differential protection (ANSI 87L)

2.1.1 Principle and current transformer connection

The differential protection function of the 7SD600 recognizes short-circuits in the protection range by comparing the summation currents detected at both ends of the line. In order to do this, the secondary phase currents from the primary current transformers are fed with variable weighting (number of windings) into the summation current transformer which combines them to produce a summation current.

Fig. 1 SIPROTEC 7SD600 line differential protection relay

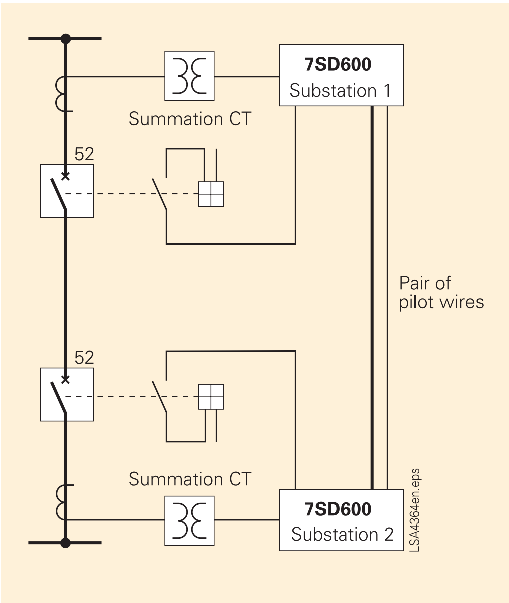

Fig. 2 Principal circuit diagram of line differential protection 7SD600

This also assumes, that current transformers with identical primary values are used at both ends, otherwise the variable windings ratio must be equalized by an appropriate arrangement of the matching transformer and/or summation current transformer.

2.1.2 Summation current transformers

The 4AM4930 summation current transformer is installed as standard in the normal circuit.

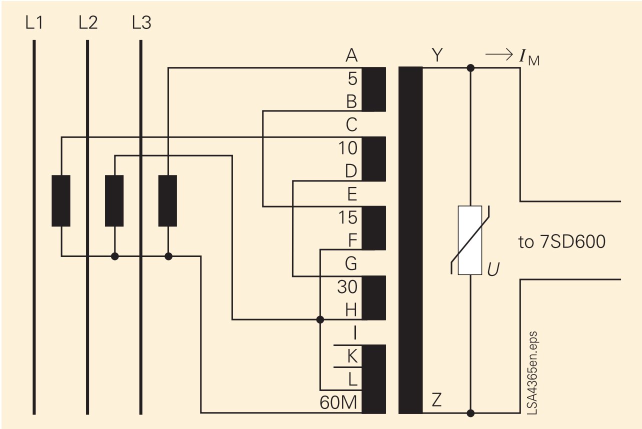

Fig. 3 4AM4930 summation current transformer normal connection

This summation current transformer has different primary windings with several tapping points allowing phase current and connection type (for example two-phase) mixing ratios to be varied. This way, increased sensitivities (e.g. of the earth current) or preferences in the case of double earth fault can be neatly ensured.

Fault	W	W / $\sqrt{3}$	I_1 for I_M = 20 mA
L1-L2-L3 (sym.)	$\sqrt{3}$	1.0	1 x I_N
L1-L2	2	1.15	0.87 x I_N
L2-L3	1	0.58	1.73 x I_N
L3-L1	1	0.58	1.73 x I_N
L1-E	5	2.89	0.35 x I_N
L2-E	3	1.73	0.58 x I_N
L3-E	4	2.31	0.43 x I_N

Table 1 Fault types and winding valencies W in case of normal connection L1 - L3 - E

The selected summation current transformer connection must be implemented identically at both ends of the line to avoid false tripping.

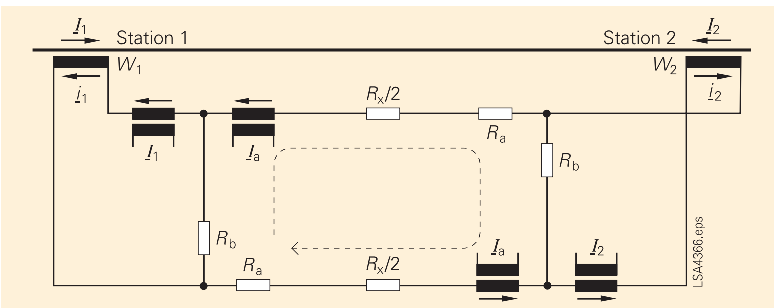

Fig. 4 Function diagram

2.1.3 Differential current

With normal summation current transformer connection and symmetrical current flow (rated quantity), 20 mA flow to the summation current transformer on the secondary side. This summation current is now measured in the local 7SD600, and also fed as voltage drop to two pilot wires via an internal resistor of the protection relay. At the remote end the summation current is formed in the same manner and also fed as voltage drop to both pilot wires, but this time with reversed polarity.

In healthy state, the reverse polarity voltages should neutralize each other out. However, under fault condition there is in the case of different summation currents a resulting voltage which will drive a current (proportional to the theoretical differential current) along both wires. This current is then measured by the protection relay and serves as a tripping parameter.

2.1.4 Transformers in the protected zone

The 7SD600 optionally also analyses the summation currents for a component of 100 Hz. This makes it possible to expand the protection range beyond a transformer. Additional external matching transformers must nevertheless ensure, that the transformation ratio of the currents and their phases is compensated analagously to the transformer.

2.1.5 Restraint current

In order to stabilize the differential protection system against overfunction (unwanted operation) in the event of external faults, the "differential current" tripping parameter is standardized to a stabilization parameter. The latter is the sum of the magnitudes of the currents detected at both ends of the protection range. This stabilization means that in the event of large currents flowing through and of measurement errors resulting from transformer faults or transformer saturation, the tripping parameter must likewise be high.

Measuring the local summation current transformer secondary currents and the current flowing through the pilot wires ensures, that each of the two protection relays can calculate both the differential and stabilizing currents and react according to the tripping characteristic.

2.1.6 Tripping characteristic

The 7SD600 tripping characteristic consists of three sections. In the area of small currents a fixed tripping threshold settable as parameter must be exceeded in order to ensure response. Both the other tripping characteristic branches have set defaults. Current-proportional transformer faults rise as the current magnitude increases. This is taken into account in the tripping diagram with a section of a straight line through the origin with a 1/3 gradient (slope). In the case of even greater currents the tripping limit is determined by a further straight line, which intersects the stabilization axis at $2.5 \cdot I_{NLine}$ and has a gradient of 2/3. This branch takes account of incipient current transformer saturation.

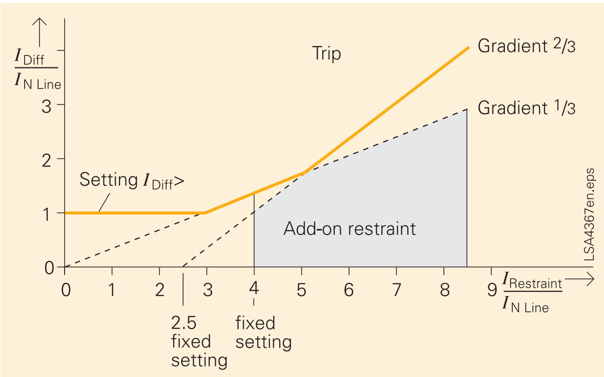

Fig. 5 Restraint characteristic of the differential protection drawn with a default of $I_{Diff}> = 1.0 \cdot I_{N\,Line}$

$I_{Diff} = |I_1 + I_2|$
$I_{Restraint} = |I_1| + |I_2|$
I_1 = Current at local line end, positive flowing into line
I_2 = Current at remote end, positive flowing into line
$I_{N\,Line}$ = Line rated current

In order that differential protection remains stable in the case of external faults with strong currents, the 7SD600 offers additional stabilization with regard to possible transformer saturation. Here, on the basis of the stabilization and differential current trend, the protection recognizes that an external fault initially occurred before the build-up of the differential current as a result of transformer saturation. When the current values enter the additional stabilization (restraint) range, the differential protection is blocked for a maximum of 1 second in order to give the transformer time to come out of saturation. However, if during this time steady state prevails in the tripping range for two network periods, blocking is neutralized and the protection makes the decision to trip.

2.1.7 Pilot wires

Symmetrical telecommunication wire pairs (typically 73 Ω/km loop resistance and 60 nF/km capacity) with a wire/wire asymmetry (at 800 Hz) of less than 10^{-3} are suitable. The loop resistance may not exceed 1200 Ω. Furthermore, the longitudinal voltage component induced in the pilot wires by the short-circuits (to earth) must be taken into account. The induced direct axis voltage component can be calculated according to the following formula:

$$U_l = 2\,\pi\, f \cdot M \cdot I_{k1} \cdot l \cdot r_1 \cdot r_2$$

where
U_l = *Induced direct axis voltage component*
f = Rated frequency [Hz]
M = Mutual inductance between power cable and pilot wires [mH/km]
I_{k1} = Maximum single-pole short-circuit current [kA]
l = Length of the parallel distance between power cable and pilot wires [km]
r_1 = Reduction factor of the power cable (in case of overhead lines $r_1 = 1$)
r_2 = Reduction factor of the pilot wire cable

The calculated induced voltage needs only be half taken into account since it builds up on the insulated pilot wires at both ends. If this exceeds 60 % of the permitted test voltage, additional measures (isolating transformers) are necessary. Isolation (barrier) transformers are available for isolation up to 5 kV and 20 kV respectively. The center tap on the side facing the protection relay must be earthed for anti-touch protection reasons, but the pilot wire connection must not be earthed or provided with surge arresters.

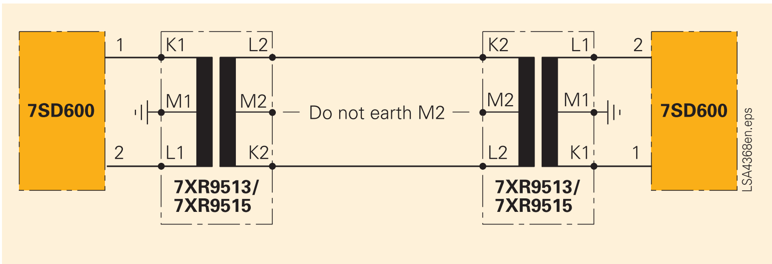

Fig. 6 Connection of isolating transformers 7XR9515 (5 kV) or 7XR9513 (20 kV)

2.2 Backup protection functions (ANSI 50)

As is usual with modern, numerical protection relays, the 7SD600 also offers further integrated protection and additional functions. The user must nevertheless be aware of the lack of hardware redundancy when deploying these functions. For this reason, at least a further separate short-circuit protection relay, for instance a 7SJ602, should be installed.

2.2.1 Overcurrent-time protection (ANSI 51)

The 7SD600 includes overcurrent-time protection alongside differential protection as an emergency function, i.e. for cases where the main function is no longer available. Parameterization makes it possible to set whether the emergency definite-time overcurrent protection should generally be activated when differential protection is ineffective, or only if the wire monitoring responds. This emergency definite-time overcurrent protection works with the local summation current and features one single stage. The current threshold is set above the maximum symmetrical load current. Since in general no time grading is possible if full selectivity is to be retained, a compromise between selectivity and speed of protection has to be found. In any case the tripping time should be delayed by at least one grading, in order to wait to see whether this high current is caused by faults on adjoining power system sections and other protection relays selectively trip upon this fault.

2.2.2 Additional functions

Pilot-wire monitoring

The ohmic resistance of the pilot-wire loop is needed for correct calculation of the summation current at the remote end of the protection range. This current is comfortably determined with the help of DIGSI during commissioning and entered into the protection relay parameters. Because no differential voltage and thus no differential current occur in flowing currents during normal operation, monitoring of the pilot-wire connection is strongly advised. Audio frequency signals are modulated onto the connection line.

Intertripping, remote tripping

In the event of protective tripping at the local end, an intertrip signal can be sent to the remote end (using the same transmission equipment) in order to isolate the faulted line. The remote tripping system, in which a signal coupled via binary input is interpreted as a shutoff command for the circuit-breaker on the remote end, works according to the same pattern. Here too an audio frequency signal is transmitted to the partner relay, as with intertripping.

■ 3. Settings

The parameter settings of both relays of the differential protection system differ in only a few points. This is the reason why only the 7SD600 settings of one line end are explained initially.

The differences are explicitly listed towards the end of this chapter.

The 7SD600 is notable for its few setting parameters, which allow it to be configured quickly and easily. Pilot-wire monitoring is the only function that can be activated (or deactivated) under "Scope of the device", provided the relay has been ordered with this option. This must be activated.

3.1 System /line data

The parameters defined by the primary equipment are set under the "system/line data" heading (see Fig. 7). These include network frequency, current transformer ratio and minimum circuit-breaker activation time in the event of protective tripping. In order to better match the differential protection characteristic, the protection parameters are referred to the line rated current; this must be input at this point and must imperatively be the same in both relays. As already described above, the resistance of the pilot-wire connection is required for correct calculation of the current value at the remote end. This can be calculated either from the pilot-wire connection data sheets or can be measured within the context of commissioning by the relay itself in accordance with the instructions in the manual. This value must subsequently be entered here. Finally, the lock-out function can be switched either on or off at this point. The activated lock-out function requires an acknowledgement of the TRIP command via the acknowledgement button on the relay or by the setting of a binary input, e.g. by using an external switch.

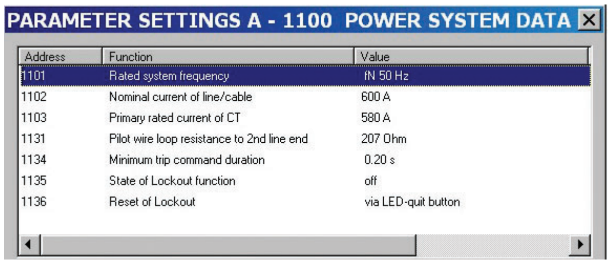

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Fig. 7 Settings for "Power system data"

3.2 Line differential protection

3.2.1 Line differential protection

As with all protection functions, the differential protection can be switched either on or off at this point in order to simplify function-selective testing. Additionally, there is the option to set these parameters to "indication only", so that for example at the time of commissioning all indications for this protection function are logged, but no tripping occurs. The differential protection function must of course be switched on for normal operation. Regarding the differential protection function, only the tripping threshold I_{DIFF}> must be set (referred to the line rated current).

Referred to the summation current, this value must thus lie below the minimum short-circuit current but above the inrush current and the transformer faults of the primary and summation current transformers, taking the weighting factors for the various fault types into account. The preset value of 1.0 · $I/I_{N,Line}$ has proved over many years to be a stable empirical figure. Taking account of a weighting factor of more than 2 for single-pole faults, this corresponds to barely five times an accepted charging current of 10 % referred to $I_{N,Line}$. Should 5 times the charging current be above this value, $I_{DIFF}>$ must be increased.
This charging current is calculated according to the equation:

$$I_C = 3.63 \cdot 10^{-6} \cdot U_N \cdot f_N \cdot C_B' \cdot s$$

I_C = Charging current to be ascertained in A primary
U_N = System rated voltage in kV
f_N = System rated frequency in Hz
C_B' = Operating capacity of the line in nF/km
s = Line length in km

3.2.2 Blocking with second harmonic

A transformer may also be situated within the 7SD600 protection range. However, in this case the transformer ratio must be recreated with external matching transformers, so that the current magnitude and phase angle of the summation current transformer inputs correspond on both sides of the transformer. For this application it is necessary to stabilize the differential protection in relation to the transformer inrush. Because no transformer is located within the protection range, blocking of the differential protection is deactivated by means of the second harmonic. Consequently, the tripping threshold set values for both the second harmonic and the maximum differential current (which is blocked by this function) are irrelevant.

3.2.3 TRIP delay

In certain applications (e.g. reverse interlocking), it can be necessary to delay the differential protection somewhat. This delay can be set at this point.

3.2.4 Local current threshold

A local current threshold (which must be exceeded) can be set as a further tripping condition at the local end. With the preset value 0 · $I_{N, Line}$ the protection relays trip at both ends if the differential protection responds. The local current threshold can be raised if, for example, in the case of single-side infeed, the remote end (from which no current is feeding onto the fault) should not be tripped.

3.2.5 Intertrip function

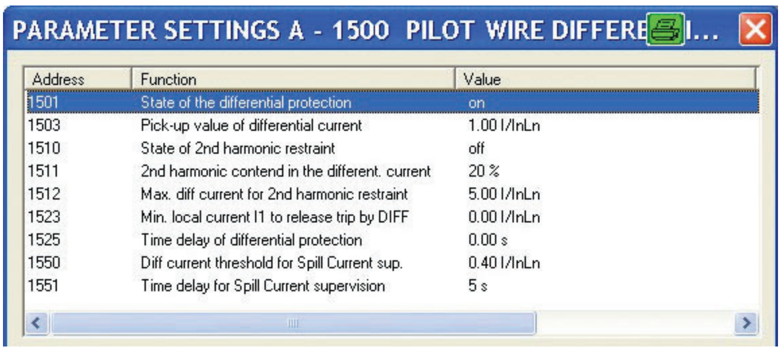
Normally, tripping is effected at both stations as a result of current comparison. Tripping at one end only can occur when an overcurrent release is used or with short-circuit currents only slightly above the tripping value. Circuit-breaker intertripping can be parameterized in the unit with integral pilot-wire monitor, so that definite tripping at both ends of the line is assured.

3.2.6 Differential protection blocking (spill current)

This differential current monitoring function reacts to a permanently low differential current, which can be produced by phase failure at the summation current transformer (e.g. due to wire break) and blocks the differential protection function. The threshold (parameter 1550) is set slightly over the capacitive losses of the pilot wires, which at a power system frequency of 50 Hz can be estimated according to

$$I_{spill}\,(\%) = 0.025 \cdot I_{N,\,Line} \cdot l_{Line}\,(\text{km})$$

With a line length of 12 km, this gives a value of 0.3 · $I_{N,\,line}$ for the spill current. In order to prevent spurious tripping, the parameter is set at 0.4 · $I_{N,\,line}$. In accordance with the default (preset) value, monitoring is delayed by 5 seconds.


PARAMETER SETTINGS A - 1500 PILOT WIRE DIFFERE... I...

Address	Function	Value
1501	State of the differential protection	on
1503	Pick-up value of differential current	1.00 I/InLn
1510	State of 2nd harmonic restraint	off
1511	2nd harmonic contend in the different. current	20 %
1512	Max. diff current for 2nd harmonic restraint	5.00 I/InLn
1523	Min. local current I1 to release trip by DIFF	0.00 I/InLn
1525	Time delay of differential protection	0.00 s
1550	Diff current threshold for Spill Current sup.	0.40 I/InLn
1551	Time delay for Spill Current supervision	5 s

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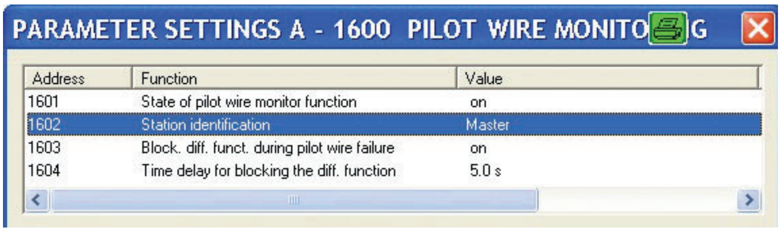
Fig. 8 Setting the differential protection function

3.3 Pilot wire monitoring

Pilot wire monitoring is extremely important for monitoring the capability of the differential protection system. Since in fault-free operation, particularly where operating currents are low, no appreciable differential current occurs (due to transformer and measurement inaccuracies), wire break or short-circuit would not be noticed, which would lead to protection malfunction. Thus the pilot-wire function will be activated and the reaction of the protection will be defined. When a connection fault is recognized, the differential protection can be blocked or the fault can simply be reported –after an adjustable delay time.

In order to begin the communication between both relays in a defined manner, the station identification must be set differently. One 7SD600 is parametrized as master, the other as slave.



PARAMETER SETTINGS A - 1600 PILOT WIRE MONITORING

Address	Function	Value
1601	State of pilot wire monitor function	on
1602	Station identification	Master
1603	Block. diff. funct. during pilot wire failure	on
1604	Time delay for blocking the diff. function	5.0 s

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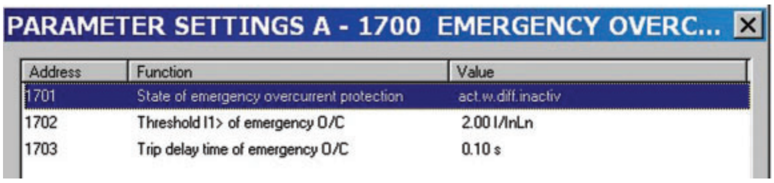
Fig. 9 Settings of the pilot-wire monitoring for the local relay (master)

3.4 Overcurrent-time protection

Emergency overcurrent-time protection can be activated either in the event of a recognized pilot-wire fault or generally when the differential protection is deactivated. The local summation current must likewise be used as a measuring quantity and the setting must be referred to the line rated current. Here too, when setting the current threshold, the weighting factors for the various fault types must also be taken into consideration. The current thresholds are set – as far as possible – between maximum operating current and minimum short-circuit current. The associated delay time is adjusted to the network grading plan as closely as possible, in order to maximize selectivity.



PARAMETER SETTINGS A - 1700 EMERGENCY OVERC...

Address	Function	Value
1701	State of emergency overcurrent protection	act.w.diff.inactiv
1702	Threshold I1> of emergency O/C	2.00 I/InLn
1703	Trip delay time of emergency O/C	0.10 s

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Fig. 10 Settings of the pilot-wire monitoring "Emergency overcurrent-time protection"

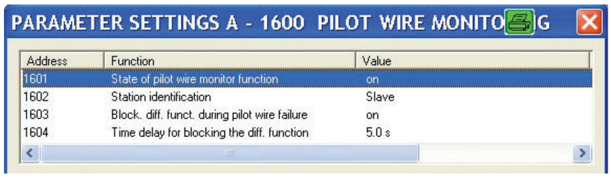
3.5 Remote tripping/Transfer trip

A signal injected via binary input (e.g. from the circuit-breaker failure protection) can be transmitted as an audio-frequency signal to the remote end through the pilot wires in order to effect tripping of the circuit-breaker there. Thus reliable transmission is ensured even when pulses are very short. The transmission duration can be prolonged. The protection relay at the remote end must be appropriately set for the reception of a remote tripping signal, i.e. the "transfer trip" function must be switched on.

To avoid an overfunction, tripping can be delayed. Hence, a transient signal will not lead to a misinterpretation. In order to ensure reliable tripping even when a short signal is received, the transfer trip signal can also be delayed until the circuit-breaker opens. The preset values are intended to ensure remote tripping.

3.6 Relay at the remote end

The parameter settings of the second 7SD600, which is installed at the remote line end, are to the greatest possible extent identical to the relay described here. The identical summation current transformer connection and the same set value for the line rated current are essential. All further parameters can normally be taken over by the local relay; however, under the key term "pilot-wire monitoring", the station identification of "master" has to be changed to "slave" so that this parameter is set differently in both relays.



PARAMETER SETTINGS A - 1600 PILOT WIRE MONITORING

Address	Function	Value
1601	State of pilot wire monitor function	on
1602	Station identification	Slave
1603	Block. diff. funct. during pilot wire failure	on
1604	Time delay for blocking the diff. function	5.0 s

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Fig. 11 Settings of the pilot-wire monitoring for the relay at the remote end (slave)

4. Summary

Undelayed and at the same time rigorously selective protection of cables and lines reduces the consequences of unavoidable power system disturbances. For one this means protection of the equipment, and secondly a contribution to a maximized level of supply security.

A differential protection system consisting of two SIPROTEC 7SD600 relays and the associated summation current transformers offers comprehensive protection of cables and overhead lines. Extensive additional functions allow trouble-free connection of the relays and integration into complex power system protection grading.

The default settings of the relay are selected in such a way, that the user only has to configure the known cable and primary transformer data. Many of the preset values can be taken over with no problem and thus substantially reduce effort involved in parameterization and setting.

Differential Protection of Cables via Fiber Optics (Relay Type: 7SD610)

- 20 kV single-core cross-linked polyethylene cable N2XS(F)2Y 1x120RM/16
- Resonant-earthed system
- Fiber-optic link
- ANSI 87L differential protection
- ANSI 50/51 definite-time overcurrent-time protection as backup protection
- ANSI 50HS instantaneous high-current switch-onto-fault protection
- ANSI 49 thermal overload protection

1. Introduction

The ever higher load imposed on primary equipment requires it to be protected in a selective manner and fast fault clearing in case of a short-circuit, in order to minimize possible consequential damage resulting from faults. For overhead lines and cables this requirement is met by line differential protection relays.

A full example of how to set SIPROTEC 4 7SD610 protection relays for a power cable in the distribution network is described, in addition to notes on design.

2. Protection concept

The 7SD610 numerical differential protection relay is a modern short-circuit protection relay for cables and overhead lines in power supply system. Due to rigorous local selectivity –the protected zone is limited at both ends of the line section – power system topology and voltage levels play no role. Furthermore, the star-point conditioning of the current network is of no significance as current comparison takes place per phase and thus variable weightings for different faults –as they occurred in the conventional summation current transformer differential protection process –are nowadays unimportant. Due to its selectivity, the differential protection is generally set as an undelayed, instantaneous main protection since no other protection can disconnect the line more quickly and selectively.

2.1 Differential protection (ANSI 87L)

The differential protection function of the 7SD610 detects short-circuits using phase-selective comparison of the current values measured by separate relays at both ends of the line in the zone to be protected, including weak current or high-resistance short-circuits.

Fig. 1 SIPROTEC 7SD610 line differential protection relay

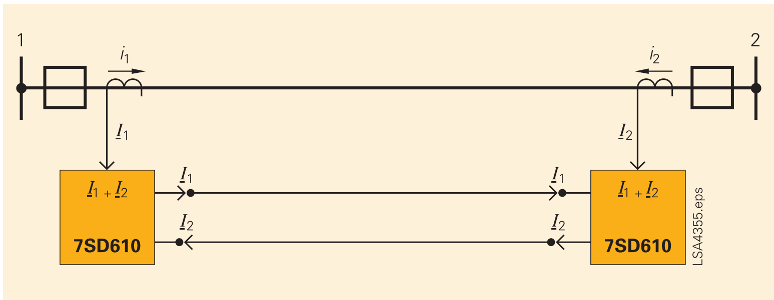

Fig. 2 Differential protection for a line

Each 7SD610 compares locally measured current values with those from the remote end and decides independently whether there is a system disturbance or not. A communication link between both relays is required to exchange the measured values. The relays are designed for a fiber-optic link, which is the preferred method. System-tested communication converters for other transmission media (copper conductors, ISDN line, digital communication networks with X21 or G703.1) are nevertheless also available.

The differential protection function implemented in the 7SD610 uses two algorithms in order to meet the demands of speed and sensitivity. The charge comparison process integrates the measured currents and compares the charge values at both ends over a short time interval. This simple process makes it possible to detect high-current faults as quickly as possible.

This crude algorithm is complemented by a substantially more sensitive vector comparison process. In this process, the current vectors per phase of both relays are compared with each other at each sampling time point. In particular, the errors for each measured value during the process are considered. This includes the current measured value error based on the stored transformer data. The error consideration also takes into account both the signal transmission time of the measured-value telegram from the partner relay and the cable charge current. Finally, each protection relay can decide whether its own (directly measured) current value corresponds to the measured value received by telegram from the remote end via the functional interface, including all magnitude and phase errors. If this is not the case, a further (fault) current must be responsible for the difference and the 7SD610 decides on tripping.

Converted to the conventional characteristic, this means that the restraint current is not simply formed as the sum of the magnitudes of the currents measured at both ends, but as the sum of the errors described above plus the minimum tripping threshold $I_{DIFF}>$, which are converted into a single current component. Protective tripping occurs at the moment when the differential current is greater than the adaptively formed restraint current.

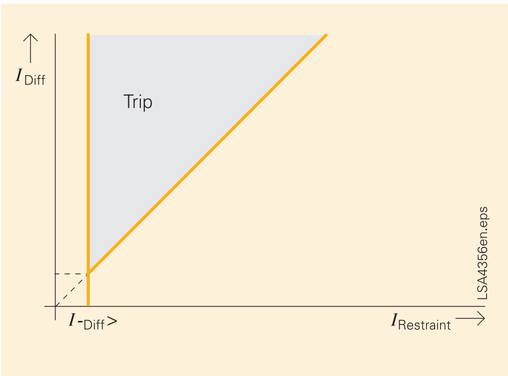

Fig. 3 Differential protection tripping characteristic

In order to ensure reliable operation of the differential protection system, the current transformers deployed must comply with the following requirements:

- 1st condition:
  When the maximum short-circuit current is flowing through, current transformers may not be saturated in steady state.
  $$n' \geq \frac{I_{Kd\,max}}{I_{N\,prim}}$$
- 2nd condition:
  The operating overcurrent factor n' must be at least 30 or a saturation-free time t'_{AL} of min ¼ period is ensured
  $n' \geq 30$ or $t'_{AL} \geq$ ¼ period
- 3rd condition:
  Maximum mutual ratio of the current transformer primary rated currents at the ends of the object to be protected
  $$\frac{I_{prim\,max}}{I_{prim\,min}} \leq 8$$

2.2 Backup protection functions

As usual with modern, numerical protection relays, the 7SD610 also offers a range of further protection and additional functions, which make it flexibly customizable for almost all uses. The user must nevertheless be aware of the lack of hardware redundancy when deploying these functions. For this reason at least one additional, separate short-circuit protection relay should be installed. Depending on voltage level and/or importance of the line, this can be a separate distance protection (7SA6) or a definite-time overcurrent-time protection relay (7SJ6).

The overcurrent-time protection included in the 7SD610 should therefore only be used as backup protection against external faults in the power system outside the differential protection zone.

2.2.1 Overcurrent-time protection (ANSI 50/51)

Parameterization makes it possible to specify whether the three-stage overcurrent-time protection included in the 7SD610 should be working permanently as an independent protection function (backup), or whether it should only be activated as an emergency function in case of malfunction in the communication link.

As mentioned above, if the backup function is used, the concept of hardware redundancy must not be neglected. Consequently, the backup definite-time overcurrent-time protection function is recommended primarily for protection outside the differential protection area, such as e.g. protection of an incoming feeder panel in a substation.

Two of the three stages (*I*> and *I*>> stage) are configured as incoming feeder protection in this case. It has only been possible to authorize and set the *I*>>> stage in such a way, that it trips high-current faults quickly in this exceptional situation, losing the selectivity. If the overcurrent-time protection is used as an emergency function, all stages can be set in terms of tripping threshold and delay time for this exceptional case, in line with selectivity and speed.

2.2.2 Instantaneous high-current switch-onto-fault protection (ANSI 50HS)

This function is meant to disconnect immediately in the event of single-end switching onto a high-current short-circuit.
The measured values of each phase, filtered to the fundamental component, are compared with the set threshold.
If the measured value exceeds twice the threshold, protective tripping occurs immediately. For this function, the circuit-breaker position of the remote end must be known.

A further stage of this protection function works without data on the status of the circuit-breaker at the remote end, but can only be used if current grading above the object to be protected is possible.

2.2.3 Thermal overload protection (ANSI 49)

The thermal overload protection prevents overloading of the object. In the case of the 7SD610, this function is used specifically for a transformer situated within the protected zone, but is also appropriate for power cables that are working to full capacity.

The 7SD610 uses a thermal model to calculate (from the measured phase currents and from the set parameters that characterize the object to be protected) the temperature of the equipment. If this temperature exceeds an adjustable threshold, the 7SD610 issues a warning message, and if a second, higher threshold is exceeded, the protection trips.

2.3 Additional functions

The additional functions listed in the following are not used in the example given and are therefore only mentioned for the sake of completeness.

- Automatic reclosure makes it possible to quench arc short-circuits on overhead lines by a brief interruption of the current flow, i.e. not necessarily immediately and fully disconnecting the line.
- The breaker failure protection in the 7SD610 has two stages. If a TRIP command issued by a protection relay does not lead to the fault current being shut off, the 7SD610 can initially repeat the TRIP command before, at the second stage, the higher-level protection is informed of this malfunction by parallel wiring and trips the circuit-breaker allocated to it.
- The 7SD610 supports three-pole and single-pole circuit-breaker activation, required particularly frequently on the high-voltage level, thanks to its phase-selective operation.
- Transformers and shunt reactors in the differential protected zone are also governed by integrated functions.
- By means of a connected binary input, a TRIP command can be generated by the 7SD610 via an external coupling.
- The digital communication link of the R2R interface makes it possible to transfer 4 remote commands and 24 remote messages from one relay to the other and process them individually in that relay.
- Because the 7SD610 also has voltage inputs, the line-to-earth voltages of the three phases and, where applicable, the shift voltage can be connected to the relay. This does not affect the protection function, but makes it possible to detect the measured voltages and to calculate with the current measured values the derived electrical magnitudes such as active power, reactive power, apparent power, cos φ (power factor) and frequency.

■ 3. Setting example:

As an example, the settings of the 7SD610 relays are described, such as are intended to protect a 20 kV single-core XLPE cable of type N2XS(F)2Y 1x120RM/16 with a length of 9.5 km. The cable rated current is 317 A, on side 1 a new 400 A/1 A, 10P10, 5 VA current transformer is used, and an existing 300 A/5 A, 10P20, 30 VA current transformer is located at the remote end. The maximum short-circuit current flowing through is 12.7 kA.

3.1 Checking the transformers

Initial checks must be made to ascertain whether or not the transformer requirements are met. The quotient of the primary side transformer rated currents evidently amounts to 400 : 300; a value smaller than 8 is thus achieved.

The operational overcurrent factor is calculated from the formula

$$n' = n \cdot \frac{P_N + P_i}{P' + P_i}$$

Equation 1

n' = Operational accuracy limiting factor
n = Rated overcurrent factor
P_N = Rated burden of the current transformers [VA]
P_i = Inherent burden of the current transformers [VA]
P' = Actual connected burden [VA]

The current transformer's own inherent load is calculated from

$$P_i = R_i \cdot I_{N,CT}^2$$

Equation 2

If R_i (the transformer's secondary winding inner resistance) is unknown, the estimation of $P_i = 20\ \% \cdot P_N$ is a good approximation. To arrive at the actually connected burdens, all burdens connected to the transformer core must be added. In this example, it is assumed that only the burdens of the protection relay (0.05 VA for relay rated current of 1 A, 0.3 VA for relay rated current of 5 A) and the incoming feeder cable load are concerned.

The latter is calculated from the formula

$$P_{Line} = \frac{2 \cdot \rho_{Cu} \cdot l_{Line}}{a_{Line}}$$

Equation 3

P_{Line} = Incoming feeder cable load [VA]
ρCu = Specific resistance of Cu [0.0175 Ω mm²/m]
l_{Line} = Secondary-side, single line length [m]
a_{Line} = Line cross-section [mm²]

It is clear from equation 2, that with a secondary-side transformer rated current of 5 A, an incoming feeder cable load 25 times higher appears than for 1 A.

For our example, a 5 m incoming feeder cable (single distance, therefore factor 2) with a cross-section of 4 mm² is assumed. From this we calculate an incoming feeder cable load for both transformers of 0.045 VA (transformer 1) and 1.116 VA (transformer 2).

The overcurrent factors for both transformers are now calculated from these values. According to equation 1 for transformer 1 we have

n' = 44.6

and for transformer 2

n' = 97.1.

These values must now be greater than or equal to the required overcurrent factors in order to be able to transmit the maximum through-flowing short-circuit current at a level of 12.7 kA in a saturation-free manner.

The following are required for transformer 1

n' > 12700 A/400 A = 31.75

and for transformer 2

n' > 12700 A/300 A = 42.33.

In both cases this is clearly achieved, as is the third condition n' > 30. Consequently, the transformers available are suitable for use in this differential protection system.

3.2 Local relay settings

The parameter settings of both the differential protection relays usually differ only in a few points. This is why only the settings mentioned at the beginning of this application example of a 7SD610 are explained initially. The settings to be changed of the second relay are explicitly listed towards the end of this chapter. Initially, using the DIGSI 4 software for configuration, the 7SD6 relay with Order No. 7SD6101-4BA39-0BA0+M2C is applied and opened in the current project.

3.2.1 Functional scope

In the next step the parameters, beginning with the "functional scope", are set. At this point, we determine which of the functions provided by the protection relay should be used. The other functions are set at "not available" and are consequently concealed for the remainder of the relay parameterization. For our example, we have selected differential protection as the main protection function together with overcurrent-time protection, instantaneous high-current switch-onto-fault protection and overload protection.

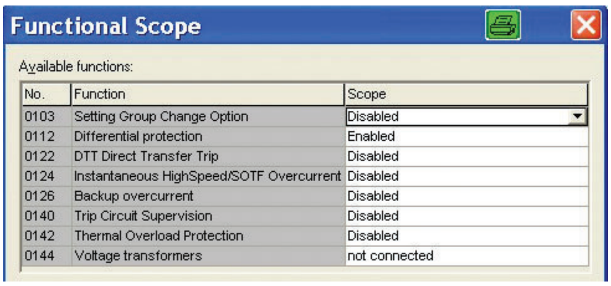

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Fig. 4 "Functional scope" menu item settings

3.2.2 Power system data

In the section called "power system data 1", the parameters defined by the primary equipment are set. These are in particular the current transformer transformation ratio (400 A/1 A), the position of its star (neutral) point (assumed to be "on the line side") as well as the rated frequency (50 Hz) of the power supply system.

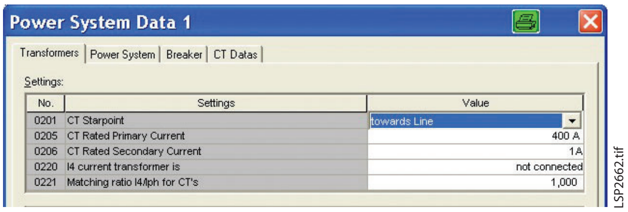


Fig. 5 "Power system data/Transformer data" menu item settings

On the next card the minimum and maximum circuit-breaker trigger times are input in order to ensure the execution of switching commands.

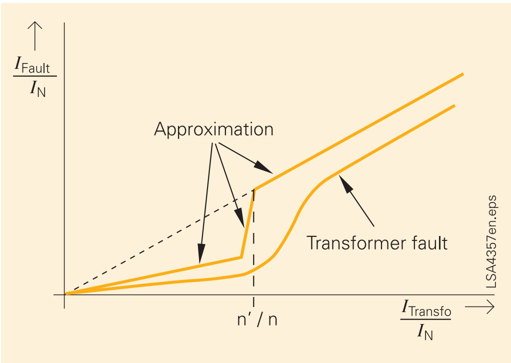


Fig. 6 Current transformer fault approximation

Next, three parameters must be set. These characterize the current transformer in terms of its characteristic progression and also define differential protection sensitivity.

Broadly, due to transformer faults, the influence of current-proportional measuring accuracy can be divided into two areas, which are separated on the current scale by the quotients n'/n. These percentage error values are dependent on the transformer class and can be taken from the Table 1 below. The footnote demonstrates that the quotient n'/n should be set at a maximum of 1.50, which corresponds to a "defensive" setting that prematurely migrates to the higher error influence and thereby increases the self-restraint.

The preset values were defined under the same aspect. They refer to a transformer in the "10P" class and also lie "on the safe side" for the quotients. These preset values can be left for all current transformer types. Under certain circumstances, some of the potentially very high differential protection sensitivity may be lost.

For our example this means, that the presetting for both error values are suitable; the quotient can be increased to the set value of 1.50, since in this case n'/n = 4.46 is clearly over the recommended maximum value of 1.50.

Transformer class	Standard	Error at rated current		Error at rated overcurrent factor	Setting recommendations		
		Transformation	Angle		Address 251	Address 253	Address 254
5P	IEC 60044-1	1.0 %	± 60 min	≤ 5 %	≤ 1.50[1)]	3.0 %	10.0 %
10P		3.0 %	–	≤ 10 %	≤ 1.50[1)]	5.0 %	15.0 %
TPX	IEC 60044-1	0.5 %	± 30 min	ε ≤ 10 %	≤ 1.50[1)]	1.0 %	15.0 %
TPY		1.0 %	± 30 min	ε ≤ 10 %	≤ 1.50[1)]	3.0 %	15.0 %
TPZ		1.0 %	± 180 min ± 18 min	ε ≤ 10 % (only *I* ~)	≤ 1.50[1)]	6.0 %	20.0 %
TPS	IEC 60044-1 BS: Class X				≤ 1.50[1)]	3.0 %	10.0 %
C100 to C800	ANSI				≤ 1.50[1)]	5.0 %	15.0 %

Table 1 Current transformer data setting recommendations

1) If n'/n ≤ 1.50, then setting = calculated value;
if n'/n > 1.50, then setting = 1.50.

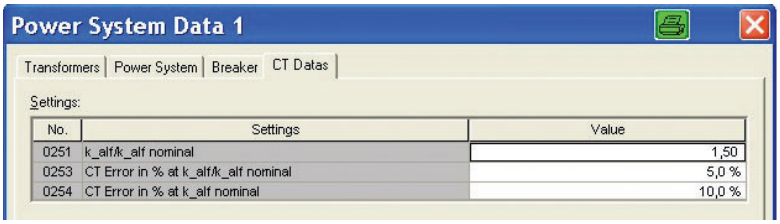


Fig. 7 Settings in the menu item "Power system data 1-*I*- CT characteristic"

When parameter set switchover is deactivated, only the "parameter set A" is available for the further settings. Under "power system data 2", only the rated operating current of the line (317 A), as well as correct line state recognition and connection recognition details, are set. At this point the rated operating current of the object to be protected (i.e. the power cable) in particular can deviate from the transformer rated current. The rated operating current must be set identically for both 7SD610 relays, since this value is the basis for the current comparison at both ends.

3.2.3 Differential protection settings

The differential protection is parameterized and set in a few steps as the main 7SD610 protection function. As in the case of all protection functions included in the scope, the differential protection can once again be switched either on or off at this point in order to simplify function-selective checking. The differential protection function must be switched on as a matter of course for normal operating status.

Concerning the differential protection function, only five parameters need be set in the example given. In particular, two discrete pickup thresholds (I_{DIFF}> and I_{DIFF}>>) of the differential protection function are set. Both these values determine the pickup thresholds of both protection algorithms (described above) of the differential protection function.

1233 I_{DIFF}>>: Pickup value

The I_{DIFF}>> value defines the charge comparison tripping threshold, which decides on tripping very quickly in the event of high-current faults. This value is usually set at rated operating current. In the case of a resonant-earthed power system, the setting must not be below the non-compensated earth-fault current. Otherwise the starting oscillation on occurrence of an earth fault could lead to (unwanted) tripping. Consequently, the Petersen coil rated current provides a good guide for setting the I_{DIFF}>> threshold if this lies above the rated line current.

1210 I_{DIFF}>: Pickup value

The I_{DIFF}> stage corresponds to the tripping threshold of the actual current comparison protection and is set at approximately 2.5 times the charge current. This charge current is calculated according to the equation:

$$I_C = 3.63 \cdot 10^{-6} \cdot U_N \cdot f_N \cdot C_B' \cdot s$$

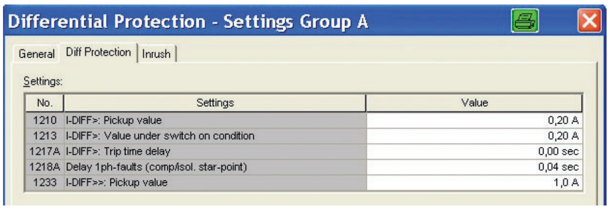
I_C Primary charge current to be calculated [A]
U_N Power system rated current [kV]
f_N Power system rated frequency [Hz]
C_B' Line operating capacity [nF/km]
s Line length [km]

The data for the single-core oil-filled cable to be protected are: C_B' = 235 nF/km, s = 9.5 km

At a rated voltage of 20 kV and a power system frequency of 50 Hz, a charge current of 8.1 A is calculated from the above equation. Consequently, a set value of 20.3 A (primary) arises for I_{DIFF}> or, in the case of a current transformer ratio of 400 A/1 A, a secondary value of 0.05 A. This figure is below the minimum threshold setting of 0.10 A (secondary). The "safe side" was once again sought with the preset value of 0.30 A. This figure results from the assumption of three times the charge current at a level of 10 %, referred to rated current. In the case of transformers with comparable response qualities and which – in the event of external faults – transmit the maximum through-flowing current while remaining unsaturated, this threshold can also be lowered to as little as 0.10 A. With various transformer types (e.g. iron-core and linear), the preset value remains unchanged, in order to ensure protection stability against transients in the event of external faults.

In this case, on comparable transformers with good response (n' high), a setting of 0.10 A or – with a safety margin – of 0.20 A is possible. If 2.5 times the charge current is greater than 0.30 A, the higher value must clearly be set.

When comparing the apparently very sensitive preset value of 0.30 A with customary differential protection settings (I_N), the different failure type weighting prevailing in the latter must be taken into account. Single-pole faults are often detected by the summation current transformer circuit with a sensitivity higher by a factor close to 3, which would also correspond to a I_{DIFF}> threshold close to 0.30 A.



No.	Settings	Value
1210	I-DIFF>: Pickup value	0,20 A
1213	I-DIFF>: Value under switch on condition	0,20 A
1217A	I-DIFF>: Trip time delay	0,00 sec
1218A	Delay 1ph-faults (comp/isol. star-point)	0,04 sec
1233	I-DIFF>>: Pickup value	1,0 A

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Fig. 8 Settings in the menu item "Settings group A – Differential protection – Diff protection"

<u>Further differential protection function parameters (settings)</u>

Three further parameters also exist for finer adjustment of the differential protection function.

First, there is the possibility to raise the $I_{\mathrm{DIFF}}>$ pickup threshold when the line is switched in. This is recommended when long off-load cables or overhead lines are energized. In order to avoid causing pickup of the differential protection in this case, this parameter $I_{\mathrm{DIFF}}>$ *SWITCH ON* should be set at approximately 3.5 times the charge current, provided that this value is greater than $I_{\mathrm{DIFF}}>$. Tripping of the current comparison protection should only be delayed in exceptional cases and it is therefore advisable to leave the presetting for T-$I_{\mathrm{DIFF}}>$ unchanged at 0.00 s. In a resonant-earthed system however, in the event of single-pole pickup, a delay is recommended in order to avoid tripping due to the earth-fault ignition process. A delay of 0.04 seconds has proved suitable.

Because it is not necessary to take a transformer into account in the range of the differential protection system, the transient rush restraint may remain deactivated. All further parameter settings of this small card are consequently irrelevant.

3.2.4 Setting the communication

Both 7SD610 relays communicate via a fiber-optic link laid parallel to the power cable. With a section length of 9.5 km, a fiber-optic cable with 9/125 µm mono-mode fibers is used. This communication link also requires a few parameter settings, which means that the presettings in the "R2R interface" section can generally be left unchanged.

As already mentioned, data (i.e. predominantly the current measured values) is transmitted between the two relays by telegram. Individual erroneous or missing telegrams pose no problem since they are counted for statistics purposes, but are otherwise ignored. However, if such an error status remains over long time periods and an initial time threshold is exceeded, a link malfunction is reported. At a second, higher threshold, this is recognized as a link failure (outage). It is also possible to set the length of time for which transmitted remote signals should retain their "old" status when a link malfunction is recognized.

In the "CT 1" card file, the R2R interface is activated and the type of communication connection, in this case "fiber-optic cable direct", is selected. Further parameters can be left at the presettings.

Under the concept of "differential protection topology" the relays must now be assigned the identification number "n". This differential protection system consists of two 7SD610 relays. One of the two relays must be set as "relay 1", the other as "relay 2". The difference lies in that the absolute chronology management of the system conforms to relay 1. Relay 2 adjusts itself accordingly and consequently the time data of both relays is always comparable. Since both the relays could also be linked to each other via a digital communication network in which more than one differential protection system is communicating, each relay can in addition have a relay identification number assigned to it. This may only be used once in the communication network. Both these addresses must be set identically in both relays. In our example of a direct fiber-optic link, no adaptation of the identification numbers is necessary.

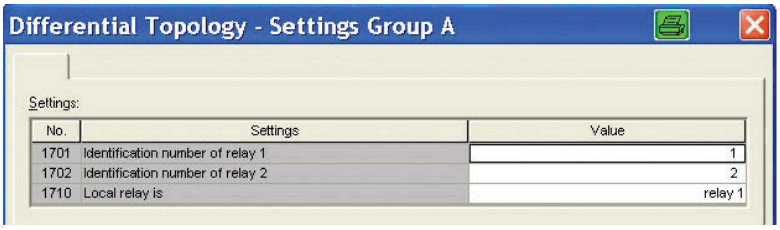

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Fig. 9 Settings in the menu item "Settings group A – differential topology"

3.2.5 Backup protection functions

3.2.5.1 Instantaneous high-current switch-onto-fault protection

This function is only operative if the circuit-breaker at the remote end is open and the local 7SD610 is informed of this via the communication link. Assuming that the function is activated in both relays, the data relating to the circuit-breaker position must also be detected by the local 7SD610. For this purpose the data items 00379 ">CB 3p Closed" and 00380 ">CB 3p Open" in the allocation matrix in the "power system data 2" data group must be combined with the associated binary inputs. The pickup threshold for the *I*>>> stage should be set at the approximate charge current of the line. This value offers a sufficient safety margin since the protection algorithm compares the instantaneous values with double the set root-mean-square (r.m.s.) value. The stage *I*>>>>, which is independent of the circuit- breaker, is left deactivated (set value "∞") as no current grading is possible via the object to be protected.

3.2.5.2 Overcurrent-time protection

Since further short-circuit protection is generally provided in addition to the differential protection – for reasons of hardware redundancy in an independent relay – the integrated definite-time overcurrent-time protection is only activated if there is a communication link failure (outage). The current thresholds are set – as far as possible – between maximum operating current and minimum short-circuit current. The associated delay time is adjusted to the power system grading plan in the best possible way, in order to maximize selectivity. In the example here – without knowing the minimum short-circuit current – the recommended setting is 20 % above the maximum permitted continuous current for the cable (407 A), i.e. 488 A or 1.22 A secondary.

If current-dependent grading via the object to be protected is possible, a high-current stage with immediate disconnection can also be set. In this case it must be ensured that the threshold does not pickup in the event of fault current flowing through.

If the definite-time overcurrent-time protection integrated into the 7SD610 is set as a permanently active backup protection function, overcurrent and high current stages can be used for regular definite-time overcurrent-time protection duties outside the differential protection area. In the event of a communication link outage, the *I*>>> stage can be used in the sense described above as an emergency definite-time overcurrent stage.

3.2.5.3 Thermal overload protection

Thermal overload protection prevents overload of the object to be protected, in this case the 20 kV cable. Because the cause of the overload normally lies outside the object to be protected, the overload current is a through-flowing current. The relay calculates the temperature rise in accordance with a thermal single-body model according to the differential equation:

$$\frac{\mathrm{d}\Theta}{\mathrm{d}t} + \frac{1}{\tau_{\mathrm{th}}} \cdot \Theta = \frac{1}{\tau_{\mathrm{th}}} \cdot \left(\frac{I}{k \cdot I_{\mathrm{N}}} \right)^2$$

For each phase, the protection function calculates a thermal replica of the object to be protected from the square of the phase current. The unfiltered measured value is used so that harmonics are also taken into account in the thermal consideration. Whether the overload function should in fact disconnect when the tripping limit is reached, or whether reaching this threshold should only be reported, must initially be set.

The basic current for overload detection is the thermally continuous permitted current of the object to be protected (compare cable data). This can be referred to the protection relay rated current via the setting factor k:

$$k = \frac{I_{\max}}{I_N}$$

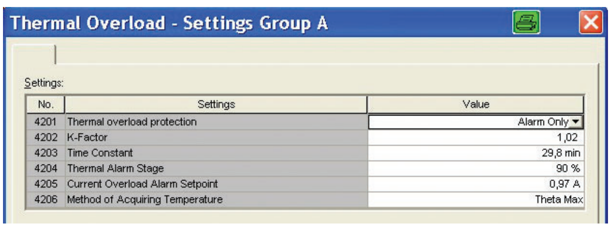
Consequently, at a maximum permitted continuous current of 407 A and a primary transformer rated current of 400 A, a value for k of 1.02 results.

The temperature rise time constant τ_{th} must also be taken from the manufacturer's data. It must be borne in mind that this must be set in minutes, whereas often a maximum permitted 1 second current is specified, and the same applies to our cable. In this case the 1 second current is 17.2 kA. The conversion formula is

$$\frac{\tau_{th}}{\min} = \frac{1}{60} \cdot \left(\frac{\text{permissible 1 second current}}{\text{permissible continuous current}} \right)^2$$

τ_{th} is 29.8 minutes in this case.

Before reaching the tripping threshold, a thermal and/or current alarm stage can be set. These should typically be set somewhere below the tripping threshold in order to give the operating staff sufficient time to reduce the equipment load. For the thermal alarm stage it is recommended that the preset value of 90 % be left unchanged. The current alarm stage is set somewhere below the maximum continuous permitted operating current. 95 % of this figure is selected here, i.e. 387 A primary. Referred to the transformer rated current, this gives approximately 0.97 A secondary. Finally, it is also possible to set the method used to calculate the temperature rise. This is calculated separately for each phase. There is a choice as to whether the maximum of the three excess temperatures (preset), the arithmetic mean of these three, or the temperature rise calculated from the maximum phase current should be significant for comparison with the tripping thresholds. In this case, the preset value remains unchanged, provided no other algorithm must be preferred.



Thermal Overload - Settings Group A

Settings:

No.	Settings	Value
4201	Thermal overload protection	Alarm Only
4202	K-Factor	1,02
4203	Time Constant	29,8 min
4204	Thermal Alarm Stage	90 %
4205	Current Overload Alarm Setpoint	0,97 A
4206	Method of Acquiring Temperature	Theta Max

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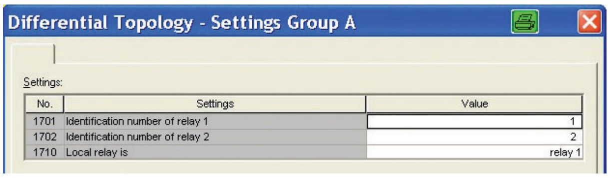
Fig. 10 Settings in the menu item "Settings group A – thermal overload protection"

3.3 Settings of the relay at the remote end

The settings of the local relay just parameterized can mostly be used as a basis for parameter assignment on the relay at the remote end. The record is simply duplicated by copying and pasting. This creates a new relay file, the only difference in which is the VD address. This ensures that the record copied belongs to another relay, even though that relay was until now identical.

In the "Settings group A – differential protection topology" section, the parameter 1710 must be set to "relay 2". In the absence of this setting, there cannot be any communication between the two relays.



Differential Topology - Settings Group A

Settings:

No.	Settings	Value
1701	Identification number of relay 1	1
1702	Identification number of relay 2	2
1710	Local relay is	relay 1

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Fig. 11 Settings for the relay at the remote end in the "Settings group A – differential topology" section

The transformer data and the transformer characteristic in the "Power system data 1" section must be adapted. Whether intertripping should be operable from both ends should also be checked. Otherwise, this must also be changed.

The settings in the "Power system data 2" (differential protection function, R2R interfaces, instantaneous switch-onto-fault and overload) are identical for both relays and need not be changed. The definite-time overcurrent-time function settings are dependent on power system topology and must therefore be checked. If the relays are connected to a substation control system or RTU, the respective relay addresses must be checked.

4. Connection example

Generally, connection of three phase current transformers to the 7SD610 in Holmgreen circuit is recommended in accordance with Fig. 12. This allows the differential protection to work with the three directly measured phase currents. For other protection functions (e.g. definite-time overcurrent-time protection), an earth current summated from the three phase currents is available. If there are higher demands for the accuracy of the earth current, a core-balance current transformer can also be connected to the 7SD610 IE input (Fig. 13). In this case the modified transformation ratio for this input must be entered via parameter 221 in "Power system data 1 – transformer data".

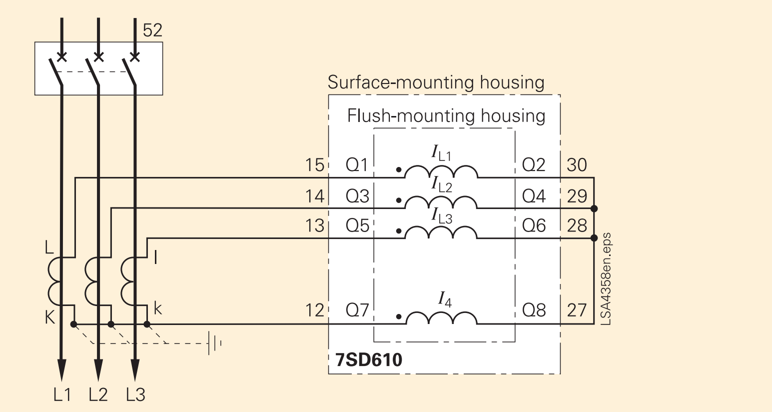
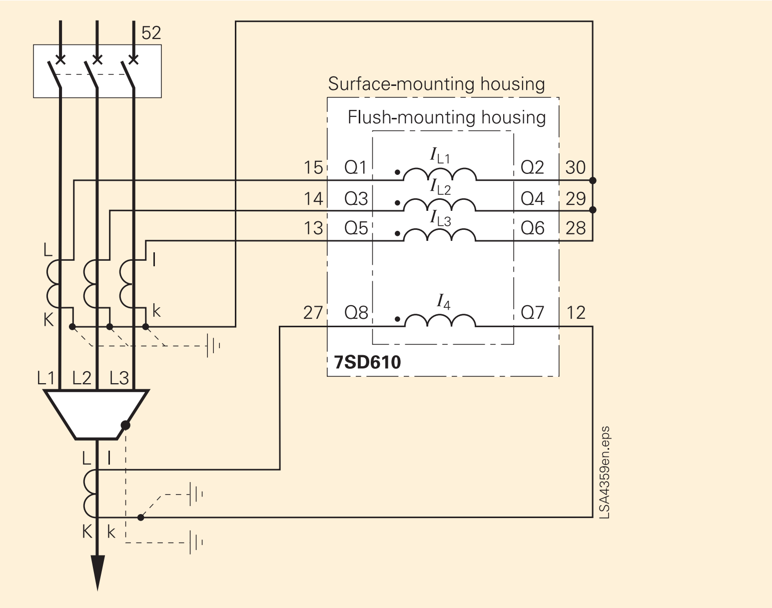


Fig. 12 Current transformer connection to three primary current transformers and neutral point current (normal connection)



Important: The cable shielding must be earthed on the cable side.

Note: Changing over the current polarity (address 0201) also causes a polarity reversal of the current input I_4.

Fig. 13 Current transformer connection to three primary current transformers and separate earthing transformer (core-balance current transformer)

5. Summary

The instantaneous and at the same time selective protection of cables and lines reduces the consequences of unavoidable power system disturbances. For one this means protection of equipment, secondly it contributes to maximizing supply security.

A differential protection system consisting of two SIPROTEC 7SD610 relays provides comprehensive safeguarding of cables and overhead lines. Built-in emergency and backup protection functions –as well as extensive additional facilities – allow problem-free connection of the relay and integration in complex power system protection grading schemes, without the need for any additional equipment.

The preset values on the relay are selected in such a way that the user only has to set the known cable and primary transformer data. Many of the preset values can be taken over without difficulty, thereby reducing the effort involved in parameterization and setting.

Thermal Overload Protection of Cables

1. Introduction

Failure of underground cables can be costly and time consuming to repair. Protection systems are designed to protect cables from the high current levels present under fault conditions. However, the temperature rise due to extended overload conditions is just as likely to cause cable failure. As the trend in power system operations is to utilize equipment as close to operating limits as possible, the importance of protecting equipment against thermal overloads becomes more critical.

Thermal overload protection calculates the temperature of the conductor based on specific conductor data and the current present in the circuit, and is used to protect conductors from damage due to extended overloads. In this application example thermal overload protection of underground cables only is described.

Thermal overload protection is normally used in an alarm mode to notify system operators of the potential for cable damage. However, thermal overload protection can be used to trip a circuit-breaker as well. In either case, the presence of thermal overload can be detected and removed before cable failure occurs.

2. Thermal overload protection

Thermal overload protection with total memory calculates a real time estimate of the temperature rise of the cable, Θ, expressed in terms of the maximum temperature rise, $\Delta\Theta_{max}$. This calculation is based on the magnitude of currents flowing to the load, and the maximum continuous current rating of the conductor. The calculation uses the solution to the first order thermal differential equation:

$$\tau\frac{d\Theta}{dt}+\Theta=I^2$$

$$\underline{\text{with}}\ =\Theta=\frac{\Delta\Theta}{\Delta\Theta_{max}}$$

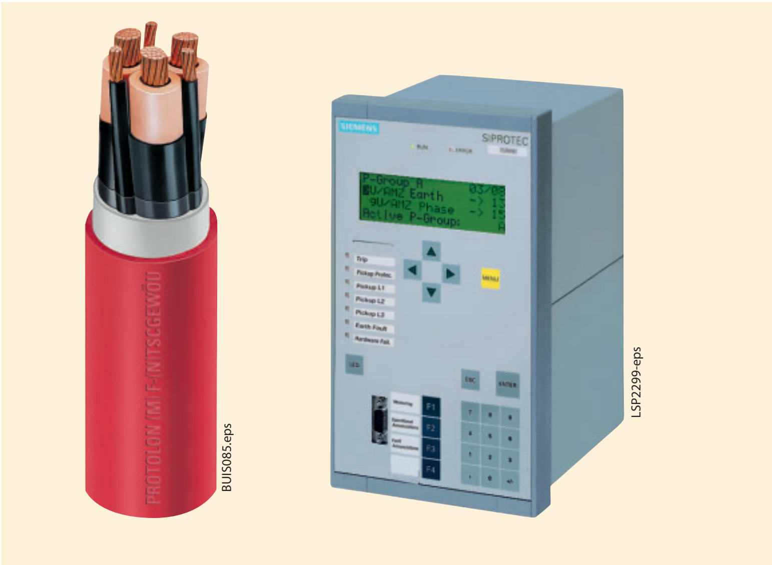


Fig. 1

$\Delta\Theta$ = temperature rise above ambient temperature
$\Delta\Theta_{max}$ = maximum rated temperature rise corresponding to maximum current
τ = thermal time constant for heating of the conductor
I = measured r.m.s. current based on the maximum rated overload current of the protected conductors: I_{meas}/I_{max}.

The solution to the thermal differential equation is:

$$\Theta_{op}=\Theta_{amb}+\Delta\Theta_{max}\left(1-e^{\frac{-t}{\tau}}\right)$$

The initial value is Θ_{amb}, the ambient temperature of the cable, and the steady state value is $\Theta_{amb}+\Delta\Theta$, where $\Delta\Theta$ is determined by the magnitude of I. The initial value, Θ_{amb}, is assumed to be that temperature on which the cable ratings are based. The steady state value is achieved when the temperature has reached its final value due to the heating effects of I. At this point, the value of $\tau d\Theta/dt$ in Equation 1 is zero. Therefore, at steady state, $\Delta\Theta = \Delta\Theta_{max}\, I^2$, where $I = I_{meas}/I_{max}$. The transition between the initial value and the steady state value is governed by the exponential expression, $1-e^{\frac{-t}{\tau}}$. τ is a constant of the cable to be protected.

Fig. 2 shows the operating temperature of the cable as a function of time and overload. With no load, the conductor is at its ambient temperature. If an overload equivalent to the maximum rated current is added at some time, the temperature of the cable will approach Θ_{max} following the exponential

$$1-e^{\frac{-t}{\tau}}.$$

The conductor temperature due to a current overload, starting from no-load conditions, has the same characteristic as shown in Fig. 2, with Θ_{max} becoming Θ_{op}, and I_{MAX} becoming I_{Load}. However, when the conductor already has some load present, the characteristic of the operating temperature changes. The conductor will heat up the cable to some steady state temperature. When an overload is added, the final temperature of the cable is calculated as if the cable was at normal operating temperature. However, the starting point of the second (overload) characteristic will coincide with the steady state temperature of the normal load. This is illustrated in Fig. 3.

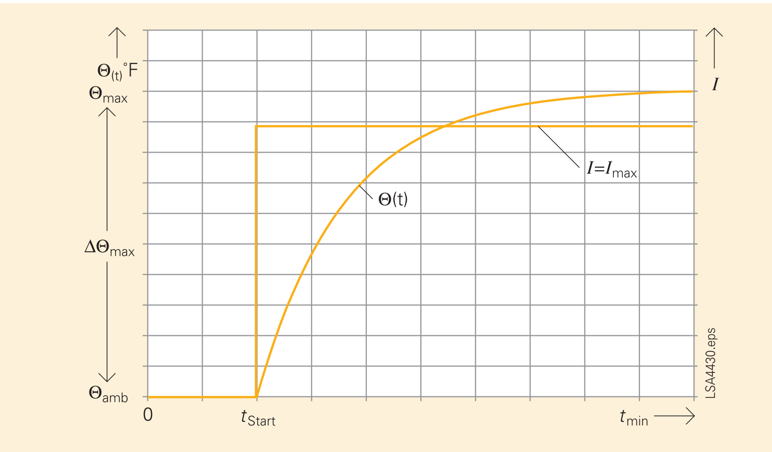


Fig. 2 Temperature vs. time for an overload of I_{max}

3. Calculation of settings

There are two required settings for thermal overload protection, the k factor, and the thermal time constant τ. τ is specific to the properties of the cable. The k factor relates the maximum continuous current rating of the cable to the relay.

3.1 Maximum continuous current of cable

The maximum continuous current rating of the cable is used in determining the k factor setting, and may be used in determining the setting for τ. This current depends on the cross-section, insulating material, cable design, and conductor configuration. Cable manufacturers may specify the maximum continuous current rating of their cable. If the rating is not available, it is possible to estimate a maximum continuous current based on conductor ampacity information. The ampacity of conductors is specified based on circuit configurations, conductor temperature, and ambient temperature. Also specified is the maximum operating temperature of the conductor, and correction factors for various conductor operating temperatures and ambient earth temperatures.

To determine the maximum continuous current rating of a cable, use the ampacity at the emergency overload operating temperature, and not that of the maximum conductor operating temperature. According to ICEA specifications, [1] *emergency overloads* are permitted for only a total of 100 hours per 12 month period, only for no more than five such periods in the life of the cable. Therefore, it is desirable to trip or alarm for any situation when the thermal overload reaches this level. To determine the maximum continuous current, remember that the conductor configuration and ambient temperature effect the current rating.

Example:

Circuit voltage:	12.47 kV
Cable size:	500 MCM shielded copper cable
Conductor temperature:	90 °C
Ambient temperature:	20 °C
Configuration:	3 circuits duct bank

From conductor tables, the ampacity for 90 °C copper conductor at 20° ambient temperature with 3 circuits in duct bank is 360 amps. The emergency overload operating temperature for 90 °C-cable is 130 °C. From Table 1, at 20 °C ambient temperature, the ampacity rating factor is 1.18.

Therefore,
360 A x 1.18 = 424.8 A maximum continuous current

3.2 Calculating the k factor

The k factor relates the operating current to the relay to permit overload detection. The k factor is defined as the ratio of the maximum continuous current I_{max} to the rated relay current I_N:

Example:

$$k = \frac{I_{max}}{I_N}$$

Circuit voltage	12.47 kV
Cable size	500 MCM shielded copper cable
Conductor temperature	90 °C
Ambient temperature	20 °C
Configuration	3 circuits in duct bank
Maximum continuous current (I_{max})	424.8 A primary
Current transformer ratio	800/5
Rated relay current (I_N)	5 A secondary

$$k = \frac{\frac{424.8}{(800/5)}}{5} = 0.53$$

3.3 Thermal time constant τ

The thermal time constant τ is a measure of the speed at which the cable heats up or cools down as load increases or decreases, and is the time required to reach 63 per cent of the final temperature rise with a constant power loss. The thermal time constant is the determining factor for calculating the operating temperature as a percent of the maximum permissible overload temperature, as shown in Equation 2. τ may be available from the cable manufacturer. If no specification for τ is available, it may be estimated from the permissible short-circuit rated current of the cable, and the maximum continuous current rating. It is common to use the 1 second rated current as the permissible short-circuit current. τ is calculated by the following equation:

$$\tau(\min) = \frac{1}{60} \cdot \left| \frac{I_{1\,second}}{I_{max}} \right|^2$$

If the short-circuit current at an interval other than one second is used, the equation is multiplied by this interval. For example, if the 0.5 second rating is used:

$$\tau(\min) = \frac{0.5}{60} \cdot \left| \frac{I_{0.5\,second}}{I_{max}} \right|^2$$

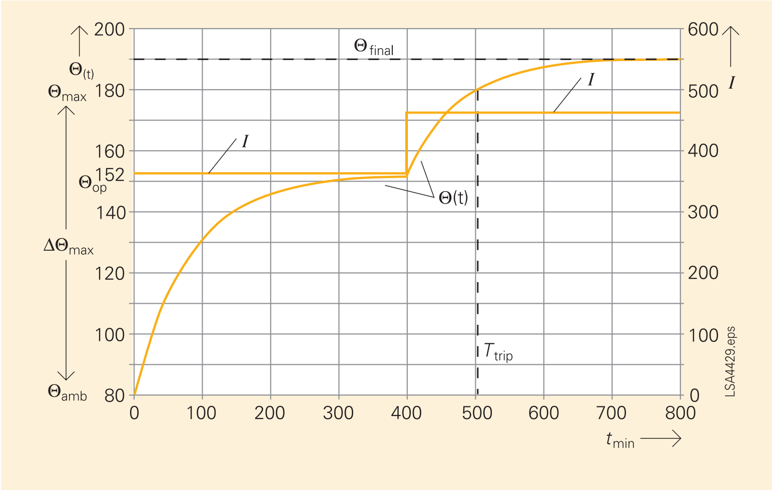


Fig. 3 Temperature vs. time with an existing overload

Example for calculating the thermal constant τ:

Circuit voltage	12.47 kV
Cable size	500 MCM shielded copper cable
Conductor temperature	90 °C
Ambient temperature	20 °C
Configuration	3 circuits in duct bank
Maximum continuos current (I_{max})	424.8 A primary
Maximum current oür 1 second	35,975 A primary

$$\tau(\min) = \frac{1}{60} \cdot \left| \frac{35{,}975}{424.8} \right|^2 = 119.5\ \min$$

Conductor size	Ampacity	Max. continuous current	Short-time withstand capability (1 sec)	τ (minutes)
1/0	160	189	7 585	27
2/0	185	218	9 570	32
3/0	205	242	12 065	41
4/0	230	271	15 214	52
250 MCM	255	301	17 975	59
350 MCM	305	360	25 165	81
500 MCM	360	425	35 950	119
750 MCM	430	507	53 925	188
1000 MCM	485	572	71 900	263

Table 1 Shielded copper conductor, 5001 - 35000 volts, 90 °C, three-conductor cable, three circuits in duct bank

Conductor temperature	Ambient earth temperature				
°C	10 °C	15 °C	20 °C	25 °C	30 °C
75	0.99	0.95	0.91	0.87	0.82
85	1.04	1.02	0.97	0.93	0.89
90	1.07	1.04	1.00	0.96	0.93
100	1.12	1.09	1.05	1.02	0.98
105	1.14	1.11	1.08	1.05	1.01
110	1.16	1.13	1.10	1.07	1.04
125	1.22	1.19	1.16	1.14	1.11
130	1.24	1.21	1.18	1.16	1.13
140	1.27	1.24	1.22	1.19	1.17

Table 2
Correction factors for various ambient earth temperatures

Short-circuit rated current for copper

- $$\left(\frac{I}{A}\right)^2 \cdot t = 0.0297 \cdot \log\left(\frac{T_2 + 234}{T_1 + 234}\right)$$

I = Short-circuit current - Amperes [A]
A = Conductor area - circular mils (0,001" diameter; convert to mm^2 where necessary)
t = time of short-circuit, seconds
T_1 = Operating temperature 90 °C
T_2 = Maximum short-circuit temperature 250 °C

Short-circuit current for aluminium

- $$\left(\frac{I}{A}\right)^2 \cdot t = 0.0125 \cdot \log\left(\frac{T_2 + 234}{T_1 + 234}\right)$$

Table 1 lists calculated values of τ for common conductors and configurations. Below Table 2 are the formulas to calculate the short-circuit rating of conductors

3.4 Analysis of relay settings

Combining the examples in Sections 3.1, 3.2, and 3.3, the cable information leads to the following relay settings:

k factor: 0.53

τ: 119.5 minutes

The operating temperature at a given moment in time can be calculated using Equation 2.

Θ_{amb} = the conductor operating temperature = 90 °C.
$\Delta\Theta_{max}$ = the maximum overload temperature minus the initial operating temperature = 130 °C - 90 °C = 40 °C.

As shown in Section 2 above, to determine the steady state temperature, the exponential term can be replaced by I^2, where $I = I_{meas}/I_{max}$. Based on these settings, and a load current of 400 A,

$$\Theta_{op} = \Theta_{amb} + \Delta\Theta_{max}\left(\frac{I_{meas}}{I_{max}}\right)^2 = 90° + 40°\left(\frac{400}{424.8}\right)^2$$

$$= 125\ °C$$

Thus, for a load of 400 A, the conductor will heat up to 125 °C.

4. Implementing thermal overload protection

Thermal overload protection in SIPROTEC relays calculates the temperature for all three phases independently, and uses the highest of the three calculated temperatures for tripping levels. Besides the k factor and the thermal time constant, there are two other settings for thermal overload protection. As seen in Figure 3, these are the "thermal alarm stage" and the "current overload alarm stage".

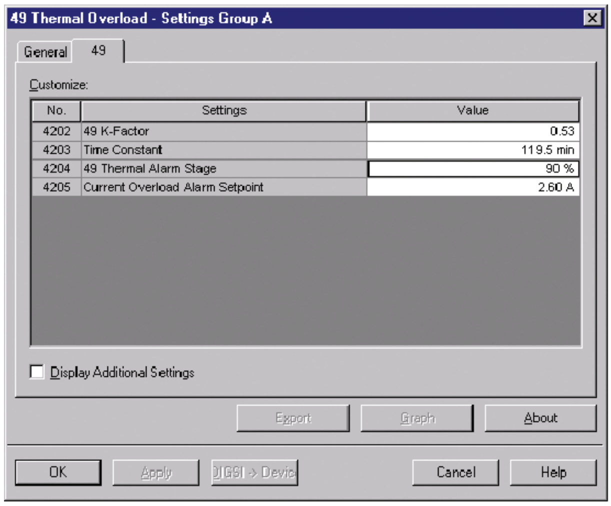


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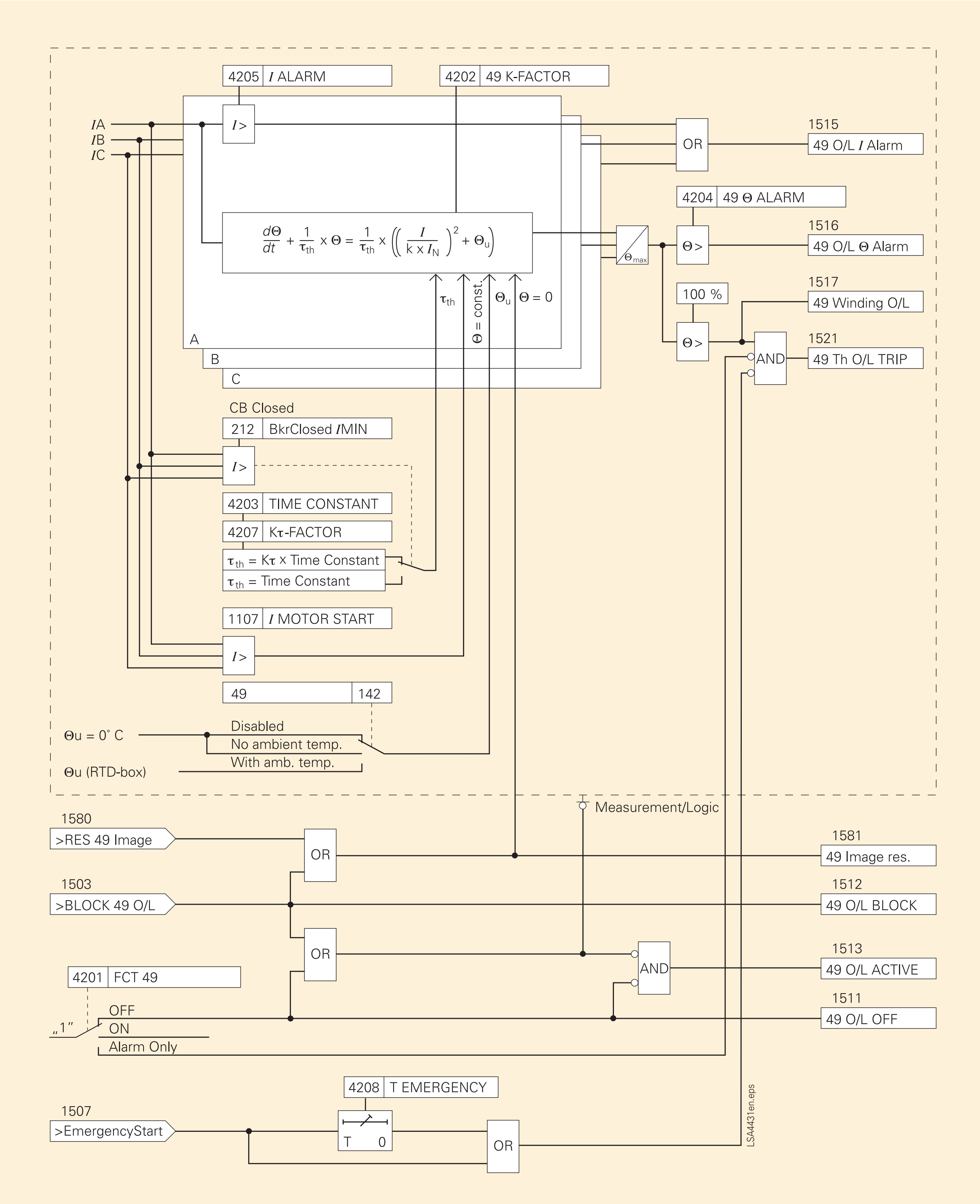
Fig. 4 Thermal overload protection settings

4.1 Thermal alarm stage

The thermal alarm stage sends an alarm signal before the relay trips for a thermal overload condition. The thermal alarm stage is also the dropout level for the thermal overload protection trip signal. Therefore, the calculated temperature must drop below this level for the protection trip to reset. This stage is set in percent of the maximum temperature. A setting of 90 % will meet most operating conditions.



$$\frac{d\Theta}{dt} + \frac{1}{\tau_{th}} \times \Theta = \frac{1}{\tau_{th}} \times \left(\left(\frac{I}{k \times I_N}\right)^2 + \Theta_u\right)$$

Fig. 5 Logic diagram of the overload protection

4.2 Current overload alarm stage

The current overload alarm stage sends an alarm when the load current exceeds the value of the setting. This setting should be set equal to, or slightly less than, the maximum continuous current rating of the cable.

4.3 Thermal overload protection as an alarm or tripping function

Thermal overload protection may be configured to either "ON" (tripping) or "Alarm only" for overload conditions, and is normally set to "Alarm only". Configuring thermal overload protection to "ON" makes this a tripping function, meaning it asserts the *0511 Relay TRIP* function. The factory default configuration of the relay has the *0511 Relay TRIP* function set to close a contact that trips the circuit-breaker.

"Alarm only" means thermal overload protection does not assert the *0511 relay trip* function. Thermal overload protection may still be programmed to operate a binary output for tripping purposes. this configuration allows the thermal overload function to be used to warn operators of potential cable failure due to overloads.

4.4 Adjusting settings for differences in ambient temperature

The ambient temperature of the earth has a significant effect on the maximum continuous current rating of the cable. In most applications, it is best to assume one ambient earth temperature to perform relay setting calculations. However, in some areas, there may be large seasonal differences in ambient earth temperature. Using multiple settings groups allows the relay to adapt the thermal overload protection settings to large changes in the seasonal temperature.

Changing the settings group can be accomplished via binary input, remote command, or function key, all of which require operator intervention to accomplish the change. Another possibility is to have the relay change settings groups based on system conditions. Wiring the output of a temperature sensor into an optional transducer input on the 7SJ63 relay will permit the changing of settings groups when the earth temperature passes a threshold for a specified period of time.

5. Summary

The failure of underground cables due to heating caused by long term overload conditions is easily prevented by using thermal overload protection. Based on information provided by cable manufacturers, circuit configuration, and operating conditions, it is simple to determine settings for thermal overload protection. Thermal overload protection is normally used to alarm for overload conditions, to allow system operators to make informed decisions on how to handle an overload to prevent cable damage. A thermal overload alarm, when combined with a SCADA system, can be used to track the amount of time the cable is exposed to overload, allowing for estimates of the remaining life of the cable.

6. References

Insulated Cable Engineers Association Standard P32-382-1994, "Short Circuit Characteristics of Insulated Cable", 1994, South Yarmouth, MA.

"Engineering Handbook", The Okonite Company, 1999, Ramsey, NJ.

H. Pender and W. Del Mar, "Electrical Engineer's Handbook", 4th Edition, Wiley & Sons, New York, NY.

Disconnecting Facility with Flexible Protection Function

1. Introduction

The flexible protection functions allow single-stage or multi-stage directional protection to be implemented. Each directional stage may be operated on one phase or on three phases. The stages may use optionally forward active power, reverse active power, forward reactive power or reverse reactive power as a measuring variable. Pickup of the protection stages can take place when the threshold value is exceeded or undershot. Possible applications for directional power protection are listed in Table 1.

A practical application example for reverse-power protection using the flexible protection function is described below.

2. System example

2.1 Functions for the disconnecting facility

Fig. 2 shows the example of an industrial switchgear with autonomous supply from the illustrated generator. All the lines and the busbar shown are in three-phase layout (except the earth connections and the connection for voltage measurement on the generator). The two feeders 1 and 2 supply the customer loads. In the standard case, the industrial customer receives power from the utility. The generator runs only in synchronous operation without feeding in power. If the utility can no longer maintain the required supply quality, the switchgear should be disconnected from the utility power system and the generator should assume autonomous supply. In the example shown, the switchgear is disconnected from the utility power system when the frequency leaves the rated range (e.g. 1-2 % of the rated frequency), the voltage drops below or exceeds a given value or the generator feeds active power back into the utility power system. Some of these criteria are combined depending on the user's philosophy. This would be implemented using CFC.

Here, reverse-power protection with the flexible protection functions is explained. Recommendations are given for frequency and voltage protection in the Chapter 4 on setting instructions.

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Fig. 1 Protection for industrial plants

	Direction	Evaluation	
		Overshoot	Undershoot
P	Forward	Monitoring of forward power limits of equipment (transformers, lines)	Detection of motors running at no load
P	Reverse	– Protection of a local industrial power system against feeding energy back into the utility power system – Detection of reverse energy supply from motors	

Table 1 Application overview, reverse-power protection

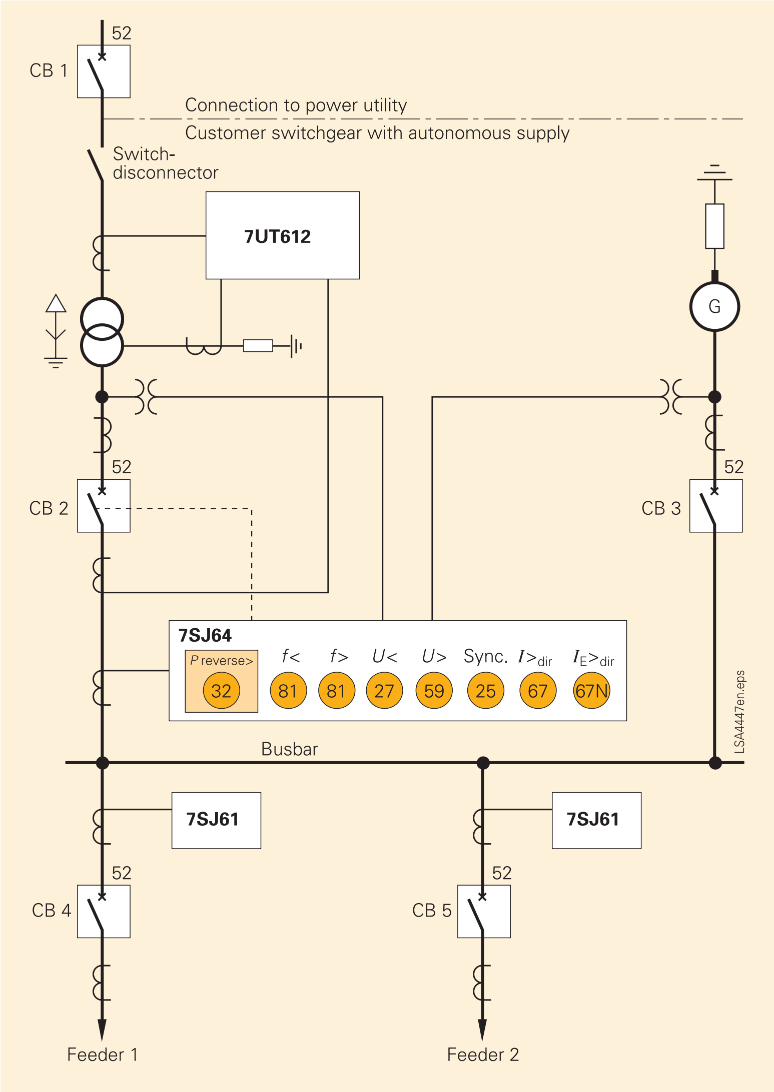

Fig. 2 Example of a switchgear with autonomous generator supply

2.2 System data

A 110 kV line connects the switchgear to the utility power system on the high-voltage side. The circuit-breaker CB1 belongs to the utility power system. The switch disconnector decouples the switchgear from the utility power system if necessary. The transformer with a ratio of 10:1 transforms the voltage level to 11 kV. On the low-voltage side the transformer, the generator and the two feeders are connected by a busbar. The circuit-breakers CB2 to CB5 disconnect loads and equipment from the busbar.

Switchgear data	
Rated power of generator	$S_{N,\,Gen}$ = 38.1 MVA
Rated power of transformer	$S_{N,\,Transfo.}$ = 40 MVA
Rated voltage of high-voltage side	U_N = 110 kV
Rated voltage of busbar side	U_N = 11 kV
Primary rated current of the current transformers on the busbar side	$I_{N,\,prim}$ = 2000 A
Secondary rated current of the current transformers on the busbar side	$I_{N,\,sec}$ = 1 A
Primary rated voltage of the voltage transformers on the busbar side	$U_{N,\,prim}$ = 11 kV
Secondary rated voltage of the voltage transformers on the busbar side	$U_{N,\,sec}$ = 100 kV

Table 2 Switchgear data for the application example

3. Protection functionality

The SIPROTEC protection relay 7SJ64 disconnects the switchgear from the utility power system if the generator feeds energy back into the power system (protection function P reverse >). This functionality is achieved by using flexible protection. Disconnection also takes place in the event of frequency or voltage fluctuations in the utility power system (protection functions f<, f>, U<, U>, I_{dir}>., I_{Edir}>/ 81, 27, 59, 67, 67N).

The protection receive the measured values via a three-phase current and voltage transformer set and a single-phase connection to the generator voltage transformer (for synchronization). The circuit-breaker CB2 is activated in the case of a disconnection.

The transformer is protected by differential protection and inverse or definite-time overcurrent-time protection functions for the phase currents. In the event of a fault, the circuit-breaker CB1 on the utility side is tripped by a remote link. Circuit-breaker CB2 is tripped additionally.

Overcurrent-time protection functions protect feeders 1 and 2 against short-circuits and overload caused by the connected loads. Both the phase currents and the zero currents of the feeders can be protected by inverse and definite-time overcurrent-time stages. The circuit-breakers CB4 and CB5 are tripped in the event of a fault.

The busbar could be equipped additionally with the differential protection 7UT635. The current transformers required for this are already shown in Fig. 2.

3.1 Synchronization when connecting the generator

In most cases the electricity customer is responsible for restoring the switchgear or substation to normal operation after shutdown. The SIPROTEC 7SJ64 tests whether synchronous conditions are satisfied. After successful synchronization, the generator is connected to the busbar. The voltages required for synchronization are measured at the transformer and at the generator. The voltage at the transformer is measured in all three-phase because this is also necessary for determining the direction. The generator feeds the phase-to-phase voltage U31 to the device input U_4 via a voltage transformer in a star-delta connection (see Fig. 3).

3.2 Connection diagram

Fig. 3 shows the connection of the relay for reverse-power protection and synchronization. The power flow in positive or forward direction takes place from the high-voltage side busbar (not shown) via the transformer to the low-voltage side busbar.

3.3 Reverse-power protection with flexible protection functions

The reverse-power protection evaluates the active power from the symmetrical fundamental components of the voltages and currents. Evaluation of the positive-sequence systems makes the reverse-power determination independent of the asymmetries in the currents and voltages and reflects the real load on the drive side. The calculated active power value corresponds to the total active power. In the connection shown in the example the power in the direction of the busbar from the relay is measured as positive.

3.4 Function logic

The logic diagram in Fig. 4 shows the function logic of the reverse-power protection.

The reverse-power protection picks up when the configured pickup threshold is exceeded. If the pickup condition persists during the equally parameterizable pickup delay, the pickup message “P reverse pickup.”is emitted.

This starts the trip command delay. If pickup does not drop out while the trip command delay is running, the trip message “P reverse TRIP”and the time-out indication “P reverse timeout”are generated (latter not illustrated). The picked-up element drops out when the value falls below the dropout threshold. The blocking input “>P reverse block”blocks the entire function; i.e. pickup, trip command and running times are reset.

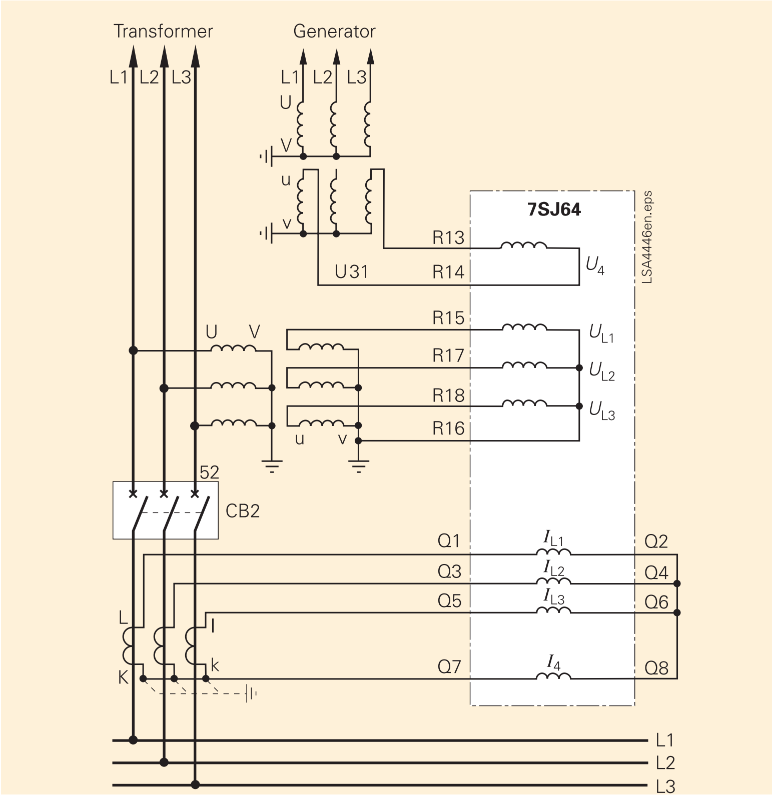

Fig. 3 Connection diagram for a 7SJ642 as reverse-power protection (flush-mounted housing)

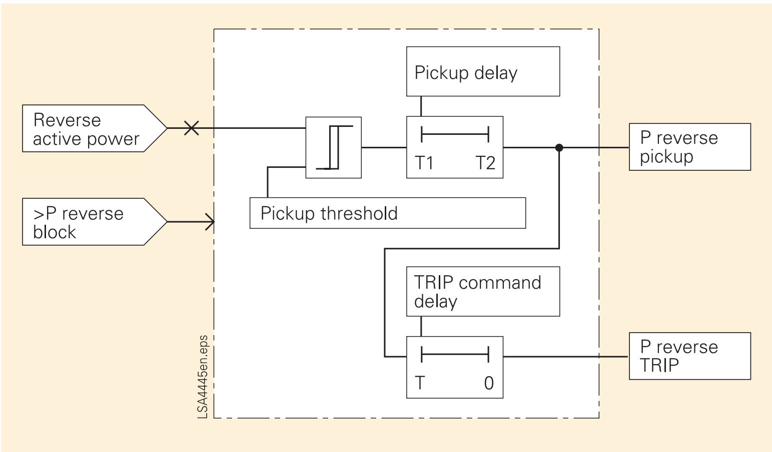

Fig. 4 Logic diagram of the reverse-power determination with flexible protection function

After the blocking has been released, the reverse power must exceed the pickup threshold and both times must run out before the protection trips.

■ 4. Setting instructions

4.1 Reverse-power protection

The pickup value of the reverse-power protection is set at 10 % of the generator rated output. In this example the setting value is parameterized as secondary power in Watts. The primary and secondary power have the relation:

$$P_{\text{sec}} = P_{\text{prim}} \cdot \frac{U_{\text{N, sec}}}{U_{\text{N, prim}}} \cdot \frac{I_{\text{N, sec}}}{I_{\text{N, prim}}}$$

With the indicated data, the pickup values can be calculated –taking account of $P_{\text{prim}} = 3.81$ MW (10 % of 38.1 MW) on the primary level –as

$$P_{\text{sec}} = 3.81\ \text{MW} \cdot \frac{100\ \text{V}}{11000\ \text{V}} \cdot \frac{1\ \text{A}}{2000\ \text{A}} = 17.3\ \text{W}$$

on the secondary level. The dropout ratio is parameterized to 0.9. This gives a secondary dropout threshold of $P_{\text{sec, dropout}} = 15.6$ W. If the pickup threshold is reduced to a value close to the lower setting limit of 0.5 W, the dropout ratio should likewise be reduced to approximately 0.7.

The reverse-power protection requires no short trip times as protection against undesirable feedback. In this example it is useful to delay pickup and dropout by about 0.5 s and tripping by about 1 s. Delaying the pickup minimizes the number of opened fault logs when the reverse power fluctuates around the threshold value. If the reverse-power protection is used to make it possible to disconnect the switchgear from the utility power supply system quickly in the event of faults in the latter, it is advisable to select a higher pickup value (e.g. 50 % of the rated power) and shorter delay times.

4.2 Frequency protection f<, f>

The relay 7SJ64 contains 4 frequency stages. One stage is parameterized as $f>$ and set to 50.5 Hz; it operates without time delay. This stage detects the frequency increase caused by a short-circuit in the utility. The other 3 frequency stages should be parameterized as $f<$ stages to serve as load shedding criteria for isolated operation of the industrial power supply system.

Suggested settings:

$f_1< = 49.5$ Hz $t_1 = 0.2$ s
$f_2< = 49$ Hz $t_2 = 0.1$ s
$f_3< = 48$ Hz $t_3 = 0.2$ s

On reaching stage $f_3<$, the generator should be operated in isolated mode to safeguard autonomous auxiliary supply coverage.

4.3 Undervoltage protection U< (ANSI 27)

The voltage dip in the event of a short-circuit in the system is detected with the $U<$ criterion. The $U<$ criterion should always be linked with the fault current direction, to open the coupler circuit-breaker only in the event of a fault in the utility system. The voltage level should be set to 0.5 x U_{N}.

4.4 Parameterization of reverse-power protection with DIGSI

A relay 7SJ64x (e.g. 7SJ642) is created and opened first in the DIGSI Manager. A flexible protection function 01 is configured for the given example in the scope of functions (Fig. 5).

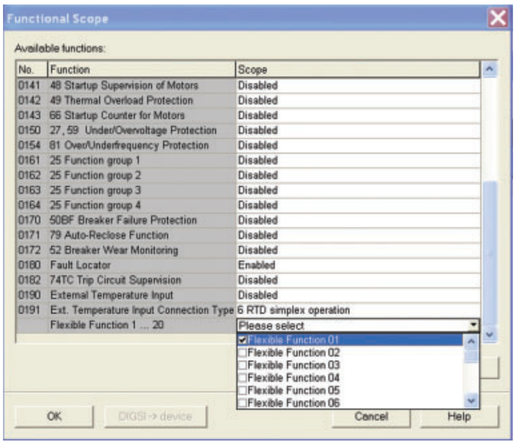

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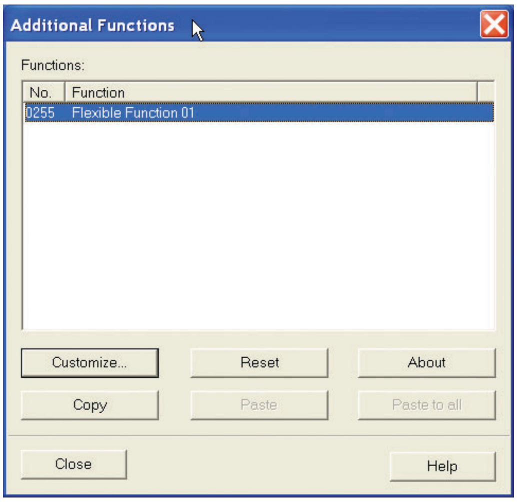
Fig. 5 Configuration of a flexible protection function

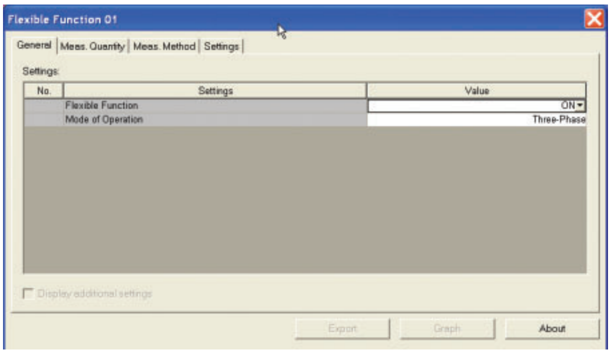
Select "Additional functions" in the "Parameters" menu to view the flexible functions (Fig. 6)



LSP2653en.tif

Fig. 6 The flexible function is visible in the function selection

First the function must be activated under "Settings → General", and "3-phase" operating mode must be selected (Fig. 7).



LSP2654en.tif

Fig. 7 Selection of three-phase operation

Select "Active power reverse" or "Overshoot" in the menu items "Measured quantity" and "Measurement method". If the "Display additional settings" box is activated in the "Settings" menu item, the threshold value, pickup delay and TRIP command delay can be configured (Fig. 8). Since the power direction cannot be determined in the event of a measuring voltage failure, protection blocking is useful in this case.

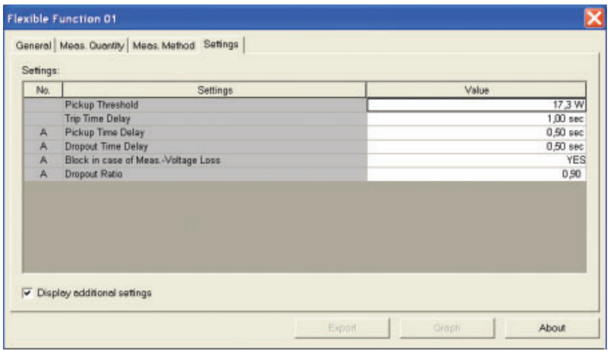


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Fig. 8 Setting options of the flexible function

4.5 Configuration for reverse-power protection in DIGSI

The names of the messages can be edited in DIGSI and adapted accordingly for this example. The names of the parameters are fixed.

The DIGSI configuration matrix initially shows the following indications (after selecting "Indications and commands only" and "No filter": Fig. 9).

Flx 01	235.2110.01	>BLOCK Flx01	>BLOCK Function Flx01	SP
	235.2111.01	>Flx01 instant.	>Function Flx01 instantaneous TRIP	SP
	235.2113.01	>Flx01 BLK.TDelay	>Function Flx01 BLOCK TRIP Time Delay	SP
	235.2114.01	>Flx01 BLK. TRIP	>Function Flx01 BLOCK TRIP	SP
	235.2118.01	Flx01 BLOCKED	Function Flx01 is BLOCKED	OUT
	235.2119.01	Flx01 OFF	Function Flx01 is switched OFF	OUT
	235.2120.01	Flx01 ACTIVE	Function Flx01 is ACTIVE	OUT
	235.2121.01	Flx01 picked up	Function Flx01 picked up	OUT
	235.2125.01	Flx01 Time Out	Function Flx01 TRIP Delay Time Out	OUT
	235.2126.01	Flx01 TRIP	Function Flx01 TRIP	OUT

LSP2656en.tif

Fig. 9 Indications prior to editing

It is possible to edit short text and long texts to suit the application by clicking the texts (Fig. 10).

Flx 01	235.2110.01	>P rev. block	>Active power reverse block	SP
	235.2111.01	>P rev. instant	>Active pow. rev. OFF instantaneous trip	SP
	235.2113.01	>P rev. BLK. T	>Active pow. rev. BLOCK TRIP Time Delay	SP
	235.2114.01	>P rev.BLK.TRIP	>Active pow. rev. BLOCK TRIP	SP
	235.2118.01	P rev. BLOCKED	Active pow. rev. is BLOCKED	OUT
	235.2119.01	P rev. OFF	Active pow. rev. is switched OFF	OUT
	235.2120.01	P rev. ACTIVE	Active pow. rev. is ACTIVE	OUT
	235.2121.01	P rev.picked up	Active pow. rev. picked up	OUT
	235.2125.01	P rev.Time Out	Active pow. rev. TRIP Delay Time Out	OUT
	235.2126.01	P rev. TRIP	Active pow. rev. TRIP	OUT

LSP2657de.tif

Fig. 10 Indications after editing

Configuring of the indications is performed in the same way as for the configuring of the indications of other protection functions.

5. Summary

With the flexible protection functions, it is easy to implement measuring criteria not available as standard, such as power direction. This measuring criterion is a fully fledged protection function and can therefore be integrated as an equivalent criterion in a disconnecting facility. The synchronization function of the SIPROTEC 7SJ64 can be used to advantage here, to synchronize the industrial power supply system to the utility power supply system.

Earth-Fault Protection in Systems with Isolated Star Point

1. General earth-fault information

In a system with isolated star point an earth fault is not a short-circuit, but an abnormal operating state. It must be signalled and corrected as quickly as possible. The way in which the earth fault is identified depends on the configuration of the system. In a radial system, sensitive earth-fault direction detection with sine φ measurement is the method; in a meshed system the transient earth-fault relay is preferred. In the case of an earth fault with no resistance, e.g. in phase L3, the voltage $U_{L3\text{-}E}$ drops to zero and the voltages $U_{L2\text{-}E}$ and $U_{L1\text{-}E}$ increase to the $\sqrt{3}$-fold value. A displacement voltage $U_{E\text{-}N}$ appears. This is also referred to a zero-sequence voltage (U_0). In normal operation it has the value of the phase-to-earth voltage. A purely capacitive earth-fault current flows at the fault location. This can create very unstable arcs. In general, isolated systems operate up to a capacitive earth-fault current of 50 A. The $U_{E\text{-}N}$ is evaluated for signalling the earth fault.

The U_0 voltage can be calculated from the phase voltages or it can be detected via the voltage transformer open delta winding (e-n delta). This winding generally has a greater ratio in the region of factor $\sqrt{3}$. In the case of an earth fault, the measuring-circuit voltage is thus approximately 100 V. A voltage relay for earth-fault detection is set at 25 V –30 V, and a time delay of 5 s is appropriate. This functionality is included in line protection relays 7SJ5.., 7SJ6.., 7SA5.. and 7SA6 depending on the configuration chosen. If the relays are equipped with three transformer inputs a phase-selective earth-fault alarm can also be provided. $U \leq 40$ V serves as the criterion for recognizing the defective phase and $U \geq 75$ V for the fault-free phases.

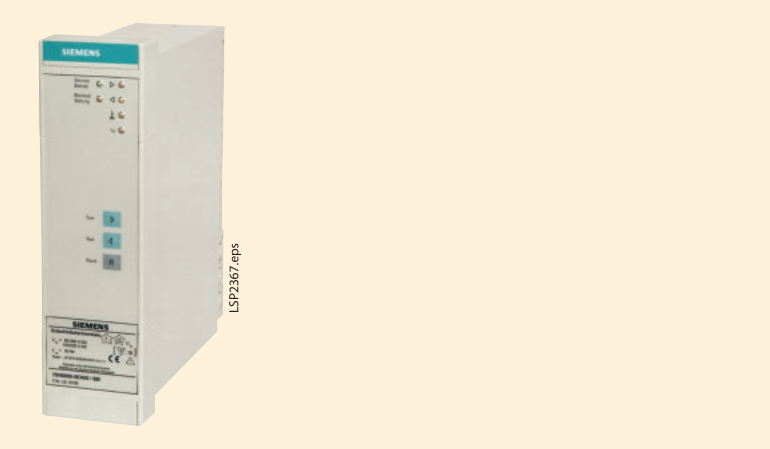
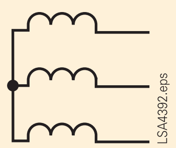


Fig. 1 Transient earth-fault relay 7SN60



- Earth fault = no short-circuit
- Operation continues during single earth fault
- Earth fault must be signaled and corrected as quickly as possible
- Earth-fault location with wattmetric earth-fault direction measurement or transient earth-fault relay

Fig. 2 Isolated system

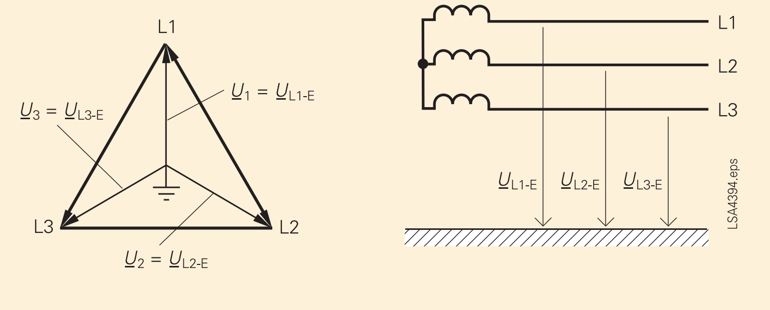


Fig. 3 Voltages in normal operation

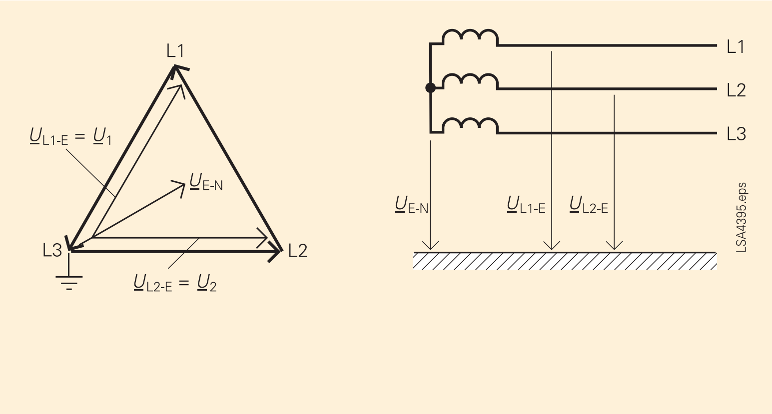


Fig. 4 Voltages for earth fault in phase L3

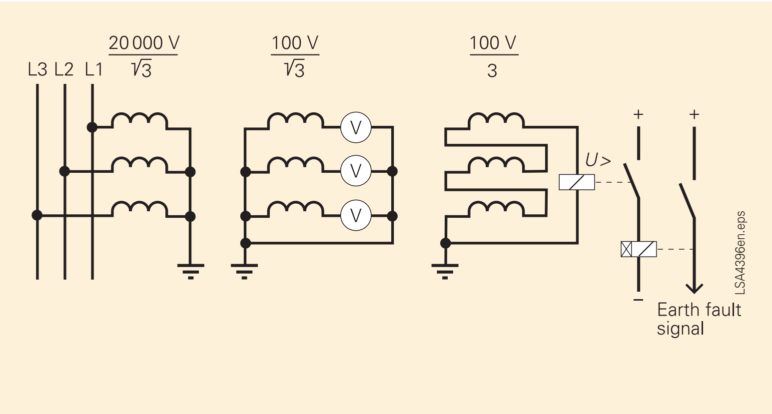


Fig. 5 Voltage transformer with open delta winding

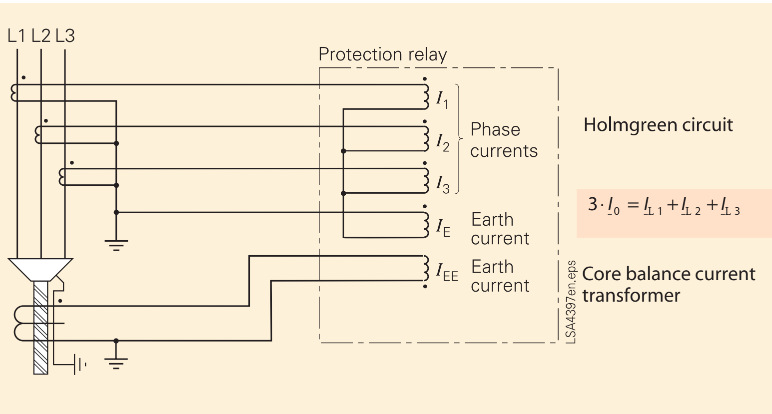


Fig. 6 Connection of currents

Two methods can be used to measure the earth current.

The *Holmgreen circuit* adds the three phase currents (by means of appropriate connection of the current transformers) and thus provides the earth current. However, because each transformer has always an error of measurement, this method for measuring the earth current is only suitable in systems with higher earth-fault currents (> 40 A) and

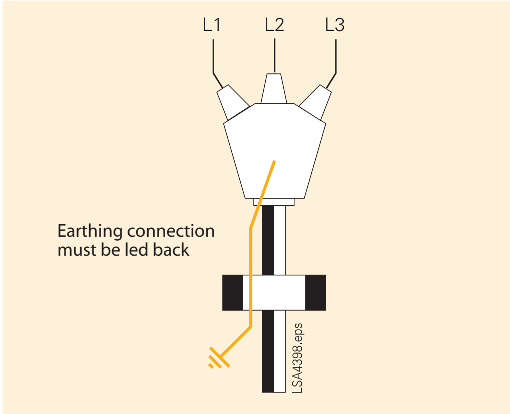


Fig. 7 Core-balance current transformer

a not excessively high ratio of the transformers (<150/1 or 150/5). The second method, measurement with a *core-balance current transformer*, can be used for smaller earth currents. It delivers better values for sensitive earth-fault detection. It is important to ensure that the transformer is assembled with precision. In the case of cut-strip wound transformers it is essential that the core surfaces lie directly on top of each other. It is also critically important that the earthing connection of the cable screen earthing is led back through the transformer so that the sum of the phase currents can actually be measured (see Fig. 6 and 7).

■ 2. *Sensitive earth-fault direction detection with sine φ measurement*

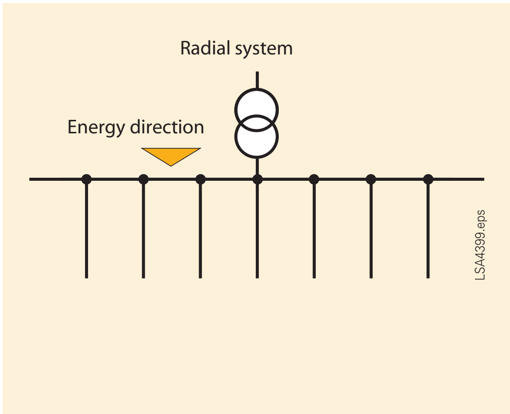


Fig. 8 Radial system

Earth-fault direction measurement is only applicable in the *radial system*. If it is used in a meshed system, meaningful results can only be expected after switching over to radial lines.

Capacitive currents			
Overhead line	20 kV	~	0.05 A/km
	110 kV	~	0.30 A/km
Cable	10 kV	~	1.5 A/km
	20 kV	~	3.0 A/km
	110 kV	~	20.0 A/km

The system capacitive current can be estimated by using the table or values given in cable manuals.

Example to determine I_E

Current
30 km 10 kV cable, 1.5 A/km
I_E = 1.5 A / km · 30 km = 45 A

Holmgreen-circuit, ratio of the main current transformer 200/1
Earth current at the protection relay 225 mA
Setting I_E> 150 mA

In the case of an earth fault only the healthy parts of the system continue to provide an earth-fault current; therefore the pickup value must always be lower than the maximum earth-fault current. In an exact calculation the value of the longest line section plus a safety margin must be subtracted from the maximum.

Voltage settings:

Attention must be paid to the voltage settings as follows:

- Displacement voltage: value in the case of earth fault: 100 V/$\sqrt{3}$
- Measured voltage at the open delta winding (e-n winding): value in the case of earth fault: 100 V
- Threefold zero-sequence voltage $3U_0$: value in the case of earth fault: 100 V· $\sqrt{3}$.

For connection to the e-n winding, a pickup value of $U_{e\text{-}n}$> = 25 V is usual. For setting tripping values for the (calculated) displacement voltage, 25 V/$\sqrt{3}$ is recommended. The proposed operating value for $3U_0$ is 25 V· $\sqrt{3}$.

Earth-fault report time delay: t = 5 s

Voltage setting for phase-selective earth-fault detection:
Affected phase $U \leq 40$ V
Healthy phases $U \geq 75$ V

Type of measurement
Sine phi

Earth-fault detection
Signal only (disconnection following an earth fault is not usual)

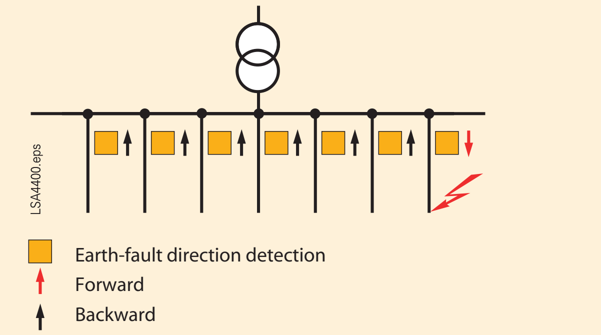


Fig. 9 Earth fault in radial system

Fig. 9 shows an example of how the indication of earth-fault direction detection could look in a specific case. It is important to note that not all the unaffected circuits (or in the worst case scenario none of them) indicate backward. If the partial current being delivered to the earth-fault location is lower than the limit value set, no direction indication occurs. However, because of the voltage ratios, the earth fault is recognized by all relays and the general earth-fault signal is given. For remote reporting the message "earth fault" must be transmitted once from the galvanically connected system. From the individual feeders it is advisable only to transmit the message "earth fault forward". If the feeder with "earth-fault forward" message is disconnected, the earth-fault message will be cleared.

If the line affected by the earth fault is an open ring with several sectioning points, it is possible to identify the earth-faulted section by moving the isolating point.

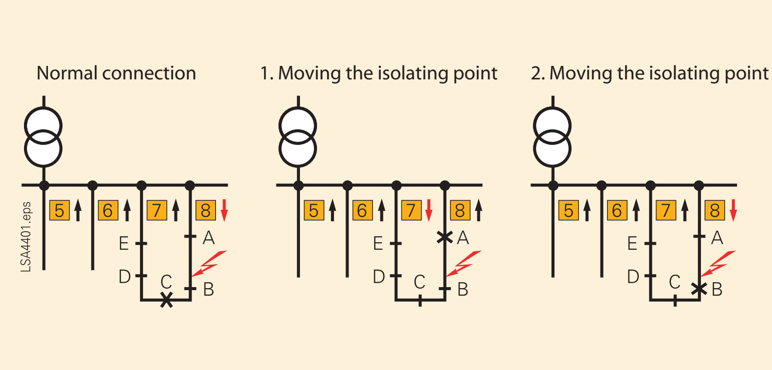


Fig. 10 Searching for the earth fault in a ring system

Example in Fig. 10:
Normally the isolating point is situated at C.
An earth fault has occurred and relay 8 has reported "forward". If the isolating point is now moved from C to A, which can be done (by load disconnection) with no interruption to supply, the relay 7 indicates "forward". The section A –C is thus affected by the earth fault. If the isolating point is now moved to B, the relay 8 once again indicates "forward". Thus section A –B is clearly affected by the earth fault.

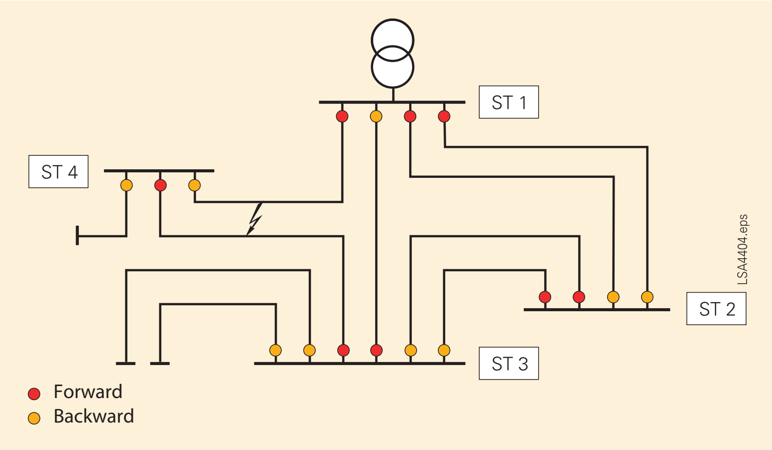


Fig. 11 Transient earth-fault relay indications

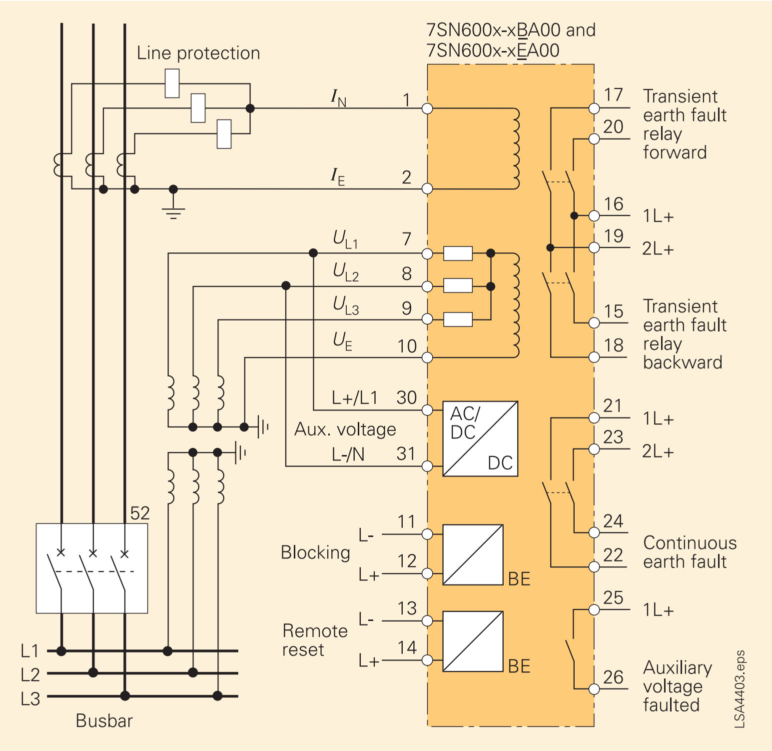


Fig. 12 Transient earth-fault relay connection

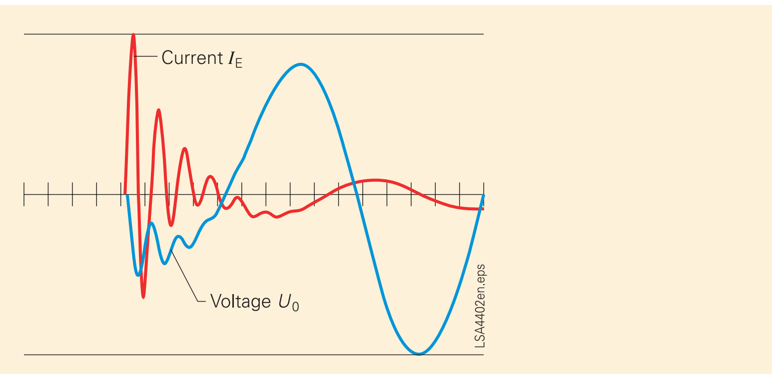


Fig. 13 Transients in an earth fault

■ 3. Earth-fault direction detection with the transient earth-fault relay 7SN60

If the system is meshed, no clear direction indication can be obtained from the sine φ measurement. The current direction in the case of an earth fault cannot be definitely detected. Good locating results are achieved using transient earth-fault relays. These relay work with the charge-reversal process, which occurs with the earth fault. The capacity of the phase affected by the earth fault is discharged to earth and the healthy phases are charged up to the higher voltage value.

This charge-reversal produces a large current, amounting to a multiplication (threefold or fourfold) of the capacitive current. The transient earth-fault relays are thus always connected to the Holmgreen circuit.

It is important to be aware that the charge-reversal process only occurs when the earth fault appears, i.e. just once. Repeat measurements following switching therefore have no meaning and lead to confusion.
In order to identify the circuit affected by the earth fault in a meshed system, an indication is required from both ends of the line. Both relays must indicate in a "forward direction". It is therefore advisable to transfer the signals from the transient earth-fault relay onto an image of the system. It is then possible to decide quickly where the earth fault is located.

In Fig. 11, the fault is located in the middle line from ST 4 to ST 3, since here both relays are indicating "forward".

■ 4. Summary

Operation can be continued when an earth fault occurs in a power system with an isolated star point. The fault can be located as described above. The operator should quickly separate the fault location from the system. Thus a double fault (which – as a short-circuit – would cause a supply interruption) can be avoided.

Earth-Fault Protection in a Resonant-Earthed System

1. General earth-fault information

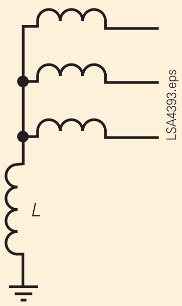
In a resonant-earthed power system an earth fault is not a short-circuit, but an abnormal operating state. It must be signalled and corrected as quickly as possible. The way in which the earth fault is identified depends on the configuration of the network. In a radial system, sensitive earth-fault direction measurement with sine φ measurement is used; in a meshed system the transient earth-fault measurement is preferred.

In the case of an earth fault with no resistance, e.g. in phase L3, the voltage $U_{L3\text{-}E}$ drops to zero and the voltages $U_{L2\text{-}E}$ and $U_{L1\text{-}E}$ increase to the $\sqrt{3}$-fold value. A displacement voltage $U_{E\text{-}N}$ accumulates. This is also referred to as zero-sequence voltage (U_0). Under normal operating conditions it has the value of the phase-to-earth voltage.

The capacitive earth-fault current at the fault location is compensated by the inductive current from the Petersen coil so that the active current at the fault location is very small. A residual resistive current remains and is determined by the ohmic part of the coil. It is in the order of magnitude of 3 % of the capacitive coil current. The $U_{E\text{-}N}$ voltage is evaluated for signalling the earth fault.

The U_0 voltage can be calculated from the phase voltages or it can be detected via the voltage transformer open delta winding (e-n delta). This winding generally has a greater ratio in the region of factor $\sqrt{3}$. In the case of an earth fault, the measuring-circuit voltage is thus approximately 100 V. A voltage relay for earth-fault detection is set at 25 –30 V, and a time delay of 5 s is appropriate. This functionality is included in line protection relays 7SJ5.., 7SJ6.., 7SA5.. and 7SA6 depending on the configuration chosen. If the relays are equipped with three transformer inputs a phase-selective earth-fault alarm can also be produced. $U \leq 40$ V serves as the criterion for recognizing the defective phase and $U \geq 75$ V for the fault-free phase.

Fig. 1 Transient earth-fault relay 7SN60



- Earth fault = No short-circuit
- Operation continues
- Earth fault must be signaled and corrected as quickly as possible
- Earth-fault location with watt-metric earth-fault direction measurement or transient earth-fault relay

Fig. 2 Resonant-earthed system

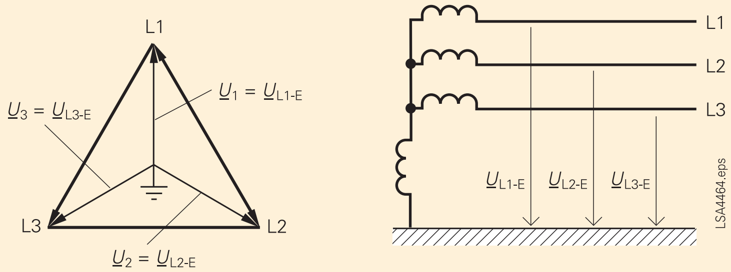


Fig. 3 Voltages in normal operation

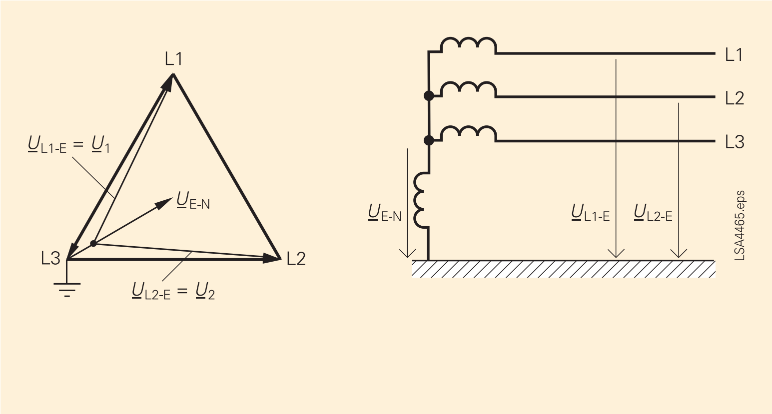


Fig. 4 Voltages for earth fault L3

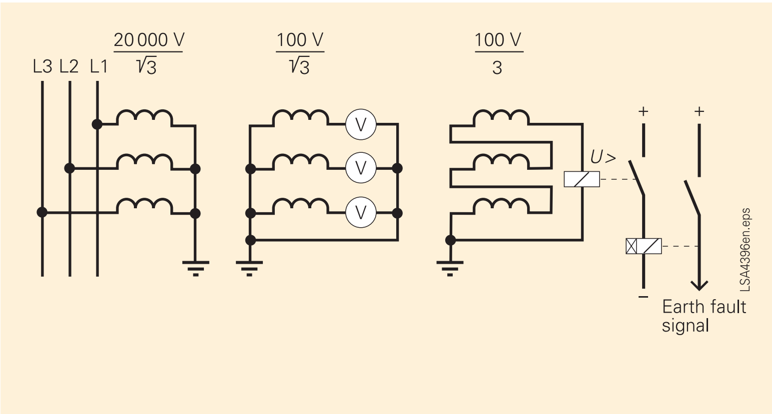


Fig. 5 Voltage transformer with open delta winding

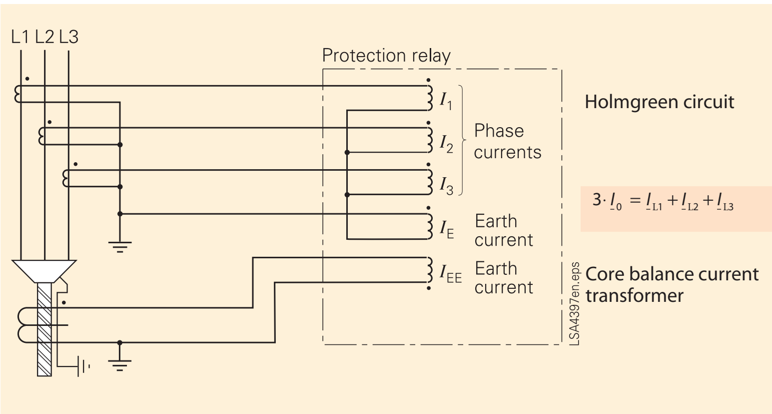


Fig. 6 Connection of currents

Two methods can be used to measure the flowing earth current.

The *Holmgreen-circuit* adds the three phase currents (by means of appropriate connection of the current transformers) and thus provides the earth current. However, because each transformer has a fault, this measurement method is not suitable for the small residual resistive currents in a resonant-

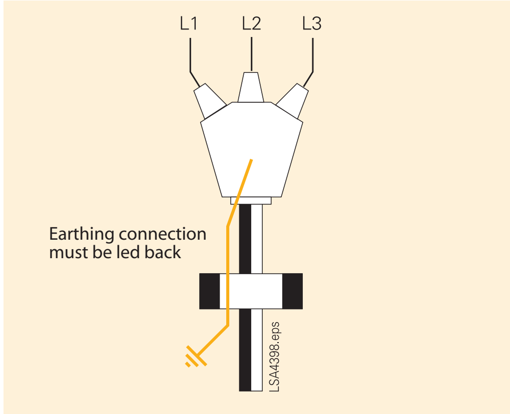


Fig. 7 Core-balance current transformer

earthed system. The second method, the *core-balance current transformer* is available for such cases. This delivers definitely better values for earth-fault detection. It is important to ensure that it is assembled with precision. In the case of cut-strip wound transformers it is essential that the core surfaces lie directly on top of each other. It is also critically important that the cable screen earthing is led back through the transformer so that the sum of the phase currents can actually be measured.

■ 2. *Watt-metric earth-fault direction detection with cos φ measurement.*

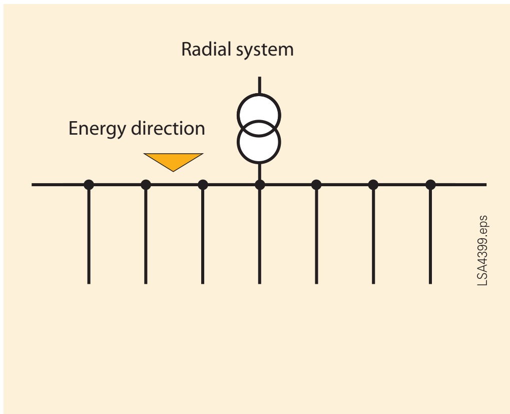


Fig. 8 Radial system

Watt-metric earth-fault direction measurement is only appropriate in the radial system. If it is used in a meshed system, meaningful results can only be expected after switching over to radial lines.

Capacitive currents			
Overhead line	20 kV	~	0.05 A/km
	110 kV	~	0.30 A/km
Cable	10 kV	~	1.5 A/km
	20 kV	~	3.0 A/km
	110 kV	~	20.0 A/km

The network's capacitive current can be estimated by using the table or values given in cable manuals. Alternatively, the value can be read from the coil.

Example:

Current
Petersen coil with a rated current of 200 A, momentarily adjusted to 180 A.
We can assume a capacitive earth-fault current of 180 A. If we estimate the residual resistive proportion at 3 %, 5.40 A is the result. This is transformed by the core-balance current transformer at 60:1, and 90 mA consequently arrive at the protection relay. The pickup value should then be set at approximately 50 mA. In the case of an earth fault only the healthy parts of the system continue to provide an earth-fault current; therefore the pickup value must always be lower than the maximum earth-fault current.

Voltage settings:
Attention must be paid to the voltage settings as follows:

- Displacement voltage: value in the case of earth fault: $100\ \text{V}/\sqrt{3}$
- Measured voltage at the open delta winding (e-n winding): value in the case of earth fault: 100 V
- Threefold zero-sequence voltage $3U_0$: value in the case of earth fault: $100\ \text{V}\cdot\sqrt{3}$.

For connection to the e-n winding, a pickup value of $U_{e\text{-}n}> = 25$ V is usual. For setting tripping values for the (calculated) displacement voltage, $25\ \text{V}/\sqrt{3}$ is recommended. The proposed pickup value for $3U_0$ is $25\ \text{V}\cdot\sqrt{3}$.

Earth-fault report time delay: $t = 5$ s

Voltage setting for phase-selective earth-fault detection:
Affected phase $U \leq 40$ V
Healthy phases $U \geq 75$ V

Type of measurement
Cos phi

Earth-fault detection
Signal only (disconnection following an earth fault is not usual)

Fig. 9 shows an example of how watt-metric indication of the earth-fault direction detection could look in a specific case. It is important to note that

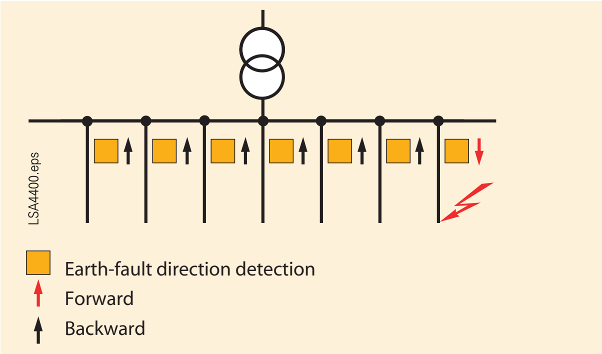


Fig. 9 Earth fault in radial network

not all the unaffected circuits (or in the worst case scenario none of them) indicate backward. If the active component of the partial current being delivered to the earth-fault location is lower than the limit value set, no direction indication occurs. However, because of the voltage ratios, the earth fault is recognized by all relays and the general earth-fault signal is given. For remote reporting the message "earth fault" must be transmitted once from the galvanically connected system. From the individual feeders it is advisable only to transmit the message "earth fault forward". If the feeder with "earth-fault forward" message is disconnected, the earth-fault message will be cleared.

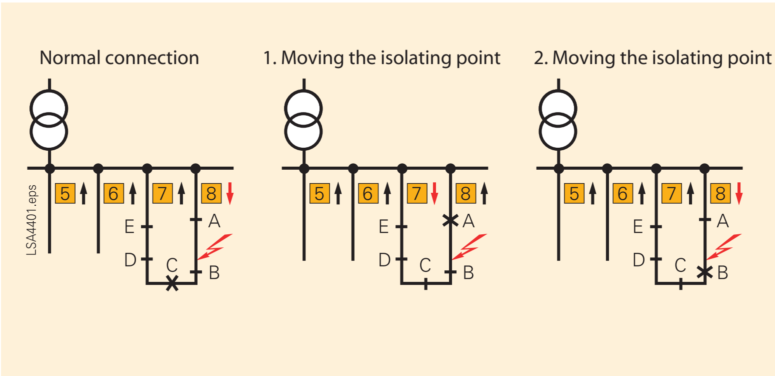


Fig. 10 Searching for the earth fault in a ring system

If the line affected by the earth fault is an open ring with several sectioning points, it is possible to identify the earth faulted section by moving the isolating point.

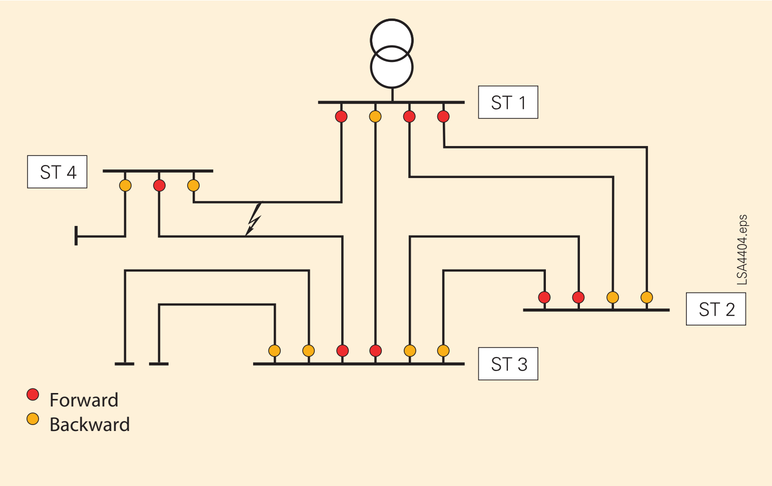


Fig. 11 Transient earth-fault relay indications

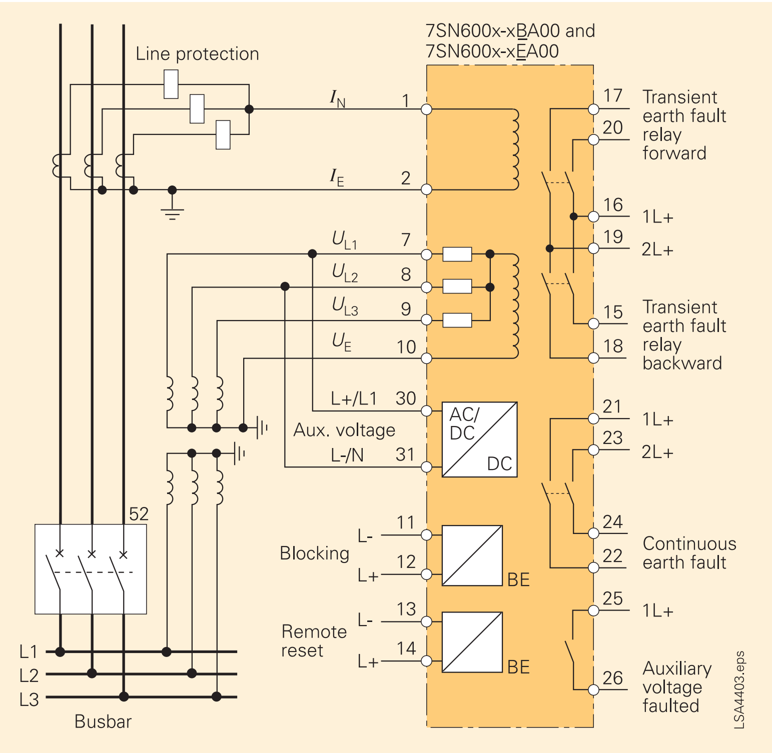


Fig. 12 Transient earth-fault relay connection

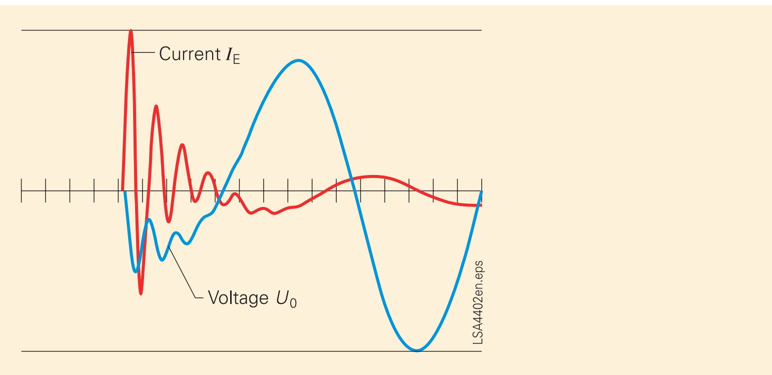


Fig. 13 Transients in an earth fault

Example in Fig. 10:
Normally the isolating point is situated at C. An earth fault has occurred and relay 8 has reported "forward". If the isolating point is now moved from C to A, which can be done (by load disconnection switches) with no interruption to supply, the relay 7 indicates "forward". The section A–C is thus affected by the earth fault. If the isolating point is now moved to B, the relay 8 once again indicates "forward". Thus section A–B is clearly affected by the earth fault.

3. Earth-fault direction detection with the transient earth-fault relay 7SN60

If the system is meshed, no clear direction indication can be obtained with watt-metric relays. The current direction in the case of an earth fault cannot be definitely detected. Good locating results are achieved using transiente earth-fault relays. These relays work with the charge-reversal process, which occurs with the earth fault. The capacity of the phase affected by the earth fault is discharged to earth and the healthy phases are charged up to the higher voltage value. This charge-reversal produces a large current, amounting to a multiplication (threefold or fourfold) of the capacitive current. The transient earth-fault relays are thus always connected to the Holmgreen-circuit. It is important to be aware that the charge-reversal process only occurs when the earth fault appears, i.e. just once. Repeat measurements following switching therefore have no meaning and lead to confusion.
In order to identify the circuit affected by the earth fault in a meshed system, an indication is required from both ends of the line. Both relays must indicate in a "forward direction". It is therefore advisable to transfer the signals from the transient earth-fault relay onto an image of the system. It is then possible to decide quickly where the earth fault is located.

In Fig. 11, the fault is located in the middle line from ST 4 to ST 3, since here both relays are indicating "forward".

4. Summary

Operation can be continued when an earth fault occurs in a resonant-earthed power system. The fault can be located as described above. The operator should quickly separate the fault location from the system. Thus a double fault (which – as a short-circuit – would cause a supply interruption) can be avoided.

Earth-Fault Protection in a Low-Resistance-Earthed System

1. General earth-fault information

In a low-resistance-earthed power system the earth fault is a short-circuit and must therefore be tripped by the short-circuit protection. In most cases, in an impedance-earthed network (predominantly medium voltage) the earth-fault current is limited to a maximum of 2000 A. The minimum short-circuit current occuring in the case of faults at a greater distance is the standard pickup value for earth-fault protection (I_E>). It must be ensured that any earth fault is safely tripped. If short-circuit calculations for the power system are carried out, it is useful to have the minimum short-circuit currents calculated as well as the maximum ones. These values less a safety margin then form the basis of the I_E> set value. The pickup value for the earth fault is lower than that for phase failure, and in unfavorable cases can actually be below the rated current.

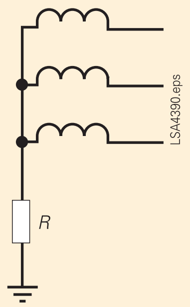
When distance protection relays (7SA5.., 7SA6.) are used, the pickup value I_E> merely acts to release the phase-to-earth measuring systems. The same setting considerations nevertheless apply.

2. Earth fault in an overhead line system

Since an earth fault is by far the most frequent fault in medium-voltage overhead line systems, measures for its quick correction are welcome. The most frequently used method is auto-reclosure (AR). On the medium-voltage level auto-reclosure is always triple-pole, and in the case of high-voltage single-pole. Single-pole auto-reclosing circuit-breakers are therefore a precondition here. If an earth fault occurs on the overhead line, the protection relays concerned will pick up.

Following a TRIP command, there is a dead time (500 ms for medium voltage, 1 s for single-pole AR at high voltage), after this the line is reconnected. If the earth fault is corrected, operation continues. If not, final disconnection takes place within the set time. Approximately 70 % of earth faults are corrected in this way without any major interruption to operation.

Fig. 1 SIPROTEC relay with earth-fault protection



- Earth fault = short-circuit
- Disconnected by the short-circuit protection
- Earth-fault detection is more sensitive than phase current detection

Fig. 2 Low-resistance-earthed system

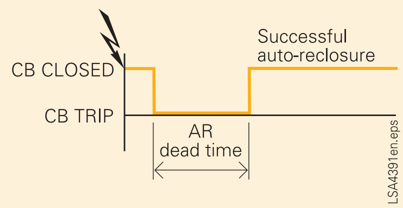


Fig. 3 Earth short-circuit in an overhead line system

Overcurrent-time protection relays 7SJ5.., 7SJ6.. can be ordered with this functional option, as can the distance protection relays 7SA5.., 7SA6..

Settings for medium voltage:

Auto-reclosure	Triple-pole
Dead time	500 ms
Action time	300 ms

Settings for high voltage (≥ 110 kV):

Auto-reclosure	Single-pole
Dead time	1 s
Action time	300 ms

3. Earth fault in a cable system

Auto-reclosure is not appropriate for a cable system. In such cases, final disconnection is unavoidable since an earth fault does not correct itself. Selective grading avoids unnecessary tripping in such cases.

4. Locating faults

It is possible to locate earth faults with the 7SJ6.. definite time overcurrent-time relay as well as with the distance protection relays 7SA5.., 7SA6... The precise setting of the line's X layer is required. This can be taken from the appropriate tables in the cable manual. In contrast, the setting of the Z_E/Z_L factor is more difficult. Only measurements can reveal the true facts here. The relays measure the impedance loop as far as the fault location.
If the above-mentioned set values are correct, an accuracy of 3 % of the given fault distance can be expected. In practice, the set values can be optimized on the basis of an exact empirical analysis of faults that have occurred.

5. Summary

In a low-resistance-earthed system an earth fault is always a short-circuit.
The sensitivity of the pickup value for the earth-fault protection has to be set adequately to reliably trip upon each earth fault.
SIPROTEC line protection relays are available with the earth-fault protection function as an option.
In an overhead system about 70 % of the earth faults are successfully eliminated by AR without significant system interruptions.

Coping with Single-Phase Load Diversity Using Adaptive Relay Settings

1. Introduction

Setting ground overcurrent elements on the typical distribution circuit is a straightforward task. The ground element setting must be sensitive enough to operate for the coordination point with the lowest ground (earth) fault current. However, for circuits with large single-phase load diversity, a large zero-sequence current (or $3I_0$), will be seen in the neutral due to this imbalance. The ground element pickup setting must also be high enough that the relay does not trip for this level of zero-sequence current. The amount of $3I_0$ present will change for different system conditions, such as summer peak versus winter peak.

Typical relaying practices for a circuit that has large single-phase load diversity involve making some tradeoffs on the reliability of the protection system. Generally, sensitivity (and therefore dependability) is lowered so the relay allows the maximum expected zero-sequence current in the neutral (maintaining security).

This application note introduces the idea of adaptive relay settings to provide better ground overcurrent protection for circuits with large single-phase load diversity. The normal settings of the relay use a ground element with maximum sensitivity for fault conditions. As system conditions change and the load diversity increases, the relay adapts by decreasing the sensitivity of the ground pickup, preventing a false operation by allowing more $3I_0$ to flow. Adaptive relay settings provide a cost-effective method of improving the protection of distribution feeders, by automatically maintaining both dependability and security as system conditions change.

2. Current practices

For circuits with large single-phase load diversity, there are three philosophies used for setting ground relay elements:

1. Disable the ground element: This allows the maximum amount of $3I_0$ present during load diversity. However, the method provides minimum protection. Only the phase elements will operate for a ground fault, and, due to load allowance requirements, they may not have the sensitivity to see all phase-to-ground faults. This method greatly lowers the dependability of the protection system to maintain security.
2. Lower the ground element sensitivity to allow the maximum amount of $3I_0$ expected. This maintains some ground protection for all system conditions and doesn't require constant correction of the relay settings. However, the sensitivity of the ground relay is not ideal, especially when load diversity is small. Like disabling the ground element, this method also lowers the dependability of the protection relay to maintain security, but not as radically.

3. Change the ground element sensitivity for specific system conditions. This method is used when load diversity increases greatly for a long period of time, such as seasonal load peaks. Protection is maximized as much as feasible, but relay settings must be changed several times a year. This method only lowers the dependability of the protection system when absolutely required, and maintains security.

All three of these methods are in common use. From a pure protection standpoint, changing the ground pickup settings for system conditions is the best method. This method provides the best system reliability, by only lowering dependability when required. The drawback is the cost involved. With electro-mechanical relays, field changes of settings are required. Numerical relays generally require remote control, auxiliary relays, and operator action to change settings groups.

3. New application concept

Adaptive relay settings allow a protection relay to automatically, and independently, change settings as the system operating conditions change. The Siemens SIPROTEC 4 overcurrent relays (7SJ61, 7SJ62, and 7SJ63), using the PLC programming capability in the Continuous Function Chart (CFC), can adapt relay settings automatically. For this application, a relay will adapt the ground element sensitivity as the amount of zero-sequence current changes due to increasing single-phase load diversity.

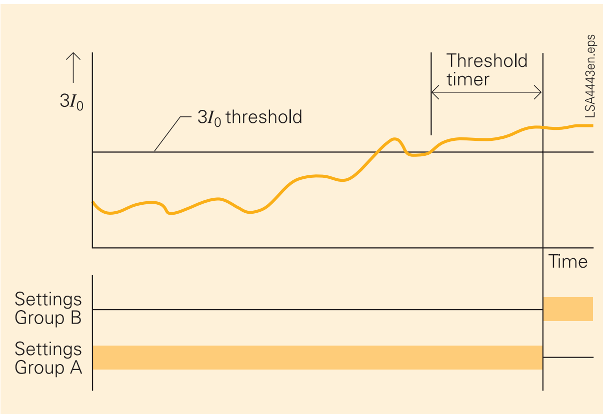


Fig. 1 Adapting ground element settings

To adapt the ground element settings, the relay is programmed to change settings groups as the measured zero-sequence current changes over time. As the amount of $3I_0$ increases, and remains above a pre-determined threshold value, the relay changes settings groups from one with maximum ground element sensitivity, to one that provides less sensitivity for higher phase diversity.

When the amount of $3I_0$ decreases, and remains below the predetermined threshold, the relay returns to the normal settings group. This concept is illustrated in Fig. 1.

Definition of the elements shown in Fig. 1:

- Settings Group A
  The "normal" settings group. The ground element pickup setting is set with maximum sensitivity to operate for a fault at the circuit reach point, while allowing the amount of $3I_0$ present during normal single-phase load diversity conditions.
- Settings Group B
  The alternate settings group. The ground element is set to allow the amount of $3I_0$ present during the maximum single-phase load diversity condition.
- $3I_0$ Current Threshold
  The level of zero-sequence current that indicates a change in single-phase load diversity of the circuit. The value of this threshold must be large enough to indicate that the load diversity is actually changing, but less than the pickup setting of the ground element for Settings Group A.
- Threshold Timer
  This time delay is used to ensure a larger load diversity exists, and that the diversity is not a transient condition. The increase in single-phase load diversity, as indicated by the amount of $3I_0$, must the load diversity settings group. The timer must be set long enough to ensure the load diversity has increased to new level, and has not just temporarily increased due to a the addition of a large, transient, single phase current draw condition. The timer must also be set so the relay can differentiate between fault conditions and changes in single-phase load diversity.
- Reset Timer
  This is the time necessary to indicate a decrease in the single-phase load diversity. The single-phase load diversity, as indicated by the amount of $3I_0$, must stay below the $3I_0$ Current Threshold for this length of time to return the relay to the original settings group. This timer must be set long enough to ensure the single-phase load diversity has actually returned to normal condition.

4. Application examples

The load information shown in Table 1 is for a circuit with a summer peak. As shown, there is a significant increase in the load and the amount of $3I_0$ during the summer. It is desirable to use peak demand values for load information, or when possible, historical data for the amount of zero-sequence current. For this example, the minimum fault current that the ground element must operate for is 1.5 A_{sec}.

	Winter	Summer
Phase A Load	1.25 A_{sec}	2.38 A_{sec}
Phase B Load	1.54 A_{sec}	1.62 A_{sec}
Phase C Load	1.35 A_{sec}	1.42 A_{sec}
$3I_0$ Current	0.26 A_{sec}	0.87 A_{sec}

Table 1 Typical circuit load

Table 2 lists possible relay settings for the circuit load information from Table 1. The ground element pickup setting in Settings Group A is set to provide a desired reach sensitivity to the minimum ground reach point, while allowing some percentage of the normal amount of $3I_0$. For dependability, to ensure the ground element trips for all faults in the zone of protection, minimum reach is set in the range of 2/1 to 3/1. For security, the ground pickup should allow 120 % to 150 % of the normal amount of $3I_0$.

The ground element pickup setting for Settings Group B is set to maintain security by allowing some percentage of the expected amount of $3I_0$. A typical setting range is 120 % to 150 %. This setting is balanced against the desire to maintain some dependability by having some reach sensitivity to the minimum ground reach point.

The $3I_0$ Current Threshold is set at a level high enough to indicate a change in the single-phase load diversity, but still below the ground element pickup setting for Settings Group A. The $3I_0$ Current Threshold level, and the Threshold Timer, must also account for the rate of change of the zero-sequence current. If the threshold is too high, or the timer too long, the zero-sequence current may increase over the ground element pickup setting before a settings change occurs. Once the ground element is in pickup, no settings group change is possible, and the ground element will eventually trip.

The Reset Timer is set at a time long enough to ensure that the single-phase load diversity has actually decreased, to prevent the relay from "bouncing" between settings groups.

Element	Setting	Calculations
Setting Group A Ground element pickup	0.5 A_{sec}	Reach = 1.5/0.5 = 3.0 Allowance = 0.5/0.26 = 192 %
Ground element time dial	1.0	
Setting Group B Ground element pickup	1.1 A_{sec}	Reach = 1.5/1.1 = 1.36 Allowance = 1.1/0.87 = 126 %
Ground element time dial	1.0	
$3I_0$ current threshold	0.45 A_{sec}	
Threshold timer	30 min	
Reset timer	15 min	

Table 2 Example relay settings

5. Implementation of adaptive relay settings in a SIPROTEC 4 relay

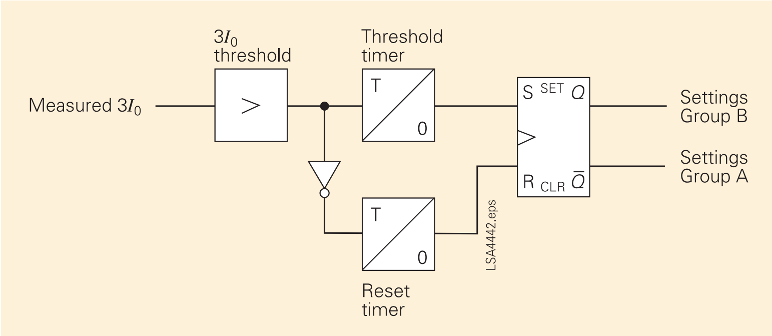


Fig. 2 Adaptive ground element logic

Implementation of the adaptive relay setting logic, using the SIPROTEC 4 7SJ61, 7SJ62, and 7SJ63 relays, is in the Continuous Function Chart (CFC) portion of the relay. This is a graphical programmable logic controller programming tool that permits the use of standard and advanced logic and control capabilities. Using the CFC, the logic of Fig. 2 is implemented in the relay.

The zero-sequence current measured by the relay is compared to the $3I_0$ Current Threshold in the "Measurement" plan of the CFC. The output of this comparison is used in the "Slow PLC" plan to start either the Threshold Timer or the Reset Timer. If the output of the comparison is logical 1, the Threshold Timer is started. Otherwise, the Reset Timer is started. When the Threshold Timer expires, a SR flip-flop is used to latch the ">Set Group Bit0" command. Asserting the ">Set Group Bit0" command changes the settings group from A to B. When the Reset Timer expires, the SR flip-flop is reset, deasserting the ">Set Group Bit0" command, and changing the settings group from B to A.

6. Summary

Adaptive relay settings provide a method for matching the reliability of the protection system to the actual system conditions. When looking at this example of single-phase load diversity, the protection engineer has typically had to give up some of the dependability of the protection system to maintain the security of the protection system. Adaptive relay settings give the relay the ability to maximize the dependability of the protection system, while not effecting security at all.

The idea of adaptive relay settings is a very powerful concept that can be extended to many applications. One possible application is to automatically change relay settings for temporary increases in circuit demand, such as during switching operations.

7. References

William D. Stevenson, Jr. Elements of Power System Analysis, 4th Ed., McGraw-Hill Book Company, New York, NY; 1982

Turan Gonen, Electric Power Distribution System Engineering, McGraw-Hill Book Company, New York, NY; 1986

DIGSI CFC Instruction Manual, Siemens Power Transmission and Distribution, Inc., Raleigh, NC; 1999

SIPROTEC Time-Overcurrent, Overload, And Motor Protective Relay with Bay Controller 7SJ61 V4.0/4.1 Instruction Manual, Siemens Power Transmission and Distribution, Inc., Raleigh, NC; 1999

400 kV Overhead Transmission Line Protection

1. Introduction

This application example will guide the reader through all the steps required to set the distance protection functions for a typical transmission line. Standard supplements such as teleprotection, power swing, switch onto fault, directional earth-fault protection, etc. are also covered.

2. Key functions applied:

- Distance protection (ANSI 21): Quadrilateral characteristic
- Teleprotection for ANSI 21: POTT
- Earth fault O/C (ANSI 67N): IEC curves, directional
- Teleprotection for ANSI 67N: Directional comparison
- Power swing blocking
- Weak infeed: Echo and trip
- Overcurrent protection: Emergency mode
- Auto-reclose: 1 and 3-pole, 1 cycle
- Synchronism check: Sync. and async. closing
- Fault locator: Single-end measurement

3. Single line diagram and power system data

The required time graded distance protection zones are:

Fig. 1 Universal protection for OHL

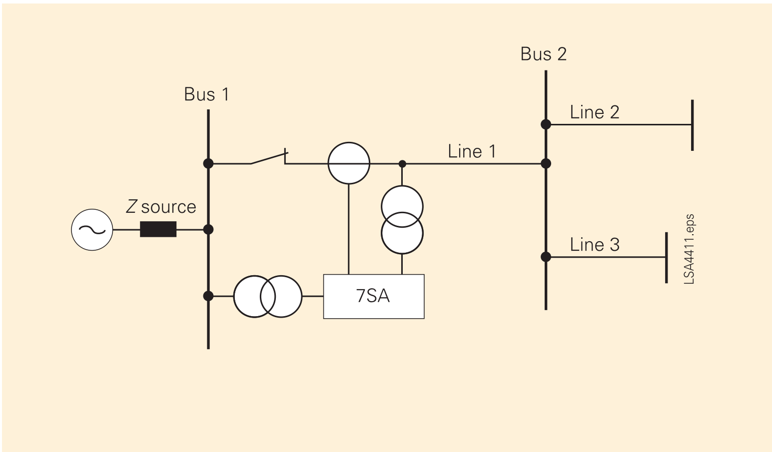


Fig. 2 Single line diagram of protected feeder

Zone number	Function	Reach	Time delay
Zone 1	Fast underreach protection for Line 1	80 % Line 1	0 s
Zone 2	Forward time delay backup, overreach	20 % less than Z1 reach on Line 3	1 time step
Zone 3	Reverse time delay backup	50 % Z-Line 1	2 time steps
Zone 4	Not applied	–	–
Zone 5	Non-directional	120 % Line 2	3 time steps

Table 1 Notes on setting the distance protection zones

	Parameter	Value
System data	Nominal system voltage phase-phase	400 kV
	Power system frequency	50 Hz
	Maximum positive sequence source impedance	10 + j100
	Maximum zero sequence source impedance	25 + j200
	Minimum positive sequence source impedance	1 + j10
	Minimum zero sequence source impedance	2.5 + j20
	Maximum ratio: Remote infeed / local infeed (I_2/I_1)	3
Instrument transformers	Voltage transformer ratio (LINE)	380 kV / 100 V
	Voltage transformer ratio (BUS)	400 kV / 110 V
	Current transformer ratio	1000 A / 1 A
	Current transformer data	5P20 20 VA P_i = 3 VA
	CT secondary connection cable	2.5 mm^2 50 m
	CT ratio / VT ratio for impedance conversion	0.2632
Line data	Line 1 –length	80 km
	Maximum load current	250 % of full load
	Minimum operating voltage	85 % nominal voltage
	Sign convention for power flow	Export = negative
	Full load apparent power (S)	600 MVA
	Line 1 –positive seq. impedance per km Z1	0.025 + j0.21 Ω/km
	Line 1 –zero seq. impedance per km Z0	0.13 + j0.81 Ω/km
	Line 2 –total positive seq. impedance	3.5 + j39.5 Ω
	Line 2 –total zero seq. impedance	6.8 + j148 Ω
	Line 3 –total positive seq. impedance	1.5 + j17.5 Ω
	Line 3 –total zero seq. impedance	7.5 + j86.5 Ω
	Maximum fault resistance, Ph - E	250 Ω
Power data	Average tower footing resistance	15 Ω
	Earth wire	60 mm^2 steel
	Distance: Conductor to tower/ground (midspan)	3 m
	Distance: Conductor to conductor (phase-phase)	5 m
Circuit-breaker	Trip operating time	60 ms
	Close operating time	70 ms

Table 2 Power system and line parameters

Based on the source and line impedance, the following minimum fault current levels can be calculated for faults on Line 1:

$$I_{\text{fault}} = \frac{U_{\text{source}}}{\sqrt{3} \cdot Z_{\text{tot}}} \quad \text{with} \quad U_{\text{source}} = 400 \text{ kV}$$

If fault resistance is neglected then for 3-phase faults:

Z_{tot} = sum of positive sequence source and line impedance (as only current magnitudes are being calculated, only the magnitude of the impedance is relevant)

$$|Z_{\text{tot}}| = |(10 + 80 \cdot 0.025) + j(100 + 80 \cdot 0.21)|$$

$$|Z_{\text{tot}}| = |12 + j116.8|$$

$$|Z_{\text{tot}}| = 117.4$$

The minimum three-phase fault current is therefore:

$$I3_{\text{ph min}} = \frac{400 \text{ kV}}{\sqrt{3} \cdot 117.4}$$

$$I3_{\text{ph min}} = 1967 \text{ A}$$

If **fault resistance is neglected** then for single-phase faults:

Z_{tot} = 1/3 (sum of positive, negative and zero sequence source and line impedance)

$$|Z_{\text{tot}}| = \frac{|2\cdot[(10+80\cdot 0.025)+j(100+80\cdot 0.21)]+(25+80\cdot 0.13)+j(200+80\cdot 0.81)|}{3}$$

$$|Z_{tot}| = |19.8 + j166.1|$$

$$|Z_{tot}| = 167.3$$

The minimum single-phase fault current without fault resistance is therefore:

$$I1_{\text{ph min}} = \frac{400\text{ kV}}{\sqrt{3}\cdot 167.3} = 1380\text{ A}$$

If **fault resistance is included** then for single-phase faults:

$$Z_{tot\_R} = Z_{tot} + R_F$$

$$|Z_{tot\_R}| = |R_F + Z_{tot}|$$

$$|Z_{tot}| = |250 + 19.8 + j166.1|$$

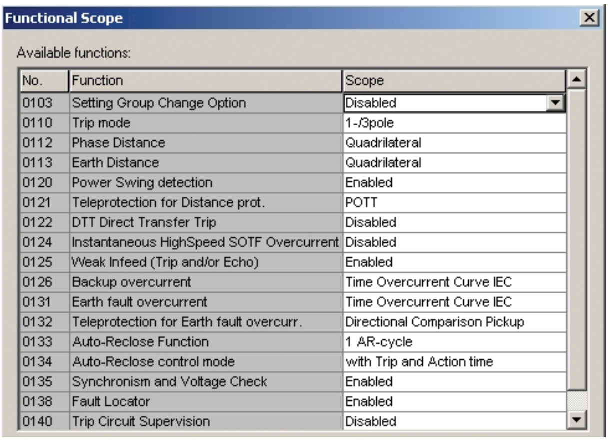
$$|Z_{tot}| = 316.8$$

The minimum single-phase fault current with high resistance is therefore:

$$I1_{\text{ph min\_R}} = \frac{400\text{ kV}}{\sqrt{3}\cdot 316.8} = 729\text{ A}$$

4. Selection of device configuration (functional scope)

After selection and opening of the device in the DIGSI Manager, the first step when applying the settings is entering the functional scope of the device. A sample screen shot showing the selection for this example is given below:


Functional Scope

Available functions:

No.	Function	Scope
0103	Setting Group Change Option	Disabled
0110	Trip mode	1-/3pole
0112	Phase Distance	Quadrilateral
0113	Earth Distance	Quadrilateral
0120	Power Swing detection	Enabled
0121	Teleprotection for Distance prot.	POTT
0122	DTT Direct Transfer Trip	Disabled
0124	Instantaneous HighSpeed SOTF Overcurrent	Disabled
0125	Weak Infeed (Trip and/or Echo)	Enabled
0126	Backup overcurrent	Time Overcurrent Curve IEC
0131	Earth fault overcurrent	Time Overcurrent Curve IEC
0132	Teleprotection for Earth fault overcurr.	Directional Comparison Pickup
0133	Auto-Reclose Function	1 AR-cycle
0134	Auto-Reclose control mode	with Trip and Action time
0135	Synchronism and Voltage Check	Enabled
0138	Fault Locator	Enabled
0140	Trip Circuit Supervision	Disabled

LSP2590.tif

Fig. 3 Selected scope of functions

The available functions displayed depend on the ordering code of the device (MLFB). The selection made here will affect the setting options during the later stages. Careful consideration is therefore required to make sure that all the required functions are selected and that the functions that are not required in this particular application are disabled. This will ensure that only relevant setting alternatives appear later on.

103 Setting Group Change Option:
Only enable this function, if more than one setting group is required. In this example only one setting group is used; therefore this function is **disabled**.

110 Trip mode:
On OHL applications, single-pole tripping is possible if the circuit-breaker is capable of this. The advantage is that during a single-pole dead time the OHL can still transport some power and reduce the risk of system instability. In this example both one and three-pole tripping is used so the setting is **1-/3-pole**.

112 Phase Distance:
As distance protection for phase faults is required, **Quadrilateral** must be selected. In some cases (depending on the ordering code) a **MHO characteristic** can also be selected.

113 Earth Distance:
Here the earth fault distance protection characteristic is selected as for 112 above. Therefore set **Quadrilateral**.

120 Power Swing detection:
If power swing conditions can occur in the vicinity of the applied relay, the power swing detection must be enabled. It is required for blocking of the distance protection during power swings. At 380 kV it is common practice to **Enable** the power swing detection.

121 Teleprotection for Distance prot.:
To achieve fast tripping for all faults on the circuit a teleprotection scheme must be applied.

Parameter	PUTT	POTT	Blocking	Unblocking
Short line	**Not suitable** as the Zone 1 operation is essential and Zone 1 setting in X and R direction must be small on short lines	**Suitable** as the Z1b setting may be substantially larger than the line impedance so that signal transmission is secure for all faults on the line	**Suitable** as reverse reach setting is independent of line length	**Suitable** as the Z1b setting may be substantially larger than the line impedance so that signal transmission is secure for all faults on the line
Weak infeed	**Not suitable** as the Zone 1 operation is essential at both ends for 100 % line coverage	**Suitable** as the strong end detects all line faults with overreaching Z1b. The weak infeed end then echos the received signal	**Partially suitable** as the reverse fault is also detected at the weak infeed end but no trip at weak infeed end	**Suitable** as the strong end detects all line faults with overreaching Z1b. The weak infeed end then echos the received signal
Amplitude modulated power line carrier	**Not suitable** as the signal must be transmitted through the fault location which attenuates the signal	**Not suitable** as the signal must be transmitted through the fault location which attenuates the signal	**Suitable** as the signal is only sent when the line is not faulted	**Not suitable** as the signal must be transmitted through the fault location which attenuates the signal
Frequency or phase modulated power line carrier	**Suitable** as the signal can be transmitted through the fault location	**Suitable** as the signal can be transmitted through the fault location	**Suitable** as the signal can be transmitted under all conditions	**Suitable** as the signal can be transmitted through the fault location
Communication independent of power line	**Suitable**	**Suitable**	**Suitable**	**Suitable**

Table 3 Selection of teleprotection scheme

In this case the selection is **POTT**

122 DTT Direct Transfer Trip:
If external inputs must be connected to initiate tripping via binary input, this function should be activated. The trip will then automatically be accompanied by the minimum trip command duration (trip circuit seal in) and event and fault recordings. In this example this function is not required and therefore **Disabled**.

124 Instantaneous High Speed SOTF Overcurrent:
When closing onto bolted faults extremely large currents arise that must be switched off as fast as possible. A special overcurrent protection stage is provided for this purpose. In this example it will not be used and is therefore **Disabled**.

125 Weak Infeed:
When weak infeed conditions exist (permanently or temporarily) at one or both ends, the weak infeed function must be **Enabled**. Refer also to Table 3.

126 Backup overcurrent:
When the distance protection is in service, it provides adequate backup protection for remote failures. The overcurrent protection in the distance relay is usually only applied when the distance function is blocked due to, for example, failure of the measured voltage circuit (VT-fuse fail). This will be done in this example, so the function must be activated. The selection of the response curve standard is **Time Overcurrent Curve IEC** in this application.

131 Earth Fault overcurrent:
For high resistance earth faults it is advisable to not only depend on the distance protection as this would demand very large reach settings in the R direction. The directional (and non-directional) earth-fault protection is very sensitive to high resistance earth faults and is therefore activated in this example. Here **Time Overcurrent Curve IEC** is selected.

132 Teleprotection for Earth fault Overcurr.:
To accelerate the tripping of the earth-fault protection (activated under 131 above) a teleprotection scheme can be applied. In this example a **Directional Comparison Pickup** scheme will be applied.

133 Auto-Reclose Function:
Most faults on overhead lines are of a transient nature so that the line can be energised successfully after fault clearance. For this purpose an automatic reclosure function can be implemented to minimise the line outage by reclosing with a set or flexible dead time. In this application **1 AR-cycle** will be applied.

134 Auto-Reclose control mode:
If, as in this example, single and three-pole tripping is used, the auto-reclose function is triggered by the trip command. If the trip is due to a backup protection operation (e.g. Zone 2) then reclosure is normally not desired. By application of an action time which monitors the time between fault detection and trip, reclosure can be prevented for time delayed tripping (longer than set action time). In this example the auto-recloser will be triggered **with Trip and Action time** monitoring.

135 Synchronism and Voltage Check:
Before closing a circuit-breaker it is advisable to check that the system conditions on both sides of the circuit-breaker are suitable for being connected. For this purpose the Synchronism and Voltage Check function is **Enabled** in this example.

138 Fault Locator:
Following fault clearance an inspection of the fault location may be needed to check that there is no permanent damage or risk of further faults at the fault location. Particularly on longer lines it is very helpful to have an indication of the fault location to allow faster access by the inspection team. For this purpose the fault locator is **Enabled** in this example.

140 Trip Circuit Supervision:
The monitoring done by the relay can be extended to include the trip circuit and trip coils. For this purpose a small current is circulated in the monitored circuits and routed via binary inputs to indicate a failure. In this example this function is not used and therefore set to **Disabled**.

5. Masking I/O (configuration matrix)

The configuration matrix is used to route and allocate the information flow in the device. All the assignments of binary inputs and outputs, as well as LED's, sequence of event records, user defined logic, controls etc. are made in the matrix.

6. User defined logic CFC

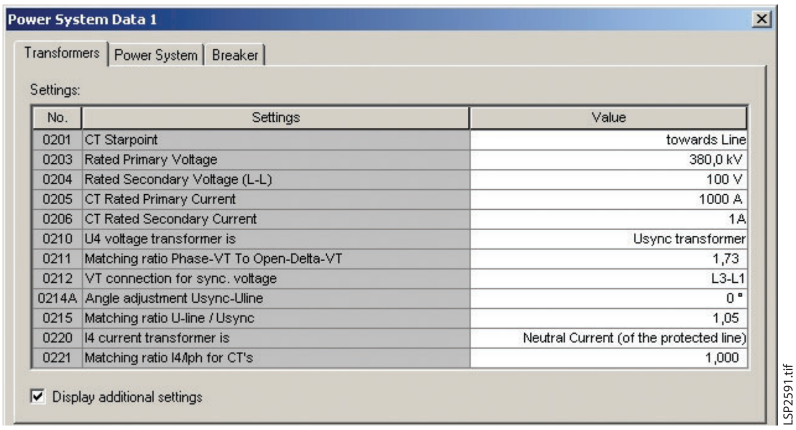
If any special logic is required in the application, the CFC task can be used for this purpose.

7. Settings for power system data 1

7.1 Instrument transformers

Under this heading power system parameters are applied. Place a 'Tick' in the box 'Display additional settings' to include 'advanced' settings (designated by A, e.g. 0214A) in the displayed list.

The 'advanced' settings can in most cases be left on the default setting value.


Power System Data 1

Transformers | Power System | Breaker

Settings:

No.	Settings	Value
0201	CT Starpoint	towards Line
0203	Rated Primary Voltage	380,0 kV
0204	Rated Secondary Voltage (L-L)	100 V
0205	CT Rated Primary Current	1000 A
0206	CT Rated Secondary Current	1A
0210	U4 voltage transformer is	Usync transformer
0211	Matching ratio Phase-VT To Open-Delta-VT	1,73
0212	VT connection for sync. voltage	L3-L1
0214A	Angle adjustment Usync-Uline	0 °
0215	Matching ratio U-line / Usync	1,05
0220	I4 current transformer is	Neutral Current (of the protected line)
0221	Matching ratio I4/Iph for CT's	1,000

☑ Display additional settings

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Fig. 4 Configuration of CT and VT circuits

201 CT Starpoint:
In this application the CTs are connected as shown below in Figure 5. The polarity of the CT connection must be selected correctly to ensure correct response by the protection. For this purpose the position of the starpoint

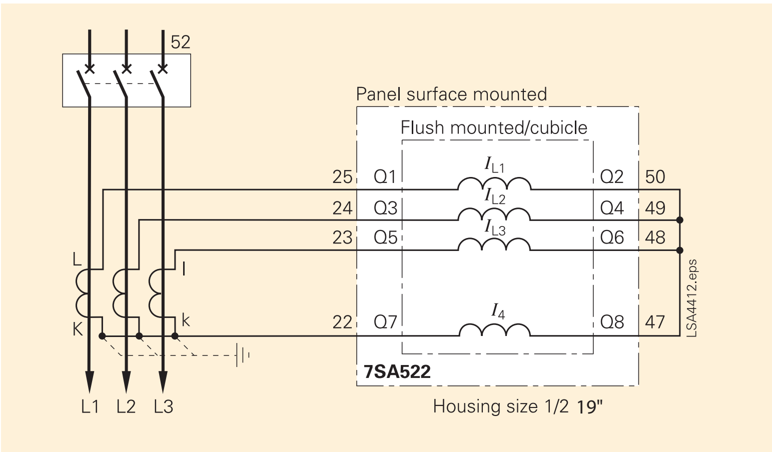


Fig. 5 Relay connections

connection is indicated: In this example it must be set **towards line**.

203 Rated Primary Voltage:
The VT ratio must be set correctly to ensure accurate measured value output. It is also possible to set the protection parameters in primary quantities. For correct conversion from primary to secondary the VT and CT data must be set correctly. In this application the VT primary voltage is **380 kV**.

204 Rated Secondary Voltage (ph-ph):
Set to **100 V** as per VT data.

205 CT Rated Primary Current:
Set to **1000 A** as per CT data.

206 CT Rated Secondary Current:
Set to **1 A** as per CT data. Note that this setting must correspond to the jumper settings on the measurement module (printed circuit board). If this is not the case, the relay will block and issue an alarm. Refer to device manual for instructions on changing jumper settings.

210 U4 voltage transformer is:
The 4th voltage measuring input may be used for a number of different functions. In this example it is connected to measure busbar voltage for synchronising check (set **Usync transformer**) as shown in Figure 6.

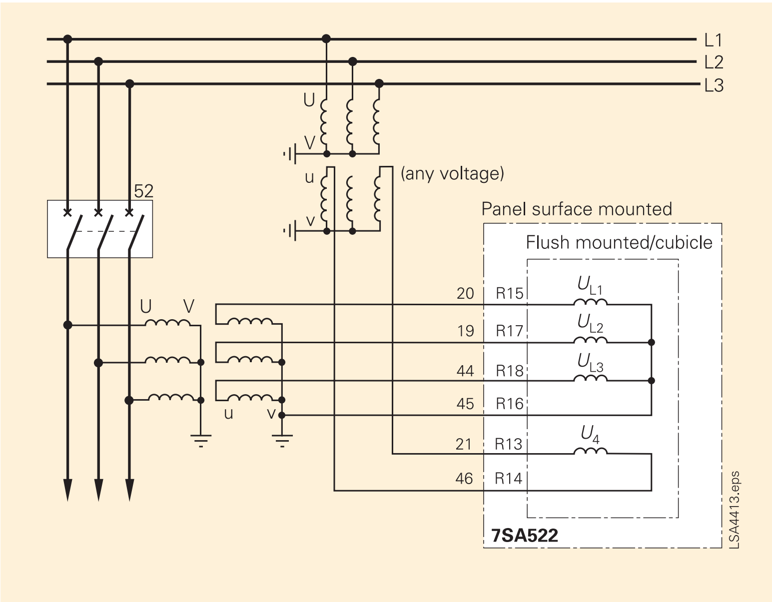


Fig. 6 VT connections

211 Matching ratio Phase-VT to Open-delta-VT:
If in setting 210 the 4th voltage measuring input is selected to measure the open-delta voltage (3 U_0) then this setting must be used to configure the transformation ratio difference between the phase VT and the open-delta VT. As sync. check is applied this setting has no relevance.

212 VT connection for sync. voltage:
If the setting 210 for the 4th voltage measuring input is selected to measure the voltage for sync. check this setting must be applied to define which voltage is used for sync. check. In this example, the voltage connected to U_4 is the phase-phase voltage **L3-L1** as shown in Figure 6.

214A Angle adjustment U_{sync}-U_{line}:
If there is a phase angle difference between the voltage U_{sync} and U_{line}, for example due to a power transformer with phase shifting vector group connected between the measuring points, then this phase shift must be set here. In this example the busbar is connected directly to the line so that there is **0°** phase shift.

215 Matching ratio U_{line}-U_{sync}:
If the transformation ratio of the VT for line voltage and sync. voltage measurement is not the same, then the difference must be set here. In this application:

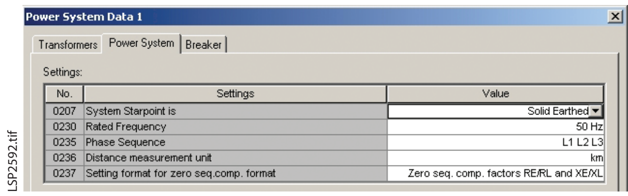
$$\text{Ratio correction} = \frac{\dfrac{U_{\text{prim Line}}}{U_{\text{sec Line}}}}{\dfrac{U_{\text{prim BUS}}}{U_{\text{sec BUS}}}} = \frac{\dfrac{380}{0.1}}{\dfrac{400}{0.11}} = \underline{\underline{1.05}}$$

The required setting is therefore **1.05**.

220 I_4 current transformer is:
The 4th current measurement may be used for a number of different functions. In this case it is used to measure the **Neutral Current** (**of the protected line**) by means of a Holmgreen connection. See Figure 5.

221 Matching ratio I_4/I_{ph} for CT's:
If the CT connected to I_4 has a different ratio, for example a core balance CT, to the ratio of the CT measuring the phase currents of the protected circuit, this difference must be set here. In this application the ratio is the same so the setting must be **1.00**.

7.2 Power system data


Power System Data 1

Transformers | Power System | Breaker

Settings:

No.	Settings	Value
0207	System Starpoint is	Solid Earthed
0230	Rated Frequency	50 Hz
0235	Phase Sequence	L1 L2 L3
0236	Distance measurement unit	km
0237	Setting format for zero seq.comp. format	Zero seq. comp. factors RE/RL and XE/XL

Fig. 7 Power system data

207 System Starpoint is:
The condition of the system starpoint earthing must be set here. If the system starpoint is not effectively earthed, isolated or resonant earthed, then the distance protection response to simple earth faults will be stabilised to prevent operation on transient earth fault currents. In this example **Solid Earthed** applies.

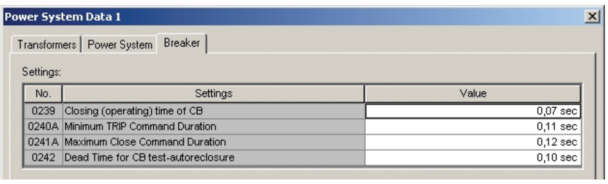
230 Rated Frequency:
Set the rated system frequency to **50 Hz or 60 Hz**.

235 Phase Sequence:
The phase sequence of the system is usually positive, L1 L2 L3. If the system has negative phase sequence this can be set here. In this example the phase sequence is positive (**L1 L2 L3**).

236 Distance measurement unit:
The distance measurement unit for the fault locator and certain line parameters can either be in km or in miles. In this example **km** is used.

237 Setting format for zero seq. comp.:
The distance protection includes a zero sequence compensation so that the same reach settings apply to phase and earth faults. The zero sequence compensation can either be set as RE/RL and XE/XL parameters (standard format used by Siemens in the past) or as the complex ratio <u>KO</u> by means of a magnitude and angle setting. In this example the setting will be applied as **Zero seq. comp. factors RE/RL and XE/XL.**

7.3 Breaker


Power System Data 1

Transformers | Power System | Breaker

Settings:

No.	Settings	Value
0239	Closing (operating) time of CB	0,07 sec
0240A	Minimum TRIP Command Duration	0,11 sec
0241A	Maximum Close Command Duration	0,12 sec
0242	Dead Time for CB test-autoreclosure	0,10 sec

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Fig. 8 Breaker parameters

239 Closing (operating) time of CB:
This setting is only relevant if synchro check with asynchronous switching is configured. Under asynchronous closing, the sync. check function will determine the instant for issuing the close command so that the primary CB contacts close when the switched voltages are in phase. For this purpose the time that expires after application of the close command to the close coil until the primary contacts of the CB make must be set here. From Table 2 the required setting is **0.07 s.**

240A Minimum TRIP Command Duration:
The trip command to the circuit-breaker must have a minimum duration to ensure that the CB responds and to prevent premature interruption of the current in the trip coil which may cause damage to the trip contact which is not rated to interrupt such a large inductive current. When primary current flow is detected (measured current > pole open current: Parameter 1130) then the trip command is sealed in by the current flow and will only reset once the current flow is interrupted (refer to Figure 9). When the trip command is issued and no current flow is detected, the minimum trip command duration set here will apply. It must be set longer than the maximum time taken for the CB auxiliary contacts to open and interrupt the current in the trip coil following the start of the trip command. The reset conditions for the trip command can be set with parameter "1135 RESET of Trip Command". From Table 2 the given circuit-breaker operating time is seen to be 60 ms. A safety margin of 50 ms is sensible so that a setting of **0.11 s** is applied.

241A Maximum Close Command Duration:
The close command must also have a minimum duration to ensure that the circuit-breaker can respond and that the auxiliary contacts can interrupt the current flow through the close coil. If, following a close command, a trip is issued due to switch on to fault, the close command is reset immediately by the new trip command. The close command maximum duration should be set at least as long as the maximum time required by the CB auxiliary contact to interrupt the close coil current after start of the close command. From Table 2 the given circuit-breaker operating time is seen to be 70 ms. A safety margin of 50 ms is sensible so that a setting of **0.12 s** is applied.

242 Dead Time for CB test-autoreclosure:
One of the test features in DIGSI is the CB test-autoreclosure. For this test the circuit-breaker is tripped and reclosed under normal load conditions. A successful test proves that the trip and close circuits and the CB are in a fully functional state. As the test causes a disruption to the power flow (either single phase or three phase), the dead time should be as short as possible. While a normal dead time must allow for the time required by the fault arc to dissipate (typically 0.5 s for three-pole trip and 1s for single-pole trip), the test cycle must only allow for the circuit-breaker mechanism to open and close. Here a dead time of **0.10 s** is usually sufficient.

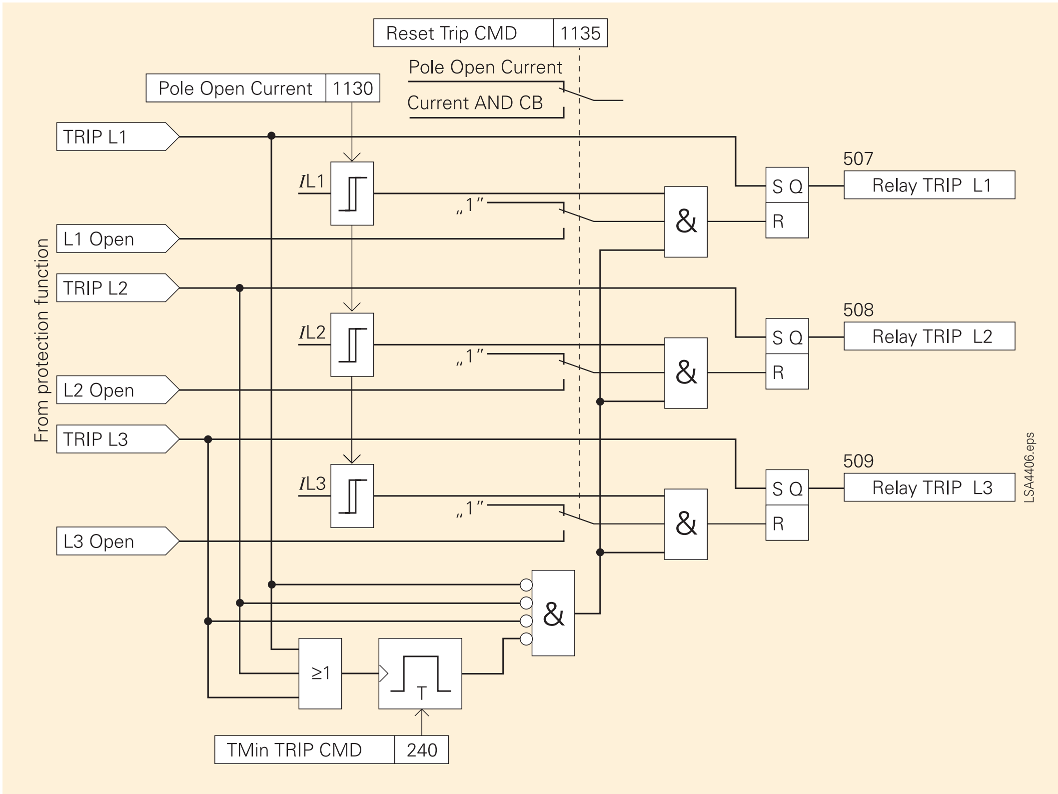
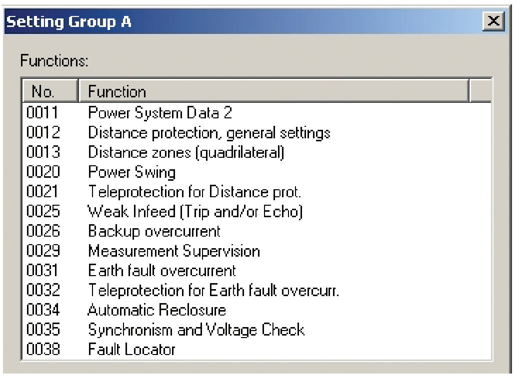


Fig. 9 Trip command seal in



Setting Group A

Functions:

No.	Function
0011	Power System Data 2
0012	Distance protection, general settings
0013	Distance zones (quadrilateral)
0020	Power Swing
0021	Teleprotection for Distance prot.
0025	Weak Infeed (Trip and/or Echo)
0026	Backup overcurrent
0029	Measurement Supervision
0031	Earth fault overcurrent
0032	Teleprotection for Earth fault overcurr.
0034	Automatic Reclosure
0035	Synchronism and Voltage Check
0038	Fault Locator

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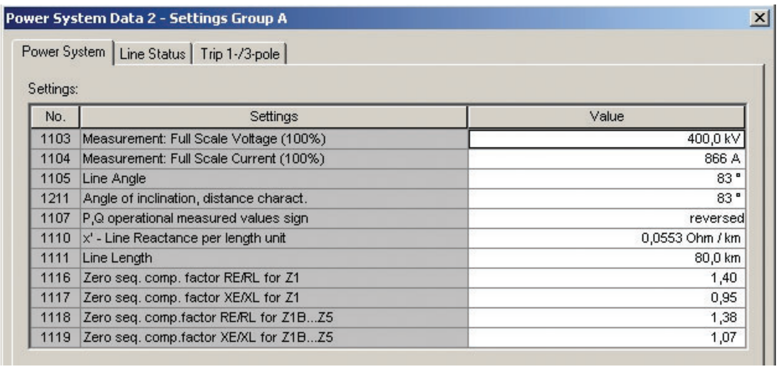
Fig. 10 Setting blocks available in Setting Group A for this application



Power System Data 2 - Settings Group A

Power System | Line Status | Trip 1-/3-pole

Settings:

No.	Settings	Value
1103	Measurement: Full Scale Voltage (100%)	400,0 kV
1104	Measurement: Full Scale Current (100%)	866 A
1105	Line Angle	83 °
1211	Angle of inclination, distance charact.	83 °
1107	P,Q operational measured values sign	reversed
1110	x' - Line Reactance per length unit	0,0553 Ohm / km
1111	Line Length	80,0 km
1116	Zero seq. comp. factor RE/RL for Z1	1,40
1117	Zero seq. comp. factor XE/XL for Z1	0,95
1118	Zero seq. comp.factor RE/RL for Z1B...Z5	1,38
1119	Zero seq. comp.factor XE/XL for Z1B...Z5	1,07

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Fig. 11 Power system settings in Power System Data 2

■ 8. Settings for Setting Group A

The setting blocks that are available in Setting Group A depend on the selections made during the selection of the device configuration (Heading 4). If the setting group changeover had been activated, a total of 4 setting groups would have been available.

■ 9. Settings for Power System Data 2

Further power system data, in addition to Power System Data 1, is set here. As these parameters are inside Setting Group A, they can be modified between the setting groups if setting group changeover is activated.

9.1 Power system

1103 Measurement: Full Scale Voltage (100 %): For the indication and processing of measured values it is important to set the full scale value on the primary side. This does not have to correspond to the VT rated primary voltage. When the primary value corresponds to this setting the percentage measured value will be 100 %. Other percentage measured values that also depend on voltage, such as for example power (*P*) will also have the full scale indication dependant on this setting. In Table 2 the system rated voltage is given and therefore set at **400 kV**.

1104 Measurement: Full Scale Current (100%):
For the indication and processing of measured values it is important to set the full scale value on the primary side. This does not have to correspond to the CT rated primary current. When the primary value corresponds to this setting the percentage measured value will be 100 %. Other percentage measured values that also depend on current, such as for example power (*P*) will also have the full scale indication dependant on this setting. In Table 2 the rated apparent power of the line is stated at 600 MVA:

$$\text{Full scale current} = \frac{\text{Rated MVA}}{\sqrt{3}\cdot\text{Full scale voltage}}$$

$$\text{Full scale current} = \frac{600}{\sqrt{3}\cdot 400} = \underline{\underline{866\ \text{A}}}$$

The measurement: Full scale current (100 %) is therefore set to **866 A**.

1105 Line Angle:
The line angle setting is calculated from the positive sequence line impedance data. In this example:

$Z1 = 0.025 + j0.21$

$$\text{Line angle} = \arctan\left(\frac{X_L}{R_L}\right)$$

Line angle = **83°**

1211 Angle of inclination, distance charact.:
This is usually set the same as the line angle. In this manner the resistance coverage for all faults along the line is the same (Fig. 12). Therefore set for this application the angle of inclination of the distance characteristic equal to the line angle which is **83°**.

1107 *P*,*Q* operational measured values sign:
The measured values *P* and *Q* are designated as positive when the power flow is into the protected object. If the opposite sign is required, this setting must be changed so that the sign of *P* and *Q* will be reversed. In Table 2 the sign convention for power flow states that exported power (flowing into the line) is designated as negative. The setting here must therefore be **reversed**.

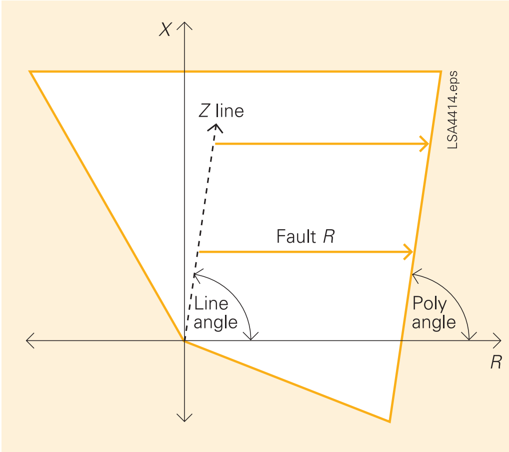


Fig. 12 Polygon and line angle

1110 x'-Line Reactance per length unit:
The line reactance per length unit (in this example per km) is required for the fault locator output in km (miles) and percent. In Table 2 this is given as 0.21 Ω/km primary. The setting can therefore be applied as primary value **0.2100 Ω/km**, or it can be converted to a secondary value:

$$x'_{\text{secondary}} = \frac{\text{CT ratio}}{\text{VT ratio}} \cdot x'_{\text{primary}} = \frac{\frac{1000}{1}}{\frac{380}{0.1}} \cdot 0.21$$

$$x'_{\text{secondary}} = 0.0553$$

The setting in secondary impedance is **0.0553 Ω/km**.

1111 Line Length:
The line length setting in km (miles) is required for the fault locator output. From Table 2 set **80.0 km**.

1116 Zero seq. comp. factor R_E/R_L for Z1:
The zero sequence compensation setting is applied so that the distance protection measures the distance to fault of all fault types based on the set positive sequence reach. The setting is applied as R_E/R_L and X_E/X_L setting; here R_E/R_L for Zone 1 with the data for Line 1 from Table 2.

$$\frac{R_E}{R_L} = \frac{1}{3}\cdot\left(\frac{R_0}{R_1} - 1\right) = \frac{1}{3}\cdot\left(\frac{0.13}{0.025} - 1\right) = \underline{\underline{1.4}}$$

Apply setting R_E/R_L for Z1 equal to **1.40**.

1117 Zero seq. comp. factor X_E/X_L for Z1:
The same consideration as for parameter 1116 above applies:

$$\frac{X_E}{X_L} = \frac{1}{3}\cdot\left(\frac{X_0}{X_1}-1\right) = \frac{1}{3}\cdot\left(\frac{0.81}{0.21}-1\right) = 0.95$$

Apply setting X_E/X_L for Z1 equal to **0.95**.

1118 Zero seq. comp. factor R_E/R_L for Z1B.Z5:
As the overreaching zones cover the protected line as well as adjacent circuits, the zero sequence compensating factor must take the impedance parameters of the protected line as well as the adjacent lines into account. The Zone 2 reach has to be co-ordinated with the protection on the shortest adjacent feeder (Line 3) so that the Zone 2 reach will be used to determine this setting. The other zone reaches are largely influenced by other system conditions such as parallel and intermediate infeeds:

If the Zone 2 reach is set to 80 % of the total impedance up to the Zone 1 reach on Line 3 (shortest adjacent line) then the total positive sequence impedance at the Zone 2 reach limit is:

$$X2_1 = 0.8\cdot(X_{Line1} + 0.8\cdot X_{Line3})$$
$$X2_1 = 0.8\cdot(80\cdot 0.21 + 0.8\cdot 17.5) = \underline{\underline{24.64}}$$

$$R2_1 = R_{Line1} + \frac{(X2 - X_{Line1})}{X_{Line3}}\cdot R_{Line3}$$

$$R2_1 = 80\cdot 0.025 + \frac{24.64 - 80\cdot 0.21}{17.5}\cdot 1.5 = 2.672$$

The corresponding zero sequence impedance is calculated as follows:

$$X2_0 = X0_{Line1} + \frac{(X2 - X_{Line1})}{X_{Line3}}\cdot X0_{Line3}$$

$$X2_0 = 80\cdot 0.81 + \frac{24.64 - 80\cdot 0.21}{17.5}\cdot 86.5$$

$$X2_0 = 103.4$$

$$R2_0 = R0_{Line1} + \frac{(X2 - X_{Line1})}{X_{Line3}}\cdot R0_{Line3}$$

$$R2_0 = 80\cdot 0.13 + \frac{24.64 - 80\cdot 0.21}{17.5}\cdot 7.5$$

$$R2_0 = 13.76$$

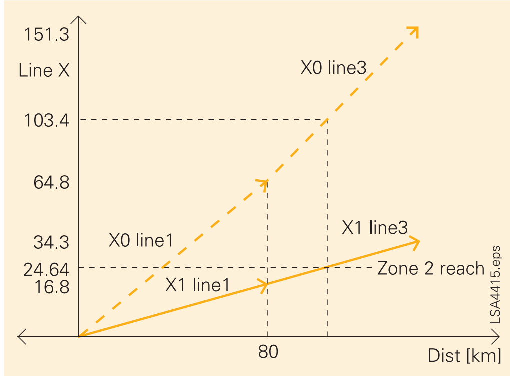


Fig. 13 Positive and zero sequence line impedance profile

This is graphically shown for the X values in Figure 13. A similar drawing can also be made for the R values. Always use the Zone 2 setting in the X direction as a reference. Now apply the derived values, $X2_1$, $R2_1$, $X2_0$ and $R2_0$ to the following equation:

$$\frac{R_E}{R_L} = \frac{1}{3}\cdot\left(\frac{R_0}{R_1}-1\right) = \frac{1}{3}\cdot\left(\frac{13.76}{2.672}-1\right) = 1.38$$

Apply setting R_E/R_L for Z1B...Z5 equal to **1.38**.

1119 Zero seq. comp. factor X_E/X_L for Z1B.Z5:
This is the X_E/X_L setting corresponding to the R_E/R_L setting 1118 above. Therefore apply the derived values, $X2_1$, $R2_1$, $X2_0$ and $R2_0$ to the following equation:

$$\frac{X_E}{X_L} = \frac{1}{3}\cdot\left(\frac{X_0}{X_1}-1\right) = \frac{1}{3}\cdot\left(\frac{103.4}{24.64}-1\right) = 1.07$$

Apply setting X_E/X_L for Z1B...Z5 equal to **1.07**.

9.2 Line status

1130A Pole Open Current Threshold:

For a number of functions in the relay the switching state of the circuit-breaker is an important logical information input. This can be derived via auxiliary contacts or by measuring the current flow in the circuit. With this parameter the current threshold is set to determine the pole open condition of the circuit-breaker. If the phase current measured by the relay is below this threshold this condition for pole open detection is true.

This setting should be as sensitive as possible (setting equal to or lower than the smallest current pick-up threshold of a protection function). Stray induced currents during a true open pole condition may however not cause incorrect pick-up.

In this example no special conditions have to be considered, so the default setting of **0.10 A** is maintained.

1131A Pole Open Voltage Threshold:

As was described for the pole open current above (1130A), the pole open voltage setting determines the threshold below which the voltage condition for pole open is true.

As single-pole tripping will be applied here and the voltage transformers are located on the line side of the circuit-breaker, the setting should be large enough to ensure that the voltage induced on the open phase is below this setting. Apply a setting that is at least 20 % below the minimum operating phase to earth voltage.

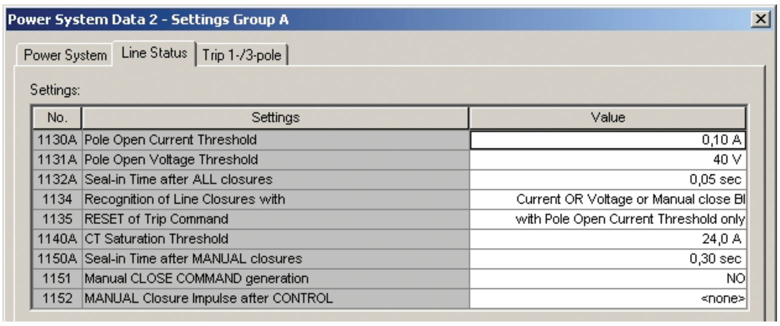
In this example the minimum operating voltage is 85 % of nominal voltage:

Setting
$< 0.8 \cdot 0.85 \cdot 400\ \text{kV}/380\ \text{kV} \cdot 100/\sqrt{3} < 41$

Therefore apply a setting of **40 V**.

1132A Seal-in Time after ALL closures:

When the feeder is energised the switch on to fault (SOTF) protection functions are activated. The line closure detection conditions are set with parameter 1135 below. This seal-in time setting applies to all line closure detections other than the manual close binary input condition. This direct detection of circuit-breaker closing responds almost at the same instant as the primary circuit-breaker contact closing. A fairly short seal in time can therefore be set here to allow for pick-up of the desired protection functions.


Power System Data 2 - Settings Group A

Power System | Line Status | Trip 1-/3-pole

Settings:

No.	Settings	Value
1130A	Pole Open Current Threshold	0,10 A
1131A	Pole Open Voltage Threshold	40 V
1132A	Seal-in Time after ALL closures	0,05 sec
1134	Recognition of Line Closures with	Current OR Voltage or Manual close BI
1135	RESET of Trip Command	with Pole Open Current Threshold only
1140A	CT Saturation Threshold	24,0 A
1150A	Seal-in Time after MANUAL closures	0,30 sec
1151	Manual CLOSE COMMAND generation	NO
1152	MANUAL Closure Impulse after CONTROL	<none>

Fig. 14 Line status settings in Power System Data 2

In this application only the distance protection will be used for switch on to fault so that a setting of **0.05 s** is sufficient.

1134 Recognition of Line Closure with:

As stated above (1132A) the recognition of line closure is important for the switch on to fault protection functions. If the manual close binary input is assigned in the matrix, it will be one of the line closure detection criteria. If other circuit-breaker closing conditions such as auto-reclose or remote closing are applied then it is advisable to apply additional criteria for line closure detection. In the table below the prerequisites for application of the individual conditions are marked with X.

1134 Recognition of Line Closure with:	Manual Close BI allocated in Matrix	CB aux allocated in Matrix	VT on line side of CB
Manual Close BI	X		
Voltage			X
Current flow	Always valid	Always valid	Always valid
CB aux		X	

Table 4 Prerequisites for application of individual conditions in Parameter 1134

In this example, the manual close binary input and CB aux contacts are not allocated in the Matrix, so the conditions Voltage and Current flow must be used for line closure detection. As the voltage transformers are on the line side, the setting **Current or Voltage or Manual Close BI** is applied. Note that the inclusion of Manual Close is of no consequence because the binary input is not allocated in the Matrix.

1135 RESET of Trip Command:
The trip command duration must always be long enough to allow the circuit-breaker auxiliary contacts to interrupt the current flowing through the trip coil. The most reliable method for sealing in the trip command is the detection of current flow in the primary circuit through the CB. The auxiliary contact status may be used as an additional condition. This is helpful when trip commands are issued in the absence of primary current flow, e.g. during testing or by protection functions that do not respond to current flow such as voltage or frequency protection. In this example, the auxiliary contacts are not allocated in the Matrix so that the trip command is reset **with Pole Open Current Threshold only**.

1140A CT Saturation Threshold:
CT saturation is normally detected by monitoring of harmonic content in the measured current. This is not possible for protection response below 1 cycle as at least one cycle of recorded fault current is required to determine the harmonic content. Below one cycle the CT saturation condition is therefore set when the current exceeds this threshold. The following calculation gives an approximation of this current threshold:

$$\text{CT Sutaration Threshold} = \frac{n'}{5} \cdot I_N$$

with

$$n' = n \cdot \frac{P_N + P_i}{P' + P_i} = \text{actual overcurrent factor}$$

P' = the actual burden connected to the secondary CT relay burden + CT secondary connection cable burden

In this example only the 7SA relay is connected to the CT, so that the relay burden is 0.05 VA per phase. Due to the Holmgreen connection, the maximum burden for earth currents is therefore twice 0.05 VA =0.1 VA.

The CT secondary cable connection burden is calculated as follows:

$$R_{cable} = \frac{2 \cdot l_{cable} \cdot \rho_{CU}}{a_{cable}}$$

l_{cable} = 50 m
ρ_{CU} = 0.0179 $\Omega mm^2/m$
a_{cable} = 2.5 mm^2

therefore:

$$R_{cable} = \frac{2 \cdot 50 \cdot 0.0179}{2.5}$$

$$R_{cable} = 0.72\ \Omega$$

at 1 A nominal secondary current, this relates to:

$P' = R_{cable} \cdot I_{N\,CT}^2 + P_{relay}$
$P' = 0.72 \cdot 1^2 + 0.1$
$P' = 0.82$ VA

From Table 2, the CT data is 5P20 20 VA, therefore:

$$n' = 20 \cdot \frac{20 + 3}{0.82 + 3} = 120$$

with this value, the setting can then be calculated:

$$\text{CT Sutaration Threshold} = \frac{120}{5} \cdot 1\ \text{A} = 24\ \text{A}$$

The applied setting in this case is therefore **24.0 A.**

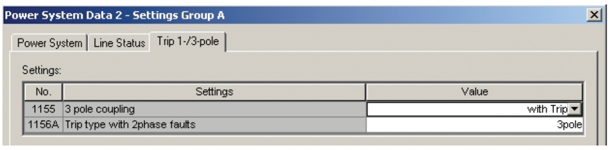
1150A Seal-in Time after MANUAL closures:
This setting is only applicable when the manual close binary input is allocated in the Matrix (refer to setting 1134 above). The time applied here should allow for the circuit-breaker response and any additional delays such as sync. check release which can occur between the initiation of the binary input and closure of the CB primary contacts. In this example, the manual close binary input is not allocated so this setting is of no consequence and therefore left on the default value of **0.30 s**.

1151 Manual CLOSE COMMAND generation:
If the manual close binary input is allocated, it may be used to generate a close command to the circuit-breaker in the relay. Alternatively the input may be used only to inform the relay that a manual close has been issued externally to the circuit-breaker. If the relay has to generate a close command following the initiation, this can be done with or without sync. check if the internal sync. check function is available. In this example the manual close binary input is not allocated so this setting should be set to **NO**.

1152 MANUAL Closure Impulse after CONTROL:
If the internal control functions are used, either via front keypad or system interface, the issued control-CLOSE command to the circuit-breaker can be used to activate the protection functions in the same manner as the manual-close binary input would. The setting options provided consist of all the configured controls in the device. In this example, the internal control functions are not used, so this setting is left on the default value: <**none**>

9.3 Trip 1/3-pole

As 1 and 3-pole tripping is applied in this example, the following settings must be applied:



Power System Data 2 - Settings Group A

Power System | Line Status | Trip 1-/3-pole

Settings:

No.	Settings	Value
1155	3 pole coupling	with Trip
1156A	Trip type with 2phase faults	3pole

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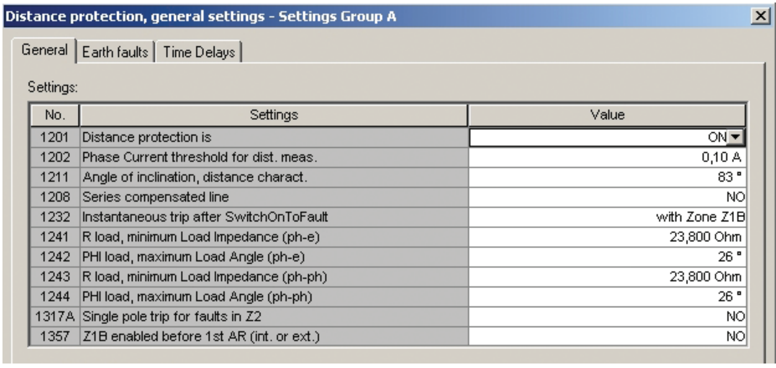
Fig. 15 Trip 1/3-pole settings in Power System Data 2

1155 3 pole coupling:
When single-pole tripping is applied the relay must select the faulted phase and trip single pole selectively. In the event of 2 simultaneous faults, e.g. inter-circuit fault on double circuit line, the relay detects two faulted phases, but only one of the two is inside a tripping zone. To ensure single-pole tripping under these conditions, set 3-pole coupling to **with Trip**.

1156A Trip type with 2phase faults:
Phase to phase faults without ground, can be cleared by single-pole tripping. On circuits where such faults occur frequently, e.g. conductor clashing due to conductor galloping with ice and wind conditions, single-pole tripping for 2-phase faults can improve availability of the circuit. The setting at both line ends must be the same. If single-pole tripping is selected, either the leading or lagging phase will then be tripped at both line ends. In this example 2-phase faults will be tripped **3-pole**.

■ 10. Distance protection, general settings – Setting Group A

10.1 General



Distance protection, general settings - Settings Group A

General | Earth faults | Time Delays

Settings:

No.	Settings	Value
1201	Distance protection is	ON
1202	Phase Current threshold for dist. meas.	0,10 A
1211	Angle of inclination, distance charact.	83 °
1208	Series compensated line	NO
1232	Instantaneous trip after SwitchOnToFault	with Zone Z1B
1241	R load, minimum Load Impedance (ph-e)	23,800 Ohm
1242	PHI load, maximum Load Angle (ph-e)	26 °
1243	R load, minimum Load Impedance (ph-ph)	23,800 Ohm
1244	PHI load, maximum Load Angle (ph-ph)	26 °
1317A	Single pole trip for faults in Z2	NO
1357	Z1B enabled before 1st AR (int. or ext.)	NO

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Fig. 16 General settings for distance protection

1201 Distance protection is:
If the distance protection must be switched off in this setting group, it can be done so with this setting.
In this example, only one setting group is used and the distance protection function is required so this setting is left on the default value which is **ON**.

1202 Phase Current threshold for dist. meas.:
Although the distance protection responds to the impedance of the faulted loop, a lower limit must apply for the current flow before the distance protection responds. If the system conditions can not ensure that this minimum current flows during all internal short-circuit faults, special weak infeed measures may be required (see chapter 14). It is common practice to apply a very sensitive setting here so that the back-up functionality of the distance protection for remote faults on other circuits is effective. The default setting of 10 % is therefore commonly applied.
In this application, no special conditions exist, so the default setting of **0.10 A** is applied.

1211 Angle of inclination, distance charact.:
This setting was already discussed and applied in chapter 9.1 "Power system", where its association with the line angle was described. It is set to **83°**.

1208 Series compensated line:
On feeders in the vicinity of series capacitors, special measures are required for direction measurement.
This application is without series capacitors on the protected or adjacent feeders, so the setting applied is **NO**.

1232 Instantaneous trip after SwitchOnToFault: When the protected circuit is switched off, a permanent fault (e.g. working earth or broken conductor on ground) may be present. After switching on the circuit, such faults must be cleared as fast as possible. It is common practice to activate non-selective stages with fast tripping for switch on to fault conditions. In the distance protection a number of alternatives exists:

Setting	Distance protection during SOTF
Inactive	No special measures
With pickup (non-directional)	All distance zones are released for instantaneous tripping
With Zone Z1B	The Zone Z1B is released for instantaneous tripping and will operate with its set direction if a polarising voltage is available
Zone Z1B undirectional	The Zone Z1B is released for instantaneous tripping and will operate as a non-directional zone. (MHO characteristic as forward and reverse zone)

Table 5 Setting alternatives for SOTF with distance protection

It is recommended to use the distance protection for SOTF conditions. In many cases the setting "with pickup (non-directional)" would result in a reach that operates due to heavy load inrush, e.g. when large machines and transformers are connected to the feeder so that the energising current is more than twice the full load current. In these cases the Zone Z1B can be applied as its reach is typically only between approx. 120 % and 200 % of the protected feeder. Of special interest is the application of Zone Z1B undirectional. If the local busbar can be energised from the remote end via the protected feeder, then SOTF conditions for busbar faults can be provided by application of this setting. Note that the line closure detection should not be with the voltage condition in this case, as the live line voltage prior to energising the busbar would prevent the SOTF release.
In this example, the local bus will not be energised via the feeder so the setting with **Zone Z1B** is applied.

1241 R load, minimum Load Impedance (ph-e): The settings 1241 to 1244 determine the "load encroachment area" for the distance relay setting characteristic. The distance zone settings must exclude the load area in the impedance plane so that operation is only possible under fault conditions. For this purpose, the smallest load impedance and the largest load impedance angle must be determined (refer to Fig. 17).

The load encroachment area is set for phase to earth loops (parameter 1241 and 1242) and for phase to phase loops (parameter 1243 and 1244) separately. Normally load conditions will not cause earth fault detection as no zero sequence current is present in the load. In the event of single-pole tripping of adjacent circuits, an earth-fault detection and increased load current flow may be present at the same time. For such contingencies, the load encroachment must also be set for earth-fault characteristics.

$$R_{\text{load min}} = \frac{U_{\text{operation min}}}{\sqrt{3} \cdot I_{\text{load max}}}$$

From Table 1, the minimum operating voltage is 85 % of nominal system voltage, and the maximum load current is 250 % of the full load apparent power.

$$U_{\text{operation min}} = 0.85 \cdot 400 \text{ kV} = 340 \text{ kV}$$

$$I_{\text{load max}} = 2.5 \cdot \frac{600 \text{ MVA}}{\sqrt{3} \cdot 400 \text{ kV}} = 2170 \text{ A}$$

By substituting these values in the above equation:

$$R_{\text{load min}} = \frac{340 \text{ kV}}{\sqrt{3} \cdot 2170} = 90.5\ \Omega$$

To convert this to a secondary value, multiply it with the factor 0.2632 (Table 2) to obtain the setting **23.8 Ω**. As worst case conditions are assumed, a safety factor is not required. If the parameters for calculation are less conservative, a safety factor, e.g. 10 to 20 % may be included in the calculation.

1242 PHI load, maximum Load Angle (ph-e): To determine the largest angle that the load impedance may assume, the largest angle between operating voltage and load current must be determined. As load current ideally is in phase with the voltage, the difference is indicated with the power factor cos φ. The largest angle of the load impedance is therefore given by the worst, smallest power factor. From Table 2 the worst power factor under full load conditions is 0.9:

$$\varphi_{\text{load}-\text{max}} = \arccos(\text{power factor}_{\text{min}})$$

$$\varphi_{\text{load}-\text{max}} = \arccos(0.9) = 26°$$

The power factor under full load conditions should be used for this calculation, as under lightly loaded conditions the VAR flow may dominate, but under these conditions the load impedance is not close to the set impedance reach. In this case the setting for PHI load, maximum Load Angle (ph-e) is **26°**.

1243 R load, minimum Load Impedance (ph-ph):
No distinction is made in this example between the maximum load during phase to earth pickup (adjacent circuit single-pole open) and phase to phase pickup, e.g. when parallel circuit is three-pole tripped. Therefore the same setting as for 1241 is applied here, being **23.8 Ω**.

1244 PHI load, maximum Load Angle (ph-ph):
Again the same setting as for the phase to earth loop is applied here, being **26°**.

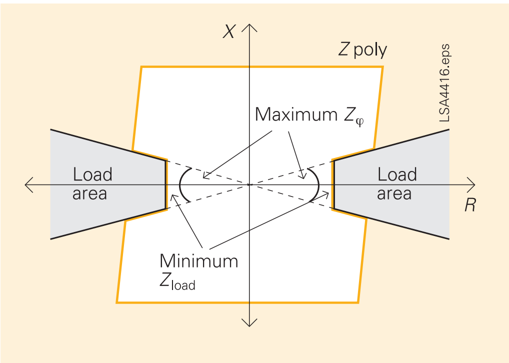
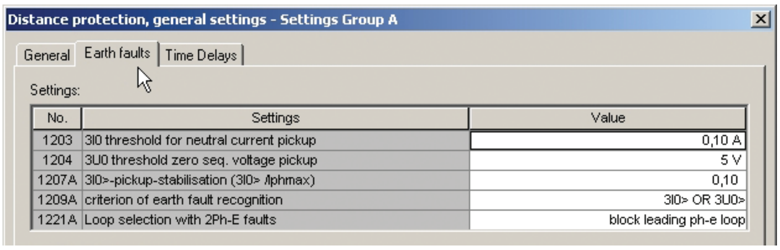


Fig. 17 Load encroachment characteristic

1317A Single pole trip for faults in Z2:
For special applications, single-pole tripping by Zone 2 can be applied. However, time delayed protection stages are usually applied with 3-pole tripping.
In this example, 3-pole tripping in Zone 2 is desired so the default setting of **NO** is left unchanged.

1357 Z1B enabled before 1st AR (int. or ext.):
In this example a teleprotection scheme (POTT) is applied. The controlled Zone Z1B operation is therefore subject to the signals from the teleprotection scheme.
In an application where no teleprotection scheme is applied or in the case of a reception failure of the teleprotection scheme, the Zone Z1B can also be controlled by the auto-reclose function.
This achieves fast tripping for all faults on the feeder although some non-selective trips can also occur. This is tolerated in such a scheme because following all fast trips there is an automatic reclosure. In this example, the Z1B will only be controlled by the teleprotection, the setting **NO** is therefore applied.

10.2 Earth faults


Distance protection, general settings - Settings Group A

General | Earth faults | Time Delays

Settings:

No.	Settings	Value
1203	3I0 threshold for neutral current pickup	0,10 A
1204	3U0 threshold zero seq. voltage pickup	5 V
1207A	3I0>-pickup-stabilisation (3I0> /Iphmax)	0,10
1209A	criterion of earth fault recognition	3I0> OR 3U0>
1221A	Loop selection with 2Ph-E faults	block leading ph-e loop

Fig. 18 Earth-fault settings for distance protection

1203 $3I_0$ threshold for neutral current pickup:
The distance protection must identify the faulted loop to ensure correct response. If an earth-fault is present, this is detected by the earth-fault detection. Only in this case will the three earth loop measurements be released subject to further phase selection criteria. The earth current pickup is the most important parameter for the earth-fault detection. Its threshold must be set below the smallest earth current expected for faults on the protected feeder. As the distance protection is also set to operate as backup protection for remote external faults, this setting is set far more sensitive than required for internal faults. In chapter 3 the minimum single-phase fault current for internal faults neglecting fault resistance was calculated to be 1380 A.
To allow for fault resistance and reach into adjacent feeders for back-up, the setting applied here should be substantially lower than this calculated value. In this example, the default value of **0.10 A** secondary (100 A primary) is maintained.

1204 $3U_0$ threshold zero seq. voltage pickup:
A further criteria for earth-fault detection is the zero sequence voltage. In an earthed system, zero sequence voltage is always present during earth faults and it decreases as the distance between the measuring point and the fault location increases. This threshold setting is therefore also used for earth-fault detection as shown in the logic diagram, Fig. 19. When the zero sequence source impedance is large, the zero sequence current component in the fault current may become small. In such an event, the zero sequence voltage will however be relatively large due to the small zero sequence current flowing through the large zero sequence source impedance.
For secure earth-fault detection the default setting of **5 V** is maintained. If system unbalance during unfaulted conditions causes larger zero sequence voltages then this setting should be increased to avoid earth-fault detection under these circumstances.

1209A Criterion for earth fault recognition:
For the settings 1203 and 1204 above, and in Fig. 19, the method and logic of the earth-fault detection were explained. With this setting the user has the means to influence the earth-fault detection logic. In earthed systems it is recommended to use the very reliable OR combination of zero sequence current and voltage for the earth-fault detection. As mentioned before, these two criteria supplement each other so that small zero sequence current is often associated with large zero sequence voltage at weak infeeds and the other way around at strong infeeds. The AND setting is only for exceptional conditions when, for example, the zero sequence voltage or current on their own are not a reliable indicator for earth faults.
In this example, the default setting **OR** is maintained for the reasons stated above.

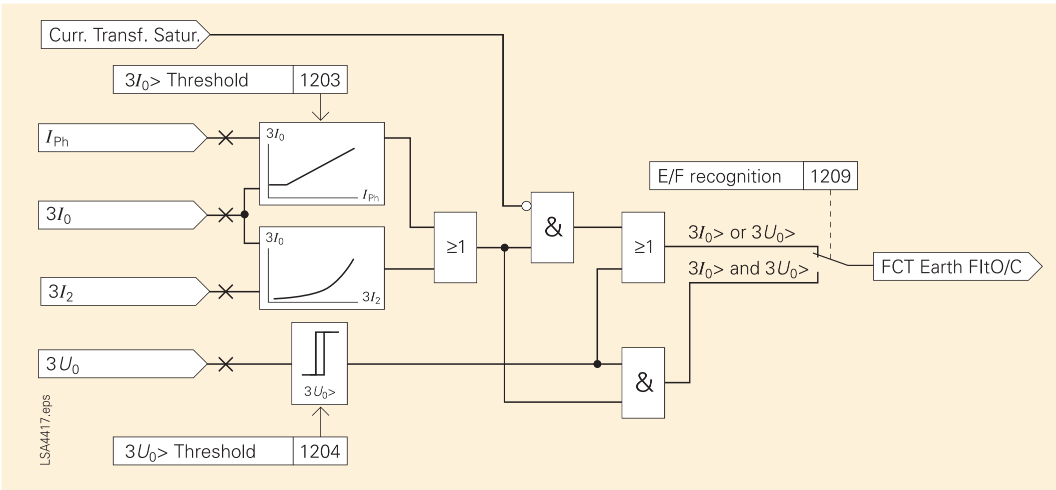


Fig. 19 Earth-fault detection logic

1207A $3I_0$> pickup stabilisation ($3I_0>/I_{\text{ph max}}$):
In the event of large phase currents, the system unbalance (e.g. non-transposed lines) and CT errors (e.g. saturation) can cause zero sequence current to flow via the measuring circuit of the relay although no earth fault is present. To avoid earth-fault detection under these conditions, the zero sequence current pickup is stabilised by this set factor.
Unless extreme system unbalance or exceptionally large CT errors are expected, the default setting of 10 % i.e. **0.10** can be maintained, as is done for this example.

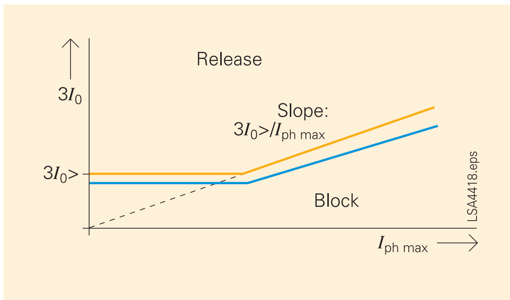


Fig. 20 Stabilised zero sequence pickup threshold

1221A Loop selection with 2Ph-E faults:
If some fault resistance (arc voltage) is present, then the measured fault loop impedances are affected by this additional voltage drop in the short-circuit loop. In the case of 2Ph-E faults this is most severe as the current in the fault resistance stems from 3 different short-circuit loops. Theoretical analysis and simulations show the following distribution of the measured loop impedances for a 2Ph-E fault:
The influence of load (remote infeed and load angle) can increase or decrease the rotation of the measured fault resistances. The leading phase to earth loop will however always tend to produce an overreach. For this reason, the default setting of **block leading Ph-E loop** will be used in this example. If the application is on a double circuit line where simultaneous earth faults on both lines can occur, the setting only phase-earth loops or all loops should be used to avoid blocking of the internal fault loop by this setting. Of course additional grading margin must be applied for Zone 1 in this case to avoid an overreach during an external 2Ph-E fault.

10.3 Time delays

1210 Condition for zone timer start:
During internal faults, all time delayed zones pickup unless there is substantial fault resistance and very strong remote infeed.
Although the fault in Fig. 23 is an internal fault it is measured only by Zone Z4 due to the fault resistance and strong remote infeed. If all zone timers are started by the distance pickup, the fault will be cleared by the relay with the set Zone 2 time after fault inception because the measured impedance moves into Zone 2 as soon as the remote, strong infeed trips the breaker on the right hand side.
From the timing diagram in Fig. 24 the influence of this setting can be seen. If the zone timers are started with distance pickup, the trip signal is issued with Zone 2 time delay (250 ms) after fault inception (distance pickup) although the Zone 2 only picks up some time later when the remote end has opened the circuit-breaker on the right hand side. The timing of the trip signals is therefore as if the fault had been inside the Zone 2 all along. For external fault back-up tripping similar operation by higher zones is achieved. This mode of operation will be applied in this example, so the setting **with distance pickup** is applied.

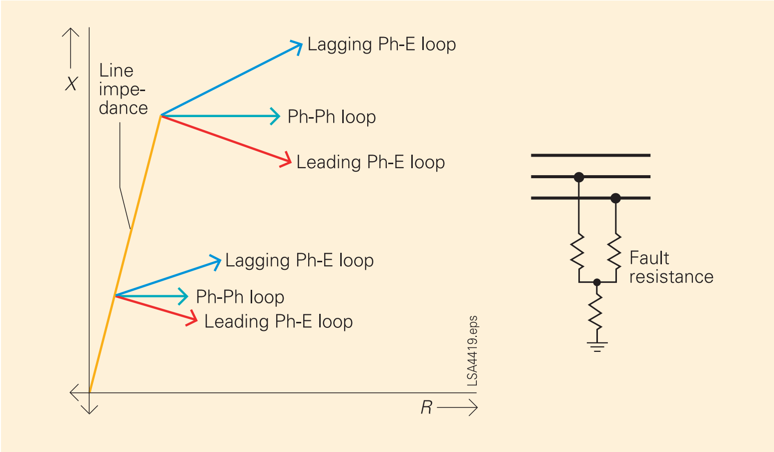


Fig. 21 Impedance distribution for 2ph-E fault with fault resistance

Distance protection, general settings - Settings Group A

General | Earth faults | Time Delays

Settings:

No.	Settings	Value
1210	Condition for zone timer start	with distance pickup
1305	T1-1phase, delay for single phase faults	0,00 sec
1306	T1multi-ph, delay for multi phase faults	0,00 sec
1315	T2-1phase, delay for single phase faults	0,25 sec
1316	T2multi-ph, delay for multi phase faults	0,25 sec
1325	T3 delay	0,50 sec
1335	T4 delay	oo sec
1345	T5 delay	0,75 sec
1355	T1B-1phase, delay for single ph. faults	0,00 sec
1356	T1B-multi-ph, delay for multi ph. faults	0,00 sec

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Fig. 22 Time delay setting for the distance zones

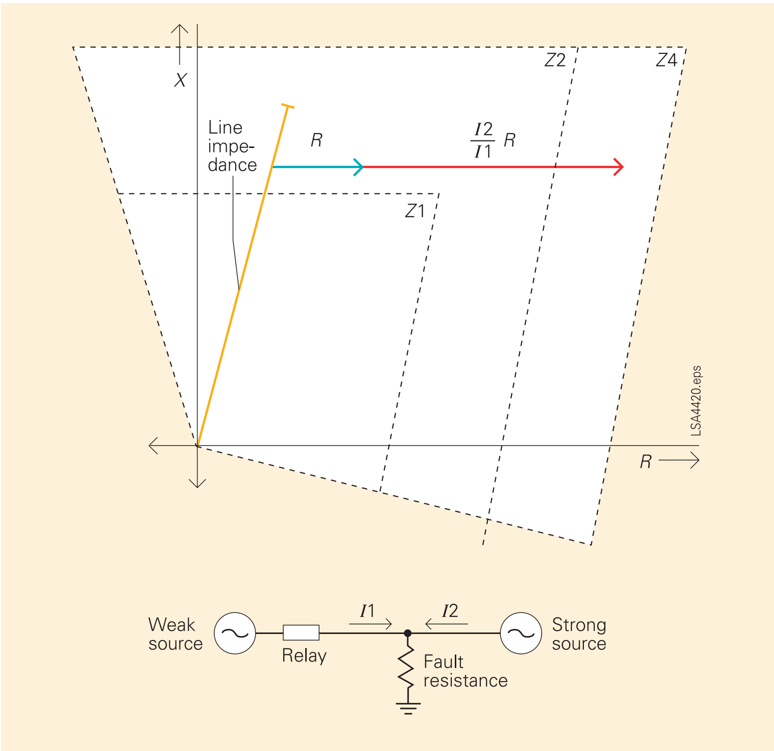


Fig. 23 Influence of fault resistance and remote infeed on measured impedance

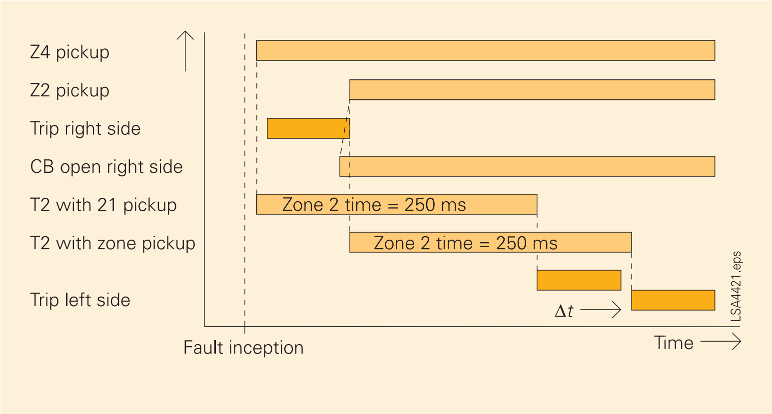


Fig. 24 Timing diagram for fault in Fig. 23

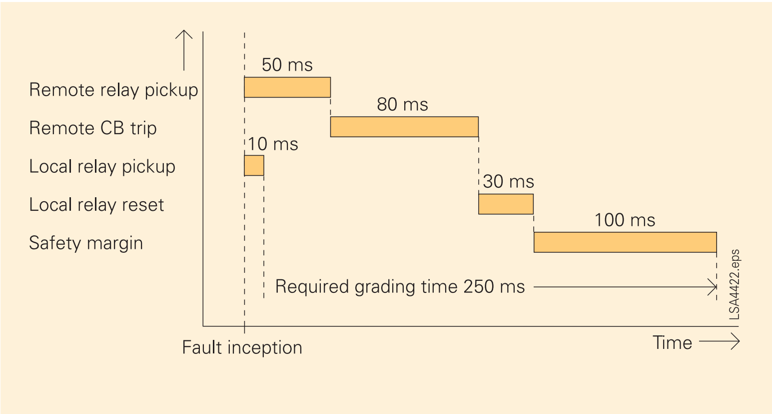


Fig. 25 Time chart to determine time step for graded protection

If co-ordination with other distance or overcurrent protection is required, the setting "with zone pickup" can be applied. For the scenario described in Fig. 23 and 24 this will however result in additional time delay (Δ*t* in Fig. 24). During external faults with backup protection operation this time delay may become very long, often a full time grading step so that reach and time grading must be applied more conservatively.

1305 T1-1phase, delay for single phase faults:
The Zone 1 is usually operated as fast tripping (instantaneous) underreach zone. For the fastest tripping all Zone 1 times are set to **0.00 s**. For special applications, the trip time of single-phase faults may be set here to differ from that for multi-phase faults which is set below with parameter 1306.

1306 T1 multi-ph, delay for multi phase faults:
Also here the zone 1 is usually operated as fast tripping (instantaneous) underreach zone. For the fastest tripping all Zone 1 times are set to **0.00 s**. Refer also to setting 1305 above.

1315 T2-1phase, delay for single phase faults:
For the Zone 2 and higher zones the co-ordination time must be calculated. This time must ensure that time graded tripping remains selective.
In Fig. 25 the parameters that need to be considered for the time grading margin are shown. The values entered apply for this example and correspond to the worst case conditions. The required time grading margin is therefore 250 ms. The Zone 2 is graded with the Zone 1 at the remote feeders so that a single time grading step is required (refer to Table 1). Set this time for single-phase faults to **0.25 s**. For special applications, the trip time of single-phase faults may be set here to differ from that for multi-phase faults which is set below with parameter 1316.

1316 T2 multi-ph, delay for multi phase faults:
As the Zone 2 will only trip three-pole in this example, and no special consideration is given to single-phase faults, this time is set the same as 1315 above to **0.25 s**.

1325 T3 delay:
From Table 1, the required time delay for this stage is two time steps = **0.50 s**.

1335 T4 delay:
From Table 1, this stage is not required so the time delay can be set to infinity, **∞ s.**

1345 T5 delay:
From Table 1, the required time delay for this stage is three time steps = **0.75 s**.

1355 T1B-1phase, delay for single ph. faults:
The zone Z1B will be used for the teleprotection in a POTT scheme. For this application no time delay is required so the setting here is **0.00 s**. For special applications, the trip time of single-phase faults may be set here to differ from that for multi-phase faults which is set below with parameter 1356.

1356 T1B-multi-ph, delay for multi ph. faults: As stated above the Zone Z1B will be used for the teleprotection in a POTT scheme. For this application no time delay is required so the setting here is **0.00 s**.

■ 11. Distance zones (quadrilateral) – Setting Group A

11.1 Zone Z1

1301 Operating mode Z1: In the case of quadrilateral distance protection zones, the user may select the operating mode for each zone as either "forward", "reverse", "non-directional" or "inactive". When the zone is "inactive", it does not produce any pickup signals or trip. The other options can be seen in the adjacent diagram where Z1, Z1B, Z2 and Z4 are set in the forward direction. Z3 is set in the reverse direction and Z5 is set non-directional. In this example, Zone 1 must be set in the **forward** direction.

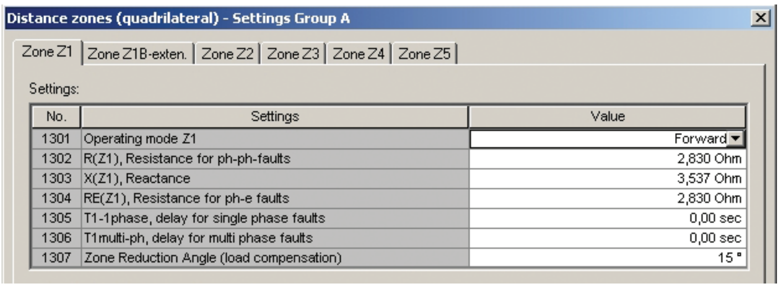
1302 R(Z1), Resistance for ph-ph faults: As the distance protection is applied with polygonal (quadrilateral) tripping characteristics, the zone limits are entered as resistance (R) and reactance (X) settings. A separate resistance reach setting is available for ph-ph measured loops and ph-e measured loops. This setting is for the ph-ph loops. With setting "1211 Angle of inclination, distance charact." the polygon R-reach is inclined such that it is parallel to the line impedance (refer to Figure 12). The resistance settings of the individual zones therefore only have to cover the fault resistance at the fault location. For the Zone 1 setting only arc faults will be considered. For this purpose the arc resistance will be calculated with the following equation:

$$R_{arc} = \frac{U_{arc}}{I_F}$$

The arc voltage (U_{arc}) will be calculated using the following rule of thumb which provides a very conservative estimate (the estimated R_{arc} is larger than the actual value):

$U_{arc} = 2500\ \text{V} \cdot l_{arc}$ whereby l_{arc} is the length of the arc.

The length of the arc is greater than the spacing between the conductors (ph-ph), because the arc is blown into a curve due to thermal and magnetic forces. For estimation purposes it is assumed that l_{arc} is twice the conductor spacing.


Distance zones (quadrilateral) - Settings Group A

Zone Z1 | Zone Z1B-exten. | Zone Z2 | Zone Z3 | Zone Z4 | Zone Z5

Settings:

No.	Settings	Value
1301	Operating mode Z1	Forward
1302	R(Z1), Resistance for ph-ph-faults	2,830 Ohm
1303	X(Z1), Reactance	3,537 Ohm
1304	RE(Z1), Resistance for ph-e faults	2,830 Ohm
1305	T1-1phase, delay for single phase faults	0,00 sec
1306	T1multi-ph, delay for multi phase faults	0,00 sec
1307	Zone Reduction Angle (load compensation)	15 °

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Fig. 26 Distance zone settings (Zone 1)

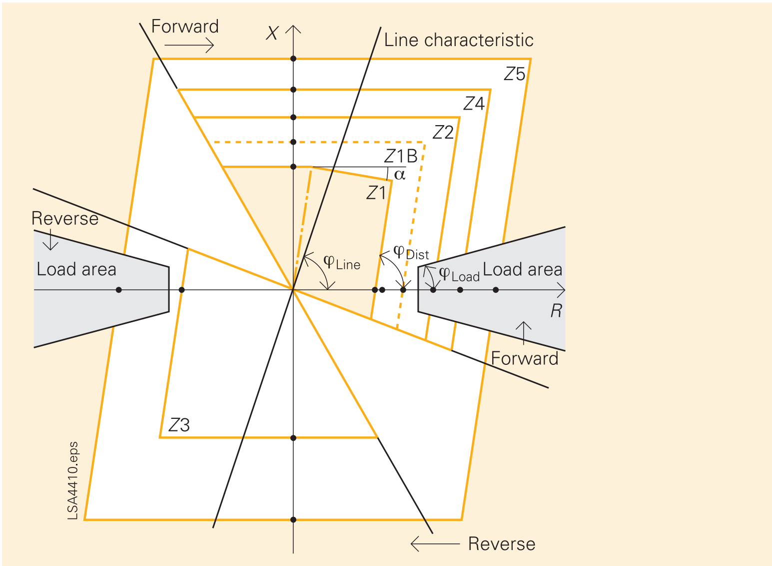


Fig. 27 Quadrilateral zone diagram

To obtain the largest value of R_{arc}, which is required for the setting, the smallest value of fault current must be used (calculated in Chapter 3):

$$R_{arc} = \frac{2500\ \text{V} \cdot 2 \cdot 5\ \text{m}}{1967\ \text{A}} = 12.7\ \Omega$$

By addition of a 20 % safety margin and conversion to secondary impedance (factor from Table 2) the following minimum setting is calculated (division by 2 because R_{arc} appears in the loop measurement while the setting is done as phase impedance or positive sequence impedance):

$$R(Z1) = \frac{1.2 \cdot 12.7 \cdot 0.2632}{2} = 2.01\ \Omega\ \text{(sec.)}$$

This calculated value corresponds to the smallest setting required to obtain the desired arc resistance coverage. Depending on the X(Z1) reach calculated (see next page), this setting may be increased to obtain the desired Zone 1 polygon symmetry.

Therefore, looking ahead at the setting result for "1303 X(Z1), Reactance" below, we see that 3.537 Ohm are applied. For overhead line protection applications, the following rule of thumb may be used for the R(Z1) setting:

$0.8 \cdot X(Z1) < R(Z1) < 2.5 \cdot X(Z1)$

In this example the lower limit applies, so the setting for R(Z1) is:

$R(Z1) = 0.8 \cdot 3.537 = 2.830\ \Omega$ (sec.)

This setting is then applied, **2.830 Ω.**

1303 X(Z1), Reactance:
The reactance reach is calculated based on the distance reach that this zone must provide. In Table 1 the reach of Zone 1 is specified as 80 % of Line 1. Therefore:

$X(Z1) = 0.8 \cdot X_{\text{Line 1}}$

$X(Z1) = 0.8 \cdot 80 \cdot 0.021 = 13.44\ \Omega$ (prim.)

This is converted to a secondary value by multiplying with the conversion factor in Table 2:

$X(Z1) = 13.44 \cdot 0.2632 = 3.537\ \Omega$ (s)

This setting is then applied, **3.537 Ω.**

1304 RE(Z1), Resistance for ph-e faults:
The phase to earth fault resistance reach is calculated along the same lines as the "1302 R(Z1)" setting for ph-ph faults. For the earth fault however, not only the arc voltage must be considered, but also the tower footing resistance. From the graph in Figure 29 it is apparent that although the individual tower footing resistance is 15 Ω (Table 2) the resultant value due to the parallel connection of multiple tower footing resistances is less than 1.5 Ω.

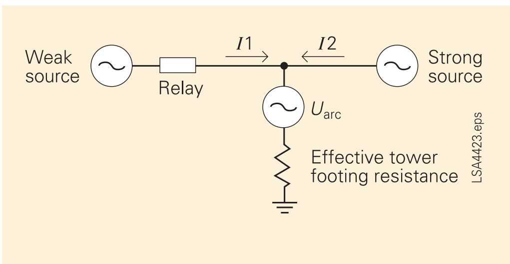


Fig. 28 Combination of arc voltage and tower footing resistance

From Fig. 28 it can be seen that the remote infeed ($I2$) will introduce an additional voltage drop across the "effective tower footing resistance" which will be measured in the fault loop by the relay (this effect is also shown in Figure 23).

To compensate for this influence, the maximum value (for practical purposes) of the ratio of $I2/I1$ is required. This is given in Table 2 as the value 3. The maximum tower footing resistance that is measured by the relay in the fault loop is therefore:

$$R_{TF} = \left(1 + \frac{I2}{I1}\right) \cdot \text{effective tower footing R}$$

$R_{TF} = (1 + 3) \cdot 1.5 = 6\ \Omega$ (prim.)

The arc voltage for the earth faults is calculated as follows using the conductor to tower/ground spacing given in Table 2:

$U_{arc} = 2500\ \text{V} \cdot l_{arc}$

$U_{arc} = 2500\ \text{V} \cdot 2 \cdot 3\ \text{m} = 15\ \text{kV}$

To obtain the largest value of R_{arc}, which is required for the setting, the smallest value of fault current must be used (calculated in Chapter 3):

$$R_{arc} = \frac{15\ \text{kV}}{1380\ \Omega} = 10.9\ \Omega$$

The total resistance that must be covered during earth faults is the sum of R_{arc} and R_{TF}. A safety factor of 20 % is included and the result is converted to secondary values (division by factor (1 + RE/RL), because R_{arc} and R_{TF} appear in the loop measurement while the setting is done as phase impedance or positive sequence impedance):

$$RE(Z1) = \frac{1.2 \cdot (10.9 + 6) \cdot 0.2632}{(1 + 1.4)} = 2.22\ \Omega(\text{sec.})$$

This calculated value corresponds to the smallest setting required to obtain the desired resistance coverage. Depending on the X(Z1) reach calculated above, this setting may be increased to obtain desired Zone 1 polygon symmetry. The setting result for "1303 X(Z1), Reactance" is 3.537 **Ω**. For overhead line protection applications, the following rule of thumb may be used for the RE(Z1) setting; note that the lower limit is the same as for ph-ph faults – this ensures fast Zone 1 tripping, while the upper limit is based on the loop reach – this avoids overreach:

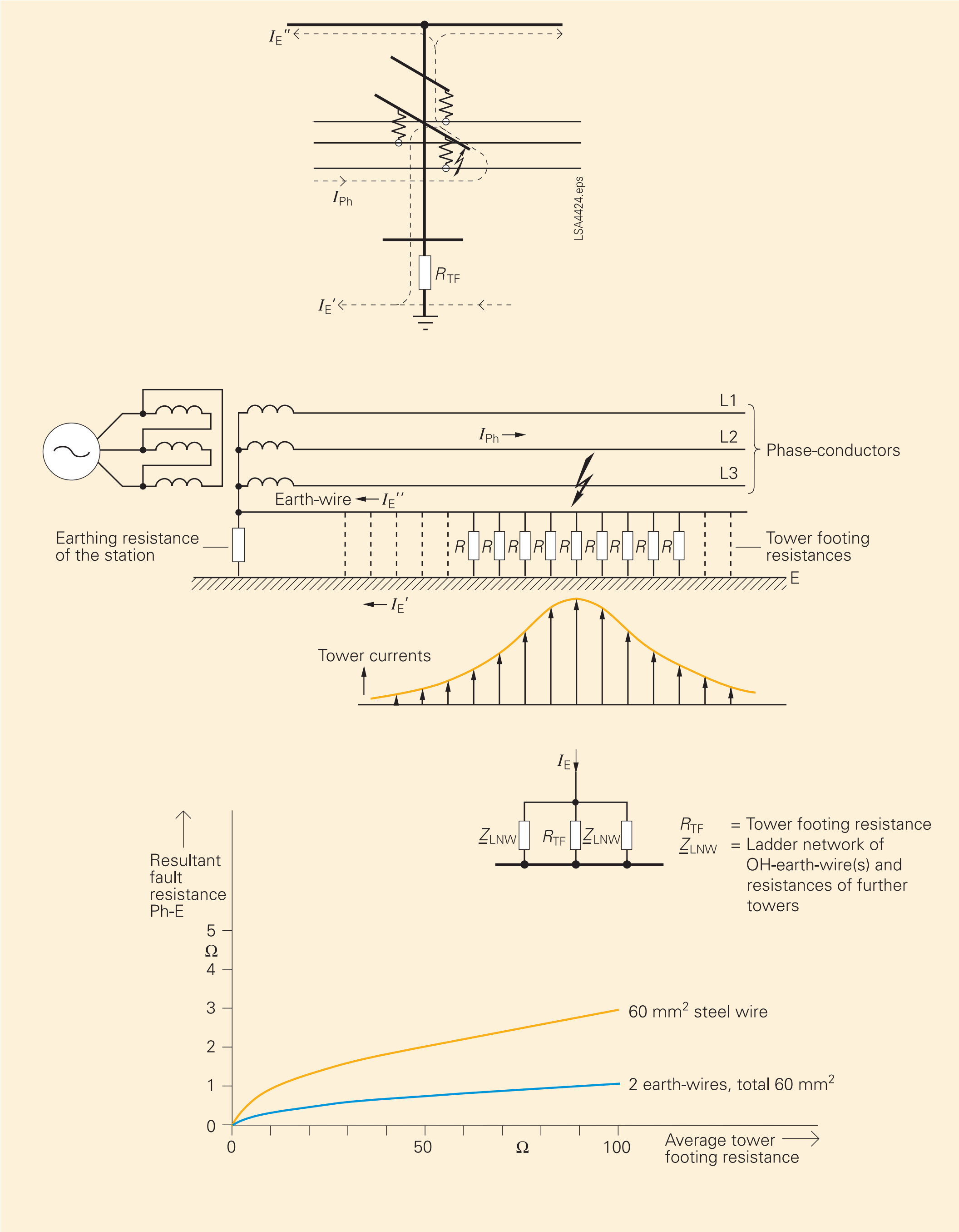


Fig. 29 Effective tower footing resistance

$$0.8 \cdot \mathrm{X(Z1)} < \mathrm{RE(Z1)} < \frac{1+\dfrac{\mathrm{XE}}{\mathrm{XL}}}{1+\dfrac{\mathrm{RE}}{\mathrm{RL}}} \cdot 2.5 \cdot \mathrm{X(Z1)}$$

In this example the lower limit applies, so the setting for RE(Z1) is:

$$\mathrm{RE(Z1)} = 0.8 \cdot 3.537 = 2.83\ \Omega\mathrm{(sec.)}$$

This setting is then applied, **2.83 Ω**.

1305 T1-1phase, delay for single phase faults: The Zone 1 is required to trip as fast as possible, therefore this time is set to **0.00 s**.

1306 T1 multi-ph, delay for multi phase faults: The Zone 1 is required to trip as fast as possible, therefore this time is set to **0.00 s**.

1307 Zone Reduction Angle (load compensation):
The Zone 1 may under no circumstances operate for external faults as this would mean a loss of selectivity. The influence of remote infeed in conjunction with fault resistance must be considered in this regard. From the voltage and current phasors in Fig. 30 the influence of the transmission angle (TA), i.e. angle between the voltages V_A and V_B, on the measured fault resistance can be seen. In the impedance plane the phasor I_2/I_1 R_F is rotated downwards by the transmission angle. The risk of the external fault encroaching into Zone 1 is shown. To prevent this, the Zone 1 X setting characteristic is tilted downwards by the "Alpha angle". A detailed calculation of the "Alpha angle" is complicated and heavily dependant on changing system conditions. A worst practical case is therefore selected to fix the "Alpha angle" setting. For this purpose the largest transmission angle that can occur in the system during normal overload conditions must be applied to the following set of curves.

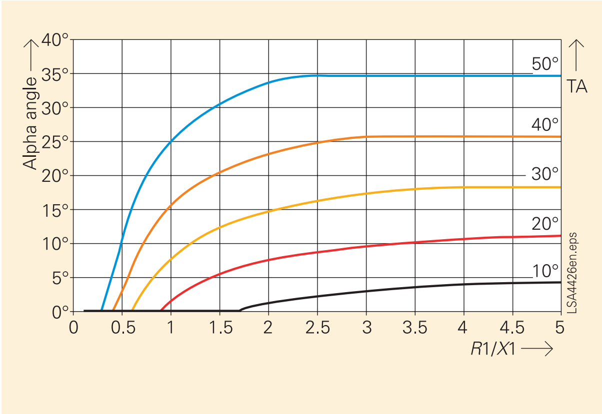


Fig. 31 Curves for selection of Alpha angle setting

From Table 2 the maximum "Transmis - sion Angle "for this application is given as 35°. If this is checked in Figure 31 together with the R1/X1 setting value of 0.8 (see above 2.830/3.537 = 0.8), then the required "Alpha Angle" setting is less than 15° (by using the TA = 40 curve). A setting of **15°** is therefore applied.

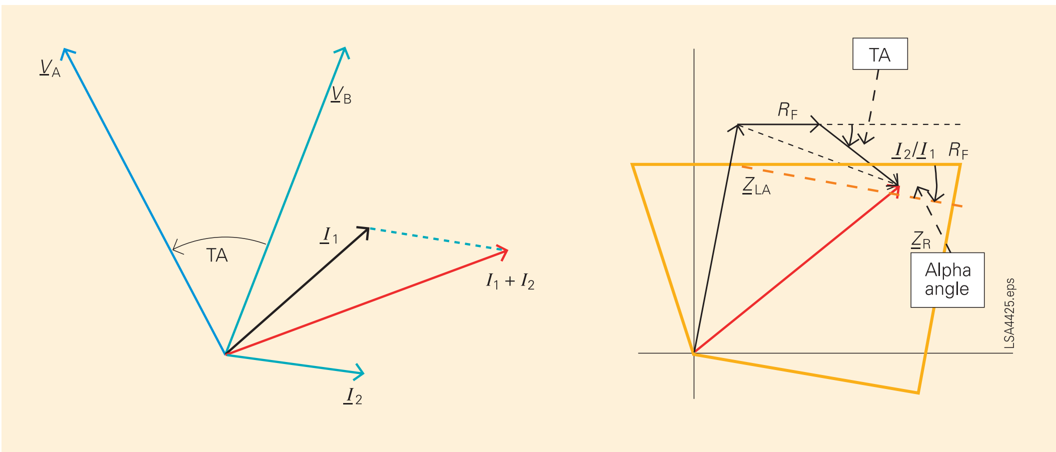


Fig. 30 Transmission angle for Alpha angle setting

11.2 Zone Z1B

1351 Operating mode Z1B (overreach zone): The Zone Z1B will be used for the teleprotection scheme POTT in this application. For this the Zone Z1B must be applied as **forward** overreach zone.

1352 R(Z1B), Resistance for ph-ph faults: As was the case for the Zone 1 settings, this setting must cover all internal arc faults. The minimum setting therefore equals the R(Z1) setting, 2.830 Ω. However, additional reach is set for the Z1B compared to Z1, because this is an overreach zone while Z1 is set to underreach. The amount of additional R reach mainly depends on the ratio of R reach to X reach setting. For the Zone Z1B the following limit is recommended:

$$X(Z1B) < R(Z1) < 4 \cdot X(Z1)$$

Looking ahead at the applied setting for "1353 X(Z1B), Reactance"which is 6.633 Ohm, it is apparent that the lower limit will apply. The setting of R(Z1B) therefore also is **6.633 Ω.**

1353 X(Z1B), Reactance: The Zone Z1B must be set to overreach Line 1. The minimum setting is 120 % of the line reactance. In practice, however, a setting of 150 % or greater is applied unless the line in question is extremely long.

The risk of underreach due to the effects shown in Figs. 21, 23 and 30 are then avoided. For this application, medium length line, a reach of 150 % is selected:

$$X(Z1B) = 1.5 \cdot X_{\text{Line 1}}$$

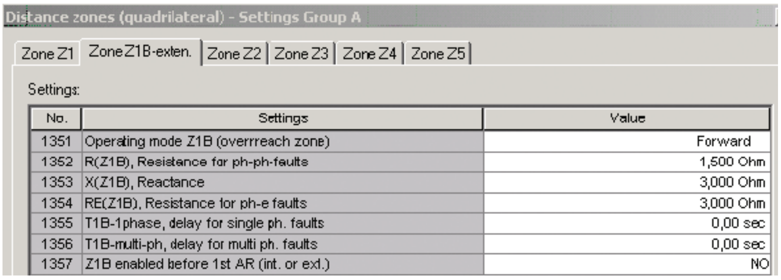
$$X(Z1B) = 1.5 \cdot 80 \cdot 0.21 = 25.2\ \Omega \text{ (prim.)}$$

The applied setting therefore is:

$$X(Z1B) = 25.2\ \Omega\text{(prim.)} \cdot 0.2632$$

$$X(Z1B) = 6.633\ \Omega\text{(sec.)}$$

6.633 Ω.


Distance zones (quadrilateral) - Settings Group A

Zone Z1 | Zone Z1B-exten. | Zone Z2 | Zone Z3 | Zone Z4 | Zone Z5

Settings:

No.	Settings	Value
1351	Operating mode Z1B (overrreach zone)	Forward
1352	R(Z1B), Resistance for ph-ph-faults	1,500 Ohm
1353	X(Z1B), Reactance	3,000 Ohm
1354	RE(Z1B), Resistance for ph-e faults	3,000 Ohm
1355	T1B-1phase, delay for single ph. faults	0,00 sec
1356	T1B-multi-ph, delay for multi ph. faults	0,00 sec
1357	Z1B enabled before 1st AR (int. or ext.)	NO

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Fig. 32 Settings for Zone Z1B

1354 RE(Z1B), Resistance for ph-e faults: As was the case for the Zone 1 settings, this setting must cover all internal arc faults. The minimum setting therefore equals the RE(Z1) setting, 2.83 Ohm. As described for setting "1352 R(Z1B)"additional reach is usually applied and the following rule of thumb is used for the RE(Z1B) setting:

$$\frac{1+\dfrac{XE}{XL}}{1+\dfrac{RE}{RL}} \cdot X(Z1B) < RE(Z1B) < \frac{1+\dfrac{XE}{XL}}{1+\dfrac{RE}{RL}} \cdot 4 \cdot X(Z1B)$$

In this example the lower limit applies, so the setting for RE(Z1B) is:

$$RE(Z1B) = \frac{(1+1.07)}{(1+1.38)} \cdot 6.633 = \underline{\underline{5.769\ \Omega\text{(sec.)}}}$$

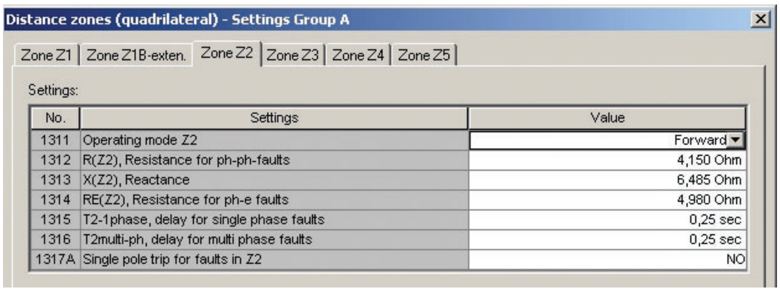
This setting is then applied, **5.769 Ω**.

1355 T1B-1phase, delay for single ph. faults: In this POTT scheme both single and multi-phase faults must be tripped without additional delay. The setting **0.00 s** is therefore applied.

1356 T1B-multi-ph, delay for multi ph. faults: In this POTT scheme both single and multi-phase faults must be tripped without additional delay. The setting **0.00 s** is therefore applied.

1357 Z1B enabled before 1st AR (int. or ext.): This setting was already applied in Chapter 10.1 and is repeated here with the other Z1B settings. The setting is **NO**.

11.3 Zone Z2


Distance zones (quadrilateral) - Settings Group A

Zone Z1 | Zone Z1B-exten. | Zone Z2 | Zone Z3 | Zone Z4 | Zone Z5

Settings:

No.	Settings	Value
1311	Operating mode Z2	Forward
1312	R(Z2), Resistance for ph-ph-faults	4,150 Ohm
1313	X(Z2), Reactance	6,485 Ohm
1314	RE(Z2), Resistance for ph-e faults	4,980 Ohm
1315	T2-1phase, delay for single phase faults	0,25 sec
1316	T2multi-ph, delay for multi phase faults	0,25 sec
1317A	Single pole trip for faults in Z2	NO

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Fig. 33 Settings for Zone Z2

1311 Operating mode Z2:
The Zone Z2 is used as the first overreaching time graded zone. It must therefore be applied in the **forward** direction.

1312 *R*(Z2), Resistance for ph-ph faults:
Resistance coverage for all arc faults up to the set reach (refer to Table 1) must be applied. As this zone is applied with overreach, an additional safety margin is included, based on a minimum setting equivalent to the X(Z2) setting and arc resistance setting for internal faults, *R*(Z1) setting. Looking ahead, X(Z2) is set to **6.485 Ω**. Therefore:

$$R(Z2)_{min} = \frac{X(Z2)}{X_{Line1}(s)} \cdot R(Z1)$$

$$R(Z2)_{min} = \frac{6.485}{80 \cdot 0.21 \cdot 0.2632} \cdot 2.83 = \underline{\underline{4.15\ \Omega(\text{sec.})}}$$

The setting of R(Z2) therefore is **4.150 Ω**.

1313 X(Z2), Reactance:
According to the grading requirement in Table 1:

$$X(Z\,2) = 0.8 \cdot (X_{Line1} + 0.8 \cdot X_{Line3}) \cdot \frac{\text{CTratio}}{\text{VTratio}}$$

$$X(Z\,2) = 0.8(80 \cdot 0.21 + 0.8 \cdot 17.5) \cdot 0.2632$$

$$X(Z\,2) = \underline{\underline{6.485\ \Omega(\text{sec.})}}$$

The applied setting therefore is **6.485 Ω**.

1314 *RE*(Z2), Resistance for ph-e faults:
Similar to the *R*(Z2) setting, the minimum required reach for this setting is based on the *RE*(Z1) setting which covers all internal fault resistance and the X(Z2) setting which determines the amount of overreach. Alternatively, the *RE*(Z2) reach can be calculated from the *R*(Z2) reach with the following equation:

$$RE(Z\,2) = \frac{X(Z\,2)}{X_{Line\,1}(\text{sec.})} \cdot RE(Z1) \cdot 1.2$$

$$RE(Z2) = \frac{6.485}{80 \cdot 0.21 \cdot 0.2632} \cdot 2.83 \cdot 1.2 = \underline{\underline{4.98\ \Omega(\text{sec.})}}$$

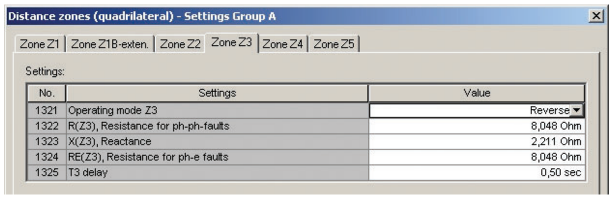
This setting is then applied, **4.98 Ω**.

1315 T2-1phase, delay for single phase faults:
This setting was already applied in Chapter 10.3 and is shown here again with all the Zone 2 settings. The setting **0.25 s** is applied.

1356 T2-multi-ph, delay for multi phase faults:
This setting was already applied in Chapter 10.3 and is shown here again with all the Zone 2 settings. The setting **0.25 s** is applied.

1317A Single pole trip for faults in Z2:
This setting was already applied in Chapter 10.1 and is shown here again with all the Zone 2 settings. The setting **NO** is applied.

11.4 Zone Z3


Distance zones (quadrilateral) - Settings Group A

Zone Z1 | Zone Z1B-exten. | Zone Z2 | Zone Z3 | Zone Z4 | Zone Z5

Settings:

No.	Settings	Value
1321	Operating mode Z3	Reverse
1322	R(Z3), Resistance for ph-ph-faults	8,048 Ohm
1323	X(Z3), Reactance	2,211 Ohm
1324	RE(Z3), Resistance for ph-e faults	8,048 Ohm
1325	T3 delay	0,50 sec

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Fig. 34 Settings for Zone Z3

1321 Operating mode Z3:
Zone Z3 is used as reverse time delayed back-up stage (refer to Table 1). It must therefore be set in the **reverse** direction.

1322 *R*(Z3), Resistance for ph-ph faults:
Resistance coverage settings for backup protection with distance protection zones is defined by a lower limit and upper limit. The lower limit is the minimum fault resistance (arc resistance) that must be covered, and the upper limit is based on the corresponding X reach setting. Note that for high resistance faults (not arc faults), the other infeeds to the reverse fault cause severe underreach.
As no detailed values are available, it is safe to assume that the required arc resistance coverage is the same as that calculated for faults on Line 1. Therefore the setting for *R*(Z1), 2.830 **Ω**, defines the lower limit. The upper limit is given by reach symmetry constraints and states that *R*(Z3)<6 times X(Z3). Looking ahead, X(Z3) is set to 2.211 **Ω**, so the upper limit is 13.266 **Ω**.
A setting halfway between these limits is a safe compromise:

$$R(Z3) = \frac{R(Z1) + 6 \cdot X(Z3)}{2}$$

$$R(Z3) = \frac{2.83 + 6 \cdot 2.211}{2} = \underline{\underline{8.048\ \Omega(\text{sec.})}}$$

The applied setting therefore is **8.048 Ω.**

1323 X(Z3), Reactance:
According to the grading requirement in Table 1:

$$X(Z3) = 0.5 \cdot X_{Line1} \cdot \frac{\text{CTratio}}{\text{VTratio}}$$

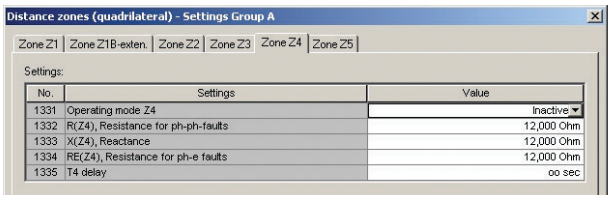
$$X(Z3) = 0.5 \cdot 80 \cdot 0.211 \cdot 0.2632 = \underline{\underline{2.211\ \Omega(\text{sec.})}}$$

The applied setting therefore is **2.211 Ω.**

1324 *R*E(Z3), Resistance for ph-e faults:
Similar to the *R*(Z3) setting, the upper and lower limits are defined by minimum required reach and symmetry. In this application set the *R*E(Z3) reach the same as *R*(Z3) to **8.048 Ω.**

1325 T3 delay:
This setting was already applied in Chapter 10.3 and is shown here again with all the Zone 3 settings. The setting **0.50 s** is applied.

11.5 Zone Z4



Distance zones (quadrilateral) - Settings Group A

Zone Z1 | Zone Z1B-exten. | Zone Z2 | Zone Z3 | Zone Z4 | Zone Z5

Settings:

No.	Settings	Value
1331	Operating mode Z4	Inactive
1332	R(Z4), Resistance for ph-ph-faults	12,000 Ohm
1333	X(Z4), Reactance	12,000 Ohm
1334	RE(Z4), Resistance for ph-e faults	12,000 Ohm
1335	T4 delay	oo sec

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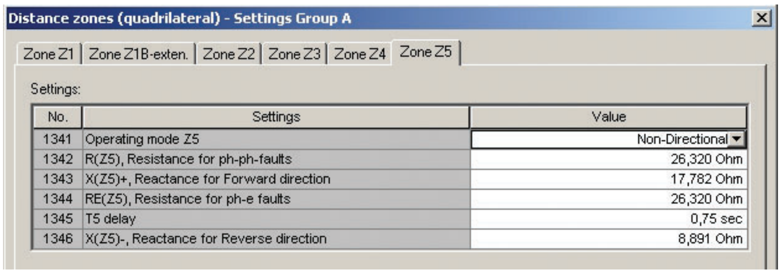
Fig. 35 Settings for Zone Z4

1331 Operating mode Z4:
Zone Z4 is not applied (refer to Table 1). It must therefore be set as **inactive** direction.

Further settings in this block are of no consequence and therefore not discussed here.

11.6 Zone Z5



Distance zones (quadrilateral) - Settings Group A

Zone Z1 | Zone Z1B-exten. | Zone Z2 | Zone Z3 | Zone Z4 | Zone Z5

Settings:

No.	Settings	Value
1341	Operating mode Z5	Non-Directional
1342	R(Z5), Resistance for ph-ph-faults	26,320 Ohm
1343	X(Z5)+, Reactance for Forward direction	17,782 Ohm
1344	RE(Z5), Resistance for ph-e faults	26,320 Ohm
1345	T5 delay	0,75 sec
1346	X(Z5)-, Reactance for Reverse direction	8,891 Ohm

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Fig. 36 Settings for Zone Z5

1341 Operating mode Z5:
Zone Z5 is used as non-directional final backup stage (refer to Table 1). It must therefore be set as **non-directional** zone.

1342 *R*(Z5), Resistance for ph-ph faults:
Resistance coverage settings for backup protection with distance protection zones is defined by a lower limit and upper limit. The lower limit is the minimum fault resistance (arc resistance) that must be covered, and the upper limit is based on the corresponding X reach setting. Note that for high resistance faults (not arc faults), the other infeeds to the reverse fault cause severe underreach.
As no detailed values are available, the required arc resistance coverage is calculated for the arc voltage (5 m) and 50 % of nominal current or 500 A primary.

$$R(Z5)_{\min} = \frac{2500\ \text{V} / \text{m} \cdot 2 \cdot 5\ \text{m}}{500\ \text{A}} \cdot \frac{\text{CTratio}}{\text{VTratio}}$$

$$R(Z5)_{\min} = \frac{2500 \cdot 2 \cdot 5}{500} \cdot 0.2632 = \underline{\underline{13.16\ \Omega(\text{sec.})}}$$

This setting would ensure detection in Zone 5, if the arc voltage, as calculated in Chapter 11.1, is for 5 m conductor spacing and the fault current is at least 500 A. The upper limit is given by reach symmetry constraints and states that *R*(Z5)< 6 times X(Z5) + or X(Z5) –. Looking ahead, X(Z5) is set to 17.782 **Ω**, so the upper limit is 106.69 **Ω**. This is far into the load area (refer to parameter 1241, calculated in Chapter 10.1). A setting of double the minimum is a safe compromise:

$R(Z5) = R(Z5)_{\min} \cdot 2$

$R(Z5) = 13.16\ \Omega \cdot 2 = \underline{26.32\ \Omega}$

The applied setting therefore is **26.320 Ω.**

1343 X(Z5)+, Reactance for Forward direction:
According to the grading requirement in Table 1:

$$X(Z5) = 1.2 \cdot (X_{Line1} + X_{Line2}) \cdot \frac{CTratio}{VTratio}$$

$$X(Z5) = 1.2 \cdot (80 \cdot 0.21 + 39.5) \cdot 0.2632$$

X(Z5) = 17.782 Ω (sec.)

The applied setting therefore is **17.782 Ω.**

1344 *RE*(Z5), Resistance for ph-e faults:
Similar to the *R*(Z5) setting, the upper and lower limits are defined by minimum required reach and symmetry. In this application set *RE*(Z5) reach to the same as *R*(Z5). The applied setting therefore is **26.32 Ω**.

1345 T5 delay:
This setting was already applied in Chapter 10.3 and is shown here again with all the Zone 5 settings. The setting **0.75 s** is applied.

1346 X(Z5)-, Reactance for Reverse direction:
For non-directional Zone Z5 the following symmetry requirement can be applied, if no other conditions are specified:

0.5 · X(Z5)+ < X(Z5)- < 2 · X(Z5)+

In this case the lower limit will apply so that:

X (Z5)- = 0.5 · X (Z5)+
X (Z5)- = 0.5 · 17.782
X (Z5)- = 8.891 Ω(sec.)

The applied setting therefore is **8.891 Ω.**

■ 12. Power swing – Setting Group A

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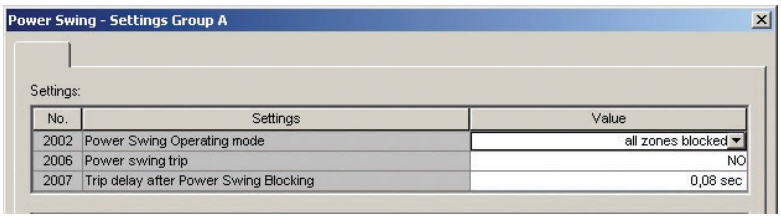
Power Swing - Settings Group A

Settings:

No.	Settings	Value
2002	Power Swing Operating mode	all zones blocked
2006	Power swing trip	NO
2007	Trip delay after Power Swing Blocking	0,08 sec

Fig. 37 Power swing settings

2002 Power Swing Operating mode:
In the event of a power swing, tripping by the distance protection due to the measurement of the "swing impedance" must be prevented. The setting **all zones blocked** is therefore applied.

2006 Power swing trip:
When the power swing is severe and an out of step condition is reached, selective power swing tripping should be applied in the system to obtain stable islanded subsystems. This relay is not positioned on such an interconnection so out of step tripping is not required, therefore setting is **NO**.

2007 Trip delay after Power Swing Blocking:
If during a power swing, which is detected by the relay, an external switching operation takes place, a jump of the measured "swing impedance" takes place. This jump can reset the power swing detection. To prevent tripping, if this impedance is inside the protected zones, a delay time of **0.08 s** is set to allow the power swing measurement to securely pick up again.

■ 13. Teleprotection for distance protection – Setting Group A

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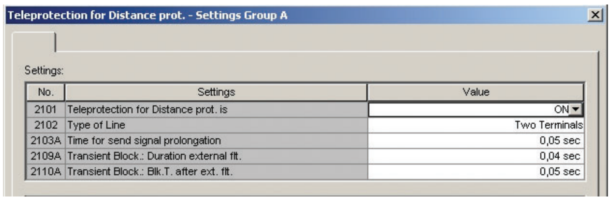

Teleprotection for Distance prot. - Settings Group A

Settings:

No.	Settings	Value
2101	Teleprotection for Distance prot. is	ON
2102	Type of Line	Two Terminals
2103A	Time for send signal prolongation	0,05 sec
2109A	Transient Block.: Duration external flt.	0,04 sec
2110A	Transient Block.: Blk.T. after ext. flt.	0,05 sec

Fig. 38 Teleprotection for distance protection settings

2101 Teleprotection for Distance prot. is:
In this application the teleprotection is **ON**.

2102 Type of Line:
The line is a **two terminal line**.

2103A Time for send signal prolongation:
In the event of sequential operation at the two line ends or very slow operation at one end, the end that trips first may reset and stop transmitting the send signal before the slow end is ready to operate. The send signal prolongation time ensures that the trip signal only resets once the remote end has had sufficient time to pickup.

In Figure 39 the delayed pickup of the remote end, after opening of the local circuit-breaker, must be considered to ensure that the send signal is not reset too soon. Channel timing is neglected as it adds on to the safety margin. The times indicated in the drawing apply in this example so that a setting of **0.05 s** is applied.

2109A Transient Block.: Duration external flt:
The transient blocking, also referred to as current reversal guard, is required with the POTT scheme, if parallel circuits are present. During clearance of a fault on the parallel circuit, the fault current may reverse on the protected circuit. To avoid operation of the POTT scheme under these conditions, the transient blocking times are applied. To ensure that transient blocking is only activated by external faults, it only starts following reverse fault detection for this time which is set to 80 % of the fastest fault clearance on the parallel circuit (including CB operation).

$$Tw = 0.8 \cdot (T_{\text{circuit\_breaker}} + T_{\text{relay\_parallel\_Line}} - T_{\text{relay\_protected\_Line}})$$

$$Tw = 0.8 \cdot (60\ \text{ms} + 10\ \text{ms} - 20\ \text{ms}) = \underline{\underline{40\ \text{ms}}}$$

The setting **0.04 s** is applied.

2110A Transient Block.: Blk. T. after ext. flt:
Following clearance of the external fault, the transient blocking condition must be maintained until both line ends securely detect the new fault condition. For this purpose the relay pickup time (re-orientation) and channel delay time must be considered.

$$Tb = 1.2 \cdot (T_{\text{channel\_delay}} + T_{\text{relay\_re-orientation}})$$

$$Tb = 1.2(20\ \text{ms} + 20\ \text{ms}) = \underline{\underline{48\ \text{ms}}}$$

The setting **0.05 s** is applied.

14. Weak infeed (trip and/or echo) – Setting Group A

2501 Weak Infeed function is:
When the POTT teleprotection scheme is used, the weak infeed function can be applied for fast fault clearance at both line ends even if one line end has very weak or no infeed. The weak infeed function must be activated at the line end where a weak infeed can occur. If a strong infeed is assured at all times, this function can be switched off. The function may also be used to only send an echo back to the strong infeed, so that it can trip with the POTT scheme, or to trip at the weak infeed end in addition to sending the echo. In this application both **Echo and Trip** will be used.

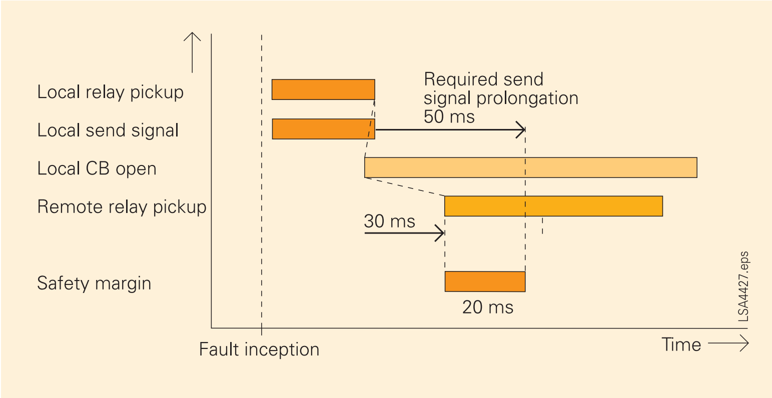
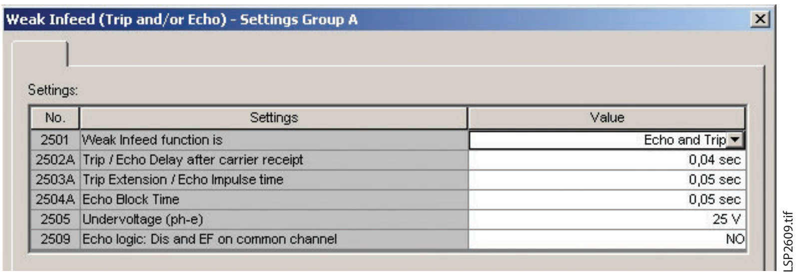


Fig. 39 Time chart to send signal prolongation time


Weak Infeed (Trip and/or Echo) - Settings Group A

Settings:

No.	Settings	Value
2501	Weak Infeed function is	Echo and Trip
2502A	Trip / Echo Delay after carrier receipt	0,04 sec
2503A	Trip Extension / Echo Impulse time	0,05 sec
2504A	Echo Block Time	0,05 sec
2505	Undervoltage (ph-e)	25 V
2509	Echo logic: Dis and EF on common channel	NO

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Fig. 40 Weak infeed settings

2502A Trip /Echo Delay after carrier receipt:
As the communication channel may produce a spurious signal (unwanted reception), a small delay is included for security purposes. Only if the receive signal is present for this time will the weak infeed function respond. In the event of 3-pole open condition of the circuit-breaker, this time delay is bypassed and the echo is sent immediately. The default setting of **0.04 s** is appropriate for this application.

2503A Trip Extention / Echo Impulse time:
To ensure that the echo signal can be securely transmitted, it must have a defined minimum length. On the other hand, a permanent echo signal is not desired. Therefore the echo is sent as a pulse with this set length. If tripping is also applied, then this time also defines the length of the internal trip signal (refer also to parameter 240 A in Chapter 7.3). The default setting of **0.05 s** is appropriate for this application.

2504A Echo Block Time:
If weak infeed echo is applied at both line ends, then it must be avoided that a received echo signal is again sent as echo in a continuous stream of echo signals. For this purpose, this blocking time is set to prevent a new weak infeed operation before it expires. A secure setting of this timer is the time required for a signal to be transmitted from one end to the other and back again (twice the channel delay time) plus a safety margin of 10 ms. In this application, a worst channel delay time of 20 ms is assumed so that a setting of **0.05 s** is appropriate.

2505 Undervoltage (ph-e):
The weak infeed trip signal (phase selective) is supervised by this undervoltage threshold. At the weak infeed end the source impedance is very large so that very small voltages are measured during faults on the protected circuit. If this threshold is set well below the minimum operational ph-e voltage then weak infeed tripping is secure and phase selective. Simulations and practical experience have shown that a setting of 50 % nominal ph-e voltage provides good results. The default setting of **25 V** is therefore applied.

2509 Echo Logic: Dis and EF on common channel:
If the distance protection and directional earth-fault protection are both applied with teleprotection (Distance with POTT and EF with directional comparison) the signals can be routed via one common channel or via two separate channels in the communication system. The weak infeed and echo logic must be set accordingly to ensure correct response. In this application, two separate channels are used so the setting is **NO**.

■ 15. Backup overcurrent – Setting Group A

15.1 General

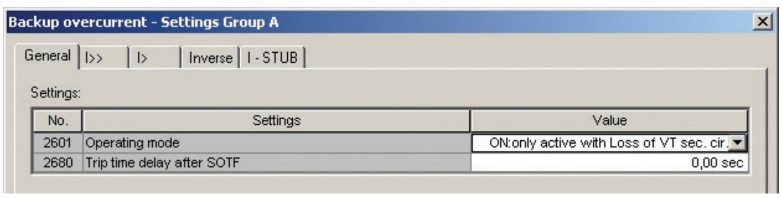

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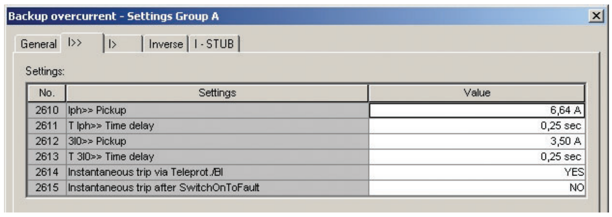
Fig. 41 General settings, backup overcurrent

2601 Operating mode:
The distance protection is more selective and more sensitive than the overcurrent protection. The overcurrent protection is therefore only required when the distance protection is blocked due to failure of the voltage measuring circuit (emergency mode). Therefore the operating mode is set to **ON: only active with loss of VT sec. cir.**

2680 Trip time delay after SOTF:
Following line closure detection the "Switch On To Fault" function is activated (refer to parameters 1132A and 1134 in Chapter 9.2). The backup overcurrent stages may also be used for SOTF tripping. This timer sets the time delay for SOTF trip with a backup overcurrent. In this application SOTF with backup overcurrent is not applied so the setting of this timer is not relevant; leave the default value of **0.00 s**.

15.2 *I>>* stage



LSP2611.tif

Fig. 42 *I>>* stage settings, backup overcurrent

2610 I_{ph}>> Pickup:
This high set stage is required to trip with single time step grading. It should therefore have a reach equivalent to the Zone 2 setting. The setting should therefore be equal to the maximum 3-phase fault current for a fault at the Zone 2 reach setting.

Based on the source and line impedances, the following maximum fault current level can be calculated for faults at the Zone 2 reach limit:

$$I_{\text{fault}} = \frac{U_{\text{source}}}{\sqrt{3} \cdot Z_{\text{tot}}} \quad \text{with} \quad U_{\text{source}} = 400 \text{ kV}$$

Z_{tot} = sum of minimum positive sequence source and line impedance up to Zone 2 reach (as only current magnitudes are being calculated, only the magnitude of the impedance is relevant)

$$|Z_{tot}| = |(R_{source\_min} + 0.8 \cdot (R_{Line1} + 0.8 \cdot R_{Line2})) + j(X_{source\_min} + 0.8 \cdot (X_{Line1} + 0.8 \cdot X_{Line2}))|$$
$$|Z_{tot}| = |(1 + 0.8 \cdot (80 \cdot 0.025 + 0.8 + 1.5)) + j(10 + 0.8 \cdot (80 \cdot 0.21 + 0.8 \cdot 17.5))|$$
$$|Z_{tot}| = |3.56 + j34.64|$$
$$|Z_{tot}| = 34.8$$

The maximum three-phase fault current at the Zone 2 reach limit therefore is:

$$I3_{ph\ Z2max} = \frac{400\ \text{kV}}{\sqrt{3} \cdot 34.8} = \underline{\underline{6636\ \text{A}}}$$

As a secondary value, the setting applied for I>> is therefore **6.64 A**.

2611 $T\ I_{ph}$>> Time delay:
This high set stage is required to trip with single time step grading. Therefore set **0.25 s** which is one time step (refer to Fig. 25).

2612 $3I_0$>> Pickup:
This high set stage is required to trip earth faults with single time step grading. It should therefore have a reach equivalent to the Zone 2 setting. The setting should therefore be equal to the maximum single-phase fault current for a fault at the Zone 2 reach setting.

Based on the source and line impedances, the following maximum fault current level can be calculated for faults at the Zone 2 reach limit:

$$I_{fault} = \frac{U_{source}}{\sqrt{3} \cdot Z_{tot}} \quad \text{with} \quad U_{source} = 400\ \text{kV}$$

Z_{tot} = 1/3 of the sum of minimum positive, negative and zero sequence source and line impedance up to Zone 2 reach (as only current magnitudes are being calculated, only the magnitude of the impedance is relevant)

For the 3-phase fault level used in setting 2610, the total positive sequence impedance was calculated. As the negative sequence impedance equals the positive sequence value, the Z_{tot} for this setting can be calculated as follows:

$$|Z_{tot}| = \frac{|2 \cdot Z_{tot\_2610} + (R0_{source\_min} + 0.8 \cdot (R0_{Line1} + 0.8 \cdot R0_{Line2})) + j(X0_{source\_min} + 0.8 \cdot (X0_{Line1} + 0.8 \cdot X0_{Line2}))|}{3}$$
$$|Z_{tot}| = \frac{|(7.12 + 2.5 + 0.8 \cdot (80 \cdot 0.13 + 0.8 \cdot 7.5)) + j(69.28 + 20 + 0.8 \cdot (80 \cdot 0.81 + 0.8 \cdot 86.5))|}{3}$$
$$|Z_{tot}| = |7.58 + j65.49|$$
$$|Z_{tot}| = 65.9$$

The maximum single-phase fault current at the Zone 2 reach limit therefore is:

$$I3_{\text{ph Z2max}} = \frac{400\ \text{kV}}{\sqrt{3}\cdot 65.9} = \underline{\underline{3504\ \text{A}}}$$

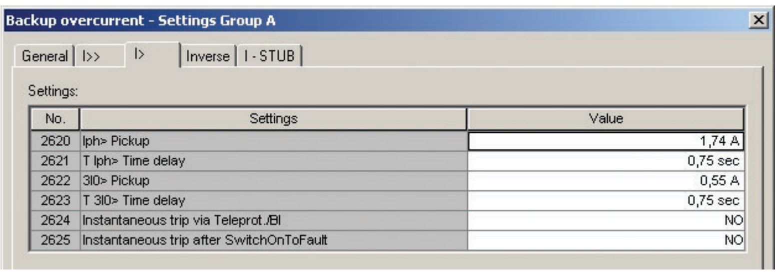
As a secondary value, the setting applied for $3I_0$>> is therefore **3.50 A**.

2613 $T\ 3I_0$>> Time delay:
This high set stage is required to trip with single time step grading. Therefore set **0.25 s** which is one time step (refer to Fig. 25).

2614 Instantaneous trip via Teleprot./BI:
The backup overcurrent is only active when the distance protection is blocked due to failure of the secondary VT circuit (refer to setting 2601 in Chapter 15.1). If under these conditions a teleprotection signal is received from the remote end, the tripping of the overcurrent protection may be accelerated. This may be safely applied for this stage, because its reach is less than the set Z1B. Therefore apply the setting **YES**. Note that for this function to work, the binary input function "7110 >O/C InstTRIP" must be assigned in parallel to the teleprotection receive binary input of the distance protection.

2615 Instantaneous trip after SwitchOnToFault:
This function is not applied (refer to setting 2680 in Chapter 15.1). Therefore **NO** is set.

15.3 *I*> stage


Backup overcurrent - Settings Group A

General | I>> | I> | Inverse | I - STUB

Settings:

No.	Settings	Value
2620	Iph> Pickup	1,74 A
2621	T Iph> Time delay	0,75 sec
2622	3I0> Pickup	0,55 A
2623	T 3I0> Time delay	0,75 sec
2624	Instantaneous trip via Teleprot./BI	NO
2625	Instantaneous trip after SwitchOnToFault	NO

LSP2612.tif

Fig. 43 *I*> stage settings, backup overcurrent

2620 I_{ph}> Pickup:
This stage is required to trip with time delay equal to Zone 5. It may not pick up due to load (permissible overload). The permissible overload is twice the full load, therefore:

$$I_{ph} > \text{Pickup} \geq \frac{2\cdot \text{Rated MVA}}{\sqrt{3}\cdot \text{Full scale voltage}}$$

$$I_{ph} > \text{Pickup} \geq \frac{2\cdot 600}{\sqrt{3}\cdot 400} = \underline{\underline{1732\ \text{A}}}$$

As a secondary value, the setting applied for *I*> is therefore **1.74 A**.

2621 $T\ I_{ph}$> Time delay:
This stage is required to trip with the same time delay as Zone 5, three time grading steps. Therefore set **0.75 s** which is three time steps (refer to Fig. 25).

2622 $3I_0$> Pickup:
This stage is required to trip with time delay equal to Zone 5. It should detect earth faults with similar sensitivity as Zone 5. Therefore, with the weakest infeed according to Table 2, an earth fault at the X reach limit of Zone 5 will have the following current magnitude:

$$3I_{0\ Z5\_min} = \frac{U_{\text{nom\_sec}}}{\sqrt{3}\cdot(X_{\text{source\_max}} + X_{Z5\_\text{sett}})\cdot\left(1+\frac{XE}{XL}\right)}$$

$$3I_{0\ Z5\_min} = \frac{100}{\sqrt{3}\cdot(100\cdot 0.2632 + 17.782)\cdot(1+1.38)}$$

$$3I_{0\ Z5\_min} = 0.55\ \text{A}$$

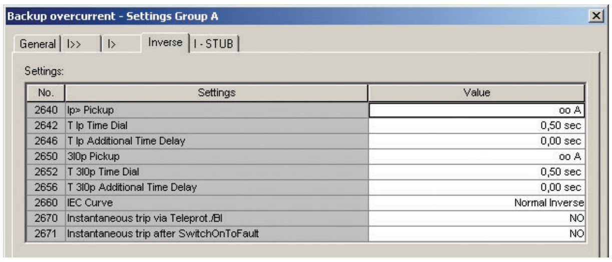
As a secondary value, the setting applied for $3I_0$> is therefore **0.55 A**.

2623 $T\ 3I_0$>> Time delay:
This high set stage is required to trip with three time grading steps. Therefore set **0.75 s** which is three time steps (refer to Fig. 25).

2624 Instantaneous trip via via Teleprot./BI:
The *I*>> stage is applied for this purpose, refer to setting 2614 in Chapter 15.2. Therefore set **NO** for this stage.

2625 Instantaneous trip after SwitchOnToFault:
This function is not applied (refer to setting 2680 in Chapter 15.1). Therefore **NO** is set.

15.4 Inverse stage



No.	Settings	Value
2640	Ip> Pickup	oo A
2642	T Ip Time Dial	0,50 sec
2646	T Ip Additional Time Delay	0,00 sec
2650	3I0p Pickup	oo A
2652	T 3I0p Time Dial	0,50 sec
2656	T 3I0p Additional Time Delay	0,00 sec
2660	IEC Curve	Normal Inverse
2670	Instantaneous trip via Teleprot./BI	NO
2671	Instantaneous trip after SwitchOnToFault	NO

LSP2613.tif

Fig. 44 Inverse stage settings, backup overcurrent

2640 I_p> Pickup:
The co-ordination of inverse time graded protection can be applied effectively to obtain reasonably fast and sensitive selective protection. In this application, the inverse stage is not used, so the setting here is infinity, ∞ **A**.

2642 $T\ I_p$ Time Dial:
As the setting of 2640 above is infinity (∞), this setting is not relevant and left on the default value of **0.50 s**.

2646 $T\ I_p$ Additional Time Delay:
This stage may also be used as a further definite time delay stage by using this setting. As the setting of 2640 above is infinity (∞), this setting is not relevant and left on the default value of **0.00 s**.

2650 $3I_{0p}$ Pickup:
The co-ordination of inverse time graded protection can be applied effectively to obtain reasonably fast and sensitive selective protection. In this application, the inverse stage is not used, so the setting here is infinity, ∞ **A**.

2652 $T\ 3I_{0p}$ Time Dial:
As the setting of 2650 above is infinity (∞), this setting is not relevant and left on the default value of **0.50 s**.

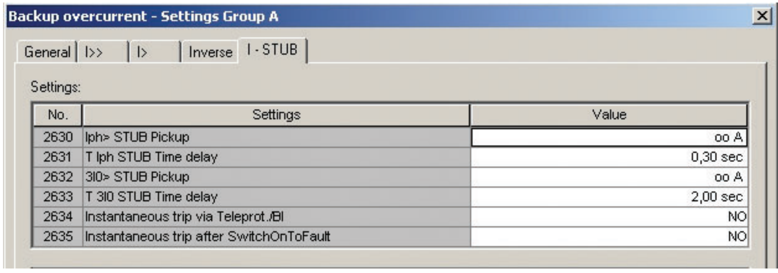
2656 $T\ 3I_{0p}$ Additional Time Delay:
This stage may also be used as a further definite time delay stage by using this setting. As the setting of 2650 above is infinity (∞), this setting is not relevant and left on the default value of **0.00 s**.

2660 IEC Curve:
During the device configuration (Chapter 4) the standard of the curves was selected with parameter 0126 to be IEC. Here the choice is made from the various IEC curves. As the stage is not applied in this application the setting is not relevant and left on the default value of **Normal inverse**.

2670 Instantaneous trip via Teleprot./BI:
The *I*>> stage is applied for this purpose, refer to setting 2614 in Chapter 15.2. Therefore set **NO** for this stage.

2671 Instantaneous trip after SwitchOnToFault:
This function is not applied (refer to setting 2680 in Chapter 15.1). Therefore **NO** is set.

15.5 *I* STUB stage



No.	Settings	Value
2630	Iph> STUB Pickup	oo A
2631	T Iph STUB Time delay	0,30 sec
2632	3I0> STUB Pickup	oo A
2633	T 3I0 STUB Time delay	2,00 sec
2634	Instantaneous trip via Teleprot./BI	NO
2635	Instantaneous trip after SwitchOnToFault	NO

LSP2614.tif

Fig. 45 *I* STUB stage settings, backup overcurrent

2630 I_{ph}> STUB Pickup:
This stage may be used as a normal definite time delay stage. In addition to this, it provides for blocking or release via binary input. For certain applications (e.g.1 ½CB) a STUB exists when the line isolator is open. By releasing this overcurrent stage via the mentioned binary inputs, a fast selective fault clearance for faults on the STUB can be obtained. In this application, no such STUB protection is required, so this stage is disabled by applying an infinite pickup value with the setting ∞ **A**.

2631 T I_{ph} STUB Time delay:
As the setting of 2630 above is infinity (∞), this setting is not relevant and left on the default value of **0.30 s**.

2632 $3I_0$> STUB Pickup:
This stage may be used as a normal definite time delay stage. In addition to this, it provides for blocking or release via binary input. For certain applications (e.g.1 ½CB) a STUB exists when the line isolator is open. By releasing this overcurrent stage via the mentioned binary inputs, a fast selective fault clearance for faults on the STUB can be obtained. In this application, no such STUB protection is required, so this stage is disabled by applying an infinite pickup value with the setting ∞ **A**.

2633 T $3I_0$ STUB Time delay:
As the setting of 2632 above is infinity (∞), this setting is not relevant and left on the default value of **2.00 s**.

2634 Instantaneous trip via Teleprot./BI:
The I>> stage is applied for this purpose, refer to setting 2614 in Chapter 15.2. Therefore set **NO** for this stage.

2635 Instantaneous trip after SwitchOnToFault:
This function is not applied (refer to setting 2680 in Chapter 15.1). Therefore **NO** is set.

16. Measurement supervision – Setting Group A

16.1 Balance / Summation

Measurement Supervision - Settings Group A

Balance / Summ. | Meas.Volt.Fail | VT mcb

Settings:

No.	Settings	Value
2901	Measurement Supervision	ON
2902A	Voltage Threshold for Balance Monitoring	50 V
2903A	Balance Factor for Voltage Monitor	0,75
2904A	Current Balance Monitor	0,50 A
2905A	Balance Factor for Current Monitor	0,50
2906A	Summated Current Monitoring Threshold	0,10 A
2907A	Summated Current Monitoring Factor	0,10
2908A	T Balance Factor for Voltage Monitor	5 sec
2909A	T Current Balance Monitor	5 sec

LSP2615.tif

Fig. 46 Balance/Summation settings, measurement supervision

2901 Measurement Supervision:
Only in exceptional cases will the measurement supervision not be activated. Therefore this setting should always be **ON**.

The advanced settings 2902A to 2909A can be used to modify the parameters of the monitoring functions. Generally, they can all be left on their default values.

16.2 Measured voltage failure

Measurement Supervision - Settings Group A

Balance / Summ. | Meas.Volt.Fail | VT mcb

Settings:

No.	Settings	Value
2910	Fuse Failure Monitor	ON
2911A	Minimum Voltage Threshold U>	30 V
2912A	Maximum Current Threshold I<	0,10 A
2913A	Maximum Voltage Threshold U< (3phase)	5 V
2914A	Delta Current Threshold (3phase)	0,10 A
2915	Voltage Failure Supervision	with current supervision
2916A	Delay Voltage Failure Supervision	3,00 sec

LSP2616.tif

Fig. 47 Measured voltage fail settings, measurement supervision

2910 Fuse Failure Monitor:
Only in exceptional cases will the fuse failure monitor not be activated. Therefore this setting should always be **ON**.

For the voltage failure detection, the default parameters can be applied for the advanced settings.

2915 Voltage Failure Supervision:
In the event of energising the primary circuit with the voltage transformer secondary circuit out of service, an alarm "168 Fail U absent" will be issued and the emer - gency mode activated. This monitoring task can be controlled with this parameter 2915. As no auxiliary contacts of the circuit-breaker are allocated, it is only controlled with **current supervision**.

16.3 VT mcb

Measurement Supervision - Settings Group A

Balance / Summ. | Meas.Volt.Fail | VT mcb

Settings:

No.	Settings	Value
2921	VT mcb operating time	0 ms

LSP2617.tif

Fig. 48 VT mcb settings, measurement supervision

2921 VT mcb operating time:
If an auxiliary contact of the mcb is utilised (allocated in the matrix), the operating time of this contact must be entered here. Note that such an input is not required in practice as the relay detects all VT failures, including the operation of the mcb via measurement. This set time will delay all distance protection fault detection so it should in general not be used. In this application, it is also not required and therefore left on the default setting of **0 ms**.

17. Earth-fault overcurrent – Setting Group A

17.1 General

Earth fault overcurrent - Settings Group A

General | 3I0>>> | 3I0>> | 3I0> | 3I0 InverseTime | Direction

Settings:

No.	Settings	Value
3101	Earth Fault overcurrent function is	ON
3102	Block E/F for Distance protection	with every Pickup
3174	Block E/F for Distance Protection Pickup	in zone Z1/Z1B
3103	Block E/F for 1pole Dead time	YES
3104A	Stabilisation Slope with Iphase	10 %
3105	3Io-Min threshold for Teleprot. schemes	0,46 A
3109	Single pole trip with earth flt.prot.	NO
3170	2nd harmonic ratio for inrush restraint	15 %
3171	Max.Current, overriding inrush restraint	7,50 A
3172	Instantaneous mode after SwitchOnToFault	with Pickup and direction
3173	Trip time delay after SOTF	0,00 sec

LSP2618.tif

Fig. 49 General settings, earth fault overcurrent

3101 Earth Fault overcurrent function is:
For the clearance of high resistance earth faults this function provides better sensitivity than the distance protection. As high resistance earth faults are expected in this application, this function is activated by setting it **ON**.

3102 Block E/F for Distance protection:
As the distance protection is more selective (defined zone reach) than the earth-fault protection and has superior phase selection it is set to block the E/F protection with **every pickup**.

3174 Block E/F for Distance Protection Pickup:
As fast single-pole tripping is only done with Zone 1 and Zone 1B with the distance protection, the earth-fault protection is only blocked when the distance protection picks up in **Zone Z1/Z1B**.

3103 Block E/F for 1pole Dead time:
During 1-pole dead times, load current can flow via the zero sequence path. To prevent incorrect operation of the earth-fault protection as a result of this it should be blocked. Therefore set **YES**.

3104A Stabilisation Slope with *I*phase:
When large currents flow during faults without ground, CT errors (saturation) will cause current flow via the residual path. The earth-fault protection, having a very sensitive pickup threshold for high resistance faults, could pick up due to this CT error current. To prevent this, a stabilising characteristic is provided to increase the threshold when the phase currents are large. The characteristic is shown below in Figure 50. The default setting of **10 %** is suitable for most applications.

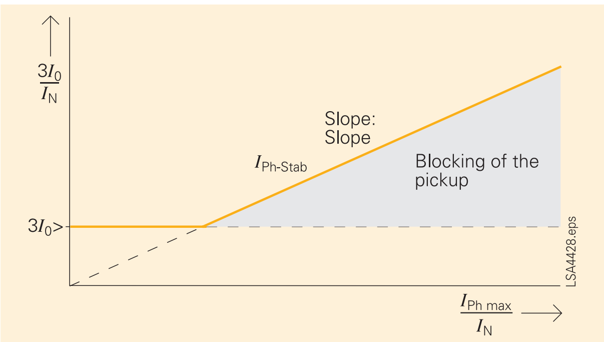


Fig. 50 Stabilisation of $3I_0$ pickup threshold

3105 $3I_0$-Min threshold for Teleprot. schemes:
For directional comparison protection, in particular for the weak infeed echo function, a teleprotection send or echo block condition must be more sensitive than the teleprotection trip condition. This threshold determines the minimum earth current for teleprotection send and is set to 80 % of the most sensitive teleprotection trip stage. Set

$$3I_0\_TP = 0.8 \cdot 3I_0 >>$$

$$3I_0\_TP = 0.8 \cdot 0.58$$

$$3I_0\_TP = 0.46\ \text{A}$$

Therefore apply the setting of **0.46 A**.

3109 Single pole trip with earth flt. prot.:
The distance protection is set to cover all arc faults on the line. High resistance faults usually are due to mechanical defects (broken conductors or obstructions in the line) so that an automatic reclosure is not sensible. Therefore, set earth fault only for three-pole tripping by application of **NO**.

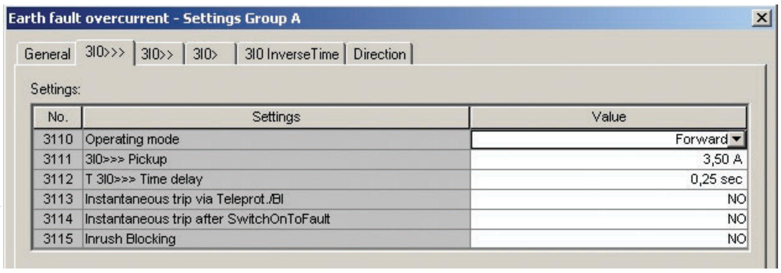
3170 2nd harmonic for inrush restraint:
When energising the line, connected transformers and load may cause an inrush current with zero sequence component. This rush current can be identified by its 2nd harmonic content. In this application inrush blocking is not required and not applied in the individual stages. The setting is of no consequence, so leave the default value of **15 %**.

3171 Max. Current, overriding inrush restraint:
If very large fault currents flow, CT errors may also cause some 2nd harmonic. Therefore the rush blocking is disabled when current is above this threshold. As stated for parameter 3170 above, the inrush restraint is not applied in this example. This setting is of no consequence, so leave the default value of **7.50 A**.

3172 Instantaneous mode after SwitchOnTo Fault:
The earth-fault protection may be activated with a set time delay (parameter 3173) in the case of line energising (SOTF). In this application, only the distance protection function is used for SOTF so that this setting is of no consequence, so leave the default value of with **pickup and direction.**

3173 Trip time delay after SOTF:
As stated for parameter 3172 above, this timer defines the delay of the SOTF trip by earth-fault protection. As it is not applied, the default value of **0.00 s** is left unchanged.

17.2 $3I_0$>>>



No.	Settings	Value
3110	Operating mode	Forward
3111	3I0>>> Pickup	3,50 A
3112	T 3I0>>> Time delay	0,25 sec
3113	Instantaneous trip via Teleprot./BI	NO
3114	Instantaneous trip after SwitchOnToFault	NO
3115	Inrush Blocking	NO

Fig. 51 $3I_0$>>> stage settings, earth fault overcurrent

3110 Operating mode:
A total of 4 stages are available, one of which may be applied as inverse stage. In this application only three stages will be used, the $3I_0$>>> stage for fast (single time step) directional operation and the $3I_0$>> stage for time delayed directional operation and fast directional comparison as well as the $3I_0$> stage for non-directional backup operation. This stage must therefore be set to **Forward**.

3111 $3I_0$>>> Pickup:
This stage must operate with the same sensitivity as the backup (emergency) overcurrent stage $3I_0$>> (refer to setting 2612). Therefore apply the setting **3.50 A** here. Note that this stage is only active when distance protection is not picked up, and it is directional (no reverse fault operation) whereas the backup O/C stage only operates in the emergency mode when distance protection is not available.

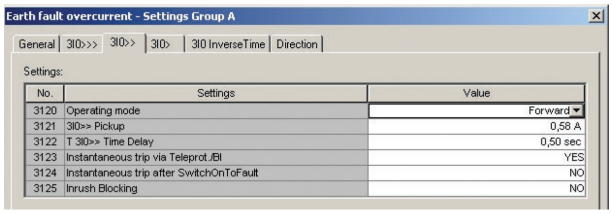
3112 $T\ 3I_0$>>> Time delay:
This stage must operate with single time step delay. Therefore set **0.25 s** here.

3113 Instantaneous trip via Teleprot./BI:
The stage $3I_0$>> will operate with teleprotection, so the setting here is **NO** .

3114 Instantaneous trip after SwitchOnToFault:
As stated above, only the distance protection operates with SOTF, so set **NO** here.

3115 Inrush Blocking:
As stated above, inrush blocking is not applied, so set **NO** here.

17.3 $3I_0$>>



No.	Settings	Value
3120	Operating mode	Forward
3121	3I0>> Pickup	0,58 A
3122	T 3I0>> Time Delay	0,50 sec
3123	Instantaneous trip via Teleprot./BI	YES
3124	Instantaneous trip after SwitchOnToFault	NO
3125	Inrush Blocking	NO

Fig. 52 $3I_0$>> stage settings, earth fault overcurrent

3120 Operating mode:
In this application only three stages will be used, the $3I_0$>>> stage for fast (single time step) directional operation and the $3I_0$>> stage for time delayed directional operation and fast directional comparison as well as the $3I_0$> stage for non-directional backup operation. This stage must therefore be set to **Forward**.

3121 $3I_0$>> Pickup:
This stage must operate for all internal high resistance faults, use a 20 % margin.

$$3I_0 >> \text{Pickup} = 0.8 \cdot I_{1\text{ph min\_R}}$$

$$3I_0 >> \text{Pickup} = 0.8 \cdot 729 = \underline{\underline{583\text{ A}}}$$

In secondary values therefore set **0.58 A**.

3122 $T\ 3I_0$>> Time delay:
This stage must operate with two time step delays. Therefore set **0.50 s** here.

3123 Instantaneous trip via Teleprot./BI:
The stage $3I_0$>> will operate with teleprotection, so the setting here is **YES** .

3124 Instantaneous trip after SwitchOnToFault:
As stated above, only the distance protection operates with SOTF, so set **NO** here.

3125 Inrush Blocking:
As stated above, inrush blocking is not applied, so set **NO** here.

17.4 $3I_0$>

Earth fault overcurrent - Settings Group A

General | 3I0>>> | 3I0>> | 3I0> | 3I0 InverseTime | Direction

Settings:

No.	Settings	Value
3130	Operating mode	Non-Directional
3131	3I0> Pickup	0,58 A
3132	T 3I0> Time Delay	1,00 sec
3133	Instantaneous trip via Teleprot./BI	NO
3134	Instantaneous trip after SwitchOnToFault	NO
3135	Inrush Blocking	NO

LSP2621.tif

Fig. 53 $3I_0$> stage settings, earth fault overcurrent

3130 Operating mode:
In this application only three stages will be used, the $3I_0$>>> stage for fast (single time step) directional operation and the $3I_0$>> stage for time delayed directional operation and fast directional comparison as well as the $3I_0$> stage for non-directional backup operation. This stage must therefore be set to **Non-Directional**.

3131 $3I_0$> Pickup:
This stage must operate for all internal high resistance faults, the same as $3I_0$>>, but non-directional and with longer time delay. In secondary values therefore set **0.58 A**.

3132 T $3I_0$> Time delay:
This stage must operate with four time step delays. Therefore set **1.00 s** here.

3133 Instantaneous trip via Teleprot./BI:
The stage $3I_0$>> will operate with teleprotection, so the setting here is **NO**.

3134 Instantaneous trip after SwitchOnToFault:
As stated above, only the distance protection operates with SOTF, so set **NO** here.

3135 Inrush Blocking:
As stated above, inrush blocking is not applied, so set **NO** here.

17.5 $3I_0$ Inverse time

Earth fault overcurrent - Settings Group A

General | 3I0>>> | 3I0>> | 3I0> | 3I0 InverseTime | Direction

Settings:

No.	Settings	Value
3140	Operating mode	Inactive
3141	3I0p Pickup	1,00 A
3143	3I0p Time Dial	0,50 sec
3147	Additional Time Delay	1,20 sec
3148	Instantaneous trip via Teleprot./BI	NO
3149	Instantaneous trip after SwitchOnToFault	NO
3150	Inrush Blocking	NO
3151	IEC Curve	Normal Inverse

LSP2622.tif

Fig. 54 $3I_0$ Inverse time stage settings, earth fault overcurrent

3140 Operating mode:
This stage is not required so it is set to **Inactive.**

Because this stage is inactive, the settings 3141 to 3151 are of no consequence and left on their default values.

17.6 Direction

Earth fault overcurrent - Settings Group A

General | 3I0>>> | 3I0>> | 3I0> | 3I0 InverseTime | Direction

Settings:

No.	Settings	Value
3160	Polarization	with U0 + IY or U2
3162A	ALPHA, lower angle for forward direction	338 °
3163A	BETA, upper angle for forward direction	122 °
3164	Min. zero seq.voltage 3U0 for polarizing	3,8 V
3166	Min. neg. seq. polarizing voltage 3U2	3,8 V
3167	Min. neg. seq. polarizing current 3I2	0,58 A
3168	Compensation angle PHI comp. for Sr	255 °
3169	Forward direction power treshold	0,3 VA

LSP2623.tif

Fig. 55 Direction settings, earth fault overcurrent

3160 Polarization:
Because both applied stages of the earth-fault overcurrent protection are directional (forward), the choice of polarising signal must be carefully considered. If both negative and zero sequence infeed are present at the relay location polarisation **with U0 + IY or U2** provides excellent results. The earth current from a star connected and earthed transformer winding is only included, when the 4th current input of the relay is connected as such. In this application, this current input measures the residual current of the protected line, (parameter 220 in Chapter 7.1). Therefore only the zero sequence or negative sequence voltage are used as polarising signal with this setting. The choice is automatic (the larger of the two values is chosen individually during each fault).

3162A ALPHA, lower angle for forward direction: The default direction limits have been optimised for high resistance faults and are left unchanged at **338°** here.

3163A BETA, upper angle for forward direction: The default direction limits have been optimised for high resistance faults and are left unchanged at **122°** here.

3164 Min. zero seq. voltage $3U_0$ for polarizing: The zero sequence voltage is one of the values for directional polarising. Under high resistance fault conditions, this value may become very small. For the setting it is calculated using the minimum single-phase fault current under high resistance fault conditions and the smallest zero sequence source impedance (this includes a safety margin as these two conditions will not coincide):

$$3I_{0\,\mathrm{min}} = I_{1\,\mathrm{ph\,min\_R}} \cdot Z_{0\,\mathrm{source\_min}}$$

$$3I_{0\,\mathrm{min}} = 729 \cdot 20 = \underline{\underline{14.58\ \mathrm{kV}}}$$

As secondary value this is:

$$3U_{0\,\mathrm{min\_sec}} = 3U_{0\,\mathrm{min}} \cdot \frac{100\ \mathrm{V}}{380\ \mathrm{kV}}$$

$$3U_{0\,\mathrm{min\_sec}} = 14.58\ \mathrm{kV} \cdot \frac{100\ \mathrm{V}}{380\ \mathrm{kV}} = \underline{\underline{3.8\ \mathrm{V}}}$$

Therefore apply the setting **3.8 V**.

3166 Min. neg. seq. polarizing voltage $3U_2$: Although a similar calculation as done for 3164 would return a smaller value (50 %), this is not applied, as an automatic selection of the larger of the two voltages was set (parameter 3160). The setting applied here therefore is the same as that for the zero sequence voltage. Therefore apply the setting **3.8 V**.

3167 Min. neg. seq. polarizing current $3I_2$: Apply here the minimum negative sequence current flowing for high resistance faults with a 20 % margin.

$$3I_{2\,\mathrm{min}} = 0.8 \cdot I_{1\,\mathrm{ph\,min\_R}}$$

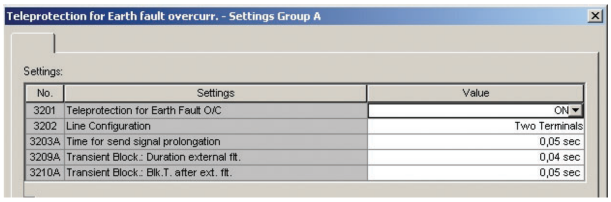
$$3I_{2\,\mathrm{min}} = 0.8 \cdot 729 = \underline{\underline{583.2\ \mathrm{A}}}$$

Therefore apply the setting **0.58 A**.

3168 Compensation angle PHI comp. for S_r: This setting is only relevant for direction decisions based on zero sequence power. In this application it is of no consequence and left on default value of **255°**.

3169 Forward direction power threshold: This setting is only relevant for direction decisions based on zero sequence power. In this application it is of no consequence and left on default value of **0.3 VA**.

18. Teleprotection for earth fault overcurrent – Setting Group A



No.	Settings	Value
3201	Teleprotection for Earth Fault O/C	ON
3202	Line Configuration	Two Terminals
3203A	Time for send signal prolongation	0,05 sec
3209A	Transient Block.: Duration external flt.	0,04 sec
3210A	Transient Block.: Blk.T. after ext. flt.	0,05 sec

Fig. 56 Teleprotection for earth fault overcurrent settings

3201 Teleprotection for Earth Fault O/C: In this application the teleprotection is required and applied as "Directional Comparison Pickup", refer to parameter 132 in Chapter 4. This function is therefore activated by setting it **ON**.

3202 Line Configuration: The line is a **two terminal line**.

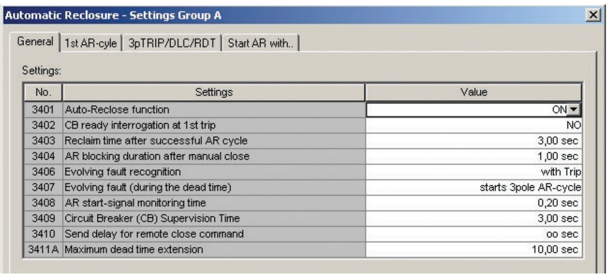
3203A Time for send signal prolongation: As the same type of communication with the same channel delay time is used for distance teleprotection and earth-fault teleprotection, the same setting consideration as for parameter 2103A in Chapter 13 applies here. Therefore in this example a setting of **0.05 s** is applied.

3209A Transient Block.: Duration external flt.: As the same type of communication with the same channel delay time is used for distance teleprotection and earth-fault teleprotection, the same setting consideration as for parameter 2109A in Chapter 13 applies here. Therefore in this example a setting of **0.04 s** is applied.

3210A Transient Block.: Blk. T. after ext. flt.: As the same type of communication with the same channel delay time is used for distance teleprotection and earth-fault teleprotection, the same setting consideration as for parameter 2110A in Chapter 13 applies here. Therefore in this example a setting of **0.05 s** is applied.

19. Automatic reclosure – Setting Group A

19.1 General



No.	Settings	Value
3401	Auto-Reclose function	ON
3402	CB ready interrogation at 1st trip	NO
3403	Reclaim time after successful AR cycle	3,00 sec
3404	AR blocking duration after manual close	1,00 sec
3406	Evolving fault recognition	with Trip
3407	Evolving fault (during the dead time)	starts 3pole AR-cycle
3408	AR start-signal monitoring time	0,20 sec
3409	Circuit Breaker (CB) Supervision Time	3,00 sec
3410	Send delay for remote close command	oo sec
3411A	Maximum dead time extension	10,00 sec

LSP2625.tif

Fig. 57 General settings, automatic reclosure

3401 Auto-Reclose function:
In this application the automatic reclosure function is required and applied with "1 Cycle" and "with Trip and Action Time", refer to parameters 133 and 134 in Chapter 4. This function is therefore activated by setting it **ON**.

3402 CB ready interrogation at 1st trip:
Before a reclosure is attempted the circuit-breaker status must be checked. This can be done before the reclose cycle is started (prior/at time of initiation) or before the reclose command is issued. In this application the breaker status is checked before the close command is issued by the recloser, so this setting must be **NO**.

3403 Reclaim time after successful AR cycle:
If the reclose is successful, the recloser must return to the normal state which existed prior to the first fault. The time set here is started by each reclose command and must take the system conditions into account (also the circuit-breaker recovery time may be considered). Here a setting of **3.00 s** is applied.

3404 AR blocking duration after manual close:
If the manual close binary input is assigned, then the AR should be blocked for a set time after manual close to prevent AR when switching onto a fault. In this application the manual close binary input is not assigned, SOTF is recognised by current flow and AR is not initiated in this case. This setting is not relevant here as the manual close binary input is not assigned, the default setting of **1.00 s** is left unchanged.

3406 Evolving fault recognition:
If during the single-pole dead time a further fault is detected (evolving fault), the AR function can respond to this in a defined manner. The detection of evolving fault in this application will be done by detection of a further (new) trip command initiation to the AR function. Therefore set **with Trip**.

3407 Evolving fault (during the dead time):
The response to the evolving fault during the single-pole dead time is set here. In this application it is set to **starts 3pole AR-cycle**.

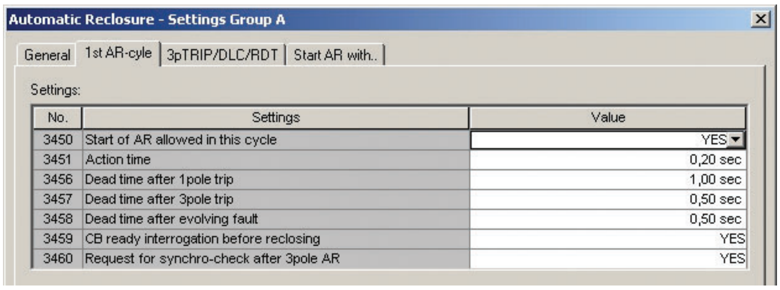
3408 AR start-signal monitoring time:
If the AR start signal (protection trip) does not reset after a reasonable time (breaker operating time plus protection reset time), then a problem with either the circuit-breaker (breaker failure) or the protection exists and the reclose cycle must not be started. Here the maximum time for the initiate signal is set. If it takes longer, the AR cycle is not started and a final trip condition is set. Apply a setting of twice the breaker operating time plus protection reset time, i.e. **0.20 s**.

3409 Circuit Breaker (CB) Supervision Time:
As the CB ready status will be checked prior to issue of the close command, a time limit must be applied during which this ready status must be reached. If it takes longer, a final trip status is set and reclosure does not take place. This time limit is set here to be **3.00 s**.

3410 Send delay for remote close command:
The AR function can be applied to send a close command to the remote end via communication channels. This is not applied here, so the time is left on the default setting of infinity, **∞ s**.

3411A Maximum dead time extension:
The AR function can be applied to wait for release by sync. check or CB status before release of close command. Here, the maximum extension of the dead time in the course of waiting for release conditions is set. In practice, a limitation to less than 1 minute is practical. In this application **10 s** will be used.

19.2 1st auto reclose cycle



No.	Settings	Value
3450	Start of AR allowed in this cycle	YES
3451	Action time	0,20 sec
3456	Dead time after 1pole trip	1,00 sec
3457	Dead time after 3pole trip	0,50 sec
3458	Dead time after evolving fault	0,50 sec
3459	CB ready interrogation before reclosing	YES
3460	Request for synchro-check after 3pole AR	YES

Fig. 58 1st AR cycle settings, automatic reclosure

3450 Start of AR allowed in this cycle:
As this is the only AR cycle that is applied, starting must be allowed in this cycle, so set this parameter to **YES**.

3451 Action time:
As indicated with parameter 134 in Chapter 4, the action time is used to differentiate between faults cleared without delay by the main protection and backup protection operation for external faults. The action time must be set below the calculated coordination time step (0.25 s) and must be longer than the slowest operation with teleprotection (60 ms). A time of **0.20 s** is applied.

3456 Dead time after 1pole trip:
The dead time must allow for the arc gases to dissipate. During single-pole trip this time is longer, because the arc is still supplied by capacitive coupled current from the healthy phases after the circuit-breaker is open single pole. In practice a time of **1.00 s** has proven to provide good results.

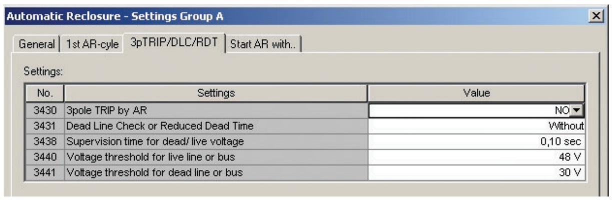
3457 Dead time after 3pole trip:
The dead time must allow for the arc gases to dissipate. During three-pole trip this time is short. In practice a time of **0.50 s** has proven to provide good results.

3458 Dead time after evolving fault:
As set in parameters 3407 and 3408 above, a three-pole dead time will be started in the case of evolving fault. Here the same time as in parameter 3457 can be used because this time is started with the three-pole trip issued due to the fault evolving from single to three phase. Therefore set **0.50 s**.

3459 CB ready interrogation before reclosing:
As stated above, the CB status will be checked before issue of close command. Therefore set **YES**.

3460 Request for synchro-check after 3pole AR:
The sync. check condition must be checked before issue of close command. Therefore set **YES**.

19.3 3pTRIP / dead line charge / reduced dead time



No.	Settings	Value
3430	3pole TRIP by AR	NO
3431	Dead Line Check or Reduced Dead Time	Without
3438	Supervision time for dead/ live voltage	0,10 sec
3440	Voltage threshold for live line or bus	48 V
3441	Voltage threshold for dead line or bus	30 V

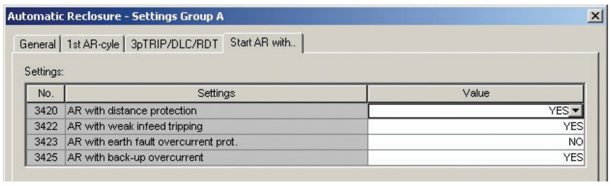
Fig. 59 3-pole Trip/DLC/RDT settings, automatic reclosure

3430 3pole TRIP by AR:
If the AR function is initiated by single-pole trip signals, it may in the course of a single-pole AR cycle detect that the conditions for single-pole reclosure are no longer valid (e.g. because of further single-pole trip during the dead time or auxiliary contact status from the breaker indicating multiple pole open, etc.). In such an event, the AR function may issue a three-pole trip before proceeding with a three-pole AR cycle or setting the final trip condition. This setting determines whether the AR function will issue such a three-pole trip. In this application no external initiate signals are applied so this setting is set to **NO**, because the internal protection functions can manage their own three-pole coupling of the trip signal when required.

3431 Dead Line Check or Reduced Dead Time:
Special reclose programs can be applied to prevent repetitive reclose onto fault and to minimise dead times. In this application these programs are not used, so set **Without**.

The settings 3438, 3440 and 3441 are of no consequence, because 3431 is set to "Without".
Leave these settings on their default values.

19.4 Start autoreclose


Automatic Reclosure - Settings Group A

General | 1st AR-cyle | 3pTRIP/DLC/RDT | Start AR with..

Settings:

No.	Settings	Value
3420	AR with distance protection	YES
3422	AR with weak infeed tripping	YES
3423	AR with earth fault overcurrent prot.	NO
3425	AR with back-up overcurrent	YES

LSP2628.tif

Fig. 60 Settings for starting the AR, Automatic reclosure

3420 AR with distance protection:
The distance protection will trip single pole and three pole and start the autoreclosure, so set **YES** here.

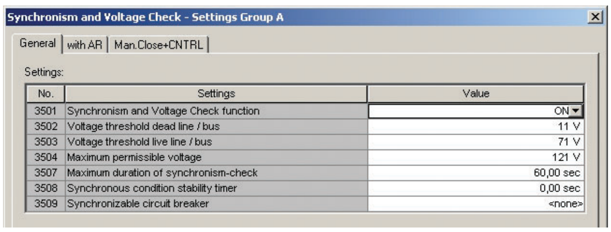
3422 AR with weak infeed tripping:
The weak infeed tripping will trip single pole and three pole and start the autoreclosure, so set **YES** here.

3423 AR with earth fault overcurrent prot.:
The earth-fault overcurrent protection will trip three pole and not start the autoreclosure, so set **NO** here.

3425 AR with back-up overcurrent:
The backup overcurrent protection will trip and start the autoreclosure, so set **YES** here. Note that due to the action time (parameter 3451 in Chapter 19.2) only the accelerated trip with teleprotection will result in reclosure.

20. Synchronism and voltage check – Setting Group A

20.1. General


Synchronism and Voltage Check - Settings Group A

General | with AR | Man.Close+CNTRL

Settings:

No.	Settings	Value
3501	Synchronism and Voltage Check function	ON
3502	Voltage threshold dead line / bus	11 V
3503	Voltage threshold live line / bus	71 V
3504	Maximum permissible voltage	121 V
3507	Maximum duration of synchronism-check	60,00 sec
3508	Synchronous condition stability timer	0,00 sec
3509	Synchronizable circuit breaker	<none>

LSP2638.tif

Fig. 61 General settings for synchronism and voltage check

3501 Synchronism and Voltage Check function:
In this application the synchro check is used, so this function must be selected **ON**.

3502 Voltage threshold dead line/bus:
If the measured line/bus voltage is below this set threshold, the line/bus is considered to be switched off (dead). In this application the L3-L1 phase to phase voltage is used for synchronism check, so that the voltage thresholds must be based on phase to phase voltage. In general, a setting of 10 % can be applied, when the voltage is below 10 %, the line/bus is definitely dead.

Where parallel lines can couple in larger voltages onto the dead line, a higher setting may be appropriate. In this case, no parallel lines exist, so the setting of 10 % will be used:

$U_{dead} = 0.1 \cdot U_N$

$U_{dead} = 0.1 \cdot 110 = 11\ \mathrm{V}$

The value for U_N in this case (110 V) is based on the busbar voltage transformers (phase to phase), as this results in the larger (more conservative) setting. Apply the setting of **11 V**.

3503 Voltage threshold live line/bus:
If the measured line/bus voltage is above this set threshold, the line/bus is considered to be switched on (live). In this application the L3-L1 phase to phase voltage is used for synchronism check, so that the voltage thresholds must be based on phase to phase voltage. The setting must be below (20 % safety clearance) the minimum anticipated operating voltage (in this example 85 % of the nominal voltage):

$U_{live} = 0.8 \cdot 0.85 \cdot U_N$

$$U_{live} = 0.8 \cdot 0.85 \cdot \frac{400\ \mathrm{kV}}{380\ \mathrm{kV}} \cdot 100 = 71.6\ \mathrm{V}$$

The value for U_N in this case (400/380 ·110 V) is based on the line voltage transformers (phase to phase), as this results in the lower (more conservative) setting. Apply the setting of **71 V**.

3504 Maximum permissable voltage:
If the measured line or bus voltage is above this setting, it is considered to be a too large operating voltage for release of a close command. This setting must be above the highest expected operating voltage that is still acceptable for release of the close command. In general, a setting of 110 % of the normal operating voltage is recommended. On long lines, the local line voltage fed from the remote end may rise to a higher value due to the Ferranti effect (normally compensated by shunt reactors on the line). In this case, a higher setting may be required. In this example we will use a **110 %** setting:

$U_{max} = 1.10 \cdot U_N$

$U_{max} = 1.10 \cdot 110 = 121\ \mathrm{V}$

The value for U_N in this case (110 V) is based on the busbar voltage transformers (phase to phase), as this results in the larger (more conservative) setting. Apply the setting of **121 V**.

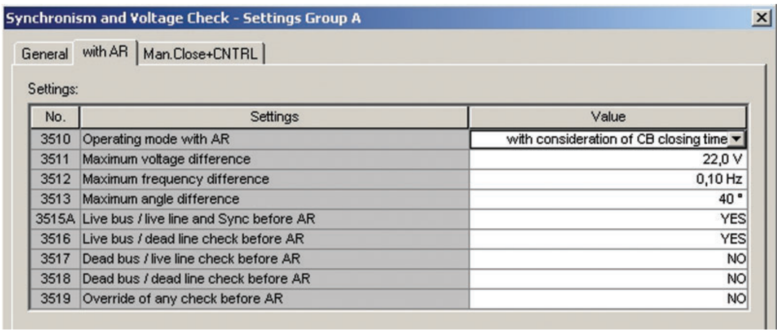
3507 Maximum duration of synchronism check: If the synchronism check conditions are not obtained within this set time, the sync. check is terminated without release or close. The person that issues the sync. check request (operator close command initiation) expects a response from the switchgear within a reasonable time. This time should be set to the maximum time such operating personnel would accept to wait for a response. Typically, a setting of **60.00 s** is an acceptable delay.

3508 Synchronous condition stability timer: When the set synchro check conditions are met, the release can be delayed by this setting to ensure that this condition is not only a transient condition. In general, this additional stability check is not required, so that this setting can be set to **0.00 s**.

3509 Synchronizable circuit breaker: The integrated control functions may also trigger the sync. check measurement. For this purpose the appropriate switchgear item can be selected in this setting. In this application example, the integrated control functions are not used, so that the setting **<none>** is applied.

20.2. Settings for operation with auto-reclosure

The following group of settings is relevant for close commands that originate from the auto-reclose function. This can be the internal AR, which is directly coupled with the internal sync. check, or an external AR device that couples the trigger signal via binary input to the sync. check function.


Synchronism and Voltage Check - Settings Group A

General | with AR | Man.Close+CNTRL

Settings:

No.	Settings	Value
3510	Operating mode with AR	with consideration of CB closing time
3511	Maximum voltage difference	22,0 V
3512	Maximum frequency difference	0,10 Hz
3513	Maximum angle difference	40 °
3515A	Live bus / live line and Sync before AR	YES
3516	Live bus / dead line check before AR	YES
3517	Dead bus / live line check before AR	NO
3518	Dead bus / dead line check before AR	NO
3519	Override of any check before AR	NO

LSP3639.tif

Fig. 62 Sync. check settings for auto-reclose trigger

3510 Operating mode with AR: If the close release must be possible under asynchronous conditions (line and bus frequency are not the same), then the circuit-breaker closing time must be considered for timing of the close command. Refer to setting 239 in Chapter 7.3. In this example closing under asynchronous conditions must be possible, so apply the setting: **with consideration of CB closing time**.

3511 Maximum voltage difference: In this setting the maximum voltage magnitude difference is set. If the magnitudes of the line and bus voltage differ by more than this setting, the sync. check function will not release reclosure. As sync. check is done with phase to phase voltage in this case, the setting must be based on ph-ph voltage. Use the difference between the maximum and minimum operating voltage to obtain the worst case result:

$$U_{\text{Diff max}} = (U_{\text{N max}} - U_{\text{N min}})$$

$$U_{\text{Diff max}} = \left(121 - \frac{400\ \text{kV}}{380\ \text{kV}} \cdot 100 \cdot 0.85\right)$$

$$U_{\text{Diff max}} = 31.5\ \text{V}$$

A setting of 31.5 V is under normal circumstances too large, as switching with such a large delta would cause a severe transient in the system. Unless special circumstances exist, such as very long lines with Ferranti voltage rise or very weak interconnections without voltage compensation (e.g. tap changers), an upper limit of approximately 20 % of the nominal voltage should be applied:

$$U_{\text{Diff max}} = 0.2 \cdot U_{\text{N}}$$

$$U_{\text{Diff max}} = 0.2 \cdot 110 = 22\ \text{V}$$

Therefore, apply a setting of **22 V**.

3512 Maximum frequency difference: If the frequency difference between line and bus voltage is less than this setting, the sync. check conditions for async. switching can be used. The sync. conditions for switching apply, if the frequency difference is less than 0.01 Hz. Switching with large frequency difference will cause severe transients to the system. In common practice, an upper limit of **0.10 Hz** is suitable.

3513 Maximum angle difference:
Under synchronous switching conditions (f_{diff} < 0.01 Hz) the angle difference between the bus and line voltage is also checked. This angle under synchronous conditions is stable and mainly due to the transmission angle of the system. In this example, a maximum angle of **40°** will be applied.

3515A Live bus / live line and Sync before AR:
In this application, the auto-reclose function may initiate closing when bus and line voltage are live; therefore set **YES**. The above sync. check conditions will then be monitored before closing is released.

3516 Live bus / dead line check before AR:
In this application, the auto-reclose function may initiate closing to energise a dead line; therefore set **YES**.

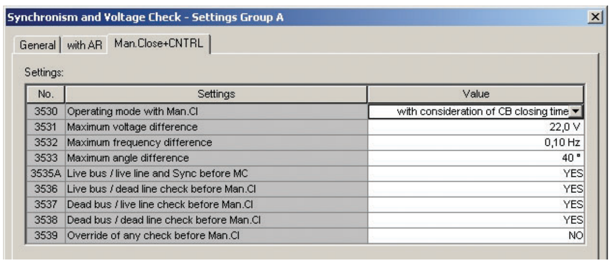
3517 Dead bus / live line check before AR:
In this application, the auto-reclose function may not initiate closing to energise a dead bus; therefore set **NO**.

3518 Dead bus / dead line check before AR:
In this application, the auto-reclose function may not initiate closing to connect a dead bus to a dead line; therefore set **NO**.

3519 Override of any check before AR:
The sync. check override is only used during testing or commissioning. Therefore set **NO**.

20.3 Settings for operation with manual close and control

The following group of settings is relevant for close commands that originate from the manual close binary input or internal control function.



No.	Settings	Value
3530	Operating mode with Man.Cl	with consideration of CB closing time
3531	Maximum voltage difference	22,0 V
3532	Maximum frequency difference	0,10 Hz
3533	Maximum angle difference	40 °
3535A	Live bus / live line and Sync before MC	YES
3536	Live bus / dead line check before Man.Cl	YES
3537	Dead bus / live line check before Man.Cl	YES
3538	Dead bus / dead line check before Man.Cl	YES
3539	Override of any check before Man.Cl	NO

LSP2640.tif

Fig. 63 Sync. check settings for manual close and control input trigger

3530 Operating mode with Man.Cl:
If the close release must be possible under asynchronous conditions (line and bus frequency are not the same), then the circuit-breaker closing time must be considered for timing of the close command. Refer to setting 239 in Chapter 7.3. In this example closing under asynchronous conditions must be possible, so apply the setting: **with consideration of CB closing time**.

3531 Maximum voltage difference:
The same consideration as for the AR closing in parameter 3511 applies. Therefore, apply a setting of **22 V**.

3532 Maximum frequency difference:
The same consideration as for the AR closing in parameter 3512 applies. Therefore, apply a setting of **0.10 Hz**.

3533 Maximum angle difference:
The same consideration as for the AR closing in parameter 3513 applies. Therefore, apply a setting of **40°**.

3535A Live bus / live line and Sync before MC:
In this application, the manual close may initiate closing when bus and line voltage are live; therefore set **YES**. The above sync. check conditions will then be monitored before closing is released.

3536 Live bus / dead line check before Man.Cl.:
It is common practice to allow all closing modes for manual close, so apply the setting **YES**.

3537 Dead bus / live line check before Man.Cl.:
Refer to setting 3536; therefore set **YES**.

3538 Dead bus / dead line check before Man.Cl.:
Refer to setting 3536; therefore set **YES**.

3539 Override of any check before Man.Cl.:
The sync. check override is only used during testing or commissioning. Therefore set **NO**.

21. Fault locator – Setting Group A

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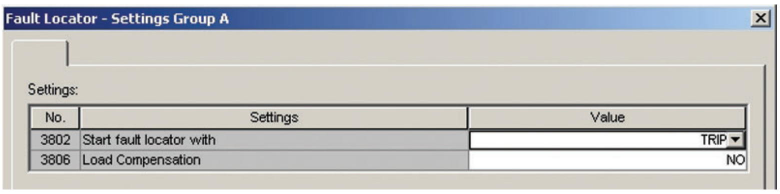

Fig. 64 Fault locator settings

3802 Start fault locator with:
The fault locator can only provide meaningful data for faults on the protected line unless the downstream feeders are in a pure radial configuration without intermediate infeed. In this application, there is infeed at the remote bus, so that the fault locator data is only desired when the protection trips for internal faults. Therefore apply the setting with **TRIP**.

3806 Load Compensation:
The result of the single ended fault location computation may be inaccurate due to the influence of load angle and fault resistance. This was described in conjunction with the parameter 1307 in Chapter 11.1. For single phase to ground faults and for phase to phase faults without ground a load compensated measurement can be applied to achieve better results. This function does not work under all conditions, and a fault location output that closely resembles the protection operation is desired in this application, so the load compensation is switched off by setting **NO** here.

22. Oscillographic fault records

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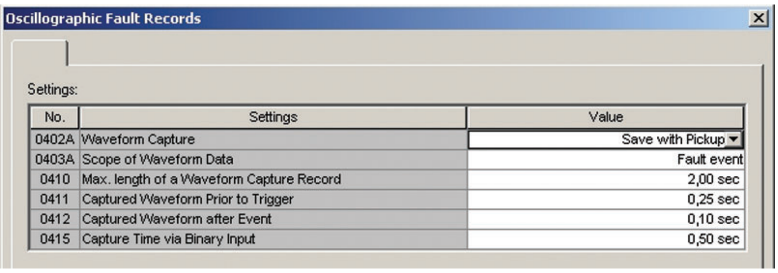

Fig. 65 Settings for the oscillographic fault recording

0402A Waveform Capture:
In this application a recording must be saved during internal and external faults, even if the relay does not trip. Therefore apply the setting **Save with Pickup** to save the recording every time the relay detects a fault (picks up).
With settings 0403A to 0415, the length and configuration of the oscillographic record can be set to match the user requirements.

23. General device settings

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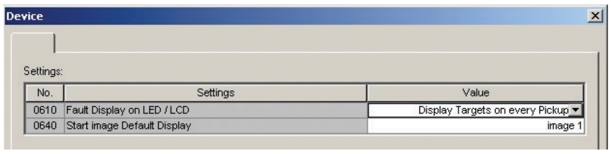

Fig. 66 General device settings

0610 Fault Display on LED / LCD:
The LED and LCD image/text can be updated following pickup or latched with trip. In this application the last pickup will be indicated: **Display Targets on every Pickup**.

0640 Start image Default Display:
The LCD display during default conditions (no fault detection or trip) can be selected from a number of standard variants. Here, variant 1 is selected with the setting **image 1**.

24. Time synchronization & time format settings

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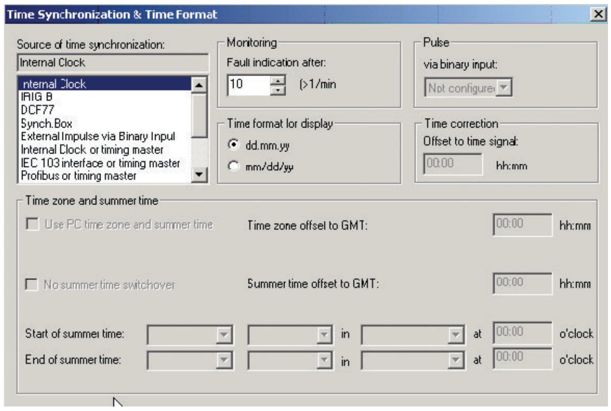
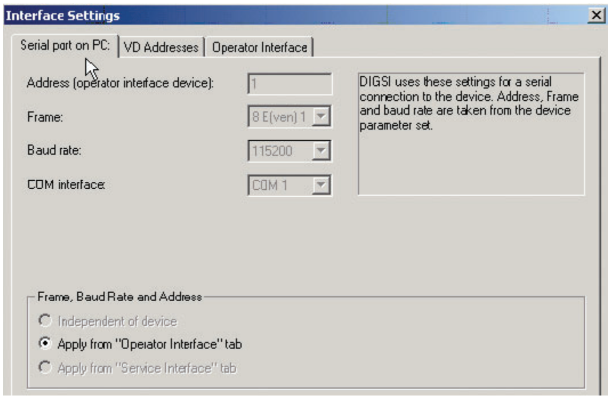


Fig. 67 Time synchronization and time format settings

Time synchronization settings can be applied here. Various sources for synchronizing the internal clock exist as shown in Figure 67.

25. Interface settings

25.1 Serial port on PC settings

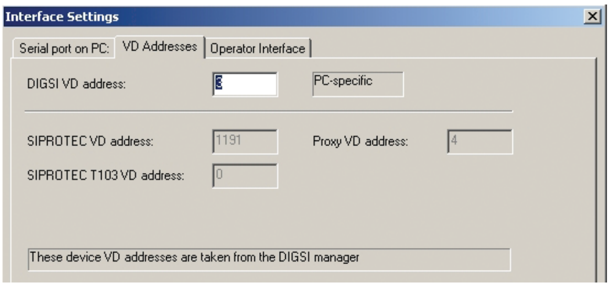


LSP2633.tif

Fig. 68 Settings for serial port on PC

The PC serial port configuration is shown here. No settings are required in this case.

25.2 VD address settings

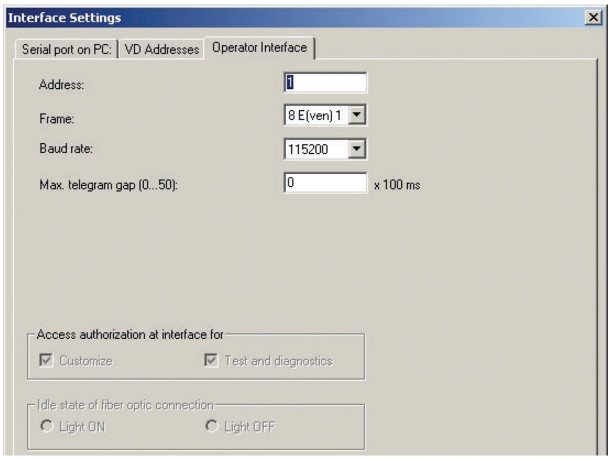


LSP2634.tif

Fig. 69 Settings for VD address

These addresses can be left on default values.

25.3 Operator interface settings

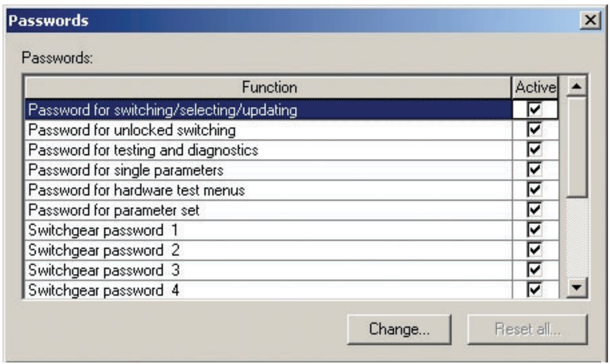


LSP2635.tif

Fig. 70 Settings for operator interface

The settings here apply to the system interface, if this is used.

26. Password settings

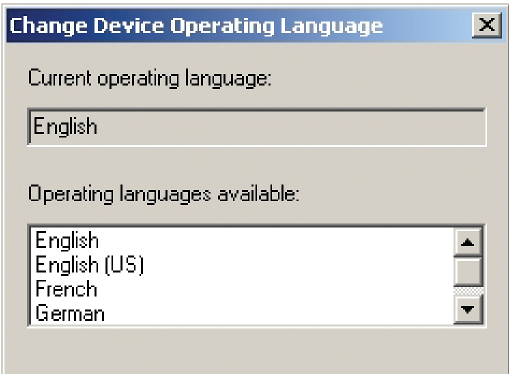


LSP2636.tif

Fig. 71 Settings for password access

Various password access levels can be applied as shown in Figure 71.

27. Language settings



LSP2637.tif

Fig. 72 Settings for language in the device

The language settings shown depend on the languages that are installed with the DIGSI device driver on the PC.

28. Summary

SIPROTEC 7SA6 protection relays comprise the functions required for overall protection of a line feeder and can thus be used universally. The diversity of parameterization options enables the relay to be adapted easily and clearly to the respective application using the DIGSI 4 operating program.

Many of the default settings can easily be accepted and thus facilitate the work for parameterization and setting. Already when ordering, economic solutions for all voltage levels can be realized by selection of the scope of functions.

Directional Phase Overcurrent Protection ANSI 67 with 7SA522 and 7SA6

1. Introduction

The implementation of a directional overcurrent stage (ANSI 67) in the distance protection relays 7SA522 and 7SA6 is possible via a simple coupling of the distance protection directional stage (in this case Zone 5) with one of the overcurrent stages (in this example stage *I*>) in the relay.
The distance protection and the directional overcurrent protection use the same measured signals, phase current and phase voltage, but the impedance measurement achieves both higher sensitivity and higher selectivity.
This document illustrates how easily the ANSI 67 function can be implemented in the 7SA522 and 7SA6 by using the CFC logic.

2. General parameters for implementation of directional overcurrent (ANSI 67)

The settings of the relay can be applied as required by the application as usual. For the ANSI 67 function at least the functions 0112 Phase Distance, 0113 Earth Distance and 0126 Backup Overcurrent must be activated in the relay configuration (Fig. 2):

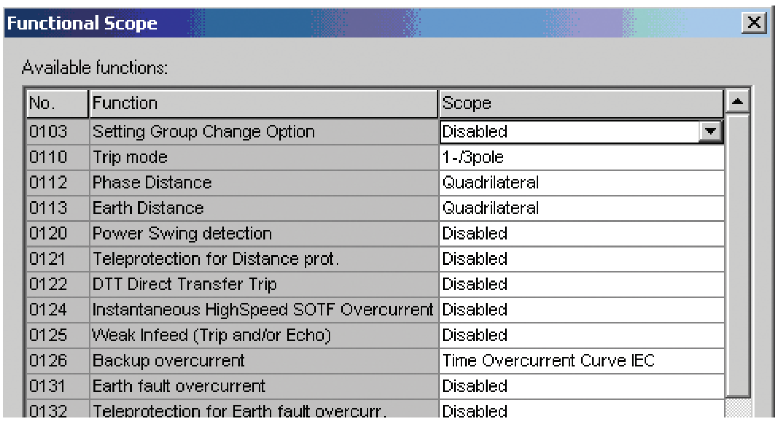
Setting parameter of 67	Designation	Example Value (secondary 1 A)
Pick-up threshold	I_{67}> pick-up	2.5 A
Time delay	Time 67	0.5 s

Table 1 Parameters for directional overcurrent I_{67}

Setting block: Relay configuration

The distance protection must be enabled (quadrilateral or MHO) for phase faults: Parameter 0112. Backup overcurrent must be enabled (time overcurrent IEC or ANSI): Parameter 0126

Fig. 1 SIPROTEC line protection 7SA522 and 7SA6



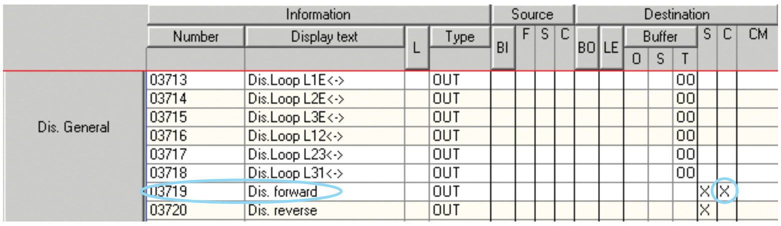
No.	Function	Scope
0103	Setting Group Change Option	Disabled
0110	Trip mode	1-/3pole
0112	Phase Distance	Quadrilateral
0113	Earth Distance	Quadrilateral
0120	Power Swing detection	Disabled
0121	Teleprotection for Distance prot.	Disabled
0122	DTT Direct Transfer Trip	Disabled
0124	Instantaneous HighSpeed SOTF Overcurrent	Disabled
0125	Weak Infeed (Trip and/or Echo)	Disabled
0126	Backup overcurrent	Time Overcurrent Curve IEC
0131	Earth fault overcurrent	Disabled
0132	Teleprotection for Earth fault overcurr.	Disabled

LSP2748.tif

Fig. 2 Setting of functional scope

Matrix: Masking I/O (configuration matrix)

Assign the signal "3719 Distance forward" in the "Distance General" block to destination CFC.



	Number	Display text	L	Type	BI	F	S	C	BO	LE	Buffer O	Buffer S	Buffer T	S	C	CM
Dis. General	03713	Dis.Loop L1E<->		OUT									00			
	03714	Dis.Loop L2E<->		OUT									00			
	03715	Dis.Loop L3E<->		OUT									00			
	03716	Dis.Loop L12<->		OUT									00			
	03717	Dis.Loop L23<->		OUT									00			
	03718	Dis.Loop L31<->		OUT									00			
	03719	Dis. forward		OUT										X	X	
	03720	Dis. reverse		OUT										X		

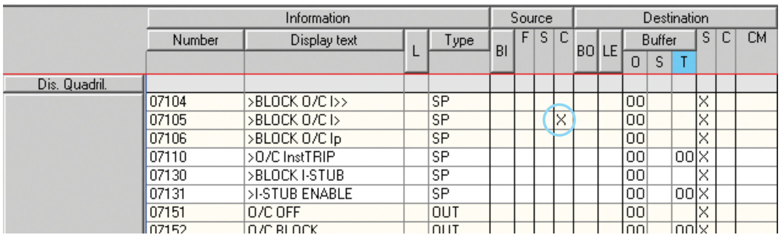
LSP2749.tif

Fig. 3 Masking of dist. signals in configuration matrix

Select that stage in the backup overcurrent that must be directional (ANSI 67). For this stage assign the corresponding blocking input signal to source CFC. Therefore either:

7104 >Block O/C I>> or
7105 >Block O/C I> (used in this example) or
7106 >Block O/C I_p

Multiple assignment is also possible.



	Number	Display text	L	Type	BI	F	S	C	BO	LE	Buffer O	Buffer S	Buffer T	S	C	CM
Dis. Quadril.																
	07104	>BLOCK O/C I>>		SP							00			X		
	07105	>BLOCK O/C I>		SP				X			00			X		
	07106	>BLOCK O/C Ip		SP							00			X		
	07110	>O/C InstTRIP		SP							00		00	X		
	07130	>BLOCK I-STUB		SP							00			X		
	07131	>I-STUB ENABLE		SP							00		00	X		
	07151	O/C OFF		OUT							00			X		
	07152	O/C BLOCK		OUT							00		00	X		

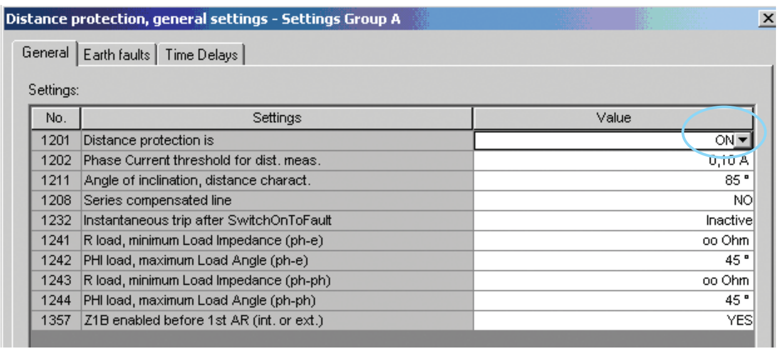
LSP2750.tif

Fig. 4 Masking of overcurrent signals in configuration matrix

■ 3. Special setting for the distance protection

The distance protection sensitivity must be greater than or equal to that of the required directional overcurrent protection. This does not present any problems, as the directional overcurrent protection will be set less sensitive than the maximum load current while the distance protection is set more sensitive than the smallest fault current.

In the relevant setting group (e.g. Setting Group A) the following distance protection settings must be checked:



Distance protection, general settings - Settings Group A

General | Earth faults | Time Delays

Settings:

No.	Settings	Value
1201	Distance protection is	ON
1202	Phase Current threshold for dist. meas.	0,10 A
1211	Angle of inclination, distance charact.	85 °
1208	Series compensated line	NO
1232	Instantaneous trip after SwitchOnToFault	Inactive
1241	R load, minimum Load Impedance (ph-e)	oo Ohm
1242	PHI load, maximum Load Angle (ph-e)	45 °
1243	R load, minimum Load Impedance (ph-ph)	oo Ohm
1244	PHI load, maximum Load Angle (ph-ph)	45 °
1357	Z1B enabled before 1st AR (int. or ext.)	YES

LSP2751.tif

Fig. 5 Distance protection function general setting

1201 Distance protection is **ON**
1202 Phase current threshold for distance measurement ≤ I_{67}> pick-up (Table 1)

To calculate the minimum reach setting of the distance protection, the overcurrent characteristic is shown in the impedance plane below in Fig. 6:

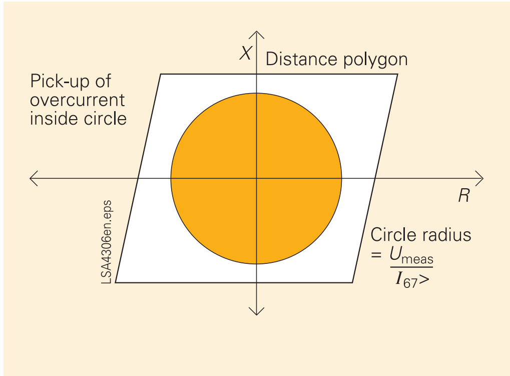


Fig. 6 Pick-up characteristic of overcurrent protection in impedance plane

From Fig. 6 it is apparent, that the largest circle radius must be determined to set the minimum impedance reach so that a direction decision is available when the overcurrent stage picks up. The maximum circle radius is obtained when the measured fault voltage together with fault current at pick-up threshold occurs. If the maximum operating voltage (unfaulted) is used, a large safety factor is already incorporated as the fault voltage will always be less than this.

$$Circle\_radius = \frac{U_{operating\ \max}}{\sqrt{3} \cdot (I_{67} > pick-up)}$$

In this example the rated secondary VT voltage is 100 V. The maximum operating voltage is 110% of rated, so the following circle radius can be calculated:

$$Circle\_radius = \frac{100 \cdot 1.1}{\sqrt{3} \cdot 2.5}$$

$$Circle\_radius = 25.4\ \Omega$$

The setting 1243 R load, minimum load impedance (ph-ph) must be greater than the calculated circle radius. In practice, this is no problem because this setting is calculated with a similar equation using the maximum load current instead of the overcurrent pick-up (I_{67}> pick-up) which must be greater than the maximum load current. Therefore, this setting when applied is by nature greater than the circle radius calculated here.

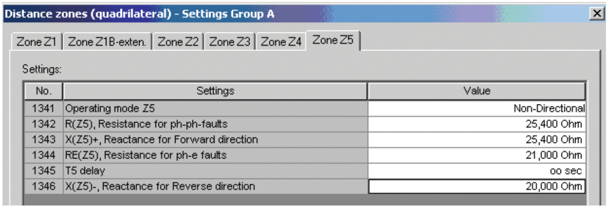
At least one of the set distance protection zones with forward or non-directional reach must have a reach greater than the circle radius. In this example the Zone 5 has the largest reach, and it is set non-directional. In this case the following must be checked:

1341 Operating mode Zone 5 is non-directional

1342 R(Z5) resistance for ph-ph faults ≥ Circle radius (25.4 Ω)

1343 X+(Z5) reactance for forward direction ≥ Circle radius (25.4 Ω)

If none of the applied zones has a sufficiently large reach, a special zone must be selected for this purpose. This zone must then be set as non-directional (for MHO set forward) with an *X* and *R* reach equal to the calculated circle radius (25. 4 Ω in this example). The time delay of this zone can be set to infinity (∞) to avoid tripping by the distance protection in this zone if required.



Distance zones (quadrilateral) - Settings Group A

Zone Z1 | Zone Z1B-exten. | Zone Z2 | Zone Z3 | Zone Z4 | Zone Z5

Settings:

No.	Settings	Value
1341	Operating mode Z5	Non-Directional
1342	R(Z5), Resistance for ph-ph-faults	25,400 Ohm
1343	X(Z5)+, Reactance for Forward direction	25,400 Ohm
1344	RE(Z5), Resistance for ph-e faults	21,000 Ohm
1345	T5 delay	oo sec
1346	X(Z5)-, Reactance for Reverse direction	20,000 Ohm

LSP2753.tif

Fig. 7 Zone settings of non-directional zone

4. Setting the backup overcurrent stage for ANSI 67

The backup overcurrent must be operated as backup protection so that it is always active:

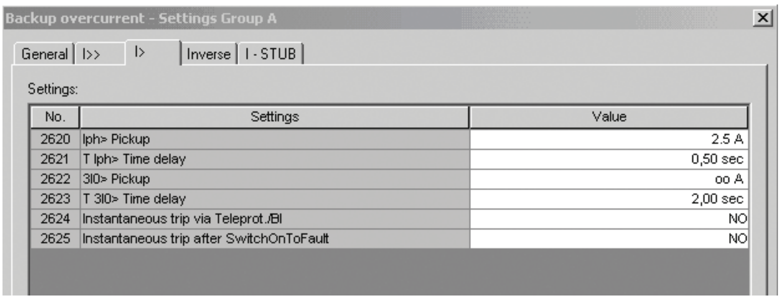
2601 Operating mode ON: always active

In the backup overcurrent proctection the following settings must be applied to the stage that is intended for the ANSI 67 function. In this example stage *I*> will be used:

2620 I_{ph}> pick-up value
set equal to required I_{67}> pick-up (in this example 2.5 A)

2621 T I_{ph}> time delay
set equal to the desired 67 time delay (in this example 0.5 s)

2622 3I_0> pick-up value
disabled by setting to infinity (∞)



Backup overcurrent - Settings Group A

General | I>> | I> | Inverse | I - STUB

Settings:

No.	Settings	Value
2620	Iph> Pickup	2.5 A
2621	T Iph> Time delay	0,50 sec
2622	3I0> Pickup	oo A
2623	T 3I0> Time delay	2,00 sec
2624	Instantaneous trip via Teleprot./BI	NO
2625	Instantaneous trip after SwitchOnToFault	NO

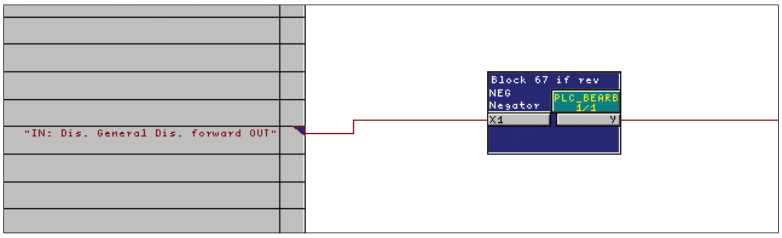
LSP2752.tif

Fig. 8 Settings for backup overcurrent function (*I*> in this example)

5. Setting up the CFC logic

In the CFC logic, the absence of a forward detection by the distance protection (in this case Zone 5) will be used to block the backup overcurrent stage (in this example stage *I*<).

In the fast PLC, insert a negator and route the signal "Dis forward" to its input. Route the negator output to the relevant blocking input to the backup overcurrent stage.



LSP2754.tif

Fig. 9 Input signal allocation in the CFC logic

6. Testing the ANSI 67 function

To test the directional overcurrent, a forward and a reverse fault condition were simulated with the Omicron®state sequencer. For both faults, the fault current level was set to 10 % above pick-up of the ANSI 67 function, 2.75 A. The angle between current and voltage for the forward fault was 0° and for the reverse fault 180°.

The fault recordings and trip log for these two cases are shown on the following page:

The trip log (Fig. 10) shows the trip signal by the backup O/C *I*> stage after 510 ms.

Trip Log - 000002 / 12.07.2004 16:05:03.111 - Test / Testbox / 7SA522 0C67 V4.3/7SA522

Number	Indication	Value	Date and time
00301	Power System fault	2 - ON	12.07.2004 16:05:03.111
00302	Fault Event	2 - ON	12.07.2004 16:05:03.111
03693	Distance Pickup L123	ON	0 ms
03704	Distance Loop L12 selected forward	ON	0 ms
03705	Distance Loop L23 selected forward	ON	0 ms
03706	Distance Loop L31 selected forward	ON	0 ms
07162	Backup O/C PICKUP L1	ON	10 ms
07163	Backup O/C PICKUP L2	ON	10 ms
07164	Backup O/C PICKUP L3	ON	10 ms
07184	Backup O/C Pickup L123	ON	10 ms
07192	Backup O/C Pickup I>	ON	10 ms
07215	Backup O/C TRIP Phases L123	ON	510 ms
07222	Backup O/C TRIP I>	ON	510 ms
00533	Primary fault current IL1	2,75 kA	514 ms
00534	Primary fault current IL2	2,75 kA	514 ms
00535	Primary fault current IL3	2,75 kA	514 ms
03805	Distance TRIP command Phases L123	ON	900 ms
07161	Backup O/C PICKED UP	OFF	989 ms
03671	Distance PICKED UP	OFF	999 ms
03704	Distance Loop L12 selected forward	OFF	1000 ms
03705	Distance Loop L23 selected forward	OFF	1000 ms
03706	Distance Loop L31 selected forward	OFF	1000 ms
00511	Relay GENERAL TRIP command	OFF	1000 ms
01128	Fault Locator Loop L3L1	ON	894 ms
01117	Flt Locator: secondary RESISTANCE	21,84 Ohm	894 ms
01118	Flt Locator: secondary REACTANCE	0,07 Ohm	894 ms
01114	Flt Locator: primary RESISTANCE	87,36 Ohm	894 ms
01115	Flt Locator: primary REACTANCE	0,27 Ohm	894 ms
01119	Flt Locator: Distance to fault	0,5 km	894 ms
01120	Flt Locator: Distance [%] to fault	0,5 %	894 ms

LSP2755.tif

Fig. 10 Trip log for forward fault

Trip Log - 000003 / 12.07.2004 16:06:00.775 - Test / Testbox / 7SA522 0C67 V4.3/7SA522

Number	Indication	Value	Date and time	Initiator
00301	Power System fault	3 - ON	12.07.2004 16:06:00.775	
00302	Fault Event	3 - ON	12.07.2004 16:06:00.775	
03693	Distance Pickup L123	ON	0 ms	
03710	Distance Loop L12 selected reverse	ON	0 ms	
03711	Distance Loop L23 selected reverse	ON	0 ms	
03712	Distance Loop L31 selected reverse	ON	0 ms	
03805	Distance TRIP command Phases L123	ON	900 ms	
00533	Primary fault current IL1	2,75 kA	904 ms	
00534	Primary fault current IL2	2,75 kA	905 ms	
00535	Primary fault current IL3	2,75 kA	905 ms	
03671	Distance PICKED UP	OFF	1000 ms	
03710	Distance Loop L12 selected reverse	OFF	1000 ms	
03711	Distance Loop L23 selected reverse	OFF	1000 ms	
03712	Distance Loop L31 selected reverse	OFF	1000 ms	
00511	Relay GENERAL TRIP command	OFF	1001 ms	
01128	Fault Locator Loop L3L1	ON	894 ms	
01117	Flt Locator: secondary RESISTANCE	-21,82 Ohm	894 ms	
01118	Flt Locator: secondary REACTANCE	-0,07 Ohm	894 ms	
01114	Flt Locator: primary RESISTANCE	-87,28 Ohm	894 ms	
01115	Flt Locator: primary REACTANCE	-0,28 Ohm	894 ms	
01119	Flt Locator: Distance to fault	-0,5 km	894 ms	
01120	Flt Locator: Distance [%] to fault	-0,5 %	894 ms	

LSP2756.tif

Fig. 11 Trip log of reverse fault

7. Summary

The implementation of a directional overcurrent stage (ANSI 67) in the distance protection relays 7SA522 and 7SA6 is possible via a simple coupling of the distance protection directional release with one of the overcurrent stages in the relay.
If one of the other backup overcurrent stages is required as an emergency protection in the event that the distance protection is blocked due to fuse failure, a similar logic may be implemented whereby the blocking signal is derived from the Fuse Fail alarm (170).

Distance Protection with Parallel Compensation

Environmental and cost consciousness are forcing utilities to install more and more parallel lines. The close arrangement of the transmission lines leads to a higher fault rate and to influencing of the measuring results. The considerable influence exerted by parallel lines on the measuring results (of up to 30 % in distance protection) and the remedial actions are considered in this application example.

■ 1. Explanation of the term parallel line

1.1 Parallel lines with common positive and negative-sequence systems

The two parallel lines have the same infeed at both line ends.

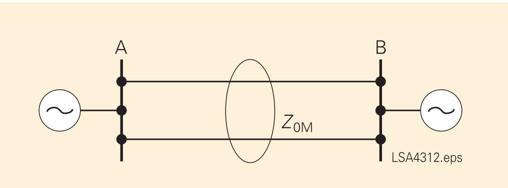


Fig. 1 Parallel lines with same infeed at both line ends

In this arrangement where both systems are connected with the same infeed, it is possible (for distance protection) to compensate the influence of the parallel line.

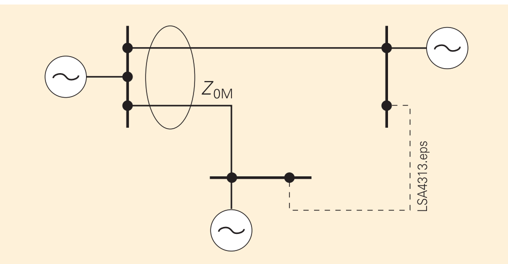


Fig. 2 Parallel line with only one common infeed

In this arrangement of parallel lines the effect can only be compensated on one side.

Fig. 3 Parallel lines over the Bosporus

1.2 Parallel lines with common positive-sequence and independent zero-sequence system

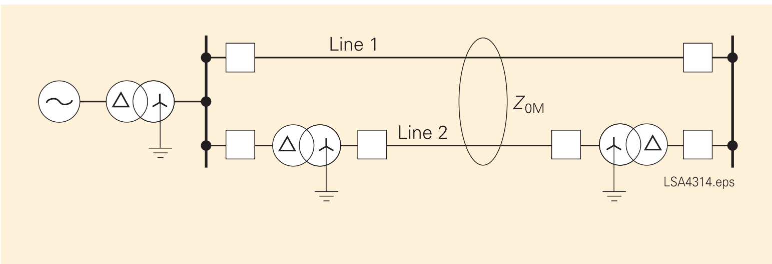


Fig. 4 Parallel line with common infeed at a common tower

This arrangement of parallel lines does not influence the distance measurement.

1.3 Parallel lines with isolated positive and zero-sequence systems

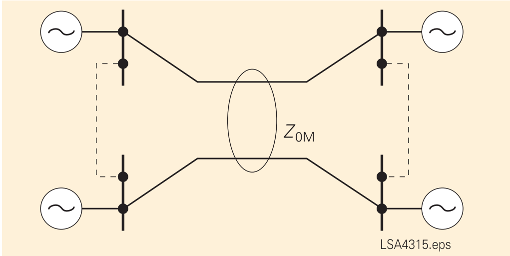


Fig. 5 Parallel lines with separate infeed

This is the most unfavorable arrangement for distance protection. Compensation of the inductive coupling of the circuits is not possible.

This arrangement causes a complicated fault voltage and current distribution due to the inductive coupling.

2. General

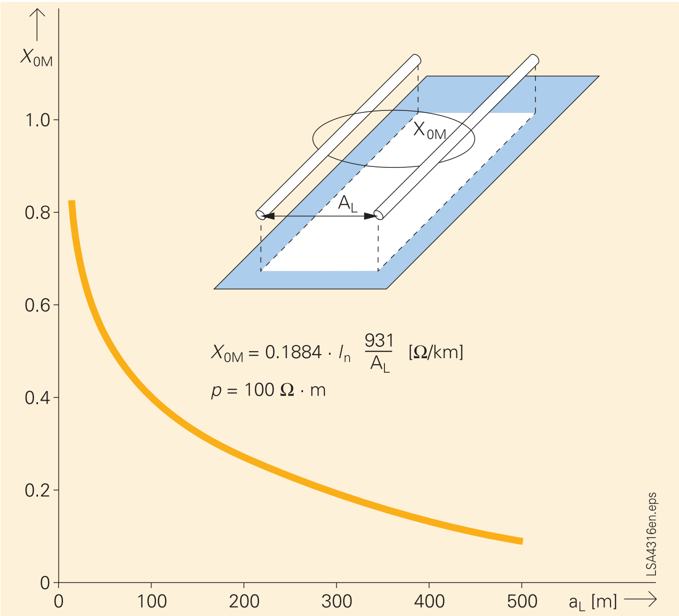


Fig. 6 Inductive coupling of parallel lines

When overhead lines follow parallel paths, a mutual, inductive coupling of the current paths exists. In the case of transposed lines, this effect in the positive and negative sequence system may be neglected for all practical purposes (mutual reactance less than 5 % of the self-impedance). This implies that during load conditions, and for all short-circuits without earth, the lines may be considered as independent.

During earth-faults, the phase currents do not add up to zero, but rather a summation current corresponding to the earth-current results. For this summated current, a fictitious summation conductor placed at the geometrical centre of the phase-conductors models the three-phase system. Two lines in parallel are modelled by two parallel single conductors with an earth return path, for which the mutual reactance must be calculated. In the case of lines with earth-wires, an additional coupling results, which must be considered in the calculations. The coupling impedance can be calculated as follows:

$$Z_M' = \frac{\pi \cdot \mu_0}{4} \cdot f + j_{\mu 0} \cdot f \cdot l_n \frac{\vartheta}{D_{ab}} \quad \left[\frac{\Omega}{km}\right]$$

$$\mu_0 = 4\pi \cdot 10^{-4} \quad \left[\Omega \cdot \frac{s}{km}\right]$$

$$\vartheta = 658\sqrt{\frac{\rho}{f}}$$

ϑ = Depth of penetration in ground
f = Frequency in Hz
ρ = Specific resistance in Ω / m
D_{ab} = Spacing in meters between the two conductors

For a typical value of the specific earth resistance of ρ = 100 Ω/m, a system frequency of 50 Hz, a conductor spacing of 20 m and an earth-fault of I_a = 1000 A, the following result is arrived at.

$$Z_M' = 0.05 + j\,0.24\ \Omega / \text{km}$$

Then the induced voltage in the parallel conductor can be calculated with $U_b = Z_M \cdot I_a$, and 250 V per km is obtained.
On a 100 km parallel line, this would give an induced voltage in the conductor of 25 kV.

3. Calculation of the measuring error of the distance protection caused by a parallel line in the event of an earth fault

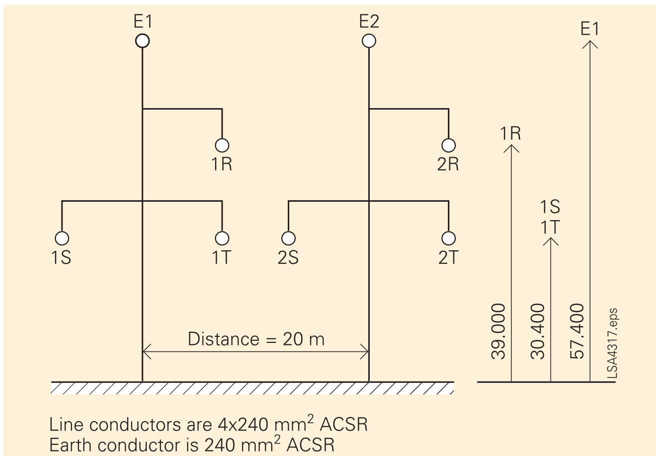


Fig. 7 Tower diagrams

	Earth resistance 100 Ω/ m
Positive impedance (Ω / km)	0.032 + j 0.254
Zero impedance (Ω / km)	0.139 + j 0.906
Coupling impedance (Ω / km)	0.107 + j 0.488

$R1$ = 0.032 Ω / km
$X1$ = 0.254 Ω /km
R_0 = 0.139 Ω / km
X_0 = 0.906 Ω / km
R_{0M} = 0.107 Ω / km
X_{0M} = 0.488 Ω / km

$$\frac{\underline{Z}_E}{\underline{Z}_L} = \frac{\underline{Z}_0 - \underline{Z}_1}{3 \cdot \underline{Z}_1} = 0.86$$

$$\frac{\underline{Z}_M}{\underline{Z}_L} = \frac{\underline{Z}_0 - \underline{Z}_1}{3 \cdot \underline{Z}_1} = 0.65$$

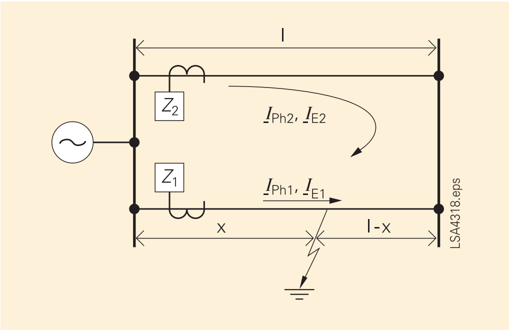


Fig. 8 Parallel line with an infeed without parallel line compensation

Phase current :
$I_{LA} = I_{A1}+I_{A2}+I_{A0}$ $\qquad$ $I_{LB} = I_{B1}+I_{B2}+I_{B0}$

Earth current:
$I_{EA} = 3\ I_{A0}$ $\qquad$ $I_{EB} = 3\ I_{B0}$

$K_0 = (Z_{Lo} - Z_{L1}) / 3\ Z_{L1}$
$K_{0M} = Z_{0M} / 3\ Z_{L1}$
$I_{C0} / I_{A0} = x / 2\text{-}x$

For measured impedance Z_A for the distance relay Z_1 is

$$\underline{Z}_1 = \frac{x}{l} \cdot \underline{Z}_L + \underbrace{\frac{x}{l} \cdot \underline{Z}_L \frac{\frac{\underline{Z}_{0M}}{3 \cdot \underline{Z}_L} \cdot \frac{x}{2l - x}}{1 + \frac{\underline{Z}_E}{\underline{Z}_L}}}_{\text{Measuring error}}$$

The measured impedance Z_B for the distance relay Z_2 is

$$\underline{Z}_2 = (2 \cdot l - x) \cdot \underline{Z}_L + \underbrace{\frac{x \cdot \frac{\underline{Z}_{0M}}{3 \cdot \underline{Z}_L}}{1 + \frac{\underline{Z}_E}{\underline{Z}_L}}}_{\text{Measuring error}}$$

By placing the values in the equations we can calculate the measuring errors for this double-circuit line with single-end infeed.
The results are shown in the diagram below:

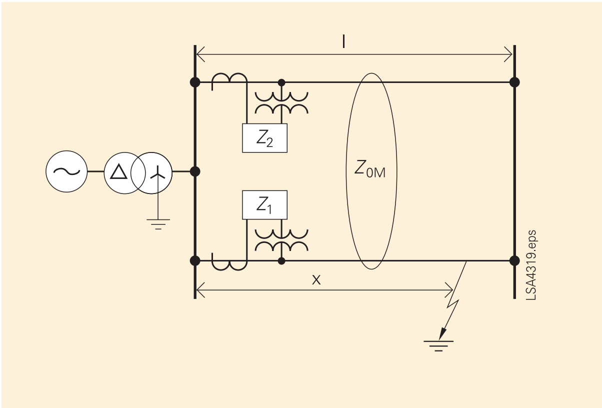


Fig. 9 Double-circuit line with single-end infeed

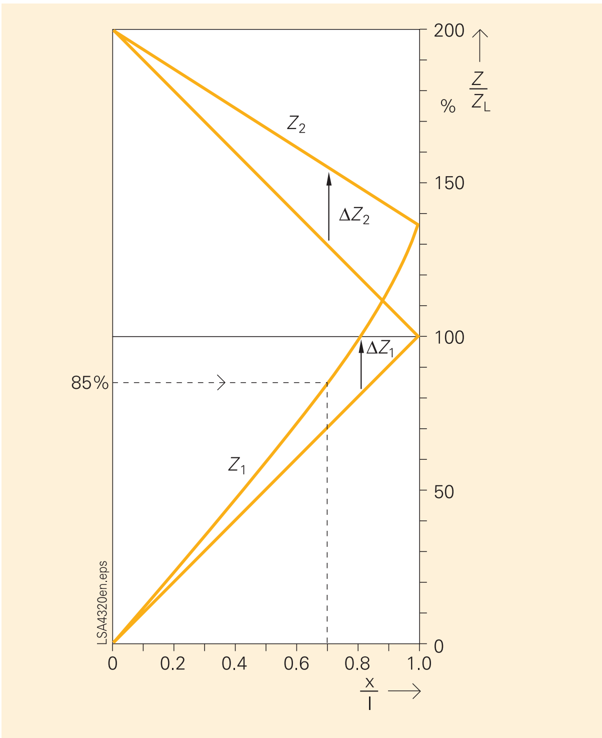


Fig. 10 Distance measuring error on a double-circuit line with single-end infeed

The greatest measuring deviation (35 %) occurs in the event of a fault at the end of the line, because the coupled length up to the fault position is at maximum.

This example shows that the zone reach needs to be reduced to 70 % to avoid overreaching in the event of earth faults.

3.1 Result

- The fault is proportional to $K_{0M} = Z_{0M} / 3\ Z_{L1}$
- The fault increases with the ratio of the earth current of the parallel line I_{EP} to the earth-fault current of the relay
- The relay has an underreach when the earth-fault current of the parallel line and the earth current of the relay are in phase (same direction)
- The relay has an overreach when the earth-fault current of the parallel line and the earth current of the relay have opposite phase (opposite direction).

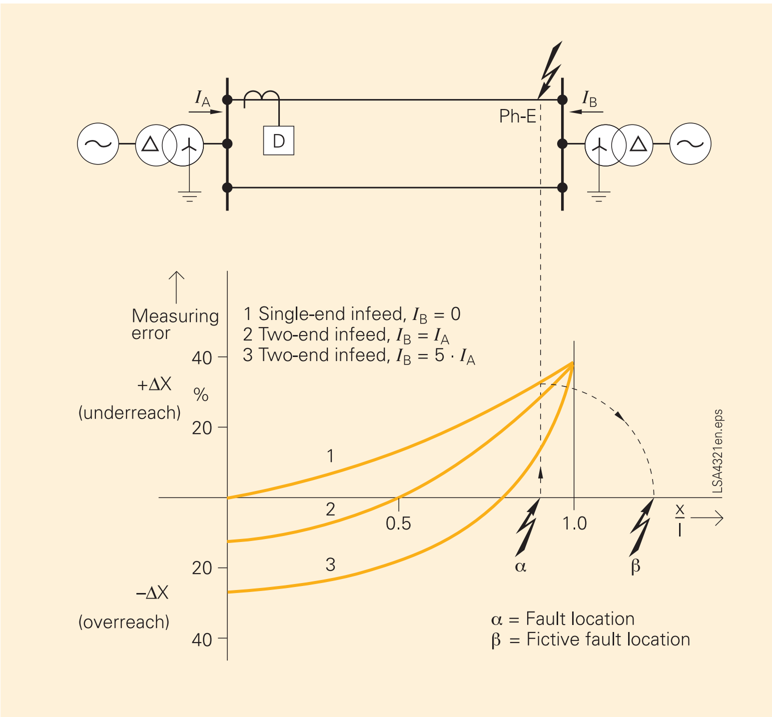


Fig. 11 Earth fault on a double-circuit line with two-end infeed

The measuring error of the relay on the faulty line with two-end infeed is shown in the above diagram. It can be seen that the fault becomes negative in the case of faults in the first 50 % of the line under the same infeed conditions. This is exactly the reach where the earth current on the parallel line flows in the opposite direction.

The following figures show that the parallel line influence changes strongly with the switching state of the parallel line. The reason is the different earth-current distribution.

$$\underline{Z}_{\mathrm{ph-E}} = \frac{\underline{U}_{\mathrm{ph-E}}}{\underline{I}_{\mathrm{ph-E}} + \underline{k}_{\mathrm{E}} \cdot \underline{I}_{\mathrm{E}} + \underline{k}_{\mathrm{EM}} \cdot \underline{I}_{\mathrm{Ep}}}$$

$$\text{with } \underline{k}_{\mathrm{EM}} = \frac{\underline{Z}_{0\mathrm{M}}}{3 \cdot \underline{Z}_{1\mathrm{L}}}$$

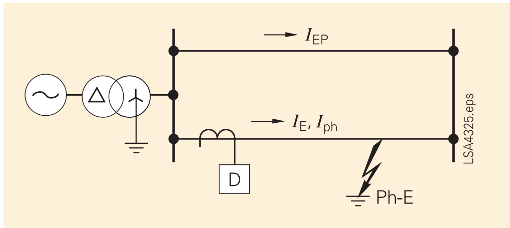


Fig. 12 Fault at the line end

$$\Delta Z = \frac{k_{\mathrm{EM}}}{1 + k_{\mathrm{E}}} \cdot Z_{\mathrm{L}} \triangleq 24\ \%\ \text{von}\ Z_{\mathrm{L}}$$

Fault at the line end (Fig. 12):
Infeed sources for positive-sequence and zero-sequence system at the line end

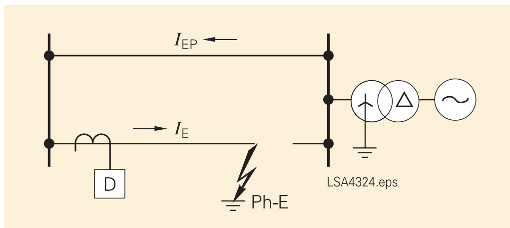


Fig. 13 Fault at the line end with open circuit-breaker

$$\Delta Z = -\frac{k_{\mathrm{EM}}}{1 + k_{\mathrm{E}}} \cdot Z_{\mathrm{L}} \triangleq 24\ \%\ \text{von}\ Z_{\mathrm{L}}$$

Fault at the line end (Fig. 13):
One switch open, star-point earthing and relay at opposite ends.

$$\Delta Z = \frac{3 \cdot k_{EM}}{1 + k_E} \cdot Z_L = \frac{Z_{0M}}{Z_0} \cdot Z_L \triangleq 40\ \%\ \text{of}\ Z_L$$

Fault at line end (Fig. 14):

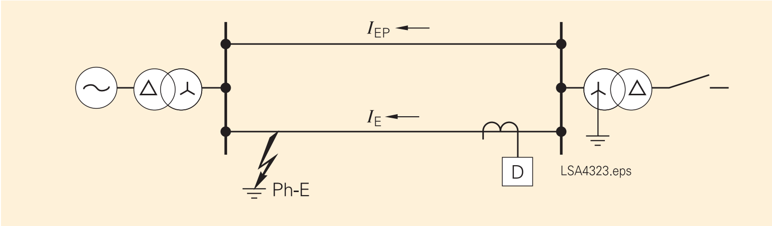


Fig. 14 Infeed sources of the positive and zero-sequence systems at opposite line ends

$$\Delta Z = -Z_L \cdot \frac{k_{EM} \cdot \frac{Z_{0M}}{Z_{0L}}}{1 + k_E} \triangleq -10\ \%\ \text{of}\ Z_L$$

Fault at line end (Fig. 15):

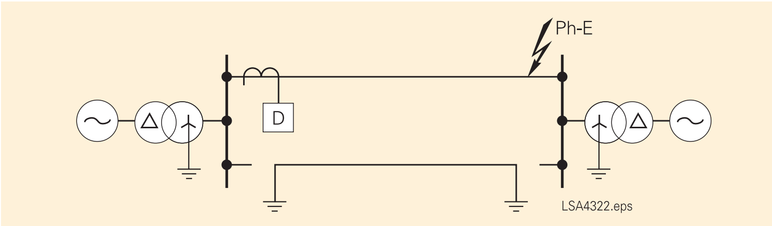


Fig. 15 Parallel line disconnected and earthed at both ends

4. Parallel line compensation

In order for the distance protection to be able to operate with parallel line compensation, it is assumed that it receives I_{EP} of the parallel line as a measuring variable.

$$\underline{Z}_A = \frac{\underline{U}_A}{\underline{I}_{ph} + \underline{k}_E \cdot \underline{I}_E}$$

$$= \frac{\underline{Z}_{1L}\left(\underline{I}_{ph} + \frac{\underline{Z}_{EL}}{\underline{Z}_{1L}} \cdot \underline{I}_E + \frac{\underline{Z}_{0M}}{3 \cdot \underline{Z}_{1L}} \cdot \underline{I}_{Ep}\right)}{\underline{I}_{ph} + \underline{k}_E \cdot \underline{I}_E}$$

As can bee seen from the equation the fault impedance is measured correctly when we add the term $\frac{Z_{0M}}{3 \cdot Z_{1L}} \cdot I_{EP}$ in the denominator. With the normal setting $\underline{k}_E = \underline{Z}_E / \underline{Z}_L$ the denominator is then reduced against the bracketed expression in the counter and $\underline{Z}_{1L}$ is produced as measured result.

The distance protection has another measuring input to which the earth current of the parallel line is connected. The addition is numeric. It should be noted that the relay on the healthy line sees the fault at too short a distance due to coupling of the earth current of the parallel line. If zone 1 of the line without a fault is set to 85 %, the distance protection would lead to an overreach through the fed parallel fault. The distance protection would still see faults on the parallel line at up to 55 % line length in zone 1.

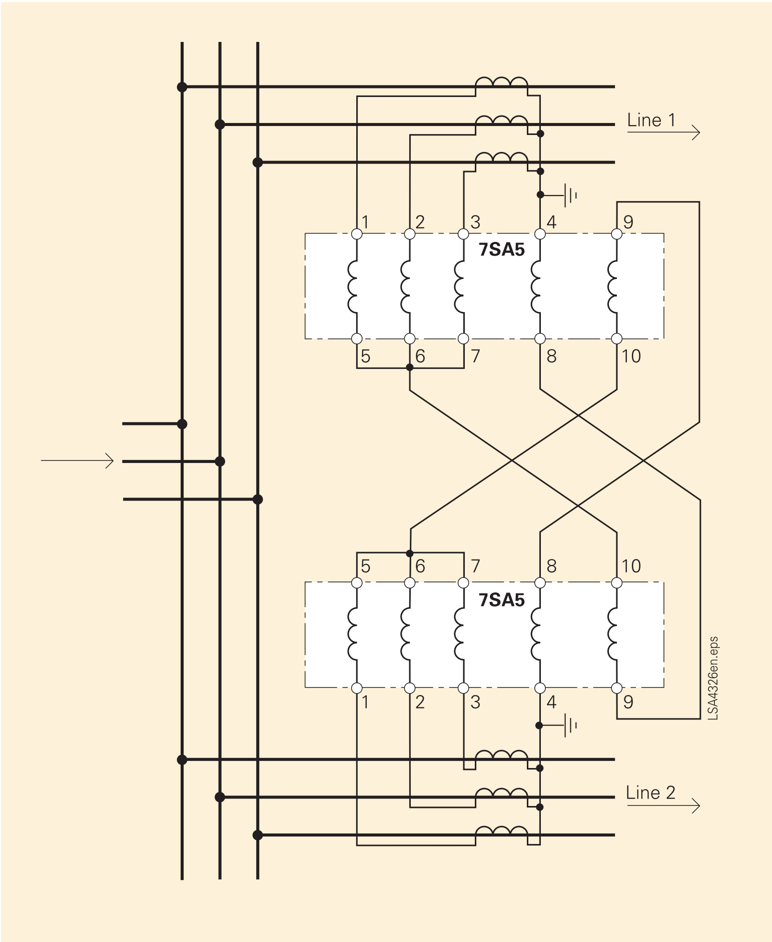


Fig. 16 Connection of the parallel line compensation

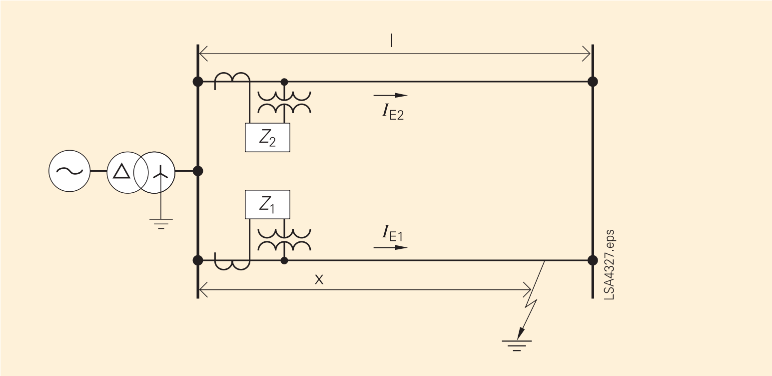


Fig. 17 Distance measurement with parallel line compensation

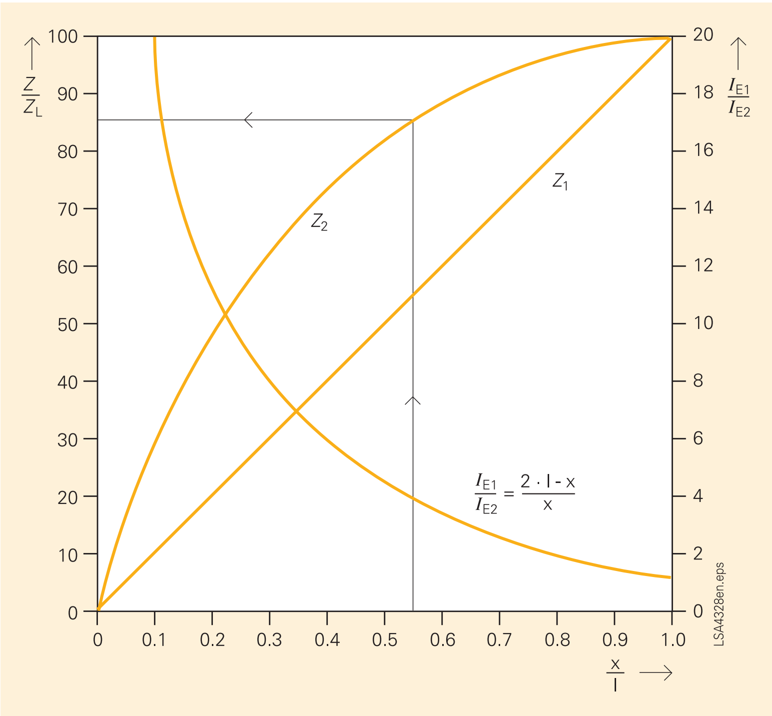


Fig. 18 Effect of the parallel line compensation

$$\left(\frac{Z_E}{Z_L} = 0.86 \;/\; \frac{Z_{0M}}{3 \cdot Z_L} = 0.65 \right)$$

Z_L = line impedance

The so-called earth-current balance is used to prevent this overfunction. It compares the earth currents of both line systems and blocks the parallel line compensation when the earth current of the parallel line exceeds the earth current of the own line by a settable factor.

$$\frac{I_{E1}}{I_{E2}} = \frac{2 \cdot l - x}{x} = \frac{2 - \frac{x}{l}}{\frac{x}{l}}$$

At a setting of x/l of 85 %, the parallel line compensation is effective for faults on the own line and for a further 15 % into the parallel line. This results in a factor of $I_{E1} / I_{E2} = 1.35$ as a standard value for the earth-current balance.

Setting instructions for the parallel line compensation

- The compensation is only possible where both lines end in the same station.
- In the distance protection the compensation is only used where no sufficient backup zone is possible without compensation (When the double-circuit line is followed by short lines).

Example:

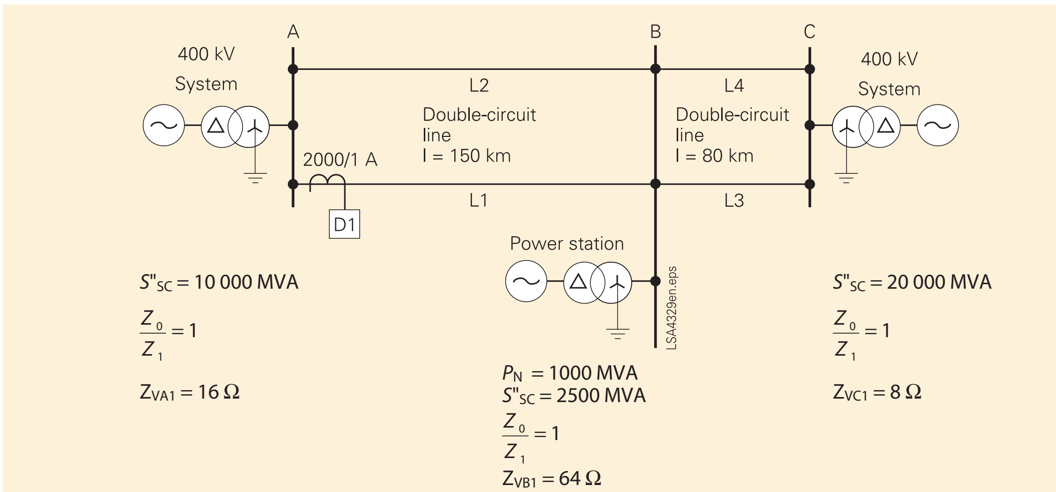


Fig. 19
Example of a double-circuit line station

5. Calculation examples

The procedure for setting a normal single-circuit line is explained in the available manuals. Special applications are dealt with here.

5.1 Double-circuit line in earthed system

The coupling in the zero-sequence system requires detailed consideration of the zone setting for earth faults.

5.2 General procedure

It is recommended to first determine the grading of the distance zones for phase faults without taking into account the parallel line coupling. In the second step the zone reaches are then checked for earth faults and a suitable earth-current compensation factor selected.
The use of parallel line compensation must be considered so that an adequate remote backup protection can be ensured in the event of earth faults.

5.3 Grading of the distance zones for phase-to-phase short-circuits

The zones must be set according to the basic rules of grading plans. For the backup zones, the parabolic course of the impedance dependent on the fault location is important.
When double-circuit lines are connected in series there are also different reaches of the backup zones dependent on the switching state and the infeed at the opposite end.
Theoretically speaking, this results in relatively high effort for creating the grading plan of double-circuit lines.
The procedure is usually simpler in practice. Half the impedance of the following parallel line can be used for practical grading of the second zone (double-circuit line follows single-circuit line). This gives:

$$Z_{2A} = GF2 \cdot (Z_{A\text{-}B} + 0.5 \cdot Z_{B\text{-}C})$$

In the third zone, the grading should be performed according to the backup protection strategy. A selective grading for all switching states leads to relatively short third stages which hardly get any longer than the corresponding second stage. In the high and extra-high voltage system, an attempt will be made for the third stage to cover the following double-circuit line in normal parallel line mode. In this case the following step setting is derived:

$$Z_{3A} = 1.1 \cdot \left(Z_{A\text{-}B} + Z_{B\text{-}C}\right)$$

In the pickup zone the following lines should be in the protected zone in the worst switching state (single line follows parallel line). The following setting should be set for this:

$$Z_{+AA} = 1.1 \cdot \left(Z_{A-B} + 2 \cdot Z_{B-C}\right)$$

As a rule infeeds are available in the intermediate stations of the double-circuit line which have to be taken into account in the grading of the backup zones. This is demonstrated by the following example (see Fig. 19):

Double-circuit line.
Setting of the distance zones for phase-to-phase short-circuits

Given:
100 kV double-circuit line
Line data:
Configuration according to
l_1 and l_2 = 150 km, l_3 and l_4 = 80 km
Z_{1L}'= 0.0185 + j 0.3559 Ω/km
Z_{0L}'= 0.2539 + j 1.1108 Ω/km
Z_{0M}'= 0.2354 + j 0.6759 Ω/km
$P_{nat.}$ = 518 MW per line
Current transformer: 2000/1 A
Voltage transformer: 400/0.1 kV

Task:
Calculation of the zone setting for relay D1.

Solution:
Only X values are used in the short-circuit calculations, for the sake of simplicity:
$X_{L1} = X_{L2}$ = 0.3559 Ω/km · 150 km = 53.4 Ω
$X_{L3} = X_{L4}$ = 0.3559 Ω/km · 80 km = 28.5 Ω
We generally apply a grading factor (GF) of 85 %.
The zone reaches are calculated as follows:
X_1 = 0.85 · 53.4 Ω
For selective grading of the 2nd stage it is assumed that the parallel line L2 is open but that always at least half the short-circuit power is available from the intermediate infeed in B. Grading takes place selectively to the end of the 1st zone of the distance relays of the following lines 3 and 4. That means we can use about half the line impedance. This gives a simplified equivalent circuit. For a three-pole fault in C we calculate the short-circuit currents drawn in the figure.

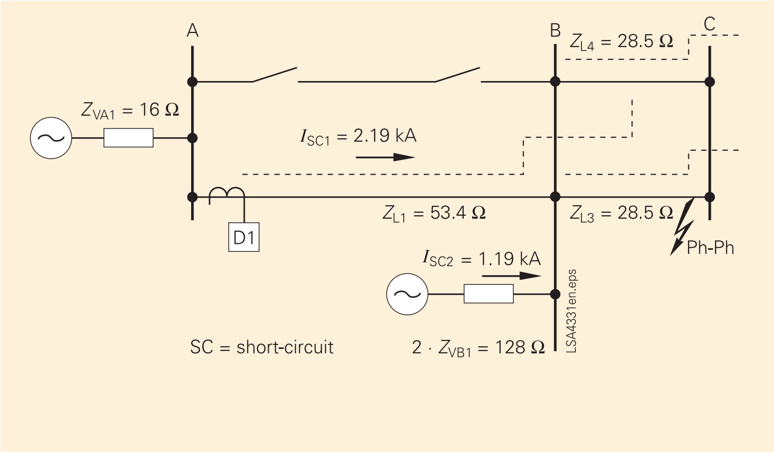


Fig. 20 Protection setting in double-circuit lines: System data for the calculation example

Under consideration of the intermediate infeed effect we get

$$X_2 = \left[53.4 + \frac{28.5}{2} \cdot \left(1 + \frac{1.19}{2.19}\right)\right] \cdot 0.85 =$$

$$64\ \Omega = 120\ \%\ X_{L1}$$

According to the above recommendation we get for zone 3

$$X_3 = (53.4 + 28.5) \cdot 1.1 = 90.1\ \Omega = 169\ \%\ X_{L1}$$

and for the pickup zone:

$$X_{+A} = (53.4 + 2 \cdot 28.5) \cdot 1.1 = 121\ \Omega = 226\ \%\ X_{L1}$$

we adapt the reach of the zones in R direction to the impedance of the natural power:

$$Z_{Nat.} = \frac{U_{N^2}}{P_{Nat.}} = \frac{400^2}{518} = 309\ \Omega$$

We assume that a new line has to transmit double the power temporarily and allow an additional safety margin of 30 %. This gives the maximum R reach of pickup as:

$$RA1 = 0.7 \cdot \frac{309}{2} = 108\ \Omega$$

We further select $\varphi_A = 50°$ and
$RA2 = 2 \cdot RA1 = 208\ \Omega$

An R/X ratio of 1 offers adequate compensation for fault resistance for the distance zones.

5.4 Zone reach during earth faults

The earth-current compensation factor $\underline{k}_E$ is decisive in the Ph-E measuring systems. For single-circuit lines this is set to the corresponding $\underline{Z}_F/\underline{Z}_L$ value. The protection then measures the same impedance for Ph-Ph and earth faults.
On double-circuit lines the zero-sequence system coupling produces a measuring error for earth faults. The measurement can be corrected with the parallel line compensation. This function is contained optionally in the relays 7SA. Only the earth current of the parallel line needs to be connected to the relay and the coupling impedance set. The earth-current balance may be left at the standard value $x/l = 85$ %. The earth-current factor must be adapted to the single-circuit line in this case.

5.5 Setting of the $\underline{k}_E$ factor (operation without parallel line compensation)

In the event that the parallel line compensation is not used, a $\underline{k}_E$ factor must be found which ensures adequate protection for the possible operating states of the double-circuit line (see Table 1).

a) This equation applies for $\frac{x}{l} \le 1$

For $\frac{x}{l} > 1$ it applies that: $\dfrac{GF1(1+k_{XER}) + k_{XEM} \cdot \dfrac{X'_{0M}}{X'_{0L}}}{1+k_{XEL}}$

b) $k_{XEL} = \left(\dfrac{X'_{EL}}{X'_{1L}}\right)_{Line}$

c) $k_{XEM} = \left(\dfrac{X'_{0M}}{3 \cdot X'_{0L}}\right)_{Line}$

Adapting the setting to a particular operating state causes an overreach or underreach in the respective other states. GF1 in % is the selected grading factor for the 1st zone (reach for phase-to-phase faults). *x*/*l* in % then specifies how far the zone 1 (Ph- E loop) reaches in the event of earth faults, referred to the line length.

Determining of the relay setting value $\underline{k}_{ER}$ is demonstrated by the example of double-circuit line operation. For a fault at the distance *x*/*l*, the voltage at the relay location is:

$$\underline{U}_{Ph\text{-}E} = \frac{x}{l} \underline{Z}_L \cdot \underline{I}_{Ph} + \frac{x}{l} \underline{Z}_E \cdot \underline{I}_E + \frac{x}{l} \frac{\underline{Z}_{0M}}{3} \cdot \underline{I}_{EP}$$

Whereby with single-end infeed:

$$I_{Ph} = I_E \text{ and } I_{EP} = \frac{\frac{x}{l}}{2-\frac{x}{l}} \cdot I_E$$

For the measurement on the Ph-E loop the result is

$$\underline{Z}_{Ph-E} = \frac{\underline{U}_{Ph\text{-}E}}{\underline{I}_{Ph} + \underline{k}_{ER} \cdot \underline{I}_E} = \frac{x}{l} \cdot \frac{\underline{Z}_L + \underline{Z}_E + \dfrac{\underline{Z}_{0M}}{3} \cdot \dfrac{\frac{x}{l}}{2-\frac{x}{l}}}{1+\underline{k}_{ER}}$$

$\underline{k}_{ER}$ is the complex earth-current compensation factor set at the relay.
X and R are calculated separately for the numerical relays 7SA. Simplified equations apply for this if phases and earth currents have the same phase relation.

This results in:

$$X_{Ph-E} = \frac{U_{Ph-E} \cdot \sin\varphi_{SC}}{I_{Ph} + \left(\dfrac{X_E}{X_L}\right)_R \cdot I_E} = \frac{x}{l} \cdot X_L \cdot \frac{1 + \dfrac{X_E}{X_L} + \dfrac{X_{0M}}{3 \cdot X_L} \cdot \dfrac{\frac{x}{l}}{2-\frac{x}{l}}}{1 + \left(\dfrac{X_E}{X_L}\right)_R}$$

$$R_{Ph-E} = \frac{U_{Ph-E} \cdot \cos\varphi_{SC}}{I_{Ph} + \left(\dfrac{R_E}{R_L}\right)_R \cdot I_E} = \frac{x}{l} \cdot R_L \cdot \frac{1 + \dfrac{R_E}{R_L} + \dfrac{R_{0M}}{3 \cdot R_L} \cdot \dfrac{\frac{x}{l}}{2-\frac{x}{l}}}{1 + \left(\dfrac{R_E}{R_L}\right)}$$

Initially, only the X value measured is of interest for the reach.

With $k_{XEL} = \dfrac{X_E}{X_L}$ and $k_{XEM} = \dfrac{X_{0M}}{3 \cdot X_L}$ this gives:

$$X_{Ph-E} = \frac{x}{l} X_L \cdot \frac{1 + k_{XEL} + k_{XEM} \cdot \dfrac{\frac{x}{l}}{2-\frac{x}{l}}}{1 + k_{XER}}$$

The Ph-E measuring system and the Ph-Ph measuring system have the same impedance pickup value (common setting value Z1).
Therefore: $Z_{Ph\text{-}E} = Z_{Ph\text{-}Ph} = Z1 = GF1 \cdot Z_L$, applies, whereby GF1 is the grading factor of the first zone. The following equation is finally arrived at for the earth-current compensation factor which must be set at the relay:

$$k_{XER} = \frac{1 + k_{XEL} + k_{XEM} \cdot \dfrac{\frac{x}{l}}{2-\frac{x}{l}}}{GF1} \cdot \frac{x}{l} - 1$$

We can vary the reach of the Ph-E measuring systems of a given zone reach for phase faults (GF1 in % of Z_L) by adjusting the k_{XER} factor.
We can also solve the previous equation according to x/l and then arrive at the reach for a given k_{XER} setting.

$$\frac{x}{l} = \frac{[GF1 \cdot (1+k_{XER}) + 2(1+k_{XEL})] - \sqrt{[..]^2 - 8(1+k_{XEL} - k_{XEM}) \cdot (1+k_{XER}) \cdot GF1}}{2 \cdot (1+k_{XEL} - k_{XEM})}$$

In the same way we derive the equations specified in Table 1 for the cases "parallel line open" and "parallel line open and earthed at both ends".

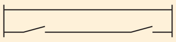
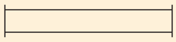
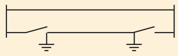
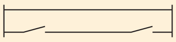
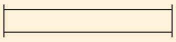
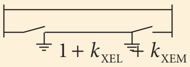
		Reach x/l at Ph-E short-circuits		
		 $\frac{x}{l} = GF1 \cdot \frac{1+k_{XER}}{1+k_{XEL}}$	 $\frac{x}{l}$ = See equation on previous page	 $\frac{x}{l} = \frac{(1+k_{XER})\cdot GF1}{1+k_{XEL} - k_{XEM}\cdot \frac{X'_{0M}}{X_{0L}}}$ a)
k_{XER}-setting with: $\frac{x}{l} = 0.85$ GF1 = 0.85 $k_{XEL} = 0.71$ b) $k_{XEM} = 0.64$ c) $X'_{0M} = 0.72$ Ω/km $X'_{0L} = 1.11$ Ω/km $X'_{1L} = 0.356$ Ω/km	 $k_{ER} = \frac{1+k_{EL}}{\mathrm{GF1}} \cdot \frac{x}{l} - 1 = 0.71\,(0.5)$	85 % (75 %)	71 % (64 %)	108 % (98 %)
	 $k_{XER} = \frac{1+k_{XEL} + k_{XEM}\cdot \frac{x/l}{2-x/l}}{GF1} - 1$ $k_{XER} = 1.18$	108 %	85 %	132 %
	 $k_{XER} = \frac{1+k_{XEL} + k_{XEM}\cdot \frac{X'_{0M}}{X'_{0L}}}{GF1} \cdot \frac{x}{l} - 1 = 0.31$	65 %	56 %	85 %

Table 1 Distance measurement in the event of earth faults: Reach (in X direction) dependent on the relay setting

$$k_{XER} = \left(\frac{X_E}{X_L}\right)_{\text{Relay}}$$ and the switching state

The choice of the setting of k_{XER} requires a compromise which takes all three cases of operation into account (Table 1)[1]. At a grading factor of GF1 = 85 %, adaptation to the single-circuit line usually offers an acceptable solution. The two-end disconnection of a line with earthing at both ends only occurs in maintenance work, so the brief overreach of 8 % is only rarely effective because overreaching is usually reduced by intermediate infeeds.

In operation with single-pole auto-reclosure, the overreach would only lead to excessive auto-reclosure and not to final disconnection, provided that a transient short-circuit is concerned (about 90 % of faults).

Alternatively, the reach can be reduced slightly for earth faults by setting a lower k_{XER} factor. If it were reduced from $k_{XER} = 0.71$ to $k_{XER} = 0.5$, overreach would just about be avoided in this example. The reach with both lines in service would then only be 64 %, taking into consideration that the parallel line coupling only takes full effect in the worst case of single-end infeed. In the normal case of two-end infeed the earth current on the parallel line is much lower in the event of faults close to the middle of the line, and the zone reach corresponds almost to the single-circuit line. In addition, the parallel line coupling at the other end of the line always has the opposite direction, i.e. the zone reach is increased. Reliable fast disconnection can always be ensured by intertripping. However, in reducing the k_{XER} factor it must be taken into account that the reach of the backup zones is also reduced accordingly in the event of earth faults. Zone reach reduction (e.g. GF1 = 0.8) should therefore also be considered instead of only reduction of the k_{XER} factor.

5.6 Setting the overreach zone

Zone Z_{1B} should be set to 120 –130 % Z_L. This reach would also apply for earth faults in the case of operation with parallel line compensation.

1) The numeric values in Table 1 were calculated with the line layers of the previous example. For the sake of simplicity the complex factors $k_{EL} = 0.71 - j0.18$ and $k_{EM} = 0.64 - j0.18$ were only taken into account with their real components, which correspond to the values $k_{XEL} = X_E/X_L$ and $k_{XEm} = X_M/(3 \cdot X_L)$ in the first approximation. This gives sufficient accuracy for the extra high-voltage system.

Adapting the setting to an operating state causes an overreach or underreach in the respective other states. GF1 in % is the selected grading factor for the 1st zone (reach for Ph-Ph faults). *x*/*l* in % then specifies how far zone 1 (Ph-E loop) reaches in the event of earth faults, referred to the line length.

Determining of the relay setting value $\underline{k}_{ER}$ is demonstrated by the example of double-circuit line operation:

The voltage at the relay location for a fault at the distance *x*/*l* is:

$$\underline{U}_{\text{Ph-E}} = \frac{x}{l} Z_L \cdot I_{\text{Ph}} + \frac{x}{l} \underline{Z}_{\text{E}} \cdot \underline{I}_{\text{E}} + \frac{X}{l} \frac{\underline{Z}_{0\text{M}}}{3} \cdot \underline{I}_{\text{EP}}$$

with single-end infeed:

$$I_{\text{Ph}} = I_{\text{E}} \text{ and } I_{\text{EP}} = \frac{\frac{x}{l}}{2 - \frac{x}{l}} \cdot I_{\text{E}}$$

for the measurement of the Ph-E loop the following is derived:

$$\underline{Z}_{\text{Ph-E}} = \frac{\underline{U}_{\text{Ph-E}}}{\underline{I}_{\text{Ph}} + \underline{k}_{\text{ER}} \cdot \underline{I}_{\text{E}}} = \frac{x}{l} \cdot \frac{\underline{Z}_{\text{L}} + \underline{Z}_{\text{E}} + \frac{\underline{Z}_{0\text{M}}}{3} \cdot \frac{\frac{x}{l}}{2 - \frac{x}{l}}}{1 + \underline{k}_{\text{ER}}}$$

whereby $\underline{k}_{ER}$ is the complex earth current compensation factor set on the relay. X and R are calculated separately in the numerical relays 7SA. Simplified equations apply for this when phases and earth currents have the same phase angle. This results in

$$X_{\text{Ph-E}} = \frac{U_{\text{Ph-E}} \cdot \sin\varphi_{\text{SC}}}{I_{\text{Ph}} + \left(\frac{X_{\text{E}}}{X_{\text{L}}}\right)_{\text{R}} \cdot I_{\text{E}}} = \frac{x}{l} \cdot X_{\text{L}} \cdot \frac{1 + \frac{X_{\text{E}}}{X_{\text{L}}} + \frac{X_{0\text{M}}}{3 \cdot X_{\text{L}}} \cdot \frac{\frac{x}{l}}{2 - \frac{x}{l}}}{1 + \left(\frac{X_{\text{E}}}{X_{\text{L}}}\right)_{\text{R}}}$$

$$R_{\text{Ph-E}} = \frac{U_{\text{Ph-E}} \cdot \cos\varphi_{\text{SC}}}{I_{\text{Ph}} + \left(\frac{R_{\text{E}}}{R_{\text{L}}}\right)_{\text{R}} \cdot I_{\text{E}}} = \frac{x}{l} \cdot R_{\text{L}} \cdot \frac{1 + \frac{R_{\text{E}}}{R_{\text{L}}} + \frac{R_{0\text{M}}}{3 \cdot R_{\text{L}}} \cdot \frac{\frac{x}{l}}{2 - \frac{x}{l}}}{1 + \left(\frac{R_{\text{E}}}{R_{\text{L}}}\right)_{\text{R}}}$$

Only the measured value is initially for the reach:

With $k_{\text{XEL}} = \frac{X_{\text{E}}}{X_{\text{L}}}$ and $k_{\text{XEM}} = \frac{X_{0\text{M}}}{3 \cdot X_{\text{L}}}$ this gives:

$$X_{\text{Ph-E}} = \frac{x}{l} X_{\text{L}} \cdot \frac{1 + k_{\text{XEL}} + k_{\text{XEM}} \cdot \frac{\frac{x}{l}}{2 - \frac{x}{l}}}{1 + k_{\text{XER}}}$$

The Ph-E measuring system and the Ph-Ph measuring system have the same impedance pickup value (common setting value Z_1).
Therefore: $Z_{\text{Ph-E}} = Z_{\text{Ph-Ph}} = Z_1 = GF1 \cdot Z_{\text{L}}$, applies, whereby GF1 is the grading factor of the first zone:

The following equation finally results for the earth-current compensation factor which must be set in the relay:

$$k_{\text{XER}} = \frac{1 + k_{XEL} + k_{XEM} \cdot \frac{\frac{x}{l}}{2 - \frac{x}{l}}}{GF1} \cdot \frac{x}{l} - 1$$

Without parallel line compensation the 120 % reach must be dimensioned for the case of parallel line operation under consideration of the previously defined k_{XER} factor.

$$GF = \frac{1 + k_{\text{XEL}} + k_{\text{XEM}} \cdot \frac{\frac{x}{l}}{2 - \frac{x}{l}}}{1 + k_{\text{XER}}} \cdot \frac{x}{l}$$

For a fault at the end of the line (*x*/*l* = 100 %) and a safety margin of 20 %, the following equation for the overreach zone is produced:

$$X1B = GF_{100\%} \cdot X_{\text{L}} \cdot \frac{120\%}{100}$$

$$= \frac{1 + k_{\text{XEL}} + k_{\text{XEM}}}{1 + k_{\text{XER}}} \cdot X_{\text{L}} \cdot 1.2$$

The selected $k_{XER} = 0.71$ produces
X1B = 165 % X_L.
Without parallel line compensation, the overreach zone must therefore be set very high, so that a safety margin of 20 % is ensured in double-circuit line operation.

5.7 Reach of the backup zones for earth faults

We observe the behavior of the distance measurement with and without parallel line compensation.

5.8 Distance measurement without parallel line compensation

For the simple case that the parallel line is followed by a single-circuit line (Fig. 21, line 4 disconnected), the measured impedance can be determined as follows:

Voltage at the relay location:

$$\underline{U}_{\text{Ph-E}} = \underline{Z}_{\text{L1}} \cdot \underline{I}_{\text{Ph1}} + \underline{Z}_{\text{E1}} \cdot \underline{I}_{\text{E1}} + \frac{\underline{Z}_{\text{0M1-2}}}{3} \cdot \underline{I}_{\text{E2}}$$

$$+ \frac{x}{l_2} \underline{Z}_{\text{L2}} \cdot \underline{I}_{\text{Ph3}} + \frac{x}{l_2} \underline{Z}_{\text{E2}} \cdot \underline{I}_{\text{E3}}$$

With $\underline{I}_{\text{Ph1}} = \underline{I}_{\text{E1}} = \underline{I}_{\text{E2}} = \underline{I}_{\text{SC}}$ and $\underline{I}_{\text{Ph3}} = \underline{I}_{\text{E3}} = 2 \cdot \underline{I}_{\text{SC}}$ we get for the relay reactance:

$$X_{\text{Ph-E}} = \frac{U_{\text{Ph-E}} \cdot \sin\varphi_{\text{SC}}}{I_{\text{Ph1}} + k_{\text{XER}} \cdot I_{\text{E1}}} =$$

$$\frac{1 + k_{\text{XEL1}} + k_{\text{XEM1-2}}}{1 + k_{\text{XER}}} \cdot X_{\text{L1}} + 2 \cdot \frac{x}{l_2} \cdot \frac{1 + k_{\text{XEL3}}}{1 + k_{\text{XER}}} \cdot X_{\text{L2}}$$

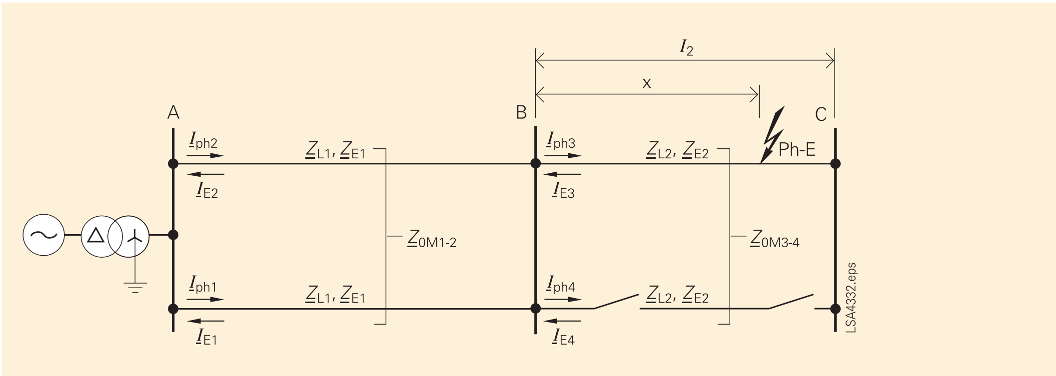


Fig. 21 Distance measurement on double-circuit lines: Fault on a following line

If we set $x/l = 0$ we arrive at the measured reactance in the event of a fault at the opposite station. For the calculated example this gives the value

$$X_{\text{Ph-E}} = \frac{1 + 0.71 + 0.64}{0.71} = 1.37 \cdot X_{\text{L1}}$$

This shows that in the case at hand the backup zones only reach beyond the next station when they are set greater than 137 % Z_{L1}. This does not apply for the 2^{nd} zone at the selected setting.

At the grading (120 %) selected on the basis of the phase-to-phase short-circuits, the 2^{nd} zone would only reach up to 91 % Z_{L1} in the parallel line state in the event of an earth fault.

This problem is particularly pronounced when the downstream line, according to which the second zone has to be graded, is substantially shorter than the protected line, and when only a short intermediate infeed is present.

$$\underline{U}_{\text{Ph-E}} = \underline{Z}_{\text{L1}} \cdot \underline{I}_{\text{Ph1}} + \underline{Z}_{\text{E1}} \cdot \underline{I}_{\text{E1}} + \frac{\underline{Z}_{\text{0M1-2}}}{3} \cdot \underline{I}_{\text{E2}} + \frac{x}{l_2} \underline{Z}_{\text{L2}} \cdot \underline{I}_{\text{Ph3}} + \frac{x}{l_2} \underline{Z}_{\text{E2}} \cdot \underline{I}_{\text{E3}} + \frac{x}{l_2} \frac{\underline{Z}_{\text{0M3-4}}}{3} \cdot \underline{I}_{\text{E4}}$$

With $\underline{I}_{\text{Ph1}} = \underline{I}_{\text{E1}} = \underline{I}_{\text{E2}} = \underline{I}_{\text{SC}}$ and

$\underline{I}_{\text{Ph3}} = \underline{I}_{\text{E3}} = \left(2 - \frac{x}{l_2}\right) \cdot \underline{I}_{\text{SC}}$ and $\underline{I}_{\text{E4}} = \frac{x}{l_2} \cdot \underline{I}_{\text{SC}}$

we get:

$$X_{\text{Ph-E}} = \frac{1 + k_{\text{XEL1}} + k_{\text{XEM1-2}}}{1 + k_{\text{XER}}} \cdot X_{\text{L1}} + \frac{\frac{x}{l_2}\left(2 - \frac{x}{l_2}\right) \cdot (1 + k_{\text{XEL2}}) + \left(\frac{x}{l_2}\right)^2 \cdot k_{\text{XEM3-4}}}{1 + k_{\text{XER}}} \cdot X_{\text{L2}}$$

Resolution according to x/l_2 produces again the equation for the reaches of the zones:

$$\frac{x}{l_2} = \frac{2(1 + k_{\text{XEL2}}) - \sqrt{4(1 + k_{\text{XEL2}})^2 - 4(1 + k_{\text{XEL2}} - k_{\text{XEM3-4}}) \cdot \Delta}}{2 \cdot (1 + k_{\text{XEL2}} - k_{\text{XEM3-4}})}$$

with

$$\Delta = \frac{X_{\text{L1}}}{X_{\text{L2}}} \cdot \left[(1 + k_{\text{XER}}) \cdot \frac{X_{\text{Zone}}}{X_{\text{L1}}} - (1 + k_{\text{XEL1}} + k_{\text{XEM1-2}})\right]$$

For zone 3 (169 % X_{L1}) we get $x/l_2 = 33$ %, i.e. only slightly more than for the single-circuit line. For the pickup zone (226 % X_{L1}) the expression under the root is negative because the zone only reaches to just past the next substation.
The limit (root = 0) is at 223 % X_{L1}.

5.9 Distance measurement with parallel line compensation

With parallel line compensation, faults on the own line are measured in the correct distance. For faults beyond the next substation the zones are extended by the factor:

$$k = \frac{1 + k_{\text{XER}} + k_{\text{XEMR}}}{1 + k_{\text{XER}}}$$

according to the compensation factors set at the relay.
The term $1 + k_{\text{XER}}$ must be replaced in the equations on pages 12 and 13 by $1 + k_{\text{XER}} + k_{\text{XEMR}}$.

This gives us a reach of up to 71 % Z_{L2} for the 2nd zone, i.e. the zone reaches up to just before the end of the first zone of the following line which is set to 85 % Z_{L2}.

Taking account of the intermediate infeed in station B, there will be a further reduction of the 2nd stage so that the safety margin is increased.
The 3rd zone (169 %Z_{L1}) just reaches with parallel line compensation and the pickup zone (226 % Z_{L1}) comfortably reaches over the next station but one (C) (A fault in C would correspond to 162 % Z_{L1}). For the final definition of the setting, the intermediate infeed again has to be taken into account.

6. Summary

The zone setting can be estimated for the double-circuit lines based on the arithmetic procedures and the derived equations shown here. In practice the intermediate infeeds must be taken into account, so that the second zone can be graded safely past the next station (whilst retaining the selectivity and reliably detecting busbar faults).

If the line lengths do not differ, an acceptable compromise for the relay setting can usually be found without parallel line compensation. For short following lines, parallel compensation must however be taken into account.

Computer programs are nowadays available for the relatively complex testing of the backup zones and the pickup.

Protection of Long Lines with SIPROTEC 7SD5

1. Introduction

The protection of long transmission lines was previously the domain of distance protection. Modern available information transmission technology –with the ability to reliably exchange com - parison signals over substantial distances –makes differential protection interesting for use on long transmission lines. High sensitivity and strict selectivity are further aspects that speak in favor of differential protection. The SIPROTEC 7SD5 relay provides, in addition to differential protection, comprehensive backup protection and additional functions for the complete protection of transmission lines.

2. Protection concept

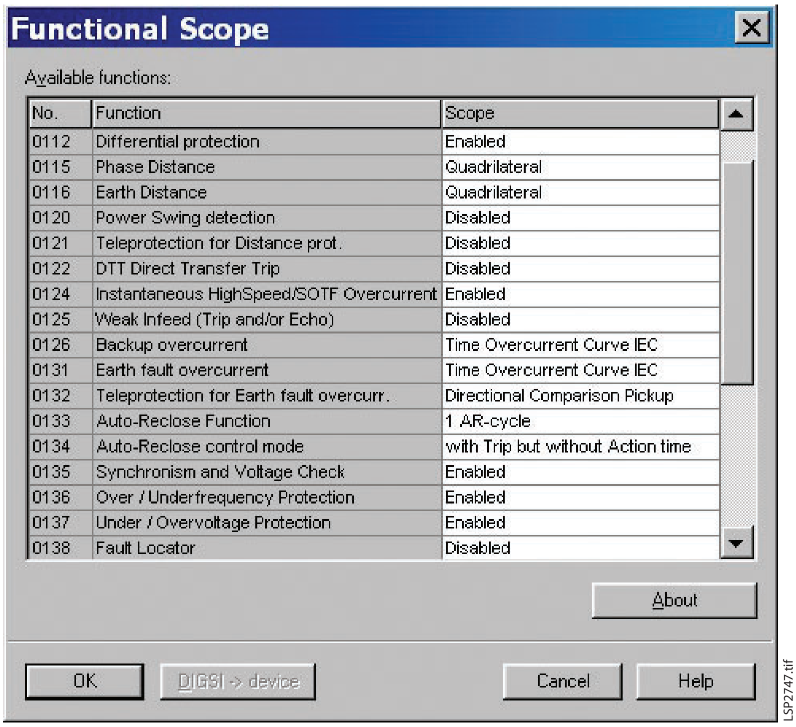
This application example describes largely differential protection of two-end lines. In addition to this use, modern SIPROTEC differential protection relays can meet the following requirements:

- Protection of multi-branch configurations
- Transformer in the protected zone
- Matching to various transmission media such as fiber optics or digital communication networks

For protection of a two-end line, we recommend to activate the following functions:

ANSI 87 L	Differential protection
ANSI 67 N	Directional overcurrent protection
ANSI 79	Auto-reclosure
ANSI 50 BF	Breaker failure protection
ANSI 59/27	Undervoltage and overvoltage protection
ANSI 25	Synchro-check and voltage check

Fig. 1 SIPROTEC 7SD5 line differential protection relay



No.	Function	Scope
0112	Differential protection	Enabled
0115	Phase Distance	Quadrilateral
0116	Earth Distance	Quadrilateral
0120	Power Swing detection	Disabled
0121	Teleprotection for Distance prot.	Disabled
0122	DTT Direct Transfer Trip	Disabled
0124	Instantaneous HighSpeed/SOTF Overcurrent	Enabled
0125	Weak Infeed (Trip and/or Echo)	Disabled
0126	Backup overcurrent	Time Overcurrent Curve IEC
0131	Earth fault overcurrent	Time Overcurrent Curve IEC
0132	Teleprotection for Earth fault overcurr.	Directional Comparison Pickup
0133	Auto-Reclose Function	1 AR-cycle
0134	Auto-Reclose control mode	with Trip but without Action time
0135	Synchronism and Voltage Check	Enabled
0136	Over / Underfrequency Protection	Enabled
0137	Under / Overvoltage Protection	Enabled
0138	Fault Locator	Disabled

Fig. 2 Settings for functional scope

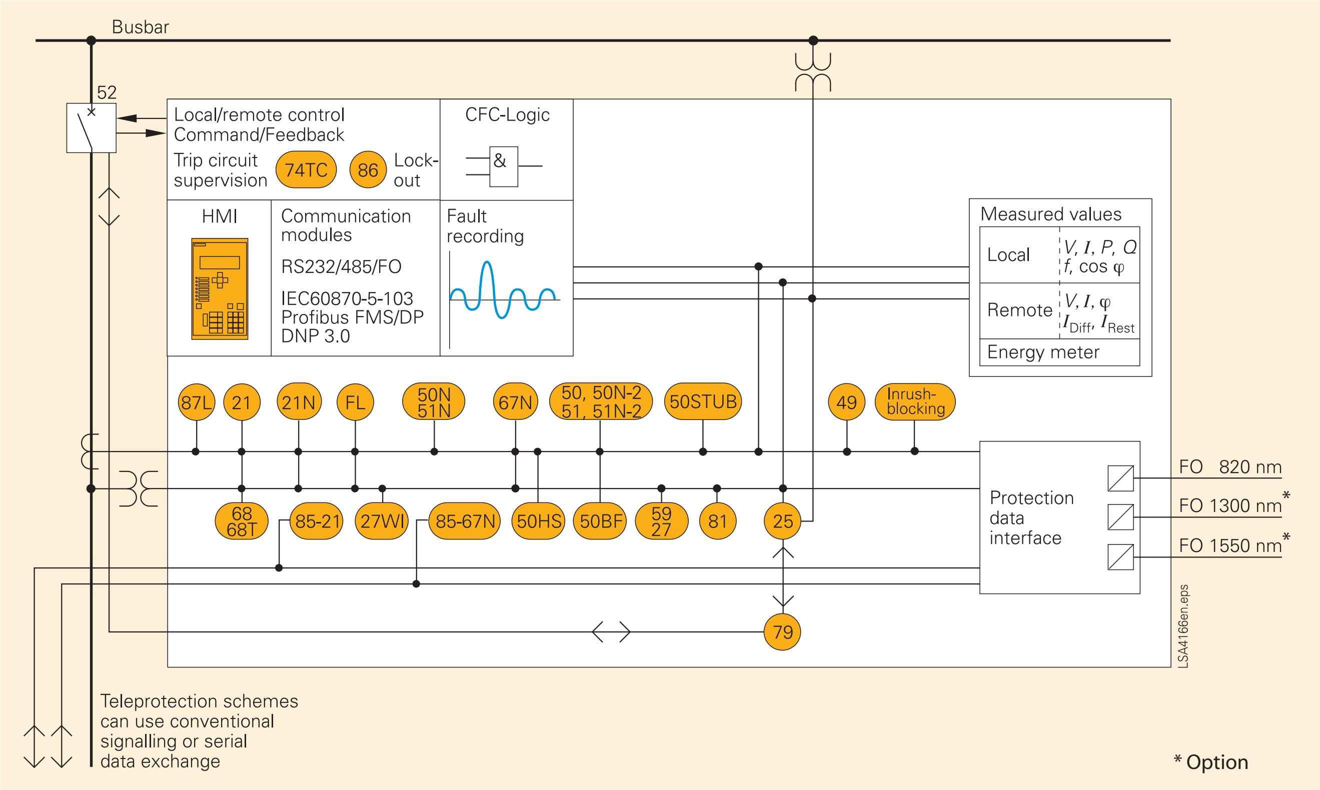


Fig. 3 Function scope of the SIPROTEC 7SD5

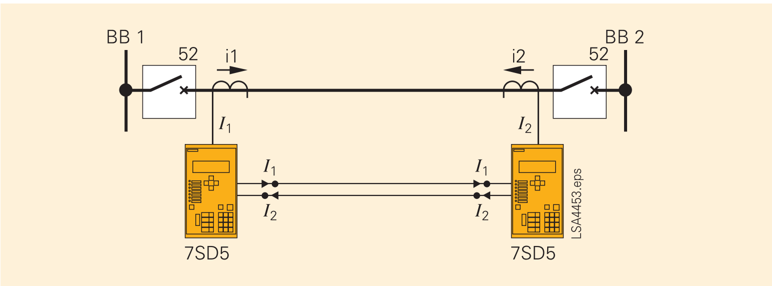


Fig. 4 Differential protection for a line with two ends (single-phase system)

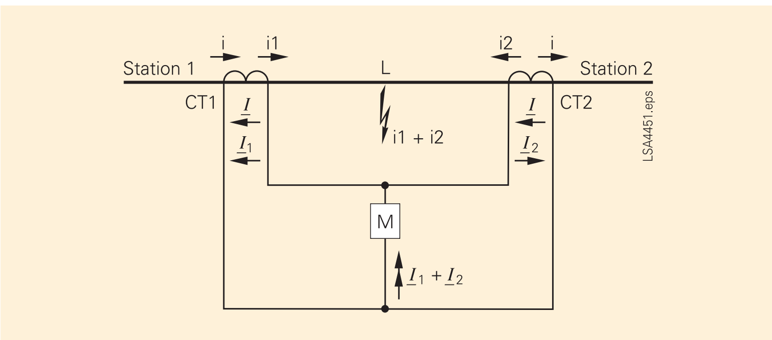


Fig. 5 Basic principle of the differential protection for a line with two ends

2.1 Differential protection

Differential protection is based on current comparison. It makes use of the fact, that e.g. a line section L (Fig. 5) carries always the same current I at its two ends in fault-free operation. This current flows into one side of the considered zone and leaves it again on the other side. A difference in current is a clear indication of a fault within this line section. If the actual current transformation ratios are the same, the secondary windings of the current transformers CT1 and CT2 at the line ends can be connected to form a closed electric circuit with a secondary current I; a measuring element M which is connected to the electrical balance point remains at zero current in fault-free operation.

When a fault occurs in the zone limited by the transformers, a current $i_1 + i_2$ which is proportional to the fault currents $I_1 + I_2$ flowing in from both sides is fed to the measuring element. As a result, the simple circuit shown in Fig. 5 ensures a reliable tripping of the protection if the fault current flowing into the protected zone during a fault is high enough for the measuring element M to pick up.

2.2 Charging current compensation

Charging current compensation is an additional function for differential protection. It allows an improvement in the sensitivity, achieved by the charging current (caused by the capacitances in the overhead line or cable and flowing through the distributed capacitance in steady state) being compensated. As a result of the capacitances of the phase conductors (to earth and mutually), charging currents flow – even in fault-free conditions – and cause a difference in the currents at the ends of the protected zone. Particularly on cables and long lines the capacitive charging currents can reach considerable levels. If the feeder-side transformer voltages are connected to the relays, the influence of the capacitive charging currents can be largely arithmetically compensated. It is possible here to activate charging current compensation, which determines the actual charging current. Where there are two line ends, each relay attends to half the charging current compensation; where there are M relays, each covers an Mth fraction. Fig. 6 shows a single-phase system, for the sake of simplicity.

In fault-free operation, steady-state charging currents can be considered as practically constant, as they are determined only by the voltage and the line capacitances. Without charging current compensation, they must therefore be taken into account when setting the sensitivity of the differential protection. With charging current compensation, there is no need to consider them at this point. With charging current compensation, the steady-state magnetization currents across shunt reactances (quadrature-axis reactances) are also taken into account.

2.3 Directional overcurrent protection (ANSI 67 N)

The zero-sequence current is used as measured quantity. According to its definition equation it is obtained from the sum of three phase currents, i.e. $3I_0 = I_{L1} + I_{L2} + I_{L3}$.
The direction determination is carried out with the measured current I_E ($= -3\ I_0$), which is compared to a reference voltage U_P.

The voltage required for direction determination U_P may be derived of the starpoint current I_Y of an earthed transformer (source transformer), provided that the transformer is available. Moreover, both the zero-sequence voltage $3U_0$ and the starpoint current I_Y of a transformer can be used for measurement. The reference magnitude U_P then is the sum of the zero-sequence voltage $3U_0$ and a value which is proportional to reference current I_Y. This value is about 20 V for rated current (Fig. 7).

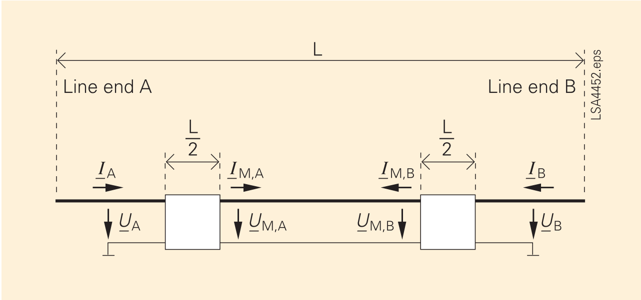


Fig. 6 Charging current compensation for a line with two ends (single-phase system)

The directional polarization using the transformer starpoint current is independent of voltage transformers and therefore also functions reliably during a fault in the voltage transformer secondary circuit. It is, however, a requirement that not all, but at least a substantial amount of the earth-fault current flows via the transformer, the starpoint current of which is measured.

For the determination of direction, a minimum current $3I_0$ and a minimum displacement voltage, which can be set as $3U_0$>, are required. If the displacement voltage is too small, the direction can only be determined if it is polarized with the transformer starpoint current and this exceeds a minimum value corresponding to the setting I_Y>. The direction determination with $3U_0$ is inhibited if a "trip of the voltage transformer mcb" is reported via binary input.

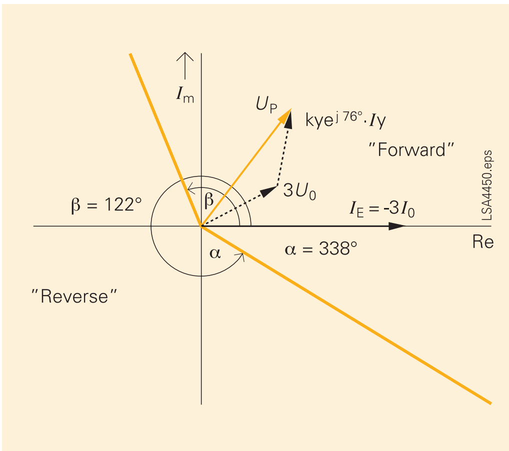


Fig. 7 Directional characteristic of the earth-fault protection

2.4 Auto-reclosure function (ANSI 79)

The 85 % of the arc faults on overhead lines are extinguished automatically after being tripped by the protection. This means that the line can be reclosed. Auto-reclosure is only permitted on overhead lines because the option of automatic extinguishing of an arc fault only exists there. It should not be used in any other case. If the protected object consists of a combination of overhead lines and other equipment (e.g. overhead line directly connected to a transformer or a combination of overhead line/cable), it must be ensured that reclosure can only be performed in the event of a fault on the overhead line. If the circuit-breaker poles can be operated individually, a single-phase auto-reclosure is usually initiated for single-phase faults and a three-pole auto-reclosure for multiple phase faults in the system with earthed system starpoint. If the earth fault still exists after auto-reclosure (arc has not disappeared, there is a metallic fault), then the protection functions will re-trip the circuit-breaker. In some systems several reclosing attempts are performed.
In a model with single-pole tripping, the 7SD5 allows phase-selective, single-pole tripping. A single and three-pole, single and multiple-shot auto-reclosure function is integrated, depending on the version.

The 7SD5 can also operate in conjunction with an external auto-reclosure device. In this case, the signal exchange between 7SD5 and the external reclosure device must be effected via binary inputs and outputs. It is also possible to initiate the integrated auto-reclose function by an external protection device (e.g. a backup protection). The use of two 7SD5 with auto-reclosure function or the use of one 7SD5 with an auto-reclosure function and a second protection with its own auto-reclosure function is also possible.

Reclosure is performed by an auto-reclosure function (AR). An example of the normal time sequence of a double reclosure is shown in Fig. 8. The integrated auto-reclosure cycle allows up to 8 reclose attempts. The first four reclose cycles may operate with different parameters (action and dead times, single/three-pole). The parameters of the fourth cycle also apply for the fifth cycle and onwards.

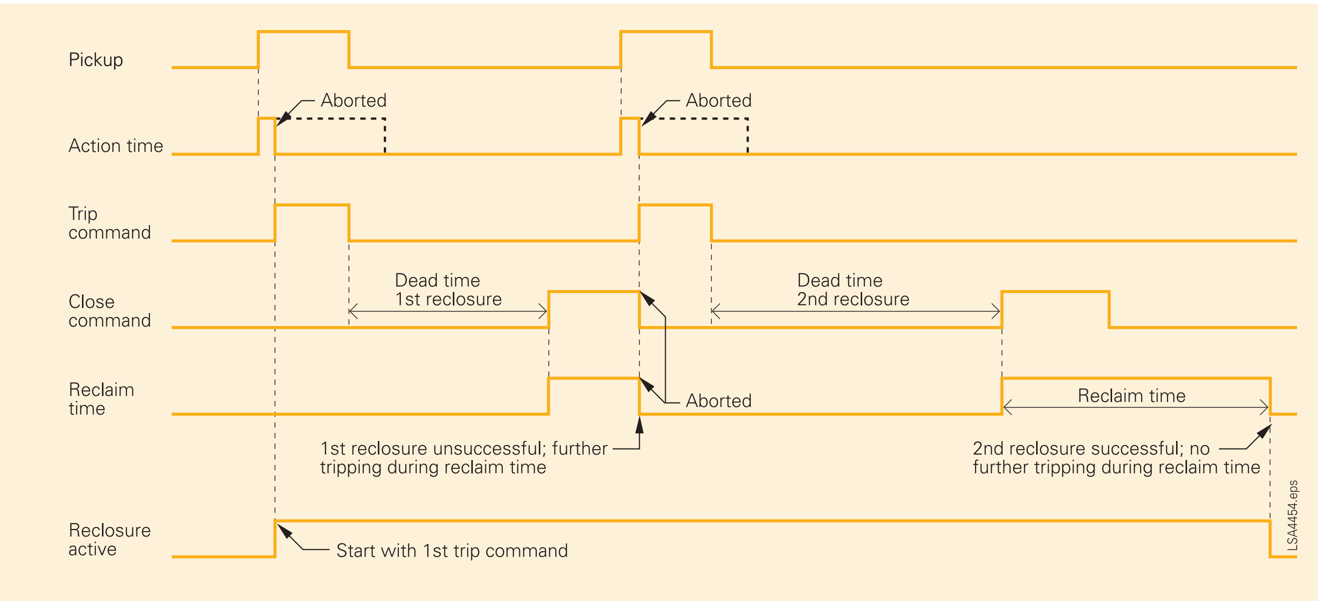


Fig. 8 Timing diagram of a double-shot reclosure with action time (2nd reclosure successful)

2.5 Breaker failure protection (ANSI 50BF)

The breaker failure protection provides rapid backup fault clearance, in the event that the circuit-breaker fails to respond to a trip command from a protection function of the local circuit-breaker. Whenever, e.g., a protection relay of a feeder issues a trip command to the circuit-breaker, this is repeated to the breaker failure protection. A timer in the breaker failure protection is started. The timer runs as long as a trip command is present and current continues to flow through the breaker poles.

2.6 Undervoltage and overvoltage protection (ANSI 27/59)

Voltage protection has the function of protecting electrical equipment against undervoltage and overvoltage. Both operational states are unfavorable as overvoltage may cause, for example, insulation problems or undervoltage may cause stability problems.
The overvoltage protection in the 7SD5 detects the phase voltages $U_{L1\text{-}E}$, $U_{L2\text{-}E}$ and $U_{L3\text{-}E}$, the phase-to-phase voltages $U_{L1\text{-}L2}$, $U_{L2\text{-}L3}$ and $U_{L3\text{-}L1}$, as well as the displacement voltage $3U_0$. Instead of the displacement voltage any other voltage that is connected to the fourth voltage input U_4 of the relay can be detected. Furthermore, the relay calculates the positive-sequence voltage and the negative-sequence voltage, so that the symmetrical components are also monitored. Here, compounding is also possible which calculates the voltage at the remote line end.

The undervoltage protection can also use the phase voltages $U_{L1\text{-}E}$, $U_{L2\text{-}E}$ and $U_{L3\text{-}E}$, the phase-to-phase voltages $U_{L1\text{-}L2}$, $U_{L2\text{-}L3}$ and $U_{L3\text{-}L1}$, as well as the positive-sequence system voltage.

2.7 Synchro-check and voltage check (ANSI 25)

The synchro-check and voltage check functions ensure, when switching a line onto a busbar, that the stability of the system is not endangered. The voltage of the feeder to be energized is compared to that of the busbar to check conformances in terms of magnitude, phase angle and frequency within certain tolerances. Optionally, deenergization of the feeder can be checked before it is connected to an energized busbar (or vice versa).

The synchro-check can either be conducted only for auto-reclosure, only for manual closure (this includes also closing via control command) or for both cases. Different close permission (release) criteria can also be programmed for automatic and manual closure. Synchronism check is also possible without external matching transformers if a power transformer is located between the measuring points. Closing is released for synchronous or asynchronous system conditions.

In the latter case, the relay determines the time for issuing the close command such that the voltages are identical the instant the circuit-breaker poles make contact.

The synchronism and voltage check function uses the feeder voltage – designated with U_{Line} – and the busbar voltage – designated with U_{Bus} – for comparison purposes. The latter may be any phase-to-earth or phase-to-phase voltage.

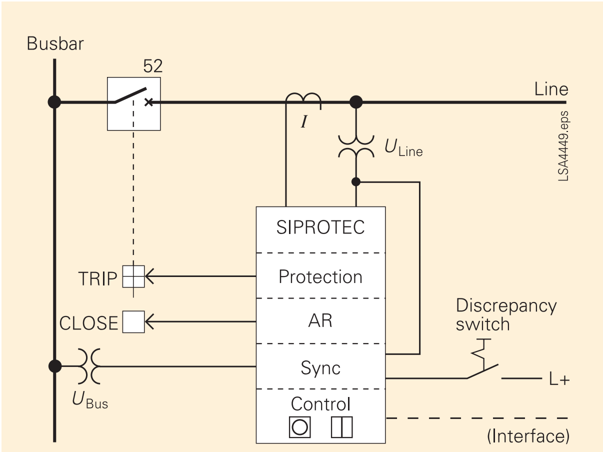


Fig. 9 Synchronism check on closing

If a power transformer is located between the feeder voltage transformers and the busbar voltage transformers (Fig. 10), its vector group can be compensated for by the 7SD5 relay, so that no external matching transformers are necessary.

The synchronism check function in the 7SD5 usually operates in conjunction with the integrated automatic reclose, manual close, and the control functions of the relay. It is also possible to employ an external automatic reclosing system. In such a case, signal exchange between the devices is accomplished via binary inputs and outputs.

When closing via the integrated control function, the configured interlocking conditions may have to be verified before checking the conditions for synchronism. After the synchronism check grants the release, the interlocking conditions are not checked a second time.

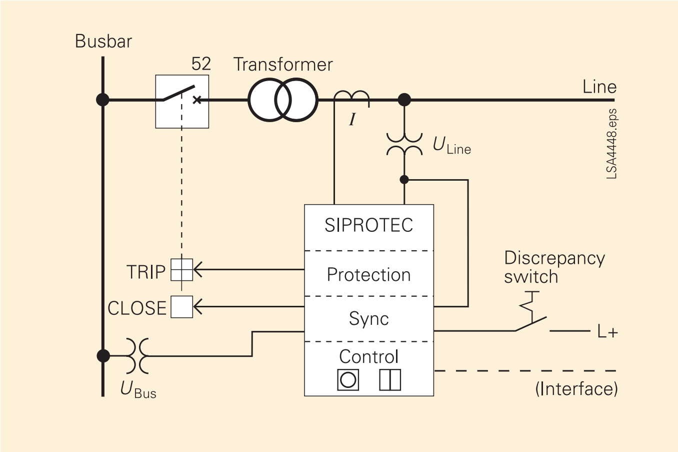


Fig. 10 Synchronism check across a transformer

Communications media

The exchange of signals between the line differential protection relays becomes particularly complicated due to the geographic coverage of the relays over medium and long distances. At the minimum, two substations find themselves using relays of the same system that exchange data over a relay-to-relay (R2R) communication channel.

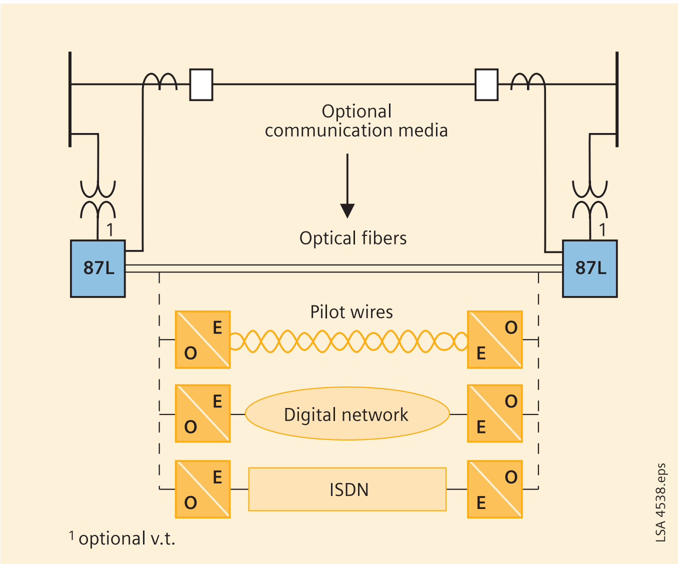


Fig. 11 Optional communication media

The communication is enabled via pilot wire or direct optical fiber connections or via communication networks. Which kind of FO media is used, depends on the distance and on the communication media available (Table 1). For shorter distances a direct connection via optical fibers having a transmission rate of 512 kBit/s is possible. A transmission via modem and communication networks can also be realized.

It is very important to note, however, that the tripping times of the different protection relays depend on the transmission quality and are prolonged in case of a reduced transmission quality and/or an increased transmission time. Fig. 11 shows some examples for communication connections. In case of a direct connection the distance depends on the type of the optical fiber. Table 1 lists the options available. The modules in the relays are replaceable. If an external communication converter is used, the relay must be equipped with an FO5 module in order to achieve correct operation. The relay and the external communication converter are linked via optical fibers. The converter itself allows connections to communication networks, two-wire copper lines or ISDN (Fig. 12).

To span larger distances with fiber-optic cables, it is presently recommended to use external repeaters. Optical modules for distances of up to 100 km are being developed and will be available in 2005.

A further option is the connection via communication network (no limitation of distance).

Module in the relay	Connector type	FO type	Optical wavelength	Perm. path attenuation	Distance, typical
FO5	ST	Multi-mode 62.5/125 µm	820 nm	8 dB	1.5 km (0.95 miles)
FO6	ST	Multi-mode 62.5/125 µm	820 nm	16 dB	3.5 km (2.2 miles)
FO7	ST	Mono-mode 9/125 µm	1300 nm	7 dB	10 km (6.25 miles)
FO8	FC	Mono-mode 9/125 µm	1300 nm	18 dB	35 km (22 miles)
FO17[1)]	LC	Mono-mode 9/125 µm	1300 nm	13 dB	24 km (14.9 miles)
FO18[1)]	LC	Mono-mode 9/125 µm	1300 nm	29 dB	60 km (37.5 miles)
FO19[1)]	LC	Mono-mode 9/125 µm	1550 nm	29 dB	100 km (62.5 miles)

Table 1 Communication via direct FO connection

1) For direct connection over short distances, a suitable optical attenuator should be used to avoid malfunctions and damage to the relay.

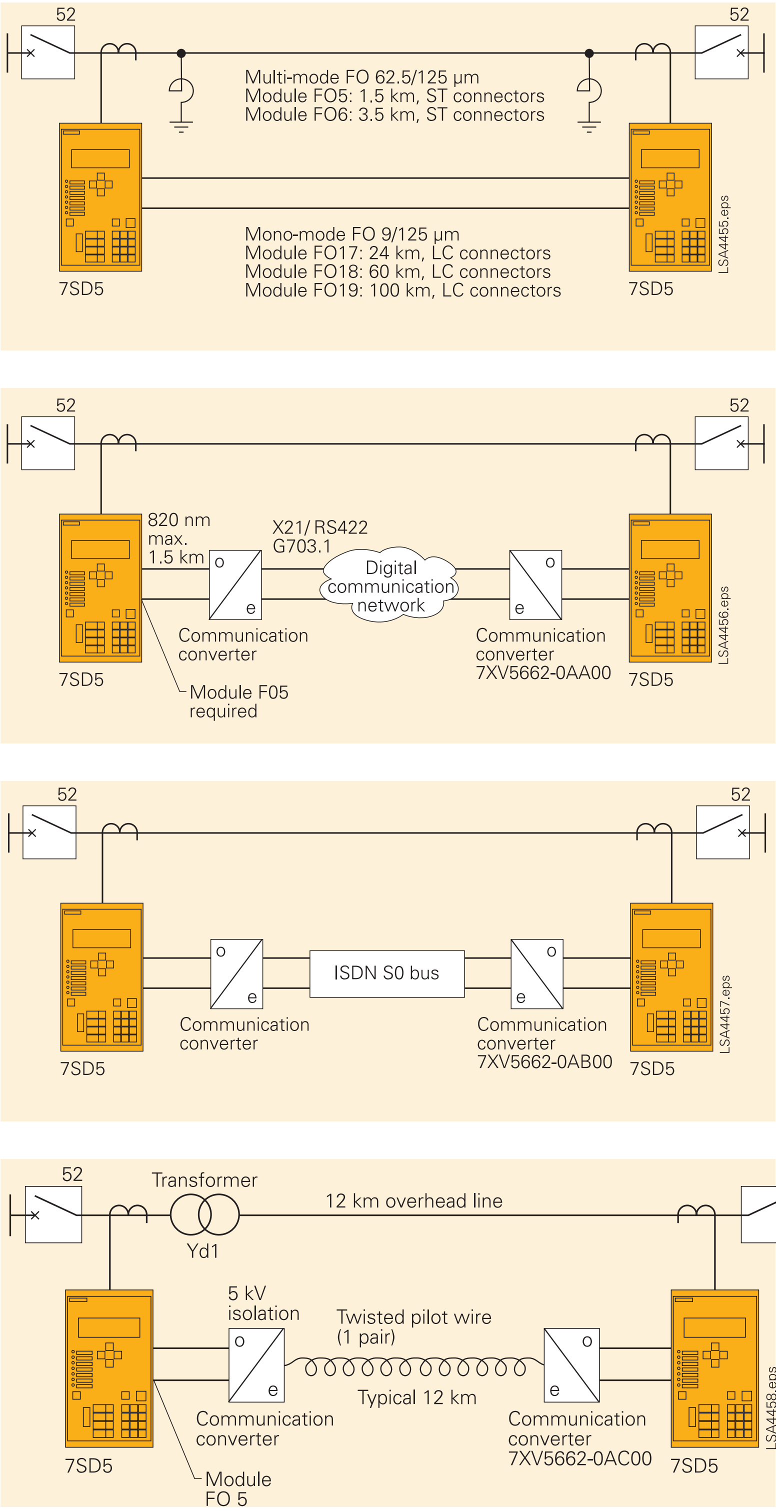


Fig.12 Examples for communication links

3. Summary

Optimal protection of transmission lines with SIPROTEC 7SD5 relays means high selectivity in fault clearing; any available parallel duplicate line remains reliably in operation. Very short release times ensure the stability of the transmission system in the event of a fault, and consequently contribute significantly to maximizing the level of supply security.

The SIPROTEC 7SD5 relay provides comprehensive main and backup protection of transmission lines in a single relay. Thanks to its flexible communication capabilities, the SIPROTEC 7SD5 can be easily matched to the existing communication infrastructure.

Protection of a Three-Winding Transformer

Three-winding transformer

110 kV/25 kV/10 kV
Yyn0d5
25 kV-side: Solidly earthed

Protection functions

ANSI 87 T - Differential protection
ANSI 87 N - Earth-fault differential protection
ANSI 50/51 - Definite-time overcurrent-time protection as backup
ANSI 49 - Thermal overload protection
ANSI 46 - Load unbalance protection (negative-sequence protection)
ANSI 24 - Overexcitation protection

Fig. 1 SIPROTEC Transformer protection relay

■ 1. Introduction

Transformers are valuable equipment which make a major contribution to the supply security of a power system. Optimum design of the transformer protection ensures that any faults that may occur are cleared quickly and possible consequential damage is minimized.
In addition to design notes, a complete setting example with SIPROTEC protection relays for a three-winding transformer in the transmission system is described.

■ 2. Protection concept

The range of high-voltage transformers comprises small distribution system transformers (from 100 kVA) up to large transformers of several hundred MVA. Differential protection offers fast, selective short-circuit protection, alone or as a supplement to Buchholz protection. It is part of the standard equipment in larger units from about 5 MVA.

2.1 Differential protection

Transformer differential protection contains a number of additional functions (matching to transformation ratio and vector group, restraint against inrush currents and overexcitation). Therefore it requires some fundamental consideration for configuration and selection of the setting values.

The additional functions integrated per relay are advantageous. However, backup protection functions have to be arranged in separate hardware (other relay) for redundancy reasons. Therefore the overcurrent-time protection contained in the differential protection relay 7UT613 can only be used as backup protection against external faults in the connected power system. The backup protection for the transformer itself must be provided as a separate overcurrent relay (e.g. 7SJ602). The Buchholz protection as fast short-circuit protection is delivered with the transformer.

Designations in accordance with ANSI (American National Standard) are used for the individual functions. The differential protection therefore has the ANSI No. 87 for example.
The 7UT613 differential protection relay is provided as independent, fast-acting short-circuit protection in addition to the Buchholz protection.

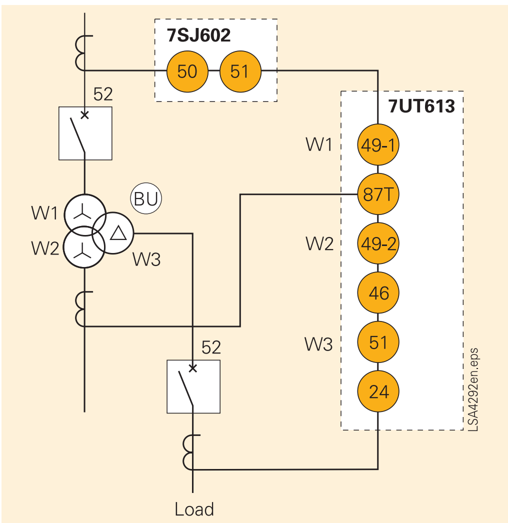


Fig. 2 Protection of a three-winding transformer

2.2 Earth-fault differential protection

Earth-fault differential protection detects earth-faults in transformers in which the star (neutral) point has low resistance or is solidly earthed. It enables fast, selective disconnection in the event of an earth fault in the winding. The protection is based on a comparison of the star-point current I_{SP} with the phase currents of the main winding.

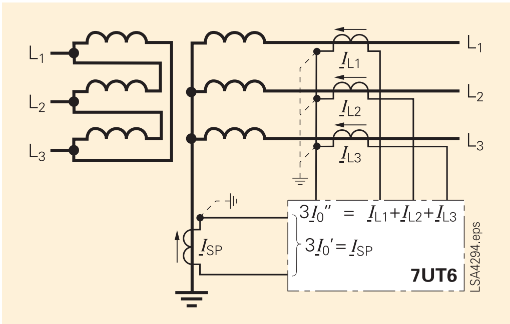


Fig. 3 Connection of an earth-fault differential protection relay

The pickup sensitivity should be ≤ 10 % of the current in the event of terminal earth fault (90 % protected zone). The single-phase auxiliary measuring input with connection I_{Z1} of 7UT613 should be used for this and assigned to the corresponding main winding by setting. The earth current of this input is then compared with the phase currents of the main winding.

2.3 Backup protection functions

The integrated overcurrent-time protection (ANSI 51) in 7UT613 serves as backup protection for faults in the system to which power is supplied. Separate overcurrent protection on the low-voltage (LV) side is therefore unnecessary.
The 7SJ602 relay can be used as backup protection against short-circuits in the transformer and as additional backup protection against faults on the LV side. The high-set, fast tripping stage I>> (ANSI 50) must be set above the through-fault current, so that it does not pick up in case of faults on the low-voltage (LV) side.

The delayed trip (ANSI 51) must be of higher priority than the overcurrent protection in 7UT613.

Owing to the different ratings, windings S2 and S3 are assigned a separate overload protection (integrated in 7UT613). The delta winding (often only used for own internal supply) has its own overcurrent-time protection (ANSI 51, integrated in 7UT613) against phase faults.
At low ratings of the tertiary winding and accordingly adapted transformer ratio, it should be checked whether an external matching transformer may be required.

2.4 Integration of Buchholz protection

The Buchholz protection of the transformer evaluates the gas pressure of the transformer tank and therefore detects internal transformer faults quickly and sensitively. The following considerations are necessary for integration:

- The trip command of the Buchholz protection should act on the circuit-breaker directly and independently of the differential protection
- The trip command of the Buchholz protection should be recorded in the fault log/fault record of the differential protection

Coupling the trip command via a binary input of the differential protection provides informative data for evaluation in the case of a fault.

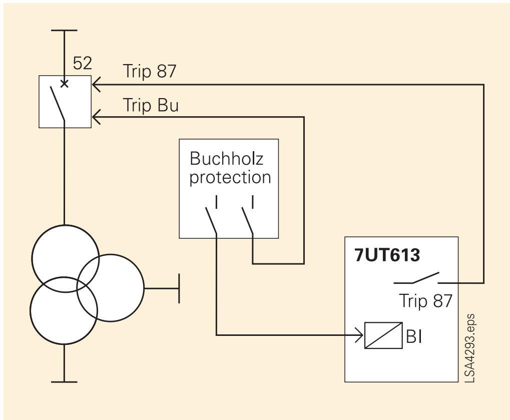


Fig. 4 Scheme for Buchholz protection

3. Settings

3.1 Setting instructions for differential protection

The differential protection as a main function of the 7UT613 is parameterized and set in a few steps:

- Parameterize "three-phase transformer" protected object
- Assign the measuring locations on the main protected object

Example:

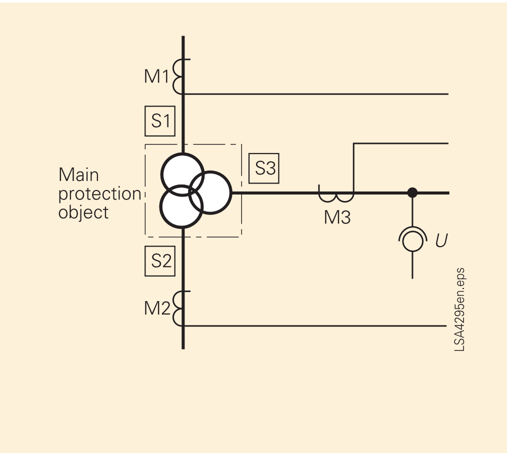


Fig. 5 Assigning of measurement locations

Sides:

S1 HV side of the main protected object (transformer)

S2 LV side of the main protected object (transformer)

S3 Side of the tertiary winding of the main protected object (transformer)

Measuring locations assigned 3-phase:

M1 Measuring location assigned to the main protected object for side 1

M2 Measuring location assigned to the main protected object for side 2

M3 Measuring location assigned to the main protected object for side 3

When defining the sides, the assignments made regarding the measuring locations (Fig. 5) at the main protected object must be observed. Side 1 is always the reference winding and therefore has current phase position 0° and no vector group code. This is usually the HV winding of the transformer. The object data refer to specifications for every side of the protected object as fixed in the assignment definition.

The relay requires the following data for the primary winding (side S1):

- The primary rated voltage U_N in kV (line-to-line)
- The rated apparent power
- The conditioning of the star point
- The transformer vector group

Generally, the currents measured on the secondary side of the current transformers with a current flowing through them are not equal. They are determined by the transformation ratio and the vector group of the transformer to be protected, and by the rated currents of the current transformers. The currents therefore have to be matched first to make them comparable.

This matching takes place arithmetically in the 7UT613. External matching equipment is therefore normally not necessary. The digitized currents are converted to the respective transformer rated currents. To do this, the transformer's rating data, i.e. rated apparent power, rated voltage and the primary rated currents of the current transformers, are entered in the protection relay.

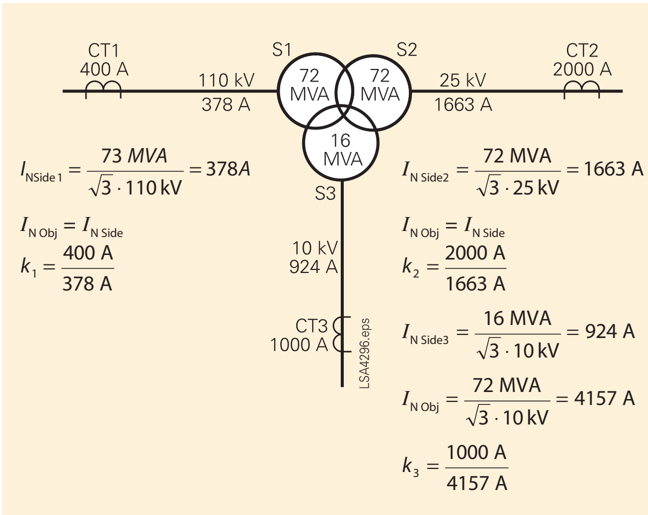


Fig. 6 Magnitude matching

Fig. 6 shows an example of magnitude matching. The primary rated currents of the two sides (windings) S1 (378 A) and S2 (1663 A) are calculated from the rated apparent power of the transformer (72 MVA) and the rated voltages of the windings (110 kV and 25 kV). Since the current transformer's rated currents deviate from rated currents of these sides, the secondary currents are multiplied by the factors k1 and k2.

The third winding (S3) on the other hand is only dimensioned for 16 MVA (e.g. as auxiliary supply winding). The rated current of this winding (= side of the protected object) is therefore 924 A. For the differential protection, however, comparable currents must be used for the calculation. Therefore, the protected object rated power of 72 MVA must also be used as a basis for the third winding. This results in a rated current (here: current under rated conditions of the protected object, i.e. at 72 MVA) of 4157 A. This is the reference variable for the currents of the third winding.

The currents are therefore multiplied by factor k3. The relay does perform this matching on the basis of the set rated values. Together with the vector group which also has to be entered, it is able to perform the current comparison according to fixed arithmetic rules. This is explained by the following example for the vector group Y(N)d5 (with earthed star-point):

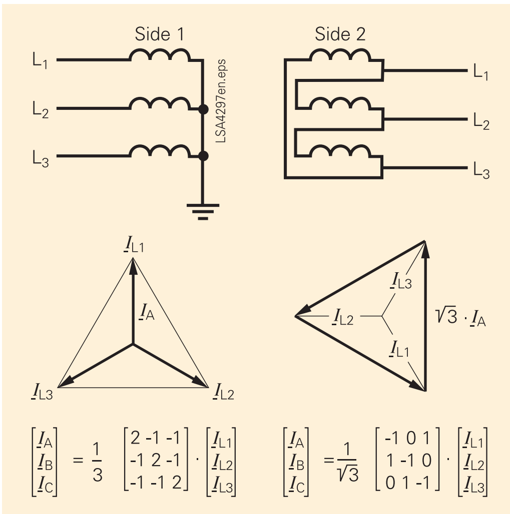


Fig. 7 Phasor diagram for vector group matching

Fig. 7 shows the windings and below them the phasor diagrams of symmetrical currents. The matrix equation in a general form is:

$$(\underline{I}_{\mathrm{m}}) = k\cdot(k)\cdot(\underline{I}_{\mathrm{n}})$$

The phase currents on the left-hand (star-point) side are equal to the winding currents (The magnitude matching of the absolute value is not taken into account in the figure).

Since there is no point earthed within the protected zone, no considerable zero-sequence current (residual current) can be produced within the protected zone in case of an earth fault outside the protected zone. This is also valid if the system star-point is earthed anywhere else in the system. In case of an earth fault within the protected zone, a zero-sequence current may occur at a measuring location if the system star-point is earthed anywhere else or another earth fault is present in the system (double earth fault in a non-earthed system). Thus, zero-sequence currents are of no concern for the stability of the differential protection as they cannot occur in case of external faults. In the case of internal faults, on the other hand, the zero-sequence currents (because they come from the outside) are absorbed almost totally by the sensitivity. A very high sensitivity in the event of earth faults in the protected zone can be achieved with overcurrent-time protection for zero-sequence current and/or the single-phase overcurrent-time protection, which can also be used as high impedance differential protection. The differential protection function must be activated by parameterization. The differential protection relay 7UT613 is delivered in inactive-circuit state. This is because the protection may not be operated without at least having set the vector groups and matching values correctly first. The relay may react unpredictably without these settings.

Setting of the characteristic of the differential protection is based on the following considerations:

- The presetting of 0.2 x I_N referred to the rated current of the transformer can be taken as a pickup value for the differential current as a rule.
- The slope 1 together with base point 1 take into account current-proportional error currents which may be caused by transformation errors of the CTs. The slope (gradient) of this section of the characteristic is set to 25 %.
- The add-on restraint increases the stability of the differential protection in the very high short-circuit current range in the event of external faults; it is based on the setting value EXF-restraint (address 1261) and has the slope 1 (address 1241).
- The slope 2 together with base point 2 lead to higher stabilization in the higher current range at which current transformer saturation can occur. The slope of this section of the characteristic is set to 50 %.

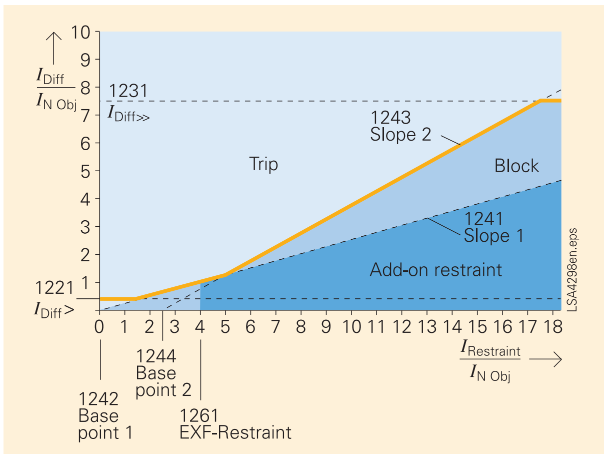


Fig. 8 Tripping characteristics of the differential protection

3.1.1 Notes on add-on restraint

In systems with very high through-flowing currents, a dynamic add-on restraint (stabilization) becomes effective for external faults. Note, that the restraint current is the arithmetic sum of the currents flowing into the protected object, i.e. is twice the through-flowing current. The add-on restraint does not affect the *I*>> stage.

The maximum duration of add-on restraint after detecting an external fault is set in multiples of a period (AC cycle). The recommended setting value is 15 periods (preset). The add-on restraint is disabled automatically – even before the set time period expires – as soon as the relay has detected that the operation point I_{Diff}/I_{Rest} is located steadily (i.e. for at least one period) within the tripping zone. The add-on restraint operates separately for each phase. Hence, blocking can be extended to all three phases thanks to the available vector-group (so called "crossblock" function). The recommended setting value for the crossblock function is 15 periods (preset).

3.1.2 Notes on setting the inrush blocking

An inrush current with a high proportion of 2^{nd} harmonics is generated when switching on the transformer, which can lead to false tripping of the differential protection. The default for the harmonic restraint with 2^{nd} harmonics of 15 % can be retained without change. A lower value can be set for greater stabilization in exceptional cases under unfavorable energizing conditions resulting from the design of the transformer.

The inrush restraint can be extended by the "crossblock" function. This means, that all three phases of the I_{Diff}> stage are blocked when the harmonic component is exceeded in only one phase. A setting value of 3 periods, effective for the time of mutual blocking after exceeding the differential current threshold, is recommended (default).

3.1.3 Notes on setting the overexcitation blocking

Stationary overexcitation in transformers is characterized by odd harmonics. The third or fifth harmonic is suitable for stabilization. Since the third harmonic is often eliminated in transformers (e.g. in a delta winding), the 5^{th} harmonic is mostly used. The proportion of 5^{th} harmonics which leads to blocking of the differential protection is set at 30 % (default). It is usually not necessary to set the crossblock function in this case.

3.2 Earth-fault differential protection

The earth-fault differential protection detects – selectively and with high sensitivity – earth faults in transformers with earthed star-point. The prerequisite is that a current transformer is installed in the star-point connection, i.e. between the star point and the earthing electrode. This star-point transformer and the phase current transformer define the limits of the protected zone.

No current I_{St} flows in the star-point connection in normal operation. The sum of the phase currents

$3I_0 = I_{L1} + I_{L2} + I_{L3}$ is almost zero.

In the event of an earth fault in the protected zone (Fig. 9) a star-point current I_{St} will flow; depending on the earthing conditions of the system, an earth current can also feed the fault position via the phase current transformer (dotted arrow), which, however, is more or less in phase with the star-point current. The currents flowing into the protected object are defined positive.

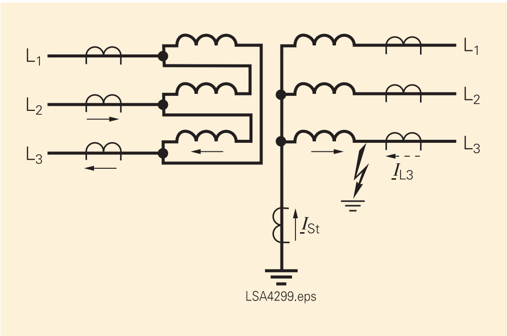


Fig. 9 Currents in case of an earth fault inside the transformer

In the event of an external earth fault a zero-sequence current also flows through the phase current transformers. This current has the same magnitude as the star-point current on the primary side and is phase-opposed to it. Therefore, both the magnitude of the currents and their relative phase positions are evaluated for stabilization. This produces the following tripping characteristic for the earth differential protection:

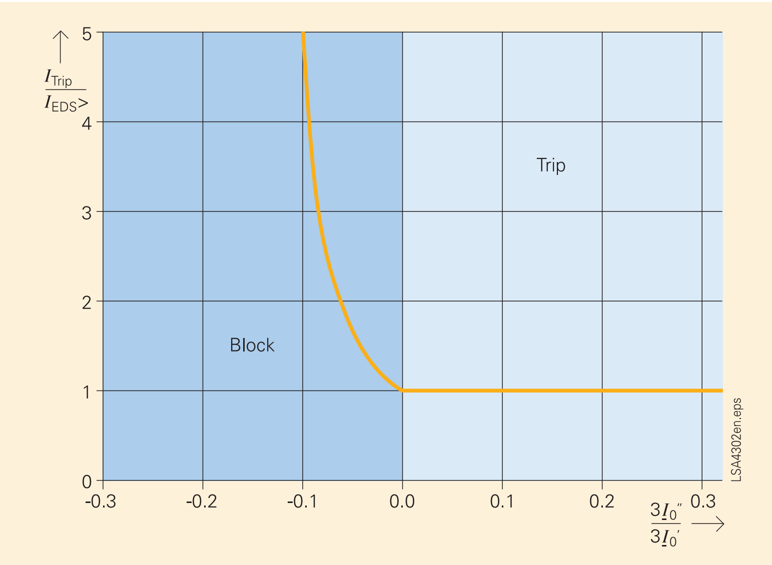


Fig. 10 Tripping characteristic for earth differential protection

In the above examples it was assumed that $3I_0$"and $3I_0$' are phase-opposed in the event of an external earth fault, which is correct as far as the primary variables are concerned. However, current transformer saturation can simulate a phase shift between the star-point current and the sum of the phase currents, which weakens the restraint value. The restraint is zero at $\varphi(3I_0''; 3\,I_0') = 90°$. This corresponds to the conventional method of direction detection by use of the vectorial sum and difference comparison.

The following phasor diagram shows the restraint value in the event of an external fault:

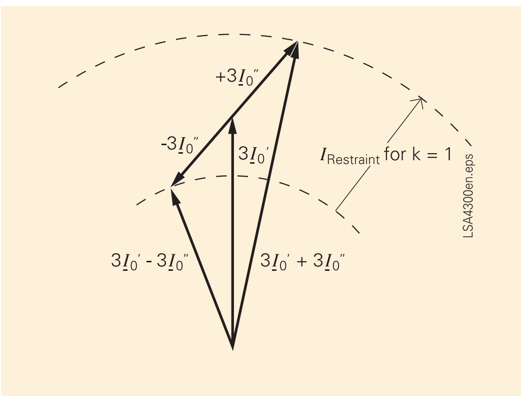


Fig. 11 Phasor diagram of restraint (stabilization) value

The earth-fault differential protection function must be activated by parameterization. The 7UT613 earth-fault differential protection relay is delivered in inactive-circuit state. This is because the protection relay may not be operated without at least having set the allocation and polarity of the current transformers correctly first. The relay may react unpredictably without these settings.

The setting of the I-EDS> value is decisive for the sensitivity of the protection. This value is the earth-fault current which flows through the star-point connection of the transformer. Another earth current flowing in from the system is not absorbed by the pickup sensitivity. The current value refers to the rated operating current of the side of the transformer to be protected. The preset pickup value of 0.15 I/I_{nS} is normally appropriate.

3.3 Backup protection functions

3.3.1 Overcurrent-time protection

The definite-time overcurrent-time protection of the 7UT613 serves as backup for the short-circuit protection of the downstream system sections when faults cannot be cleared in time there, meaning that the protected object is in danger.

The overcurrent-time protection can be assigned to one of the three voltage sides of the transformer. Correct allocation between the measuring inputs of the relay and the measuring locations (current transformer sets) of the power plant must also be observed. The stage I>> together with stage I> or stage I_P produces a two-stage characteristic. If the overcurrent-time protection acts on the feed side of the transformer, stage I>> is set so that it picks up for short-circuits extending into the protected object, but not for a short-circuit current flowing through it.

Calculation example:
Transformer Y(N)d5
72 MVA
25 kV/10 kV
u_{SC} = 12 %
Current transformer 2000 A/1 A on the 25-kV-side
The overcurrent-time protection acts on the 25 kV side (= feed side).
The maximum possible three-phase short-circuit current on the 10 kV side with rigid voltage on the 25 kV side would be:

$$I_{3polemax} = \frac{1}{U_{SC\,Transf.}} \cdot I_{N\,Transf.} = \frac{1}{U_{SC\,Transf.}} \cdot \frac{S_{N\,Transf.}}{\sqrt{3} \cdot U_N} =$$

$$\frac{1}{0.12} \cdot \frac{72\text{ MVA}}{\sqrt{3} \cdot 25\text{ kV}} = 13856.4\text{ A}$$

With a safety factor of 20 % this gives the primary setting:

I>> = 1.2 x 13856.4 A = 16628 A

With parameterization in secondary variables the currents in amperes are converted to the secondary side of the current transformers.

Secondary setting value:

$$I >> = \frac{16628\text{ A}}{2000\text{ A}} \cdot 1\text{ A} = 8{,}314\text{ A}$$

i.e. at short-circuit currents above 16628 A (primary) or 8,314 A (secondary), there is definitely a short-circuit in the transformer area. This can be cleared immediately by the overcurrent-time protection. Increased inrush currents are disarmed by the delay times of the *I*>> stage if their fundamental exceeds the setting value. The inrush restraint does not affect the stages *I*>>.

Stage *I*> represents the backup protection for the subordinate busbar. It is set higher than the sum of the rated outgoing currents. Pickup by overload must be ruled out because the relay operates with correspondingly short command times as short-circuit protection in this mode and not as overload protection. This value must be converted to the HV side of the transformer. The delay time depends on the grading time in the outgoing lines. It should be set 300 ms more than the highest grading time on the LV side. Moreover, the inrush restraint for the *I*> stage must be parameterized effectively in this case, so that false pickup of the *I*> stage (resulting from the inrush of the transformer) is prevented.

3.3.2 Load unbalance protection (negative-sequence protection)

The load unbalance protection (phase-balance current protection or negative-sequence protection) can be used in the transformer as sensitive protection function on the feed side for weak-current single and two-pole faults. LV side, single-pole faults can also be detected which cause no zero-sequence current on the HV side (e.g. in vector group DYN).

The load unbalance protection of the HV winding (110 kV in the example) can detect the following fault currents on the LV side (25 kV in the example):

If $I_2 >= 0.1$ A is set for the HV side, a fault current of

$$I_{F1} = 3 \cdot \frac{110\text{ kV}}{25\text{ kV}} \cdot \frac{400\text{ A}}{1\text{ A}} \cdot 0.1\text{ A} = 528\text{ A}$$

can be detected for a single-phase fault and of

$$I_{F2} = \sqrt{3} \cdot \frac{100\text{ kV}}{25\text{ kV}} \cdot \frac{400\text{ A}}{1\text{ A}} \cdot 0.1\text{ A} = 305\text{ A}$$

for a two-phase fault on the LV side. This corresponds to 26 % or respectively 15 % of the transformer's rated current. Since this is a LV side short-circuit, the delay time must be coordinated with the times of the subordinate protection relays. The definite-time characteristic is two-stage.

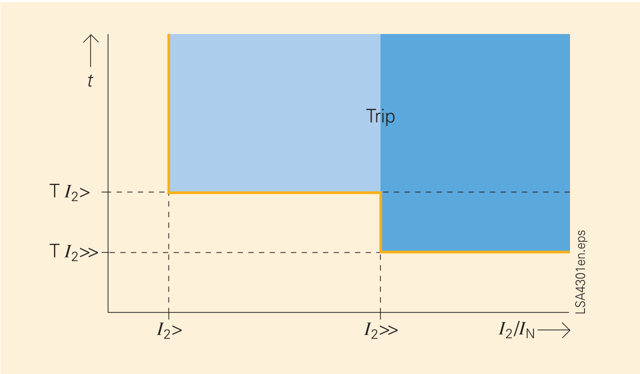


Fig. 12 Tripping characteristic of load unbalance protection

Stage I_2> can be used for warning. A trip command can be given at the end of the delay time of stage I_2>>.

3.3.3 Overload protection

The thermal overload protection prevents overload of the transformer to be protected. Two methods of overload detection are available in the 7UT6:

- Overload protection with thermal replica according to IEC 60255-8,
- Hot-spot calculation with determining of the relative ageing rate according to IEC 60354.

One of these two methods can be selected. The first is notable for easy handling and a low number of setting values; the second requires some knowledge of the protected object, its ambient context and its cooling, and needs the input of the coolant temperature via a connected thermobox. The second method is used when the transformer is operated at the limit of its performance and the relative ageing rate is to be monitored by the hot-spot calculation.
Overload protection with thermal replica (to act on the HV side) is chosen for this application example. Since the cause of the overload is normally outside the protected object, the overload current is a through-flowing current. The relay calculates the temperature rise according to a thermal single-body model by means of the thermal differential equation

$$\frac{\mathrm{d}\Theta}{\mathrm{d}t}+\frac{1}{\tau_{\mathrm{th}}}\cdot\Theta=\frac{1}{\tau_{\mathrm{th}}}\cdot\left(\frac{I}{I_{\mathrm{N\,Obj}}}\right)^2$$

The protection function therefore represents a thermal replica of the object to be protected (overload protection with memory function). Both the history of an overload and the heat transmitted to the ambient area are taken into account. Pickup of the overload protection is output as a message.

Notes on the setting
In transformers, the rated current of the winding to be protected, which the relay calculates from the set rated apparent power and the rated voltage, is significant. The rated current of the side of the main protected object assigned to the overload protection is used as the basic current for detecting the overload. The setting factor k is determined by the ratio of the thermally permissible continuous current to this rated current:

$$k=\frac{I_{\mathrm{max}}}{I_{\mathrm{N\,Obj}}}$$

The permissible continuous current is at the same time the current at which the e-function of the overtemperature has its asymptote. The presetting of 1.15 can be accepted for the HV winding.

Time constant τ in thermal replica:
The heating time constant τ_{th} for the thermal replica must be specified by the transformer manufacturer. It must be ensured that the time constant is set in minutes. There are often other specifications from which the time constant can be determined:

Example:
t_6 time: This is the time in seconds for which 6 times the rated current of the transformer winding may flow.

$$\frac{\tau_{\mathrm{th}}}{\mathrm{min}}=0.6\cdot t6$$

If the transformer winding has a τ_6 time of 12 s

$$\frac{\tau_{\mathrm{th}}}{\mathrm{min}}=0.6\cdot 12\ s=7.2$$

the time constant τ must be set to 7.2 min.

3.3.4 Overexcitation protection

The overexcitation protection serves to detect increased induction in generators and transformers, especially in power station unit transformers. An increase in the induction above the rated value quickly leads to saturation of the iron core and high eddy current losses which in turn lead to impermissible heating up of the iron.

Use of the overexcitation protection assumes that measuring voltages are connected to the relay. The overexcitation protection measures the voltage/frequency quotient U/f, which is proportional to the induction B at given dimensions of the iron core. If the quotient U/f is set in relation to voltage and frequency under rated conditions of the protected object $U_{\mathrm{NObj}}/f_{\mathrm{N}}$, a direct measure is obtained of the induction related to the induction under rated conditions B/B_{NObj}. All constant variables cancel each other:

$$\frac{B}{B_{\mathrm{N\,Obj}}}=\frac{\dfrac{U}{U_{\mathrm{N\,Obj}}}}{\dfrac{f}{f_{\mathrm{N}}}}=\frac{U\,/\,f}{U_{\mathrm{N\,Obj}}\,/\,f_{\mathrm{N}}}$$

The relative relation makes all conversions unnecessary. All values can be specified directly related to the permissible induction. The rated variables of the protected object have already been entered in the 7UT613 relay with the object and transformer data when setting the differential protection.

Setting instructions

The limit value of permanently permissible induction in relation to the rated induction (B/B_N) specified by the protected object manufacturer forms the basis for setting the limit value. This value is at the same time a warning stage and the minimum value for the thermal characteristic (see Fig. 13).

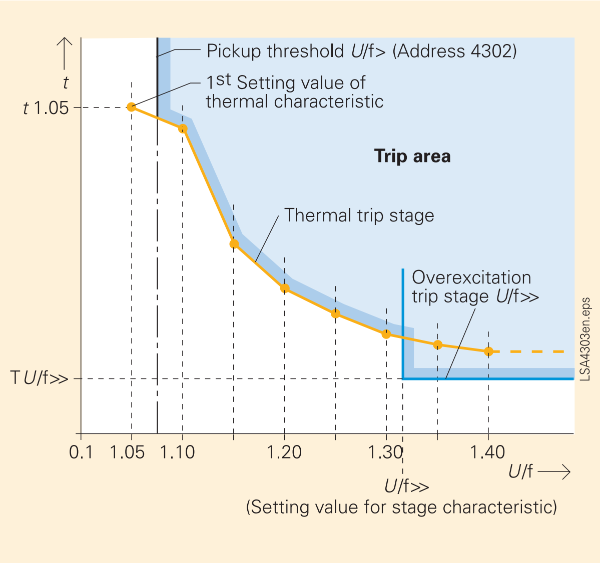


Fig. 13 Tripping characteristic of the overexcitation protection

An alarm is output after the relevant set delay time (about 10 s) of the overexcitation stage *U*/*f* has expired. Major overexcitation endangers the protected object already after a short time. The high-set tripping stage *U*/*f*>> is therefore set to a maximum of 1 s.

The thermal characteristic should simulate the heating, i.e. temperature rise, of the iron core resulting from overexcitation. The heating characteristic is approximated by entering 8 delay times for 8 given induction values B/B_{NObj} (referred to in simplified form as *U*/*f*). Intermediate values are obtained by linear interpolation. If no data are available from the protected object manufacturer, the preset standard characteristic is used.

■ 4. Further functions

4.1 Integration into substation control system

The protection can be connected to a substation control system via the system interface and operated in parallel by PC via the service interface to a star coupler for separate remote communication.

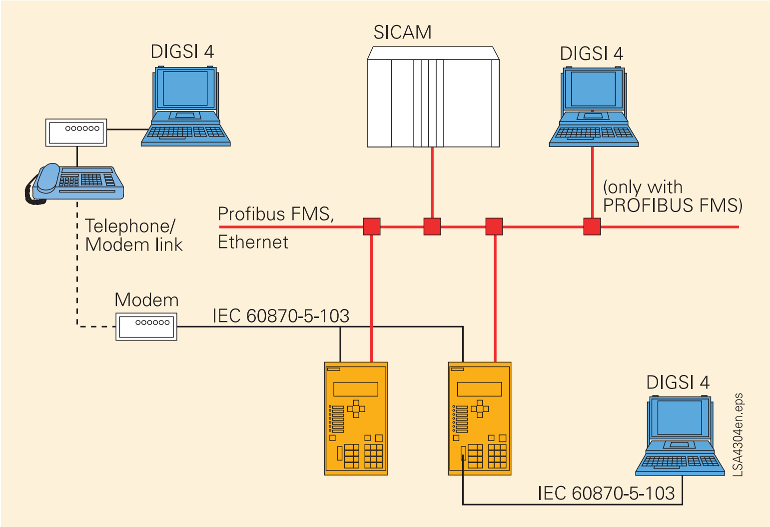


Fig. 14 Integration into substation control system

Via the interface,

- Messages
- Alarms
- Measured values

are transmitted from the transformer differential protection to the substation control system. Messages are available for every one of the activated protection functions, which can be either transmitted to the substation control system in the course of plant equipment parameterization, or allocated to the LEDs or alarm contacts in the protection relay. This configuration is made clear and easy by the DIGSI matrix.

Service interface

The 7UT613 has a separate service interface which can be read out by telecommunication via a modem. The user is informed in the office quickly and in detail about the transformer fault. The data are then analyzed in the office by DIGSI. If this remote fault clearing is insufficient, the fault data provide hints for an efficient service mission.

5. Connection diagram

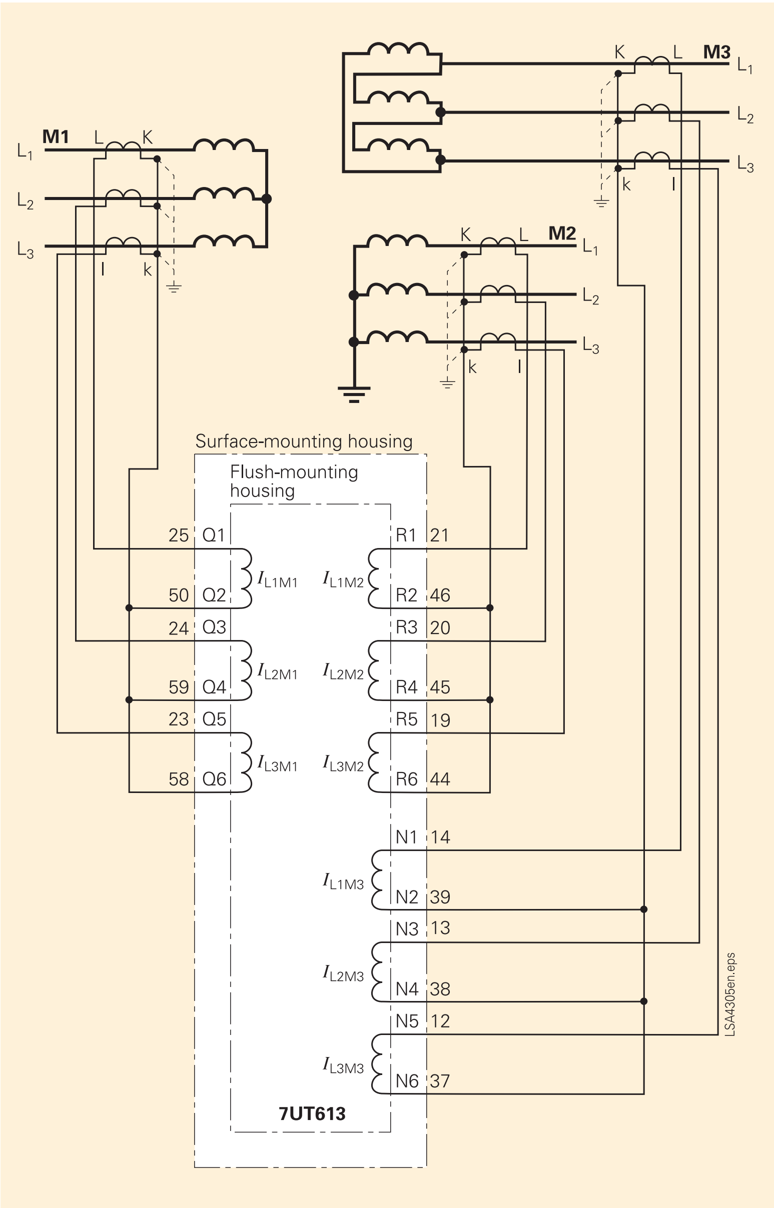


Fig. 15 Connection diagram of 7UT613

6. Summary

Optimum protection of the transformer with SIPROTEC relays means security of investment for valuable operating equipment and therefore makes a contribution to maximum supply security.

From a technical point of view, the SIPROTEC 7UT613 relay offers extensive short-circuit protection for both the main and the backup protection of transformers in one single relay. Extensive measuring functions allow trouble-free connection of the relay without the need for additional equipment, and enable monitoring of the transformer in operation in terms of its electrical and thermal parameters. The relay's presettings are chosen so that the user need only parameterize the known data of the main and primary transformers. Many of the default settings can simply be accepted as they are, and therefore make parameterization and setting easier.

Protection of a Transformer with Tap Changer

1. Introduction

Transformers are among the most important and cost-intensive equipment in electrical power systems, meaning that faults which occur in these components not only entail an interruption in the electrical power supply over wide areas but also cause considerable losses in financial terms. A continuous fault-free power supply must therefore be ensured, over the course of years if possible. Faults and signs of potential failures of the transformers must therefore be detected in time in order to take suitable measures for troubleshooting.

For this reason transformers are equipped with various monitoring and protection relays depending on their type and size. The electrical protection should be highlighted particularly in addition to the mechanical protection.

Fuses and definite-time overcurrent-time relays are sufficient in smaller distribution transformers for both technical and economic reasons. Fuses and definite-time overcurrent-time relays represent time-delayed protection measures. Time-delayed protection tripping relays are unacceptable for larger transformers in distribution, transmission and power generation applications and must be disconnected immediately to avoid system instability and cost-intensive shutdowns.

Transformer faults can generally be divided into five categories:

- Interturn and terminal fault
- Winding fault
- Fault on the transformer tank and auxiliary devices
- Fault on the transformer tap changer
- Abnormal operating conditions (temperature, humidity, dirt)
- External fault

This application example gives an insight into the protection of regulated power transformers with tap changer function.

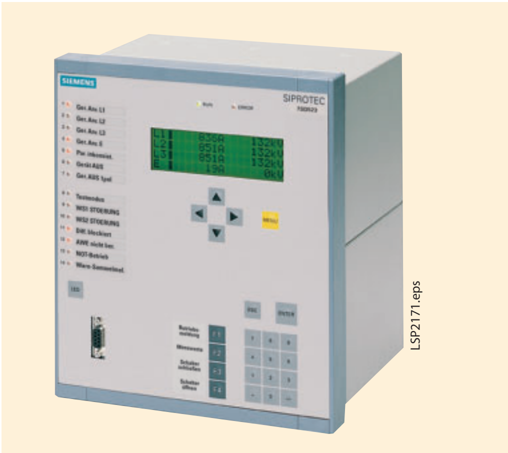


Fig. 1 SIPROTEC 7UT6 transformer protection

2. Protection concept

Depending on the type and size of the transformers, Buchholz protection, overload protection and overcurrent time protection are used as fast, selective short-circuit protection in addition to the classic differential protection (as from approximately 1 MVA and higher). These are only mentioned briefly here because they are described in detail in other application examples.

2.1 Differential protection as main protection

Differential protection represents the main protection function for the transformer and is featured in the SIPROTEC relays 7UT6* (addr. 1201) and 7UM62* (addr. 2001). It also comprises a number of additional functions (matching to transformation ratio and vector group, restraint against inrush currents). Therefore false differential currents caused by transformation errors of the current transformers are to be expected in practice. In regulated transformers an additional error current is to be expected caused by adjustment of the tap changer.

The additional functions integrated in the relays are influenced by the use of a transformer with tap changer and the resulting correction values. This is explained in chapter 4 by a calculation example.

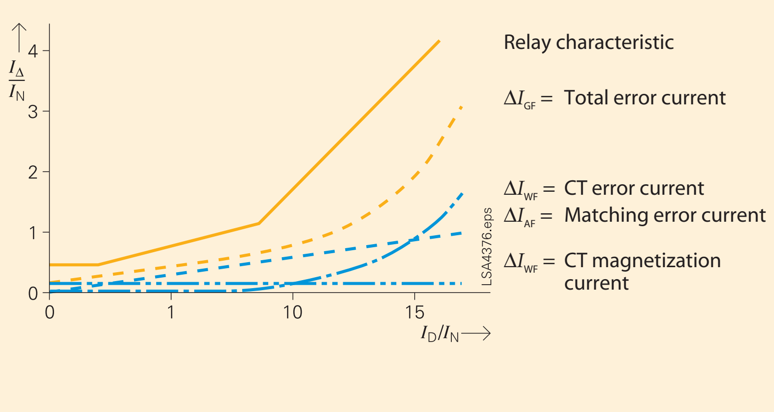


Fig. 2 False differential current in the event of load and continuity faults and matched relay characteristic

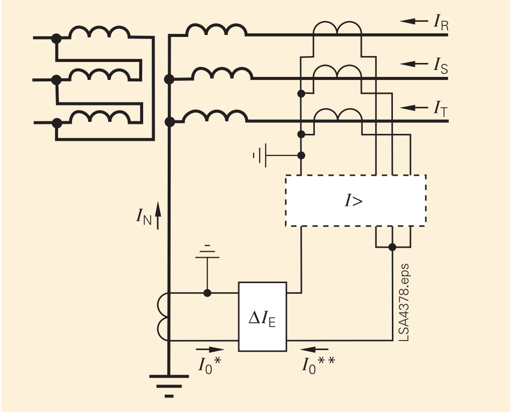


Fig. 4 Earth-fault differential protection

Backup protection such as overcurrent time protection are provided in separate relays (e.g. 7SJ602, 7SJ45/46). The overcurrent-time protection and/or overload protection contained in the differential protection relays serve merely as backup protection against external faults in the connected power system.

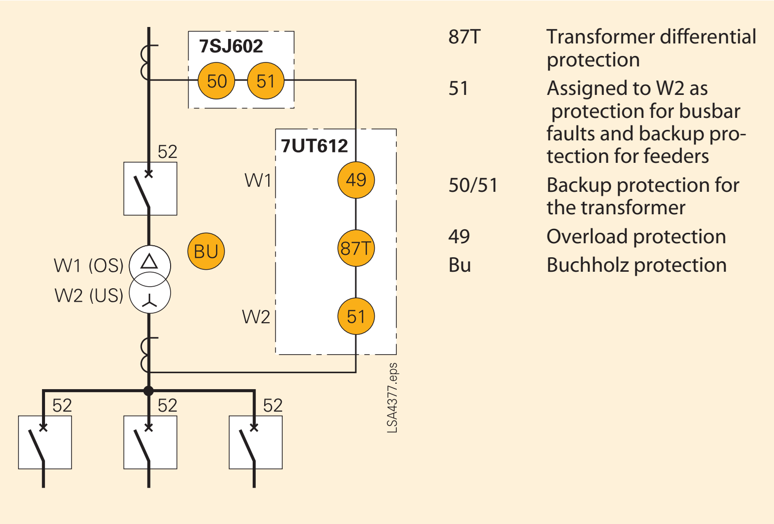


Fig. 3 Protection of a two-winding transformer

2.2 Earth-fault differential protection

In transformer windings with star-point earthing via an impedance (earth-current limiting), the earth-current differential protection (7UT6* addr. 1301) is an ideal supplement to the phase protection to enhance the response sensitivity in the earth fault.

In this method the measured star-point current I_0* in the transformer star-point is compared with the calculated summation current I_0** of the phase currents.

2.3 Buchholz protection

The Buchholz protection is coupled into the relay (alarm, tank and trip message) as an external protection (7UT6*, 7UM62* addr. 8601, 8701) and is used for liquid-cooled transformers and reactors with expansion tank. The Buchholz relay responds to faults which cause the forming of gas in the tank (winding fault, interturn fault, loss of insulating fluid, accumulation of air).

3. Integration of the transformer tap changer in differential protection

3.1 Purpose of a transformer tap changer

Voltage regulation on transformers with load tap changers is an important topic for power supply companies. In accordance with DIN/IEC standards it is necessary to keep the 230 V/400 V voltage in the public low-voltage system constant, at least in the range ± 10 %. To keep the voltage constant in this bandwidth, a transformer tap changer is controlled by a transformer voltage regulator (e.g. Maschinenfabrik Rheinhausen TAPCON® 230/240). The voltage regulator constantly compares the actual value U_{act} (output voltage at the transformer) and a fixed or load-dependent setpoint U_{setp}.

The voltage regulator supplies the setting variable for the transformer's load tap changer dependent on the deviation of the actual value from the setpoint. The load tap changer switches when the given bandwidth (U_{setp} +/- B%) is dropped below or exceeded. The voltage at the transformer is thus kept constant. Fluctuations within the permissible bandwidth have no influence on the control behavior or the switching process.

The parameters of the voltage regulator can be adapted optimally to the behavior of the system voltage so that a balanced control behavior is achieved at a low number of cycles of the load tap changer.

system data. Former relay generations required separate matching transformers for (e.g.) vector group adaptation.

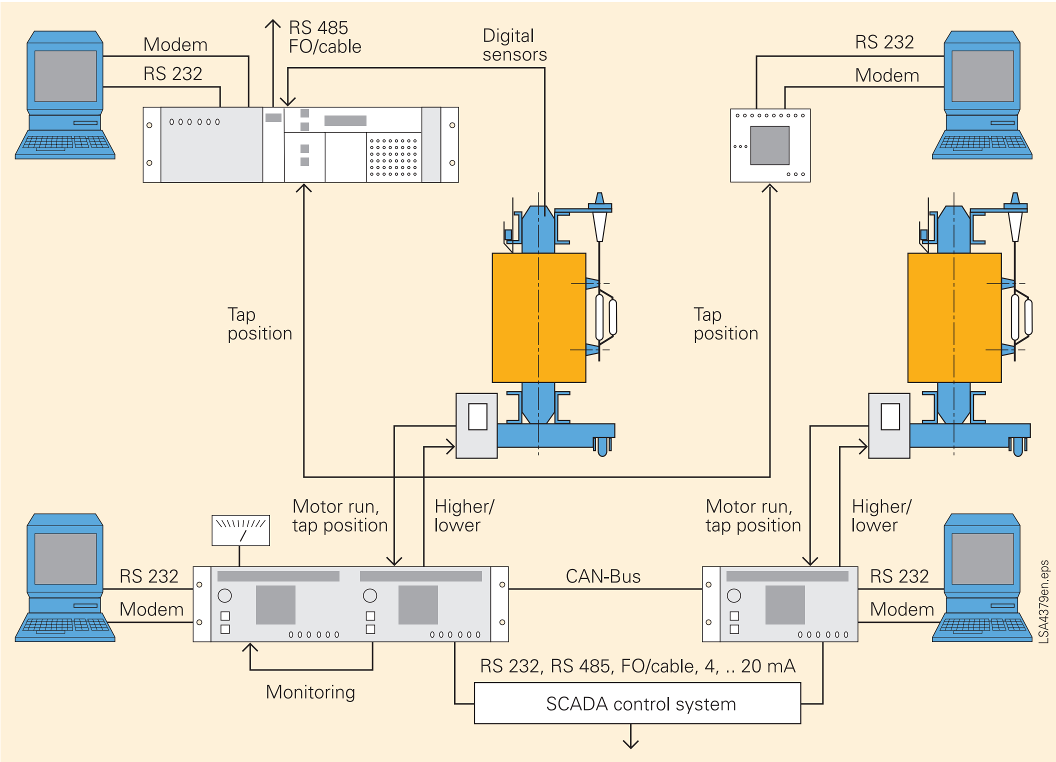


Fig. 5 Voltage regulation of a regulated transformer using a TAPCON® system

3.2 Correcting "false" differential currents

Most calculations of differential and restraint currents are made without taking the tap changer position into account. In practice, however, most power transformers are equipped with a tap changer. Two types are distinguished:

- Off-load tap changer
- On-load tap changer

Whilst most transformers are equipped for off-load tap changing, on-load tap changing is used for voltage regulation in power systems. The protection parameterization must take the different tap changer positions into consideration to avoid the possibility of false tripping (especially with extreme positions).

Correct operation of the differential protection requires that the differential currents on the primary and secondary side correspond to real conditions under normal load and fault conditions. The primary and secondary side current transformers do not pick up the real transformer ratio. Today's protection relays such as those in the SIPROTEC series compensate these faults with calculated correction factors based on the parameterized power

If the winding is regulated, not the actual rated voltage is used as U_N for the stabilized side, but the voltage corresponding to the mean current of the regulated range.

$$U_N = 2 \cdot \frac{U_{max} \cdot U_{min}}{U_{max} + U_{min}} = \frac{2}{\frac{1}{U_{max}} + \frac{1}{U_{min}}}$$

with U_{max}, U_{min} as limits for the regulated range.

Example:

Transformer Ynd5
35 MVA
110 kV/20 kV
Y side regulated ± 20%

For the regulated winding (110 kV) this results in

Maximum voltage U_{max} = 132 kV
Minimum voltage U_{min} = 88 kV

Voltage to be set

$$U_{N\text{-PRI SIDE 1}} = \frac{2}{\frac{1}{132\text{ kV}} + \frac{1}{88\text{ kV}}} = 105.6\text{ kV}$$

Parameters in relevant SIPROTEC relays

7UT612	addr. 240
7UT613/63*	addr. 311
7UM62	addr. 240

4. Calculation example Influence of tap positions on differential and restraint currents

A two-winding transformer with a tap change range of –15 % to + 5 % is used for the following example. The tap changer is integrated in the primary winding for voltage regulation.

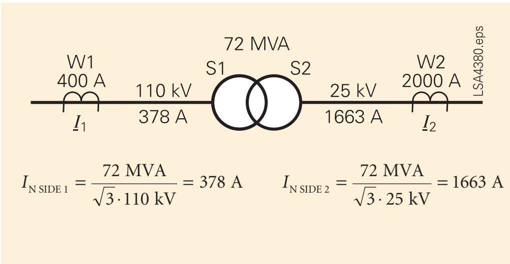


Fig. 6

Transformer	YNd5
	(irrelevant for the calculation)
	72 MVA
	110 kV/25 kV
	Y side regulated -15 %/+5 %
	CT_1 = 400 (1 A)
	CT_2 = 2000 (5 A)

4.1 Calculations of the voltage, object rated currents and correction factors to be set

The voltage to be set is calculated using the formula in chapter 3.2 and parameterized as $U_{\text{N WIND.S1}}$ in the SIPROTEC relays 7UT6*, 7UM62*.

For the regulated winding (110 kV) this gives a calculated
maximum voltage U_{max} = 115.5 kV
minimum voltage U_{min} = 93.5 kV

Voltage to be set

$$U_{\text{N 1}} = 2\cdot\frac{U_{\max}\cdot U_{\min}}{U_{\max}+U_{\min}} = \frac{2}{\frac{1}{U_{\max}}+\frac{1}{U_{\min}}}$$

$$= 2\cdot\frac{115.5\text{ kV}\cdot 93.5\text{ kV}}{115.5\text{ kV}+93.5\text{ kV}} = 103.3\text{ kV}$$

Object rated current of the regulated side

$$I_{\text{N 1}} = \frac{S_{\text{N}}}{\sqrt{3}\cdot U_{\text{N 1}}} = \frac{72\text{ MVA}}{\sqrt{3}\cdot 103.3\text{ kV}} = 402.3\text{ A}$$

corresponds on the CT_1 secondary side to

$$I_{\text{N 1}} = \frac{I_{\text{N1}}}{CT_1} = \frac{402.3\text{ A}}{400} = 1.00575\text{ A} \cong I_{\text{NObj}}$$

(referred to S1)

Object rated current of the unregulated side (remains constant)

$$I_{\text{N2}} = \frac{S_{\text{N}}}{\sqrt{3}\cdot U_{\text{N2}}} = \frac{72\text{ MVA}}{\sqrt{3}\cdot 25\text{ kV}} = 1663\text{ A}$$

corresponds on the CT_2 secondary side to

$$I_{\text{N2}} = \frac{I_{\text{N2}}}{CT_2} = \frac{1663\text{ A}}{2000} = 0.8315\text{ A} \cong I_{\text{NObj}}$$

(referred to S2)

4.2 Calculations of the differential/restraint currents in the tap changer extreme positions

4.2.1 Tap position +5 %

Object current in maximum tap position

$$I_{\text{N 1}(+5\%)} = \frac{S_{\text{N}}}{\sqrt{3}\cdot U_{\max}} = \frac{72\text{ MVA}}{\sqrt{3}\cdot 115.5\text{ kV}} = 359.9\text{ A}$$

corresponds on the CT_1 secondary side to

$$I_{\text{N 1}(+5\%)} = \frac{I_{\text{N1}(+5\%)}}{CT_1} = \frac{359.9\text{ A}}{400} = 0.8997\text{ A} \cong 0.8946\cdot I_{\text{NObj}}$$

Differential current in maximum tap position

$$I_{\text{Diff}} = \left|I_{\text{N 1}(+5\%)} - I_{\text{NObj}}\right| = \left|0.8946\cdot I_{\text{NObj}} - I_{\text{NObj}}\right| = 0.1054\cdot I_{\text{NObj}}$$

Restraint current in maximum tap position

$$I_{\text{Restraint}} = \left|I_{\text{N1}(+5\%)}\right| + \left|I_{\text{NObj}}\right| = \left|0.8946\cdot I_{\text{NObj}}\right| + \left|I_{\text{NObj}}\right| = 1.8946\cdot I_{\text{NObj}}$$

4.2.2 Tap position -15 %

Object current in minimum tap position

$$I_{\text{N 1}(-15\%)} = \frac{S_{\text{N}}}{\sqrt{3}\cdot U_{\min}} = \frac{72\text{ MVA}}{\sqrt{3}\cdot 93.5\text{ kV}} = 444.6\text{ A}$$

corresponds on the CT_1 secondary side to

$$I_{\text{N 1}(-15\%)} = \frac{I_{\text{N1}(-15\%)}}{CT_1} = \frac{444.6\text{ A}}{400} = 1.1115\text{ A} \cong 1.1051\cdot \text{I}_{\text{NObj}}$$

Differential current in maximum tap position

$$I_{\text{Diff}} = \left|I_{\text{N 1}(-15\%)} - I_{\text{N2}}\right| = \left|1.1051\cdot I_{\text{NObj}} - I_{\text{NObj}}\right| = 0.1051\cdot I_{\text{NObj}}$$

Restraint current in maximum tap position

$$I_{\text{Restraint}} = \left|I_{\text{N 1}(+5\%)}\right| + \left|I_{\text{N2}}\right| = \left|1.051\cdot I_{\text{NObj}}\right| + \left|I_{\text{NObj}}\right| = 2.1051\cdot I_{\text{NObj}}$$

At the voltage to be set according to chapter 3.2 the same differential current portion of the object rated current is measured respectively in the extreme positions The calculated voltage U_{N1} to be set corresponds to the middle position of the transformer tap changer.

4.3 Difference between operating current and restraint current

$I_{op} = m \cdot I_{Restraint}$

Presetting m = 0.25

$I_{op} = 0.25 \cdot I_{Restraint}$

At maximum tap position + 5 % it follows that

$$I_{op} = 0.25 \cdot 1.8496 \cdot I_{NObj} = 0.4624 \cdot I_{NObj}$$

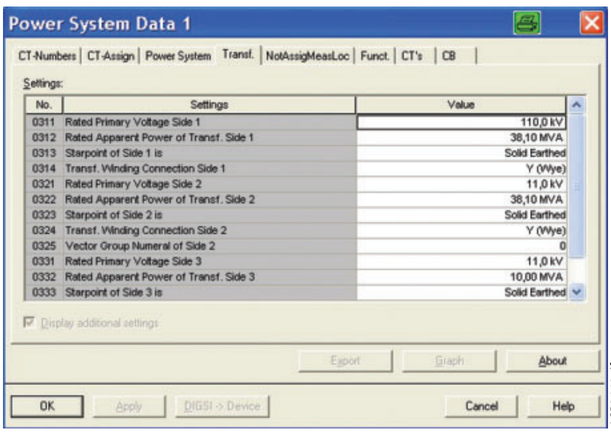
At minimum tap position - 15 % it follows that

$$I_{op} = 0.25 \cdot 2.1051 \cdot I_{NObj} = 0.5263 \cdot I_{NObj}$$

From the calculations it can also be derived that, under rated conditions and at the tap changer extreme positions, the operating currents are not in the tripping area (due to the characteristic). Therefore the slope (gradient) of the trip characteristic (7UT6* addr. 1241, 7UM62* addr. 2041) need not be adapted to conditions (presetting m = 0.25).

5. Parameterization notes

Direct coupling of the transformer tap changer into the protection algorithm is available as from V4.6 for 7UT63* relays (approx. available as of mid-2005). By reading in the tap positions (with the codings BCD, binary, 1 from n table), the transformation ratio can be adapted depending on the position, and the faulty differential currents compensated as a result. This improves both the sensitivity and the stability of the differential protection.



No.	Settings	Value
0311	Rated Primary Voltage Side 1	110,0 kV
0312	Rated Apparent Power of Transf. Side 1	38,10 MVA
0313	Starpoint of Side 1 is	Solid Earthed
0314	Transf. Winding Connection Side 1	Y (Wye)
0321	Rated Primary Voltage Side 2	11,0 kV
0322	Rated Apparent Power of Transf. Side 2	38,10 MVA
0323	Starpoint of Side 2 is	Solid Earthed
0324	Transf. Winding Connection Side 2	Y (Wye)
0325	Vector Group Numeral of Side 2	0
0331	Rated Primary Voltage Side 3	11,0 kV
0332	Rated Apparent Power of Transf. Side 3	10,00 MVA
0333	Starpoint of Side 3 is	Solid Earthed

Fig. 7 7UT613/63* parameterization in transformer system data

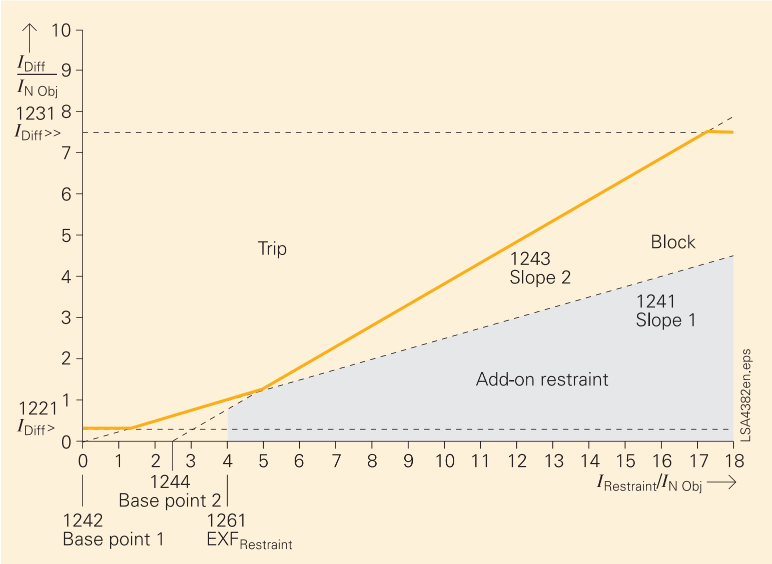


Fig. 8 Tripping characteristic of the differential protection in 7UT6* and 7UM62*

The matching is currently performed by correction of the primary voltage according to the formula in chapter 3.2 and parameterization by means of the appropriate addresses or DIGSI.

6. Integration of tap positions in DIGSI

Transformer taps can be indicated either by the DIGSI PC or the graphic display of the SIPROTEC relay. The transformer taps are signaled via binary inputs on the relay. The binary inputs are assigned according to the coding type and number of transformer taps (see Fig. 9).

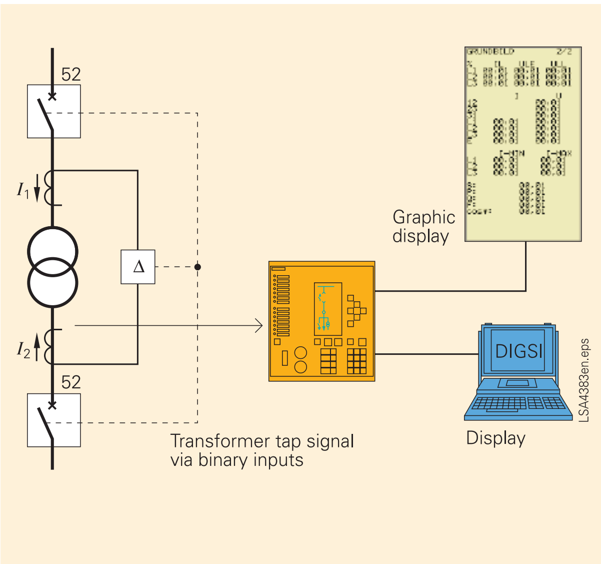


Fig. 9 Schematic diagram – Reading in of tap position by DIGSI or graphic display

In order to display the transformer taps, the transformer tap message type must first be entered in the configuration matrix.

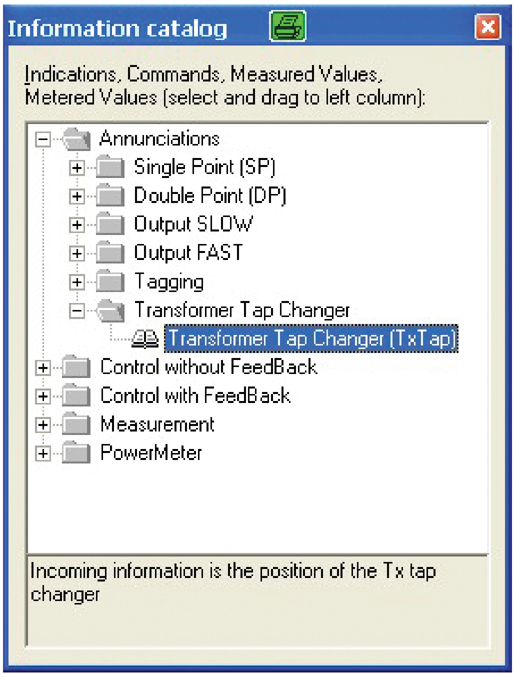


Fig. 10 Activating the transformer tap message in the information catalog

The transformer tap message is entered in the configuration matrix and activated by configuration of the binary inputs.

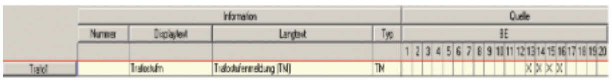


Fig. 11 Entry of the transformer tap message in the DIGSI configuration matrix

Detailed settings must be made under the object properties of the transformer tap message.

- Number of bits: necessary for coding; number depends on the selected coding
- Display offset: the value by which the size of the displayed value is to be shifted in positive or negative direction in relation to the magnitude of the actual value
- Moving contact: if the moving contact option is activated, the tap position is not recognized as valid and accepted until the moving contact signals that it has reached the taps (always the highest ranking contact)

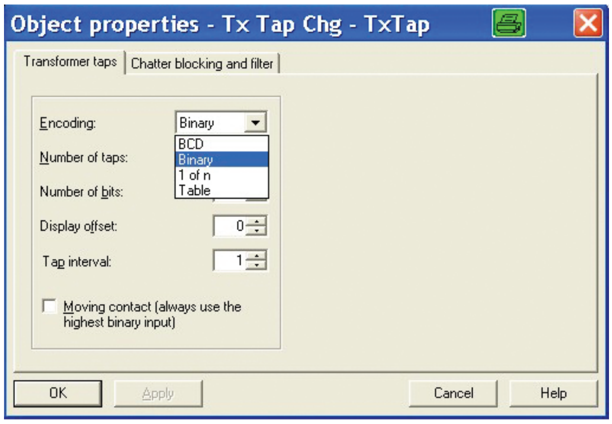


Fig. 12 Object properties, transformer tap message

7. Summary

In most differential protection relays the influence of the transformer tap changer is mainly taken into account with the corrected input of the primary voltage (determined in the middle position of the tap changer).

Owing to the demand for stabilized voltages and regulation by tap changers, the probabilities of tripping faults in the extreme positions of the tap changer can be limited in future by matching of the transformation ratio. This requirement is met by inclusion of the tap position in the protection relay and consideration of the protection algorithm in the SIPROTEC 7UT63* relays.

Protection of an Autotransformer

■ 1. Introduction

Transformers are valuable equipment which make a major contribution to the supply security of the power system. Optimum design of the transformer protection ensures that any faults that may occur are found quickly, so that consequential damage is minimized. A special variant is the so-called autotransformer in which, unlike in the full transformer, the voltage and current transformation is not performed by two independent windings but uses part of the winding from both sides, allowing a much more compact design. The spectrum of autotransformers ranges from small distribution system transformers (from 1000 kVA) to large transformers of several hundred MVA. Their use becomes more interesting, the less the ratio between the high-voltage (HV) side and low-voltage (LV) side deviates from 1, i.e. the less energy is transmitted via the magnetic coupling which leads to a saving in iron material. In addition to the design notes, a complete setting example with SIPROTEC protection relays for a triple-wound autotransformer in the transmission system is described.

■ 2. Protection concept

Differential protection offers fast, selective short-circuit protection, alone or as a supplement to the Buchholz protection. In larger units from about 5 MVA it is part of the standard equipment. In addition to the main protection function which reliably clears a short-circuit within the protected object, a fully-fledged protection concept contains a number of additional functions which take care of other problems such as overload, overexcitation, etc. All the necessary functions are already contained in the SIPROTEC 4 relays. Backup protection functions are a useful addition.

Fig. 2 shows an example of a full protection concept for an autotransformer.

Fig. 1 SIPROTEC 7UT6 transformer protection

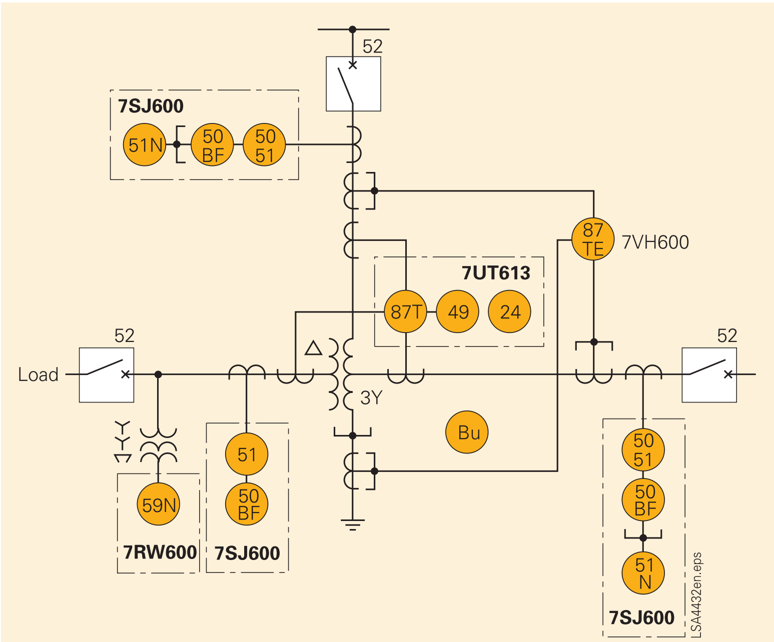
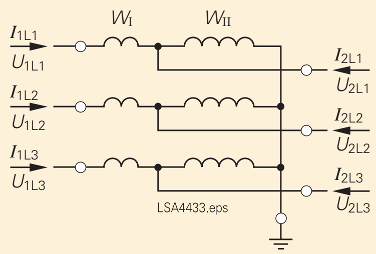


Fig. 2 Protection of an autotransformer

For this example a differential protection ANSI 87T (3-windings version) must be selected (7UT613), so that the delta stabilizing winding can be included in the protected zone (different alternatives for connection are explained in detail in chapter 3). If this is missing, an autotransformer can also be fully protected with the 7UT612. The integrated overload protection ANSI 49 is adapted to the load and protects the transformer from overheating and premature aging. The overexcitation protection ANSI 24 prevents impermissible heating of the iron.
To increase the earth-fault sensitivity, an additional high-impedance earth-fault differential protection ANSI 87TE is often used in English-influenced regions. The single-phase relay 7VH600 is on the parallel circuit of the outgoing side transformers and of the star-point transformer. The seven transformers (3 side 1, 3 side 2, 1 star point) must be provided additionally, however, and be designed according to class TPS (IEC 60 044-6). A pickup value of 10 % I_n is usually achieved. Additionally or alternatively, an overcurrent relay $I_e>t$ ANSI 50N can be provided in the star-point link. However, this must be in time coordination with the subordinate overcurrent relay.
The delta winding which, in addition to its stabilizing (restraint) function, is also often used for autonomous supply, gets its own overcurrent-time protection ANSI 50, 50N for external phase faults. The voltage relay 7RW600 (ANSI 59N) on the open delta winding of the voltage transformer measures the displacement voltage $3U_0$ with which an earth fault in the tertiary winding or in the connected distribution system is indicated.
An overcurrent-time protection ANSI 50, 50N is arranged on the HV and LV sides, each with a instantaneous tripping stage $I>>$ and delayed stage $I>$ (against phase and earth-faults). Integrated overcurrent-time protection can also configured optionally in 7UT613 on one of the two sides.
For every outgoing circuit the breaker failure protection ANSI 50 BF must be activated in the relevant protection relay.

The individual elements shown in an overview are described step by step as follows.

3. Structure of an autotransformer



$$N = \frac{W_I + W_{II}}{W_{II}} \qquad \frac{U_1}{U_2} = N; \quad \frac{I_1}{I_2} = \frac{1}{N}$$

Fig. 3 Structure and transmission ratios of a two-winding autotransformer

Autotransformers only have the vector group YNyn0; i.e. there is no phase shift of the currents and voltages between the primary and secondary sides. The common star point is always earthed. Therefore both sides are always electrically connected. The distribution of the star-point current on both sides depends on several factors, e.g. winding distribution and presence of a tertiary winding.

4. Implementation with SIPROTEC

4.1 Differential protection

Transformer differential protection contains a number of additional functions (matching to transformation ratio and vector group, stabilization (restraint) against inrush currents and overexcitation) and therefore requires some fundamental consideration for configuration and selection of the setting values. The additional functions integrated per relay can be used to advantage. However, it must be considered that backup protection functions must be arranged in separate hardware (further relay) for reasons of hardware redundancy. This means that the overcurrent-time protection in the differential protection 7UT612/ 613 can only be used as backup protection against external faults in the connected power system. The backup protection for the transformer itself must be provided as a separate overcurrent relay (e.g. 7SJ602). The Buchholz protection as fast short-circuit protection is supplied with the transformer.

Designations according to ANSI (American National Standard) are used for the individual functions. The differential protection therefore has ANSI No. 87, for example. The differential protection is provided as a definite-time fast short-circuit protection in addition to the Buchholz protection.
The differential protection for an autotransformer can be implemented in 2 different ways depending on the available current transformers.

1. Differential protection over the whole transformer bank (protection to be used 7UT612 (2 windings) / 7UT613 (3 windings):
In this case, as shown in Fig. 4, three phase current transformers are used for each side. The star-point transformer is insignificant for the differential protection but can be used for backup overcurrent-time protection. It can be set on both sides depending on further use by other protection functions.

2. Current comparison per autotransformer winding
Use of phase current transformers upstream of the star-point junction (earth-current winding). Fig. 5 shows, that the supply lines to the star (neutral) point all have a phase current transformer. In this case, the autotransformer can be treated as a node object with three terminals.

Both connection types are basically different and are treated separately in chapter 5.

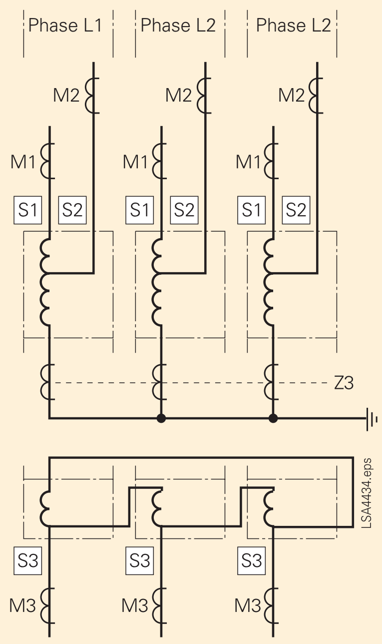
4.2 Earth-fault differential protection

The earth-fault differential protection cannot be used in the autotransformer.

4.3 Backup protection functions

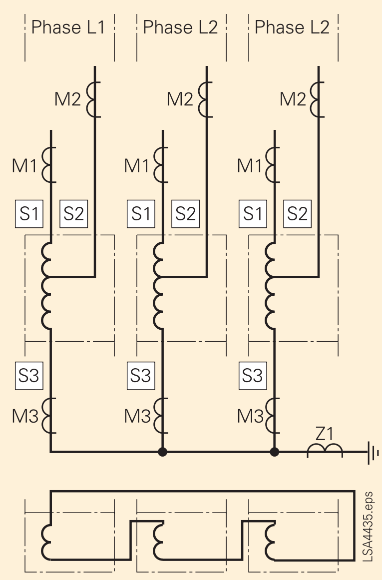
The integrated overcurrent-time protection (ANSI 51) in the 7UT613 serves as backup protection for faults in the supplied system. Separate overcurrent protection on the LV side is therefore unnecessary. The 7JS600 relay on the HV side can be used as backup protection against short-circuits in the transformer and as additional backup protection against LV side faults. The high-set, fast tripping stage *I*>> (ANSI 50) must be set above the short-circuit current flowing through it, so that it does not pick up in the event of faults on the LV side. The delayed tripping (ANSI 51) must be graded with the overcurrent protection in the 7UT613.

The windings S1 and S2 can be protected with the integrated overload protection.



Sides:
S1 HV side of the autotransformer winding on the main protected object
S2 LV side of the autotransformer winding (tapping) on the main protected object
S3 Side of the tertiary winding (stabilizing winding) on the main protected object
3-phase measuring locations, assigned:
M1 Measuring location for side 1 assigned to the main protected object
M2 Measuring location for side 2 assigned to the main protected object
M3 Measuring location for side 3 assigned to the main protected object
Additional measuring locations 1-phase, assigned (summation current of the transformer set):
Z3 Measuring location for side 1 and side 2 assigned to the main protected object

Fig. 4 Topology of a transformer bank consisting of 3 single-phase autotransformers with a stabilizing winding designed as a tertiary winding



Sides:
S1 HV side of the autotransformer winding on the main protected object
S2 LV side of the autotransformer winding (tapping) on the main protected object
S3 Star-point side of the autotransformer on the main protected object
3-phase measuring locations, assigned:
M1 Measuring location for side 1 assigned to the main protected object
M2 Measuring location for side 2 assigned to the main protected object
M3 Measuring location for side 3 assigned to the main protected object
Additional measuring locations 1-phase, assigned (summation current of the transformer set)
Z3 Measuring location for side 1 and side 2 assigned to the main protected object

Fig. 5 Topology of a transformer bank consisting of 3 single-phase autotransformers; topology definitions for one current comparison protection per phase, i.e. there is phase-selective current measurement at M3 before the star-point junction

The delta winding – which is often only used for own, internal supply – has its own overcurrent-time protection (ANSI 51) against phase faults and because of its reduced rated power it requires a separate overload protection. Both can be realized with a 7SJ600 as shown in Fig. 2, for example.

4.4 Integration of Buchholz protection

The Buchholz protection of the transformer evaluates the gas pressure of the transformer tank and therefore detects internal faults in the transformer quickly and sensitively. The following should be considered for the integration:

- The trip command of the Buchholz protection should act on the circuit-breaker directly and independently of the differential protection
- The trip command of the Buchholz protection should be recorded in the fault event log / fault record of the differential protection

Coupling the trip command via the binary input of the differential protection provides informative data for evaluation in the event of a fault.

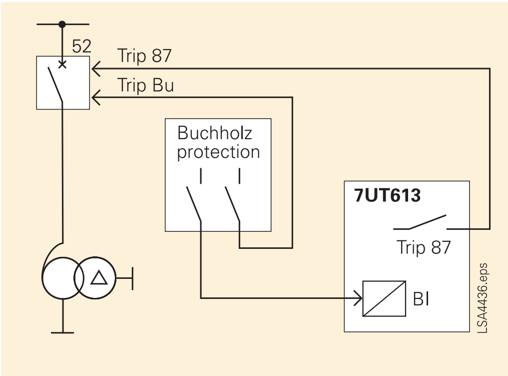


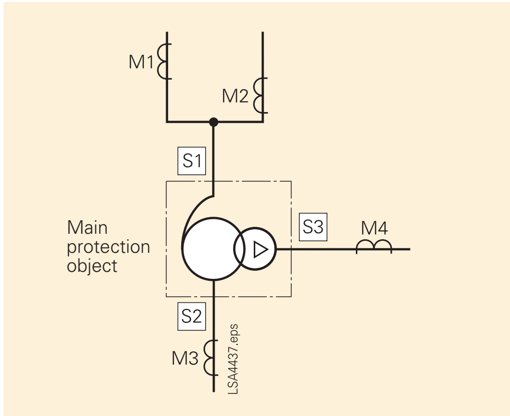
Fig. 6 Integration in the Buchholz protection

5. Settings

5.1 Setting instructions for differential protection over the whole transformer bank

The differential protection as a main protection function of the 7UT612/613 is parameterized and set in a few steps:

- Parameterize protected object "autotransformer"
- Assign the measuring locations on the main protected object



Sides:
S1 HV side of the main protected object (autotransformer)
S2 LV side of the main protected object (autotransformer)
S3 Side of the tertiary winding (stabilizing winding) of the main protected object (autotransformer)
3-phase measuring locations, assigned:
M1 Measuring location for side 1 assigned to the main protected object
M2 Measuring location for side 1 assigned to the main protected object
M3 Measuring location for side 2 assigned to the main protected object
M4 Measuring location for side 3 assigned to the main protected object

Fig. 7 Topology of an autotransformer with a stabilizing winding designed as a tertiary winding

The topology in the autotransformer is defined as follows:
Side 1 is the first of the autotransformer windings; the HV side is usually chosen here.
Side 2 is the second of the autotransformer windings; the LV side is usually chosen here.

This may be followed by further tappings. If there is a delta stabilizing winding, this should be assigned last.

The relay requires the following data of the protected object:

- The primary rated voltage U_N in kV (line-to-line)
- The secondary rated voltage U_N in kV (line-to-line)
- The rated apparent power which is the same for both sides in the autotransformer.

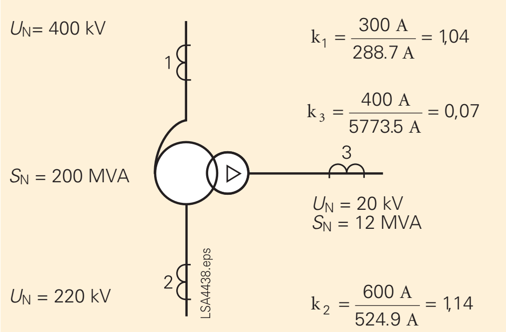
The "autotransformer" setting in the configuration automatically defines that no vector group shift is performed (phase angle 0° between HV and LV side) and the zero current elimination is performed on both sides.

In transformers, the currents measured on the secondary side of the current transformer when current flows through are not generally equal, but are determined by the ratio of the transformer to be protected and the rated currents of the current transformers. To make the currents comparable they therefore have to be matched first. This takes place arithmetically in the 7UT613. External matching equipment is therefore normally superfluous (frequent exception: tertiary winding with low rated apparent power). The digitized currents are converted to the respective transformer rated currents. To do this, the transformer rating data, i.e. rated apparent power, rated voltages and the primary rated currents of the current transformers, are entered in the protection relay.

Fig. 8 shows an example for magnitude matching. The primary rated currents of the two sides S1 (288.7 A) and S2 (525 A) are calculated from the rated apparent power of the transformer (200 MVA) and the rated voltages of the windings (400 kV and 220 kV). Since the current transformer rated currents deviate from these transformer rated currents, the secondary currents are multiplied by the factors k1 and k2. The third winding (S3) on the other hand is only dimensioned for 12 MVA (e.g. as an auxiliary supply winding). The rated current of this winding (= side of the protected object) is therefore 346 A. For the differential protection, however, comparable currents according to the ratio of the individual sides of the transformer must be used for the calculation. Therefore the rated power of the protected object of 200 MVA must likewise be taken as basis for the third winding. This gives a theoretical rated current (here = current under rated conditions of the protected object, i.e. at 200 MVA) of 5773.5 A. This is the reference variable for the currents of the third winding. The currents are therefore multiplied by factor k3. The relay performs this magnitude matching based on the set rated values.

The technical data of the 7UT612/613 show a permissible ratio of 0.25 < k < 4 specified for phase currents. This means that in the case of the winding 3, k3 has an impermissibly small ratio. A matching transformer must be provided here to reach the permissible range. It should be dimensioned so that the matching factor reaches just above the minimum figure of 0.25. In this case it could therefore be assumed:

n > 0.25 / (400A / 5773.5A) = 3.6, e.g. n=4.



$$I_{NT1} = \frac{S_N}{\sqrt{3} \cdot U_N} = \frac{200\text{ MVA}}{\sqrt{3} \cdot 400\text{ kV}} = 288.7\text{ A} \rightarrow I_{NCT1} = 300\text{ A}$$

$$I_{NT2} = \frac{200\text{ MVA}}{\sqrt{3} \cdot 220\text{ kV}} = 524.9\text{ A} \rightarrow I_{NCT2} = 600\text{ A}$$

$$I_{NT3} = \frac{12\text{ MVA}}{\sqrt{3} \cdot 20\text{ kV}} = 346\text{ A} \rightarrow I_{NCT3} = 400\text{ A}$$

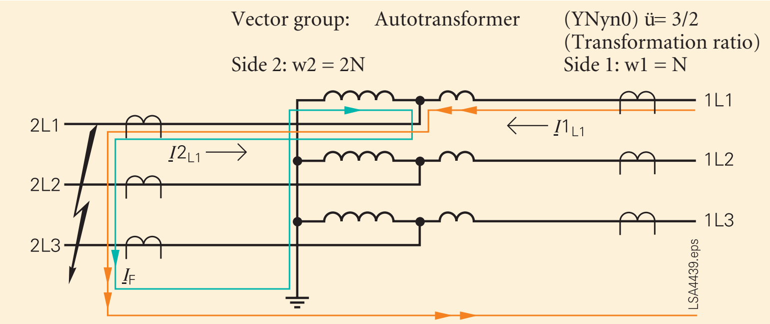
$$I_{N\,obj1} = I_{NT1} = 288.7\text{ A}$$

$$I_{N\,obj2} = I_{NT2} = 524.9\text{ A}$$

$$I_{N\,obj3} = \frac{200\text{ MVA}}{\sqrt{3} \cdot 20\text{ kV}} = 5773.5\text{ A}$$

Fig. 8 Example of an autotransformer for magnitude matching

Together with the autotransformer information the protection relay is now able to perform a current comparison. The principle is explained in the following example (see Figs. 9 and 10):



Side 2:

$$\begin{pmatrix}\underline{I2}_A\\ \underline{I2}_B\\ \underline{I2}_C\end{pmatrix}=\frac{1}{3}\cdot\begin{pmatrix}2&-1&-1\\-1&2&-1\\-1&-1&2\end{pmatrix}\cdot\begin{pmatrix}\underline{I2}_{L1}\\ \underline{I2}_{L2}\\ \underline{I2}_{L3}\end{pmatrix}$$

$\underline{I2}_{L1} = -\underline{I}_F$

$\underline{I2}_{L2} = 0$

$\underline{I2}_{L3} = 0$

$$\begin{pmatrix}\underline{I2}_A\\ \underline{I2}_B\\ \underline{I2}_C\end{pmatrix}=\frac{1}{3}\cdot\begin{pmatrix}-2\cdot\underline{I}_F&+0&+0\\ \underline{I}_F&+0&+0\\ \underline{I}_F&+0&+0\end{pmatrix}$$

Side 1:

$$\begin{pmatrix}\underline{I1}_A\\ \underline{I1}_B\\ \underline{I1}_C\end{pmatrix}=\frac{1}{3}\cdot\begin{pmatrix}2&-1&-1\\-1&2&-1\\-1&-1&2\end{pmatrix}\cdot\begin{pmatrix}\underline{I1}_{L1}\\ \underline{I1}_{L2}\\ \underline{I1}_{L3}\end{pmatrix}$$

$\underline{I1}_{L1} = ü\cdot 2/3\cdot\underline{I}_F = \underline{I}_F$

$\underline{I1}_{L2} = 0$

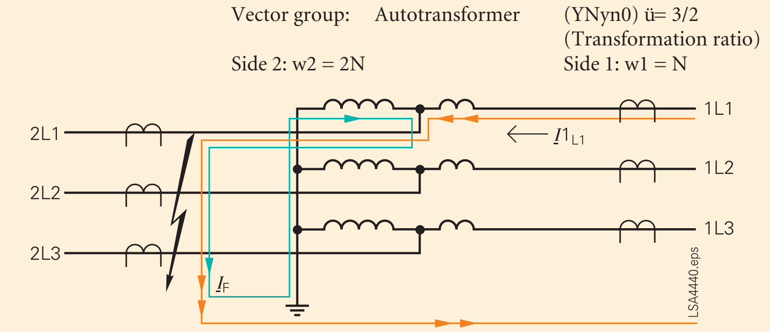
$\underline{I1}_{L3} = 0$

$$\begin{pmatrix}\underline{I1}_A\\ \underline{I1}_B\\ \underline{I1}_C\end{pmatrix}=\frac{1}{3}\cdot\begin{pmatrix}2\cdot\underline{I}_F&+0&+0\\ -1\underline{I}_F&-0&+0\\ -1\underline{I}_F&+0&-0\end{pmatrix}=\frac{1}{3}\begin{bmatrix}2\underline{I}_F\\ -\underline{I}_F\\ -\underline{I}_F\end{bmatrix}$$

$$\begin{pmatrix}IDiff_A\\ IDiff_B\\ IDiff_C\end{pmatrix}=\left|\begin{pmatrix}\frac{2\underline{I}_F}{3}\\ -\frac{\underline{I}_F}{3}\\ -\frac{\underline{I}_F}{3}\end{pmatrix}+\begin{pmatrix}-\frac{2\underline{I}_F}{3}\\ \frac{\underline{I}_F}{3}\\ \frac{\underline{I}_F}{3}\end{pmatrix}\right|=\begin{pmatrix}0\\0\\0\end{pmatrix}$$

No trip

Fig. 9 Calculation of the differential current in the autotransformer for an external fault



Side 2:

$$\begin{pmatrix}\underline{I2}_A\\ \underline{I2}_B\\ \underline{I2}_C\end{pmatrix}=\frac{1}{3}\cdot\begin{pmatrix}2&-1&-1\\-1&2&-1\\-1&-1&2\end{pmatrix}\cdot\begin{pmatrix}\underline{I2}_{L1}\\ \underline{I2}_{L2}\\ \underline{I2}_{L3}\end{pmatrix}$$

$\underline{I2}_{L1} = 0$

$\underline{I2}_{L2} = 0$

$\underline{I2}_{L3} = 0$

$$\begin{pmatrix}\underline{I2}_A\\ \underline{I2}_B\\ \underline{I2}_C\end{pmatrix}=\frac{1}{3}\cdot\begin{pmatrix}0\\0\\0\end{pmatrix}$$

Side 1:

$$\begin{pmatrix}\underline{I1}_A\\ \underline{I1}_B\\ \underline{I1}_C\end{pmatrix}=\frac{1}{3}\cdot\begin{pmatrix}2&-1&-1\\-1&2&-1\\-1&-1&2\end{pmatrix}\cdot\begin{pmatrix}\underline{I1}_{L1}\\ \underline{I1}_{L2}\\ \underline{I1}_{L3}\end{pmatrix}$$

$\underline{I1}_{L1} = ü\cdot 2/3\cdot\underline{I}_F = \underline{I}_F$

$\underline{I1}_{L2} = 0$

$\underline{I1}_{L2} = 0$

$$\begin{pmatrix}\underline{I1}_A\\ \underline{I1}_B\\ \underline{I1}_C\end{pmatrix}=\frac{1}{3}\cdot\begin{pmatrix}2\cdot\underline{I}_F&+0&+0\\ -1\underline{I}_F&-0&+0\\ -1\underline{I}_F&+0&-0\end{pmatrix}=\frac{1}{3}\begin{bmatrix}2\underline{I}_F\\ -\underline{I}_F\\ -\underline{I}_F\end{bmatrix}$$

$$\begin{pmatrix}IDiff_A\\ IDiff_B\\ IDiff_C\end{pmatrix}=\left|\begin{pmatrix}\frac{2\underline{I}_F}{3}\\ -\frac{\underline{I}_F}{3}\\ -\frac{\underline{I}_F}{3}\end{pmatrix}+\begin{pmatrix}0\\0\\0\end{pmatrix}\right|=\begin{pmatrix}\frac{2\underline{I}_F}{3}\\ -\frac{\underline{I}_F}{3}\\ -\frac{\underline{I}_F}{3}\end{pmatrix}$$

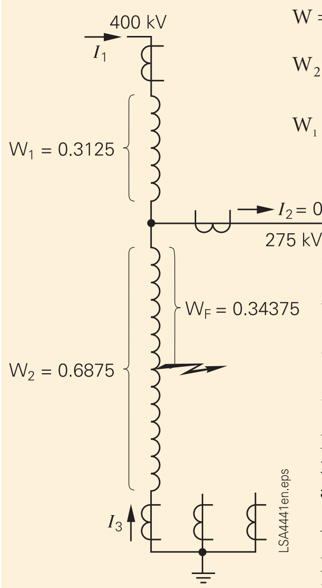
Trip

Fig. 10 Calculation of the differential current in the event of an internal fault

Both sides are converted to a "virtual" side, based on which the current comparison is made. In case of vector group 0 (as is always the case with the autotransformer) this is done by a standard matrix. The matrices used are given by the standard matrix by subtracting the zero current from the measurement (corresponds to 1/3 of the sum of all three phase currents). This is necessary, because it is not possible to divide the star-point current on both sides of the protected object.

5.2 Setting instructions for differential protection in current comparison per autotransformer winding

If current transformers are available for each phase on the supply lines to the star point (earth winding), one node protection per phase can be implemented. Current transformation ratios and their tap changes have no effect, because the three entry points of the current are measured here and form the end points of the Kirchoff node.
Such a current comparison is more sensitive for earth-faults than normal differential protection (see Fig. 11). This is of interest, because these faults have the highest probability in transformer banks. Any stabilizing winding or tertiary winding must not be integrated in the protection in this application, even if it is connected externally and equipped with current transformers, because this does not belong to the protected (phase-selective) node.



$W = 1 = W_1 + W_2$

$W_2 = \frac{275\text{ kV}}{400\text{ kV}} = 0.6875$

$W_1 = W - W_2 = 1 - 0.6875 = 0.3125$

Example:
Fault in winding W_2 at 50 %

$W_F = 0.5\ W_2 = 0.34375$

$I_1\ (W_1 + W_F) = I_3\ (W_2 - W_F)$

$I_3 = I_1 \frac{W_1 + W_F}{W_2 - W_F} = 1.909\cdot I_1$

Differential current in the 2-winding differential protection acc. to Chap. 5.1

$I_{Diff} = I_1 \quad (I_2 = 0)$

Differential current in the 3-winding differential protection (incl. earth winding) acc. to Chap. 5.2

$I_{Diff} = I_1 + I_3 = I_1 + 1.909\cdot I_1$
$= 2.909\cdot I_1$

Fig. 11 Increasing the sensitivity by using phase-selective earth windings

The topology is determined as follows:
The two autotransformer windings become S1 and S2 (tapping).
The earth winding must in this case be set as side 3. If there is a further tapping, the earth winding is specified as side 4. As soon as one of the sides is defined as earth winding, the protection automatically places node differential protection across all autotransformer windings involved.

The differential protection function must be activated by parameterization. The differential protection relay 7UT613 is delivered in inactive-circuit state. This is because the protection may not be operated without at least having set the vector groups and matching values correctly first. The relay may react unpredictably without these settings.

Setting of the characteristic of the differential protection is based on the following considerations:

- The presetting for $I_{Diff}>$ of 0.2 x I_N referred to the rated current of the transformer can be taken as a pickup value for the differential current as a rule.
- The slope 1 together with base point 1 take into account current-proportional false currents which may be caused by transformation errors of the CTs. The slope of this section of the characteristic is set to 25 %.
- The add-on restraint increases the stability of the differential protection in the very high short-circuit current range in the event of external faults; it is based on the setting value EXF-$_{Restraint}$ (address 1261) and has the slope 1 (address 1241).
- The slope 2 together with base point 2 lead to higher stabilization in the higher current range at which current transformer saturation can occur. The slope of this characteristic section is set to 50 %.
- The $I_{Diff}>>$ stage works without restraint (stabilization) and is designed for high internal fault currents on the primary side of the transformer with a high degree of saturation. It should be set to at least 20 % above the max. through flowing fault current or the max. inrush currents, respectively.

Notes on add-on restraint

In systems with very high traversing currents, a dynamic add-on restraint becomes effective for external faults. Presetting 4.0 can, as a rule, be taken over without change. The value is referred to the rated current of the protected object.
Note that the restraint current is the arithmetic sum of the currents flowing into the protected object, i.e. is double the traversing current. The add-on restraint does not affect the $I>>$ stage.
The maximum duration of add-on restraint after detecting an external fault is set in multiples of a period (AC cycle). The recommended setting value is 15 periods (preset). The add-on restraint is automatically disabled before the set time period expires as soon as the relay has detected that the operation point $I_{Diff}/I_{Restraint}$ is located steadily (i.e. for at least one period) within the tripping zone near to the fault characteristic. The add-on restraint operates separately for each phase but can be extended to blocking all phases depending on the used vector group (crossblock function).
The recommended setting value for the crossblock function is 15 periods (preset).

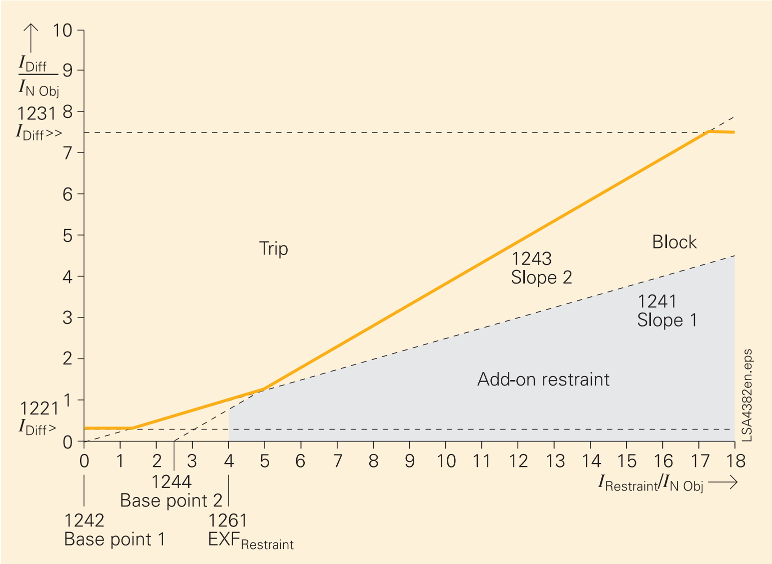


Fig. 12 Differential protection tripping characteristics

Notes on setting the inrush blocking

An inrush current with a high proportion of 2nd harmonics is generated when switching the transformer on, which can lead to false tripping of the differential protection. The preset value for the inrush restraint with 2nd harmonics of 15 % can be accepted unchanged. A lower value can be set for greater restraint in exceptional cases under unfavorable energizing conditions resulting from the design of the transformer.

The inrush restraint can be extended by the crossblock function. This means, that all three phases of the $I_{Diff}>$ stage are blocked when the harmonic component is exceeded in only one phase. A setting value of 3 periods, effective for the time of mutual blocking after exceeding the differential current threshold, is recommended (preset).

Notes on setting the overexcitation blocking

Stationary overexcitation in transformers is characterized by odd harmonics. The third or fifth harmonic is suitable for restraint. Since the third harmonic is often eliminated in transformers (e.g. in a delta winding), the 5^{th} harmonic is mostly used. The proportion of 5^{th} harmonics which leads to blocking of the differential protection is set at 30 % (preset). It is not usually necessary to set the crossblock function in this case.

5.3 Backup protection functions

5.3.1 Overcurrent time protection

The definite-time overcurrent-time protection of the 7UT612/613 serves as backup for the short-circuit protection of the downstream power system sections when faults cannot be cleared in time there, meaning that the protected object is in danger.
The overcurrent-time protection can be assigned to one of the three voltage sides of the transformer. Correct allocation between the measuring inputs of the relay and the measuring locations (current transformer sets) of the power plant must also be observed. The stage $I{>>}$ together with stage $I{>}$ or stage I_P produces a two-stage characteristic. If the overcurrent-time protection acts on the feed side of the transformer, stage $I{>>}$ is set so that it picks up for short-circuits extending into the protected object, but not for a short-circuit current flowing through it.

Calculation example:

Autotransformer YNyn0
50 MVA
66 kV/33 kV
u_{SC} = 12 %
Current transformer 500 A/1 A on the 66 kV side
The overcurrent-time protection acts on the 66 kV side (= feed side).
The maximum possible three-phase short-circuit current on the 33 kV side with rigid voltage on the 66 kV side would be:

$$I_{3\text{pole max}} = \frac{1}{u_{\text{SC Transfo}}} \cdot I_{\text{N Transfo}} = \frac{1}{u_{\text{SC Transfo}}} \cdot \frac{S_{N\ \text{Transfo}}}{\sqrt{3}U_{\text{N}}}$$

$$= \frac{1}{0.12} \cdot \frac{35\ \text{MVA}}{\sqrt{3} \cdot 66\ \text{kV}} = 3645\ \text{A}$$

With a safety factor of 20 % this gives the primary setting:

$I{>>}$ = 1.2 x 3645 A = 4374 A

With parameterization in secondary values the currents in amperes are converted to the secondary side of the current transformers.

Secondary setting value:

$$I >> = \frac{4375\ \text{A}}{500\ \text{A}} \cdot A = 8.75\ \text{A}$$

i.e. at short-circuit currents above 4374 A (primary) or 8.8 A (secondary), there is definitely a fault in the transformer area, which can be eliminated immediately by the overcurrent time protection. Increased inrush currents must be considered as well. The inrush restraint does not affect the stage $I{>>}$.

Stage $I{>}$ represents the backup protection for the downstream busbar. It is set higher than the sum of the rated outgoing currents. Pickup by overload must be ruled out because the relay operates with correspondingly short command times as short-circuit protection in this mode and not as overload protection. This value must be converted to the higher-voltage side of the transformer. The delay time depends on the grading time in the outgoing lines. It should be set e.g. 200 ms more than the greatest grading time on the LV side. Moreover, the inrush restraint for the $I{>}$ stage must be parameterized effectively in this case, so that false pickup of the $I{>}$ stage (resulting from the inrush of the transformer) is prevented.

5.3.2 Overload protection

The thermal overload protection prevents overloading of the transformer to be protected. Two methods of overload detection are possible in the 7UT6:

- Overload protection with thermal replica according to IEC 60255-8,
- Hot-spot calculation with determining of the relative ageing rate according to IEC 60354

One of these two methods can be selected. The first is notable for easy handling and a low number of setting values; the second requires some knowledge of the protected object, its ambient context and its cooling, and needs the input of the coolant temperature via a connected thermobox. The second method is used when the transformer is operated at the limit of its performance and the relative ageing rate is to be monitored by the hot-spot calculation.

Overload protection with thermal replica (to act on the HV side) is chosen for this application. Since the cause of the overload is normally outside the protected object, the overload current is a traversing current. The relay calculates the temperature rise according to a thermal single-body model by means of the thermal differential equation

$$\frac{d\Theta}{dt}+\frac{1}{\tau_{th}}\cdot\Theta=\frac{1}{\tau_{th}}\cdot\left(\frac{I}{k\cdot I_{N\,Obj}}\right)^2$$

The protection function therefore represents a thermal replica of the object to be protected (overload protection with memory function). Both the history of an overload and the heat transmitted to the ambient area are taken into account. Pickup of the overload protection is output as a message.

Notes on the setting

In transformers, the rated current of the winding to be protected, which the relay calculates from the set rated apparent power and the rated voltage, is significant. The rated current of the side of the main protected object assigned to the overload protection is used as the basic current for detecting the overload. The setting factor k is determined by the ratio of the thermally permissible continuous current to this rated current:

$$k=\frac{I_{max}}{I_{N\,Obj}}$$

The permissible continuous current is at the same time the current at which the e-function of the overtemperature has its asymptote. The presetting of 1.15 can be accepted for the HV winding.

Time constant τ in thermal replica:

The heating time constant τ_{th} for the thermal replica must be specified by the transformer manufacturer. It must be ensured that the time constant is set in minutes. There are often other specifications from which the time constant can be determined:

Example:
t_6 time: This is the time in seconds for which 6 times the rated current of the transformer winding may flow.

$$\frac{\tau_{th}}{\min}=0.6\cdot t_6$$

If the transformer winding has a t6 time of 12 s

$$\frac{\tau_{th}}{\min}=0.6\cdot 12\,\text{s}=7.2$$

the time constant τ must be set to 7.2 min.

5.3.3 Overexcitation protection

The overexcitation protection serves to detect increased induction in generators and transformers, especially in power station unit transformers. An increase in the induction above the rated value quickly leads to saturation of the iron core and high eddy current losses which in turn lead to impermissible heating up of the iron.
Use of the overexcitation protection assumes that measuring voltages are connected to the relay. The overexcitation protection measures the voltage/frequency quotient *U*/*f*, which is proportional to the induction B at given dimensions of the iron core. If the quotient *U*/*f* is set in relation to voltage and frequency under rated conditions of the protected object $U_{N\,Obj}/f_N$, a direct measure is obtained of the induction related to the induction under rated conditions $B/B_{N\,OBj}$. All constant variables cancel each other:

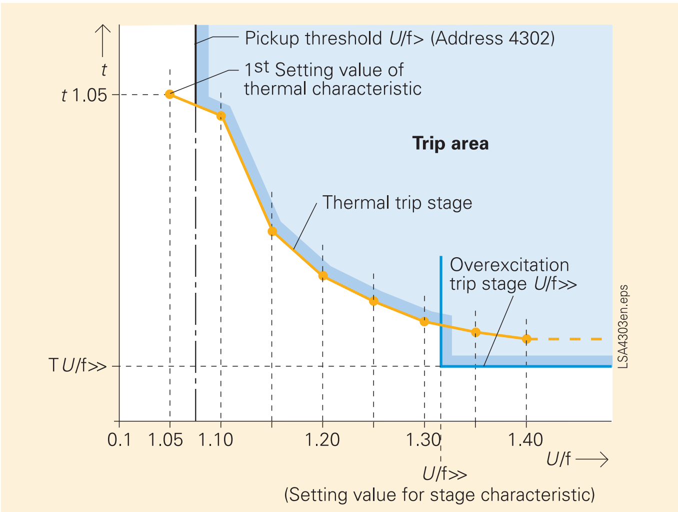
$$\frac{B}{B_{N\,Obj}}=\frac{\dfrac{U}{U_{N\,Obj}}}{\dfrac{f}{f_N}}=\frac{U\,/\,f}{U_{N\,Obj}\,/\,f_N}$$

The relative relation makes all conversions unnecessary. All values can be specified directly related to the permissible induction. The rated variables of the protected object have already been entered in the 7UT613 relay with the object and transformer data when setting the differential protection.

Setting instructions

The limit value of permanently permissible induction in relation to the rated induction (B/B_N) specified by the protected object manufacturer forms the basis for setting the limit value. This value is at the same time a warning stage and the minimum value for the thermal characteristic (see Fig. 13)

Fig. 13
Tripping characteristic of the overexcitation protection



An alarm is output after of the relevant set delay time (about 10 s) of the overexcitation stage *U*/*f* has expired. Major overexcitation endangers the protected object already after a short time. The high-set, fast tripping stage *U*/*f*>> is therefore set to a maximum of 1 s.

The thermal characteristic should simulate the heating, i.e. temperature rise, of the iron core resulting from overexcitation. The heating characteristic is approximated by entering 8 delay times for 8 given induction values B/B_{NObj} (referred to in simplified form as *U*/*f*). Intermediate values are obtained by linear interpolation. If no data are available from the protected object manufacturer, the preset standard characteristic is used.

6. Further functions

6.1 Integration in substation control and protection

The protection can be connected to a substation control system via the system interface and operated in parallel by PC via the service interface to a star coupler for separate remote communication.

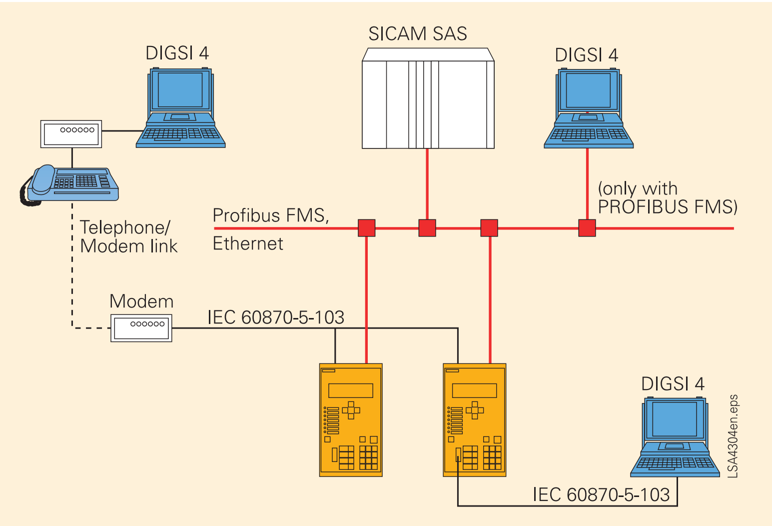


Fig. 14 Integration in substation control and protection

Via the interface,

- Messages
- Alarms
- Measured values

are transmitted from the transformer differential protection to the substation control system. Messages are available for every one of the activated protection functions, which can be either transmitted to the substation control system in the course of plant equipment parameterization, or configured to the LEDs or message contacts in the protection relay. Configuration is made clear and easy by the DIGSI matrix.

Service interface

The 7UT613 has a separate service interface which can be read out by telecommunication via a modem. The user is informed in the office quickly and in detail about the transformer fault. The data are then analyzed in the office by DIGSI. If this remote fault clearance is insufficient, the fault data provide hints for an efficient service mission.

7. Summary

Optimum protection of the transformer with SIPROTEC relays means security of investment for valuable operating equipment and therefore makes a contribution to maximum supply security.

From a technical point of view, the 7UT612 or 7UT613 relay offers extensive short-circuit protection for both the main and the backup protection of transformers in one single relay. Further SIPROTEC relays supplement the main protection and enhance the reliability of the protection scheme by way of hardware redundancy.

Extensive measuring functions allow trouble-free connection of the relay without the need for additional equipment, and enable monitoring of the transformer in operation in terms of its electrical and thermal parameters. The relay's presettings are chosen so that the user need only parameterize the known data of the main and primary transformers. Many of the default settings can simply be accepted as they are, and therefore make parameterization and setting easier.

Protection of a Motor up to 200 kW

1. Introduction

Drive motors often play a decisive role in the functioning of a production process. Motor damage and breakdowns not infrequently lead also to consequential damage and production shutdowns, the cost of which significantly exceeds the cost of repairing the motor. Optimum design of the motor protection ensures that damage following thermal overload is prevented, meaning that there is no reduction to the normal service life. Secondary faults are minimized in the event of short-circuits, earth faults and winding faults.

The spectrum extends from small low-voltage motors with an output of a few kW to high-voltage motors with outputs measured in MW. Protection system design must be based on the rating of the motor, the importance of the drive for the technological process, the operating conditions and the requirements of the motor manufacturer.

The setting of a SIPROTEC protection relay for motor protection is described below taking a high-voltage motor (10 kV) as the example.

2. The tasks of motor protection

Motors have some striking features in their operating conditions. These are important for understanding the various possible causes of failure and must be taken into account when designing protection systems.

2.1 Protection of the stator against thermal overload

The power drawn by the motor from the supply system during operation is supplied to the shaft as mechanical power for the production machine. The power lost to the winding during this energy conversion is the decisive factor for the arising motor temperatures. The loss of heat is proportional to the square of the current. The motor heating time characteristic is determined by its heat storage capability and heat transfer properties, and characterized by the thermal time constant [τ]. Electrical machines are at particular risk from long-term overload. Thermal overloading of the motor leads to damage to the insulation and therefore to secondary faults or to a reduction in the total service life of the motor.

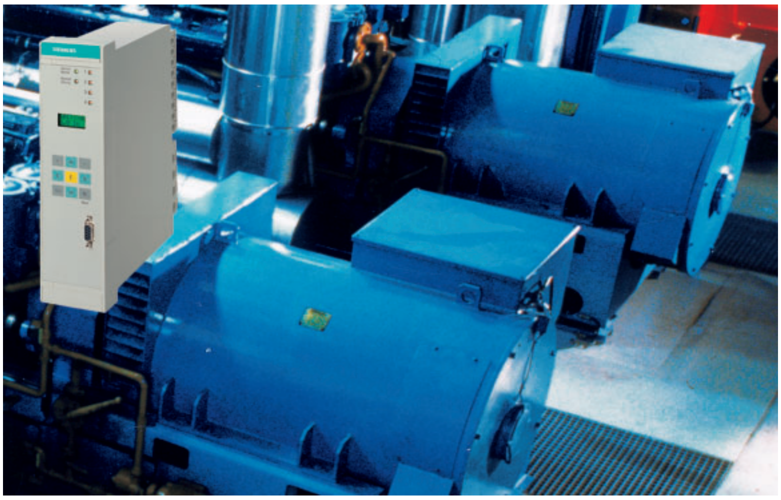


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Fig. 1 SIPROTEC 7SJ602 multifunction protection

Such overloading cannot and should not be detected by short-circuit protection since any potential delay must be very short on these occasions. Overload protection prevents thermal overloading of the motor to be protected. The 7SJ602 relay detects stresses either before overload occurs (overload protection with complete memory = thermal replica) or only after exceeding a preset start-up current (overload protection without memory function).

- Overload protection without memory
  If overload protection without memory is chosen, the tripping time is calculated according to a simple formula. Pre-stressing is not taken into account because currents are only recorded if they are greater than 1.1 times the set value.

$$t = \frac{35}{(I / I_B)^2 - 1} \cdot t_{6IB} \quad \text{for } I > 1.1\, I_B$$

t	Tripping time
I	Overload current
I_B	Set threshold
t_{6IB}	Set time factor (t6-time = tripping time when applying 6 times the actual set value I_B)

- Overload protection with memory
  The relay calculates the temperature rise in accordance with a thermal homogenous-body model and a thermal differential equation. In this way the previous load, with all load cycles, can be recorded and evaluated correctly by the relay. Such a thermal replica can be optimally adapted to the overload capacity of the protected equipment.

2.2 Protection of the rotor from thermal overload

Among the many causes of excessive temperatures caused by currents in motors is an unacceptably long start-up time or, in limit cases, blocking of the rotor. Such conditions are caused by an excessive mechanical load torque, such as can occur in overfilled mills and breakers or overloaded centrifuges, etc.

- Start-up time monitoring
  The protection relay has start-time monitoring, which represents a meaningful addition to overload protection for electrical machines. The trip time depends on the current. This enables even extended start-up times to be correctly evaluated when the start-up current is reduced because of voltage sags when the engine is started. The start-up time monitoring begins when a set current level is exceeded. The trip time depends on the actual measured start-up current. If the permissible locked rotor time is shorter than the start-up time, the rotational speed (motor stationary or rotating) must also be requested via a binary input.
- Restart inhibit
  Restart inhibit prevents the motor restarting if, during this start-up, the permissible rotor heating is expected to be exceeded.
  The rotor temperature of a motor generally lies well below its permitted temperature limit both during normal operation and with increased load currents. On the other hand, during start-up, with the associated high start-up currents, the rotor is at a higher risk of thermal damage than the stator because of its smaller thermal time constant. The motor must be prevented from switching on if the permissible rotor heating is expected to be exceeded during this start-up. This is the task of the restart inhibit. Because the rotor current is not directly measurable, stator currents must be relied upon from which the rotor temperature is indirectly calculated. It is therefore assumed that the thermal limit values for the rotor winding in the data provided by the motor manufacturer for the rated start-up current equal the maximum permitted start-up time and the number of the permitted start-ups from cold (n_c) and operating temperature (n_W) conditions. The relay calculates from this the value of the thermal rotor replica and gives a blocking command until the thermal replica of the rotor reaches a value below the restart limit and therefore permits a new start-up. As long as a blocking command prevails, switching on by the relay's integrated switch control is prevented. In this case, it is not necessary to allocate the restart inhibit's blocking command to a command relay or an external link with the switch control. If however the motor can be switched on from another position, an output relay must be allocated to the blocking command and its contact looped into the starting circuit.

2.3 Negative-sequence protection

In protection of the motor, negative sequence (unbalanced load) protection assumes particular importance. Unbalanced loads produce a reverse field in motors which drives the rotor at twice the frequency. Eddy currents are induced on the surface of the rotor, leading to local temperature rises in the rotor. If the motor is protected by fuses, a phase voltage failure is a frequent fault in practice. During this breakdown, the line-to-line voltage is fed to the stator winding by the remaining working phases. Depending on the load, a more or less circular rotating field is maintained by the motor, so that it can develop sufficient torque with increased current input. There is also the risk of thermal overload if the system voltage is unbalanced. Even small voltage unbalances can lead to large negative sequence currents because of the small negative sequence reactance.

The 7SJ602's negative-sequence protection filters the fundamental out of the fed phase currents and breaks it down into balanced components (negative phase-sequence system I_2 and positive phase-sequence system I_1). The "negative phase-sequence system/rated current (I_2/I_N)" relationship is assessed to detect the unbalanced load. The negative-sequence protection is set up in two stages. After reaching a first, adjustable threshold I_2> a time stage TI_2>is started; after reaching a second, adjustable threshold I_2>> the time stage TI_2>> is started. After one of the operating times has passed a tripping command is set up. The threshold comparison can only be made if the largest of the three phase currents is at least 10 % of the rated current.

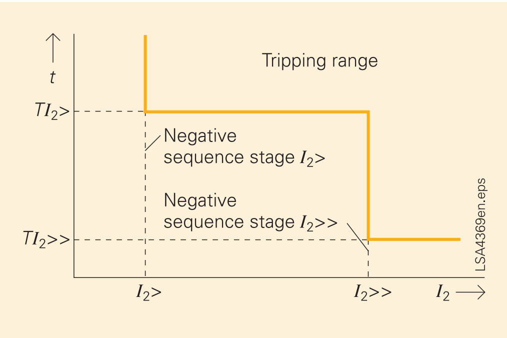


Fig. 2 Characteristics of the negative sequence protection

2.4 Earth-fault protection

When designing earth-fault protection it is important to know how the star point of the power supply system is connected. This must also be taken into account when selecting protection relay hardware. Two versions of the 7SJ602 are available, differing in the design of the transformer inputs.

7SJ6021../7SJ6025.. for low-resistance earthed power systems

The relay has a fourth input transformer with "normal" sensitivity for recording the earth current. This can be connected to the star point lead wire of the current transformer unit or to a separate core-balance current transformer.

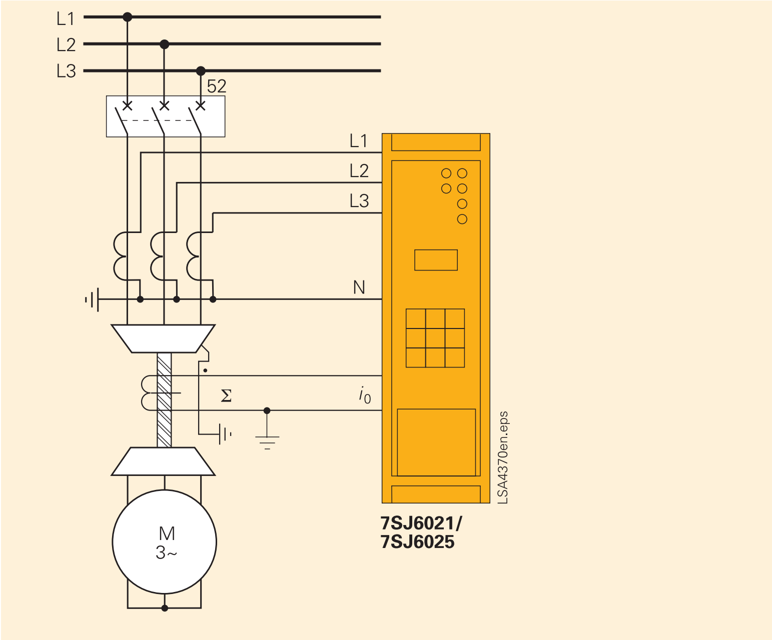


Fig. 3 Connection of 4 CTs with measurement of the earth current

7SJ6022../7SJ6026.. for resonant-earthed, isolated or high-resistance earthed power systems

The relay has two phase current transformers, a sensitive earth current input and a voltage input, e.g. to record U_{en} Voltage.

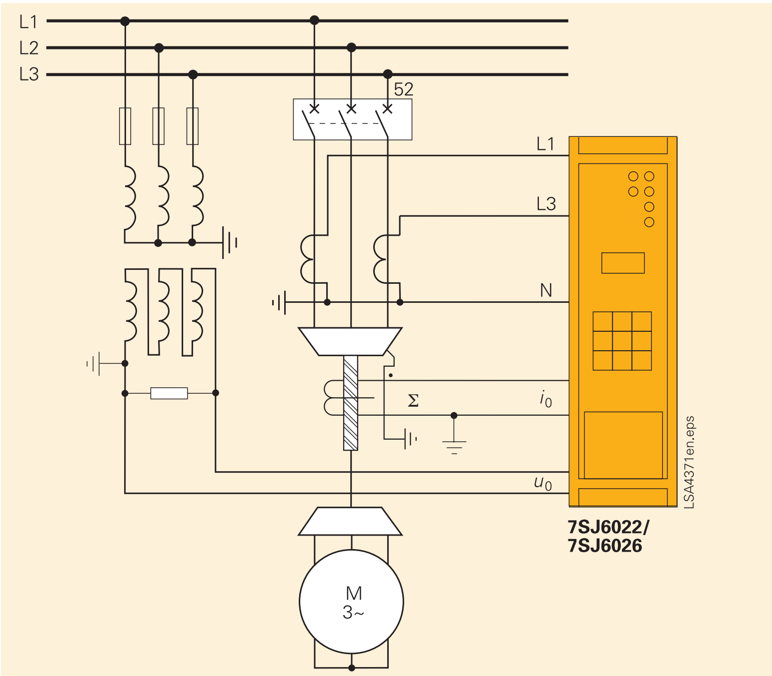


Fig. 4 Connection of 3 CTs and 1 VT with measurement of the earth current and one phase voltage

Earth-fault protection detects earth faults in the stator winding of three-phase machines. Because motors are usually connected directly by a busbar to a power supply system (directly connected to a busbar) it is important to recognize whether the earth fault is in the machine feeder or on another feeder of the busbar.

With earthed systems, this can usually be clearly recognized from the magnitude of the earth current. When a fault occurs in the machine, the full earth-fault current driven by the power supply system flows via the protection measuring point. The machine must be isolated from the power supply system as quickly as possible to prevent more damage. When there is a power system earth-fault the recorded earth current is essentially determined by the machine capabilities and therefore considerably smaller. There must be no tripping.

In compensated, isolated and low-resistance earthed systems, a design with sensitive earth-current input and sensitive earth-fault detection should be chosen. The high-resistance earth-fault detection then replaces the earth-current stage of the overcurrent-time protection. Because of its high sensitivity it is not suitable for detecting earth faults with large earth currents (more than around $1.6 \cdot I_N$ on the terminals for sensitive earth-current connection).
Overcurrent-time protection for earth currents must be used here.
Should the magnitude of the earth current be sufficient to determine the earth fault, no voltage input is needed. The 7SJ602 has a two-stage current/time characteristic which works with earth-current values. They are appropriate where the magnitude of the earth current enables the location of the earth fault to be defined. This can, for example, happen with machines on low-resistance earthed systems (with earth-current limiting).

With machines directly connected to a busbar to isolated power systems, it is essential that the capacity of the upstream power system delivers a sufficiently large earth current but that the earth current at the relay location is comparably small in the case of earth faults on the power system side. The magnitude of the earth current is used to reach a decision on the position of the fault location.

If this is not the case an additional earth-current production device must be installed on the busbar. This produces a defined earth current during an earth fault. The connected displacement voltage is then used to make a direction decision. Should a load device (earth-current production device) be installed, it should only be used when dimensioning the setting in order to be independent of the circuit state in the power supply system. With machines in compensated power supply systems a load device and measurement of the displacement voltage are always recommended so that a safe earth-fault decision can be made.

2.5 Short-circuit protection

The task of the short-circuit protection when a short-circuit occurs is both to prevent increased damage to the motor (destruction of the iron core, etc.) by quickly switching off the motor and to minimize the effect on the power supply system with its connected loads (voltage unbalance, voltage sags, etc.).

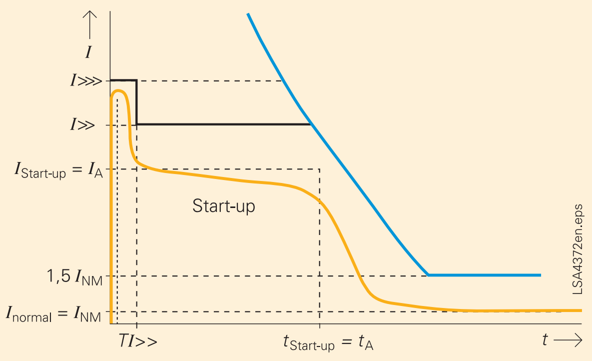
The overcurrent-time protection in the 7SJ602 can take the form both of definite-time overcurrent-time protection and of inverse-time overcurrent-time protection. For the latter, a range of characteristics defined in IEC 60255---3 or in ANSI standards is available. A high-current stage *I>>*, which always works with definite tripping time, can be superimposed on the selected overcurrent characteristics. An instantaneous tripping stage *I>>>* can also be superimposed on the phase branches. In this way the tripping characteristics can be optimally adapted to the motor's start-up characteristics.

In order to be able to switch off during high current faults in the machine, the 7SJ602 has a special instantaneous tripping stage. The *I>>>* stage must be set safely above the motor's inrush current, so that switching on the motor does not lead to tripping. Experience has shown that the inrush currents can be around 1.5 to 1.6 times the start-up current.

The *I>>* stage should be set above the motor start-up current to prevent tripping. With the time delay *TI>>* the period of the inrush current must be taken into account. Because the inrush current lasts only a few ms, the *TI>>* can be selected at around 50 ms.

In the overcurrent-time protection function an inverse-time characteristic must be chosen since this can be better adapted to the motor's operational performance.

The inverse-time short-circuit protection I_p> protects the motor from short-circuits during operation in transient condition (after ramping up). The higher the short-circuit current the quicker the tripping. The extreme inverse characteristic must be selected as tripping characteristic.



I_p> Short-circuit protection, inverse-time stage
I>> Short-circuit protection, definite-time stage
I>>> High-set instantaneous tripping stage, definite-time stage

Fig. 5 Current characteristic of motor start-up

3. Adjustments

Calculation examples are oriented towards the following motor data:

<u>Motor/system data</u>

Current transformer phase	
I_{NPRIM}/I_{NSEC}	100 A / 1 A
Current transformer earth	
(60/1) I_{EE}/I_{PH}	0.6 (core-balance CT)
Voltage transformer	10 kV / 100 V
Motor rated current I_{NM}	74 A
Max. permissible unbalanced load	10 %
Permissible unbalanced load period	15 s
Permissible continuous thermal current I_{Max}	$1.1 \cdot I_{NM}$
Thermal stator time constant τ_{th}	40 min
Standstill transient factor kτ	5
Start-up current I_A	$5 \cdot I_{NM}$

Data of the system and equipment to be protected is input. Some data which particularly involves motor protection functions is worthy of mention here.

For some protection functions it is important to recognize whether the circuit-breaker is closed or open. As a criterion for this overshooting or undershooting a current threshold is applied. The set value applies for all three phases. If the set current value in one phase is exceeded, the circuit-breaker is considered closed. In machines the value selected must be smaller than the machine's minimum no-load current.

Motor data is generally related to the rated motor current. A matching factor must be communicated in the system data to the 7SJ602 so that the settings for motor protection functions can be provided directly as a reference quantity.

Example:

Current transformer 100 A / 1 A
Rated motor current I_{NM} = 74 A

- Ratio of rated motor current to rated transformer current
  $I_m = I_{NM}/I_{NTRANSF} = 0.74$ [from transformer data]
  The motor's start-up current is likewise preset in the 7SJ602's system data.
  The start-up current is specified as a value related to the rated motor current (I_{NM}).
  It depends on the size and nature of the motor and in a normal load-free start-up is approximately $5 \cdot I_{NM}$.
- Motor start-up current referred to rated motor current
  $I_a = 5$ [from motor data sheet]
  In the 7SJ602, the motor's start-up time is preset in the system data. After this time the start-up current must be safely undershot.
- Motor start-up time
  $t_{START-UP} = 4.3$ [from motor data sheet]

3.1 Overload protection

For overload protection the load must be taken into account before the overload occurs; i.e. the overload function must be used with full memory.

The relay calculates the temperature rise in accordance with a thermal homogenous-body model and a thermal differential equation:

$$\frac{d\Theta}{dt} + \frac{1}{\tau_{\tau\eta}} \cdot \Theta = \frac{1}{\tau_{th}} \cdot I^2$$

Θ Present temperature rise referred to the final temperature with maximum permissible line current $k \cdot I_N$

τ_{th} Thermal time constant for heating of the object to be protected

I Present effective current referred to the maximum permissible current $I_{max} = k \cdot I_N$

The following parameters must be set:

- Set value of the k factor = $I_{max}/I_{NTransf}$
  I_{max} = maximum permissible continuous thermal current = 1.1 · I_{NM} = 81.4 A
  k = **0.82**
- Set value of the thermal time constant τ_{th} in minutes
  τ_{th} = **40 min** [from motor data sheet]

For motors the t_6 time, i.e. the permissible time for the six-fold permissible continuous current, is often specified instead of the time constant.
As a result the τ_{th} is calculated as follows:

$$\text{Set value } \tau_{th}[\min] = \frac{\frac{t_6}{s}}{60} \cdot 36 = 0.6 \cdot \frac{t_6}{s}$$

- Transient factor k_τ between time constant (during standstill) and running of the motor
  k_τ = **5** according to motor data
- Alarm temperature rise as a percentage of the operating temperature rise $\Theta_{ALARM}/\Theta_{TRIP}$
  Θ_{ALARM} = **90 %** [preset]

The 7SJ602 also provides the option to connect an external thermobox to the relay. This affords an opportunity to connect the coolant temperature or ambient temperature of the protected object into the relay using the serial interface and include it in the overload calculation.

3.2 Start-up time monitoring

The start-up time monitoring interprets overshooting the current value I_a> as a motor start-up. Consequently this value must be chosen so that it is safely exceeded during motor start-up in all load and voltage conditions by the actual start-up current but is not reached during permissible, short-term overload. It must also be configured above the maximum load current. The set value is related to the rated motor current. Half the value of the rated start-up current is customary. If the start-up current is 5 · rated motor current (I_{NM}), I_a> is set at 2.5 · rated motor current.
The tripping time is calculated quadratically according to the magnitude of the current:

$$t_{TRIP} = t_{START\text{-}UP} \cdot \left(\frac{I_a}{I}\right)^2 \quad \text{with } I > I_a>$$

t_{TRIP}	Actual tripping time for flowing current I
$t_{START\text{-}UP}$	Max. start-up time
I	Actual flowing current (measured quantity)
I_a	Rated motor start-up current

The following parameters must be set:

- Start-up current threshold I_a> for start-up time monitoring, referred to rated motor current I_{NM} with I_a = 5 · I_{NM} motor data entered with system data
  I_a> = 0.5 · I_a = 2.5 · I_{NM}

Should the start-up time exceed the tripping time of the overcurrent time protection, said protection is blocked during start-up after 70 ms.

- Blocking the I> / I_p stages during start-up
  NO

If the permissible locked rotor time is less than the start-up time, the rotational speed (engine stands or rotates) must be additionally requested via a binary input.

3.3 Restart inhibit

Rotor temperature simulation plays a decisive role in the restart limit. The parameters required for this such as start-up current, rated motor current and maximum permissible start-up time are configured with the system data.

The following parameters must also be set in addition during restart inhibit:

- Temperature equalization time of the rotor
  As the thermal time constant of the rotor is considerably smaller than that for the stator, a value of 1 min. at most (preset) is practicable for the temperature equalization time of the rotor.
  t_{EQUAL} = **1min** [empirical value]
- Number of maximum permissible warm start-ups
  n_W = 2 [empirical value]

If no specifications are available from the motor data sheet, empirical value 2 is set.

- Difference between the number of maximum permissible cold start-ups and the maximum number of permissible warm start-ups
  $n_c - n_W$ = 1 [empirical value]

  If no specifications are available from the motor data sheet, empirical value 1 is set.

- Factor for the thermal cooling-down time of the rotor when the machine is at standstill.
  The reduced cooling (when the motor is at standstill) in motors with self-ventilation is taken into account by the factor $k_{\tau STI}$ (related to the time constant during no-load operation). Undershooting the current threshold set in the system data as LS I> is considered as criterion for the motor's standstill.

1 is set in forced-ventilated motors.
$k_{\tau STI} = 5$ [empirical value]

If no specifications are available from the motor data sheet, empirical value 5 is set.

- Factor for the thermal cooling-down time of the rotor when the machine is running.
  This factor takes into account the different cooling-down of a loaded, running motor compared to that of a motor which is switched off. It is effective as soon as the current exceeds LS $I>$ (set in system data).
  With $k_{\tau operation} = 1$ heating and cooling-down time constants are equal under normal operating conditions.
  $k_{\tau BET} = 2$ [empirical value]
  If no specifications are available from the motor data sheet, empirical value 2 is set.
- Minimum lock-out time
  The minimum lock-out time t_{LOCK} relates to the motor manufacturer's specifications or operating conditions. It must be greater than the time of temperature equalization t_{EQUAL}.
  $t_{LOCK} = 6$ min [assumption]

3.4 Negative-sequence protection

In electrical machines, negative-sequence (unbalanced load) protection is of particular importance.

The definite-time characteristic is set up in two stages. When a first, adjustable $I_2>$ threshold is reached, a pick-up signal is given and a time stage $T\,I_2>$ started. When a second stage $I_2>>$ is reached, another signal is transmitted and the time stage $T\,I_2>>$ started. After one of the delays has elapsed, a tripping command is given. The $I_2>>$ stage is well suited to faults in the secondary transformer circuit with lower sensitivity and very short tripping time, for example.

The preset values for pick-up and time delay are mostly sufficient. If the machine manufacturer has stated values concerning continuous permissible unbalanced load and the duration of loadability as a function of the magnitude of the unbalanced load, these should have priority.

The percentage values are related to the transformer's rated current.

- Pick-up value of stage $I_2>$ (related to rated transformer current I_N)
  $I_2> = 10\ \%$ [from motor data sheet]
- Tripping delay of stage $I_2>$
  $TI_2 = 15$ s [from motor data sheet]
- Pick-up value of stage $I_2>>$
  $I_2>> = 50\ \%$ [preset]
- Tripping delay of stage $I_2>>$
  $TI_2>> = 1$ s [preset]

3.5 Earth-fault protection

Earth-fault protection detects earth faults in the stator winding of three-phase machines. The design of the earth-fault protection depends on how the star point of the power supply system is connected. The star point of the motor must always be set up isolated as follows. The 7SJ602 is suitable both for power systems with earthed star point and for power systems with isolated, compensated or low-resistance earthed star point. Two hardware variants cover all these system configurations. These must be taken into account when ordering.

The following depicts the earth-fault protection setting for a motor feeder in a 10 kV isolated system.

As this is an isolated system the variant must be chosen with sensitive earth-fault detection.

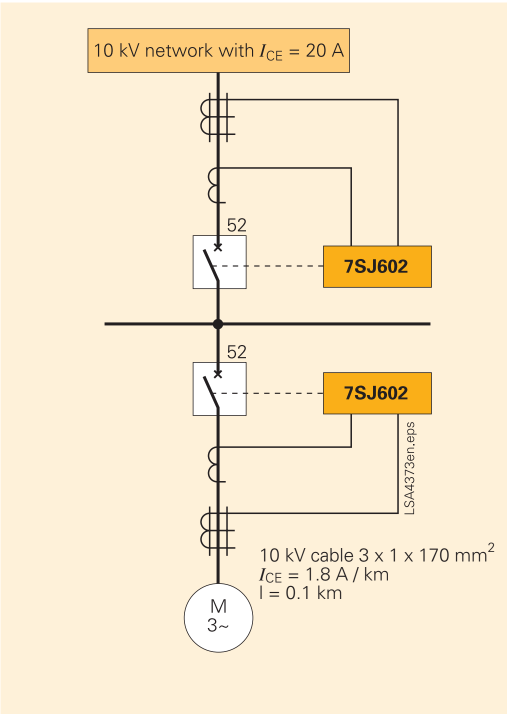


Fig. 6 Application example motor protection

In our example it is assumed that the supplying 10 kV power system has a corresponding size and, during an earth fault, a capacitive earth-fault current I_{CE} of approximately 20 A flows to the fault location. Information about the magnitude of the capacitive earth-fault current must be requested from the power system operator. Of course, the motor feeder also delivers an earth-fault current. The motor feeder must be connected via a 100 m long 10 kV cable. The motor feeder earth-fault current is calculated as follows:

$I_{CEcable} = I'_{CE} \cdot l$

$I'_{CE} = 1.8$ A/km (from the cable data sheet)
$l = 0.1$ km

$I_{CEcable} \approx 0.20$A

The following earth-fault current distribution is the result.

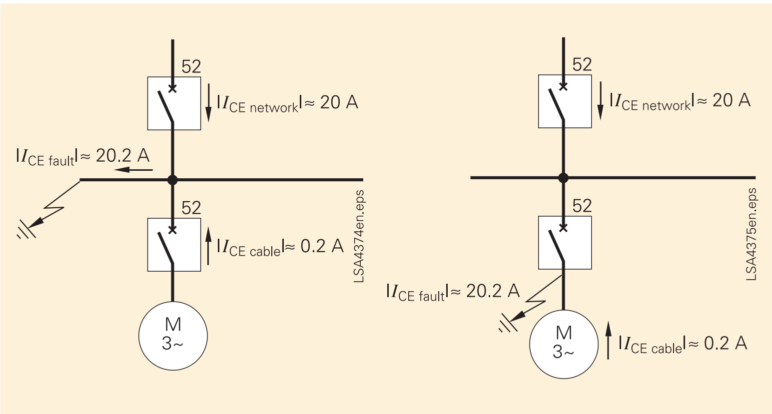


Fig. 7 Earth-fault current distribution depending on the fault location

From the current distribution it is clear, that the fault can be unambiguously located from the magnitude of the earth-fault current.

In the event of an earth fault on the busbar, only the 7SJ602 in the incoming feeder bay may pick up. If the fault location is in the motor feeder, the 7SJ602 must pick up both in the incoming feeder bay and in the motor outgoing feeder. In this example, therefore, a statement of the situation can only be made via the magnitude of the earth current.

The following setting recommendation for the motor outgoing feeder has been produced as a pickup threshold: For safety reasons $I_{CEtotal}$ must not be assumed since, for example, this may be reduced as a result of power system disconnections. As a base $I_{EE}> \approx 0.5 \cdot I_{CE}$ can be chosen.

Should an earth fault not lead to tripping, the $I_{EE}>$ function can also be adjusted only to signals. If no second pickup threshold is needed, $I_{EE}>>$ can be deactivated.

If the earth current is insufficient for fault location, an earth-fault direction determination is configured. In this case a voltage input (U_{en}) is obligatory.

With sensitive earth-fault direction determination it is not the magnitude of the current that counts but rather the component of the current vertical to a settable directional characteristic (symmetry axis). A precondition for direction determination is exceeding of the displacement voltage stage U_E and a likewise parameterizable current component that determines the direction (active [cos φ] or reactive component [sin φ]).

In electrical machines directly connected to busbar on the isolated power system, cos φ and a correction angle of around +45° can be set for the measuring mode, because the earth-fault current often consists of a superimposition of the capacitive earth-fault current from the power system and the resistive current of a load resistor.

3.6 Short-circuit protection

Short-circuit protection is the main protection function of the 7SJ602. It has in all three stages for phase currents, and two for the earth current. The overcurrent stage ($I>$) can if need be work with definite or inverse command time. High-current tripping ($I>>$) and instantaneous tripping ($I>>>$) always work with a definite command time.

For a motor's short-circuit protection, it must be ensured that the set value $I>>>$ is lower than the smallest (2-pole) short-circuit current and greater than the highest start-up current. Because the maximum inrush current is usually below 1.6 × the rated start-up current, even under unfavorable circumstances, the following setting conditions apply for the short-circuit stage $I>>>$.

$1.6 \text{ x } I_{Start\text{-}up} < I>>> < I_{k2pole}$

As safety distance, the setting value should be selected approx. 30 % above the expected start-up current.

$I>>> = 2.0 \cdot I_A = 2.0 \cdot 5 \cdot I_{NM} = 2.0 \cdot 5 \cdot 74/100 \cdot I_N \approx 7.4 \cdot I_N$

- Pickup value of the instantaneous release stage $I>>> = 7.4 \cdot I_N$

The setting of $I>>$ is aligned to the motor start-up current. A safety factor of around 1.5 must be set in order that correct start-up does not lead to tripping.

$1.5 \cdot I_{\text{Start-up}} < (I>>) < (I>>>)$

$I>>$ should be set above the motor start-up current so that it is not tripped by it.

$I>> = 1.5 \cdot I_A = 1.5 \cdot 5 \cdot I_{NM} = 1.5 \cdot 5 \cdot 74/100 \cdot I_N \approx 5.5\ I_N$

- Pick-up value of the high-current stage
  $I>> = 5.5 \cdot I_N$

The time delay for the high-current stage should be delayed until the maximum inrush current has safely decayed. The values in the motor data sheet must always have priority over the assumptions and empirical values used in these applications.

- Tripping delay for the high-current stage
  $TI>> = 50$ ms

In the overcurrent protection function an inverse-time characteristic must be chosen since this can be better adapted to the motor's operational performance.

The inverse-time short-circuit protection I_p protects the motor from short-circuits during normal operation (after start-up). The higher the short-circuit current the quicker the tripping. The extreme inverse-time characteristic must be selected for tripping.

The maximum normal current is essential for setting the overcurrent stage I_p. Pickup by overload must be ruled out, because with this mode the relay works with correspondingly short command times as a short-circuit protection, not as an overload protection.

$I_p = 1.5 \cdot I_{NM}/1.1 = 1.5/1.1 \cdot 74/100 \cdot I_N \approx 1.0\ I_N$

- Time multiplier for phase currents
  $T_p = 1.5$ s
- Set value of the overcurrent stage I_p for the phase currents
  $I_p = 1.0\ I_N$

4. Summary

In this example for setting, it is evident that a SIPROTEC relay can provide comprehensive protection of a motor, and that thereby (in addition to actual protection of the equipment) protection of the remaining power supply system is also available.

From a protection point of view, the relay offers extensive protection functions for low power class motors in addition to short-circuit protection. Because all protective functions are available in one relay, connection and testing costs are minimized.

The relay presettings are selected so that the user can apply many parameters, even if they are not well known. Motor sheet data is mainly used to select the required values, thus making setting easier.

Protection of a Medium-Sized Generator up to 5 MW

■ 1. Introduction

Small-scale stations are making a significant contribution to power generation. Hydropower plants currently still account for the largest share of system infeed. The most significant increase in the number of generating plants has been in wind energy.
Electrical protection is essential for the reliable operation of such equipment.
The scope of protection must be in proportion to the overall costs and importance of the plant. The scope and choice of protection functions are influenced by plant type, generator design and additional equipment, output level and power system connection. The following table gives an overview of the protection functions used depending on generator output.

Fig. 1 SIPROTEC 7UM generator, motor and transformer protection

	For hydropower generators				For diesel generators and turbogenerators			
	Up to 300 kVA	300 to 700 kVA	700 to 1500 kVA	> 1500 kVA	up to 300 kVA	300 to 700 kVA	700 to 1500 kVA	> 1500 kVA
Thermal and short-time delayed trip and shunt release for *U*~ on generator circuit-breaker	x	–	–	–	x	–	–	–
Only shunt releases for *U*~ on generator circuit-breaker	–	x	x	x	–	x	x	x
Rise-in-voltage protection	x	x	x	x	–	–	x	x
Reverse-power protection	–	–	–	–	x	x	x	x
Overcurrent-time protection	–	x	x	x	–	x	x	x
Differential protection	–	–	–	x	–	–	–	x
Rotor earth-fault protection	–	–	–	x	–	–	–	x
Is DC auxiliary voltage for protection required?	–	x	x	x	–	x	x	x

Table 1 Protection functions for small-scale power stations

2. Protection concept

In small-scale power stations, the basic circuits for busbar and unit connection (as shown in Fig. 1) can be assumed.

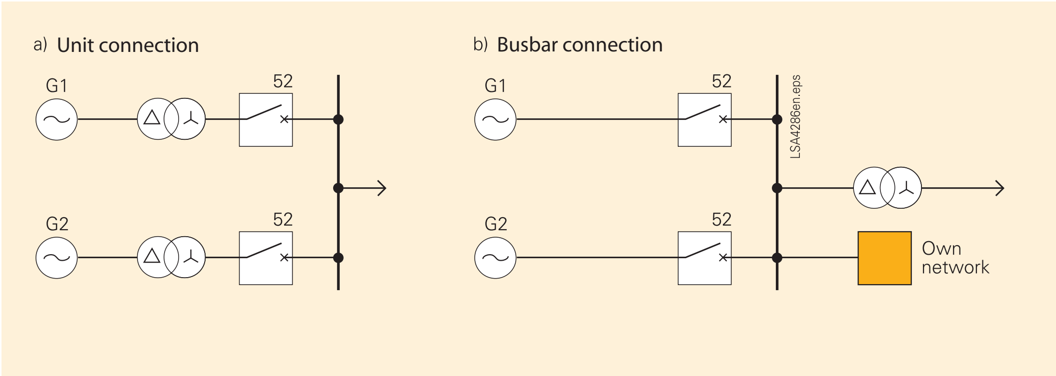


Fig. 2 Plant basic circuit

Fault type	Cause	Protection function	Remarks
Overload	$S_{ab}>S_{produced}$ Controller error Maloperation	Thermal overload protection (I^2t)	Evaluation of current r.m.s. value with previous load recording
Short-circuit (2 or 3 phase)	Deterioration of insulation Winding displacement Overvoltages Manufacturing defects	Overcurrent-time protection (I>) Differential protection (ΔI)	Time delay must be coordinated with system protection
Earth fault (Stator)	Same cause as for short-circuit	Stator earth-fault protection U_0> in unit connection Earth-fault direction in busbar connection (/U_E, I_E)	The protected zone (approximately 80 %) is determined by plant conditions (see discussion in text)
Earth fault (Rotor)	Deterioration of insulation Winding displacement Brush abrasion on the slipring surface Material fatigue	Rotor earth-fault protection with system frequency signal coupling in rotor circuit	Used as from 5 MW, if sliprings available; below 5 MW optional
Reverse-power	Drive failure Shutdown	Reverse-power protection (-P)	Only necessary for steam and diesel drive systems
Speed irregularities	Leaking stream valves Sudden changes in active power Overload	Frequency protection (f> or f<)	As from 5 MW f> and f< Below 5 MW so far only f>; f< is likewise recommended if available
Overvoltage	Controller error or manual maloperation	Overvoltage protection (U>)	Evaluation of phase-to-phase voltage
Unpermissible under-excitation	Fault in exciter circuit Operation in underexcited state (high reactive power demand in system) Maloperation, controller error	Underexcitation protection (e.g. -Q, or Z)	Used as from 5 MW Below 5 MW so far not usual; recommended if function available
Asymmetric load	Unequal loading of conductor	Negative-sequence (or load unbalance) protection (I_2>)	Used from 5 MW; Below 5 MW so far not usual; recommended if possible,

Table 2 Fault type, protection functions

In **unit connection**, the generator is linked to the higher voltage level busbar via a transformer. In the case of several parallel units, the generators are electrically isolated by the transformers.

In **busbar connection**, several generators feed onto a common busbar. Subsequently, the next higher voltage level is fed via a transformer. The generators are galvanically connected.

Owing to the low overall plant costs, the busbar connection is frequently chosen for **small-scale power stations**. This application is therefore considered in greater detail in the following.

Table 2 shows the protection functions suitable for small-scale power stations in accordance with today's state-of-the-art. Fault type, cause and the protection function to be deployed are indicated, together with general notes on particular features of the protection function.

3. Applications

Table 1 shows, that even with small generators of < 5MW, relays must be used with a number of protection functions. Numerical protection relays are the current state-of-the-art.
The SIPROTEC range provides a good choice. As shown in Table 3, 7SJ relays are well suited for simple protection functions for small generators.

The decisive advantage of the 7UM6* generator protection relay is the automatic adjustment of the sampling frequency. To ensure that the protection and measurement functions deliver correct results over a wide frequency range, the actual frequency is continuously measured and the measurement processing sampling frequency continuously tracked. This ensures the measuring accuracy in the frequency range from 11 Hz to 69 Hz.
This relay offers a wide range of additional protection functions. If differential protection is required and the appropriate transformer sets are available, a 7UM62 is recommended. As differential protection is applied usually for generators above 5 MW, the example shown opposite refers to a 7UM61 relay for a 5 MW generator in busbar connection.

Protection functions	ANSI	7SJ60	7SJ61	7SJ62	7SJ63/64	7UM61
Rotor overload protection	49	X	X	X	X	X
Earth-fault protection directional / non directional	64G 50G 67G	X X X	 X 	X X X	X X X	X X X
Overcurrent-time protection	50 51	X	X	X	X	X
Negative-sequence protection	46	X	X	X	X	X
Rotor earth-fault protection	64R		X[1]	X[1]	X[1]	X[1]
Reverse-power protection	32				X[2]	X
Overcurrent protection	59			X	X	X
Underexcitation protection	40					X
Frequency protection	81			X	X	X
Temperature monitoring (by an external monitoring box called thermo-box)	38	X		X	X	X
Breaker failure protection	50BF	X	X	X	X	X
Programmable logic			X	X	X	X
Control functions		X	X	X	X	X
Flexible serial interface		1	2	2	2/3	2

1) via I_{EE} measuring input if earth-fault direction function is not used.
2) in 7SJ63 with CFC, in 7SJ64 with flexible functions.

Table 3 Protection relays – selection matrix

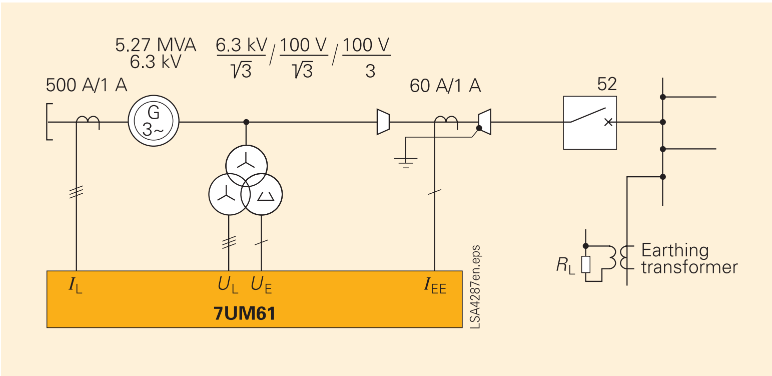


Fig. 3 Busbar connection with core-balance CT

4. Settings

In the following sections, the individual protection and additional functions (see Table 3) are explained. Notes on the setting values are also given. The calculation examples are oriented towards the reference plant shown in Fig. 3. For the tripping concept, it is assumed that the protection directly actuates the tripping (circuit-breaker, de-excitation, turbine valve closing or diesel cut-off).

4.1 Thermal overload protection (ANSI 49)

Overload protection prevents thermal overload of the stator windings on the machine to be protected. The relay calculates the temperature rise in accordance with a thermal single-body model by means of the thermal differential equation and takes account of both previous overload history and emission of heat into the ambient area.

After an initial, adjustable threshold has been reached, an alarm signal is emitted for the purpose of enabling a load reduction in good time, for example.
The second temperature threshold disconnects the machine from the system. For example, ambient or coolant temperatures can be input via the PROFIBUS-DP interface.

Low ambient or coolant temperatures mean that the generator can be loaded with more current; high temperatures signify that the loadability is less.

Example
Generator and transformer with the following data:

- Permissible continuous current $I_{max\ prim} = 1.15 \cdot I_{N,\ generator}$
- Rated generator current $I_{N,\ generator} = 483$ A
- Current transformer 500 A/1 A

Set value k-factor = 1.15 483A/500A = 1.11

Note:
Taking the k factor at the usual figure of 1.1, applying the generator rated current (with the primary transformer current matched) produces a temperature rise of $\Theta / \Theta_K = 1 / 1.1^2 = 0.83$ of the tripping temperature. The alarm stage should thus be set between end temperature at rated current (83 % in this case) and tripping temperature (100 %).

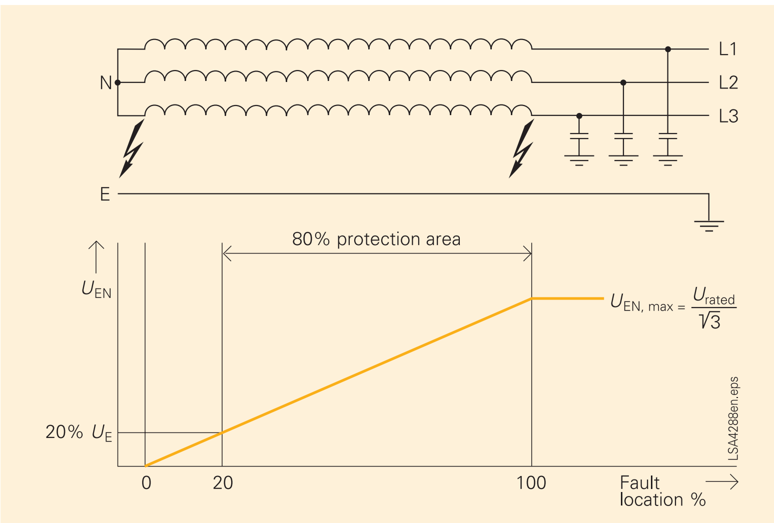
With an assumed load current of $I = 1.5\ I_N$ (relay) and a preload of $I_{pre} = 0$, the following tripping times are derived for various ambient temperatures

$\Theta_K = 40\ °C$ $t = 463$ s
$\Theta_K = 80\ °C$ $t = 366$ s
$\Theta_K = 0\ °C$ $t = 637$ s

4.2 Definite-time overcurrent-time protection (I>, I>>) (ANSI 50/51)

General
Overcurrent-time is the form of short-circuit protection for extra-low or low voltage generators. In order that internal faults are always responded to, the generator protection is connected to the current transformer set located in the star point connection of the generator. In the case of generators whose excitation voltage is taken from the machine terminals, in the event of nearby faults (i.e. in the generator or the unit transformer region) the short-circuit current decays very quickly since there is no longer any excitation current, and within a few seconds falls below the overcurrent-time protection pickup value. In these cases undervoltage seal-in is used.

Fig. 4
Displacement voltage as a function of the fault location in the stator winding



4.3 Definite-time overcurrent-time protection (I>) with undervoltage seal-in (ANSI 51V)

Setting example:
Pickup value $1.4 \cdot I_{NGenerator}$
Tripping delay 3 s
Undervoltage seal-in $0.8\ U_{NGenerator}$
Seal-in time of $U < 4$ s
Dropout ratio 0.95

4.4 Earth-fault protection

In addition to short-circuit protection, which as described above is provided in a familiar fashion via overcurrent (or differential) protection, earth-fault protection is of particular significance for small-scale machines.

4.4.1 Principle

A particular feature of electric machines with isolated star point is that the displacement voltage decreases linearly as the fault location moves in the direction of the generator star-point (Fig. 4). The earth-fault current, the magnitude of which is determined by the earth capacitances in addition to the displacement voltage, thus also decreases. In the event of faults close to the star point, the displacement voltage and earth current become so small that they can no longer be reliably measured.

A protected zone of 80 –90 % is consequently spoken of.

In unit connection (Fig. 2a), the protected zone discussed above is additionally determined by the disturbance signal injection from the upstream system. If an earth fault occurs in the system, a displacement voltage is identifiable via the coupling capacitance of the unit transformer. The magnitude of the interference voltage is determined by the coupling capacitance, the generator-side earth capacitance (stator, incoming line) and the difference between rated system voltage and rated generator voltage.

In busbar connection, the displacement voltage can only be used for earth-fault indication due to the galvanical connection of the generators. The earth-fault direction protection makes selective tripping possible. The protected zone is determined by the earth current, which is measured by a core-balance current transformer (60 A/1 A). As shown in Fig. 2b the sum of the component earth currents flows through the generator affected by the fault. The cable network connected to the generators is decisive for the fault current magnitude.

Example:
In the case of 10 kV cables (lead sheath, polymer-insulated) the capacitive earth-fault current lies between 1.2 to 3.5 A/km. If with a full displacement voltage we assume an earth current of max. 3 A and aim for a protected zone of 80 %, approximately 0.6 A flows on the primary side. This current (secondary approximately 10 mA) can be handled reliably by the protection.

If the capacitive current is not sufficient where higher power levels are concerned, it is worth investing in an earthing transformer on the busbar or in disconnectable load resistors on the generator star point. The earth-current increases as a result of the resistive current.

4.4.2 Note

In industry, busbar systems are designed with high or low resitive switchable star-point resistors. For earth-fault detection, the star-point current and the summation current are measured by the core-balance current transformer and fed into the protection relay as a current difference (see Fig. 4). The earth-current component coming from the star-point resistor, as well as any from the system, contribute to the total earth-current. In order to rule out overfunction as a result of transformer faults, the displacement voltage serves for tripping. The protection then decides on generator earth-fault if both of the following criteria apply:

- Displacement voltage is greater than setting value U_0>,
- Earth-fault current difference ΔI_E greater than setting value 3 I_0>, magnitude.

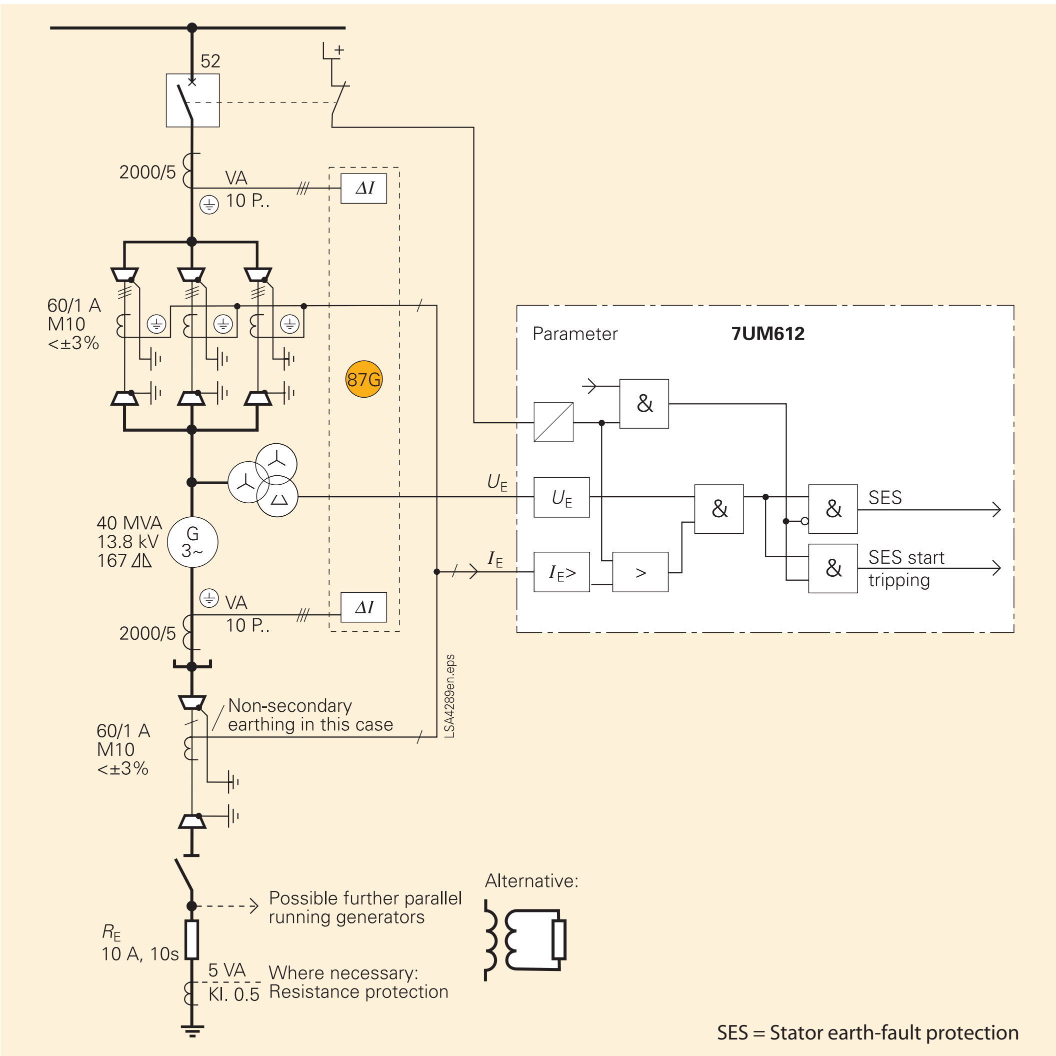


Fig. 5 Earth-fault protection by differentiation with core-balance current transformers

The pickup value should be at least twice the operational asymmetries. A value of 10% of the full displacement voltage is normal.

4.5 Sensitive earth-fault detection (ANSI 50/51 GN)/ rotor earth-fault protection (ANSI 64R)

Sensitive earth-current protection is used for detecting earth faults in isolated or high-resistance earthed systems. This protection function can also serve to detect rotor winding earth-faults if the rotor circuit is artificially displaced with a system-frequency voltage to earth ($U_V \approx 42$ V by means of 7XR61 coupling device). In this case the maximum flowing earth current is limited by the magnitude of the selected U_{RE} voltage and by the capacitive coupling to the rotor circuit. Monitoring of the measuring circuit is provided (for this application) as rotor earth-fault protection via the sensitive earth-current measuring input. It is regarded as closed if the earth current (which also flows with healthy insulation) resulting from the earth capacitance of the rotor circuit exceeds a parametrizable minimum value I_{EE}<. Should the earth-current fall below this value, a failure signal is issued after a short delay time (2 s).

A typical pickup value is approximately 2 mA. If this value is set at 0, the monitoring stage is ineffective. This can become necessary if the earth capacitances are too low. The setting of the earth-fault pickup I_{EE}> is selected in such a way that the insulation (earth) resistances R_E can be detected in the range from about 3 kΩ to 5 kΩ: The value set should in this case be at least twice as high as the interference current owing to the earth capacitances of the rotor circuit. The tripping delays T I_{EE}> and T I_{EE}>> do not include operating times.

4.6 Reverse-power protection (ANSI 32R)

Reverse-power protection serves to protect a turbine generator unit if, in the event of drive power failure, the synchronous generator runs as a motor and drives the turbine and is thereby drawing the required motoring energy out of the system. This state will endanger the turbine blades and must be interrupted without delay by opening the network circuit-breaker. For the generator there exists the additional danger that in the event of residual steam leakage (defective seal valves) after opening of the circuit-breaker, the turbine generator unit can be run up to overspeed. For this reason disconnection from the power system should only take place after detection of active power input into the machine. The value of the consumed active power is determined by the friction losses to be overcome and, depending on the system, is approximately:

- Steam turbines: $P_{Reverse}/S_N \approx 1$ % to 3%
- Gas turbines: $P_{Reverse}/S_N \approx 3$ % to 3%
- Diesel drives: $P_{Reverse}/S_N > 5$ %

However, it is advisible to measure the reverse power with the protection itself in the primary test. About 0.5 times of the measured motoring energy is chosen as a setting value. The motoring energy value can be found at the "percentage op - erational measured-values".

4.7 Frequency protection (ANSI 81)

Frequency protection detects overfrequencies and underfrequencies of the generator. If the frequency lies outside the permitted range, the appropriate switching operations are initiated, such as separating the generator from the system. Decrease of frequency is caused by an increase active power demand the system or by malfunctions in the frequency or speed control. Frequency decrease protection is also used on generators that (temporarily) feed a separate island system, since in such a case the reverse-power protection cannot work if the drive power fails. The generator can be disconnected from the system by the frequency decrease protection. Frequency increase is caused for example by load shedding (separate island system) or malfunctions in the frequency control. In such cases there is a danger of self-excitation of generators which feed long, no-load lines. The frequency values are generally set in accordance with the specifications of the system or power station operator. Frequency decrease protection has the task of securing power for the station-service equipment by disconnecting it from the system in good time. The turbo regulator then adjusts the machine set to rated speed so that the station-service power can continue to be supplied at rated frequency. A frequency increase can occur for example in the event of load shedding or speed control malfunction (e.g. in a separate island system). The frequency increase protection is thus used for example as overspeed protection.

Stage	Cause	Setting values		
		at f_N = 50 Hz	at f_N = 60 Hz	Delay
f_1	Disconnection from system	48.00 Hz	58.00 Hz	1 s
f_2	Shutdown	47.00 Hz	57.00 Hz	6 s
f_3	Alarm	49.50 Hz	59.50 Hz	20 s
f_4	Alarm or tripping	52.00 Hz	62.00 Hz	10 s

Setting example

4.8 Overvoltage protection (ANSI 59)

Overvoltage protection serves to protect the electric machine and the connected system components from impermissible voltage increases, thereby protecting the insulation from damage. Voltage increases result for example from incorrect operation in manual control of the excitation system, from malfunction of the automatic voltage regulator or from (full) shedding of a generator load, separation of a generator from the system or in separate island operation. Setting of the limit values and delay times of the overvoltage protection depends on the speed with which the voltage regulator can control voltage changes. The protection may not intervene in the control process when it is operating trouble-free. The two-stage characteristic must therefore always be above the voltage time characteristic of the control process. The long-time stage should intervene in the event of steady-state overvoltages. It is set to approximately 110 % to 115 % of U_N and, depending on the regulator speed, at 1.5 s to 5 s.

4.9 Underexcitation protection (ANSI 40)

Underexcitation protection (loss-of-field) protects a synchronous machine from loss of synchronism in the event of malfunction of excitation or control and from local rotor overheating.
In order to detect underexcitation, the relay processes all three phase currents and all three voltages as stator circuit criteria as well as the signal of an external excitation voltage monitor as rotor circuit criterion (Fig. 6).

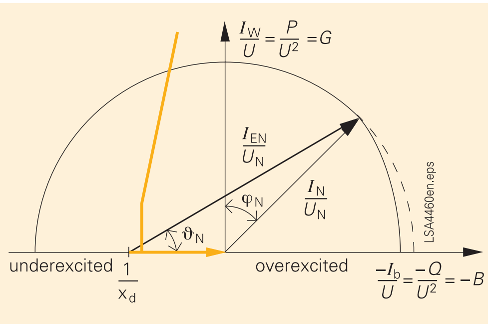


Fig. 6 Admittance diagram of turbo generators

The tripping characteristics of the underexcitation protection are composed of straight lines in the diagram, each defined by its conductance section $1/x_d$ (= coordinate admittance distance) and its angle of inclination α (Fig. 7).

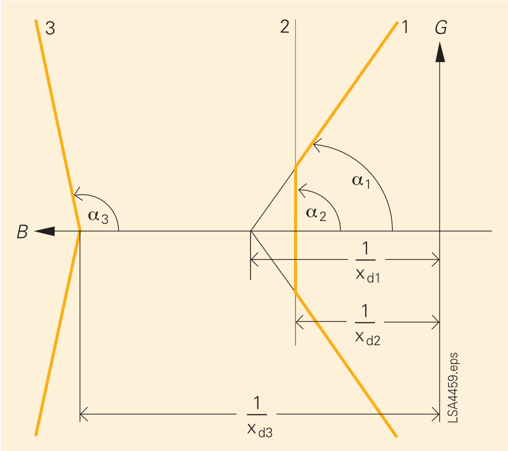


Fig. 7 Underexcitation protection characteristics in the admittance plane

The straight lines ($1/x_d$ Char. 1) / α 1 (characteristic 1) and ($1/x_d$ Char. 2) / α 2 (characteristic 2) form the static underexcitation limit. ($1/x_d$ Char.1) corresponds to the reciprocal value of the reference synchronous direct reactance

$$\frac{1}{x_d} = \frac{1}{x_d} \cdot \frac{U_N}{\sqrt{3} \cdot I_N}$$

If the synchronous machine voltage regulator includes underexcitation limitation, the static characteristics are set such that intervention by the underexcitation limitation is enabled before the characteristic 1 is reached. The generator performance diagram can be used as a basis for setting. If the axis sizes are divided by the rated apparent power, the generator diagram is obtained in "per unit" form (corresponding to a "per unit" representation of the admittance diagram). Multiplying $1/x_d$ by a safety factor of approximately 1.05 produces the setting value.

For α 1 the angle of the voltage regulator underexcitation limitation is selected, or the inclination angle from the restraint characteristic of the machine can be read. α 1 is normally between 60° to 80°. For low active power levels, the machine manufacturer normally specifies a minimum excitation. Here the characteristic 1 is cut off from characteristic 2 when the active power is low. α 2 is set to 90 °. With characteristic 3, the protection can be matched to the dynamic stability limits of the machine. If no more precise details are available, a value roughly between the synchronous direct-axis reactance x_d and the transient reactance x_d is selected; it should however be greater than 1.

For the angle α 3, 80 ° to 110 ° is normally selected, in order to ensure that only dynamic instability can lead to tripping with characteristic 3. If the static limit curve (consisting of characteristics 1 and 2) is exceeded, initially the voltage regulator must be given the opportunity to increase the excitation; for this reason an alarm signal is delayed "long time" (at least 10 s). If the relay is nevertheless "informed" of excitation voltage failure (by an external excitation voltage monitor via binary input), disconnection can take place with a short delay time.

Characteristic 1 and 2 steady-state stability	Instantaneous	Excitation signal Exc < Exc
Characteristic 1 and 2 steady-state stability	Long time-delay T Char. 1 = T Char. 2 ≈ 10 s	Trippings Exc < Char. 1 TRIP / Err < Char. 2 TRIP
Characteristic 1 and 2 Excitation voltage failure	Short time-delay T SHORT U_{ex} < ≈ 1.5 s	Tripping Exc < UPU < TRIP
Characteristic 3 Dynamic stability	Short time-delay T Char. 3 ≈ 0,5 s	Tripping Exc < Char. 3 TRIP

Setting of underexcitation protection

Note:
Selecting very short delay times can lead to dynamic transients (possibly overfunctions).
It is therefore advisable not to set the times below 0.05 s.

4.10 Negative-sequence protection (ANSI 46)

Negative-sequence (or unbalanced load) protection is used to detect asymmetrical loading of three-phase induction machines. Asymmetrical loads create a reverse field, which affects the rotors with double the frequency. Eddy currents are induced on the surface of the rotor, leading to local overheating in the rotor end zones and slot wedges. Furthermore, interruptions, faults or incorrectly inter-changed connections to the current transformers can also be detected with this protection function. Additionally, single and two-phase faults with fault currents lower than the maximum load currents can be identified.

Setting example:
Setting value $I_{2\,\text{permissible}}$ = 11 % · (483 A/500 A) = 10.6 %
Factor k = 18.7 s
T cooling = 1650 s

5. Communication

The SIPROTEC 7UM6 relays fully satisfy the requirements of modern communication technology. They have interfaces that enable integration into
– superordinate control centers,
– convenient parameter assignment and operation via PC (locally or via modem connection).

- PROFIBUS DP, RS485 or optical 820 nm double-ring ST connector,
- IEC 60870-5-103,
- DNP3.0; RS485 or optical 820 nm double-ring ST connector and
- MODBUS; RS485 or optical 820 nm double-ring ST connector

7UM6 supports the widely used, internationally standardized open communication standards.

6. Summary

Based on the recommendations for protection functions [1] it has been described how, despite the cost aspects that have to be taken into account in small-scale power generating plants, modern relays can be used to create technically effective yet uncomplicated concepts.

In contrast to traditional individual relays, state-of-the-art multifunctional numerical protection equipment now provides a wider scope of functions. Self-monitoring contributes to avoidance of underfunctions (failure to detect relay failure). A generator can be adequately protected with a single relay. For more detailed information on selecting functions and settings, the 7UM61 manual is recommended, chapter 2.1 of which has been provided as an application handbook.

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Siemens AG; PTD:
SIPROTEC 7UM61 V4.1 Multifunctional Machine Protection Manual

System Solutions for Protecting Medium and Large Power Station Units

■ 1. Introduction

Electrical protection is essential for reliable operation and high availability in power stations. Electrical protection equipment cannot prevent faults from occurring in the power station unit itself, but can limit the damage and thereby shorten the station's downtime.

Protection equipment will not be discussed in detail here. Detailed reports on protection functions and measurement procedures can be found in “Protection of a Medium-Sized Generator up to 5 MW”and “Protection of Medium-Sized and Large Generators with SIPROTEC 7UM6.

The subject of this publication is the design of protection systems with regard to reliability, availability and operational safety. Various equipment technologies (and how these affect the design and operation of a protection system) are compared.

■ 2. Safety and availability of the protection system

Protection equipment serves to detect faults or impermissible operating conditions in power supply systems and to shut them down when such conditions occur. When the station is operating trouble-free, conventional protection equipment does not indicate whether it is functioning correctly or not. The operator must therefore check to make sure that the protection relays are working, using recurrent function tests. This confirmation of correct operation only applies for the duration of the function test. For the time between such periodic function tests, no dependable statement about the condition of the protection relays can be made. Maintenance and testing is discussed in more detail in Chapter 4 of this application example.

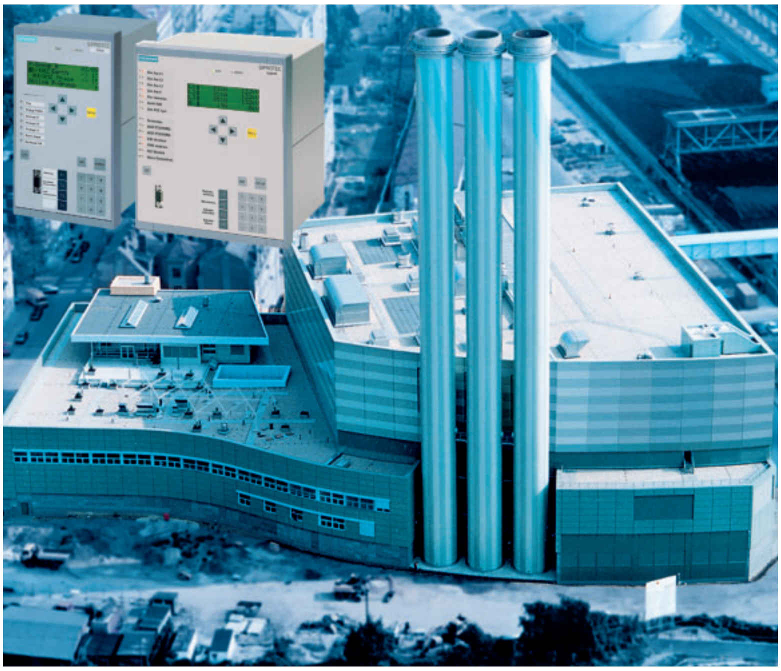

Fig. 1 SIPROTEC Generator protection for power stations

Possible failures in electromechanical protection relay can go unnoticed and the relay then almost always fails to function properly. Availability of the protection system is no longer ensured. For this reason the protection equipment for large-scale plants –including of course large power station units –is duplicated. The statistical proba - bility that both protection relays will fail at the same time is so slight that the availability of a redundant protection system can be considered as sufficient (see Fig. 2).

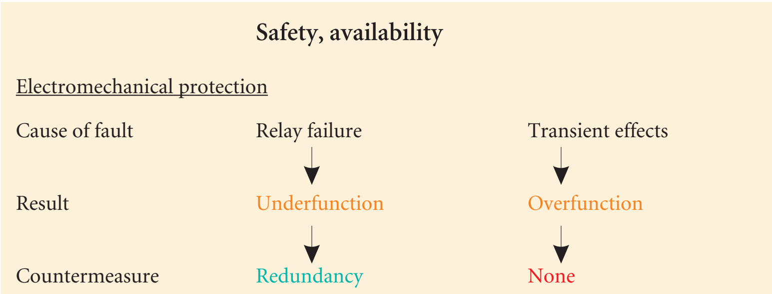

Fig. 2 Safety design for electromechanical protection

In the use of analog electronic protection relays an additional aspect comes into play. A fault on an electromechanical protection relay almost always causes relay failure. A relay fault in an analog static protection relay can cause either underfunction or overfunction, with approximately the same probability. Underfunction can, as with electromechanical protection systems, be mastered by redundant design. The danger of overfunction can be prevented in a limited sense by dual-channel design of the measuring circuits (see Fig. 3).

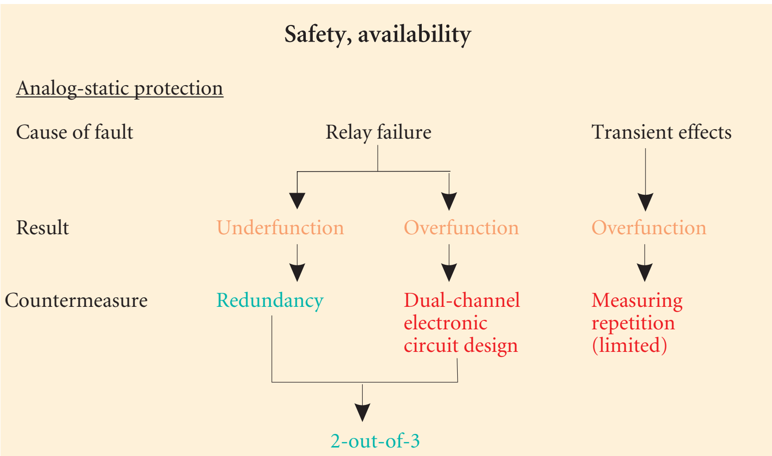

Fig. 3 Safety design for analog-static protection

If a high level of safety and availability is to be attained with analog technology, the 2-out-of-3 principle can be applied. Three identical or equivalent protection systems must be linked with each other externally so that two tripping signals from different systems are always connected in series. This way a very high level of safety from overfunction and underfunction can be achieved.

In a study in the 1970s the safety and reliability of different analog protection system configurations were statistically researched (see Table 1).

System design	Underfunction	Overfunction
1-out-of-1	5 years	5 years
1-out-of-2	600 years	2,5 years
2-out-of-2	2,5 years	21,750 years
2-out-of-3	200 years	7,250 years

Table 1 Overview system design

The MTBF (Mean Time Between Failures) was calculated for different system configurations. The 2-out-of-3 system in analog design offers the highest reliability against overfunction and underfunction. However, a 2-out-of-3 system is technically very complex and cost-intensive and for this reason only used in a few nuclear power plants.

A notable characteristic of numerical protection relays are continuous self-monitoring of hardware and software. Reliability against overfunction and underfunction is inherently provided (see Fig. 4). Any relay failure causes blocking of individual protection functions or of the entire relay. This provides an effective measure against overfunction of the protection relays and thereby of the protection system as a whole. Relay failure is signaled at the same time. This feature means that defective protection relays can be immediately replaced and the statistical availability of the protection system is enhanced.

In power stations that either have a relatively low-output or are of comparatively minor significance for secure power supplies, the requirement for a redundant protection system can consequently be re-assessed. If brief shutdown of the plant is acceptable, the investment costs can be reduced by dispensing with redundancy. "Brief" here means a period of one or two days until the replacement equipment is installed and put into operation.

In most power stations, however, shutdown due to defective protection relays is not acceptable nor is continued operation without complete protection. Consequently, a redundant protection system must be considered in medium and large power station units. From a technical point of view, complete redundancy of the protection functions enables continuous operation of the unit for a short time until defective protection relays are replaced.

For the sake of completeness, the influence of transient phenomena on the behavior of protection relays (Figs. 2, 3 and 4) must be mentioned. Electromechanical protection relays offered, apart from their time-lag characteristics, practically no effective compensation for transient influences. With analog technology, disturbing transient measured variables can be eliminated to a certain extent by multiple measurements. Only numerical technology enables reliable control of transient disturbances through consistent digital filtering and repeat measurements.

Producing complete redundancy does not require 100% duplication of all protection relays. Redundancy can also be achieved by two different measurement procedures for one and the same fault. For example a redundant protection concept can be realized against short-circuits by combining current differential protection and impedance protection in mutually independent relays. For some protection functions, differing measurement principles are even desirable. Duplicate differential protection provides two fast and selective protection against short-circuits in the machine. Impedance protection as the second stage of short-circuit protection includes at the same time backup protection against power system faults (see Figs. 5 and 6).

A few special features must be noted in the redundant design of protection functions whose principle is based on supplying an external voltage (100% stator earth-fault protection with 20 Hz injection and rotor earth-fault protection). The auxiliary devices cannot be operated in duplicate on the generator. It is, however, possible and appropriate to operate the protection functions themselves in redundancy. Here, the measuring inputs of both protection relays are fed in parallel from the same 20 Hz or 1 Hz frequency generator. If a very high level of statistical availability is aimed for, the auxiliary devices can be installed in duplicate with one changeover switch in the protection cabinet. If any auxiliary devices fails, the parallel relay is activated by the changeover switch.

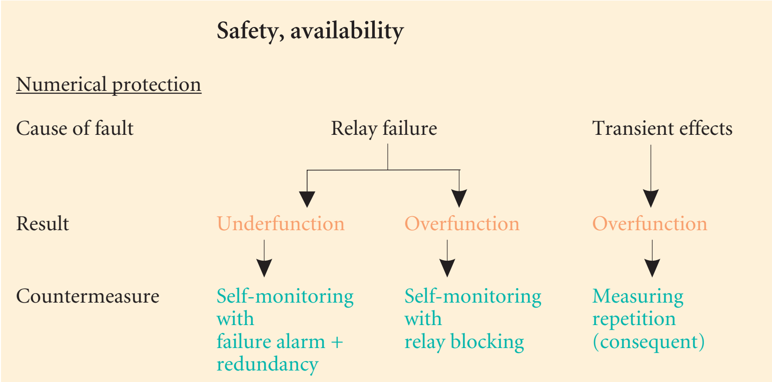

Fig. 4 Safety design for numerical protection

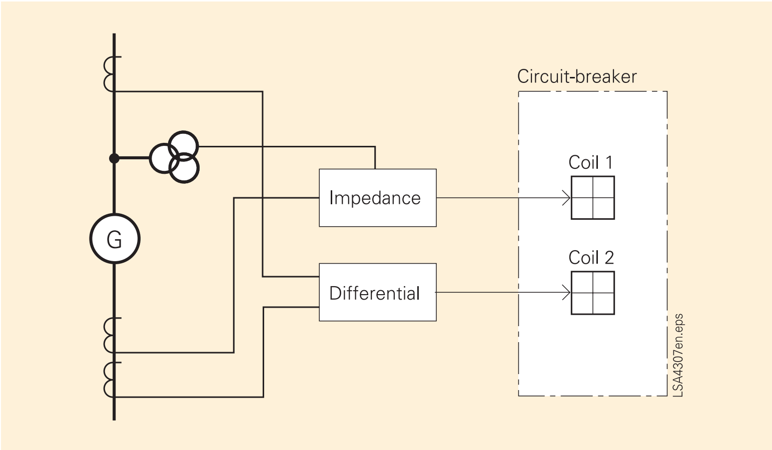

Fig. 5 Diverse redundancy: Backup protection against system faults

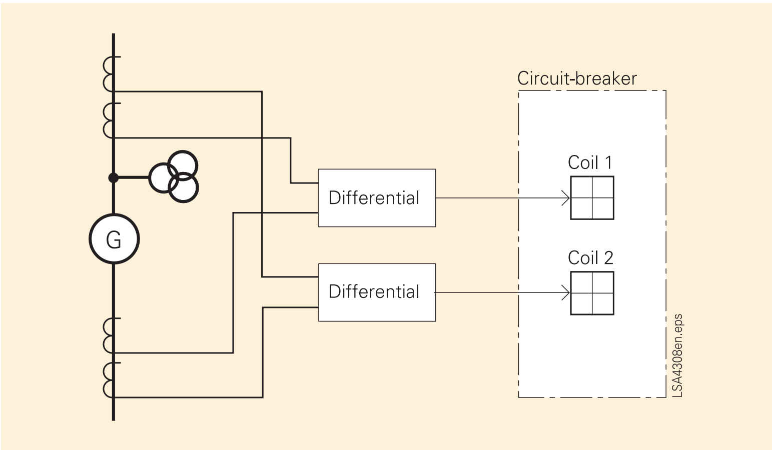

Fig. 6 Mirrored redundancy: No backup protection against system faults

■ 3. Indication processing and communication

Numerical protection relays offer the operator considerably more scope for status and fault indications than do conventional relays. In the interests of more reliable operation and control of the power station, it is the planning engineer's responsibility, from the abundance of available information, to provide (to operating personnel) precisely those indications and measured values that are needed for each task. Rather than succumbing to the temptation to make all available information accessible at each workstation, the planning engineer is responsible for working out an intelligent indication signalling concept.

This means that each member of staff receives the information needed to make quick and reliable decisions about technical operation and control of the power station. Fig. 7 provides a concept for such an information network. Group indications from the protection system are provided in the power station control room. These indications enable a quick overview of the operating state of the power station unit in terms of electrical faults or impermissible operating states. The recommended spontaneous indications for the control room are:

- Tripping on faults
- Protection faulty
- Negative-sequence (unbalanced load) alarm
- Stator earth-fault alarm
- Rotor earth-fault alarm
- Underexcitation alarm

In addition to these spontaneous indications, measured values from the protection relays can also be requested via the bus connection as necessary. An information network with connected PC is available for detailed fault analysis after tripping on faults has occurred. Via this means of communication, the protection expert can read out all the available information from the protection relays. Using the message lists and the transient fault records the expert can draw up an exact profile of the fault that led to the power station unit being shut down. Alternatively, this detailed information can be read out on the front of the protection relays.

■ 4. Maintenance and testing

Continuous self-monitoring of numerical protection relays creates new opportunities for operation and testing. While it was essential to monitor the state of conventional protection relays by means of periodic function tests, numerical protection relays do most of this work themselves.

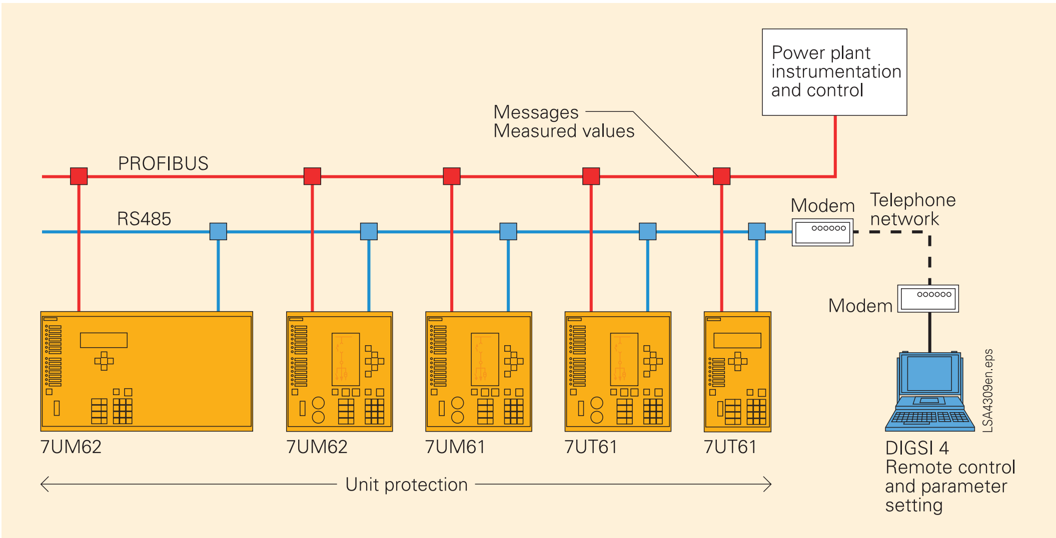

Fig. 7 Integration of protection relays into power station control and protection system

The self-monitoring installed in each numerical protection relay continuously checks that the hardware and software are working correctly. This produces a series of consequences for maintenance and testing of a numerical protection system.

Protection relays can be regularly checked by feeding in fault currents and voltage over a longer period of time. Such overall testing should be carried out in the context of regular power station maintenance. Since this check does not take place during operation of the power station, special test switches or plugs are not necessary. Current and voltage is fed in via the cabinet terminals. In view of the multi-functional protection relay concept for generators it is practically impossible to test individual protection functions without intervening in the relay parameterization. This is also not necessary because all protection functions of a relay are handled on the same hardware. The conventional approach involving protection characteristics with measurement of tolerances is not provided in numerical protection. Thanks to digital measured-value processing, the ageing or temperature drift of analog components is nowadays practically unknown. The function test is thus limited to a sensitivity check of the protection relay as a whole.

During power station operation the self-monitoring performs continuous testing of the numerical protection relays. As well as monitoring the program flow using Watchdog, the correct condition of the hardware components is continually checked. This takes place for example using write/read cycles for the memory and with the processing of reference parameters for the analog/digital converter. The protection relay also monitors external connections, where possible. One example of many is monitoring of the measuring voltage balance (Figs. 8 and 9).

Tasks: – Detection of a wire breakage in the voltage circuit
- Detection of device-internal faults in the voltage circuit

Operating condition: $\frac{U_{min}}{U_{max}} <$ SYM.FAK.U und $U_{max} \geq k \cdot$ SYM.UGREN

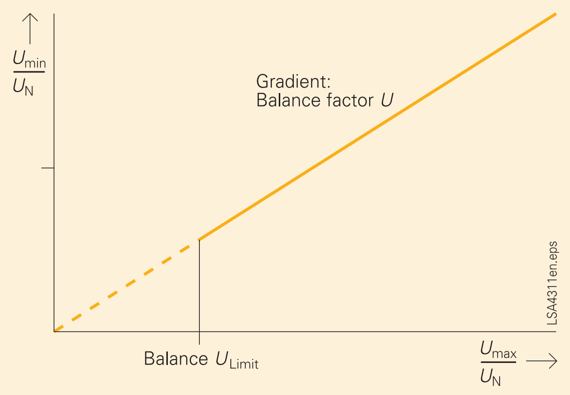

Fig. 9 Voltage balance monitoring

As a reaction to an identified fault, a defective protection relay produces either just an indication or blocks itself partly or wholly to prevent overfunction. Taking into account the recognized fault, the protection relay reacts in a graded way according to the seriousness of the fault (Fig. 10).

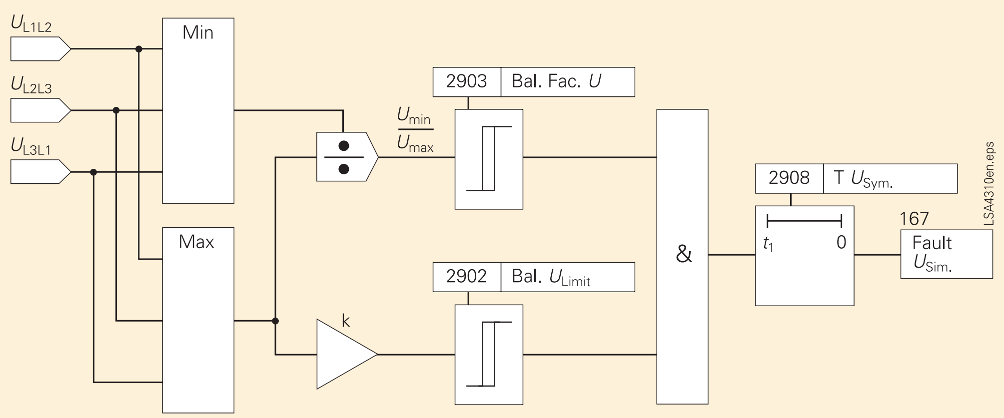

Fig. 8 Voltage balance monitoring

Possible reactions of a monitoring function

Minor faults

- Transmitting an indication
- Blocking individual protection functions. Only functions relating to the fault are blocked
- Withdrawal from service of all protection functions.
  The relay remains operable and indications can still be read out.
- Restarting the equipment. A maximum of 2 restarts are possible.
  After the 3rd restart the relay switches to monitor mode.
- Switch to monitor mode. This usually means a hardware fault.
  The cause can be determined by evaluating a fault buffer

Serious faults

Fig. 10 Design of monitoring functions

During normal power station operation, numerical protection relays make it possible to check the complete measured-value acquisition circuit by reading out status measured-values. Measured values can be indicated on the equipment display without adversely affecting the protection functions. A comparison of these measured values with other measuring devices or protection relays represents an inspection and test sequence which would be unthinkable in conventional technology without additional equipment. This test step includes the following power station and device components:

- Current and voltage transformer
- Transformer supply cables
- Cubicle wiring for the measuring circuits
- Input measuring transmitter for the protection relays
- Analog/digital converter
- Measured-value memory

This inspection and test sequence is of minimal duration and can be carried out at any time, without intervening in the protection processing of the relay.

5. Summary

The development of numerical technology for protection relays brought about considerable benefits in terms of enhanced performance, reliability and availability of the protection system. These benefits upgrade the availability of the power supply system. Quantity and quality of information retrieved from the numerical protection relays have reached such a high level that operation and maintenance of the power station can be performed much safer and with less efforts. The increase in functionality in the numerical protection relays requires a well-designed protection and information system, making the best of the many different opportunities.

Protection of Medium-Sized and Large Generators with SIPROTEC 7UM6

■ 1. Introduction

Medium-sized and large generators make a major contribution to power generation. They carry the basic load and ensure the stability of an energy system.

The task of electrical protection in these systems is to detect deviations from the normal condition and to react according to the protection concept and the setting. Based on experience with larger power station units, cost-effective protection concepts can also be implemented with SIPROTEC relays for medium-sized generators.

The scope of protection must be in reasonable relation to the total system costs and the importance of the system.

■ 2. Basic connections

In medium-sized and large power stations the generators are operated exclusively in unit connection.

In the unit connection the generator is linked to the busbar of the higher voltage level via a transformer. In the case of several parallel units, the generators are electrically isolated by the transformers. A circuit-breaker can be connected between the generator and the transformer (see Figs. 2 and 3).

Fig. 1 SIPROTEC generator protection

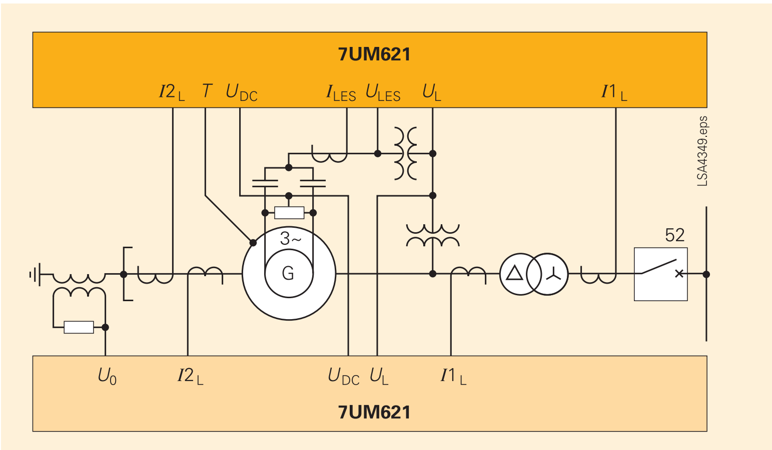

Fig. 2 Block diagram of generator protection

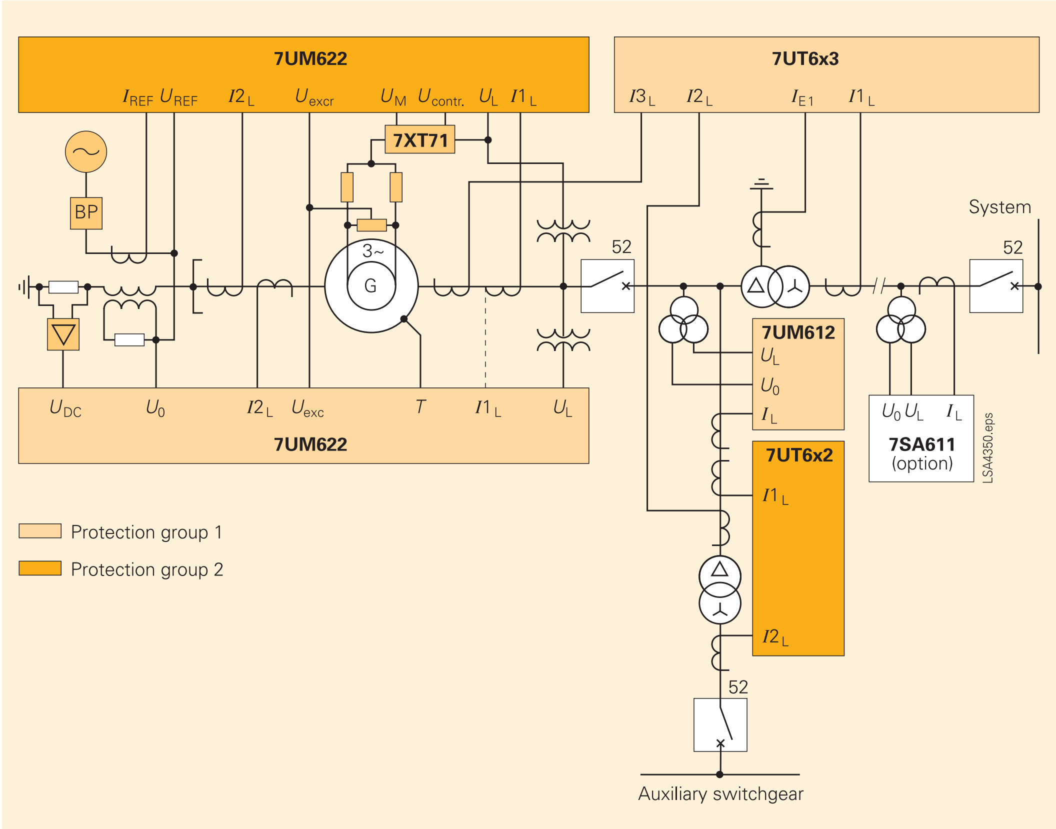

Fig. 3 Redundant protection concept for large generators

3. Protection concept

Components of the protection concept are:

- The redundancy concept
- The tripping concept
- Protection function scope

3.1 Redundancy concept

The redundancy concept is crucial in the design of protection systems. Many concepts are based on the n-1 principle. That means that the failure of a component is under control and does not lead to a total system failure. However, this principle is not always applied consistently. In smaller systems there is a compromise between redundancy and costs. The following strategies are common in practice for medium-sized and large generators.

Partial redundancy (see Fig. 4)

At least 2 protection relays are used here. The protection relays/functions are selected so that the system can continue to operate when a relay fails. However, certain restrictions have to be accepted. This system design is seldom used in high-power generators. The protection is connected to the same transformers for example.

Full redundancy (see Fig. 5)

In this system design the redundancy concept is applied consistently throughout by duplicating all the essential components. As shown in Fig. 5, the redundancy begins with separate transformers or transformer cores, continues through the protection relays, and the TRIP signal is passed through separate DC voltage paths to switchgear with 2 circuit-breaker coils (see Fig. 5). In the protection relays the protection functions can be duplicated on the one hand; on the other hand additional protection functions with different measuring principles are desired. Typical examples are earth-fault and short-circuit protection.

The displacement voltage measurement covers about 90 % of the protected zone in the event of an earth fault. The totally different method – injecting an external voltage (20 Hz) into the stator circuit – ensures 100 % protection.

The same can be implemented for the short-circuit protection. The main protection is the fast and selective current differential protection. Supplementary to this, impedance protection is used, with which the backup protection for the power system protection can be achieved by appropriate grading.

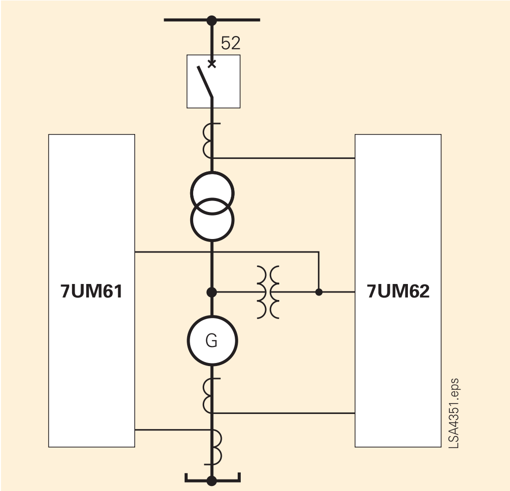

Fig. 4 Example: Partial redundancy

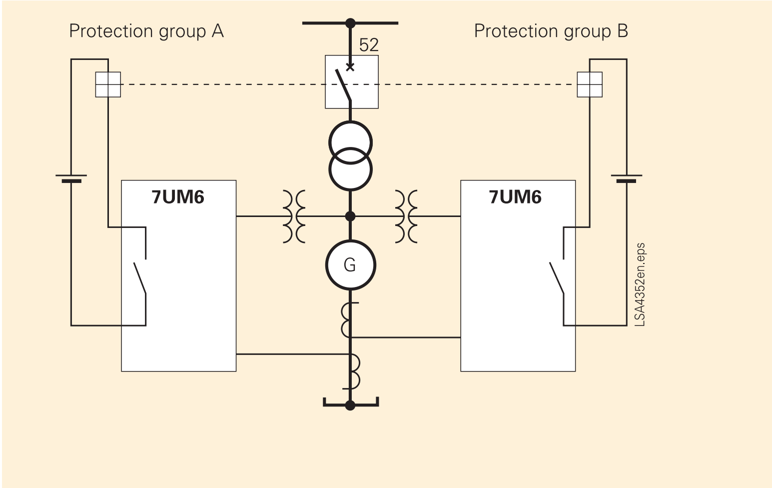

Fig. 5 Example: Full redundancy

3.2 Tripping concept

The special feature of generator protection is that different switching devices have to be activated depending on the fault. The number is basically determined by the system/plant concept. As a rule, most of the switching devices need to be actuated in the larger units. Special trippings are used in hydro-electric power stations.

Fig. 6 shows the basic concepts. On one side there are the switching devices to be actuated and on the other side the connected protection functions. The tripping program or tripping concept depends on the recommendations/experiences and the operating conditions. There are two opposing philosophies. The tripping program is determined individually by a tripping matrix (a software matrix in digital technology) and the switching devices are activated directly. The other (American-influenced) variant reduces the tripping to two programs, e.g. exclusive shutdown of the generator and shutdown of the power station unit. Lockout relays are used to control the switching devices. The protection needs only a few trip contacts.

3.3 Protection function scope

Numerous protection functions are necessary for reliable protection of electrical generators. The scope and the combination are determined by various factors such as generator size, operating principle, system design, availability requirements, experiences and philosophies. This automatically leads to a multifunctionality which can be controlled excellently by numerical technology.

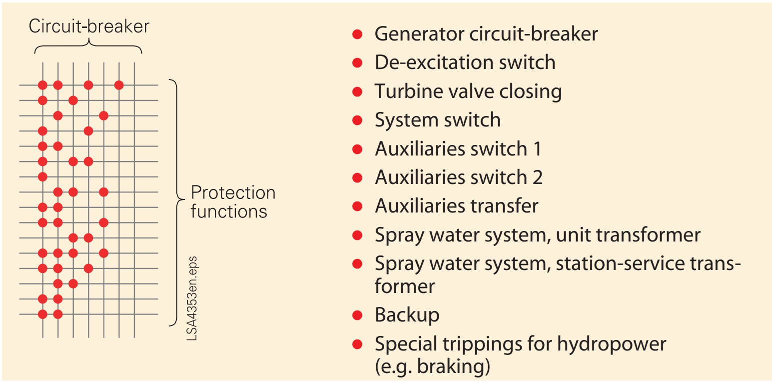

Fig. 6 Protection tripping by the matrix

The function matrix is scalable to meet different requirements (see Table 1).

The selection simplifies division into object and application-related groups.

Protection functions	Generator rated power		
	5 - 50 MVA	50 - 200 MVA	> 200 MVA
Stator earth-fault protection 90 %	■	■	■
Stator earth-fault protection 100 %		■	■
Differential protection	■	■	■
Overcurrent-time protection	■	○	○
Impedance protection		■	■
Rotor earth-fault protection	■	■	■
Negative-sequence (or load unbalance) protection	■	■	■
Underexcitation protection	■	■	■
Out-of-step protection		○	■
Stator overload protection	■	■	■
Rotor overload protection			■
Overvoltage protection	■	■	■
Frequency protection *f* >	■	■	■
Frequency protection *f* <	■	■	■
Reverse-power protection	■	■	■
Undervoltage protection	⊙	⊙	⊙
Overexcitation protection	○	■	■

■ Available
○ Optional
⊙ Pumped-storage station (motor protection and phase modifier operation)

Table 1 Recommended protection functions according to generator rated power

A function selection taking redundancy into consideration is shown in Table 2.

Protection group A (System 1, 7UM622)	Protection group B (System 2, 7UM622)
Stator earth-fault 100 %	Stator earth-fault 90 %
Differential protection	Differential protection (as unit protection)
Impedance	Impedance
Rotor earth-fault	Negative-sequence
Negative-sequence	Underexcitation
Underexcitation	Out-of-step
Overvoltage	Stator overload
Frequency *f* ><	Overvoltage
Reverse power	Frequency *f* ><
Overexcitation	Reverse power
	Overexcitation

Table 2 Function selection for a redundancy concept

4. Protection functions and setting

The basic connection (Fig. 2) is considered for the setting value calculation – with generator data from the Table 3. Manufacturer characteristics (e.g. power diagram) are necessary for some protection settings. The physical backgrounds and the formulae for calculation are in the manual. The secondary setting values are shown.

Generator data	
Rated voltage U_N	15.75 kV ± 5 %
Rated apparent power (40 °C cold gas) S_N	327 MVA
Circuit-breaker cos φ	0.8
Rated active power P_N	261.6 MW
Rated current I_N	12 kA
Rated frequency f_N	50 Hz
Maximum overexcitation (U/f)max %	from the manufacturer's overexcitation characteristic
Permissible overexcitation duration t (U/f)max	from the manufacturer's overexcitation characteristic
Synchronous longitudinal reactance x_d (for drum rotor generators: $x_d = x_q$)	264.6 %
Transient reactance x_{d1}	29.2 %
Maximum exciter voltage $U_{exc\text{-}min}$	77 V
Maximum continuous permissible inverse current $I_{max\,prim} / I_N$	10 %
Thermal continuous permissible primary current I_{max} / I_N	1.2
Asymmetry factor (I_2) $K = (I_2/I_N)^2\,t$	20 s

Current transformer	I_{prim}	I_{sec}	ü	Target
Star-point side				
T1, core 1	14 kA	1 A	14 000	System 1
T1, core 3	14 kA	1 A	14 000	System 2
Busbar side				
T2, core 1	14 kA	1 A	14 000	System 1
T2, core 3	14 kA	1 A	14 000	System 2
110 kV side				
T3, core 1	2 000 A	1 A	2 000	System 2

Earthing transformer	U_{prim}	U_{sec}	ü	Target
T4; U_0	15.75 kV/$\sqrt{3}$	5 V/$\sqrt{3}$	54.56	System 1

External voltage transformer	U_{prim}	U_{sec}	ü	Target
Generator side T5, U_{L1}, U_{L2}, U_{L3}	15.75 kV/$\sqrt{3}$	100 V/$\sqrt{3}$	157.5	System 1, 2

Unit transformer data Vector group	Ynd5	
Total coupling capacity HV-LV C_k	14.4 nF (4.8 per phase)	
Maximum overexcitation (U/f)max	120 %	
Permissible overexcitation time t (U/f)max	from the manufacturer's overexcitation characteristic	
Permissible overload I_{max} / I_N	from the manufacturer's overexcitation characteristic	
Winding	Primary	Secondary
Rated voltage U_N	115 kV	15.75 kV
Rated apparent power S_N	318 MVA	318 MVA
Rated current I_N	1.596 kA	11.657 kA
Short-circuit voltage u_{SC}	15 %	
Control range of the tap changer	± 9 x 1.25 %	

Table 3 Data of the power station unit with gas turbine

4.1 Current differential protection (ANSI 87G, 87M, 87T)

The function is the instantaneous short-circuit protection in generators, motors and transformers and is based on the current differential protection principle (node set). The difference and restraint (stabilization) current is calculated from the phase currents. Optimized digital filters safely attenuate disturbance variables such as aperiodic DC elements and harmonics. The high resolution of the measuring variables enables small difference currents (10 % of I_N) to be picked up, i.e. a very high sensitivity. A settable restraint characteristic allows optimum adaptation to the conditions of the protected object.

Setting instructions

An important setting is the position of the star points of the current transformer sets on both sides of the protected object. In addition, the rated data ($S_{N\ GEN/MOTOR}$, $U_{N\ GEN/MOTOR}$) of the generator to be protected and the primary and secondary rated currents of the main current transformers are requested on both sides. The setting values refer to these. In addition, they are used for example to determine the primary measured values.

As an additional security measure against unwanted operation when connecting a previously non-energized protected object, the increased pickup value can be switched on when starting up.

The table below shows the setting options of selected parameters. The settings are relevant for the generator and not for the unit (protection group A).

Parameter	Setting options	Default *)
Pickup value of the trip stage I_{diff}>	0.05 to 2.0 $I/I_{NObject}$	0.2 $I/I_{NObject}$
Delay of the trip stage I_{diff}>	0 to 60.0 s; ∞	0.00 s
Pickup value of the trip stage I_{diff}>>	0.05 to 12.0 $I/I_{NObject}$	7 $I/I_{NObject}$
Delay of the trip stage I_{diff}>>	0 to 60.0 s; ∞	0.00 s
Slope 1 of the trip characteristic	0.1 to 0.5	0.15
Foot of slope 1 of the trip characteristic	0 to 2.0 $I/I_{NObject}$	0 $I/I_{NObject}$
Slope 2 of the trip characteristic	0.25 to 0.95	0.5
Foot for slope 2 of the trip characteristic	0 to 10.0 $I/I_{NObject}$	2.50 $I/I_{NObject}$

Table 4 Parameter overview for the differential protection

*) In this example, most of the default settings can be used.

4.2 Stator overload protection (ANSI 49)

The overload protection should protect the stator winding of generators and motors against excessively high continuous current overloads. All load cycles are evaluated by a mathematical model. The basis for the calculation is the thermal effect of the current r.m.s. value. The transformation corresponds to IEC 60255-8.

Setting instructions

The cooling time constant is prolonged automatically, dependent on the current. If the ambient temperature or coolant temperature is fed in through a transducer (MU2) or via the PROFIBUS-DP, the model automatically adapts to the ambient conditions; otherwise a constant ambient temperature is assumed.

The following table shows the setting options and the setting example of important parameters (without taking the ambient or coolant temperature into account).

Parameter	Setting options	Setting
k-factor	0.1 to 4.0	1.11
Thermal warning level	70 to 100 %	95 %
Current warning level	0.1 to 4.0 A	1.0 A
k_t-time factor at standstill	1.0 to 10.0	1.0
Limit current for the thermal replica	0.5 to 8.0 A	3.30 A
Dropout time after emergency start	10 to 15000 s	100 s

Table 5 Parameter overview for the stator overload protection

The setting ranges and presettings (defaults) are specified for a secondary rated current of $I_N = 1$ A. At a secondary rated current of $I_N = 5$ A, these values must be multiplied by 5. The ratio of the current transformer must be taken into account additionally for settings of primary values.

4.3 Negative-sequence protection (ANSI 46)

Asymmetrical current loads of the three phases of a generator lead to heating up in the rotor due to the reverse field. The protection detects an unbalanced load of three-phase generators. It operates on the basis of symmetrical components and evaluates the negative-sequence component of the phase currents. The thermal processes are taken into account in the algorithm and lead to an inverse-time characteristic. In addition, the negative-sequence is evaluated by a definite-time warning and tripping stage which is supplemented by delay elements.

Setting instructions
Thermal characteristic

The generator manufacturers specify the permissible negative-sequence with the following formula:

$$t_{\text{perm}} = \frac{K}{\left(\frac{I_2}{I_N}\right)^2}$$

t_{perm} = Maximum permissible application time of the negative-sequence current I_2

K = Asymmetry factor (generator constant)

I_2/I_N = Negative-sequence (ratio of negative-sequence current I_2 to rated current I_N)

The asymmetry factor is generator-dependent and represents the time in seconds for which the generator may be loaded at the maximum with 100 % unbalanced load. The factor is mainly in the range between 5 s and 30 s. On exceeding the permissible load unbalance (value of the continuously permissible negative-sequence current), simulation of the heating of the object to be protected in the relay begins. The current-time-area is calculated continuously taking different load cases correctly into consideration. If the current-time-area $((I_2/I_N)^2 \cdot t)$ reaches the asymmetry factor K, tripping takes place with the thermal characteristic.

Table 6 shows the setting options and the setting example.

Parameter	Setting options	Setting
Continuously permissible load unbalance	3.0 to 30.0 %	8.6 %
Delay time of warning stage	0 to 60.0 s; ∞	10.0 s
Asymmetry factor K	2.0 to 100.0 s; ∞	11 s
Cooling time of thermal model	0 to 50000 s	1500 s
Excitation current I_2>>	10 to 100 %	51.4 %
Delay time T I_2>>	0 to 60.0 s; ∞	3.0 s

Table 6 Parameter overview for negative-sequence protection

4.4 Underexcitation protection (ANSI 40)

The protection prevents damage due to out-of-steps resulting from underexcitation. The complex master value is calculated from the generator terminal voltage and current. The protection function offers three characteristics for monitoring the static and dynamic stability. The exciter voltage can be fed in through a transducer and a fast response of the protection can be achieved by timer switching in the event of a failure. The straight line characteristics allow optimum adaptation of the protection to the generator diagram. The setting values can be read out directly from the per-unit representation of the diagram. The positive-sequence components of the currents and voltages are used for calculating the variables, whereby correct operation is ensured even under asymmetrical conditions.

Setting instructions

The tripping characteristics of the underexcitation protection are made up of straight lines in the master value diagram, defined by their reactive part of the admittance $1/x_d$ and their angle of inclination α.
Table 7 shows the settings for this application example.

Parameter	Setting options	Default *)
Pickup threshold $1/x_d$ characteristic 1	0.25 to 3.0	0.37
Characteristic slope characteristic 1	50 to 120 °	80 °
Delay time characteristic 1	0 to 60.0 s; ∞	10.0 s
Pickup threshold $1/x_d$ characteristic 2	0.25 to 3.0	0.33
Characteristic slope characteristic 2	50 to 120 °	90 °
Delay time characteristic 2	0 to 60.0 s; ∞	10.0 s
Pickup threshold $1/x_d$ characteristic 3	0.25 to 3.0	1.0
Characteristic slope characteristic 3	50 to 120 °	100 °
Delay time characteristic 3	0 to 60.0 s; ∞	1.5 s

Table 7 Parameter overview for underexcitation protection

*) In this example, most of the default settings can be used.

4.5 Reverse-power protection (ANSI 32R)

The reverse-power protection monitors the active power direction and picks up in the event of a mechanical energy failure, because the drive energy is then taken out of the system. This function can be used for operational shutdown of the generator but also prevents damage to steam turbines. The position of the emergency tripping valve is entered as binary information. This switches between two delays of the open command. The reverse power is calculated from the positive phase sequence systems of current and voltage. Asymmetrical system conditions therefore do not impair the measuring accuracy.

If reverse power occurs, the turbo set must be disconnected from the system, because operation of the turbines is not permissible without a certain minimum steam throughput (cooling effect), or the motorized load is too great for the system in a gas turbo set.

The trip command is delayed by an adjustable time to bridge any brief power consumption during synchronization or in the event of power swings due to system faults. In the event of a closed emergency tripping valve on the other hand, the unit must be shut down with a short delay. By entering the position of the emergency tripping valve through a binary input, the short delay becomes effective in the event of emergency tripping. It is also possible to block the tripping by means of an external signal.

The value of the consumed active power is determined by the friction losses to be overcome and, depending on the system, is approximately:

- Steam turbines: P_{rev}/S_N 1 % to 3 %
- Gas turbines: P_{rev}/S_N 3 % to 5 %
- Diesel drives: P_{rev}/S_N > 5 %

However, it is advisable to measure the reverse power with the protection itself in the primary test. About 0.5 times of the measured motoring energy, which can be read out under the "percentage operational measured values", is chosen as a setting value.

Table 8 shows the setting of selected parameters.

Parameter	Setting options	Setting
Delay time with emergency tripping	0 to 60.0 s; ∞	∞ s
Delay time without emergency tripping	0 to 60.0 s; ∞	6.00 s
Pickup threshold reverse power	30.0 to 0.50 %	-3.42 %
Pickup seal-in time	0 to 60.0 s; ∞	1.00 s

Table 8 Parameter overview of reverse-power protection

4.6 Impedance protection (ANSI 21)

This fast acting short-circuit protection protects the generator or unit transformer on the one hand and is the backup protection for the system. It has two adjustable impedance stages whereby the first stage is additionally switchable by a binary input. The impedance measuring range can be extended with open system switch. The overcurrent pickup with undervoltage seal-in provides reliable pickup and loop selection logic for determining the faulty loop. It also allows correct measurement through the transformer.

Setting instructions

The maximum load current occurring during operation is decisive for setting the overcurrent pickup. Pickup by overload must be ruled out. The pickup value must therefore be set above the maximum expected (over) load current. Recommended setting: 1.2 to 1.5 times rated generator current.

The pickup logic corresponds to that of the definite-time overcurrent protection $I>$. If the excitation is derived from the generator terminals and the short-circuit current is able to drop below the pickup value due to collapsing voltage, the undervoltage seal-in is activated.
The undervoltage seal-in $U<$ is set to a value just below the lowest phase-to-phase voltage occurring during operation, e.g. to $U<$ = 75 % to 80 % of the rated voltage. The seal-in time must be greater than the maximum fault clearance time in the backup case. (Recommended: This time + 1 s).

As described in the manual, the protection has three characteristics which can be set independently:

- Zone (instantaneous zone Z1) with the setting parameters
  ZONE Z1 reactance = reach,
  ZONE1 T1 = 0 or short delay if necessary.
- Overreach zone Z1B, controlled externally by a binary input with the setting parameters
  OVERR. Z1B reactance = reach,
  OVERR. T1B T1B = 0 or short delay if necessary.
- 2nd zone (Zone Z2) with the setting parameters
  ZONE Z2 reactance = reach,
  ZONE2 T2 T2 should be chosen so high that it is above the grading time of the system protection.
- Undirected final stage with the setting parameters T END T END must be chosen such that the second or third stage of the series-connected power system distance protection is overreached.

Since it can be assumed that the impedance protection measures into the generator transformer, it must be ensured that the parameterization selec- tion sufficiently considers the control range of the transformer. For ZONE Z1, a reach of about 70 % of the zone to be protected is therefore normally chosen (i.e. about 70 % of the transformer reactance) without or with only slight delay (i.e. = 0 s to 0.50 s).

For ZONE Z2, the reach could be set to about 100 % of the transformer reactance or a system impedance additionally. The corresponding time stage ZONE2 T2 must be chosen so that it overgrades the system protection relays of the following lines.

The following settings apply for the configuration example (without activation of the out-of-step block):

Parameter	Setting options	Setting
Pickup value of the overcurrent pickup	0.10 to 20.0 A	1.20 A
Pickup voltage of the undervoltage seal-in	10.0 to 125.0 V	75.0 V
Seal-in time of the undervoltage seal-in	0.1 to 60.0 s	10.0 s
Trip time of the end time stage	0.1 to 60.0 s	3.0 s
Impedance zone Z1	0.05 to 130.0 Ω	7.28 Ω
Trip time zone Z1	0 to 60.0 s; ∞	0.30 s
Impedance overreach stage Z1B	0.05 to 65.0 Ω	11.44 Ω
Trip time overreach stage Z1B	0 to 60.0 s; ∞	8.00 s
Impedance zone Z2	0.05 to 65.0 Ω	11.44 Ω
Trip time Z2	0 to 60.0 s; ∞	8.00 s

Table 9 Parameter overview for the impedance protection

4.7 Overvoltage protection (ANSI 59)

This protection prevents insulation faults as a result of high voltage. Optionally the maximum phase-to-phase voltages or phase-to-earth voltages (in low-voltage generators) can be evaluated. In the phase-to-phase voltages, the measuring result is independent of the zero point displacements resulting from earth-faults. The protection function is designed in two stages.

The setting of the limit values and delay times of the overvoltage protection depends on the speed at which the voltage regulator can regulate voltage fluctuations. The protection may not intervene in the regulating process of the voltage regulator when it is operating trouble-free. The two-stage characteristic must therefore always be above the voltage time characteristic of the regulating process.

Setting instructions

The long-time stage $U>$ and T $U>$ should intervene in the case of steady-state overvoltages. It is set to about 110 to 115 % U_N and to 1.5 to 5 s, depending on the regulator speed. In the event of a full load disconnection of the generator, the voltage first rises according to the transient voltage and is reduced to its rated value by the voltage regulator afterwards. The $U>>$ stage is generally set as a short-time stage so that the transient process in full load shutdown does not lead to tripping. About 130 % U_N – with a delay T $U>>$ ranging from zero to 0.5 s – are usual (for example) for $U>>$.

Parameter	Setting options	Default *)
Pickup voltage *U*>	30 to 170 V	115 V
Delay time *T U*>	0 to 60 s; ∞	3 s
Pickup voltage *U*>>	30 to 170 V	130 V
Delay time *T U*>>	0 to 60 s; ∞	0.50 s
Dropout ratio RV *U*>	0.90 to 0.99	0.95

Table 10 Parameter overview for the overvoltage protection

4.8 Frequency protection (ANSI 81)

Frequency protection prevents impermissible loading of the equipment (e.g. turbine) at under and overfrequency, and also serves often as a monitoring and control element. The function is designed in four stages, whereby the stages can operate either as under or overfrequency protection. Each stage can be delayed individually. The complex frequency measuring algorithm also filters out the fundamental harmonic reliably in the event of distorted voltages and determines frequency very accurately. The frequency measurement can be blocked by an undervoltage stage.

Setting instructions

If the frequency protection is used for the task of system decoupling and load shedding, the setting values depend on the concrete system conditions. Usually a grading according to the importance of the consumers or consumer groups is aimed at for load shedding. Other applications are to be found in the power station sector. Basically the frequency values to be set depend on the presettings of the system or power station operator.

The following table shows the settings which meet practical requirements.

Parameter	Setting options	Setting
Pickup frequency *f*1	40 to 65 Hz	47.5 Hz
Delay time *T f*1	0 to 600 s	40 s
Pickup frequency *f*2	40 to 65 Hz	47 Hz
Delay time *T f*2	0 to 100 s	20 s
Pickup frequency *f*3	40 to 65 Hz	51.50 Hz
Delay time *T f*3	0 to 100 s	40 s
Pickup frequency *f*4	40 to 65 Hz	52 Hz
Delay time *T f*4	0 to 100 s	20 s
Minimum voltage	10 to 125 V; 0	65 V

Table 11 Parameter overview for frequency protection

4.9 Overexcitation protection (ANSI 24)

Overexcitation protection serves to detect an impermissibly high induction (proportional to *U*/*f*) in generators or transformers which leads to thermal overloading. This danger can occur in start-up processes, in full load disconnections, in "weak" systems and in separate island operation. The inverse-time characteristic is set with the manufacturer data by way of 8 points. A definite-time alarm stage and a short-time stage can be used additionally. Apart from the frequency, the maximum of the three phase-to-phase voltages is used for calculating the quotient *U*/*f*. The monitorable frequency range is between 11 and 69 Hz.

Setting instructions

The overexcitation protection contains two-staged characteristics and one thermal characteristic for approximate simulation of the heating of the protected object due to overexcitation. On exceeding of an initial pickup threshold (alarm stage *U*/*f*), a time stage T *U*/*f* > is started, at the end of which an alarm message is output.

The limit value of induction in relation to the rated induction (B/B_N) specified by the protected object manufacturer forms the basis for setting the limit value *U*/*f* >.

The characteristic for a Siemens standard transformer has been chosen as default. If the protected object manufacturer supplies no data, the default standard characteristic is retained. Otherwise, any tripping characteristic can be specified by point-by-point input of parameters by a maximum of 7 straight sections.

*) In this example, most of the default settings can be used.

4.10 90 % stator earth-fault protection directional, non-directional (ANSI 59N, 64G, 67G)

In generators operated with an isolated star point, an earth fault is indicated by occurrence of a displacement voltage. In unit connection, the displacement voltage is a sufficient, selective protection criterion. If a generator is connected electrically to a busbar, the direction of the flowing earth-current must be evaluated additionally for selective earth-fault detection. The protection measures the displacement voltage on a voltage transformer in the generator star point, or at the open delta winding of a voltage transformer. Optionally the zero-sequence voltage can also be calculated from the phase-to-earth voltages. Depending on the system design, 90 to 95 % of the stator winding of a generator can be protected.

When starting, it is possible to switch over to zero-sequence voltage measurement via an externally coupled signal. Various earth-fault protection concepts can be implemented with the function, according to the protection setting.

Setting instructions
For generators in unit connection, the pickup value must be chosen so high that displacement voltages, which affect the stator circuit through the coupling capacitances of the unit transformer, do not lead to pickup. The damping by the load resistance must also be taken into account here. The setting value is twice the displacement voltage value coupled in at full system displacement. Final specification of the setting comes during commissioning with primary variables according to the manual. Tripping in the event of stator earth-fault is set time-delayed (*T* SES). The overload capacity of the load equipment must also be taken into account when setting the delay. All set times are additional delays which do not include the operating times (measuring time, dropout time) of the protection function.

Table 12 shows the setting options for selected parameters. The settings are selected for this protection configuration.

Parameter	Setting options	Setting
Pickup voltage U_0>	2 to 125 V	10 V
Pickup current $3I_0$>	2 to 1000 mA	5 mA
Slope angle of the directional lines	0 to 360 °	15 °
Delay time *T* SES	0 to 60 s; ∞	0.30 s

Table 12 Parameter overview for the stator earth-fault protection

4.11 Rotor earth-fault protection (ANSI 64R)

This protection function can be effected with the 7UM62 in three ways. The simplest form is the method of rotor earth-current measurement (see the manual: Chapter on sensitive earth-fault protection, resistance measurement at system frequency voltage).

The second form is rotor earth-resistance measurement with system frequency voltage coupling into the rotor circuit (see the manual: Chapter on rotor earth-fault protection). The coupled voltage and the flowing rotor earth-current are detected by the protection. Taking account of the complex resistance of the coupling device (7XR61), the rotor earth resistance is calculated by a mathematical model. This form is often used for medium-sized generators.

The third form is resistance measurement with square-wave voltage injection of 1 to 3 Hz. In larger generators a higher sensitivity is required. On the one hand, disturbances caused by the rotor earth capacitance must be eliminated better, and on the other hand the interference margin to the harmonic (e.g. 6^{th} harmonic) of the exciter device must be increased. The injection of a low-frequency square-wave voltage into the rotor circuit has proven effective here (recommended for this application). The square-wave voltage injected by the controller unit 7XT1 leads to polarity reversal of the rotor earth capacitance. Through a shunt in the 7XT1, the flowing earth-current is detected and injected into the protection (measuring input). In a fault-free case ($R_E \sim \infty$), the rotor earth-current after charging of the earth capacitance is nearly zero. In the event of a fault, the earth resistance – including coupling resistance (7XR6004) and the incoming supply voltage – determines the steady-state current. Via the second input (control input), the transfers, the current square-wave voltage and the polarity reversal frequency are recorded. Fault resistances up to 80 kΩ can be detected with this measuring principle.

Monitoring of the rotor earth circuit for interruption takes place by evaluating the current during polarity reversals.

Setting instructions (1 to 3 Hz protection)
Since the protection calculates the resistive rotor earth resistance directly from the values of applied voltage, series resistance and flowing earth-current, the limit values for the alarm stage (R_E WARN) and the trip stage (R_E TRIP) can be set immediately as resistance values. In most cases the preset values (R_E WARN = 40 kΩ and R_E TRIP = 5 kΩ) are sufficient. Depending on the insulation resistance and coolant, these values can be changed. It is important to pay attention to an adequate margin between the setting value and the actual insulation resistance. As a result of possible disturbances due to the exciter device, the setting for the alarm stage is finally determined during the primary tests.
The delay is usually set for the alarm stage (T R_E WARN) to about 10 s, and for the trip stage (T R_E TRIP) to a short time of about 1 s.
The set times are additional time delays which do not include the operating times (measuring time, dropout time) of the protection function.

Parameter	Setting options	Default *)
Pickup value of the alarm stage	5 to 80 kΩ	40 kΩ
Pickup value of the trip stage	1 to 10 kΩ	5 kΩ
Delay time of the alarm stage	0 to 60 s; ∞	10 s
Delay time of the trip stage	0 to 60 s; ∞	1 s

Table 13 Parameter overview for the rotor earth-fault protection

4.12 100 % stator earth-fault protection with 20 Hz injection (ANSI 64 G (100 %))

The injection of a 20 Hz voltage for detection of faults in the star point or close to the star point of generators has proven a safe and reliable method. Unlike the 3rd harmonic criterion (see page 12, Catalog SIP 6.1), it is independent of the generator properties and the operating method. Measurement at system standstill is still possible. This protection function is designed so that it detects earth-faults both in the whole generator (real 100 %) and in all galvanically connected system components. The protection relay detects the injected 20 Hz voltage and the flowing 20 Hz current. Disturbance variables such as stator earth capacitances are eliminated, and the ohmic fault resistance is determined by a mathematical model. As a result, high sensitivity is ensured and the use in generators with high earth capacitances – e.g. large hydroelectric generators – is enabled. Angle faults due to the earthing or star-point transformer are detected during commissioning and corrected in the algorithm. The protection function has a warning and trip stage. In addition, the measuring circuit is monitored and a failure of the

20 Hz generator detected. Regardless of the earth resistance calculation, the protection function additionally evaluates the r.m.s. value of the current. Another stage is available for earth-faults in which the displacement voltage and thus the fault current exceed a certain value.

Taking the following parameters into consideration, the following settings for the application example apply.

- Load resistance on the earthing transformer R_L = 4.63 Ω
- Transformation ratio, voltage divider $ü_{Kl}$ = 200 / 5
- Transformation ratio, voltage divider $ü_{divider}$ = 2 / 5
- Transformation ratio, earthing transformer $ü_{transf} = 15.75: \sqrt{3} / 0.5$ kV

Parameter	Setting options	Setting
Pickup value of the alarm stage SES 100 %	20 to 700 Ω	193 Ω
Pickup value of the trip stage SES 100 %	20 to 700 Ω	48 Ω
Delay time of the alarm stage SES 100 %	0 to 60 s; ∞	10 s
Delay time of the trip stage SES 100 %	0 to 60 s; ∞	1 s
Pickup value 100 % *I*>>	0.02 to 1.5 A	0.27 A
Monitoring threshold for 20 Hz voltage	0.3 to 15 V	1 V
Monitoring threshold for 20 Hz current	5 to 40 mA	10 mA
Angle correction for *I* SES	60 °	0 °
Transition resistance *R*ps	0 to 700 Ω	0 Ω
Parallel load resistance	20 to 700 Ω; ∞	∞ Ω

Table 14 Parameter overview for the 100 % stator earth-fault protection

*) In this example, most of the default settings can be used.

4.13 Out-of-step protection (ANSI 78)

This protection function serves to detect power swings in the system. If generators feed too long onto a system short-circuit, a compensation process (active power swings) may take place between the system and the generator after fault disconnection. If the center of power swings is in the area of the unit, the "active power surges" lead to impermissible mechanical stressing of the generator and the whole generator mounting – including the turbine. Since these are symmetrical processes, the positive-sequence impedance is calculated from the voltage and current positive-sequence components and the impedance curve is evaluated. In addition, the symmetry is monitored by evaluating the negative-phase sequence system current. Two characteristics in the R/X diagram describe the range of effect (generator, unit transformer or system) of the out-of-step protection. The appropriate counters are incremented, depending on in which characteristic range the impedance vector enters and exits. If the set counter reading is reached, tripping takes place. If no more power swings occur after a set time, the counters are automatically reset. Every power swing can be signalled by a settable pulse. The extending of the characteristic in R direction determines the detectable power swing angle. 120 ° are practicable. The characteristic can be tilted at an adjustable angle to adapt to the conditions when the system is feeding off several parallel generators.

Setting instructions

A minimum value of the positive-sequence components of the currents $I_1>$ must be exceeded (overcurrent pickup) to enable the measurement. In addition, a maximum value of the negative-sequence components of the currents $I_2<$ may not be exceeded, due to the symmetry condition. As a rule, the setting value $I_1>$ is chosen above rated current – i.e. about 120 % I_N – to avoid pickup by overload. The pickup threshold of the negative-sequence component of the current $I_2<$ is set to about 20 % I_N.

The impedances of the protected zone seen from the protection relay are decisive for determining the setting values. In the direction of the generator (seen from the installation position of the voltage transformer set), the power swing reactance of the generator must be taken into account; it can be set approximately equal to the transient reactance $x_{d'}$. This means the transient reactance related to the secondary side is calculated and set for Zb $x_{d'}$ (see Fig. 7).

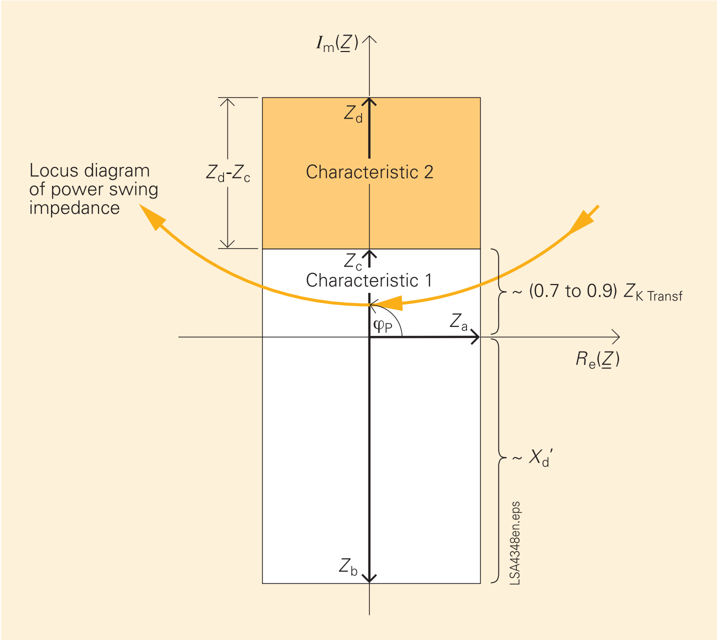

Fig. 7 Power swing polygon

The meaning, calculation and setting of the parameters for the trip characteristics are described in detail in the manual.

The following table shows the setting options and the calculated settings.

Parameter	Setting options	Setting
Pickup value of the measurement release $I_1>$	20 to 400 %	120 %
Pickup value of the measurement release $I_2>$	5 to 100 %	20 %
Resistance Z_a of the polygon (width)	0.2 to 130 Ω	8.25 Ω
Reactance Z_b of the polygon (reverse)	0.1 to 130 Ω	19.60 Ω
Reactance Z_c of the polygon (forward char. 1)	0.1 to 130 Ω	8.90 Ω
Reactance difference char. 2 – char. 1	0 to 130 Ω	1.10 Ω
Inclination angle of the polygon	60 to 90 °	90 °
Number of oscillations by characteristic 1	1 to 4	1
Number of oscillations by characteristic 2	1 to 8	4
Seal-in time of characteristic 1 and characteristic 2	0.2 to 60 s	20 s
Seal-in time of the message out-of-step, char. 1 and out-of-step char. 2	0.02 to 0.15 s	0.05 s

Table 15 Parameter overview for out-of-step protection

The setting ranges and presettings are specified for a secondary rated current of $I_N = 1$ A.

5. Connection diagram

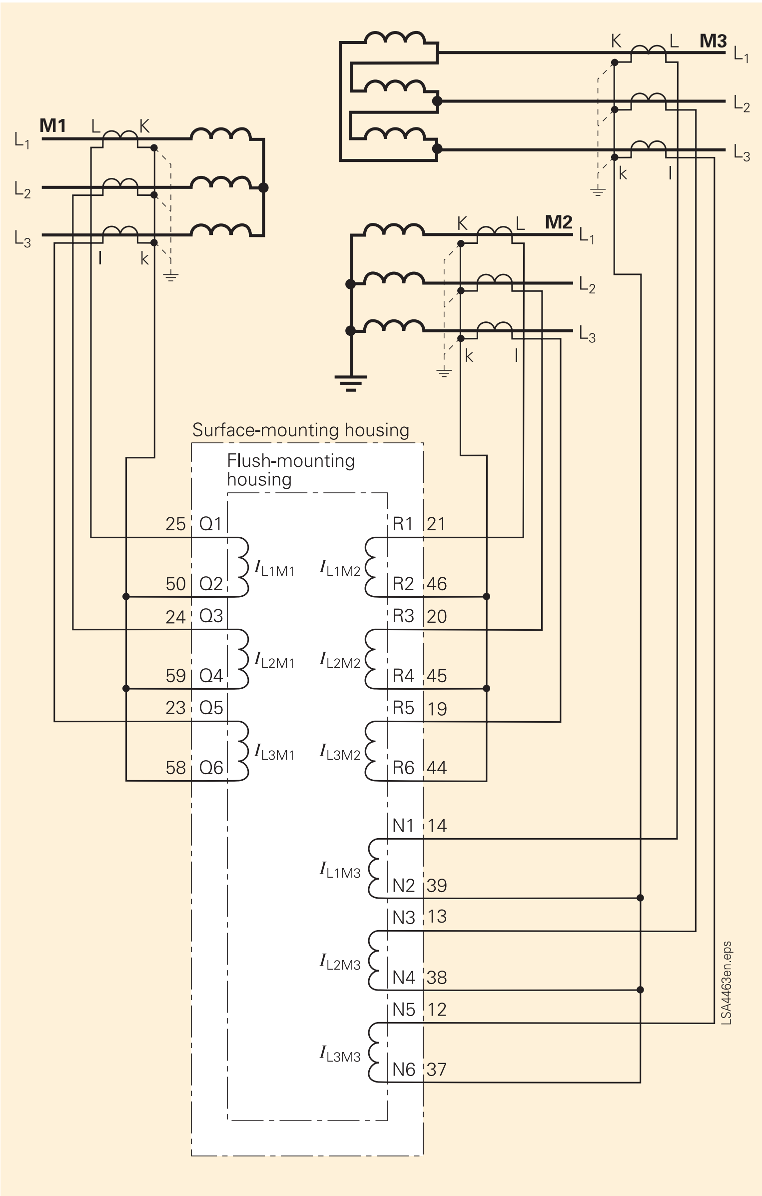

Fig. 8 Connection diagram of 7UM6

6. Communication

The 7UM6 relays fully meet the requirements of modern communication technology. They have interfaces which allow integration in master control stations, convenient parameterization and operation by PC (locally or via a modem). The 7UM6 supports the widely used international open communication standards

- PROFIBUS-DP, RS485 or optical 820 nm double-ring ST connector
- IEC 60870-5-103,
- DNP3.0, RS485 or optical 820 nm double-ring ST connector and
- MODBUS, RS485 or optical 820 nm double-ring ST connector

Note

All SIPROTEC 4 relays also operate with star coupler. This enables the user to access all information from the office or en route (for simple applications). With the PROFIBUS-DP protocol, SIPROTEC relays can easily be integrated in PLC-based process control systems (e.g. SIMATIC S5/S7). The protocols DNP3.0 and MODBUS ASCII/RTU allow integration in numerous instrumentation and control systems of other manufacturers.

7. Summary

Beginning with the recommendations for protection functions [1], it has been described that efficient concepts can be created with modern SIPROTEC relays in medium-sized generators, despite the need to consider cost factors. The multifunctional, numerical SIPROTEC relays enable a greater functional scope than the previous single relays. Self-monitoring substantially improves the availability of the protection relays.

For further information about the function range and setting, the 7UM62 manual is recommended, chapter 2 of which has been compiled as an application manual.

8. References

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Manual
7UM62 Multifunction Generator, Motor and Transformer Protection Relay

Unit Protection System for Pumped-Storage Power Stations

■ 1. Introduction

In many power systems, pumped-storage power stations are used in addition to run-of-river power stations. These power stations serve primarily to cover load peaks in the power system. In such peak load periods the machines operate as generators and feed active power into the grid. In slack periods, e.g. during the night, the machines operate as motors and pump water into the upper reservoir which is then available later as an energy source for peak load supply. In this way, large-scale thermal power units can be continuously run to cover basic load.

Fig. 2 shows a typical redundant protection system design for pumped-storage units with an active power output greater than 100 MW.

Fig. 1 SIPROTEC 7UM62

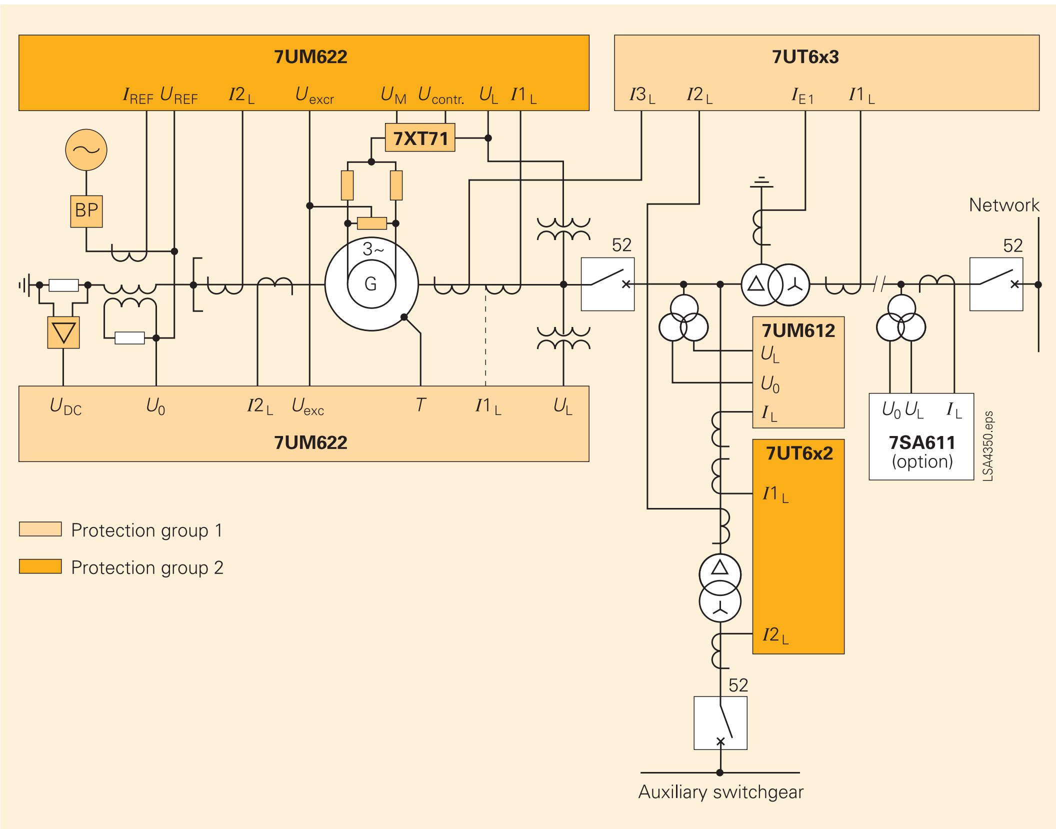

Fig. 2 Redundant protection system for pumped-storage power stations

If the protection requirements of a pumped-storage power station are compared with those of a unit for pure energy generation, certain particular features emerge as well as many parallels. Designing a protection system for medium and large-scale power stations is described in another publication. This guide explains the special protection functions and the working of a pumped-storage unit.

Table 1 below describes a typical basic concept for a pumped-storage unit.

Protection functions	ANSI code	Protection Group A	Protection Group B
Stator earth-fault protection 90 %	64		
Stator earth-fault protection 100 %	64 (100 %)	■	■
Differential protection	87	■	
Winding fault		■	
Overcurrent-time protection	51		■
Impedance protection	21		■
Rotor earth-fault protection	64R	■	■
Load unbalance protection	46	■	■
Underexcitation protection	40	■	
Out-of-step protection	78		■
Stator overload protection	49	■	■
Rotor overload protection	49E	■	
Overvoltage protection	59	■	■
Frequency protection $f>$	81 ($f>$)	■	■
Frequency protection $f<$	81 ($f<$)	■	■
Reverse power protection	32	■	
Underpower protection	37	■	
Undervoltage protection	27	■	
Overexcitation protection	24	■	

Table 1 Protection concept for pumped-storage power plants

The protection system described can be supplemented by extra protection functions, depending on technical requirements or country-specific customary protection concepts. Likewise, the level of function redundancy can be expanded or reduced.

The advantage of the 7UM6 multifunctional protection relays lies in the ease of configuration.

With the aid of the DIGSI®configuration pro - gram, each of the protection functions contained in the relay can be switched active or inactive.

2. Selected protection functions

2.1 Stator earth-fault protection

The same principle applies for generators in pumped-storage power stations as for other power station types: the most frequent electrical fault is an earth fault. Simple stator earth-faults cause no damage to the generator provided the earthing transformer and loading resistor have been correctly designed. A second earth fault would, however, result in such high fault currents that the generator would be severely damaged. For this reason a simple stator earth-fault must be detected at an early stage and at least signalled. In large generators simple earth faults nearly always result in disconnection unless restrictions in the power system operation and control exclude this.

The 100 % stator earth-fault with 20 Hz infeed (Fig. 3) complies with the requirements for reliable detection of a stator earth-fault throughout the stator winding up to the star point. With infeed of a generator-independent auxiliary voltage, this protection principle allows so-called standstill testing. External supply to the 20 Hz generator enables the machine to be tested for possible stator earth-faults before startup. In normal operation the sensitive signal level indicates the start of an earth fault early on. The protection relay calculates the resistive component from the measured earth current. The result is therefore independent of the capacitance of the stator to earth. This advantage is especially effective in large hydroelectric generators which have a high capacitance to earth. The insulation value of the earthed stator winding can be shown on the protection relay display, providing the operator with valuable information about whether the machine can continue to run until the next planned inspection shutdown.

2.2 Negative-sequence protection (ANSI 46)

Various settings are required for phase-sequence-dependent protection functions if the machine is switched between generator operation and pump operation. An example of such a function is negative-sequence (or unbalanced load) protection, whose pickup criterion is based on measuring or calculating the reverse field. One possible solution is installing two identical protection relays with respective setting values for generator operation and pump operation. One of the two protection relay is always blocked to prevent spurious operation.

A more elegant and cost-effevtive solution would be to switch over the parameter sets in the protection relay when changing between the two operating modes. The 7UM6 numerical generator protection relay allows the read-in of two independent parameter sets. When changing between the machine's two operating modes, a control signal to the protection relay digital input activates the other parameter set for protection processing. For negative-sequence protection, this means that, from the calculated symmetrical components of the measured current, the positive phase-sequence system and the negative phase-sequence system are exchanged for further protection processing.

2.3 Underexcitation protection (ANSI 40)

Large pumped-storage units are often used for reactive power compensation, in addition to balancing peak loads in the power system. Consequently, the generator can be run close to its stability limit, depending on reactive-power demand over a long period. Slight increases in reactive-power demand can make the generator fall out of step. Consequently, particular emphasis is laid on underexcitation protection in large pumped-storage power stations.

Primarily, the excitation system itself detects an overshoot of the stability characteristics of the generator and compensates this by readjusting the excitation voltage. Electrical underexcitation protection comes into action if this automatic readjustment is unsuccessful. The generator moves into the capacitive working range and finally falls out of step. This impermissible operating state can damage the generator and create instability in the power system linked to the power station. The asynchronously running generator suffers severe mechanical stressing of the shaft and bearings, which could result in costly repair work. It also produces electrical oscillations in the power system which can lead to other generators falling out of step. Asynchronous operation can be caused by defective excitation equipment or excessive reactive-power demand in the connected transmission network.

In view of the wide range for active and reactive power in such a pumped-storage unit, particular attention must be paid to setting the underexcitation protection characteristic. Simple detection of reactive-power demand by a circular protection characteristic will not meet these operating requirements. A combination of pickup characteristics in accordance with Fig. 4 is ideally suited for the requirements described here.

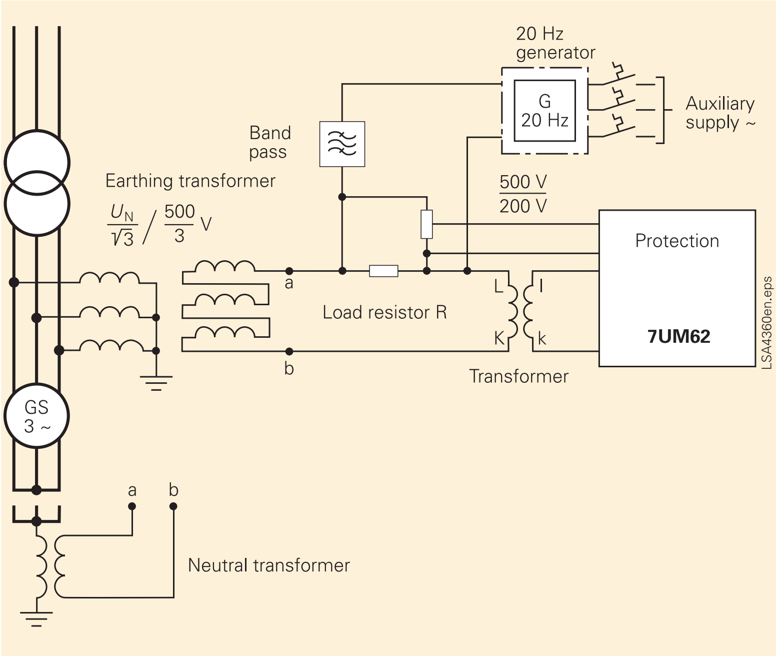

Fig. 3 Stator earth-fault protection with generator, 20 Hz

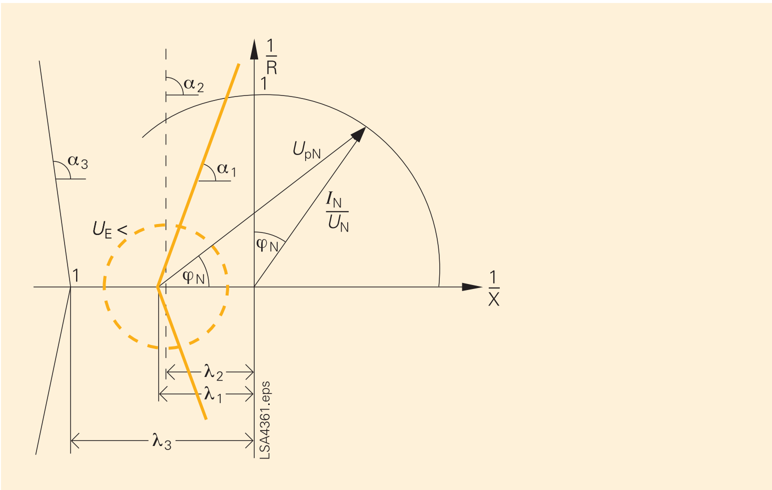

Fig. 4 Characteristic of underexcitation protection

These protection characteristics form the stability characteristics of the machine and combine high availability of the pumped-storage unit with optimum protection of the machine and the connected power system.

The pickup characteristics of the underexcitation protection are made up of the machine's steady-state and dynamic stability characteristics. An overshoot of the steady-state characteristic is an initial indication that stability is endangered.

If the excitation equipment is functioning correctly the machine can be returned to synchronous operation again by automatically readjusting the excitation voltage. Only an overshoot of the dynamic restraint characteristic finally makes the machine fall out of step. Both characteristics, sometimes referred to as the stator criterion, are calculated from machine currents and voltages. The excitation voltage U_{excit} (or rotor criterion) is used as an additional measured variable for optimum operation and control. The recommended function logic of the underexcitation protection is shown in Table 2 below.

Measurement criterion	Protection reaction
Steady-state characteristic	Indication (optional tripping approx. 10 s)
Steady-state characteristic + U_{excit} <	Tripping approx. 0.3 s
Dynamic characteristics	Tripping approx. 0.3 s
U_{excit} <	Indication

Table 2

An overshoot of the steady-state stability characteristic without simultaneous excitation voltage dip is only signalled. The operating personnel can manually intervene to return the machine to stable operation. The cause of underexcitation can lie in power factor correction.

Only a simultaneous drop in the excitation voltage below a set value causes shutdown of the machine in short time. This is probably due to a fault in the excitation equipment. It is then only a question of time before the machine reaches the dynamic stability characteristic and finally falls out of step. Shutting down at an early stage prevents this additional pole slipping and protects both machine and power system.

The setting value I_B is matched to the rated motor current

The rated temperature Θ_N is reached at $I = I_B$

The tripping temperature Θ_A is reached at $I = 1.1\, I_B$

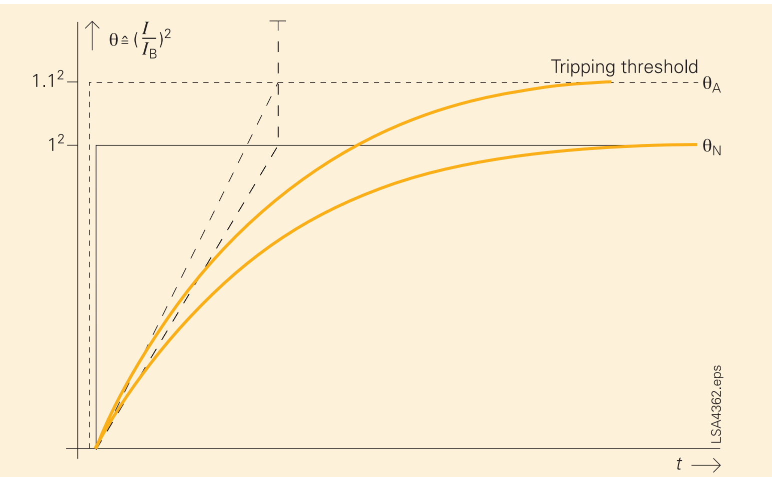

Fig. 5 Principle of overload protection

This logical linking of stator criteria with rotor criteria enables the pumped-storage unit to continue operation up to its real stability limit. The exact replica of the machine characteristics ensures that the unit does not switch off unnecessarily within the permissible limit range. On the other hand, this optimum utilization of the operating range involves no danger to the machine or power system. If the stability of the machine is no longer guaranteed, it is shut down quickly and safely.

2.4 Stator overload protection

An important protection function for pump operation is stator overload protection. In generator mode, the thermal loading on the stator winding is limited by the turbine output if the power station unit is correctly designed. In pump mode, there may be thermal overload of the machine in motor mode. A thermal replica with complete memory prevents such overloads. Particularly with quick load changes, the thermal replica is more exact than a direct temperature measurement on the winding.

The thermal replica calculates the temperature of the stator winding from the stator current practically instantaneously (Fig. 5) according to the formula I^2t. A direct measurement of the temperature on the insulation of the stator winding follows load changes only after a delay and therefore does not always show the current temperature of the conductor.

2.5 Rotor monitoring

In large machine units special attention must be paid to monitoring the rotor circuit, owing to the high power per pole. This monitoring includes insulation of the rotor winding as well as the thermal load on the rotor winding.

To monitor the rotor insulation a specially developed measurement principle is used which largely compensates for the disturbing influence of the rotor capacitance to earth and fluctuations of the excitation voltage. A reverse polarity square-wave voltage in a clock pulse from 1 to 3 Hz is applied between rotor circuit and earth (see Fig. 6). The steady-state circulating current remaining after the capacitive charging current has decayed is a measure of the insulation resistance of the rotor winding. The protection relay measures only the resistive component of the earth impedance regardless of the level of earth capacitance.

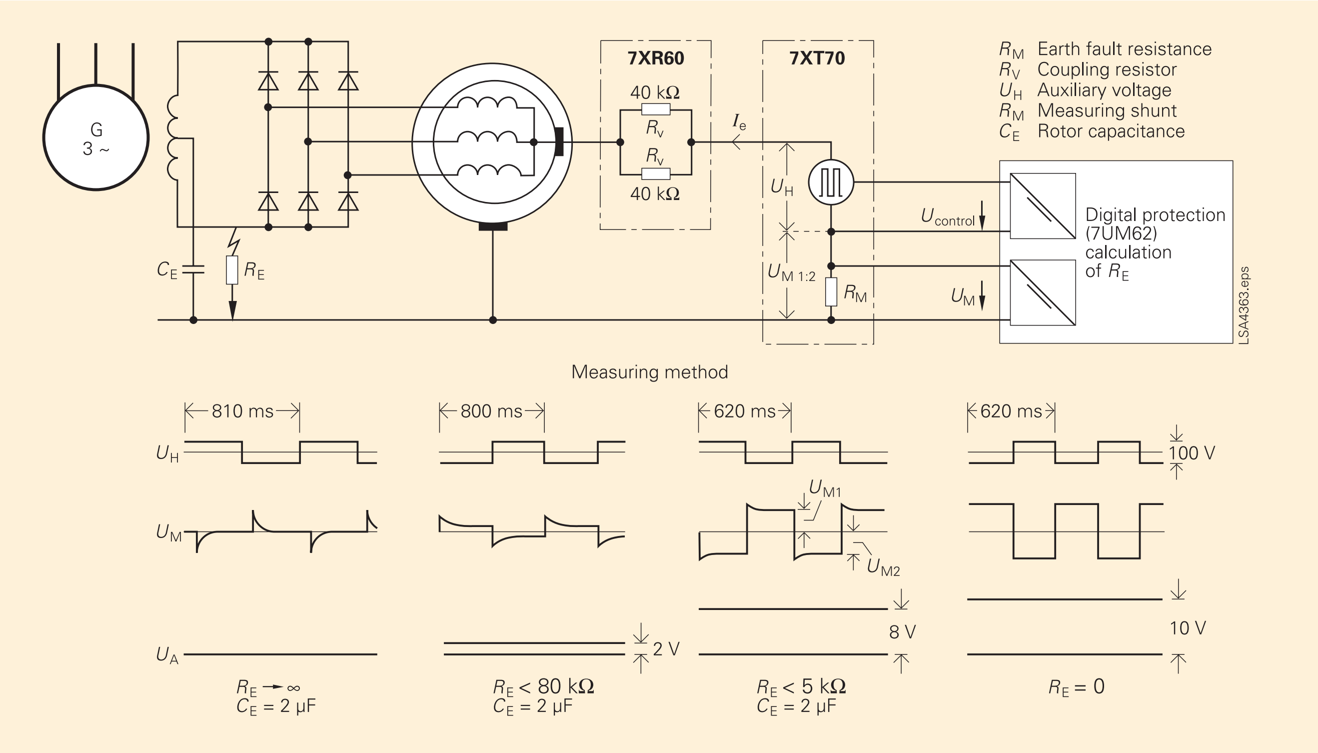

Fig. 6 Principle of rotor earth-fault protection

The differential measurement of the resistive earth current from positive and negative polarity compensates on the one hand the disturbance of the excitation voltage and also stops measurement errors owing to operation-related changes in the excitation voltage. This sophisticated measuring procedure measures an insulation resistance (to earth) in the rotor winding up to the order of 80 kΩ. Hence, the protection relay detects a rotor earth-fault as it arises. The operator can plan the necessary maintenance work on the machine for the long term. Protection-related shutdown of the pumped-storage unit is thereby almost always prevented which considerably enhances the availability of the unit.

As a result of the various operating modes of the pumped-storage unit

- Generator mode
- Generator and VAR compensation mode
- Pump mode
- Pump and VAR compensation mode
- Any electrical brake

the rotor circuit of the excitation system may be exposed to high thermal loads. Overload protection on the high-voltage side of the excitation transformer measures the current flowing there which is in direct relationship to the thermal rotor load. Overload protection works as a thermal replica with complete memory and enables flexible operation and control of the unit within the permissible limits, with simultaneous safe protection against overloads.

2.6 Power system failure in pump operation

The power-shortfall protection function is only activated in pump mode. This happens by way of the above-described parameter set changeover when the mode is changed. In the parameter set for generator mode, the power-shortfall function is deactivated. This protection function recognises the sudden failure of the power system supply (when the machine is in pump mode) by measuring the active power in the infeed direction. If a fault is detected, the pumped-storage unit is switched off and the spherical valves are closed.

A second measurement principle for detecting a line side supply failure is underfrequency protection, which is likewise included in the protection concept.

The underfrequency protection is not in operation during run-up and switchover of the system's various operating states, and is only activated after the machine has been synchronized with the power system. A binary input from the protection relay, which requests the position of the system circuit-breaker, effects this control.

3. Summary

In view of their particular status in hydropower engineering, pumped-storage power stations place special demands on the electrical protection system. Owing to the various operating modes

- Generator mode for energy supply
- Pump mode to feed back energy
- VAR compensation mode

a protection system is required that automatically adapts itself to these changing operating states. The SIPROTEC 7UM6 relays are specifically designed to handle these variable operating conditions. This applies both to the protection functions comprised in the relays and to the flexible adaptation of the protection system via external control signals from the power station.

Application of Low-Impedance 7SS601 Busbar Differential Protection

1. Introduction

Utilities have to supply power to their customers with highest reliability and minimum down time. System disturbances, especially short-circuits, cannot always be avoided. They are caused by human error, accidents, nature's influence such as storm, lightning, etc...
However, damage to primary equipment, such as transformers, switchgear, overhead lines, etc. must be limited in order to reduce the repair time and, thus, the downtime.
Although busbar faults are rare, they are considered most dangerous for people (staff) and the switchgear. Hence, fast tripping in case of busbar faults is essential!
This can be achieved primarily by differential protection.

Especially in medium and high-voltage switchgear, busbar differential protection is often regarded as an expensive accessory. However, responsible engineers are aware of the risk of extensive outages, if busbar faults are not cleared fast and selectively.
Siemens offers with its 7SS601 low-impedance busbar differential protection a low-cost solution, particularly suitable for single busbar with or without bus sectionalizer or simple double busbar configurations.
The 7SS601 combines important advantages of numerical protection with a cost-effective and an easy-to-use protection system:

- Self-supervision, fault logging and event recording, setting with DIGSI required for only a few parameters.
- Highest flexibility with regard to busbar configuration, number of feeders, different CT-ratios, low CT requirements.
- Measured-value acquisition by summation or matching current transformers (phase-selective)
- Fast and selective tripping for all busbar faults.
- Suitable for all voltage levels, up to 500 kV

The following article describes the basics of low-impedance busbar protection; some of its typical applications on a single busbar with bus sectionalizer with disconnect switch or bus sectionalizer with circuit-breaker).
The example is tailored for a solidly earthed network.

Fig. 1 SIPROTEC 7SS601 centralized numerical busbar protection relay

2. Principle of low-impedance protection

Fig. 2 illustrates the basic principle of the low-impedance protection.

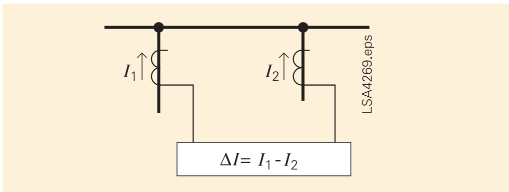

Fig. 2 Principle of differential protection

Differential protection is based on the Law of Kirchhoff: in a healthy system, the sum of currents in a node must be zero. This is the ideal case. But CT errors and measuring errors need to be considered. For that reason, the protection needs to be stabilized.
The differential criteria and the restraint criteria are defined as follows:

Differential current: $I_{\mathrm{Diff}} = |I_1 + I_2 + \ldots\ I_n|$
Restraint current: $I_{\mathrm{Restraint}} = |I_1| + |I_2| + \ldots |I_n|$

Fig. 3 shows, how I_{Diff} and $I_{\mathrm{Restraint}}$ are being derived.

It can be seen, that for load or through-flowing currents the differential criteria is almost zero, whereas the restraint quantity rises instantly.
In case of an internal fault both, the differential and the restraint quantity rise at the same time. Hence, even within a few milliseconds, the protection relay can decide whether there is an internal or external fault.

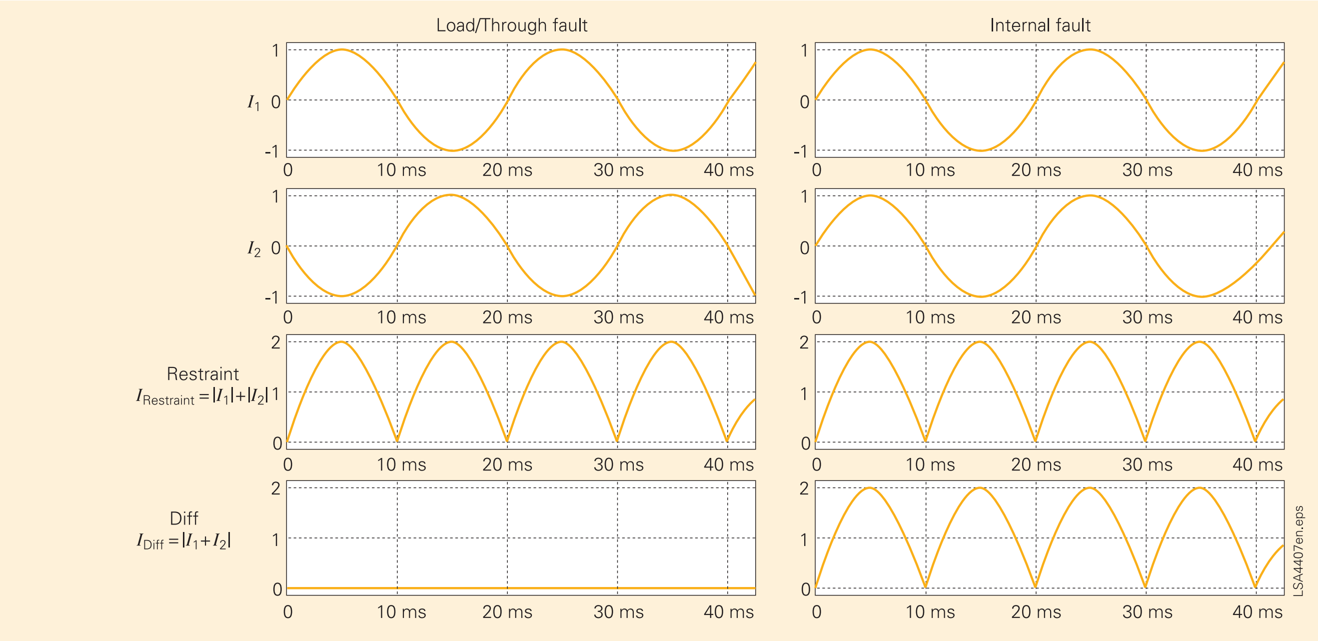

Fig. 3
Derivation of I_{Diff} and $I_{Restraint}$

For more than 50 years Siemens has been using this kind of stabilized differential protection.
It was introduced for the first time in the electro-mechanical protection 7SS84, later in the analog static protection 7SS10 and is now being employed in the numerical protections 7SS52 and 7SS601.

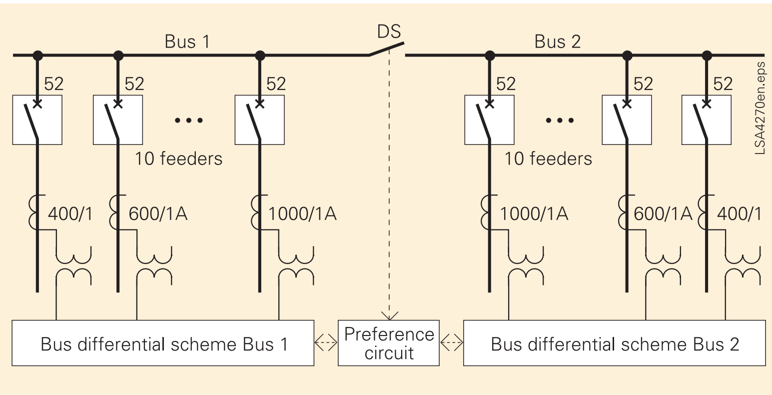

Fig. 4 Single busbar with disconnector in bus sectionalizer

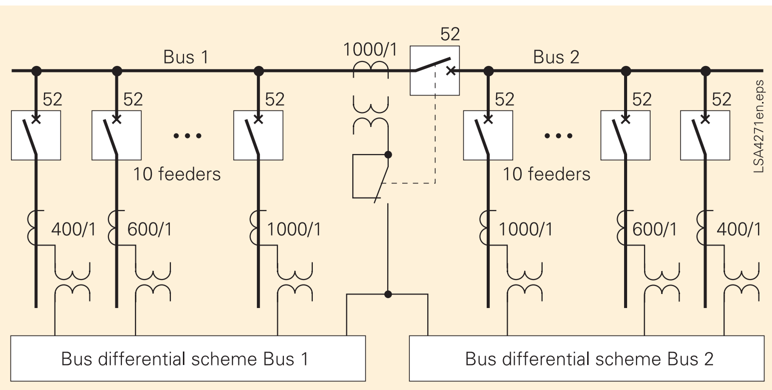

Fig. 5 Single busbar with circuit-breaker in bus sectionalizer

3. Protected objects

Fig. 4 and 5 show examples with 10 feeders on each bus section. However, the number of feeders per bus section is not limited.

3.1 Single busbar with disconnector (DS) in bus sectionalizer. In this case, no CTs are used in the bus sectionalizer. See Fig. 4

3.1.1 If the DS is open, both measuring systems (bus differential schemes) work independently. In case of a busbar fault, only the circuit-breakers (52) connected to the faulty bus will be tripped.

3.1.2 If the DS is closed the busbar must be considered as "one unit". The preference circuit (preferential treatment module) will switch the currents of all feeders to one measuring system only. In case of a busbar fault, all circuit-breakers will be tripped.

3.2 Single busbar with circuit-breaker and a CT in the bus sectionalizer. See Fig. 5.

3.2.1 If the circuit-breaker is open, both systems work independently. In case of a busbar fault, only the CBs connected to the faulty bus will be tripped.
Since the circuit-breaker is open, the CT is not required for measurement and thus shorted.
In case of a fault between the circuit-breaker and the CT in the bus sectionalizer, system 1 will detect the fault as "internal" and trip all CBs connected to bus 1.

3.2.2 If the circuit-breaker in the bus sectionalizer is closed both systems work independently. In case of a busbar fault, all circuit-breakers connected to the faulty busbar will be tripped. The circuit-breaker in the bus sectionalizer will be tripped by both systems. In case of a fault between the circuit-breaker in the bus sectionalizer and the CT, system 2 will detect this fault as "internal" and trip all circuit-breakers of bus 2 including the circuit-breaker in the bus sectionalizer.
System 1 remains stable for the time being.
Once the circuit-breaker in the bus sectionalizer has tripped, the CTs are shorted. Now system 1 will detect this fault also as "internal" and finally clears the fault by tripping the circuit-breakers of bus 1.

■ 4. Summation current transformers and adaptation of different CT ratios

The advantage of the low-impedance scheme is that other protection relays may be connected in series with the summation or matching current transformers (Fig. 6). This reduces the overall costs of the switchgear.
As mentioned earlier, the low-impedance scheme can process different CT ratios. Thus, upgrading of existing switchgear with low-impedance busbar protection is easily possible without changing or adding CT cores!

The standard connection of a summation current transformer is shown in Fig. 7.
The summation current transformer is used to do a "magnetic" summation of the currents. The resulting currents depend on the ratio of the windings. The following calculation shows some examples of how the currents of the summation current transformers are being calculated.

It can be shown that the optimum ratio of the primary windings are 2:1:3. This ensures increased sensitivity for earth faults.

Example: $W_{P1} = 60$ windings
$W_{P2} = 30$ windings
$W_{P3} = 90$ windings
$W_S = 500$ windings (fixed)

General equation:

$$i_p \cdot W_P = i_s \cdot W_S \Rightarrow i_s = i_p \frac{W_P}{W_S}$$

For the above example: assume $i = I_N = 1$ A

$$\underline{i}_{L1} = 1\,\mathrm{A}\frac{W_{P1}+W_{P3}}{W_S} = 1\,\mathrm{A}\frac{150}{500} = 0.3\,\mathrm{A} \qquad 0.3 \cdot e^{j0}$$
$$\underline{i}_{L1} = 0.3 + j0$$

$$\underline{i}_{L2} = 1\,\mathrm{A}\frac{W_{P3}}{W_S} = 1\,\mathrm{A}\frac{90}{500} = 0.18\,\mathrm{A} \qquad 0.18 \cdot e^{j120}$$
$$\underline{i}_{L2} = -0.09 + j0.156$$

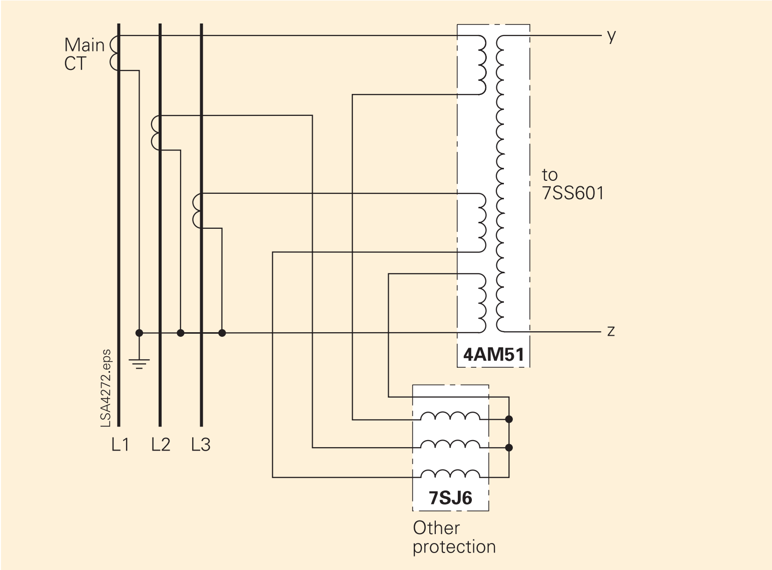

Fig. 6 Serial connection of summation CTs with other relays

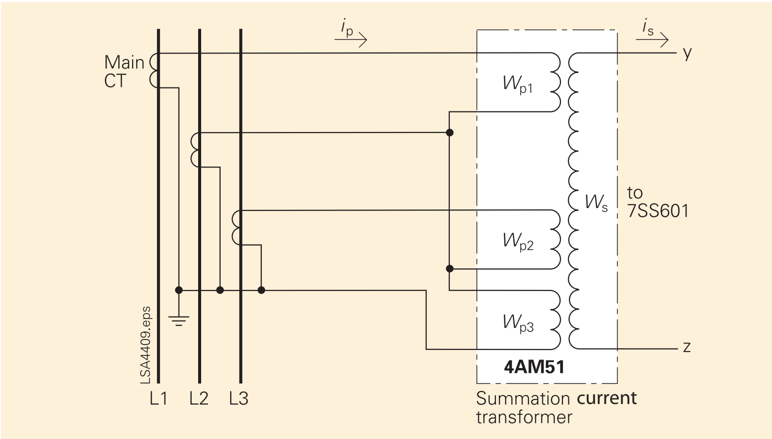

Fig. 7 Standard connection of summation current transformer

W_P = primary winding of summation current transformer
W_s = secondary winding of summation current transformer

$$\underline{i}_{L3} = 1\,\mathrm{A}\frac{W_{P2}+W_{P3}}{W_S} = 1\,\mathrm{A}\frac{120}{500} = 0.24\,\mathrm{A}$$
$$0.24 \cdot e^{j240} \qquad \underline{i}_{L3} = -0.12 - j0.21$$

Result: summation $\underline{i}_{L1} + \underline{i}_{L2} + \underline{i}_{L3} = \underline{i}_s$

$$\underline{i}_s = 0.09 - j0.054 \qquad \underline{i}_s = 0.105 \cdot e^{-j30^\circ}$$

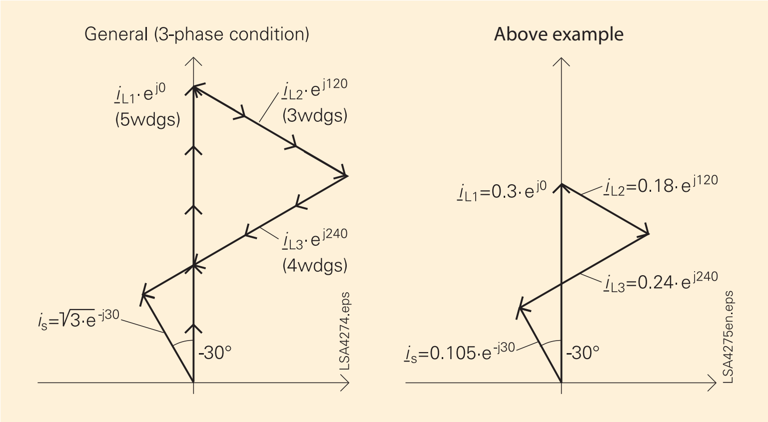

Fig. 8 Phasor diagram of measurings

As can be seen the secondary current is ≈ 100 mA, which corresponds to the rated current of the 7SS601 protection relay.
The graphical addition leads to the same result. See Fig. 8.

In order to adapt different CT-ratios, the 4AM5120 summation current transformer has 7 primary windings, which can be combined by means of connecting the windings in series.
The 4AM 5120-3DA00-0AN2 summation current transformer is suitable for 1A rated current:

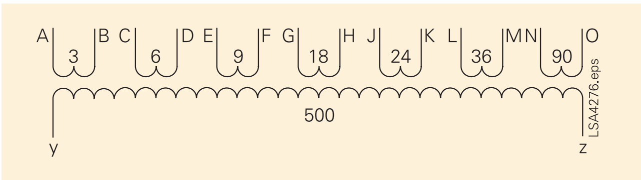

Fig. 9 Tapping of summation current transformers

As mentioned before, the ratio of the primary windings should be 2:1:3 in standard applications. Table 1 shows the most commonly used ratios.

Note
Always be aware of the orientation of the windings !

The examples of Figures 4 and 5 respectively show CT-ratios of 400/1A, 600/1A and 1000/1A.
The differential protection can only compare currents, if the basis for comparison is equal, i.e. the CT-ratios must be matched.
A simple procedure has to be followed:

- The difference in CT-ratios may not exceed 1:10 (i.e. 400 / 600 / 1000 is possible, 200 / 800 / 2500 is not possible).
- The max. possible number of windings of the summation current transformer shall be used. Thus, accuracy is increased.
- The highest CT-ratio is always the reference.

Wind-ings	Refer-ence	Phase	Connec-tions	Links
6-3-9	1	L1 L3 N	C, D A, B E, F	
12-6-18	2	L1 L3 N	A, F C, D G, H	B-E
18-9-27	3	L1 L3 N	G, H E, F A, K	 B-J
24-12-36	4	L1 L3 N	J, K A, F L, M	 B-E
30-15-45	5	L1 L3 N	C, K B, H E, M	D-J A-G magnetic subtraction F-L
36-18-54	6	L1 L3 N	A, K G, H M, O	B-E, F-J L-N magnetic subtraction
42-21-63	7	L1 L3 N	C, M B, K F, O	D-L A-J magnetic subtraction E-H, G-N magnetic subtraction
48-24-72	8	L1 L3 N	A, M J, K H, O	B-E; F-L G-N magnetic subtraction
54-27-81	9	L1 L3 N	G, M A, K F, O	H-L B-J E-N magnetic subtraction
60-30-90	10	L1 L3 N	J, M A, H N, O	K-L B-E, F-G

Table 1 Selected ratios of summation current transformers at $I_N = 1$ A

- Choose the smallest common integer multiple of the CT-ratios, of which the result of division may not exceed "10".
Example
400 / 600 / 1000 smallest multiple:
2 → 200 / 300 / 500: Not possible !
400 / 600 / 1000 smallest multiple with result ≤ 10 : 100 → 4 / 6 / 10. Possible !

The result of this calculation is used to select the ratios of the summation transformer from Table 1 (Reference number).

400 / 1A	→	4	→	24-12-36
600 / 1A	→	6	→	36-18-54
1000 / 1A	→	10	→	60-30-90

Fig. 10 shows that with the above selected ratios the secondary currents of the summation current transformers are equal. The differential protection can now compare all currents.

In case of short-circuits, the sensitivity of the differential protection varies due to the winding ratio 2:1:3 and the resulting secondary currents. Refer to Table 2.

Short circuits	Effective windings W	$\frac{W}{\sqrt{3}}$	I_1 for i_M = 100 mA
L1 - L2 - L3	$\sqrt{3}$	1.00	$1.00 \cdot I_N$
L1 - L2	2	1.15	$0.87 \cdot I_N$
L2 - L3	1	0.58	$1.73 \cdot I_N$
L3 - L1	1	0.58	$1.73 \cdot I_N$
L1 - E	5	2.89	$0.35 \cdot I_N$
L2 - E	3	1.73	$0.58 \cdot I_N$
L3 - E	4	2.31	$0.43 \cdot I_N$

Table 2 Result of secondary current matching

To ensure reliable tripping, the minimum short-circuit currents must be above the lowest pickup value of the respective fault type.

Example: Setting of the pickup threshold:

$I_{Diff} > 1.20\ I_{NO}$*

* I_{NO} is the rated current of the reference ratio (1000/1 A)

	1000 / 1 A
3-phase faults	1.20
L1 - L2	1.04
L2 - L3	2.08
L3 - L1	2.08
L1 - E	0.42
L2 - E	0.69
L3 - E	0.52

Table 3 Sensitivity of 7SS60 according to type of fault

Hence, the minimum short-circuit current must exceed:

1200 A for 3-phase faults
2080 A for phase to phase faults
690 A for phase to ground faults

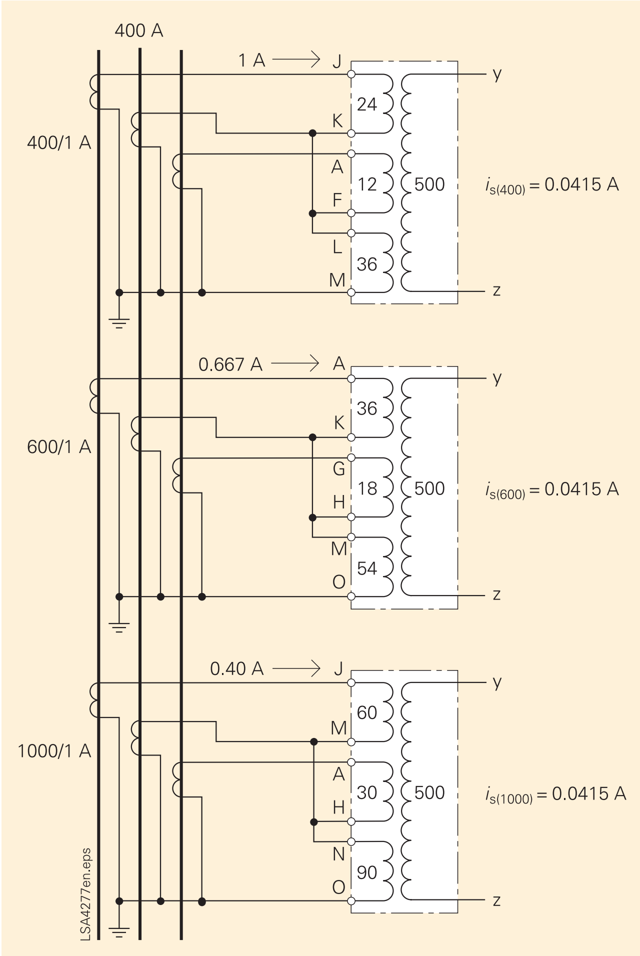

Fig. 10 Adaption of different CT ratios

■ 5. Components of the 7SS601 centralized numerical busbar protection

The basic principles are shown in Fig. 11 and 12: 4AM5120 summation current transformers, restraint/command output 7TM70 modules, 7TR71 isolator replica/preferential treatment module and 7SS601 protection relay are required:

- Summation current transformers: one for each feeder.
- Restraint modules: each module 7TM70 contains 5 input transformers with rectifiers and 5 tripping relays.
- Measuring system(protection relay): one for each bus section.
- 7TR71 preferential treatment/isolator replica module. For allocation of current and preferential treatment via isolator replica.
- 7XP20 housing to accommodate 7TM70 and 7TR71 modules. One housing can accommodate up to 4 modules.

Fig. 11 shows the scheme with a disconnector in the bus sectionalizer. In this case, 7TR71 is used as preferential treatment module. If the disconnector is closed the entire bus must be seen as "one unit". All currents must be measured by one system only. Thus all currents are routed to system 2.
The trip circuits of both busses are switched in parallel.
Fig. 11 corresponds to the example shown in Fig. 4.

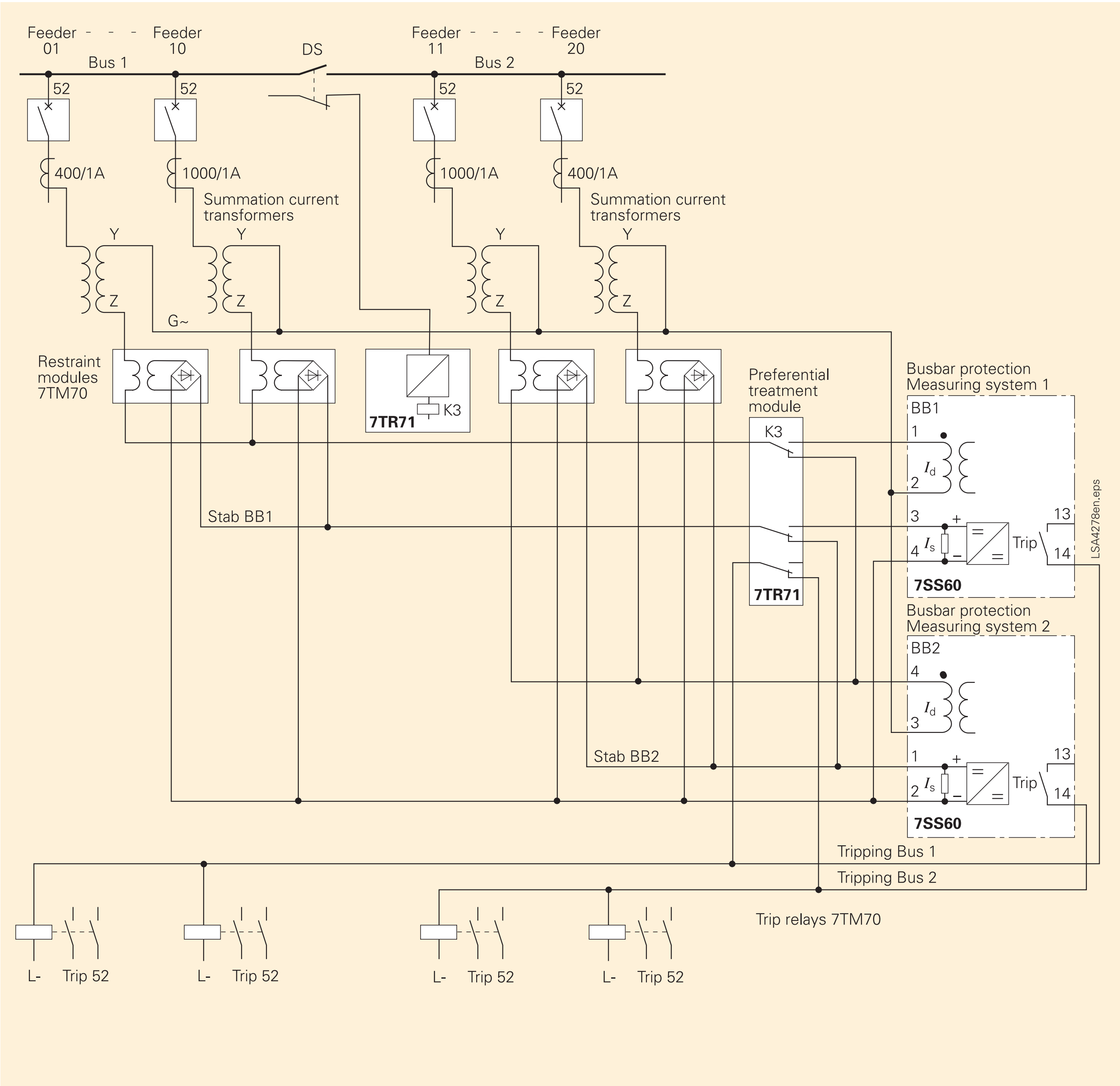

Fig. 11 Block diagram of the 7SS60 with disconnector in bus sectionalizer

Fig. 12 shows the scheme with a circuit-breaker in the bus sectionalizer. In this case, 7TR71 is used as "circuit-breaker position replica" module. If the circuit-breaker is open, the secondary side of the summation CT is shorted because no current flows in the bus section anyway.
If the circuit-breaker is closed, the differential and restraint currents are fed to both measuring systems with opposite direction.
In case of a busbar fault, a busbar-selective tripping is possible. The circuit-breaker in the bus sectionalizer will be tripped by both measuring systems.

Fig. 12 corresponds to the example shown in Fig. 5.

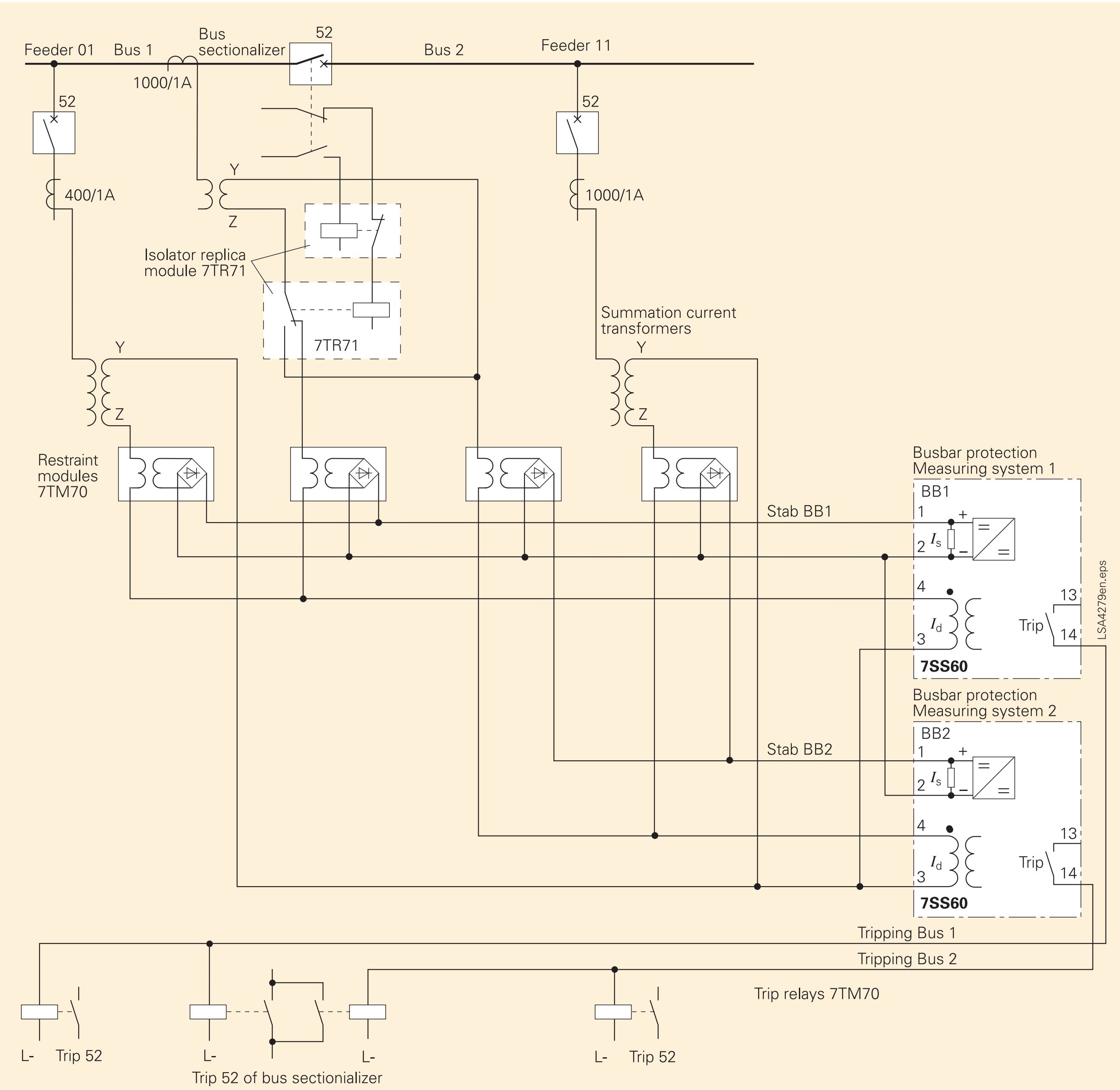

Fig. 12 Block diagram of the 7SS60 with circuit-breaker in bus sectionalizer

Busbar protection for switchgear (20 feeders) as shown in Fig. 11, comprises the following components:

- 20 x 4 AM 5120 summation current transformers (10 feeders on each busbar)
- 4 x 7TM70 restraint modules (4 x 5 inputs = 20 inputs)
- 2 x 7SS601 protection relays
- 1 x 7TR71 preferential treatment module
- 2 x 7XP20 housings

Busbar protection for switchgear (20 feeders + bus sectionalizer with circuit-breaker)

- 21 x 4AM5120 summation current transformers (20 feeders +1 for the sectionalizer)
- 5 x 7TM70 restraint modules (25 inputs)
- 2 x 7SS601 protection relays
- 1 x 7TR71 isolator/CB replica module
- 2 x 7XP20 housings

The above modules can be accommodated in a standard protection cubicle.
Please refer to our documentation (instruction manual, catalog and circuit diagrams) for more details.

6. Setting and design considerations

CTs shall be dimensioned such that all CTs transform currents without saturation for at least ≥ 4ms.
The number of feeders connected in parallel to one protection relay is unlimited.

Please refer to the instruction manual in case of systems with transformers of which the star point is isolated.
A lock-out function of the trip command may be activated in the 7SS601. No external lock-out relays are required !

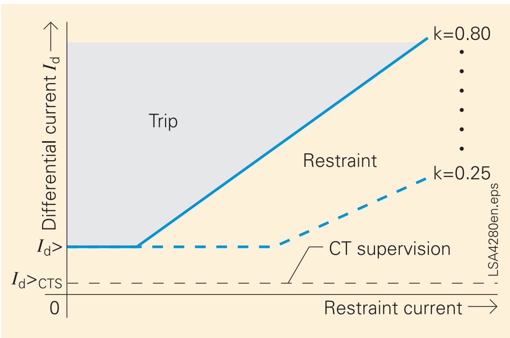

Fig. 13 Tripping characteristic

Fig. 13 shows the tripping characteristic of the protection relay.

The threshold I_d > should be set above max. load current (e.g. 1.2 · I_{Load}) to avoid tripping by the load current in case of a fault in the CT circuit.
If, however, the minimum short-circuit currents require a lower setting, additional trip criteria may be introduced (e.g. voltage).

On the other hand, to ensure tripping under minimum short-circuit conditions, I_d> should be set at about 50 % below minimum short-circuit currents. For instance: I_{scmin} = 3000 A → 50 % = 1500 A
I_d > = 1.2 I_{NO}, if the reference ratio is 1000/1 A.

The threshold $I_{d>CTS}$ is the pickup value for CT supervision.
If a CT secondary circuit is open or shorted, a differential current will appear. The differential protection will be blocked and an alarm given. This will avoid unnecessary overfunction in case of heavy through-flowing currents.

The k-factor changes the slope of the tripping characteristic as shown in Fig. 13 and thus determines the stability of the protection.
Although a high setting for this factor improves the stability with regard to faults outside the protected zone, it reduces the sensivity for the detection of busbar faults. The k-factor should therefore be chosen as low as possible and as high as necessary. If the measuring system (protection relay) is to be used for zone-selective protection, which will be the case in most applications, it is advisable to use the presetting of 0.6 of the k-factor.

7. Comparison of high and low-impedance busbar protection

Nowadays high impedance protection is still widely used, because it is considered "cheap and easy".
But most users only look at the relay price itself, without considering the additional costs for the switchgear and other *disadvantages of a high-impedance schemes*:

- All CTs must have the same ratio
- Class X for all CT cores
- Bus sectionalizers with circuit-breaker must be equipped with two CTs
- Separate CT cores for busbar protection
- Advantages of numerical protection technology (e.g. fault recording, communication, etc.) not available
- Check zone needs separate CT cores
- Isolator replica requires switching of CT secondaries. Additional check zone obligatory.

8. Summary

The low-impedance 7SS601 busbar protection is a cost-effective solution for medium and high-voltage switchgear.

Apart from the application described the 7SS601 can also be applied

- With phase-segregated measurement
- On switchgear with double busbars.

For a quotation, we would need the following information:

- Single-line diagram, showing
  - Busbar configuration
  - Number of feeders, bus sectionalizers with disconnector/circuit-breaker
  - Ratio of CTs
  - Phase-segregated or single phase measurement
  - Complete cubicles or components only

For more information please contact your local Siemens partner.
More details may be obtained from our documentation (instruction manuals, relay catalog SIP2004, CD's). Circuit diagrams for standard applications are available on the Internet at: www.siprotec.com

Basic Busbar Protection by Reverse Interlocking

Busbars have a particular key role in power transmission and distribution. They are the central distribution point for many feeders. In the event of a fault, the short-circuit current on the busbar is very high, resulting potentially in mechanical destruction and the consequent long repair times, which would affect all feeders. On the high and extra-high-voltage level, a fast 7SSx busbar protection relay is used, which, with a tripping time of <12 ms, limits the damage by busbar faults. Fast busbar protection is also used in all important medium-voltage switchgear.

For basic medium-voltage switchgear with one incoming feeder, no special busbar protection is used (for reasons of economy). In such cases busbar protection is provided by the time-overcurrent relay of the incoming feeder. As shown in Fig. 1, tripping of the time-overcurrent protection for the E1 feeder occurs with a grading time of 300 ms more than the longest grading time of the A1-A3 feeder protection. The times selected in Fig. 1 have been taken as examples. The E1 protection serves as backup protection for each A1-A3 feeder protection.
A busbar fault is however then only disconnected after 0.9 seconds, which would result in damage of considerable magnitude.

In the case of single busbars with one defined incoming feeder and otherwise only defined outgoing feeders, fast busbar protection can be provided with no major additional effort by means of reverse interlocking. Such busbar configurations are common in medium-voltage systems and in auxiliary supply networks. The time-overcurrent relays already available for feeder protection are used, as shown in Fig. 1. An additional benefit is that all SIPROTEC relays are equipped with at least two definite-time current stages, which can be blocked individually.

The reverse interlocking concept is shown in Fig. 2. With the time-overcurrent protection E1 of the incoming feeder, a further stage *I*>> with a time delay of t_2 = 50 ms is provided in addition to stage *I*> with t_1. The expiry of time t_2 can be blocked via the binary input BI1.

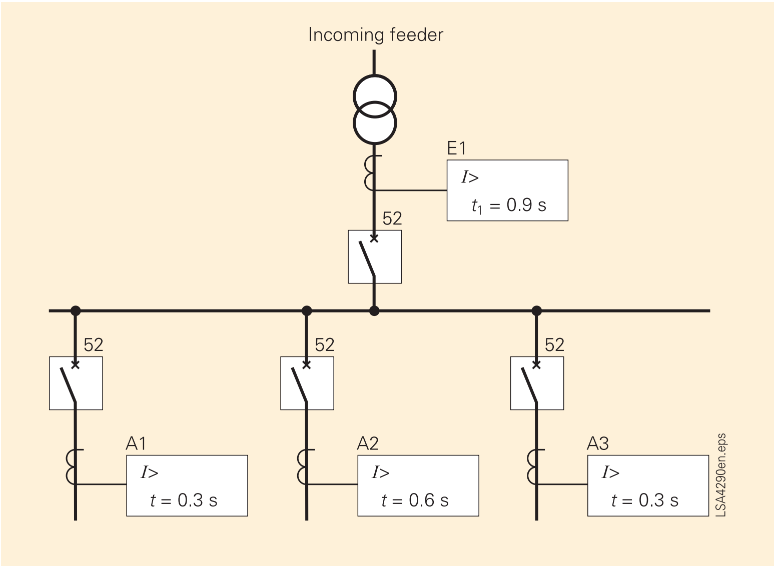

Fig. 1 Single busbar with feeder protection

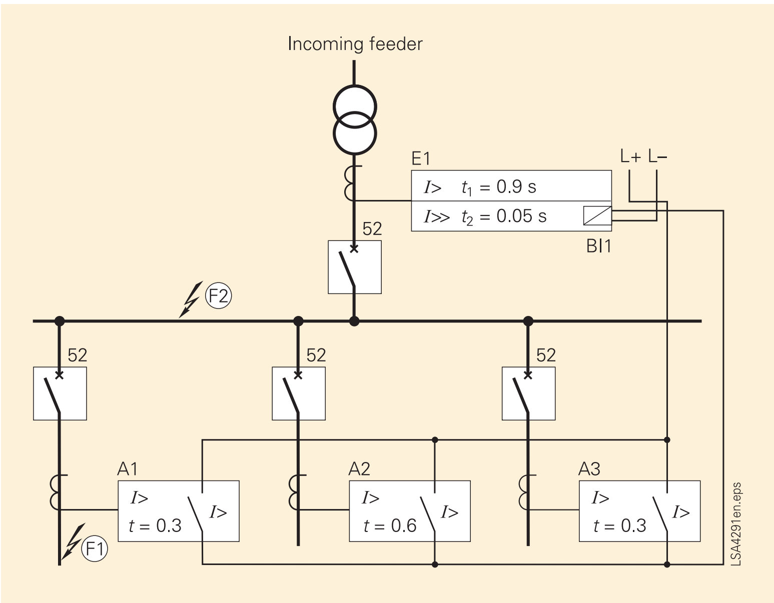

Fig. 2 Single busbar with feeder protection and busbar protection by reverse interlocking

The tripping threshold of the stages $I>$ and $I>>$ is set at the same level in accordance with the network conditions (approximately 1.5 x I_{rated}). For the time-overcurrent relays of outgoing feeders A1-A3, the pick-up signal is allocated to a dedicated contact. The pick-up signals of all feeders are connected in parallel and given as a blocking signal to the binary input BI1 of the relay of the incoming feeder. Wiring is effected by means of a copper core, looped from panel to panel (see Fig. 2). This means that a pickup in an outgoing feeder A1-A3 will block the tripping of the $I>>$ stage (t_2) of the incoming feeder E1.

Function in the case of a fault in the outgoing feeder:
In the case of a fault on the outgoing feeder (see "F1"in Fig. 2), both stages in relay E1 of the incoming feeder pick up. The relay A1 of the outgoing feeder also picks up and issues a blocking signal via the pick-up signal to binary input BI1 of the relay E1 of the incoming feeder. The expiry of t_2 is thus blocked. The fault is disconnected from the relay A1 of the outgoing feeder. The relay E1 of the incoming feeder operates as backup protection with t_1.

Function in the case of a fault on the busbar:
In the case of a busbar fault (see "F2"in Fig. 2), both stages in relay E1 of the incoming feeder pick up and t_1 and t_2 are started. From an A1-A3 outgoing feeder there can be no infeed onto the fault. Consequently there is no blocking signal. In the relay E1 of the incoming feeder, time t_2 expires and trips the circuit-breaker after 50 ms. The busbar fault is thus disconnected within a short time and the extent of the fault is limited.

Summary

For busbars with one incoming feeder and radial outgoing feeders, i.e. without back-feeding, the reverse interlocking principle grants an effective and fast busbar protection. Additional hardware is not required, because the SIPROTEC devices incorporate this function in their basic versions. Attention shall be paid to motor feeders, which may feed a busbar fault in the generating mode. They cannot always be treated as feeders without back-feeding.

Prospects for further applications

In the case of ring busbars with two incoming feeders or single busbars with sectionalizer, a similar reverse interlocking principle can be applied by way of short-circuit direction detection. This case will be presented in a separate application.

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Exclusion of liability

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Further application examples can be found on the Internet. Please visit us at: www.siprotec.com

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