Overview/Applications

Page

2

SIPROTEC Relay Families

Solutions for today's and future power supply systems – for more than 100 years

SIPROTEC has established itself on the energy market for decades as a powerful and complete system family of numerical protection relays and bay controllers from Siemens.

SIPROTEC protection relays from Siemens can be consistently used throughout all applications in medium and high voltage. With SIPROTEC, operators have their systems firmly and safely under control, and have the basis to implement cost-efficient solutions for all duties in modern, intelligent and "smart" grids. Users can combine the units of the different SIPROTEC device series at will for solving manifold duties – because SIPROTEC stands for continuity, openness and future-proof design.

As the innovation driver and trendsetter in the field of protection systems for 100 years, Siemens helps system operators to design their grids in an intelligent, ecological, reliable and efficient way, and to operate them economically. As a pioneer, Siemens has decisively influenced the development of numerical protection systems (Fig. 2/2). The first application went into operation in Würzburg, Germany, in 1977. Consistent integration of protection and control functions for all SIPROTEC devices was the innovation step in the 90ies. After release of the communication standard IEC 61850 in the year 2004, Siemens was the first manufacturer worldwide to put a system with this communication standard into operation.

Fig. 2/1

How can system operators benefit from this experience?

- Proven and complete applications
- Easy integration into your system
- Highest quality of hardware and software
- Excellent operator friendliness of devices and tools
- Easy data exchange between applications
- Extraordinary consistency between product- and system-engineering
- Reduced complexity by easy operation
- Siemens as a reliable, worldwide operating partner.

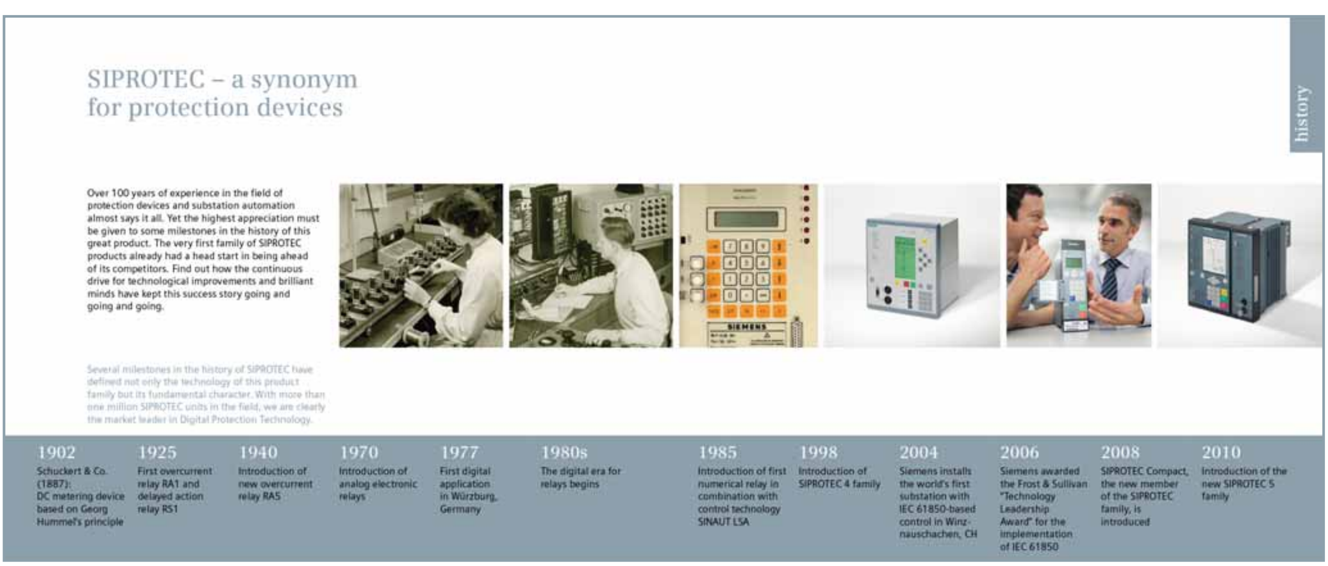


Fig. 2/2 SIPROTEC – Pioneer over generations

SIPROTEC Relay Families

SIPROTEC easy

SIPROTEC easy are CT power supplied or auxiliary power supplied, numerical overcurrent-time protection relays, which can be used as line and transformer protection (back-up protection) in electrical power supply systems with single-ended supply. They offer definite-time and inverse-time overcurrent protection functions according to IEC and ANSI. The comfortable operation via DIP switch is self-explanatory and simple.

- Two-stage overcurrent-time protection
- Saving the auxiliary power supply by operation via integrated current transformer supply
- Cost-efficient due to the use of instrument transformers with low ratings
- Tripping via pulse output (24 V DC / 0.1 Ws) or tripping relay output
- Simple, self-explanatory parameterization and operation via DIP switch directly at the device
- Easy installation due to compact assembly on DIN rail.

Fig. 2/3 SIPROTEC easy

SIPROTEC Compact (series 600)

The devices of the SIPROTEC Compact series (series 600) are compact, numerical protection devices for application in medium-voltage or industrial power supply systems. The corresponding device types are available for the different applications such as overcurrent-time protection, line differential protection, transient earth-fault relay or busbar protection.

- Space-saving due to compact design
- Reliable process connections by means of solid terminal blocks
- Effective fault evaluation by means of integrated fault recording and SIGRA 4
- Communication interface
- Operable and evaluable via DIGSI 4
- Different device types available for directional and non-directional applications.

Fig. 2/4 SIPROTEC Compact (series 600)

SIPROTEC Compact – Maximum protection-minimum space

Perfect protection, smallest space reliable and flexible protection for energy distribution and industrial systems with minimum space requirements. The devices of the SIPROTEC Compact family offer an extensive variety of functions in a compact and thus space-saving 1/6 x 19" housing. The devices can be used as main protection in medium-voltage applications or as back-up protection in high-voltage systems.

SIPROTEC Compact provides suitable devices for many applications in energy distribution, such as the protection of feeders, lines or motors. Moreover, it also performs tasks such as system decoupling, load shedding, load restoration, as well as voltage and frequency protection.

The SIPROTEC Compact series is based on millions of operational experience with SIPROTEC 4 and a further-developed, compact hardware, in which many customer suggestions were integrated. This offers maximum reliability combined with excellent functionality and flexibility.

- Simple installation by means of pluggable current and voltage terminal blocks
- Thresholds adjustable via software (3 stages guarantee a safe and reliable recording of input signals)
- Easy adjustment of secondary current transformer values (1 A/5 A) to primary transformers via DIGSI 4
- Quick operations at the device by means of 9 freely programmable function keys
- Clear overview with six-line display
- Easy service due to buffer battery replaceable at the front side
- Use of standard cables via USB port at the front
- Integration in the communication network by means of two further communication interfaces
- High availability due to integrated redundancy (electrical or visual) for IEC 61850 communication
- Reduction of wiring between devices by means of cross-communication via Ethernet (IEC 61850 GOOSE)
- Time synchronization to the millisecond via Ethernet with SNTP for targeted fault evaluation
- Adjustable to the protection requirements by means of “flexible protection functions”
- Comfortable engineering and evaluation via DIGSI 4.

Fig. 2/5 SIPROTEC Compact

Fig. 2/6 SIPROTEC Compact – rear view

Fig. 2/7 Feeder automation relay 7SC80

SIPROTEC Relay Families

SIPROTEC 5 – the new benchmark for protection, automation and monitoring of transmission grids

The SIPROTEC 5 series is based on the long field experience of the SIPROTEC device series, and has been especially designed for the new requirements of modern high-voltage systems. For this purpose, SIPROTEC 5 is equipped with extensive functionalities and device types. With the holistic and consistent engineering tool DIGSI 5, a solution has also been provided for the increasingly complex processes, from the design via the engineering phase up to the test and operation phase.

Thanks to the high modularity of hardware and software, the functionality and hardware of the devices can be tailored to the requested application and adjusted to the continuously changing requirements throughout the entire life cycle.

Besides the reliable and selective protection and the complete automation function, SIPROTEC 5 offers an extensive database for operation and monitoring of modern power supply systems. Synchrophasors (PMU), power quality data and extensive operational equipment data are part of the scope of supply.

- Powerful protection functions guarantee the safety of the system operator's equipment and employees
- Individually configurable devices save money on initial investment as well as storage of spare parts, maintenance, expansion and adjustment of your equipment
- Clear and easy-to-use of devices and software thanks to user-friendly design
- Increase of reliability and quality of the engineering process
- High reliability due to consequent implementation of safety and security
- Powerful communication components guarantee safe and effective solutions
- Full compatibility between IEC 61850 Editions 1 and 2
- Efficient operating concepts by flexible engineering of IEC 61850 Edition 2
- Comprehensive database for monitoring of modern power grids
- Optimal smart automation platform for transmission grids based on integrated synchrophasor measurement units (PMU) and power quality functions.

Fig. 2/8 SIPROTEC 5 – modular hardware

Fig. 2/9 SIPROTEC 5 – rear view

Fig. 2/10 Application in the high-voltage system

SIPROTEC 4 – the proven, reliable and future-proof protection for all applications

SIPROTEC 4 represents a worldwide successful and proven device series with more than 1 million devices in field use.

Due to the homogenous system platform, the unique engineering program DIGSI 4 and the great field experience, the SIPROTEC 4 device family has gained the highest appreciation of users all over the world. Today, SIPROTEC 4 is considered the standard for numerical protection systems in all fields of application.

SIPROTEC 4 provides suitable devices for all applications from power generation and transmission up to distribution and industrial systems.

SIPROTEC 4 is a milestone in protection systems. The SIPROTEC 4 device series implements the integration of protection, control, measuring and automation functions optimally in one device. In many fields of application, all tasks of the secondary systems can be performed with one single device. The open and future-proof concept of SIPROTEC 4 has been ensured for the entire device series with the implementation of IEC 61850.

- Proven protection functions guarantee the safety of the systems operator's equipment and employees
- Comfortable engineering and evaluation via DIGSI 4
- Simple creation of automation solutions by means of the integrated CFC
- Targeted and easy operation of devices and software thanks to user-friendly design
- Powerful communication components guarantee safe and effective solutions
- Maximum experience worldwide in the use of SIPROTEC 4 and in the implementation of IEC 61850 projects
- Future-proof due to exchangeable communication interfaces and integrated CFC.

Fig. 2/11 SIPROTEC 4

Fig. 2/12 SIPROTEC 4 rear view

Fig. 2/13 SIPROTEC 4 in power plant application

SIPROTEC Relay Families

To fulfill vital protection redundancy requirements, only those functions that are interdependent and directly associated with each other are integrated into the same unit. For backup protection, one or more additional units should be provided.

All relays can stand fully alone. Thus, the traditional protection principle of separate main and backup protection as well as the external connection to the switchyard remain unchanged.

"One feeder, one relay" concept

Analog protection schemes have been engineered and assembled from individual relays. Interwiring between these relays and scheme testing has been carried out manually in the workshop.

Data sharing now allows for the integration of several protection and protection-related tasks into one single numerical relay. Only a few external devices may be required for completion of the total scheme. This has significantly lowered the costs of engineering, assembly, panel wiring, testing and commissioning. Scheme failure probability has also been lowered.

Engineering has moved from schematic diagrams toward a parameter definition procedure. The powerful user-definable logic of SIPROTEC 4 allows flexible customized design for protection, control and measurement.

Measuring included

For many applications, the accuracy of the protection current transformer is sufficient for operational measuring. The additional measuring current transformer was required to protect the measuring instruments under short-circuit conditions. Due to the low thermal withstand capability of the measuring instruments, they could not be connected to the protection current transformer. Consequently, additional measuring core current transformers and measuring instruments are now only necessary where high accuracy is required, e.g., for revenue metering.

Corrective rather than preventive maintenance

Numerical relays monitor their own hardware and software. Exhaustive self-monitoring and failure diagnostic routines are not restricted to the protection relay itself but are methodically carried through from current transformer circuits to tripping relay coils.

Equipment failures and faults in the current transformer circuits are immediately reported and the protection relay is blocked.

Thus, service personnel are now able to correct the failure upon occurrence, resulting in a significantly upgraded availability of the protection system.

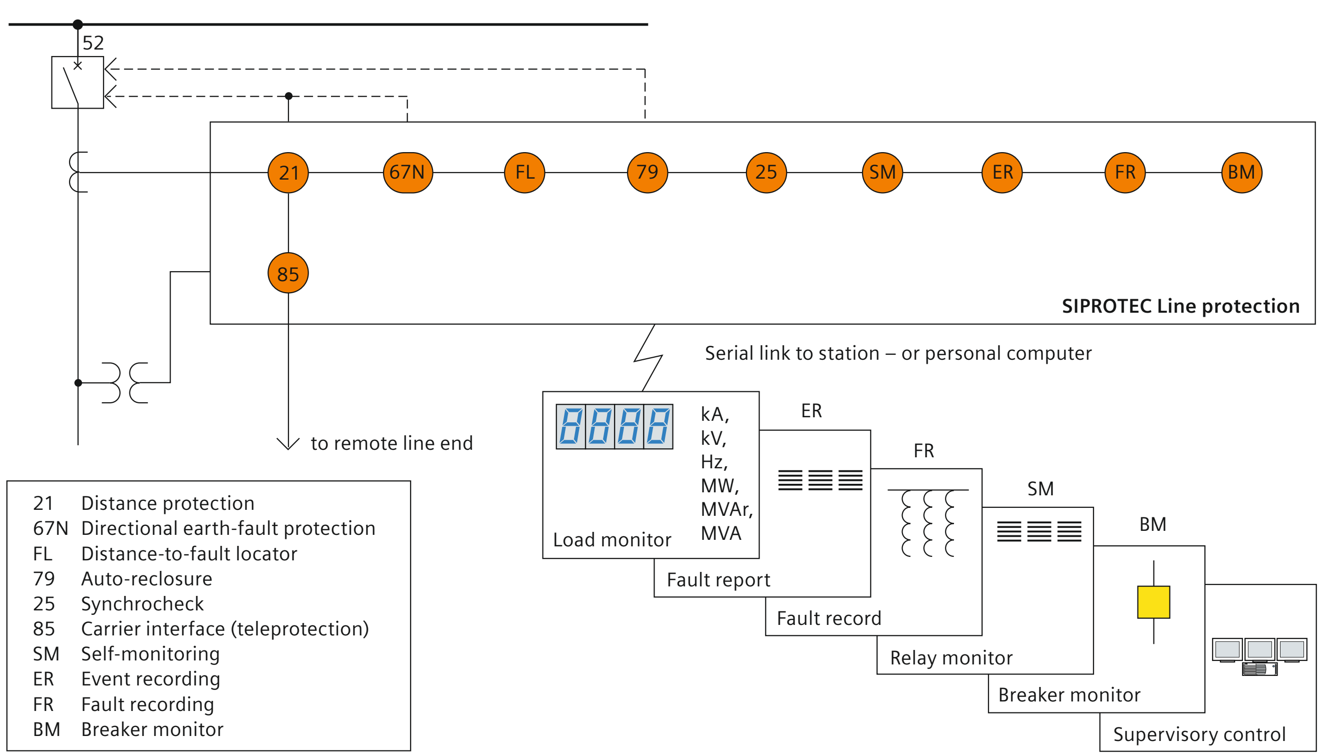


Fig. 2/14 Numerical relays offer increased information availability

Adaptive relaying

Numerical relays now offer reliable, convenient and comprehensive matching to changing conditions. Matching may be initiated either by the relay's own intelligence or from other systems via contacts or serial telegrams. Modern numerical relays contain a number of parameter sets that can be pretested during commissioning of the scheme. One set is normally operative. Transfer to the other sets can be controlled via binary inputs or a serial data link (Fig. 2/15).

There are a number of applications for which multiple setting groups can upgrade the scheme performance, for example:

- For use as a voltage-dependent control of overcurrent-time relay pickup values to overcome alternator fault current decrement to below normal load current when the automatic voltage regulator (AVR) is not in automatic operation
- For maintaining short operation times with lower fault currents, e.g., automatic change of settings if one supply transformer is taken out of service
- For "switch-onto-fault" protection to provide shorter time settings when energizing a circuit after maintenance so that normal settings can be restored automatically after a time delay
- For auto-reclosure programs, that is, instantaneous operation for first trip and delayed operation after unsuccessful reclosure
- For cold load pickup problems where high starting currents may cause relay operation
- For "ring open" or "ring closed" operation.

Implemented functions

SIPROTEC relays are available with a variety of protective functions (please refer to Fig. 2/17). The high processing power of modern numerical units allows further integration of non-protective add-on functions.

The question as to whether separate or combined relays should be used for protection and control cannot be unambiguously answered. In transmission-type substations, separation into independent hardware units is still preferred, whereas a trend toward higher function integration can be observed on the distribution level. Here, the use of combined feeder / line relays for protection, monitoring and control is becoming more common (Fig. 2/16).

Relays with protection functions only and relays with combined protection and control functions are being offered. SIPROTEC 4 relays offer combined protection and control functions. SIPROTEC 4 relays support the "one relay one feeder" principle, and thus contribute to a considerable reduction in space and wiring requirements.

With the well-proven SIPROTEC 4 family, Siemens supports both stand-alone and combined solutions on the basis of a single hardware and software platform. The user can decide within wide limits on the configuration of the control and protection, and the reliability of the protection functions (Fig. 2/17).

The following solutions are available within one relay family:

- Separate control and protection relays
- Feeder protection and remote control of the line circuit-breaker via the serial communication link
- Combined relays for protection, monitoring and control.

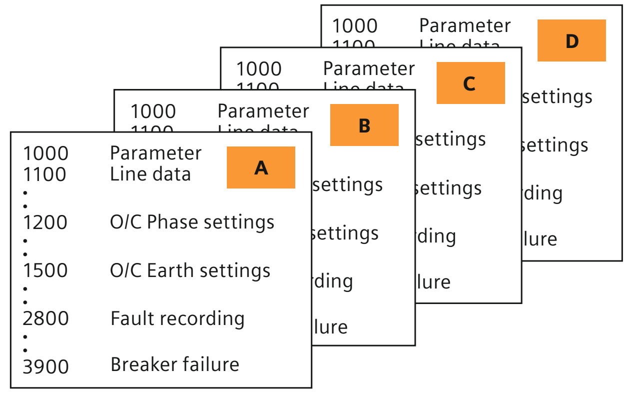
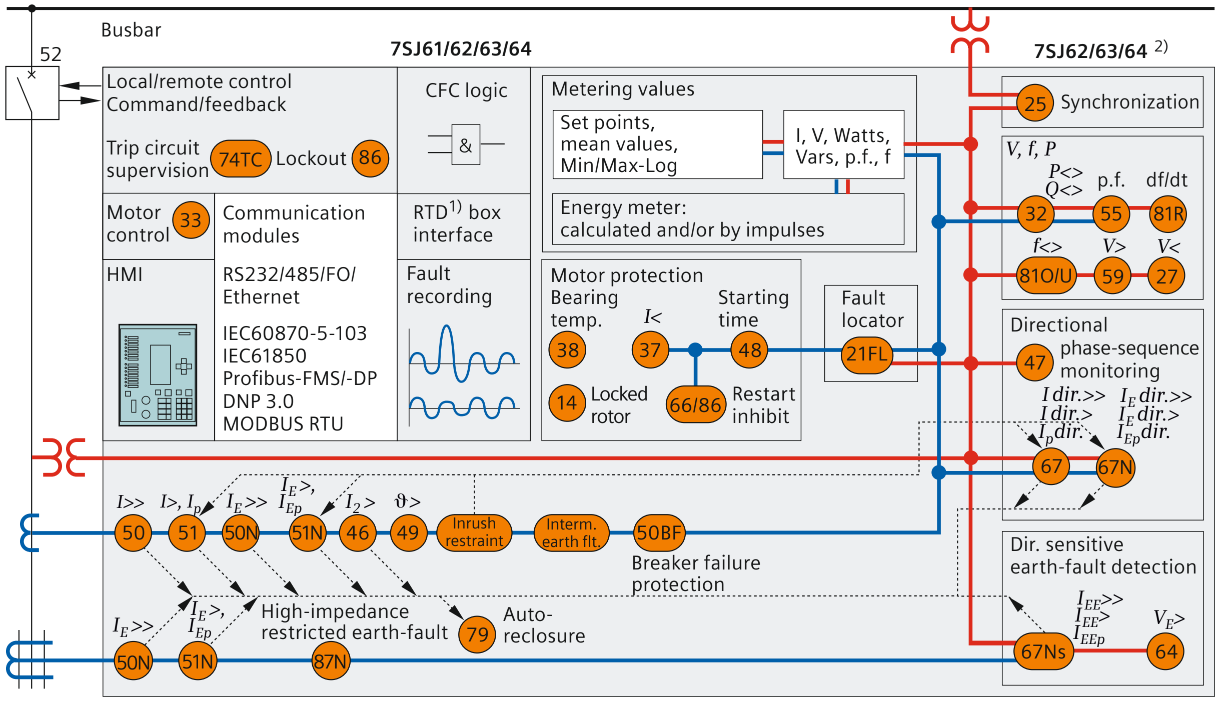


Fig. 2/15 Alternate parameter groups

Fig. 2/16 Left: switchgear with numerical relay (7SJ62) and traditional control; right: switchgear with combined protection and control relay (7SJ64)

SIPROTEC Relay Families



1) RTD = resistance temperature detector   2) VT connection for 7SJ62/63/64 only

Fig. 2/17 SIPROTEC 4 relays 7SJ61 / 62 / 63, 64 implemented functions

Terminals: Standard relay version with screw-type terminals

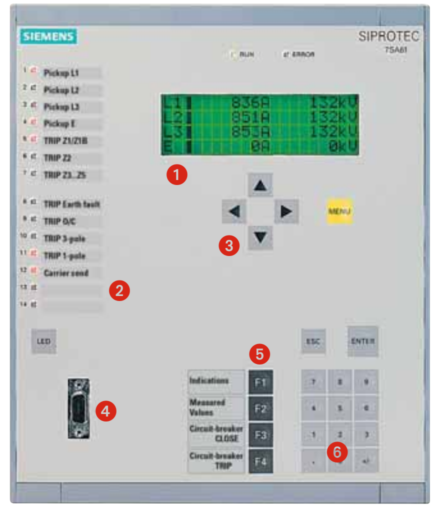
Current terminals	
Connection	W_{max} =12 mm
Ring cable lugs	*d1* =5 mm
Wire size	2.7 – 4 mm² (AWG 13 – 11)
Direct connection	Solid conductor, flexible lead, connector sleeve
Wire size	2.7 – 4 mm² (AWG 13 – 11)
Voltage terminals	
Connection	W_{max} =10 mm
Ring cable lugs	*d1* = 4 mm
Wire size	1.0 – 2.6 mm² (AWG 17 – 13)
Direct connection	Solid conductor, flexible lead, connector sleeve
Wire size	0.5 – 2.5 mm² (AWG 20 – 13)
Some relays are alternatively available with plug-in voltage terminals	
Current terminals	
Screw type (see standard version)	
Voltage terminals	
2-pin or 3-pin connectors	
Wire size	0.5 – 1.0 mm²
	0.75 – 1.5 mm²
	1.0 – 2.5 mm²

Mechanical Design

SIPROTEC 4 relays are available in 1 / 3 to 1 / 1 of 19” wide housings with a standard height of 243 mm. Their size is compatible with that of other relay families. Therefore, compatible exchange is always possible (Fig. 2/18 to Fig. 2/20).

All wires (cables) are connected at the rear side of the relay with or without ring cable lugs. A special relay version with a detached cable-connected operator panel (Fig. 2/21) is also available. It allows, for example, the installation of the relay itself in the low-voltage compartment, and of the operator panel separately in the door of the switchgear.

Fig. 2/18 1 / 1 of 19" housing



1. On the backlit LCD display, process and device information can be displayed as text.
2. Freely assignable LEDs are used to display process or device information. The LEDs can be labeled according to user requirements. An LED reset key resets the LEDs and can be used for LED testing.
3. Keys for navigation
4. RS232 operator interface (for DIGSI)
5. 4 configurable function keys permit the user to execute frequently used actions simply and fast.
6. Numerical keys

Fig. 2/22 Local operation: All operator actions can be executed and information displayed via an integrated user interface. Two alternatives for this interface are available.

Fig. 2/19 1 / 2 of 19" housing

Fig. 2/20 1 / 3 of 19" housing

Fig. 2/21 SIPROTEC 4 combined protection, control and monitoring relay with detached operator panel

1. Process and relay information can be displayed on the large illuminated LC display either graphically in the form of a mimic diagram or as text in various lists.
2. The keys mainly used for control of the switchgear are located on the "control axis" directly below the display.
3. Two key-operated switches ensure rapid and reliable changeover between "local" and "remote" control, and between "interlocked" and "non-interlocked" operation.

Fig. 2/23 Additional features of the interface with graphic display

SIPROTEC Relay Families

Apart from the relay-specific protection functions, the SIPROTEC 4 units have a multitude of additional functions that

- provide the user with information for the evaluation of faults
- facilitate adaptation to customer-specific application
- facilitate monitoring and control of customer installations.

Operational measured values

The large scope of measured and limit values permits improved power system management as well as simplified commissioning.

The r.m.s. values are calculated from the acquired current and voltage along with the power factor, frequency, active and reactive power. The following functions are available depending on the relay type

- Currents I_{L1}, I_{L2}, I_{L3}, I_N, I_{EE} (67Ns)
- Voltages V_{L1}, V_{L2}, V_{L3}, V_{L1-L2}, V_{L2-L3}, V_{L3-L1}
- Symmetrical components I_1, I_2, $3I_0$; V_1, V_2, $3V_0$
- Power Watts, V_{ars}, V_A / P, Q, S
- Power factor p.f. (cos φ)
- Frequency
- Energy ± kWh ± kVarh, forward and reverse power flow
- Mean as well as minimum and maximum current and voltage values
- Operating hours counter
- Mean operating temperature of overload function
- Limit value monitoring
  Limit values are monitored using programmable logic in the CFC. Commands can be derived from this limit value indication.
- Zero suppression
  In a certain range of very low measured values, the value is set to zero to suppress interference.

Metered values (some types)

For internal metering, the unit can calculate energy metered values from the measured current and voltage values. If an external meter with a metering pulse output is available, some SIPROTEC 4 types can obtain and process metering pulses via an indication input.

The metered values can be displayed and passed on to a control center as an accumulation with reset. A distinction is made between forward, reverse, active and reactive energy.

Operational indications and fault indications with time stamp

The SIPROTEC 4 units provide extensive data for fault analysis as well as control. All indications listed here are stored, even if the power supply is disconnected.

- Fault event log
  The last eight network faults are stored in the unit. All fault recordings are time-stamped with a resolution of 1 ms.
- Operational indications
  All indications that are not directly associated with a fault (e.g., operating or switching actions) are stored in the status indication buffer. The time resolution is 1 ms (Fig. 2/24, Fig. 2/25).

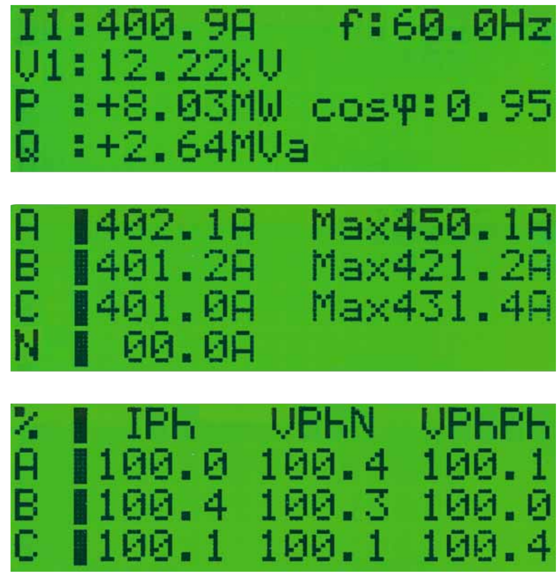


Fig. 2/24 Operational measured values

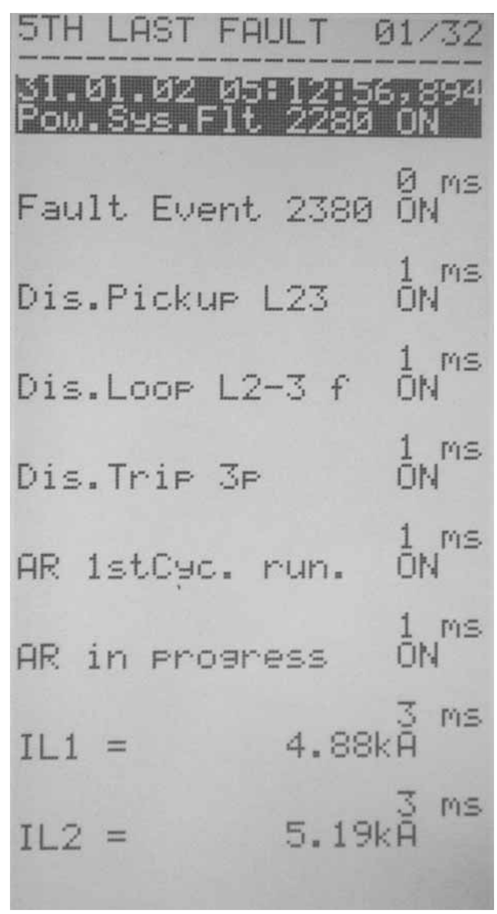


Fig. 2/25 Fault event log on graphical display of the device

Display editor

A display editor is available to design the display on SIPROTEC 4 units with graphic display. The predefined symbol sets can be expanded to suit the user. The drawing of a single-line diagram is extremely simple. Load monitoring values (analog values) and any texts or symbols can be placed on the display where required.

Four predefined setting groups for adapting relay settings

The settings of the relays can be adapted quickly to suit changing network configurations. The relays include four setting groups that can be predefined during commissioning or even changed remotely via a DIGSI 4 modem link. The setting groups can be activated via binary inputs, via DIGSI 4 (local or remote), via the integrated keypad or via the serial substation control interface.

Fault recording up to five or more seconds

The sampled values for phase currents, earth (ground) currents, line and zero-sequence currents are registered in a fault record. The record can be started using a binary input, on pickup or when a trip command occurs. Up to eight fault records may be stored. For test purposes, it is possible to start fault recording via DIGSI 4. If the storage capacity is exceeded, the oldest fault record in each case is overwritten.

For protection functions with long delay times in generator protection, the RMS value recording is available. Storage of relevant calculated variables (V_1, V_E, I_1, I_2, I_{EE}, P, Q, f-f_n) takes place at increments of one cycle. The total time is 80 s.

Time synchronization

A battery-backed clock is a standard component and can be synchronized via a synchronization signal (DCF77, IRIG B via satellite receiver), binary input, system interface or SCADA (e.g., SICAM). A date and time is assigned to every indication.

Selectable function keys

Four function keys can be assigned to permit the user to perform frequently recurring actions very quickly and simply.

Typical applications are, for example, to display the list of operating indications or to perform automatic functions such as “switching of circuit-breaker”.

Continuous self-monitoring

The hardware and software are continuously monitored. If abnormal conditions are detected, the unit immediately signals. In this way, a great degree of safety, reliability and availability is achieved.

Reliable battery monitoring

The battery provided is used to back up the clock, the switching statistics, the status and fault indications, and the fault recording in the event of a power supply failure. Its function is checked by the processor at regular intervals. If the capacity of the battery is found to be declining, an alarm is generated. Regular replacement is therefore not necessary.

All setting parameters are stored in the Flash EPROM and are not lost if the power supply or battery fails. The SIPROTEC 4 unit remains fully functional.

Commissioning support

Special attention has been paid to commissioning. All binary inputs and output contacts can be displayed and activated directly. This can significantly simplify the wiring check for the user. Test telegrams to a substation control system can be initiated by the user as well.

CFC: Programming logic

With the help of the CFC (Continuous Function Chart) graphic tool, interlocking schemes and switching sequences can be configured simply via drag and drop of logic symbols; no special knowledge of programming is required. Logical elements, such as AND, OR, flip-flops and timer elements are available. The user can also generate user-defined annunciations and logical combinations of internal or external signals.

Communication interfaces

With respect to communication, particular emphasis has been placed on high levels of flexibility, data integrity and utilization of standards commonly used in energy automation. The design of the communication modules permits interchangeability on the one hand, and on the other hand provides openness for future standards.

Local PC interface

The PC interface accessible from the front of the unit permits quick access to all parameters and fault event data. Of particular advantage is the use of the DIGSI 4 operating program during commissioning.

2

SIPROTEC Relay Families

Retrofitting: Communication modules

It is possible to supply the relays directly with two communication modules for the service and substation control interfaces, or to retrofit the communication modules at a later stage. The modules are mounted on the rear side of the relay. As a standard, the time synchronization interface is always supplied.

The communication modules are available for the entire SIPROTEC 4 relay range. Depending on the relay type, the following protocols are available: IEC 60870-5-103, PROFIBUS DP, MODBUS RTU, DNP 3.0 and Ethernet with IEC 61850. No external protocol converter is required.

With respect to communication, particular emphasis is placed on the requirements in energy automation:

- Every data item is time-stamped at the source, that is, where it originates.
- The communication system automatically handles the transfer of large data blocks (e.g., fault records or parameter data files). The user can apply these features without any additional programming effort.
- For reliable execution of a command, the relevant signal is first acknowledged in the unit involved. When the command has been enabled and executed, a check-back indication is issued. The actual conditions are checked at every command-handling step. Whenever they are not satisfactory, controlled interruption is possible.

Fig. 2/26 Protection relay

Fig. 2/27 Communication module, optical

Fig. 2/28 Communication module RS232,RS485

Fig. 2/29 Communication module, optical ring

The following interfaces can be applied:

1 Service interface (optional)
Several protection relays can be centrally operated with DIGSI 4, e.g., via a star coupler or RS485 bus. On connection of a modem, remote control is possible. This provides advantages in fault clearance, particularly in unmanned power stations. (Alternatively, the external temperature monitoring box can be connected to this interface.)

2 System interface (optional)
This is used to carry out communication with a control system and supports, depending on the module connected, a variety of communication protocols and interface designs.

3 Time synchronization interface
A synchronization signal (DCF 77, IRIG B via satellite receiver) may be connected to this input if no time synchronization is executed on the system interface. This offers a high-precision time tagging.

Fig. 2/30 Rear view with wiring, terminal safety cover and serial interfaces

Safe bus architecture

- Fiber-optic double ring circuit via Ethernet
  The fiber-optic double ring circuit is immune to electromagnetic interference. Upon failure of a section between two units, the communication system continues to operate without interruption. If a unit were to fail, there is no effect on the communication with the rest of the system (Fig. 2/31).
- RS485 bus
  With this data transmission via copper wires, electromagnetic interference is largely eliminated by the use of twisted-pair conductors. Upon failure of a unit, the remaining system continues to operate without any faults (Fig. 2/32).
- Star structure
  The relays are connected with a fiber-optic cable with a star structure to the control unit. The failure of one relay / connection does not affect the others (Fig. 2/33).

Depending on the relay type, the following protocols are available:

- IEC 61850 protocol
  Since 2004, the Ethernet-based IEC 61850 protocol is the worldwide standard for protection and control systems used by power supply corporations. Siemens is the first manufacturer to support this standard. By means of this protocol, information can also be exchanged directly between feeder units so as to set up simple masterless systems for feeder and system interlocking. Access to the units via the Ethernet bus will also be possible with DIGSI.
- IEC 60870-5-103
  IEC 60870-5-103 is an internationally standardized protocol for efficient communication between the protection relays and a substation control system. Specific extensions that are published by Siemens can be used.
- PROFIBUS DP
  For connection to a SIMATIC PLC, the PROFIBUS DP protocol is recommended. With the PROFIBUS DP, the protection relay can be directly connected to a SIMATIC S5 / S7. The transferred data are fault data, measured values and control commands.

Substation automation system

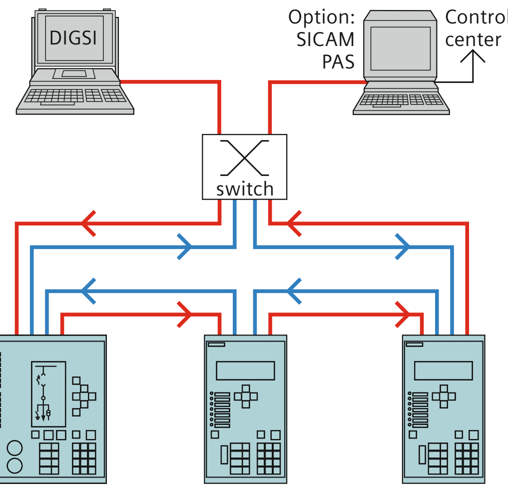


Fig. 2/31 Ring bus structure for station bus with Ethernet and IEC 61850

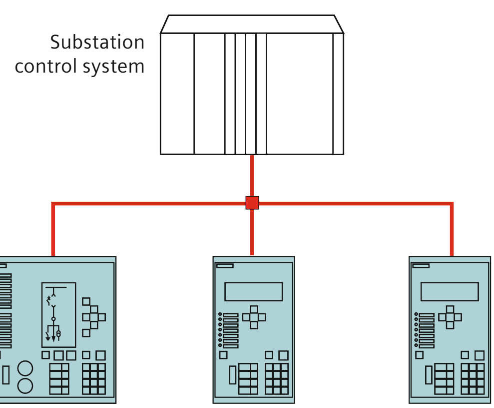


Fig. 2/32 PROFIBUS: Electrical RS485 bus wiring

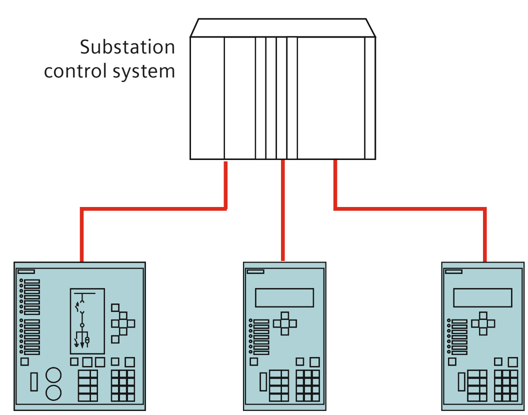


Fig. 2/33 IEC 60870-5-103: Star structure with fiber-optic cables

SIPROTEC Relay Families

MODBUS RTU

MODBUS is also a widely utilized communication standard and is used in numerous automation solutions.

DNP 3.0

DNP 3.0 (Distributed Network Protocol, version 3) is a messaging-based communication protocol. The SIPROTEC 4 units are fully Level 1 and Level 2-compliant with DNP 3.0, which is supported by a number of protection unit manufacturers.

Control

In addition to the protection functions, the SIPROTEC 4 units also support all control and monitoring functions required for operating medium-voltage or high-voltage substations. The main application is reliable control of switching and other processes. The status of primary equipment or auxiliary devices can be obtained from auxiliary contacts and communicated to the relay via binary inputs.

Therefore, it is possible to detect and indicate both the OPEN and CLOSED positions or a faulty or intermediate breaker position. The switchgear can be controlled via:

- Integrated operator panel
- Binary inputs
- Substation control system
- DIGSI 4.

Automation

With the integrated logic, the user can set specific functions for the automation of the switchgear or substation by means of a graphic interface (CFC). Functions are activated by means of function keys, binary inputs or via the communication interface.

Switching authority

The following hierarchy of switching authority is applicable: LOCAL, DIGSI 4 PC program, REMOTE. The switching authority is determined according to parameters or by DIGSI 4. If the LOCAL mode is selected, only local switching operations are possible. Every switching operation and change of breaker position is stored in the status indication memory with detailed information and time tag.

Fig. 2/34 Protection engineer at work

Command processing

The SIPROTEC 4 protection relays offer all functions required for command processing, including the processing of single and double commands, with or without feedback, and sophisticated monitoring. Control actions using functions, such as runtime monitoring and automatic command termination after output check of the external process, are also provided by the relays. Typical applications are:

- Single and double commands using 1, 1 plus 1 common or 2 trip contacts
- User-definable feeder interlocking
- Operating sequences combining several switching operations, such as control of circuit-breakers, disconnectors (isolators) and earthing switches
- Triggering of switching operations, indications or alarms by logical combination of existing information (Fig. 2/34).

The positions of the circuit-breaker or switching devices are monitored by feedback signals. These indication inputs are logically assigned to the corresponding command outputs. The unit can therefore distinguish whether the indication changes as a consequence of a switching operation or due to a spontaneous change of state.

Indication derivation

A further indication (or a command) can be derived from an existing indication. Group indications can also be formed. The volume of information to the system interface can thus be reduced and restricted to the most important signals.

Typical Protection Schemes

1. Cables and overhead lines

Radial systems

Notes:

1) Auto-reclosure (ANSI 79) only with overhead lines.
2) Negative sequence overcurrent protection 46 as sensitive backup protection against asymmetrical faults.

General notes:

- The relay at the far end (D) is set with the shortest operating time. Relays further upstream have to be time-graded against the next downstream relay in steps of about 0.3 s.
- Inverse time or definite time can be selected according to the following criteria:
  - Definite time:
    Source impedance is large compared to the line impedance, that is, there is small current variation between near and far end faults.
  - Inverse time:
    Longer lines, where the fault current is much less at the far end of the line than at the local end.
  - Strong or extreme inverse-time:
    Lines where the line impedance is large compared to the source impedance (high difference for close-in and remote faults), or lines where coordination with fuses or reclosers is necessary. Steeper characteristics also provide higher stability on service restoration (cold load pickup and transformer inrush currents).

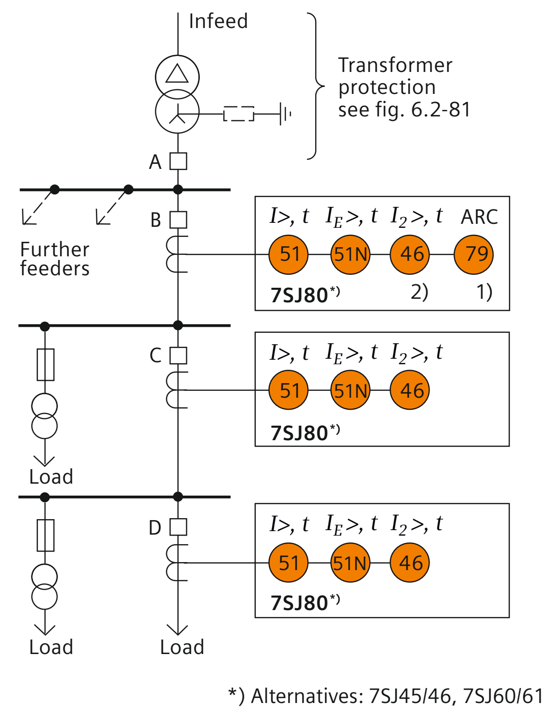


Fig. 2/35 Radial systems

Ring-main circuit

General notes:

- Operating time of overcurrent relays to be coordinated with downstream fuses of load transformers (preferably with strong inverse-time characteristic with about 0.2 s grading-time delay)
- Thermal overload protection for the cables (option)
- Negative sequence overcurrent protection (46) as sensitive protection against asymmetrical faults (option).

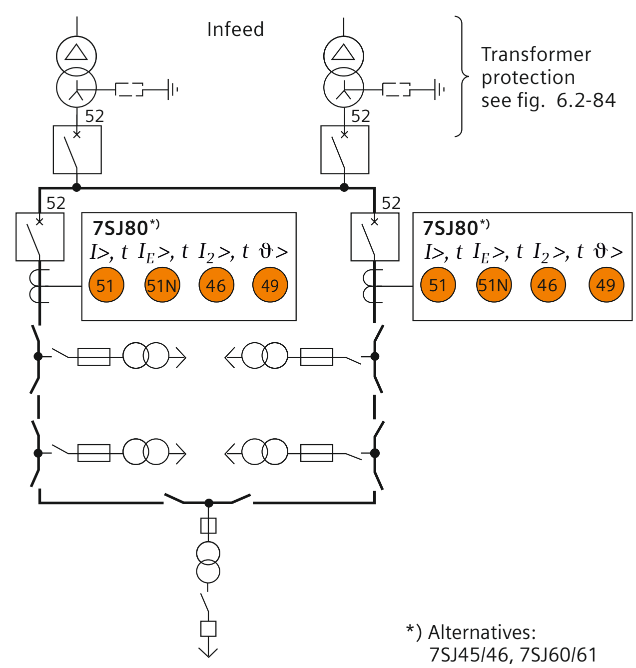


Fig. 2/36 Ring-main circuit

Typical Protection Schemes

Switch-onto-fault protection

If switched onto a fault, instantaneous tripping can be effected. If the internal control function is used (local, via binary input or via serial interface), the manual closing function is available without any additional wiring. If the control switch is connected to a circuit-breaker bypassing the internal control function, manual detection using a binary input is implemented.

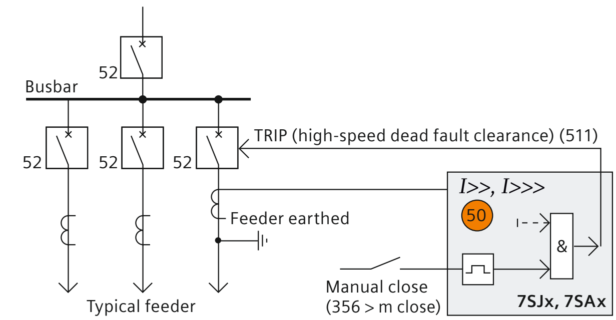


Fig. 2/37 Switch-onto-fault protection

Directional comparison protection (cross-coupling)

Cross-coupling is used for selective protection of sections fed from two sources with instantaneous tripping, that is, without the disadvantage of time coordination. The directional comparison protection is suitable if the distances between the protection stations are not significant and pilot wires are available for signal transmission. In addition to the directional comparison protection, the directional coordinated overcurrent-time protection is used for complete selective backup protection. If operated in a closed-circuit connection, an interruption of the transmission line is detected.

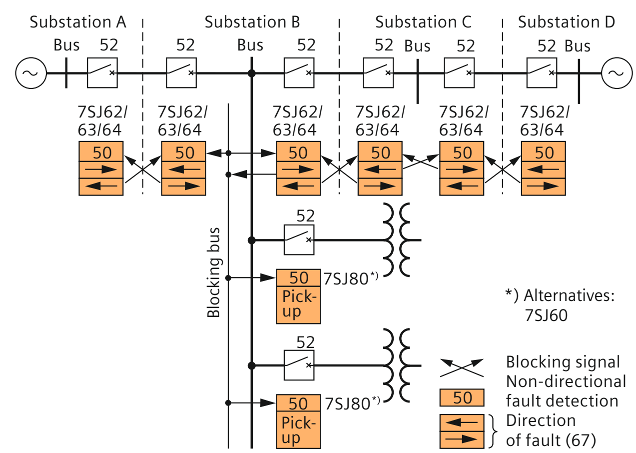


Fig. 2/38 Directional comparison protection

Distribution feeder with reclosers

General notes:

- The feeder relay operating characteristics, delay times and auto-reclosure cycles must be carefully coordinated with downstream reclosers, sectionalizers and fuses.
  The 50 / 50N instantaneous zone is normally set to reach out to the first main feeder sectionalizing point. It has to ensure fast clearing of close-in faults and prevent blowing of fuses in this area ("fuse saving"). Fast auto-reclosure is initiated in this case. Further time-delayed tripping and reclosure steps (normally two or three) have to be graded against the recloser.
- The overcurrent relay should automatically switch over to less sensitive characteristics after long breaker interruption times in order to enable overriding of subsequent cold load pickup and transformer inrush currents.

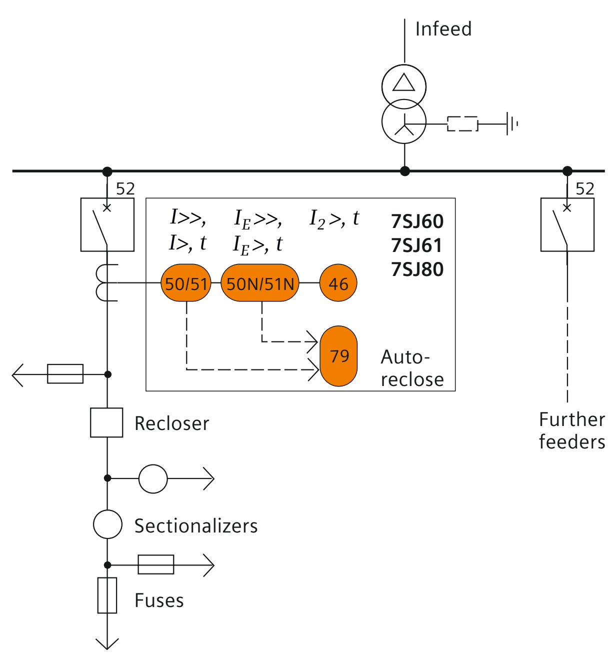


Fig. 2/39 Distribution feeder with reclosers

3-pole multishot auto-reclosure (AR, ANSI 79)

Auto-reclosure (AR) enables 3-phase auto-reclosing of a feeder that has previously been disconnected by overcurrent protection.

SIPROTEC 7SJ61 allows up to nine reclosing shots. The first four dead times can be set individually. Reclosing can be blocked or initiated by a binary input or internally. After the first trip in a reclosing sequence, the high-set instantaneous elements (I>>>, I>>, I_E>>) can be blocked. This is used for fuse-saving applications and other similar transient schemes using simple overcurrent relays instead of fuses. The low-set definite-time (I>, I_E>) and the inverse-time (I_p, I_{Ep}) overcurrent elements remain operative during the entire sequence.

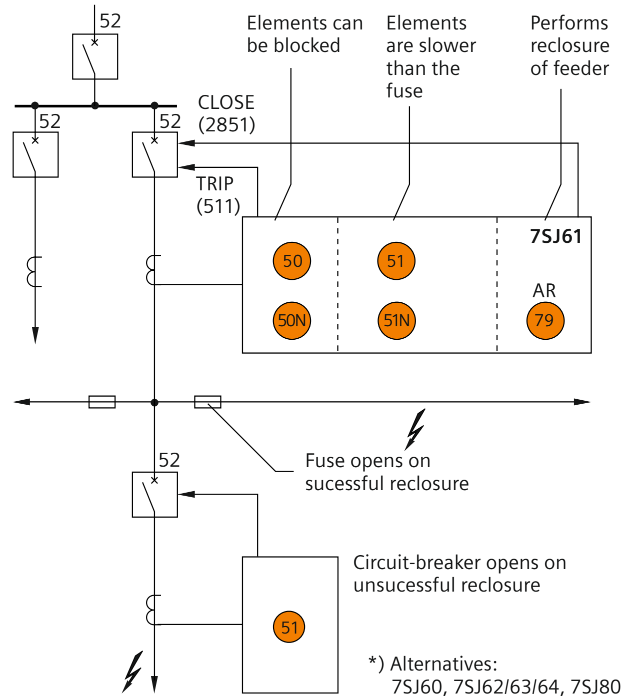


Fig. 2/40 3-pole multishot auto-reclosure (AR, ANSI 79)

Parallel feeder circuit

General notes:

- The preferred application of this circuit is in the reliable supply of important consumers without significant infeed from the load side.
- The 67 / 67N directional overcurrent protection trips instantaneously for faults on the protected line. This saves one time-grading interval for the overcurrent relays at the infeed.
- The 51 / 51N overcurrent relay functions must be time-graded against the relays located upstream.

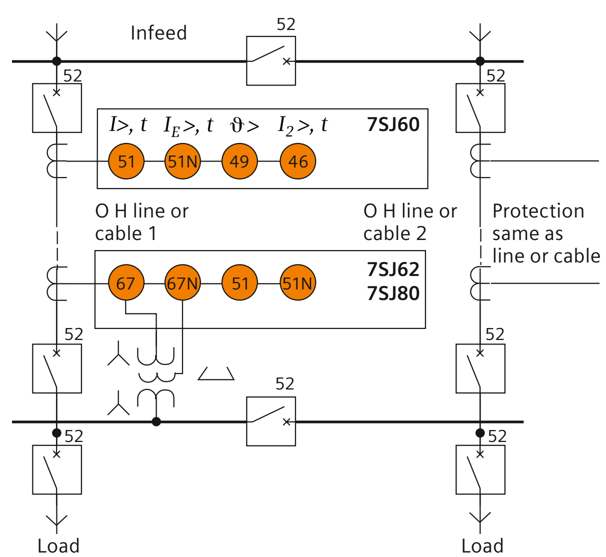


Fig. 2/41 Parallel feeder circuit

2

Typical Protection Schemes

Reverse-power monitoring at double infeed

If a busbar is fed from two parallel infeeds and a fault occurs on one of them, only the faulty infeed should be tripped selectively in order to enable supply to the busbar to continue from the remaining supply. Unidirectional devices that can detect a short-circuit current or energy flow from the busbar toward the incoming feeder should be used. Directional time-overcurrent protection is usually set via the load current. However, it cannot clear weak-current faults. The reverse-power protection can be set much lower than the rated power, thus also detecting the reverse-power flow of weak-current faults with fault currents significantly below the load current.

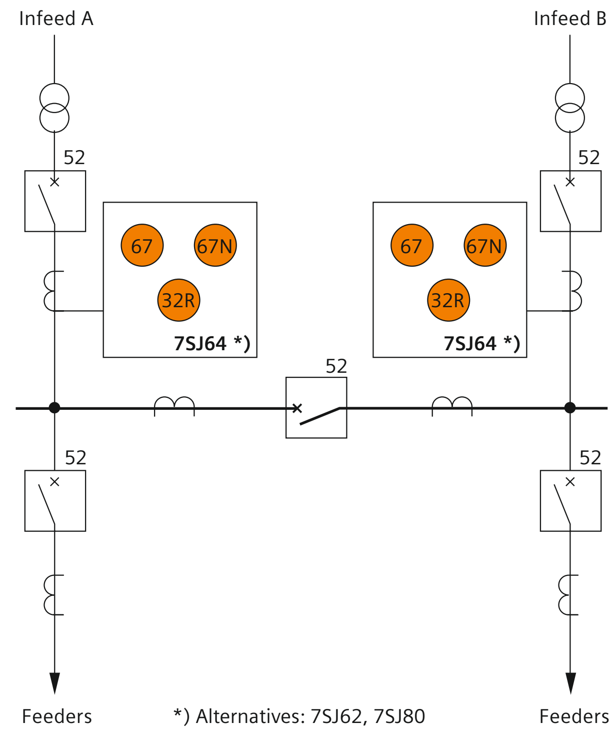


Fig. 2/42 Reverse-power monitoring at double infeed

Synchronization function

Note:

Also available in relays 7SA6, 7SD5, 7SA522, 7VK61.

General notes:

- When two subsystems must be interconnected, the synchronization function monitors whether the subsystems are synchronous and can be connected without risk of losing stability.
- This synchronization function can be applied in conjunction with the auto-reclosure function as well as with the control function CLOSE commands (local / remote).

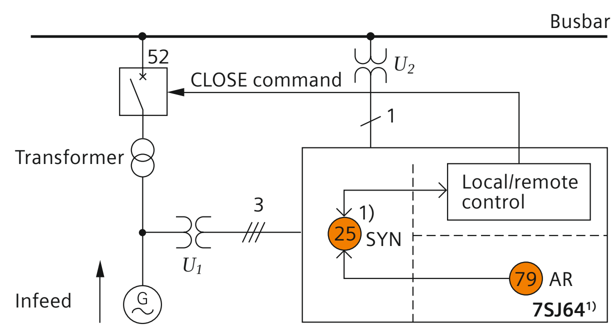


Fig. 2/43 Synchronization function

Cables or short overhead lines with infeed from both ends

Notes:

1) Auto-reclosure only with overhead lines

2) Differential protection options:

- Type 7SD5 or 7SD610 with direct fiber-optic connection up to about 100 km or via a 64 kbit / s channel (optical fiber, microwave)
- Type 7SD52 or 7SD610 with 7XV5662 (CC-CC) with 2 and 3 pilot wires up to about 30 km
- Type 7SD80 with pilot wire and/or fibre optic protection data interface.

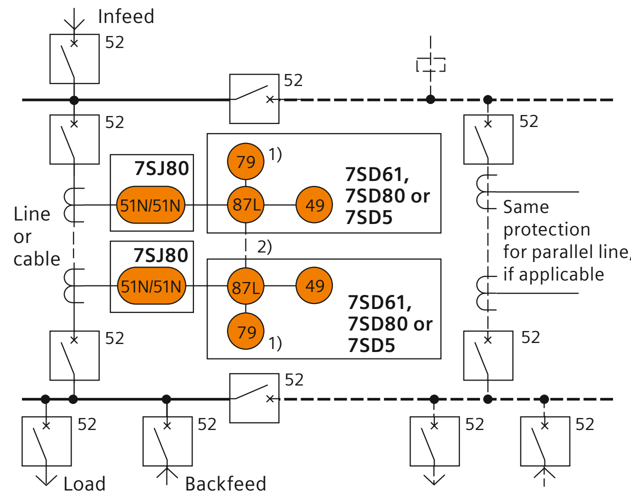


Fig. 2/44 Cables or short overhead lines with infeed from both ends

Overhead lines or longer cables with infeed from both ends

Notes:

1) Teleprotection logic (85) for transfer trip or blocking schemes. Signal transmission via pilot wire, power line carrier, digital network or optical fiber (to be provided separately). The teleprotection supplement is only necessary if fast fault clearance on 100 % line length is required, that is, second zone tripping (about 0.3 s delay) cannot be accepted for far end faults. For further application notes on teleprotection schemes, refer to the table on the following page.

2) Directional earth-fault protection 67N with inverse-time delay against high-resistance faults

3) Single or multishot auto-reclosure (79) only with overhead lines.

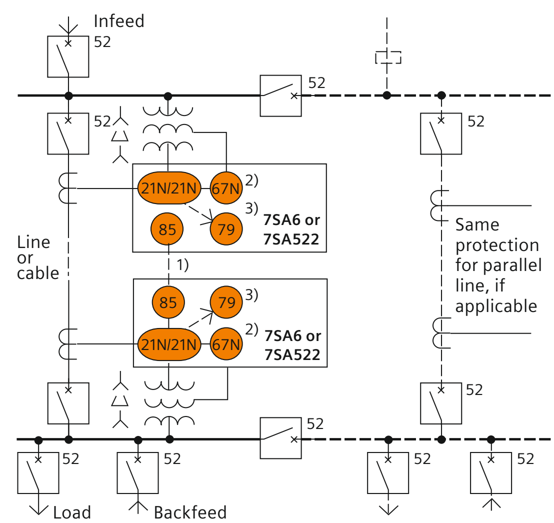


Fig. 2/45 Overhead lines or longer cables with infeed from both ends

Subtransmission line

Note:

Connection to open delta winding if available. Relays 7SA6 / 522 and 7SJ62 can, however, also be set to calculate the zero-sequence voltage internally.

General notes:

- Distance teleprotection is proposed as main protection and time-graded directional overcurrent as backup protection.
- The 67N function of 7SA6 / 522 provides additional high-resistance earth-fault protection. It can be used in parallel with the 21 / 21N function.
- Recommended teleprotection schemes: PUTT on medium and long lines with phase shift carrier or other secure communication channel POTT on short lines. BLOCKING with On / Off carrier (all line lengths).

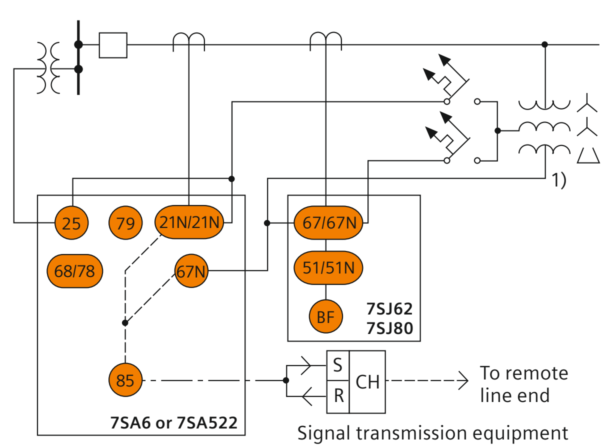


Fig. 2/46 Subtransmission line

Typical Protection Schemes

<table>
<tr><th colspan="2"></th><th>Permissive underreach transfer trip (PUTT)</th><th>Permissive overreach transfer trip (POTT)</th><th>Blocking</th><th>Unblocking</th></tr>
<tr><td rowspan="2">Preferred application</td><td>Signal transmission system</td><td colspan="2">Dependable and secure communication channel:
• Power line carrier with frequency shift modulation.
HF signal coupled to 2 phases of the protected line, or even better, to a parallel circuit to avoid transmission of the HF signal through the fault location.
• Microwave radio, especially digital (PCM)
• Fiber-optic cables</td><td>Reliable communication channel (only required during external faults)
• Power line carrier with amplitude modulation (ON / OFF). The same frequency may be used on all terminals)</td><td>Dedicated channel with continuous signal transfer
• Power line carrier with frequency shift keying. Continuous signal transmission must be permitted.</td></tr>
<tr><td>Characteristic of line</td><td>Best suited for longer lines – where the underreach zone provides sufficient resistance coverage</td><td>• Excellent coverage on short lines in the presence of fault resistance.
• Suitable for the protection of multi-terminal lines with intermediate infeed</td><td>All line types – preferred practice in the US</td><td>Same as POTT</td></tr>
<tr><td colspan="2">Advantages</td><td>• Simple technique
• No coordination of zones and times with the opposite end required. The combination of different relay types therefore presents no problems</td><td>• Can be applied without underreaching zone 1 stage (e.g., overcompensated series uncompensated lines)
• Can be applied on extremely short lines (impedance less than minimum relay setting)
• Better for parallel lines as mutual coupling is not critical for the overreach zone
• Weak infeed terminals are no problem (Echo and Weak Infeed logic is included)</td><td>Same as POTT</td><td>Same as POTT but:
• If no signal is received (no block and no uncompensated block) then tripping by the overreach zone is released after 20 ms</td></tr>
<tr><td colspan="2">Drawbacks</td><td>• Overlapping of the zone 1 reaches must be ensured. On parallel lines, teed feeders and tapped lines, the influence of zero sequence coupling and intermediate infeeds must be carefully considered to make sure a minimum overlapping of the zone 1 reach is always present.
• Not suitable for weak infeed terminals</td><td>• Zone reach and signal timing coordination with the remote end is necessary (current reversal)</td><td>Same as POTT
• Slow tripping – all teleprotection trips must be delayed to wait for the eventual blocking signal
• Continuous channel monitoring is not possible</td><td>Same as POTT</td></tr>
</table>

Table 2/1 Application criteria for frequently used teleprotection schemes

Transmission line with reactor (Fig. 2/47)

Notes:

1) 51N only applicable with earthed reactor neutral.
2) If phase CTs at the low-voltage reactor side are not available, the high-voltage phase CTs and the CT in the neutral can be connected to a restricted earth-fault protection using one 7VH60 high-impedance relay.

General notes:

- Distance relays are proposed as main 1 and main 2 protection. Duplicated 7SA6 is recommended for series-compensated lines.
- Operating time of the distance relays is in the range of 15 to 25 ms depending on the particular fault condition. These tripping times are valid for faults in the underreaching distance zone (80 to 85 % of the line length). Remote end faults must be cleared by the superimposed teleprotection scheme. Its overall operating time depends on the signal transmission time of the channel, typically 15 to 20 ms for frequency shift audio-tone PLC or microwave channels, and lower than 10 ms for ON / OFF PLC or digital PCM signaling via optical fibers. Teleprotection schemes based on distance relays therefore have operating times on the order of 25 to 30 ms with digital PCM coded communication. With state-of-the-art two-cycle circuit-breakers, fault clearing times well below 100 ms (4 to 5 cycles) can normally be achieved.
- Dissimilar carrier schemes are recommended for main 1 and main 2 protection, for example, PUTT, and POTT or Blocking / Unblocking.
- Both 7SA522 and 7SA6 provide selective 1-pole and / or 3-pole tripping and auto-reclosure. The earth-current directional comparison protection (67N) of the 7SA6 relay uses phase selectors based on symmetrical components. Thus, 1-pole auto-reclosure can also be executed with high-resistance faults. The 67N function of the 7SA522 relay can also be used as time-delayed directional overcurrent backup.
- The 67N functions are provided as high-impedance fault protection. 67N is often used with an additional channel as a separate carrier scheme. Use of a common channel with distance protection is only possible if the mode is compatible (e.g., POTT with directional comparison). The 67N may be blocked when function 21 / 21N picks up. Alternatively, it can be used as time-delayed backup protection.

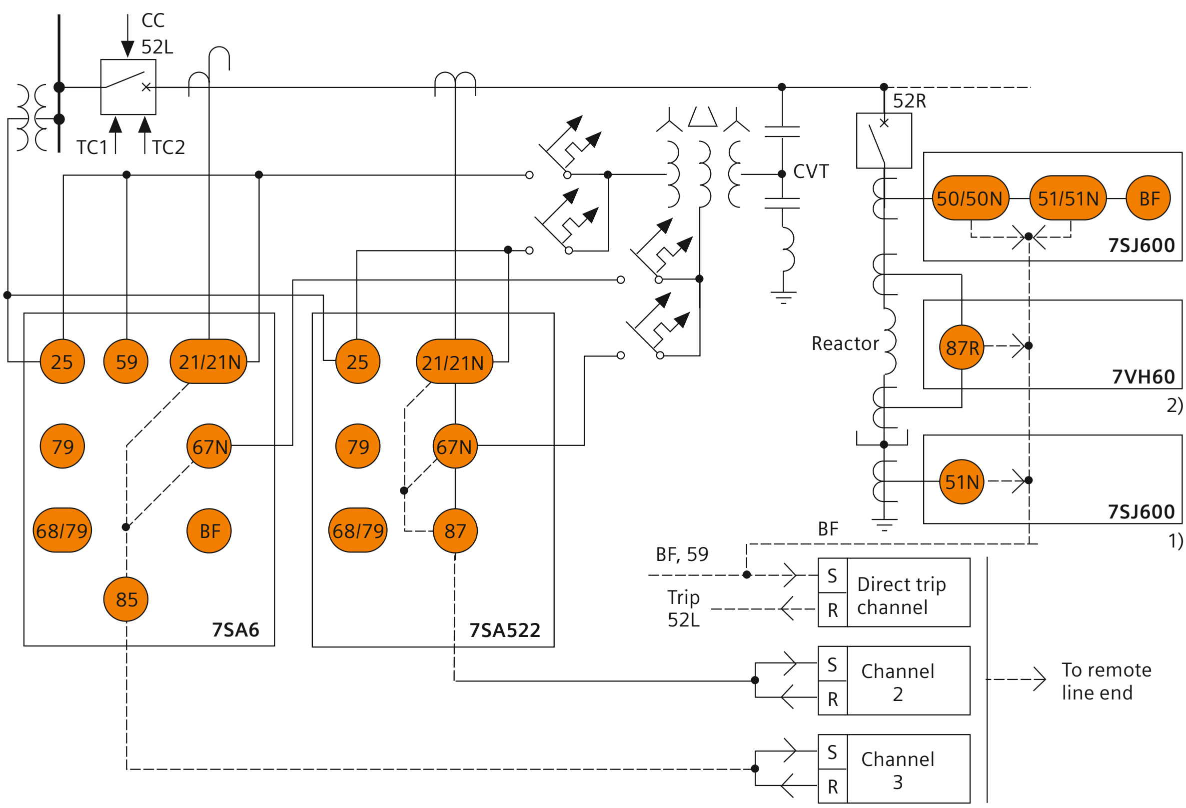


Fig. 2/47 Transmission line with reactor

Typical Protection Schemes

Transmission line or cable (with wide-band communication)

General notes:

- Digital PCM-coded communication (with n × 64 kbit / s channels) between line ends is becoming more and more frequently available, either directly by optical or microwave point-to-point links, or via a general-purpose digital communication network.
  In both cases, the relay-type current differential protection 7SD52 / 61 can be applied. It provides absolute phase and zone selectivity by phase-segregated measurement, and is not affected by power swing or parallel line zero-sequence coupling effects. It is, furthermore, a current-only protection that does not need a VT connection. For this reason, the adverse effects of CVT transients are not applicable.
  This makes it particularly suitable for double and multi-circuit lines where complex fault situations can occur.
  The 7SD5 / 61 can be applied to lines up to about 120 km in direct relay-to-relay connections via dedicated optical fiber cores (see also application “Cables or short overhead lines with infeed from both ends”, page 2/21), and also to much longer distances of up to about 120 km by using separate PCM devices for optical fiber or microwave transmission. The 7SD5 / 61 then uses only a small part (64 to 512 kbit / s) of the total transmission capacity (on the order of Mbits / s).
- The 7SD52 / 61 protection relays can be combined with the distance relay 7SA52 or 7SA6 to form a redundant protection system with dissimilar measuring principles complementing each other (Fig. 2/48). This provides the highest degree of availability. Also, separate signal transmission ways should be used for main 1 and main 2 line protection, e.g., optical fiber or microwave, and power line carrier (PLC).
  The current comparison protection has a typical operating time of 15 ms for faults on 100 % line length, including signaling time.

General notes for Fig. 2/49:

- SIPROTEC 7SD5 offers fully redundant differential and distance relays accommodated in one single bay control unit, and provides both high-speed operation of relays and excellent fault coverage, even under complicated conditions. Precise distance-to-fault location avoids time-consuming line patrolling, and reduces the downtime of the line to a minimum.
- The high-speed distance relay operates fully independently from the differential relay. Backup zones provide remote backup for upstream and downstream lines and other power system components

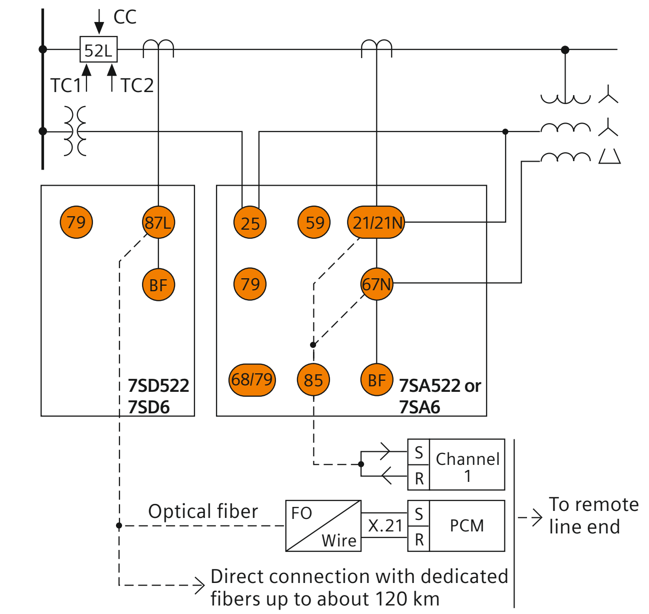


Fig. 2/48 Redundant transmission line protection

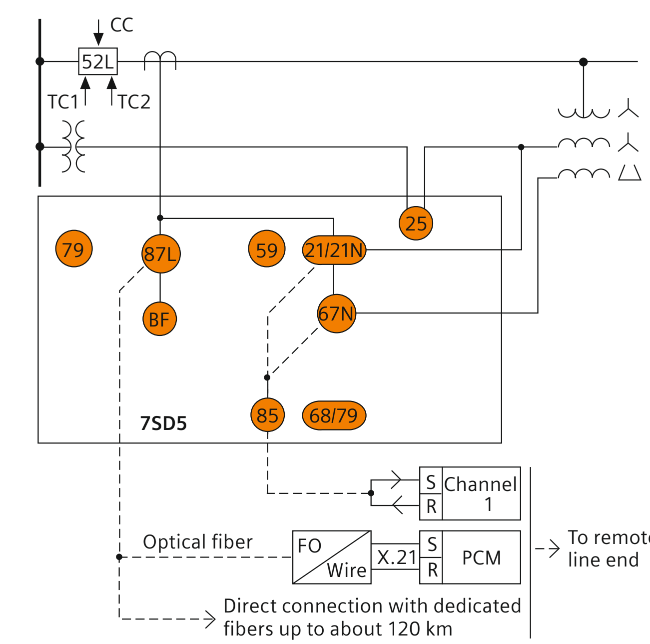


Fig. 2/49 Transmission line protection with redundant algorithm in one device

Transmission line, one-breaker-and-a-half terminal

Notes:

1) When the line is switched off and the line line disconnector (isolator) is open, high through-fault currents in the diameter may cause maloperation of the distance relay due to unequal CT errors (saturation).
   Normal practice is therefore to block the distance protection (21 / 21N) and the directional earth-fault protection (67N) under this condition via an auxiliary contact of the line line disconnector (isolator). A standby overcurrent function (50 / 51N, 51 / 51N) is released instead to protect the remaining stub between the breakers ("stub" protection).
2) Overvoltage protection only with 7SA6 / 52.

General notes:

- The protection functions of one diameter of a breaker-and-a-half arrangement are shown.
- The currents of two CTs have each to be summed up to get the relevant line currents as input for main 1 and 2 line protection.
- The location of the CTs on both sides of the circuit-breakers is typical for substations with dead-tank circuit-breakers. Live-tank circuit-breakers may have CTs only on one side to reduce cost. A fault between circuit-breakers and CT (end fault) may then still be fed from one side even when the circuit-breaker has opened. Consequently, final fault clearing by cascaded tripping has to be accepted in this case.
- The 7VK61 relay provides the necessary end fault protection function and trips the circuit-breakers of the remaining infeeding circuits.

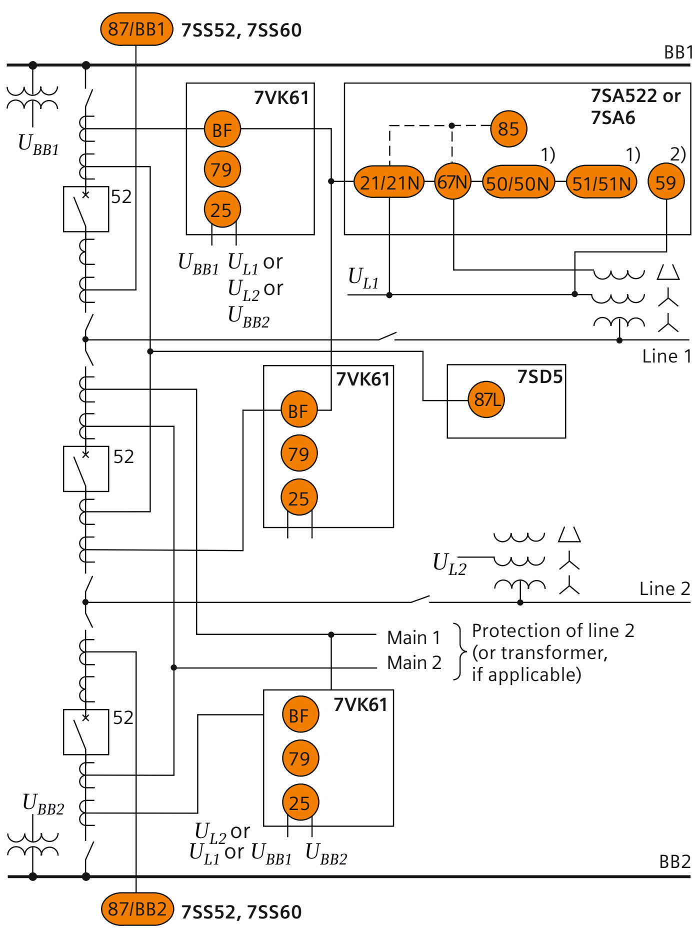


Fig. 2/50 Transmission line, one-breaker-and-a-half terminal, using 3 breaker management relays 7VK61

Typical Protection Schemes

General notes for Fig. 2/50 and 2/51:

- For the selection of the main 1 and main 2 line protection schemes, the comments of application examples "Transmission with reactor", page 2/23 and "Transmission line or cable", page 2/24 apply.
- Auto-reclosure (79) and synchrocheck function (25) are each assigned directly to the circuit-breakers and controlled by main 1 and 2 line protection in parallel. In the event of a line fault, both adjacent circuit-breakers have to be tripped by the line protection. The sequence of auto-reclosure of both circuit-breakers or, alternatively, the auto-reclosure of only one circuit-breaker and the manual closure of the other circuit-breaker, may be made selectable by a control switch.
- A coordinated scheme of control circuits is necessary to ensure selective tripping interlocking and reclosing of the two circuit-breakers of one line (or transformer feeder).
- The voltages for synchrocheck have to be selected according to the circuit-breaker and disconnector (isolator) position by a voltage replica circuit.

General notes for Fig. 2/51:

- In this optimized application, the 7VK61 is only used for the center breaker. In the line feeders, functions 25, 79 and BF are also performed by transmission line protection 7SA522 or 7SA6.

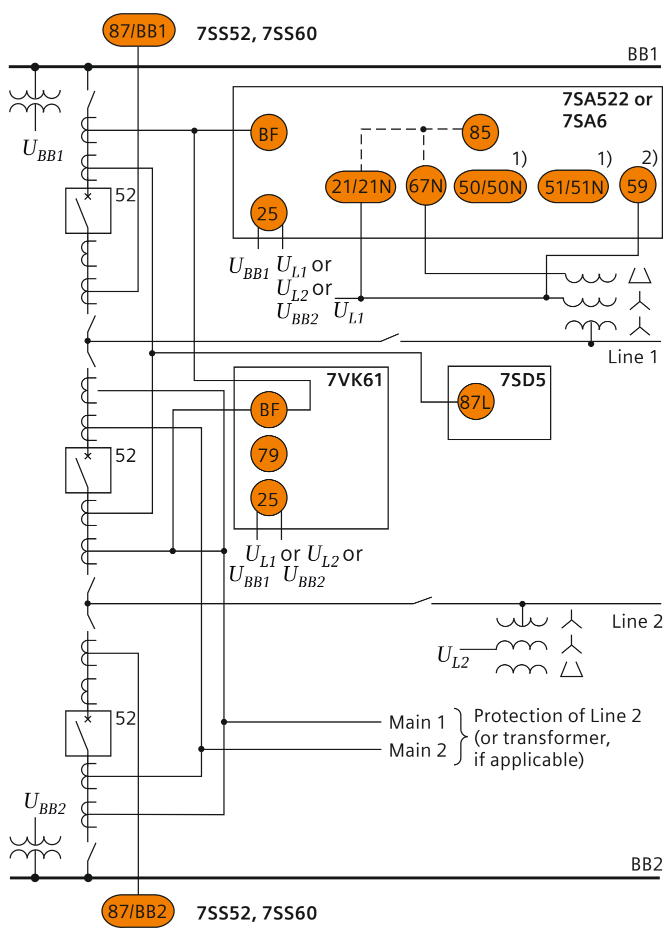


Fig. 2/51 Tranmission line, breaker-and-a-half terminal, using 1 breaker management relay 7VK61

2. Transformers

Small transformer infeed

General notes:

- Earth faults on the secondary side are detected by current relay 51N. However, it has to be time-graded against downstream feeder protection relays.
- The restricted earth-fault relay 87N can optionally be applied to achieve fast clearance of earth faults in the transformer secondary winding.
  Relay 7VH60 is of the high-impedance type and requires class × CTs with equal transformation ratios.
- Primary circuit-breaker and relay may be replaced by fuses.

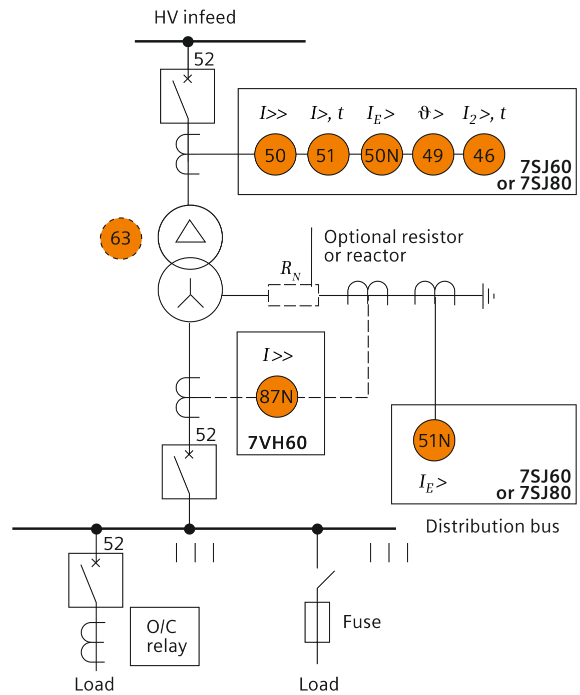


Fig. 2/52 Small transformer infeed

Large or important transformer infeed

General note:

- Relay 7UT612 provides numerical ratio and vector group adaptation. Matching transformers as used with traditional relays are therefore no longer applicable.

Notes:

1) If an independent high-impedance-type earth-fault function is required, the 7VH60 earth-fault relay can be used instead of the 87N inside the 7UT612. However, class × CT cores would also be necessary in this case (see small transformer protection).
2) 51 and 51N may be provided in a separate 7SJ60 if required.

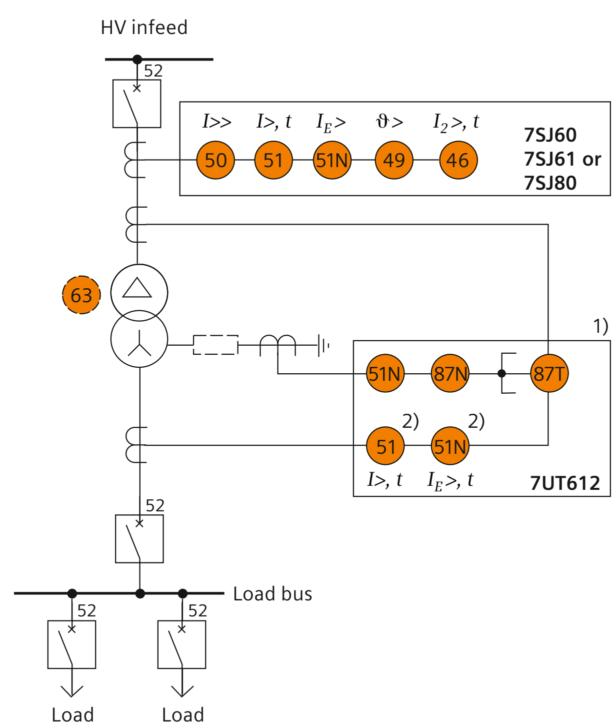


Fig. 2/53 Large or important transformer infeed

Typical Protection Schemes

Dual infeed with single transformer

General notes:

- Line CTs are to be connected to separate stabilizing inputs of the differential relay 87T in order to ensure stability in the event of line through-fault currents.
- Relay 7UT613 provides numerical ratio and vector group adaptation. Matching transformers, as used with traditional relays, are therefore no longer applicable.

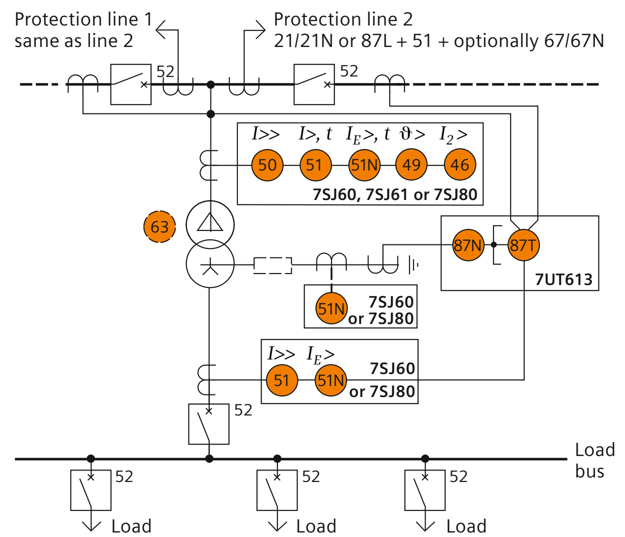


Fig. 2/54 Dual infeed with single transformer

Parallel incoming transformer feeders

Note:

The directional functions 67 and 67N do not apply for cases where the transformers are equipped with the transformer differential relays 87T.

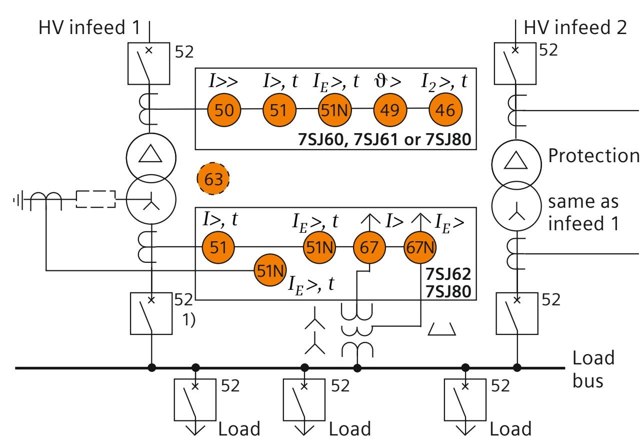


Fig. 2/55 Parallel incoming transformer feeders

Parallel incoming transformer feeders with bus tie

General notes:

- Overcurrent relay 51, 51N each connected as a partial differential scheme. This provides simple and fast busbar protection and saves one time-grading step.

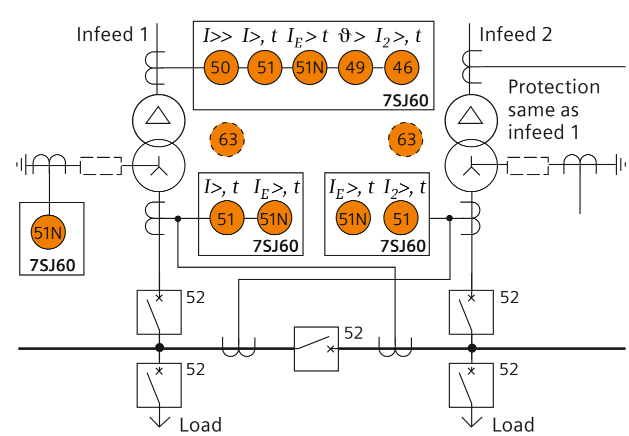


Fig. 2/56 Parallel incoming transformer feeders with bus tie

Three-winding transformer

Notes:

1) The zero-sequence current must be blocked before entering the differential relay with a delta winding in the CT connection on the transformer side with earthed starpoint. This is to avoid false operation during external earth faults (numerical relays provide this function by calculation). About 30 % sensitivity, however, is then lost in the event of internal faults. Optionally, the zero-sequence current can be regained by introducing the winding neutral current in the differential relay (87T). Relay type 7UT613 provides two current inputs for this purpose. By using this feature, the earth-fault sensitivity can be upgraded again to its original value.
   Restricted earth-fault protection (87T) is optional. It provides backup protection for earth faults and increased earth-fault sensitivity (about 10 % IN, compared to about 20 to 30 % IN of the transformer differential relay). Separate class × CT-cores with equal transmission ratio are also required for this protection.
2) High impedance and overcurrent in one 7SJ61.

General notes:

- In this example, the transformer feeds two different distribution systems with cogeneration. Restraining differential relay inputs are therefore provided at each transformer side.
- If both distribution systems only consume load and no through-feed is possible from one MV system to the other, parallel connection of the CTs of the two MV transformer windings is admissible, which allows the use of a two-winding differential relay (7UT612).

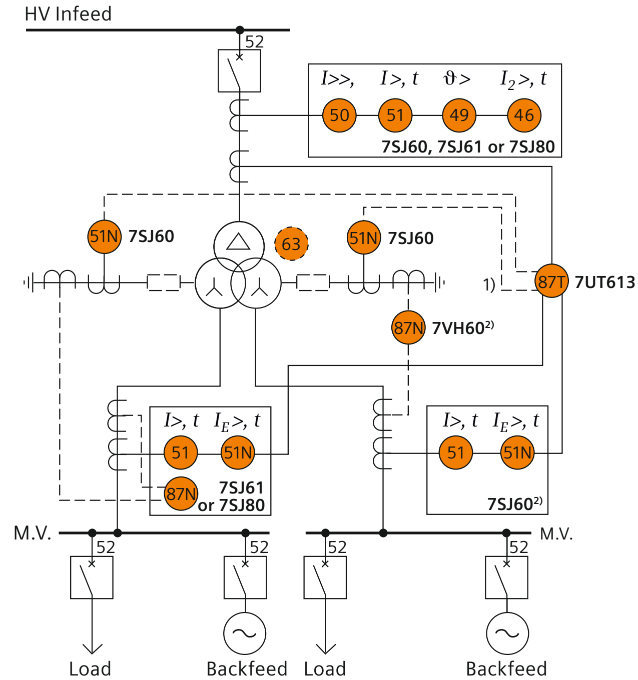


Fig. 2/57 Three-winding transformer

Autotransformer

Notes:

1) 87N high-impedance protection requires special class × current transformer cores with equal transformation ratios.
2) The 7SJ60 relay can alternatively be connected in series with the 7UT613 relay to save this CT core.

General note:

- Two different protection schemes are provided: 87T is chosen as the low-impedance three-winding version (7UT613). 87N is a 1-phase high-impedance relay (7VH60) connected as restricted earth-fault protection. (In this example, it is assumed that the phase ends of the transformer winding are not accessible on the neutral side, that is, there exists a CT only in the neutral earthing connection.).

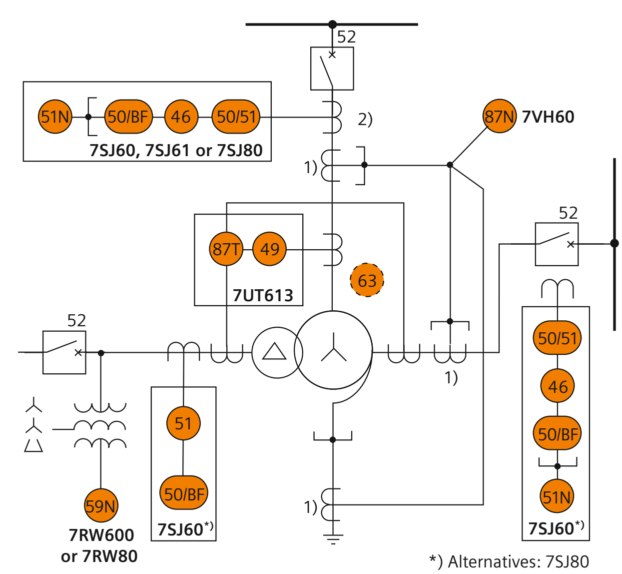


Fig. 2/58 Autotransformer

Typical Protection Schemes

Large autotransformer bank

General notes:

- The transformer bank is connected in a breaker-and-a-half arrangement.
  Duplicated differential protection is proposed:
- Main 1: Low-impedance differential protection 87TL (7UT613) connected to the transformer bushing CTs.
- Main 2: High-impedance differential overall protection 87TL (7VH60). Separate class × cores and equal CT ratios are required for this type of protection.
- Backup protection is provided by distance protection relay (7SA52 and 7SA6), each "looking" with an instantaneous first zone about 80 % into the transformer and with a time-delayed zone beyond the transformer.
- The tertiary winding is assumed to feed a small station supply system with isolated neutral.

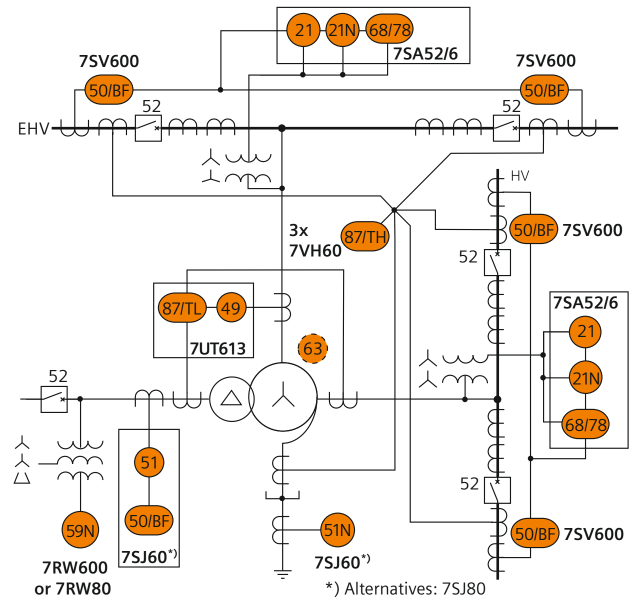


Fig. 2/59 Large autotransformer bank

3. Motors

Small and medium-sized motors < about 1 MW

a) With effective or low-resistance earthed infeed ($I_E \geq I_{N\ Motor}$)

General note:

- Applicable to low-voltage motors and high-voltage motors with low-resistance earthed infeed ($I_E \geq I_{N\ Motor}$)

b) With high-resistance earthed infeed ($I_E \leq I_{N\ Motor}$)

Notes:

1) Core-balance CT.

2) Sensitive directional earth-fault protection (67N) only applicable with infeed from isolated or Petersen coil earthed system (for dimensioning of the sensitive directional earth-fault protection, see also application circuit page 2/33 and Fig. 2/68)

3) The 7SJ602 relay can be applied for isolated and compensated systems.

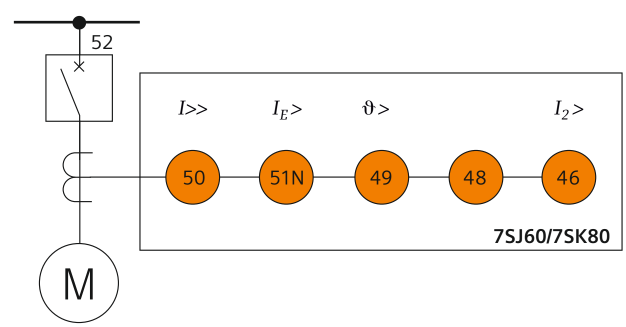


Fig. 2/60 Motor protection with effective or low-resistance earthed infeed

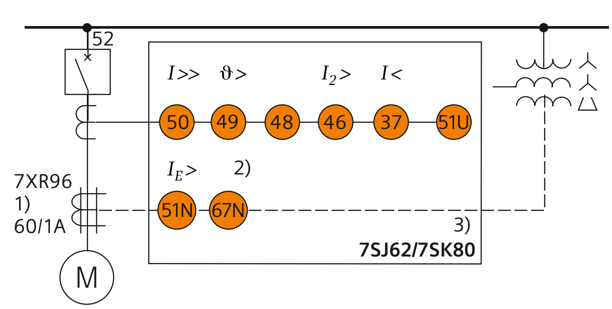


Fig. 2/61 Motor protection with high-resistance earthed infeed

Large HV motors > about 1 MW

Notes:

1) Core-balance CT.
2) Sensitive directional earth-fault protection (67N) only applicable with infeed from isolated or Petersen coil earthed system.
3) This function is only needed for motors where the startup time is longer than the safe stall time tE. According to IEC 60079-7, the tE time is the time needed to heat up AC windings, when carrying the starting current I_A, from the temperature reached in rated service and at maximum ambient air temperature to the limiting temperature. A separate speed switch is used to supervise actual starting of the motor. The motor circuit-breaker is tripped if the motor does not reach speed in the preset time. The speed switch is part of the motor supply itself.
4) Pt100, Ni100, Ni120
5) 49T only available with external temperature detector device (RTD-box 7XV5662)

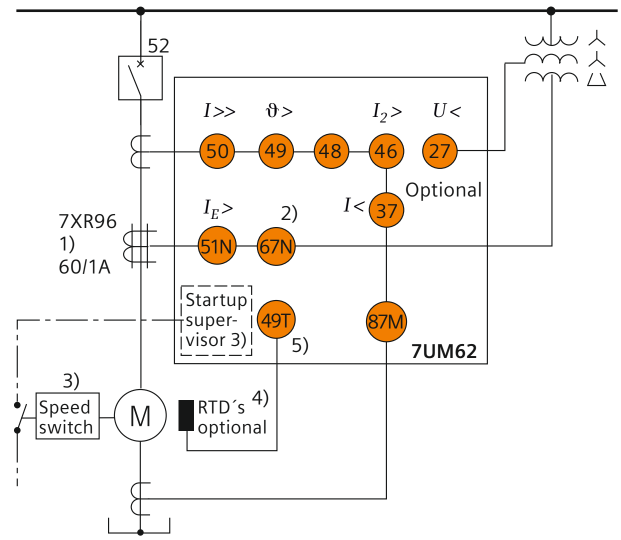


Fig. 2/62 Protection of large HV motors > about 1 MW

Cold load pickup

By means of a binary input that can be wired from a manual close contact, it is possible to switch the overcurrent pickup settings to less sensitive settings for a programmable amount of time. After the set time has expired, the pickup settings automatically return to their original setting. This can compensate for initial inrush when energizing a circuit without compromising the sensitivity of the overcurrent elements during steady-state conditions.

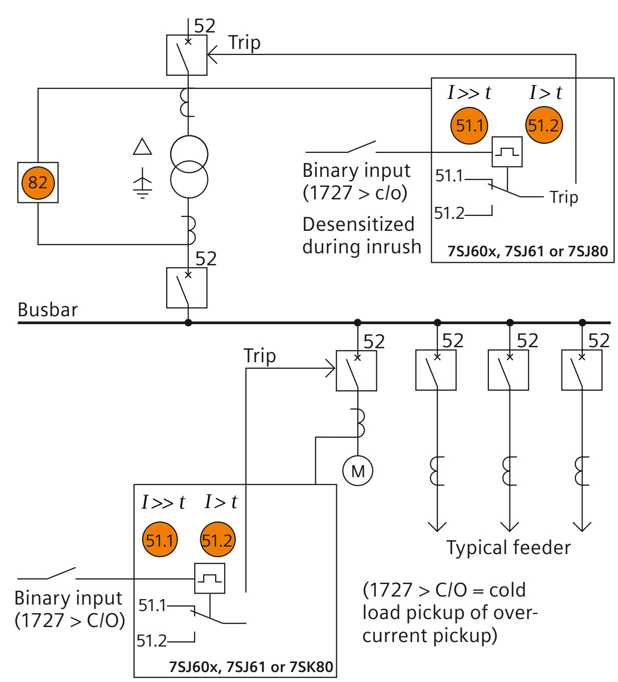


Fig. 2/63 Cold load pickup

Typical Protection Schemes

4. Generators

Generators < 500 kW (Fig. 2/64 and Fig. 2/65)

Note:

If a core-balance CT is provided for sensitive earth-fault protection, relay 7SJ602 with separate earth-current input can be used.

Generators, typically 1–3 MW

(Fig. 2/66)

Note:

Two VTs in V connection are also sufficient.

Generators > 1–3 MW

(Fig. 2/67)

Notes:

1) Functions 81 and 59 are required only where prime mover can assume excess speed and the voltage regulator may permit rise of output voltage above upper limit.

2) Differential relaying options:
– Low-impedance differential protection 87.
– Restricted earth-fault protection with low-resistance earthed neutral (Fig. 2/66).

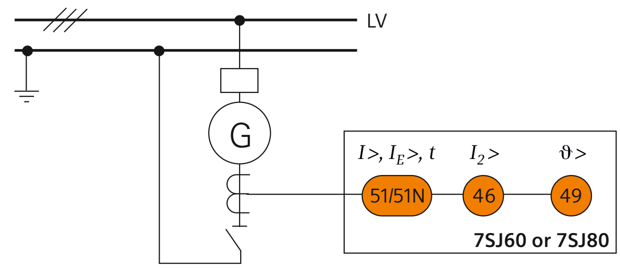


Fig. 2/64 Generator with solidly earthed neutral

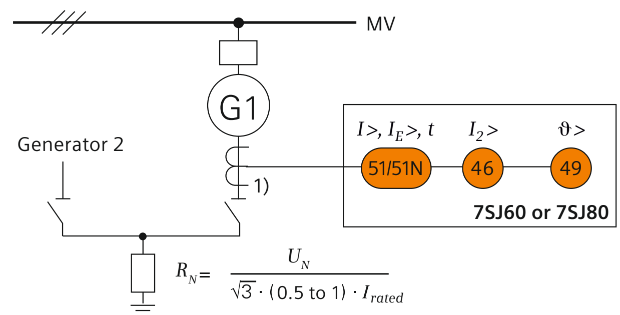


Fig. 2/65 Generator with resistance-earthed neutral

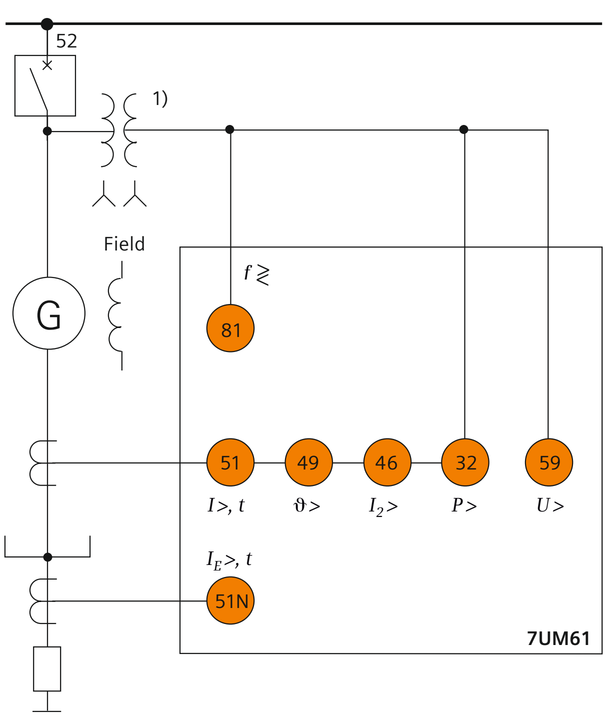


Fig. 2/66 Protection for generators 1–3 MW

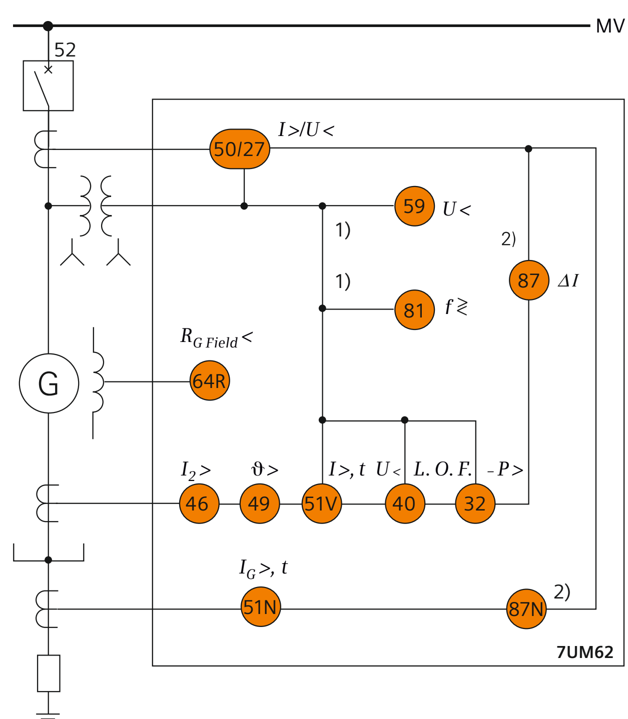


Fig. 2/67 Protection for generators >1–3 MW

Generators > 5–10 MW feeding into a system with isolated neutral

(Fig. 2/68)

General notes:

- The setting range of the directional earth-fault protection (67N) in the 7UM6 relay is 2–1,000 mA. Depending on the current transformer accuracy, a certain minimum setting is required to avoid false operation on load or transient currents.
- In practice, efforts are generally made to protect about 90 % of the machine winding, measured from the machine terminals. The full earth current for a terminal fault must then be ten times the setting value, which corresponds to the fault current of a fault at 10 % distance from the machine neutral.

Relay earth-current input connected to:	Minimum relay setting:	Comments:
Core-balance CT 60 / 1 A: 1 single CT 2 parallel CTs 3 parallel Cts 4 parallel CTs	 2 mA 5 mA 8 mA 12 mA	
Three-phase CTs in residual (Holmgreen) connection	1 A CT: 50 mA 5 A CT: 200 mA	In general not suitable for sensitive earth-fault protection
Three-phase CTs in residual (Holmgreen) connection with special factory calibration to minimum residual false currents (≤ 2 mA)	2–3 ‰ of secondary rated CT current $I_{n\,SEC}$ 10–15 mA with 5 A CTs	1 A CTs are not recommended in this case

For the most sensitive setting of 2 mA, we therefore need 20 mA secondary earth current, corresponding to (60 / 1) × 20 mA = 1.2 A primary.

If sufficient capacitive earth current is not available, an earthing transformer with resistive zero-sequence load can be installed as earth-current source at the station busbar. The smallest standard earthing transformer TGAG 3541 has a 20 s short-time rating of input connected to: S_G = 27 kVA

In a 5 kV system, it would deliver:

$$I_{G\,20\,s} = \frac{\sqrt{3}\cdot S_G}{U_N} = \frac{\sqrt{3}\cdot 27{,}000\text{ VA}}{5{,}000\text{ V}} = 9.4\text{ A}$$

corresponding to a relay input current of 9.4 A × 1 / 60 A = 156 mA. This would provide a 90 % protection range with a setting of about 15 mA, allowing the use of 4 parallel connected core-balance CTs. The resistance at the 500 V open-delta winding of the earthing transformer would then have to be designed for

$$R_B = U^2{}_{SEC} / S_G = 500\ U^2 / 27{,}000\text{ VA} = 9.26\ \Omega\ (27\text{ kW, }20\text{ s})$$

For a 5 MVA machine and 600 / 5 A CTs with special calibration for minimum residual false current, we would get a secondary current of $I_{G\,SEC}$ = 9.4 A / (600 / 5) = 78 mA.

With a relay setting of 12 mA, the protection range would in this case be $100\left(1-\frac{12}{78}\right) = 85\ \%$.

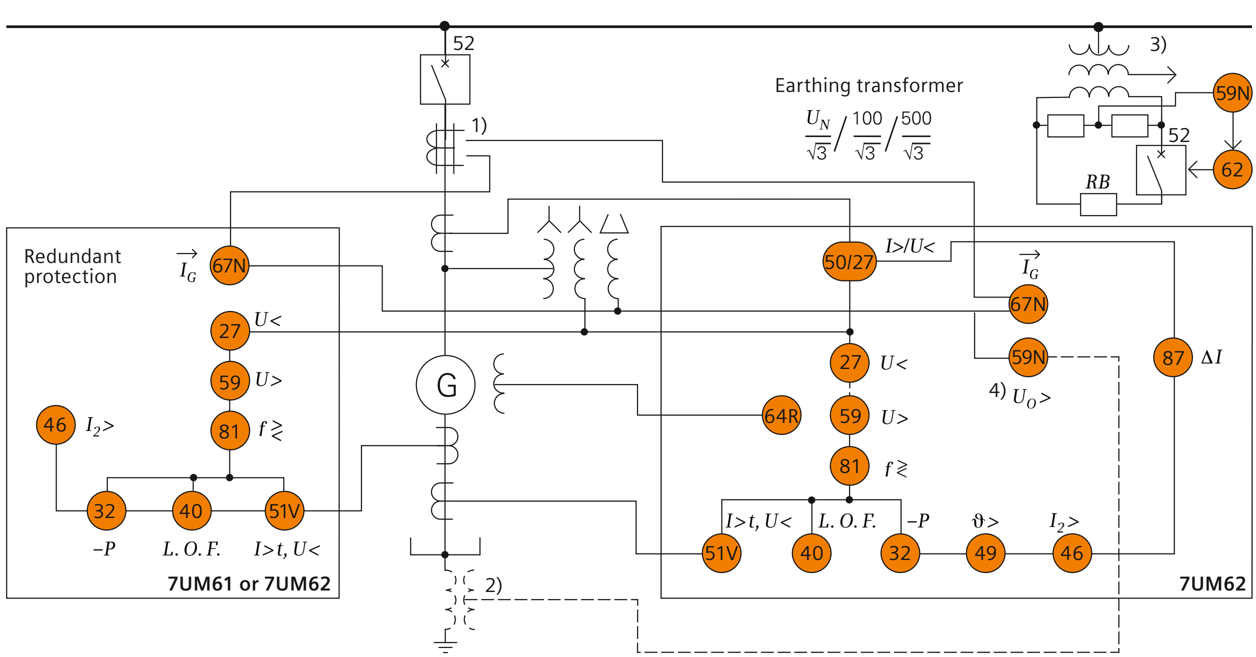


Fig. 2/68 Protection for generators > 5 –10 MW

Typical Protection Schemes

Notes (Fig. 2/68):

1) The standard core-balance CT 7XR96 has a transformation ratio of 60 / 1 A.
2) Instead of an open-delta winding at the terminal VT, a 1-phase VT at the machine neutral could be used as zero-sequence polarizing voltage.
3) The earthing transformer is designed for a short-time rating of 20 s. To prevent overloading, the load resistor is automatically switched off by a time-delayed zero-sequence voltage relay (59N + 62) and a contactor (52).
4) During the startup time of the generator with the open circuit-breaker, the earthing source is not available. To ensure earth-fault protection during this time interval, an auxiliary contact of the circuit-breaker can be used to change over the directional earth-fault relay function (67N) to a zero-sequence voltage detection function via binary input.

Generators > 50–100 MW in generator transformer unit connection

(Fig. 2/69)

Notes:

1) 100 % stator earth-fault protection based on 20 Hz voltage injection
2) Sensitive rotor earth-fault protection based on 1–3 Hz voltage injection
3) Non-electrical signals can be incoupled in the protection via binary inputs (BI)
4) Only used functions shown; further integrated functions available in each relay type; for more information, please refer to part 1 of this catalog.

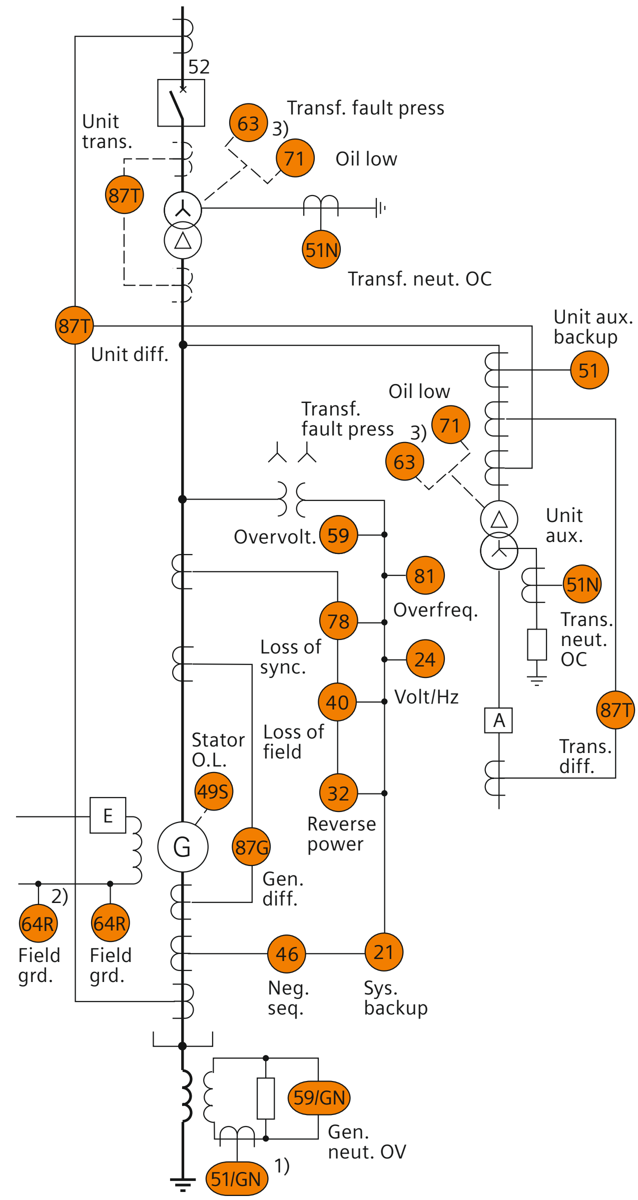


Fig. 2/69 Protections for generators > 50 MW

Relay type	Functions[4]	Number of relays required
7UM62	21, 24, 32, 40, 46, 49, 51GN 1), 59GN, 59, 64R, 64R 2), 78, 81, 87G, via BI: 71, 63	2
7UM61 or 7UM62	51, 51N, optionally 21, 59, 81, via BI: 71, 63	1
7UT612	87T, 51N, optionally	1 2
7UT613	87T	1

Fig. 2/70 Assignment for functions to relay type

Synchronization of a generator

Fig. 2/71 shows a typical connection for synchronizing a generator. Paralleling device 7VE6 acquires the line and generator voltage, and calculates the differential voltage, frequency and phase angle. If these values are within a permitted range, a CLOSE command is issued after a specified circuit-breaker make time. If these variables are out of range, the paralleling device automatically sends a command to the voltage and speed controller. For example, if the frequency is outside the range, an actuation command is sent to the speed controller. If the voltage is outside the range, the voltage controller is activated.

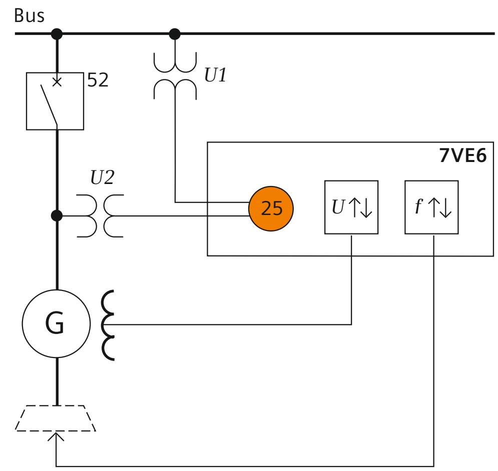


Fig. 2/71 Synchronization of a generator

5. Busbars

Busbar protection by overcurrent relays with reverse interlocking

General note:

- Applicable to distribution busbars without substantial ($< 0.25 \times I_N$) backfeed from the outgoing feeders.

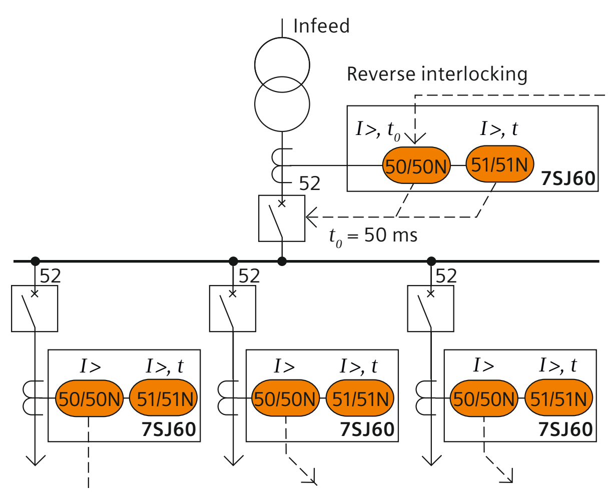


Fig. 2/72 Busbar protection by O / C relays with reverse interlocking

Typical Protection Schemes

High-impedance busbar protection

General notes:

- Normally used with single busbar, and one-breaker-and-a-half schemes.
- Requires separate class X current transformer cores. All CTs must have the same transformation ratio.

Note:

A varistor is normally applied across the relay input terminals to limit the voltage to a value safely below the insulation voltage of the secondary circuits.

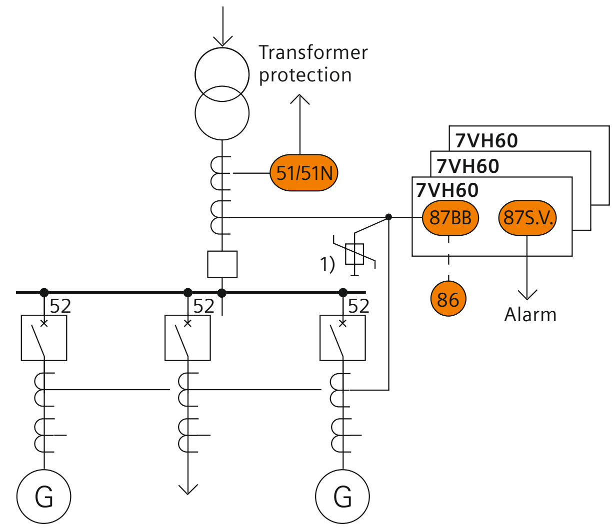


Fig. 2/73 High-impedance busbar protection

Low-impedance busbar protection 7SS60

General notes:

- Normally used with single busbar, one-breaker-and-a-half, and double busbar schemes, different transformation ratios can be adapted by matching transformers.
- Unlimited number of feeders.
- Feeder protection can be connected to the same CT core.

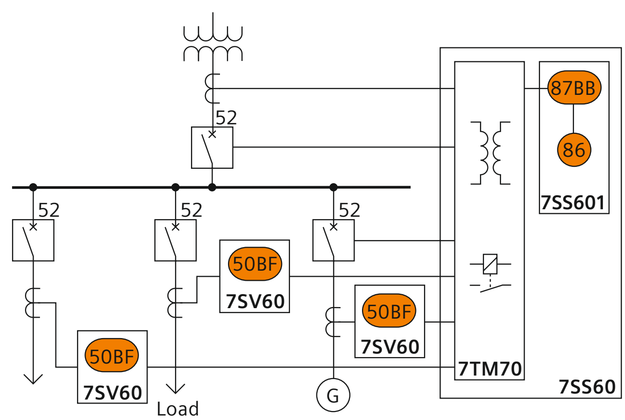


Fig. 2/74 Low-impedance busbar protection 7SS60

Distributed busbar protection 7SS52

General notes:

- Suitable for all types of busbar schemes.
- Preferably used for multiple busbar schemes where a disconnector (isolator) replica is necessary.
- The numerical busbar protection 7SS52 provides additional breaker failure protection.
- Different CT transformation ratios can be adapted numerically.
- The protection system and the disconnector (isolator) replica are continuously self-monitored by the 7SS52.
- Feeder protection can be connected to the same CT core.

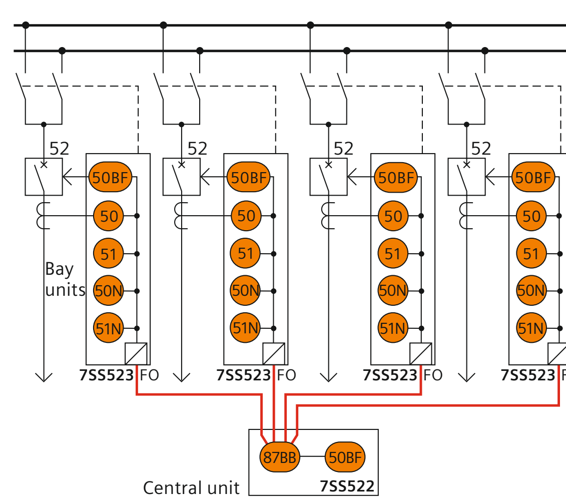


Fig. 2/75 Distributed busbar protection 7SS52

6. Power systems

Load shedding

In unstable power systems (e.g., isolated systems, emergency power supply in hospitals), it may be necessary to isolate selected loads from the power system to prevent overload of the overall system. The overcurrent-time protection functions are effective only in the case of a short-circuit.

Overloading of the generator can be measured as a frequency or voltage drop.

(Protection functions 27 and 81 available in 7RW600, 7SJ6 and 7SJ8.)

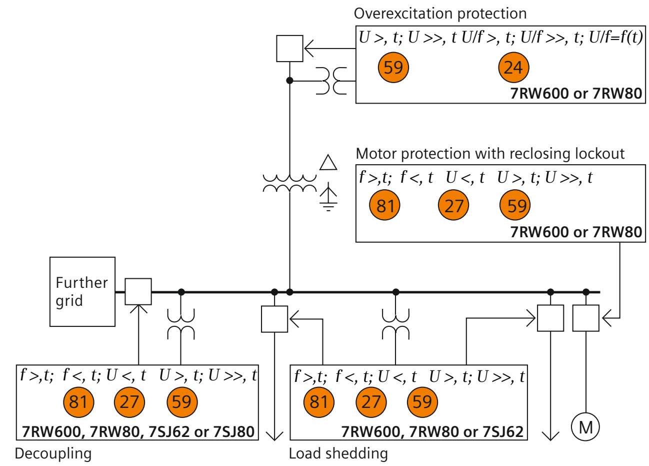


Fig. 2/76 Load shedding

Load shedding with rate-of-frequency-change protection

The rate-of-frequency-change protection calculates, from the measured frequency, the gradient or frequency change df / dt. It is thus possible to detect and record any major active power loss in the power system, to disconnect certain consumers accordingly and to restore the system to stability. Unlike frequency protection, rate-of-frequency-change protection reacts before the frequency threshold is undershot. To ensure effective protection settings, it is recommended to consider requirements throughout the power system as a whole. The rate-of-frequency-change protection function can also be used for the purposes of system decoupling. Rate-of-frequency-change protection can also be enabled by an underfrequency state.

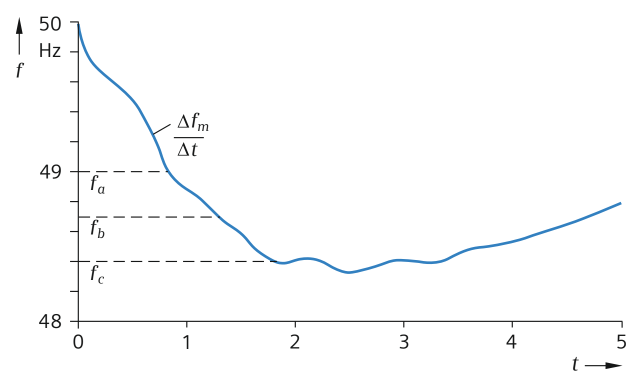


Fig. 2/77 Load shedding with rate-of-frequency-change protection

Trip circuit supervision (ANSI 74TC)

One or two binary inputs can be used for the trip circuit supervision.

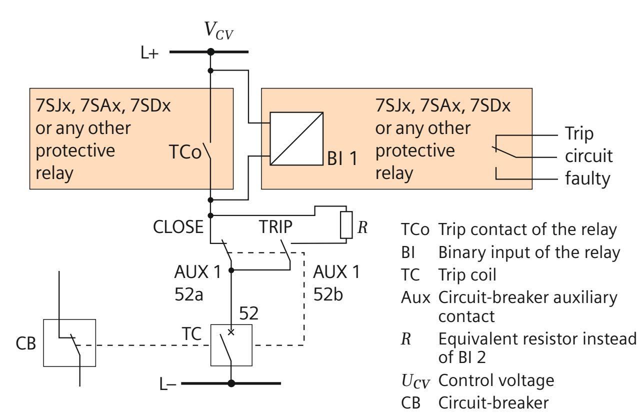


Fig. 2/78 Trip circuit supervision (ANSI 74TC)

Typical Protection Schemes

Disconnecting facility with flexible protection function

General note:

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).

Notes:

1) The transformer is protected by differential protection and inverse or definite-time overcurrent 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 also tripped.
2) 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 stages. The circuit-breakers CB4 and CB5 are tripped in the event of a fault.

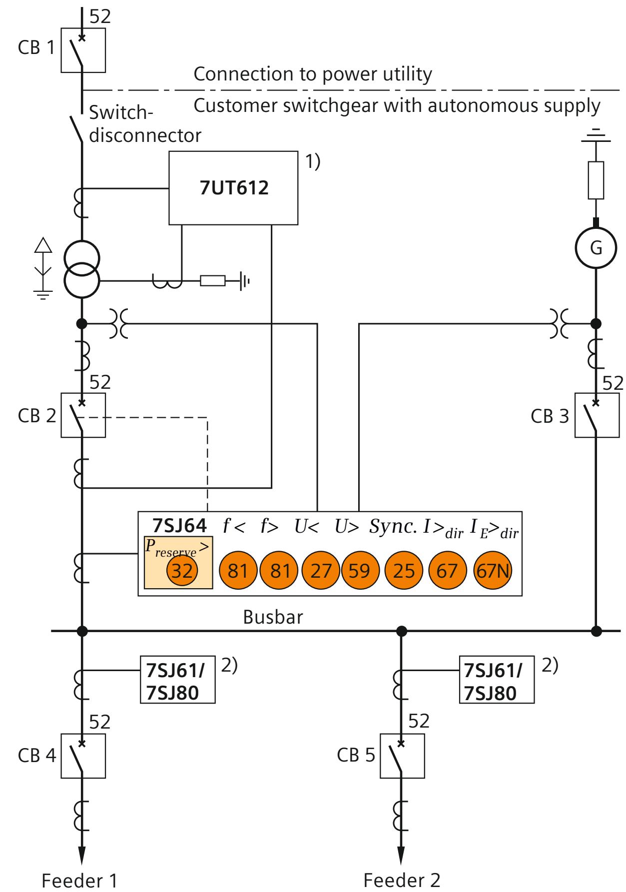


Fig. 2/79 Example of a switchgear with autonomous generator supply

Protection Coordination

Typical applications and functions

Relay operating characteristics and their settings must be carefully coordinated in order to achieve selectivity. The aim is basically to switch off only the faulty component and to leave the rest of the power system in service in order to minimize supply interruptions and to ensure stability.

Sensitivity

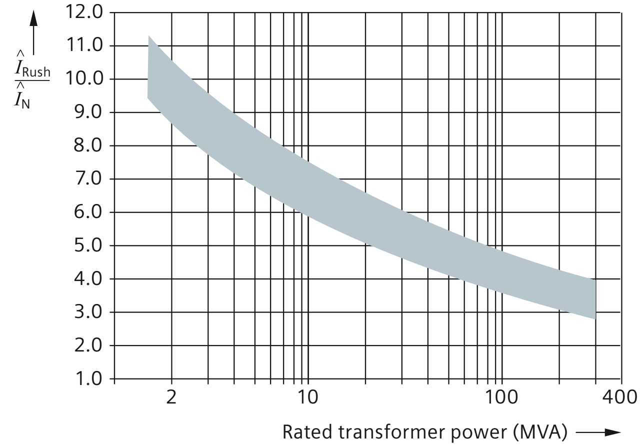
Protection should be as sensitive as possible in order to detect faults at the lowest possible current level. At the same time, however, it should remain stable under all permissible load, overload and through-fault conditions. For more information: http://www.siemens.com/systemplanning. The Siemens engineering programs SINCAL and SIGRADE are especially designed for selective protection grading of protection relay systems. They provide short-circuit calculations, international standard characteristics of relays, fuses and circuit-breakers for easy protection grading with respect to motor starting, inrush phenomena, and equipment damage curves.

Phase-fault overcurrent relays

The pickup values of phase overcurrent relays are normally set 30 % above the maximum load current, provided that sufficient short-circuit current is available. This practice is recommended particularly for mechanical relays with reset ratios of 0.8 to 0.85. Numerical relays have high reset ratios near 0.95 and allow, therefore, about a 10 % lower setting. Feeders with high transformer and / or motor load require special consideration.

Transformer feeders

The energizing of transformers causes inrush currents that may last for seconds, depending on their size (Fig. 2/79). Selection of the pickup current and assigned time delay have to be coordinated so that the inrush current decreases below the relay overcurrent reset value before the set operating time has elapsed. The inrush current typically contains only about a 50 % fundamental frequency component. Numerical relays that filter out harmonics and the DC component of the inrush current can therefore be set to be more sensitive. The inrush current peak values of Fig. 2/80 will be reduced to more than one half in this case. Some digital relay types have an inrush detection function that may block the trip of the overcurrent protection resulting from inrush currents.



Time constant of inrush current			
Nominal power (MVA)	0.5 … 1.0	1.0 … 10	> 10
Time constant (s)	0.16 … 0.2	0.2 … 1.2	1.2 … 720

Fig. 2/80 Peak value of inrush current

Earth-fault protection relays

Earth-current relays enable a much more sensitive setting, because load currents do not have to be considered (except 4-wire circuits with 1-phase load). In solidly and low-resistance earthed systems, a setting of 10 to 20 % rated load current can generally be applied. High-resistance earthing requires a much more sensitive setting, on the order of some amperes primary. The earth-fault current of motors and generators, for example, should be limited to values below 10 A in order to avoid iron burning. In this case, residual-current relays in the start point connection of CTs cannot be used; in particular, with rated CT primary currents higher than 200 A. The pickup value of the zero-sequence relay would be on the order of the error currents of the CTs. A special core-balance CT is therefore used as the earth-current sensor. The core-balance CT 7XR96 is designed for a ratio of 60 / 1 A. The detection of 6 A primary would then require a relay pickup setting of 0.1 A secondary. An even more sensitive setting is applied in isolated or Petersen coil earthed systems where very low earth currents occur with 1-phase-to-earth faults. Settings of 20 mA and lower may then be required depending on the minimum earth-fault current. Sensitive directional earth-fault relays (integrated into the relays 7SJ62, 63, 64, 7SJ80, 7SK80, 7SA6) allow settings as low as 5 mA.

Protection Coordination

Motor feeders

The energization of motors causes a starting current of initially 5 to 6 times the rated current (locked rotor current).

A typical time-current curve for an induction motor is shown in Fig. 2/81.

In the first 100 ms, a fast-decaying asymmetrical inrush current also appears. With conventional relays, it was common practice to set the instantaneous overcurrent stage of the short-circuit protection 20 to 30 % above the locked rotor current with a short-time delay of 50 to 100 ms to override the asymmetrical inrush period.

Numerical relays are able to filter out the asymmetrical current component very rapidly so that the setting of an additional time delay is no longer applicable.

The overload protection characteristic should follow the thermal motor characteristic as closely as possible. The adaptation is made by setting the pickup value and the thermal time constant, using the data supplied by the motor manufacturer. Furthermore, the locked-rotor protection timer has to be set according to the characteristic motor value.

Time grading of overcurrent relays (51)

The selectivity of overcurrent protection is based on time grading of the relay operating characteristics. The relay closer to the infeed (upstream relay) is time-delayed against the relay further away from the infeed (downstream relay). The calculation of necessary grading times is shown in Fig. 2/81 by an example for definite-time overcurrent relays.

The overshoot times take into account the fact that the measuring relay continues to operate due to its inertia, even if when the fault current is interrupted. This may be high for mechanical relays (about 0.1 s) and negligible for numerical relays (20 ms).

Inverse-time relays (51)

For the time grading of inverse-time relays, in principle the same rules apply as for the definite-time relays. The time grading is first calculated for the maximum fault level and then checked for lower current levels (Fig. 2/82).

If the same characteristic is used for all relays, or if when the upstream relay has a steeper characteristic (e.g., very much over normal inverse), then selectivity is automatically fulfilled at lower currents.

Differential relay (87)

Transformer differential relays are normally set to pickup values between 20 and 30 % of the rated current. The higher value has to be chosen when the transformer is fitted with a tap changer.

Restricted earth-fault relays and high-resistance motor / generator differential relays are, as a rule, set to about 10 % of the rated current.

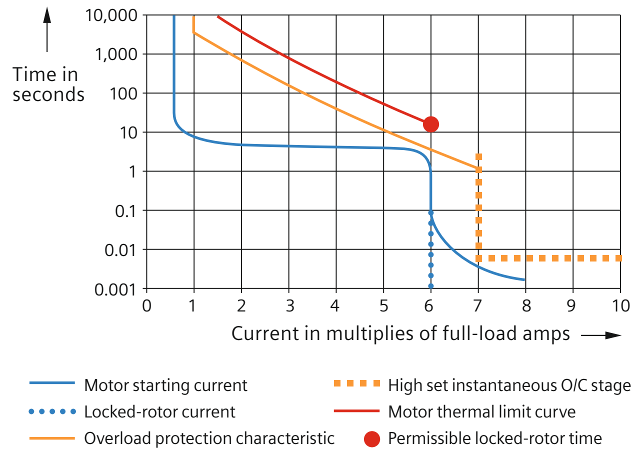


Fig. 2/81 Typical motor current-time characteristics

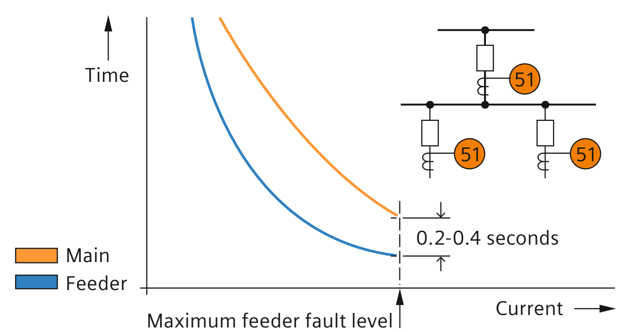


Fig. 2/82 Coordination of inverse-time relays

Instantaneous overcurrent protection (50)

This is typically applied on the final supply load or on any protection relay with sufficient circuit impedance between itself and the next downstream protection relay. The setting at transformers, for example, must be chosen about 20 to 30 % higher than the maximum through-fault current. The relay must remain stable during energization of the transformer.

Calculation example

The feeder configuration of Fig. 2/84 and the associated load and short-circuit currents are given. Numerical overcurrent relays 7SJ60 with normal inverse-time characteristics are applied.

The relay operating times, depending on the current, can be derived from the diagram or calculated with the formula given in Fig. 2/85.

The I_p/I_N settings shown in Fig. 2/84 have been chosen to get pickup values safely above maximum load current.

This current setting should be lowest for the relay farthest downstream. The relays further upstream should each have equal or higher current settings.

The time multiplier settings can now be calculated as follows:

Station C:

- For coordination with the fuses, we consider the fault in location F1.
  The short-circuit current $I_{scc.}$ max. related to 13.8 kV is 523 A.
  This results in 7.47 for I/I_p at the overcurrent relay in location C.
- With this value and $T_p = 0.05$, an operating time of t_A = 0.17 s can be derived from Fig. 2/85.

This setting was selected for the overcurrent relay to get a safe grading time over the fuse on the transformer low-voltage side. Safety margin for the setting values for the relay at station C are therefore:

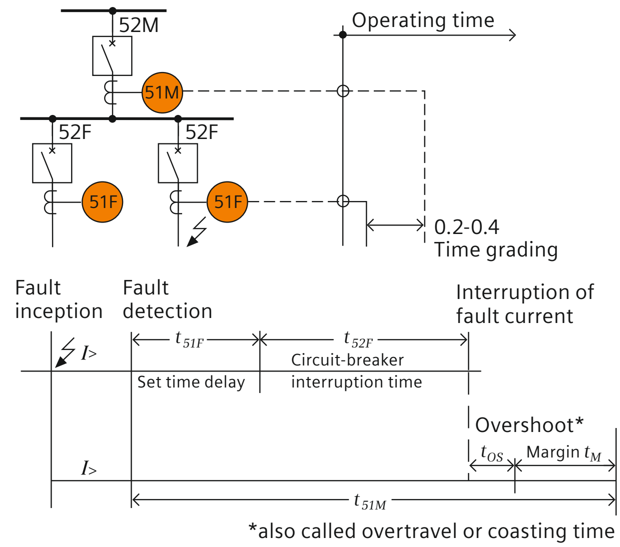
- Pickup current: $I_p/I_N = 0.7$
- Time multiplier: $T_p = 0.05$.

Station B:

The relay in B has a primary protection function for line B-C and a backup function for the relay in C. The maximum through-fault current of 1.395 A becomes effective for a fault in location F2. For the relay in C, an operating time time of 0.11 s ($I/I_p = 19.93$) is obtained.

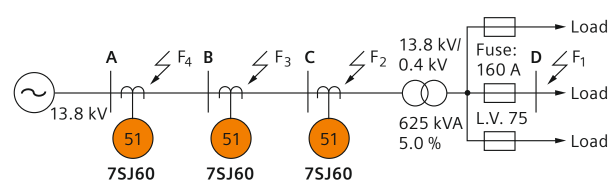
It is assumed that no special requirements for short operating times exist and therefore an average time grading interval of 0.3 s can be chosen. The operating time of the relay in B can then be calculated.

- $t_B = 0.11 + 0.3 = 0.41$ s
- Value of $I_p/I_N = \dfrac{1{,}395\text{ A}}{220\text{ A}} = 6.34$ (Fig. 2/84)
- With the operating time 0.41 s and $I_p/I_N = 6.34$, $T_p = 0.11$ can be derived from Fig. 2/85.



Time grading	
$t_{rs} = t_{51M} - t_{51F} = t_{52F} + t_{OS} + t_M$	
Example 1	t_{TG} =0.10 s + 0.15 s + 0.15 s = 0.40 s
Oil circuit-breaker	t_{52F} = 0.10 s
Mechanical relays	t_{OS} = 0.15 s
Safety margin for measuring errors, etc.	t_M = 0.15 s
Example 2	t_{TG} = 0.08 + 0.02 + 0.10 = 0.20 s
Vacuum circuit-breaker	t_{52F} = 0.08 s
Numerical relays	t_{OS} = 0.02 s
Safety margin	t_M = 0.10 s

Fig. 2/83 Time grading of overcurrent-time relays



Station	Max. load A	$I_{SCC.}$ max* A	CT ratio	I_p/I_N**	I_{prim}*** A	$I/I_p = \dfrac{I_{scc.\,max}}{I_{prim}}$
A	300	4,500	400 / 5	1.0	400	11.25
B	170	2,690	200 / 5	1.1	220	12.23
C	50	1,395	100 / 5	0.7	70	19.93
D	–	523	–	–	–	–

*) $I_{SCC.\,max}$ = Maximum short-circuit current
**) I_p/I_N = Relay current multiplier setting
***) I_{prim} = Primary setting current corresponding to I_p/I_N

Fig. 2/84 Time grading of inverse-time relays for a radial feeder

Protection Coordination

The setting values for the relay at station B are:

- Pickup current: $I_p/I_N = 1.1$
- Time multiplier $T_p = 0.11$

Given these settings, the operating time of the relay in B for a close fault in F3 can also be checked: The short-circuit current increases to 2,690 A in this case (Fig. 2/84). The corresponding I/I_p value is 12.23.

- With this value and the set value of $T_p = 0.11$, an operating time of 0.3 s is obtained again (Fig. 2/85).

Station A:

- Adding the time grading interval of 0.3 s, the desired operating itme is $t_A = 0.3 + 0.3 = 0.6$ s.

Following the same procedure as for the relay in station B, the following values are obtained for the relay in station A:

- Pickup current: $I_p / I_N = 1.0$
- Time multiplier $T_p = 0.17$
- For the close-in fault at location F4, an operating time of 0.48 s is obtained.

The normal way

To prove the selectivity over the whole range of possible short-circuit currents, it is normal practice to draw the set of operating curves in a common diagram with double log scales. These diagrams can be calculated manually and drawn point-by-point or constructed by using templates.

Today, computer programs are also available for this purpose. Fig. 2/86 shows the relay coordination diagram for the selected example, as calculated by the Siemens program SIGRADE (Siemens Grading Program). For further information: http://www.siemens.com/systemplanning.

Note:

To simplify calculations, only inverse-time characteristics have been used for this example. About 0.1 s shorter operating times could have been reached for high-current faults by additionally applying the instantaneous zones *I>>* of the 7SJ60 relays.

Coordination of overcurrent relays with fuses and low-voltage trip devices

The procedure is similar to the above-described grading of overcurrent relays. A time interval of between 0.1 and 0.2 s is usually sufficient for a safe time coordination.

Strong and extremely inverse characteristics are often more suitable than normal inverse characteristics in this case. Fig. 2/87 shows typical examples.

Simple distribution substations use a power fuse on the secondary side of the supply transformers (Fig. 2/87a).

In this case, the operating characteristic of the overcurrent relay at the infeed has to be coordinated with the fuse curve.

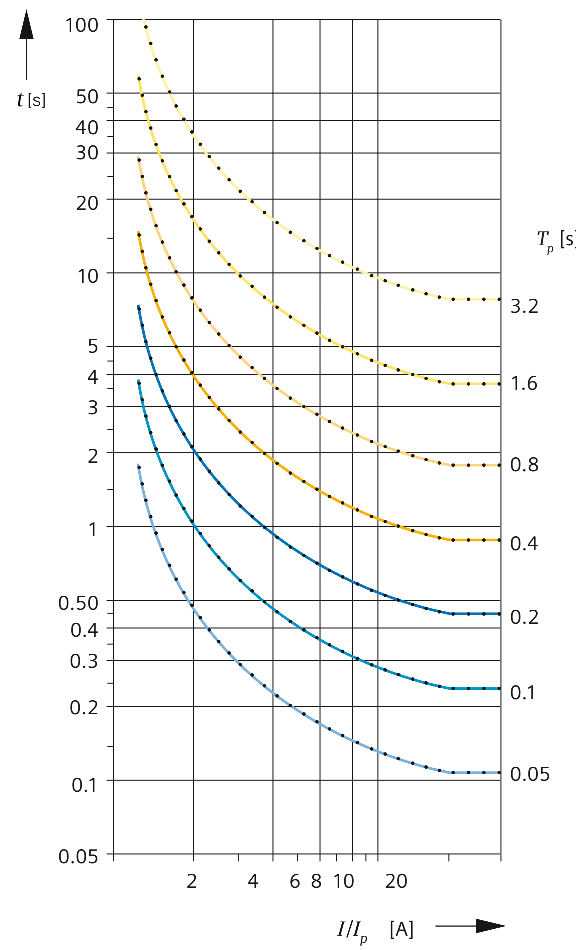


Fig. 2/85 Normal inverse-time characteristic of the 7SJ60 relay

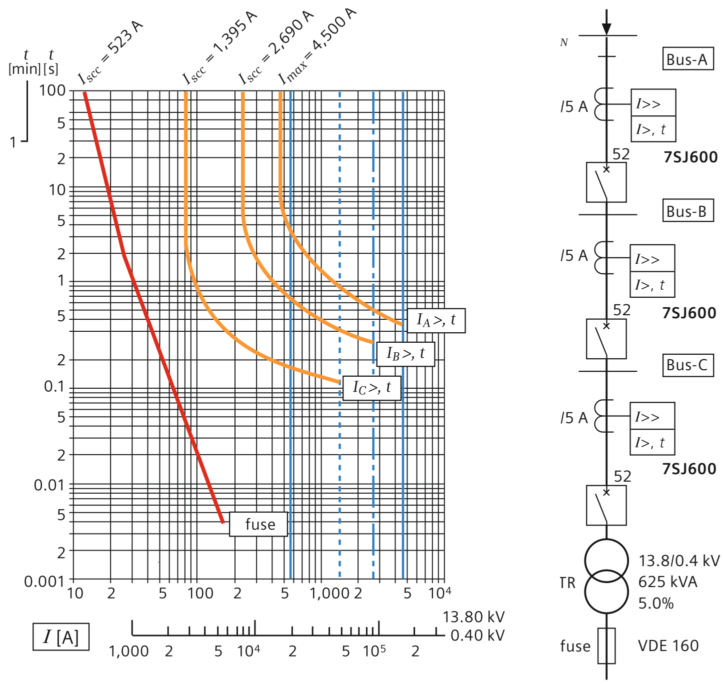
Normal inverse

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

Strong inverse characteristics may be used with expulsion-type fuses (fuse cutouts), while extremely inverse versions adapt better to current limiting fuses.

In any case, the final decision should be made by plotting the curves in the log-log coordination diagram.

Electronic trip devices of LV breakers have long-delay, short-delay and instantaneous zones. Numerical overcurrent relays with one inverse-time and two definite-time zones can closely be adapted to this (Fig. 2/87b).



Setting range setting	
$I_p = 0.10 - 4.00\ I_N$ $T_p = 0.05 - 3.2$ s $I{>>} = 0.1 - 25\ I_N$	$I_p = 1.0\ I_N$ $T_p = 0.17$ s $I{>>} = \infty$
$I_p = 0.10 - 4.00\ I_N$ $T_p = 0.05 - 3.2$ s $I{>>} = 0.1 - 25\ I_N$	$I_p = 1.0\ I_N$ $T_p = 0.11$ s $I{>>} = \infty$
$I_p = 0.10 - 4.00\ I_N$ $T_p = 0.05 - 3.2$ s $I{>>} = 0.1 - 25\ I_N$	$I_p = 0.7\ I_N$ $T_p = 0.05$ s $I{>>} = \infty$
HRC fuse 160 A	

Fig. 2/86 Overcurrent-time grading diagram

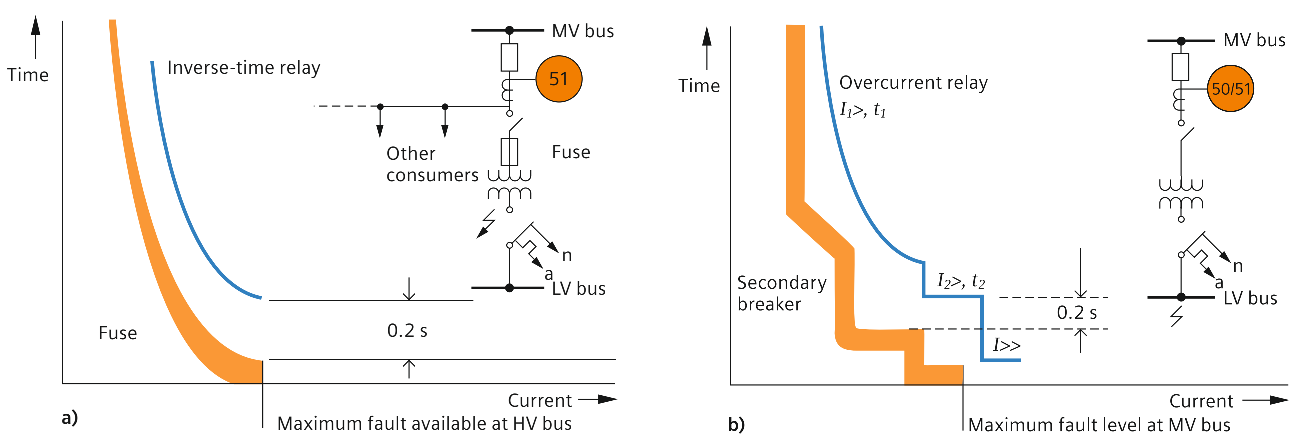


Fig. 2/87 Coordination of an overcurrent relay with an MV fuse and low-voltage breaker trip device

Coordination of distance relays

The distance relay setting must take into account the limited relay accuracy, including transient overreach (5 %, according to IEC 60255-6), the CT error (1 % for class 5P and 3 % for class 10P) and a security margin of about 5 %. Furthermore, the line parameters are often only calculated, not measured. This is a further source of errors. A setting of 80 to 85 % is therefore common practice; 80 % is used for mechanical relays, while 85 % can be used for the more accurate numerical relays.

Where measured line or cable impedances are available, the protected zone setting may be extended to 90 %. The second and third zones have to keep a safety margin of about 15 to 20 % to the corresponding zones of the following lines. The shortest following line always has to be considered (Fig. 2/88).

As a general rule, the second zone should at least reach 20 % over the next station to ensure backup for busbar faults, and the third zone should cover the longest following line as backup for the line protection.

Protection Coordination

Grading of zone times

The first zone normally operates undelayed. For the grading of the time delays of the second and third zones, the same rules as for overcurrent relays apply (Fig. 2/83, page 41). For the quadrilateral characteristics (relays 7SA6 and 7SA5), only the reactance values (X values) have to be considered for the protected zone setting. The setting of the R values should cover the line resistance and possible arc or fault resistances. The arc resistance can be roughly estimated as follows:

$$R_{Arc} = \frac{2.5 \cdot l_{arc}}{I_{SCC\ Min}}\ [\Omega]$$

l_{arc} = Arc length in mm

$I_{SCC\ Min}$ = Minimum short-circuit current in kA

- Typical settings of the ratio R / X are:
  - Short lines and cables (≤ 10 km): R / X =2 to 6
  - Medium line lengths < 25 km: R / X =2
  - Longer lines 25 to 50 km: R / X =1

Shortest feeder protectable by distance relays

The shortest feeder that can be protected by underreaching distance zones without the need for signaling links depends on the shortest settable relay reactance.

$$X_{Prim\ Min} = X_{Relay\ Min} \cdot \frac{VT_{ratio}}{CT_{ratio}}$$

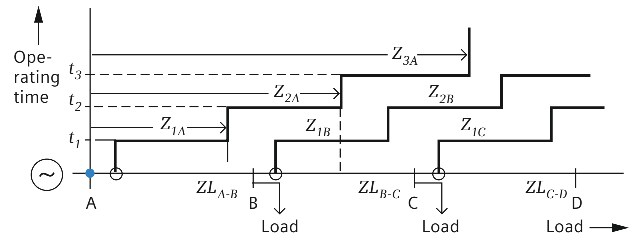
$$l_{min} = \frac{X_{Prim\ Min}}{X'_{Line}}$$

The shortest setting of the numerical Siemens relays is 0.05 Ω for 1 A relays, corresponding to 0.01 Ω for 5 A relays. This allows distance protection of distribution cables down to the range of some 500 meters.

Breaker failure protection setting

Most numerical relays in this guide provide breaker failure (BF) protection as an integral function. The initiation of the BF protection by the internal protection functions then takes place via software logic. However, the BF protection function may also be initiated externally via binary inputs by an alternate protection. In this case, the operating time of intermediate relays (BFI time) may have to be considered. Finally, the tripping of the infeeding breakers requires auxiliary relays, which add a small time delay (BFI) to the overall fault clearing time. This is particularly the case with one-breaker-and-a-half or ring bus arrangements where a separate breaker failure relay (7SV600 or 7VK61) is used per breaker (Fig. 2/83, Fig. 2/84).

The decisive criterion of BF protection time coordination is the reset time of the current detector (50BF), which must not be exceeded under any condition during normal current interruption. The reset times specified in the Siemens numerical relay manuals are valid for the worst-case condition: interruption of a fully offset short-circuit current and low current pickup setting (0.1 to 0.2 times rated CT current).



$Z_{1A} = 0.85 \cdot ZL_{A-B}$

$Z_{2A} = 0.85 \cdot (ZL_{A-B} + Z_{1B})$

$Z_{2A} = 0.85 \cdot (ZL_{A-B} + Z_{2B})$

Fig. 2/88 Grading of distance zones

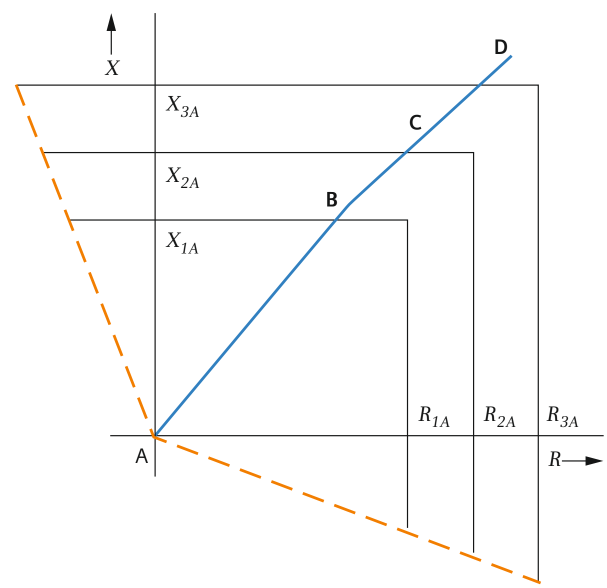


Fig. 2/89 Operating characteristics of Siemens distance relays

The reset time is 1 cycle for EHV relays (7SA6 / 52, 7VK61) and 1.5 to 2 cycles for distribution type relays (7SJ**).

Fig. 2/90 (next page) shows the time chart for a typical breaker failure protection scheme. The stated times in parentheses apply for transmission system protection and the times in square brackets for distribution system protection.

High-impedance differential protection; verification of design

The following design data must be established: CT data

The prerequisite for high-impedance scheme is that all CTs used for that scheme must have the same ratio. They should also be of low leakage flux design according to Class PX of IEC 60044-1 (former Class X of BS 3938) or TPS of IEC 60044-6, when used for high-impedance busbar protection scheme. When used for restricted earth-fault differential protection of e.g. a transformer winding especially in solidly grounded networks, CTs of Class 5P according to IEC 60044-1 can be used as well. In each case the excitation characteristic and the secondary winding resistance are to be provided by the manufacturer. The knee-point voltage of the CT must be at least twice the relay pickup voltage to ensure operation on internal faults.

The relay

The relay can be either:
a) dedicated design high-impedance relay, e.g., designed as a sensitive current relay 7VH60 or 7SG12 (DAD-N) with external series resistor R_{stab}. If the series resistor is integrated into the relay, the setting values may be directly applied in volts, as with the relay 7VH60 (6 to 60V or 24 to 240 V); or
b) digital overcurrent protection relay with sensitive current input, like 7SJ6 or 7SR1 (Argus-C). To the input of the relay a series stabilizing resistor R_{stab} will be then connected as a rule in order to obtain enough stabilization for the high-impedance scheme. Typically, a non-linear resistor V (varistor) will be also connected to protect the relay and wiring against overvoltages.

Sensitivity of the scheme

For the relay to operate in the event of an internal fault, the primary current must reach a minimum value to supply the relay pickup current (I_{set}), the varistor leakage current (I_{var}) and the magnetizing currents of all parallel-connected CTs at the set pickup voltage. A low relay voltage setting and CTs with low magnetizing current therefore increase the protection sensitivity

Stability during external faults

This check is made by assuming an external fault with maximum through-fault current and full saturation of the CT in the faulty feeder. The saturated CT is then substituted with its secondary winding resistance R_{CT}, and the appearing relay voltage VR corresponds to the voltage drop of the in-feeding currents (through-fault current) across R_{CT} and R_{lead}. The current (voltage) at the relay must, under this condition, stay reliably below the relay pickup value.

In practice, the wiring resistances R_{lead} may not be equal. In this case, the worst condition with the highest relay voltage (corresponding to the highest through-fault current) must be sought by considering all possible external feeder faults.

Setting

The setting is always a trade-off between sensitivity and stability. A higher voltage setting leads not only to enhanced through-fault stability but also to higher CT magnetizing and

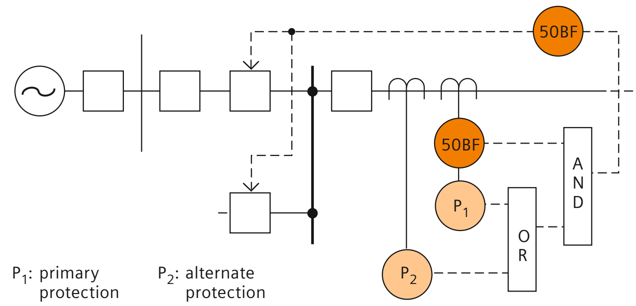


Fig. 2/90 Breaker failure protection, logic circuit

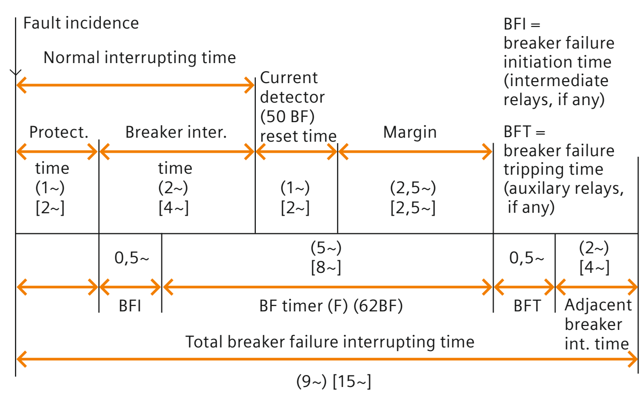
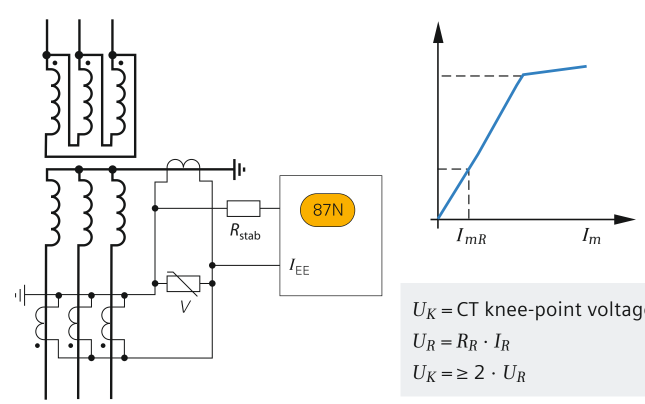


Fig. 2/91 Time coordination of BF time setting



U_K = CT knee-point voltage
$U_R = R_R \cdot I_R$
$U_K = \geq 2 \cdot U_R$

Fig. 2/92 Principle connection diagram for high-impedance restricted earth-fault protection of a winding of the transformer using SIPROTEC digital overcurrent relay (e.g. 7SJ61)

Relay setting U_{rms}	C	β	Varistor type
≤ 125	450	0.25	600 A / S1 / S256
125 – 240	900	0.25	600 A / S1 / S1088

Protection Coordination

Calculation example:

Restricted earth fault protection for the 400 kV winding of 400 MVA power transformer with $I_{r,\,400\,kV} = 577$ A installed in a switchgear with rated withstand short-circuit current of 40 kA.
Given:
N = 4 CTs connected in parallel; $I_{pn} / I_{sn} = 800$ A / 1 A – CT ratio;
$U_k = 400$ V – CT Knee-point voltage;
$I_m = 20$ mA – CT magnetizing current at U_k;
$R_{CT} = 3\ \Omega$ – CT internal resistance;
$R_{lead} = 2\ \Omega$ – secondary wiring (lead) resistance
Relay: 7SJ612; Time overcurrent 1Phase input used with setting range I_{set} = 0.003 A to 1.5 A in steps of 0.001 A; relay internal burden
$R_{relay} = 50\ \text{m}\Omega$

Stability calculation

$$U_{s,min} = I_{k,\,max,\,thr} \frac{I_{sn}}{I_{pn}} (R_{CT} + R_{lead}) = 10{,}000 \frac{1}{800} (3+2) = 62.6 \text{ V}$$

with $I_{k,\,max,\,thr}$ taken as $16 \cdot I_{r,\,400kV} = 16 \cdot 577$ A = 9,232 A, rounded up to 10 kA.

The actual stability voltage for the scheme U_s can be taken with enough safety margin as $\boldsymbol{U_s = 130\,V}$ (remembering that $2U_s < U_k$).

Fault setting calculation

For the desired primary fault sensitivity of 125 A, which is approx. 22 % of the rated current of the protected winding $I_{r,\,400\,kV}$ (i.e. $I_{p,\,des} = 125$ A) the following current setting can be calculated:

$$I_{set} = I_{p,des} \frac{I_{sn}}{I_{pn}} - N \cdot I_m \frac{U_s}{U_k} = 125 \frac{1}{800} - 4 \cdot 0.02 \frac{130}{400} = 0.13\ A$$

Stabilizing resistor calculation

From the $\boldsymbol{U_s}$ and $\boldsymbol{I_{set}}$ values calculated above the value of the stabilizing resistor $\boldsymbol{R_{stab}}$ can be calculated:

$$R_{stab} = \frac{U_s}{I_{set}} - R_{relay} = \frac{130}{0.13} - 0.05 = \approx 1{,}000\ \Omega$$

where the relay resistance can be neglected.

The stabilizing resistor R_{stab} can be chosen with a necessary minimum continuous power rating $P_{stab,cont}$ of:

$$P_{stab,cont} \geq \frac{U_s^2}{R_{stab}} = \frac{130^2}{1000} = 16.9\ W$$

Moreover, R_{stab} must have a short time rating large enough to withstand the fault current levels before the fault is cleared. The time duration of 0.5 seconds can be typically considered ($P_{stab,0.5s}$) to take into account longer fault clearance times of back-up protection.
The rms voltage developed across the stabilizing resistor is decisive for the thermal stress of the stabilizing resistor. It is calculated according to formula:

$$U_{rms,relay} = 1.3 \cdot \sqrt[4]{U_k^{\,3} \cdot R_{stab} \cdot I_{k,\max,\text{int}} \frac{I_{sn}}{I_{pn}}} = 1.3 \cdot \sqrt[4]{400^3 \cdot 1000 \cdot 50} = 1738.7V$$

The resulting short-time rating P_{stab}, 0.5 s equals to:

$$P_{stab,0.5s} \geq \frac{U_{rms,relay}^{\;2}}{R_{stab}} = \frac{1739^2}{1000} = 3023W$$

Check whether the voltage limitation by a varistor is required

The relay should normally be applied with an external varistor which should be connected across the relay and stabilizing resistor input terminals. The varistor limits the voltage across the terminals under maximum internal fault conditions. The theoretical voltage which may occur at the terminals can be determined according to following equation:

$$U_{k,\,max,\,int} = I_{k,\,max,\,int} \frac{I_{sn}}{I_{pn}} (R_{relay} + R_{stab}) = 40{,}000 \frac{1}{800} (0.05+1000) = 50003 \text{ V}$$

with $I_{k,max,int}$ taken as the rated short-circuit current of the switchgear = 40 kA.
The resulting maximum peak voltage across the panel terminals
(i.e. tie with relay and Rstab connected in series):

$$\hat{U}_{\max,relay} = 2\sqrt{2U_k\left(U_{k,\max,\text{int}} - U_k\right)} = 2\sqrt{2 \cdot 400(50003 - 400)} = 12600V$$

Since $U_{max,\,relay} > 1.5$ kV the varistor is necessary.

Exemplarily, a METROSIL of type 600A / S1 / Spec.1088 can be used ($\beta = 0.25$, $C = 900$).
This Metrosil leakage current at voltage setting U_s =130 V equals to

$$I_{rms} = 0.52 \left(\frac{U_{set,\,rms} \cdot \sqrt{2}}{C} \right)^{1/\beta} = 0.91 \text{ mA}$$

and can be neglected by the calculations, since its influence on the proposed fault-setting is negligible.

varistor leakage currents, resulting consequently in a higher primary pickup current.

A higher voltage setting also requires a higher knee-point voltage of the CTs and therefore greater size of the CTs. A sensitivity of 10 to 20 % of I_r (rated current) is typical for restricted earth-fault protection. With busbar protection, a pickup value ≥ Ir is normally applied. In networks with neutral earthing via impedance the fault setting shall be revised against the minimum earth fault conditions.

Non-linear resistor (varistor)

Voltage limitation by a varistor is needed if peak voltages near or above the insulation voltage (2 kV … 3kV) are expected. A limitation to U_{rms} = 1,500 V is then recommended. This can be checked for the maximum internal fault current by applying the formula shown for $U_{max\ relay}$. A restricted earth-fault protection may sometimes not require a varistor, but a busbar protection in general does. However, it is considered a good practice to equip with a varistor all high impedance protection installations. The electrical varistor characteristic of a varistor can be expressed as $U = C\,I^{\beta}$ where C and β are the varistor constants.

CT requirements for protection relays

Instrument transformers

Instrument transformers must comply with the applicable IEC recommendations IEC 60044 and 60186 (PT), ANSI / IEEE C57.13 or other comparable standards.

Voltage transformers (VT)

Voltage transformers (VT) in single-pole design for all primary voltages have typical single or dual secondary windings of 100, 110 or 115 V / √3 with output ratings between 10 and 50 VA suitable from most application with digital metering and protection equipment, and accuracies of 0.1 % to 6 % to suit the particular application. Primary BIL values are selected to match those of the associated switchgear.

Current transformers

Current transformers (CT) are usually of the single-ratio type with wound or bar-type primaries of adequate thermal rating. Single, double or triple secondary windings of 1 or 5 A are standard. 1 A rating should, however, be preferred, particularly in HV and EHV stations, to reduce the burden of the connected lines. Output power (rated burden in VA), accuracy and saturation characteristics (rated symmetrical short-circuit current limiting factor) of the cores and secondary windings must meet the requirements of the particular application.The CT classification code of IEC is used in the following:

- Measuring cores
  These are normally specified 0.2 % or 0.5 % accuracy (class 0.2 or class 0.5), and an rated symmetrical short-circuit current limiting factor FS of 5 or 10.
  The required output power (rated burden) should be higher than the actually connected burden. Typical values are 2.5, 5 or 10 VA. Higher values are normally not necessary when only electronic meters and recorders are connected.
  A typical specification could be: 0.5 FS 10, 5 VA.
- Cores for billing values metering
  In this case, class 0.25 FS is normally required.
- Protection cores
  The size of the protection core depends mainly on the maximum short-circuit current and the total burden (internal CT burden, plus burden of connected lines plus relay burden)
  Furthermore, a transient dimensioning factor has to be considered to cover the influence of the DC component in the short-circuit current.

Glossary of used abbreviations (according to IEC 60044-6, as defined)		
K_{ssc}	=	Rated symmetrical short-circuit current factor (example: CT cl. 5P20 → K_{ssc} = 20)
K'_{ssc}	=	Effective symmetrical short-circuit current factor
K_{td}	=	Transient dimensioning factor
$I_{ssc\,max}$	=	Maximum symmetrical short-circuit current
I_{pn}	=	CT rated primary current
I_{sn}	=	CT rated secondary current
R_{ct}	=	Secondary winding d.c. resistance at 75 °C / 167 °F (or other specified temperature)
R_b	=	Rated resistive burden
R'_b	=	$R_{lead} + R_{relay}$ = connected resistive burden
T_P	=	Primary time constant (net time constant)
U_K	=	Kneepoint voltage (r.m.s.)
R_{relay}	=	Relay burden
R_{lead}	=	$\dfrac{2 \cdot \rho \cdot l}{A}$
with		
l	=	Single conductor length from CT to relay in m
ρ	=	Specific resistance = 0.0175 Ωmm²/ m (copper wires) at 20 °C / 68 °F (or other specified temperature)
A	=	Conductor cross-section in mm²

In general, an accuracy of 1 % in the range of 1 to 2 times nominal current (class 5 P) is specified. The rated symmetrical short-circuit current factor K_{SSC} should normally be selected so that at least the maximum short-circuit current can be transmitted without saturation (DC component is not considered).

This results, as a rule, in rated symmetrical short-circuit current factors of 10 or 20 depending on the rated burden of the CT in relation to the connected burden. A typical specification for protection cores for distribution feeders is 5P10, 10 VA or 5P20, 5 VA.

The requirements for protective current transformers for transient performance are specified in IEC 60044-6. In many practical cases, iron-core CTs cannot be designed to avoid saturation under all circumstances because of cost and space reasons, particularly with metal-enclosed switchgear.

The Siemens relays are therefore designed to tolerate CT saturation to a large extent. The numerical relays proposed in this guide are particularly stable in this case due to their integrated saturation detection function.

CT dimensioning formulae
$K'_{ssc} = K_{ssc} \cdot \dfrac{R_{ct} + R_b}{R_{ct} + R'_b}$ (effective)
with $K'_{ssc} \geq K_{td} \cdot \dfrac{I_{scc\,max}}{I_{pn}}$ (required)

The effective symmetrical short-circuit current factor K'_{SSC} can be calculated as shown in the table above.

The rated transient dimensioning factor K_{td} depends on the type of relay and the primary DC time constant. For relays with a required saturation free time from ≤ 0.4 cycle, the primary (DC) time constant TP has little influence.

CT design according to BS 3938 / IEC 60044-1 (2000)
IEC Class P can be approximately transfered into the IEC Class PX (BS Class X) standard definition by following formula:
$U_k = \dfrac{(R_b + R_{ct}) \cdot I_n \cdot K_{ssc}}{1.3}$
Example: IEC 60044: 600 / 1, 5P10, 15 VA, R_{ct} = 4 Ω
IEC PX or BS: $U_K = \dfrac{(15 + 4) \cdot 1 \cdot 10}{1.3} = 146$ V, R_{ct} = 4 Ω
For *CT design according to ANSI / IEEE C 57.13* please refer to page 2/50.

The CT requirements mentioned in table 2/2 are simplified in order to allow fast CT calculations on the safe side. More accurate dimensioning can be done by more intensive calculation with Siemens's CTDIM (www.siemens.com / ctdim) program. Results of CTDIM are released by the relay manufacturer.

Adaption factor for 7UT6, 7UM62 relays in Fig. 2/92 (limited resolution of measurement)

$$F_{Adap} = \frac{I_{pn}}{I_{nO}} \cdot \frac{I_{Nrelay}}{I_{sn}} = \frac{I_{pn} \cdot \sqrt{3} \cdot U_{nO}}{S_{Nmax}} \cdot \frac{I_{Nrelay}}{I_{sn}} \rightarrow \text{Request: } 1/8 \leq 8$$

7SD52, 53, 610, when transformer inside protected zone

$$\frac{I_{n\text{-}pri}\text{-}CT_{max}}{I_{n\text{-}pri}\text{-}CT_{min}} \cdot \frac{1}{\text{Transformer Ratio}^*} \leq 8$$

* If transformer in protection zone, else 1

$I_{n\text{-}pri}$-CT-Transf-Site ≤ 2 · I_n-Obj-Transf-Site AND

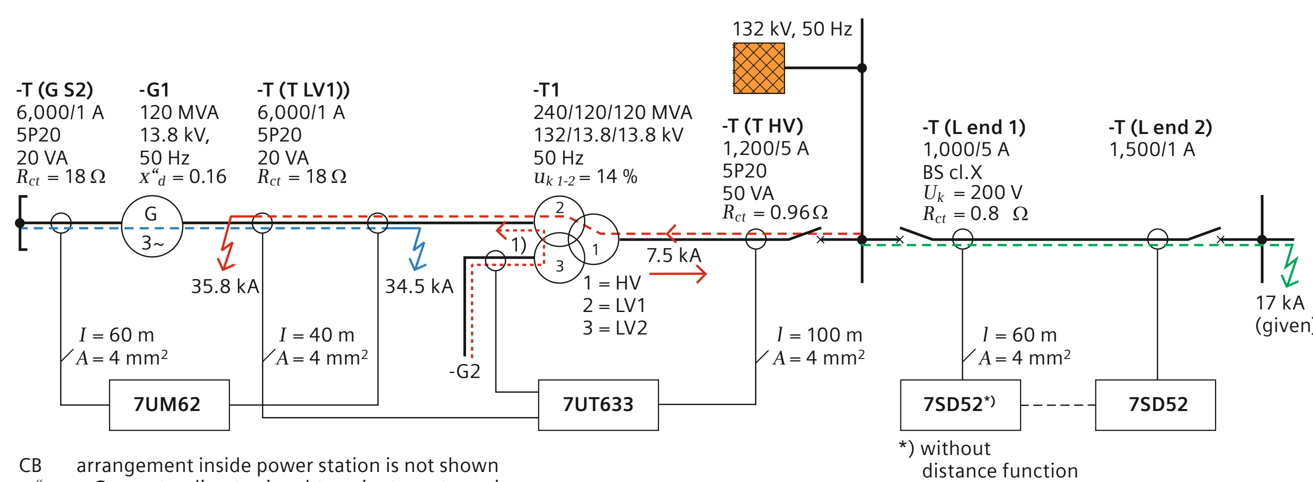
$I_{n\text{-}pri}$-CT-Transf-Site ≥ I_n-Obj-Transf-Site with

I_{nO} = Rated current of the protected object
U_{nO} = Rated voltage of the protected object
I_{Nrelay} = Rated current of the relay
S_{Nmax} = Maximun load of the protected object (for transformers: winding with max. load)

Protection Coordination

Relay type	Transient dimensioning factor K_{td}	Min. required sym. short-circuit current factor K'_{ssc}	Min. required knee-point voltage U_k
Overcurrent-time and motor protection 7SJ511, 512, 531 7SJ45, 46, 60 7SJ61, 62, 63, 64 7SJ80, 7SK80	–	$K'_{ssc} \geq \frac{I_{High\ set\ point}}{I_{pn}}$ at least: 20	$U_k \geq \frac{I_{High\ set\ point}}{1.3 \cdot I_{pn}} \cdot (R_{ct} + R'_b) \cdot I_{sn}$ at least: $\frac{20}{1.3} \cdot (R_{ct} + R'_b) \cdot I_{sn}$
Line differential protection (pilot wire) 7SD600	–	$K'_{ssc} \geq \frac{I_{scc\ max\ (ext.\ fault)}}{I_{pn}}$ and: $\frac{3}{4} \leq \frac{(K'_{ssc} \cdot I_{pn})_{end1}}{(K'_{ssc} \cdot I_{pn})_{end2}} \leq \frac{4}{3}$	$U_k \geq \frac{I_{scc\ max\ (ext.\ fault)}}{1.3 \cdot I_{pn}} \cdot (R_{ct} + R'_b) \cdot I_{sn}$ and: $\frac{3}{4} \leq \frac{(U_k/(R_{ct}+R'_b) \cdot I_{pn}/I_{sn})_{end1}}{(U_k/(R_{ct}+R'_b) \cdot I_{pn}/I_{sn})_{end2}} \leq \frac{4}{3}$
Line differential protection (without distance function) 7SD52x, 53x, 610 (50/60 Hz)	Transformer 1.2 · Busbar/Line 1.2 · Gen./Motor 1.2	$K'_{ssc} \geq$ $K_{td} \cdot \frac{I_{scc\ max\ (ext.\ fault)}}{I_{pn}}$ and (only for 7SS): $\frac{I_{scc\ max\ (ext.\ fault)}}{I_{pn}} \leq 100$ (measuring range)	$U_K \geq$ $K_{td} \cdot \frac{I_{scc\ max\ (ext.\ fault)}}{1.3 \cdot I_{pn}} \cdot (R_{ct} + R'_b) \cdot I_{sn}$ and (only for 7SS): $\frac{I_{scc\ max\ (ext.\ fault)}}{I_{pn}} \leq 100$ (measuring range)
Tranformer / generator differential protection 7UT612, 7UT612 V4.0 7UT613, 633, 635, 7UT612 V4.6 7UM62	Transformer / Busbar/Line / Gen./Motor: 4 / 4 / 5 3 / 3 / 5 4 / – / 5		
Busbar protection 7SS52, 7SS60	for stabilizing factors k ≥ 0.5 0.5		
Distance protection 7SA522, 7SA6, 7SD5xx (with distance function)	primary DC time constant T_p [ms]: ≤ 30 / ≤ 50 / ≤ 100 / ≤ 200 K_{td} (a): 1 / 2 / 4 / 4 K_{td} (b): 4 / 5 / 5 / 5	$K'_{ssc} \geq$ $K_{td}\,(a) \cdot \frac{I_{scc\ max\ (close-in\ fault)}}{I_{pn}}$ and: $K_{td}\,(b) \cdot \frac{I_{scc\ max\ (zone\ 1-end\ fault)}}{I_{pn}}$	$U_K \geq$ $K_{td}\,(a) \cdot \frac{I_{scc\ max\ (close-in\ fault)}}{1.3 \cdot I_{pn}} \cdot (R_{ct} + R'_b) \cdot I_{sn}$ and: $K_{td}\,(b) \cdot \frac{I_{scc\ max\ (zone\ 1-end\ fault)}}{I_{pn}} \cdot (R_{ct} + R'_b) \cdot I_{sn}$

Table 2/2 CT requirements



CB arrangement inside power station is not shown
x''_d = Generator direct axis subtransient reactance in p.u.
$u_{k\ 1-2}$ = Transformer impedance voltage HV side – LV side in %
R_{relay} = Assumed with 0.1 Ω, (power consumption for above relays is below 0.1 VA)

1) Current from side 3 is due to $u_{k\ 2-3}$ and x''_d of G2 in most cases negligible

Fig. 2/93 Example 1 – CT verification for 7UM62, 7UT6, 7SD52 (7SD53, 7SD610)

-T (G S2), 7UM62	-T (T LV1), 7UT633	-T (T HV), 7UT633	-T (L end 1), 7SD52
$I_{scc\,max\,(ext.\,fault)} = \frac{c \cdot S_{NG}}{\sqrt{3} \cdot U_{NG}\, x''_d}$ $= \frac{1.1 \cdot 120{,}000\ \text{kVA}}{\sqrt{3} \cdot 13.8\ \text{kV} \cdot 0.16} = 34{,}516\ \text{A}$	$I_{scc\,max\,(ext.\,fault)} = \frac{S_{NT}}{\sqrt{3} \cdot U_{NT}\, u_k''}$ $= \frac{120{,}000\ \text{kVA}}{\sqrt{3} \cdot 13.8\ \text{kV} \cdot 0.14} = 35{,}860\ \text{A}$	$I_{scc\,max\,(ext.\,fault)} = \frac{S_{NT}}{\sqrt{3} \cdot U_{NT}\, u_k''}$ $= \frac{240{,}000\ \text{kVA}}{\sqrt{3} \cdot 132\ \text{kV} \cdot 0.14} = 7{,}498\ \text{A}$	$I_{scc\,max\,(ext.\,fault)} = 17\ \text{kA}$ (given)
$K_{td} = 5$ (from table 2/2)	$K_{td} = 3$ (from table 2/2)	$K_{td} = 3$ (from table 2/2)	$K_{td} = 1.2$ (from table 2/2)
$K'_{ssc} \geq K_{td} \cdot \frac{I_{scc\,max\,(ext.\,fault)}}{I_{pn}}$ $= 5 \cdot \frac{31{,}378\ \text{A}}{6{,}000\ \text{A}} = 28.8$	$K'_{ssc} \geq K_{td} \cdot \frac{I_{scc\,max\,(ext.\,fault)}}{I_{pn}}$ $= 3 \cdot \frac{35{,}860\ \text{A}}{6{,}000\ \text{A}} = 17.9$	$K'_{ssc} \geq K_{td} \cdot \frac{I_{scc\,max\,(ext.\,fault)}}{I_{pn}}$ $= 3 \cdot \frac{7{,}498\ \text{A}}{1{,}200\ \text{A}} = 18{,}7$	
$R_b = \frac{S_n}{I^2_{sn}} = \frac{20\ \text{VA}}{1\ \text{A}^2} = 20\ \Omega$	$R_b = \frac{S_n}{I^2_{sn}} = \frac{20\ \text{VA}}{1\ \text{A}^2} = 20\ \Omega$	$R_b = \frac{S_n}{I^2_{sn}} = \frac{50\ \text{VA}}{(5\ \text{A})^2} = 2\ \Omega$	
$R'_b = R_{lead} + R_{relay}$ $R_b = \frac{2 \cdot p \cdot l}{A} + 0.1\ \Omega$ $= \frac{2 \cdot 0.0175 \frac{\Omega\ \text{mm}^2}{\text{m}} \cdot 60\ \text{m}}{4\ \text{mm}^2}$ $+ 0.1\ \Omega$ $= 0.625\ \Omega$	$R'_b = R_{lead} + R_{relay}$ $R_b = \frac{2 \cdot p \cdot l}{A} + 0.1\ \Omega$ $= \frac{2 \cdot 0.0175 \frac{\Omega\ \text{mm}^2}{\text{m}} \cdot 640\ \text{m}}{4\ \text{mm}^2}$ $+ 0.1\ \Omega$ $= 0.450\ \Omega$	$R'_b = R_{lead} + R_{relay}$ $R_b = \frac{2 \cdot p \cdot l}{A} + 0.1\ \Omega$ $= \frac{2 \cdot 0.0175 \frac{\Omega\ \text{mm}^2}{\text{m}} \cdot 100\ \text{m}}{4\ \text{mm}^2}$ $+ 0.1\ \Omega$ $= 0.975\ \Omega$	$R'_b = R_{lead} + R_{relay}$ $R_b = \frac{2 \cdot p \cdot l}{A} + 0.1\ \Omega$ $= \frac{2 \cdot 0.0175 \frac{\Omega\ \text{mm}^2}{\text{m}} \cdot 60\ \text{m}}{4\ \text{mm}^2}$ $+ 0.1\ \Omega$ $= 0.625\ \Omega$
$K'_{ssc} = K_{ssc} \cdot \frac{R_{ct} + R_b}{R_{ct} + R'_b}$ $= 20 \cdot \frac{18\ \Omega + 20\ \Omega}{18\ \Omega + 0.625\ \Omega} = 40.8$	$K'_{ssc} = K_{ssc} \cdot \frac{R_{ct} + R_b}{R_{ct} + R'_b}$ $= 20 \cdot \frac{18\ \Omega + 20\ \Omega}{18\ \Omega + 0.450\ \Omega} = 41.2$	$K'_{ssc} = K_{ssc} \cdot \frac{R_{ct} + R_b}{R_{ct} + R'_b}$ $= 20 \cdot \frac{0.96\ \Omega + 2\ \Omega}{0.96\ \Omega + 0.975\ \Omega} = 30.6$	$U_K \geq K_{td} \cdot \frac{I_{scc\,max\,(ext.\,fault)}}{1.3 \cdot I_{pn}} \cdot (R_{ct} + R'_b) \cdot I_{sn}$ $= 1.2 \cdot \frac{17{,}000\ \text{A}}{1.3 \cdot 1{,}000\ \text{A}} \cdot (0.8\ \Omega + 0.625\ \Omega) \cdot 5\ \text{A}$ $= 111.8\ \text{V}$
K'_{ssc} required = 28.8, K_{ssc} effective = 40.8 $28.8 < 40.8$ → CT dimensioning is ok	K'_{ssc} required = 17.9, K_{ssc} effective = 41.2 $17.9 < 41.2$ → CT dimensioning is ok	K'_{ssc} required = 18.7, K_{ssc} effective = 30.6 $18.7 < 30.6$ → CT dimensioning is ok	U_K required = 111.8 V, U_K effective = 200 V $111.8\ \text{V} < 200\ \text{V}$ → CT dimensioning is ok
$F_{Adap} = \frac{I_{pn} \cdot \sqrt{3} \cdot U_{nO}}{S_{Nmax}} \cdot \frac{I_{Nrelay}}{I_{sn}}$ $= \frac{6{,}000\ \text{A} \cdot \sqrt{3} \cdot 13.8\ \text{kV}}{120{,}000\ \text{kVA}} \cdot \frac{1\ \text{A}}{1\ \text{A}}$ $= 1.195$ $1/8 \leq 1.195 \leq 8$ → ok!	$F_{Adap} = \frac{I_{pn} \cdot \sqrt{3} \cdot U_{nO}}{S_{Nmax}} \cdot \frac{I_{Nrelay}}{I_{sn}}$ $= \frac{6{,}000\ \text{A} \cdot \sqrt{3} \cdot 13.8\ \text{kV}}{240{,}000\ \text{kVA}} \cdot \frac{1\ \text{A}}{1\ \text{A}}$ $= 0.598$ $1/8 \leq 0.598 \leq 8$ → ok!	$F_{Adap} = \frac{I_{pn} \cdot \sqrt{3} \cdot U_{nO}}{S_{Nmax}} \cdot \frac{I_{Nrelay}}{I_{sn}}$ $= \frac{1{,}200\ \text{A} \cdot \sqrt{3} \cdot 132\ \text{kV}}{240{,}000\ \text{kVA}} \cdot \frac{5\ \text{A}}{5\ \text{A}}$ $= 1.143$ $1/8 \leq 1.143 \leq 8$ → ok!	$\frac{I_{pn\,max}}{I_{pn\,min}} \leq 8$ $\frac{1{,}500\ \text{A}}{1{,}000\ \text{A}} = 1.5 \leq 8$ → ok!

Table 2/3 Example 1 (continued) – verfication of the numerical differential protection

Attention (only for 7UT6 V4.0): When low-impedance REF is used, the request for the REF side (3-phase) is:

$^1/_4 \leq F_{Adap} \leq 4$, (for the neutral CT: $^1/_8 \leq F_{Adap} \leq 8$)

Further condition for 7SD52x, 53x, 610 relays (when used as line differential protection without transformer inside protected zone): Maximum ratio between primary currents of CTs at the end of the protected line:

$$\frac{I_{pn\,max}}{I_{pn\,min}} \leq 8$$

Protection Coordination

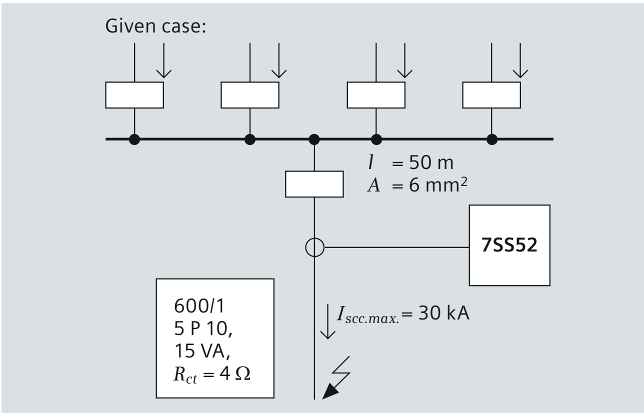


Fig. 2/94 Example 2

$$\frac{I_{scc\ max}}{I_{pn}} = \frac{30{,}000\ \text{A}}{600\ \text{A}} = 50$$

According to table 6.2-2, page 287 $K_{td} = {}^1/_2$

$$K'_{ssc} \geq \frac{1}{2} \cdot 50 = 25$$

$$R_b = \frac{15\ \text{VA}}{1\ \text{A}^2} = 15\ \Omega$$

$$R_{relay} = 0.1\ \Omega$$

$$R_{lead} = \frac{2 \cdot 0.0175 \cdot 50}{6} = 0.3\ \Omega$$

$$R'_b = R_{lead} + R_{relay} = 0.3\ \Omega + 0.1\ \Omega = 0.4\ \Omega$$

$$K'_{ssc} = \frac{R_{ct} + R_b}{R_{ct} + R'_b} \cdot K_{ssc} = \frac{4\ \Omega + 15\ \Omega}{4\ \Omega + 0.4\ \Omega} \cdot 10 = 43.2$$

Result:
The effective K'_{ssc} is 43.2, the required K'_{ssc} is 25. Therefore the stability criterion is fulfilled.

Relay burden
The CT burdens of the numerical relays of Siemens are below 0.1 VA and can therefore be neglected for a practical estimation. Exceptions are the busbar protection 7SS60 and the pilot-wire relays 7SD600.

Intermediate CTs are normally no longer necessary, because the ratio adaptation for busbar protection 7SS52 and transformer protection is numerically performed in the relay.

Analog static relays in general have burdens below about 1 VA.

Mechanical relays, however, have a much higher burden, up to the order of 10 VA. This has to be considered when older relays are connected to the same CT circuit.

In any case, the relevant relay manuals should always be consulted for the actual burden values.

Burden of the connection leads
The resistance of the current loop from the CT to the relay has to be considered:

$$R_{lead} = \frac{2 \cdot \rho \cdot l}{A}$$

l = Single conductor length from the CT to the relay in m

Specific resistance:

$$\rho = 0.0175\ \frac{\Omega \cdot \text{mm}^2}{\text{m}}\ \text{(copper wires) at 20 °C / 68 °F}$$

A = Conductor cross-section in mm²

CT design according to ANSI / IEEE C 57.13

Class C of this standard defines the CT by ist secondary terminal voltage at 20 times rated current, for which the ratio error shall not exceed 10 %. Standard classes are C100, C200, C400 and C800 for 5 A rated secondary current.

This terminal voltage can be approximately calculated from the IEC data as follows:

ANSI CT definition

$$U_{s.t.max} = 20 \cdot 5\ \text{A} \cdot R_b \cdot \frac{K_{ssc}}{20}$$

with

$$R_b = \frac{P_b}{I_{sn}^2}$$ and $I_{Nsn} = 5$ A, the result is

$$U_{s.t.max} = \frac{P_b \cdot K_{ssc}}{5\ \text{A}}$$

Example:
IEC 60044: 600 / 5, 5P20, 25 VA,

ANSI C57.13: $U_{s.t.max} = \frac{(25\ \text{VA} \cdot 20)}{5\ \text{A}} = 100$ V, acc. to class C100