Protection and Substation Control

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Protection and Substation Control General Overview

General overview

Three trends have emerged in the sphere of substation secondary equipment: intelligent electronic devices (IEDs), open communication and operation with a PC. Numerical relays and cumputerized substation control are now state-of-the-art.

The multitude of conventional, individual devices prevalent in the past as well as comprehensive parallel wiring are being replaced by a small number of multifunctional devices with serial connections.

One design for all applications

In this respect, Siemens offers a uniform, universal technology for the entire functional scope of secondary equipment, both in the construction and connection of the devices and in their operation and communication. This results in uniformity of design, coordinated interfaces and the same operating concept being established throughout, whether in power system and generator protection, in measurement and recording systems, in substation control and protection or in telecontrol.

All devices are highly compact and immune to interference, and are therefore also suitable for direct installation in switchgear cells. Furthermore, all devices and systems are largely self-monitoring, which means that previously costly maintenance can be reduced considerably.

"Complete technology from one partner"

The Protection and Substation Control Systems Division of the Siemens Power Transmission and Distribution Group supplies devices and systems for:

- Power System Protection
- Substation Control
- Remote Control (RTUs)
- Measurement and Recording
- Monitoring and Conditioning of Power Quality

This covers all of the measurement, control, automation and protection functions for substations*.

Furthermore, our activities cover:

- Consulting
- Planning
- Design
- Commissioning and Service

This uniform technology "all from one source" saves the user time and money in the planning, assembly and operation of his substations.

*An exception is revenue metering. Meters are separate products of our Metering Division.

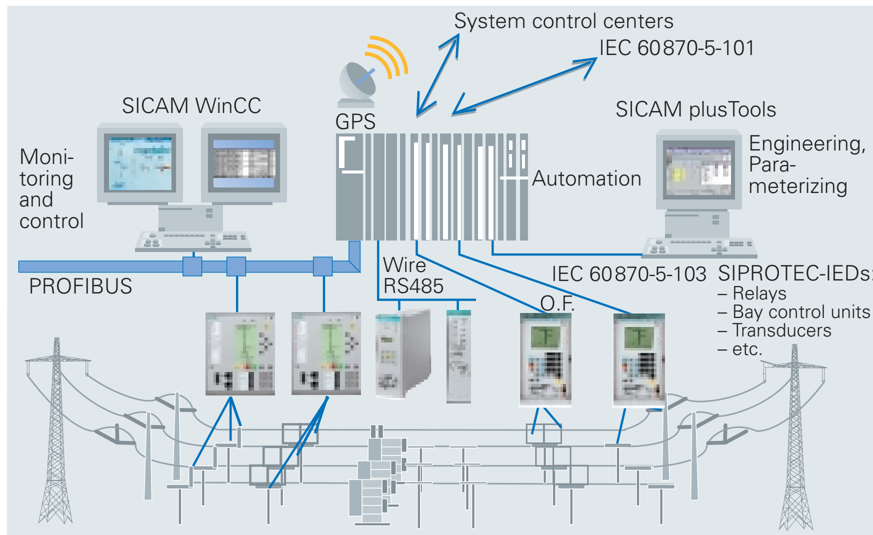

Fig. 1: The digital substation control system SICAM implements all of the control, measurement and automation functions of a substation. Protection relays are connected serially

Fig. 2a: Protection and control in HV GIS switchgear

Fig. 2b: Protection and control in bay dedicated kiosks of an EHV switchyard

Rationalization of operation	by means of SCADA-like operation control and high-performance, uniformly operable PC tools
Savings in terms of space and costs	by means of integration of many functions into one unit and compact equipment design
Simplified planning and operational reliability	by means of uniform design, coordinated interfaces and universally identical EMC
Efficient parameterization and operation	by means of PC tools with uniform operator interface
High levels of reliability and availability	by means of type-tested system technology, complete self-monitoring and the use of proven technology – 20 years of practical experience with digital protection, more than 150,000 devices in operation (1999) – 15 years of practical experience with substation automation (SINAUT LSA and SICAM), over 1500 substations in operation (1999)

Fig. 3: For the user, "complete technology from one source" has many advantages

Protection and Substation Control
General Overview

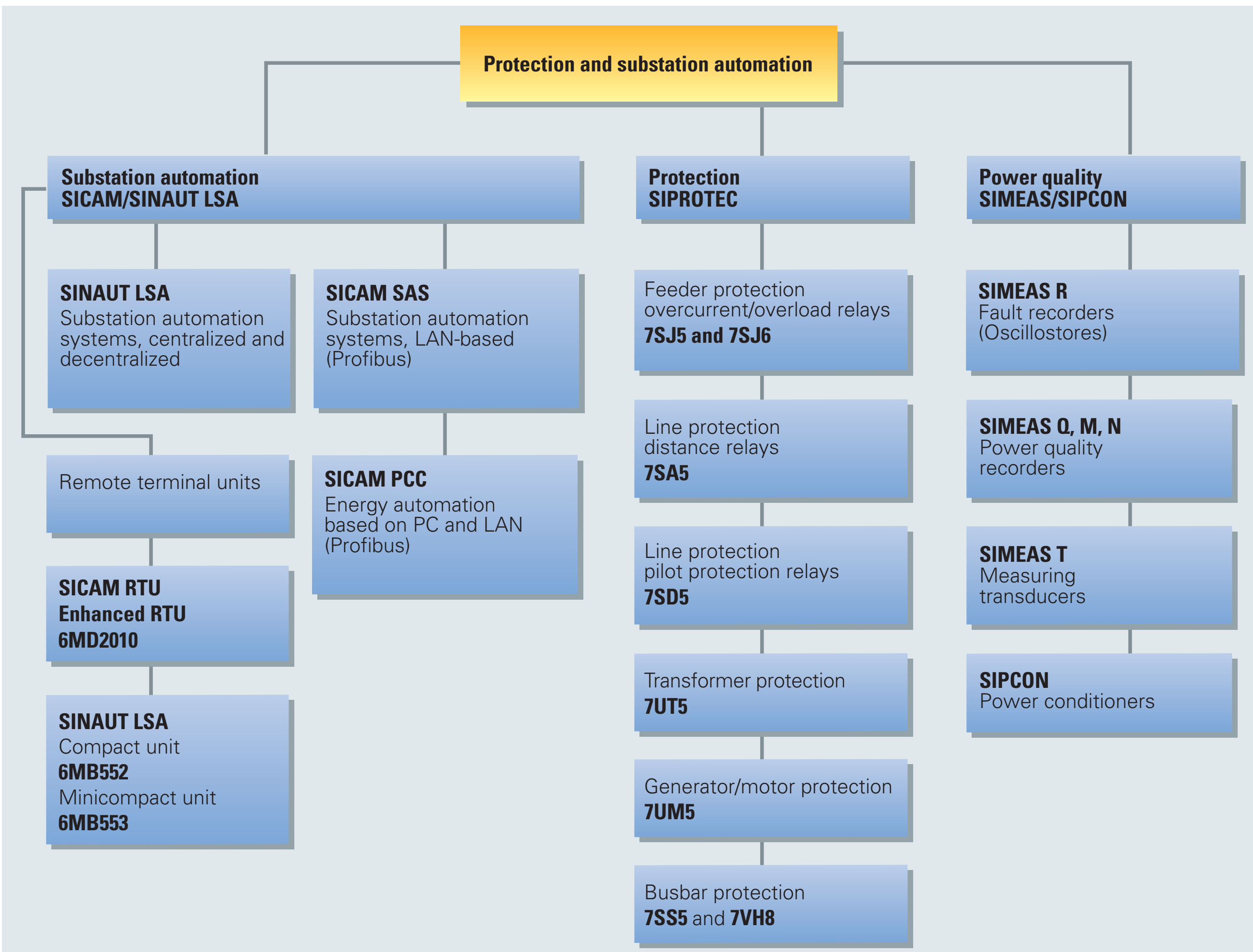

Fig. 4: Siemens Protection and Substation Control comprises these systems and product ranges

System Protection

Siemens offers a complete spectrum of multifunctional, numerical relays for all applications in the field of network and machine protection.

Uniform design and electromagnetic-interference-free construction in metal housings with conventional connection terminals in accordance with public utility requirements assure simple system design and usage just as with conventional relays.

Numerical measurement techniques ensure precise operation and necessitate less maintenance thanks to their continuous self-monitoring capability.

The integration of additional protection and other functions, such as real-time operational measurements, event and fault recording, all in one unit economizes on space, design and wiring costs.

Setting and programming of the devices can be performed through the integral, plaintext, menu-guided operator display or by using the comfortable PC program DIGSI for Windows*.

Open serial interfaces, IEC 870-5-103-compliant, allow free communication with higher level control systems, including those from other manufacturers. Connection to a Profibus substation LAN is optionally possible.

Thus the on-line measurements and fault data registered in the protective relays can be used for local and remote control or can be transmitted via telephone modem connections to the workplace of the service engineer.

Siemens supplies individual devices as well as complete protection systems in factory finished cubicles. For complex applications, for example, in the field of extra-high-voltage transmission, type and design test facilities are available together with an extensive and comprehensive network model using the most modern simulation and evaluation techniques.

* Windows is a registered product of Microsoft

Protection and Substation Control General Overview

Substation control

The digital substation control systems SICAM and SINAUT LSA provide all control, measurement and automation functions (e.g. transformer tap changing) required by a switching station. They operate with distributed intelligence. Communication between feeder-located devices and central unit is made via interference-free fiber optic connections.
Devices are extremely compact and can be built directly into medium and high-voltage switchgear.

To input data, set and program the system, the unique PC programs SICAM PlusTools and LSA-TOOLS are available. Parameters and values are input at the central unit and downloaded to the field devices, thus ensuring error-free and consistent data transfer.

The operator interface is menu-guided, with SCADA comparable functions, that is, with a level of convenience which was previously only available in a network control center. Optional telecontrol functions can be added to allow coupling of the system to one or more network control centers.

In contrast to conventional controls, digital technology saves enormously on space and wiring. SICAM and LSA systems are subjected to full factory tests and are delivered in fully functional condition.

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Remote control

Siemens remote control equipment 6MB55* and 6MD2010 fulfills all the classic functions of remote measurement and control. Furthermore, because of the powerful microprocessors with 32-bit technology, they provide comprehensive data preprocessing, automation functions and bulk storage of operational and fault information.

In the classic case, connections to the switchgear are made through coupling relays and transducers. This method allows an economically favorable solution when modernizing or renewing the secondary systems in older installations. Alternatively, especially for new installations, direct connection is also possible. Digital protection devices can be connected by serial links through fiber-optic conductors.

In addition, the functions ”operating and monitoring“ can be provided by the connection of a PC, thus raising the telecontrol unit to the level of a central station control system. Using the facility of nodal functions, it is also possible to build regional control points so that several substations can be controlled from one location.

Switchgear interlocking

The digital interlocking system 8TK is used for important substations in particular with multiple busbar arrangements. It prevents false switching and provides an additional local bay control function which allows fail-safe switching, even when the substation control system is not available. Therefore the safety of operating personnel and equipment is considerabely enhanced.

The 8TK system can be used as a stand-alone interlocked control, or as back-up system together with the digital 6MB substation control.

Power Quality (Measurement, recording and power compensation)

The SIMEAS product range offers equipment for the superversion of power supply quality (harmonic content, distortion factor, peak loads, power factor, etc.), fault recorders (Oscillostore), data logging printers and measurement transducers.

Stored data can be transmitted manually or automatically to PC evaluation systems where it can be analyzed by intelligent programs. Expert systems are also applied here. This leads to rapid fault analysis and valuable indicators for the improvement of network reliability.

For local bulk data storage and transmission, the central processor DAKON can be installed at substation level. Data transmission circuits for analog telephone or digital ISDN networks are incorporated as standard. Connection to local or wide-area networks (LAN, WAN) is equally possible.

We also have the SIMEAS T series of compact and powerful measurement transducers with analog and digital outputs.

The SIPCON Power Conditioner solves numerous system problems. It compensates (for example) unbalanced loads or system voltage dips and suppresses system harmonics. It performs these functions so that sensitive loads are assured of suitable voltage quality at all times. In addition, the system ist also capable of eliminating the perturbation produced by irregular loads. The use of SIPCON can enable energy suppliers worldwide to provide the end consumer with distinctive quality of supply.

Advantages for the user

The concept of ”Complete technology from one partner“ offers the user many advantages:

- High-level security for his systems and operational rationalization possibilities
  - powerful system solutions with the most modern technology
  - compliance with international standards
- Integration in the overall system SIPROTEC-SICAM-SIMATIC
- Space and cost savings
  - integration of many functions into one unit and compact equipment packaging
- Simple planning and secure operation
  - unified design, matched interfaces and EMI security throughout
- Rationalized programming and handling
  - menu-guided PC Tools and unified keypads and displays
- Fast, flexible mounting, reduced wiring
- Simple, fast commissioning
- Effective spare part stocking, high flexibility
- High-level operational security and availability
  - continuous self-monitoring and proven technology:
  - 20 years digital relay experience (more than 150,000 units in operation)
  - 10 years of SINAUT LSA and SICAM substation control (more than 1500 systems in operation)
- Rapid problem solving
  - comprehensive advice and fast response from local sales and workshop facilities worldwide.

Application hints

All named devices and systems for protection, metering and control are designed to be used in the harsh environment of electrical substations, power plants and the various industrial application areas.

When the devices were developed, special emphasis was placed on EMI. The devices are in accordance with IEC 60 255 standards. Detailed information is contained in the device manuals.

Reliable operation of the devices is not affected by the usual interference from the switchgear, even when the device is mounted directly in a low-voltage compartment of a medium-voltage cubicle.

Protection and Substation Control
Application Hints

It must, however, be ensured that the coils of auxiliary relays located on the same panel, or in the same cubicle, are fitted with suitable spike quenching elements (e.g. free-wheeling diodes).

When used in conjunction with switchgear for 100 kV or above, all external connection cables should be fitted with a screen grounded at both ends and capable of carrying currents. That means that the cross section of the screen should be at least 4 mm^2 for a single cable and 2.5 mm^2 for multiple cables in one cable duct.

All equipment proposed in this guide is built-up either in closed housings (type 7XP20) or cubicles with protection degree IP 51 according to IEC 60 529:

- Protected against access to dangerous parts with a wire
- Sealed against dust
- Protected against dripping water

Climatic conditions:

- Permissible temperature during service
  –5 °C to +55 °C
  permissible temperature during storage
  –25 °C to +55 °C
  permissible temperature during transport
  –25 °C to +70 °C
  Storage and transport with standard works packaging
- Permissible humidity
  Mean value per year ≤ 75% relative humidity; on 30 days per year 95% relative humidity; Condensation not permissible

We recommend that units be installed such that they are not subjected to direct sunlight, nor to large temperature fluctuations which may give rise to condensation.

Mechanical stress

Vibration and shock during operation

- Standards:
  IEC 60255-21 and IEC 60068-2
- Vibration
  – sinusoidal
  IEC 60255-21-1, class 1
  – 10 Hz to 60 Hz:
  ± 0.035 mm amplitude;
  IEC 60068-2-6
  – 60 Hz to 150 Hz:
  0.5 g acceleration
  sweep rate 10 octaves/min
  20 cycles in 3 orthogonal axes

Fig. 5: Installation of the numerical protection in the door of the low-voltage section of medium-voltage cell

Vibration and shock during transport

- Standards:
  IEC 60255-21and IEC 60068-2
- Vibration
  – sinusoidal
  IEC 60255-21-1, class 2
  – 5 Hz to 8 Hz:
  ± 7.5 mm amplitude;
  IEC 60068-2-6
  – 8 Hz to 150 Hz: 2 g acceleration
  sweep rate 1 octave/min
  20 cycles in 3 orthogonal axes
- Shock
  IEC 60255-21-2, class 1
  IEC 60068-2-27

Insulation tests

- Standards:
  IEC 60255-5
  – High-voltage test (routine test)
  2 kV (rms), 50 Hz
  – Impulse voltage test (type test)
  all circuits, class III
  5 kV (peak); 1.2/50 µs; 0.5 J; 3 positive and 3 negative shots at intervals of 5 s

Electromagnetic compatibility

EC Conformity declaration (CE mark):

All Siemens protection and control products recommended in this guide comply with the EMC Directive 99/336/EEC of the Council of the European Community and further relevant IEC 255 standards on electromagnetic compatibility.
All products carry the CE mark.

EMC tests; immunity (type tests)

- Standards:
  IEC 60255-22 (product standard)
  EN 50082-2 (generic standard)
- High frequency
  IEC 60255-22-1 class III
  – 2.5 kV (peak);
  1 MHz; τ = 15 µs;
  400 shots/s;
  duration 2 s
- Electrostatic discharge
  IEC 60255-22-2 class III
  and EN 61000-4-2 class III
  – 4 kV contact discharge;
  8 kV air discharge;
  both polarities;
  150 pF; R_i = 330 Ohm
- Radio-frequency electromagnetic field, nonmodulated;
  IEC 60255-22-3 (report) class III
  – 10 V/m; 27 MHz to 500 MHz
- Radio-frequency electromagnetic field, amplitude-modulated;
  ENV 50140, class III
  – 10 V/m; 80 MHz to 1000 MHz, 80%;
  1 kHz; AM
- Radio-frequency electromagnetic field, pulse-modulated;
  ENV 50140/ENV 50204, class III
  – 10 V/m; 900 MHz;
  repetition frequency 200 Hz;
  duty cycle 50%
- Fast transients
  IEC 60255-22-4 and EN 61000-4-4, class III
  – 2 kV; 5/50 ns; 5 kHz;
  burst length 15 ms; repetition rate 300 ms; both polarities;
  R_i = 50 Ohm; duration 1 min
- Conducted disturbances induced by radio-frequency fields HF, amplitude-modulated
  ENV 50141, class III
  – 10 V; 150 kHz to 80 MHz;
  80%; 1kHz; AM
- Power-frequency magnetic field
  EN 61000-4-8, class IV
  – 30 A/m continuous;
  300 A/m for 3 s; 50 Hz

EMC tests; emission (type tests)

- Standard:
  EN 50081-2 (generic standard)
- Interference field strength CISPR 11, EN 55011, class A
  – 30 MHz to 1000 MHz
- Conducted interference voltage, aux. voltage CISPR 22, EN 55022, class B
  – 150 kHz to 30 MHz

Instrument transformers

Instrument transformers must comply with the applicable IEC recommendations IEC 60044, formerly IEC 60185 (c.t.) and 186 (p.t.), ANSI/IEEE C57.13 or other comparable standards.

Potential transformers

Potential transformers (p.t.) in single- or double-pole design for all primary voltages have single or dual secondary windings of 100, 110 or 120 V/$\sqrt{3}$, with output ratings between 10 and 300 VA, and accuracies of 0.2, 0.5 or 1% to suit the particular application. Primary BIL values are selected to match those of the associated switchgear.

Current transformers

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

Measuring cores

They are normally specified with 0.5% or 1.0% accuracy (class 0.5 M or 1.0 M), and an accuracy limiting factor of 5 or 10.
The required output power (rated burden) must be higher than the actually connected burden. Typical values are 5, 10, 15 VA. Higher values are normally not necessary when only electronic meters and recorders are connected.
A typical specification could be: 0.5 M 10, 15 VA.

Cores for revenue metering

In this case, class 0.2 M is normally required.

Protection cores:

The size of the protection core depends mainly on the maximum short-circuit current and the total burden (internal c.t. burden, plus burden of connecting leads, plus relay burden).

Further, an overdimensioning factor has to be considered to cover the influence of the d.c. component in the short-circuit current.

In general, an accuracy of 1% (class 5 P) is specified. The accuracy limiting factor K_{ALF} should normally be designed so that at least the maximum short-circuit current can be transmitted without saturation (d.c. component not considered).

This results, as a rule, in rated accuracy limiting factors of 10 or 20 dependent on the rated burden of the c.t. in relation to the connected burden. A typical specification for protection cores for distribution feeders is 5P10, 15 VA or 5P20, 10 VA.

The requirements for protective current transformers for transient performance are specified in IEC 60044-6. The recommended calculation procedure for saturation-free design, however, leads to very high c.t. dimensions.
In many practical cases, the c.t.s 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 c.t. saturation to a large extent. The numerical relays proposed in this guide are particularly stable in this case due to their integral saturation detection function.

$$K_{ALF} \geq \frac{R_{BC} + R_i}{R_{BN} + R_i} \cdot K^*_{ALF}$$

K_{ALF} : Rated c.t. accuracy limiting factor
K^*_{ALF} : Effective c.t. accuracy limiting factor
R_{BN} : Rated burden resistance
R_{BC} : Connected burden
R_i : Internal c.t. burden (resistance of the c.t. secondary winding)

with:

$$K^*_{ALF} \geq K_{OF} \cdot \frac{I_{scc.max.}}{I_N}$$

$I_{scc.max.}$ = Maximum short-circuit current
I_N = Rated primary c.t. current
K_{OF} = Overdimensioning factor

Fig. 6: C.t. dimensioning formulae

The required c.t. accuracy-limiting factor K_{ALF} can be determined by calculation, as shown in Fig. 6.

The overdimensioning factor K_{OF} depends on the type of relay and the primary d.c. time constant. For the normal case, with short-circuit time constants lower than 100 ms, the necessary value for K^*_{ALF} can be taken from the table in Fig. 9.
The recommended values are based on extensive type tests.

C.t. design according to BS 3938

In this case the c.t. is defined by the knee-point voltage U_{KN} and the internal secondary resistance R_i.
The design values according to IEC 60 185 can be approximately transferred into the BS standard definition by the following formula:

$$U_{KN} = \frac{(R_{NC} + R_i) \cdot I_{2N} \cdot K_{ALF}}{1.3}$$

I_{2N} = Nominal secondary current
Example:
IEC 185 : 600/1, 15 VA, 5P10, R_i = 4 Ohm
BS : $U_{KN} = \frac{(15 + 4) \cdot 1 \cdot 10}{1.3} = 146$ V
R_i = 4 Ohm

Fig. 7: BS c.t. definition

C.t. design
according to ANSI/IEEE C 57.13

Class C of this standard defines the c.t. by its secondary terminal voltage at 20 times nominal current, for which the ratio error shall not exceed 10%. Standard classes are C100, C200, C400 and C800 for 5 A nominal secondary current.
This terminal voltage can be approximately calculated from the IEC data as follows:

$$V_{s.t.\,max} = 20 \times 5\,A \times R_{BN} \cdot \frac{K_{ALF}}{20}$$

with:

$$R_{BN} = \frac{P_{BN}}{I_{Nsec}^2} \text{ and } I_{Nsec} = 5\,A\text{, we get}$$

$$V_{s.t.\,max} = \frac{P_{BN} \cdot K_{ALF}}{5}$$

Example:
IEC 185 : 600/5, 25 VA, 5P20,
ANSI C57.13: $V_{s.t.\,max} = \frac{25 \cdot 20}{5} =$
= 100, i.e. class C100

Fig. 8: ANSI c.t. definition

Relay type	Minimum K^*_{ALF}
o/c protection 7SJ511, 512, 551, 7SJ60, 61, 62, 63	$= \frac{I_{\text{High set point}}}{I_N}$, at least 20
Transformer differential protection 7UT51	$= \frac{I_{\text{scc. max. (internal fault)}}}{I_N}$ and $\frac{1}{2} < \frac{[K^*_{ALF} \cdot U_N \cdot I_N]_{\text{(High voltage)}}}{[K^*_{ALF} \cdot U_N \cdot I_N]_{\text{(Low voltage)}}} < 2$
Line differential (fiber-optic) protection 7SD511/512	$= \frac{I_{\text{scc. max. (internal fault)}}}{I_N}$ and $\frac{1}{3} < \frac{[K^*_{ALF} \cdot I_N]_{\text{(line-end 1)}}}{[K^*_{ALF} \cdot I_N]_{\text{(line-end 2)}}} < 3$
Line differential (pilot wire) protection 7SD502/503/600	$= \frac{I_{\text{scc. max. (internal fault)}}}{I_N}$ and $\frac{3}{4} < \frac{K^*_{\text{ALF (line-end 1)}}}{K^*_{\text{ALF (line-end 2)}}} < \frac{4}{3}$
Numerical busbar protection (low impedance type) 7SS5	$= \frac{1}{2} \cdot \frac{I_{\text{scc. max. (outflowing current for ext. fault)}}}{I_N}$
Distance protection 7SA511, 7SA513, 7SA522	$= a \cdot \frac{I_{\text{scc. max. (close-in fault)}}}{I_N}$ — $\frac{T_N < 50\text{ ms:}}{a = 2}$ and $= 10 \cdot \frac{I_{\text{scc. max. (line-end fault)}}}{I_N}$ — $T_N < 100$ ms: $a = 3$ for 7SA511, $a = 2$ for 7SA513 and 7SA522

Fig. 9: Required effective accuracy limiting factor K^*_{ALF}

Relay burden

The c.t. 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 7SS50 (1.5 VA) and the pilot wire relays 7SD502, 7SD600 (4 VA) and 7SD503 (3 VA + 9 VA per 100 Ohm pilot wire resistance).
Intermediate c.t.s are normally no longer applicable as the ratio adaption for busbar and transformer protection is numerically performed in the relay.
Analog static relays in gereral also 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 c.t. 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 c.t. to the relay has to be considered:

$$R_l = \frac{2 \cdot \rho \cdot l}{A} \text{ Ohm}$$

l = single conductor length from the c.t. to the relay in m.

Specific resistance:

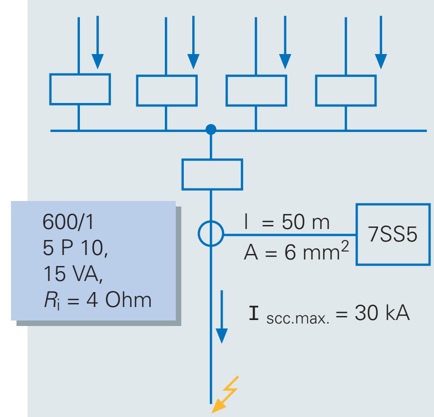
$\rho = 0.0179 \frac{\text{Ohm} \cdot \text{mm}^2}{\text{m}}$ (copper wires)

A = conductor cross section in mm^2

Fig. 10

Example: Stability-verification of the numerical busbar protection 7SS50

Given case:



$$\frac{I_{\text{scc.max.}}}{I_N} = \frac{30{,}000}{600} = 50$$

According to Fig. 9:

$$K^*_{ALF} \geq \frac{1}{2} \cdot 50 = 25$$

$$R_{BN} = \frac{15\text{ VA}}{1\text{ A}^2} = 15\text{ Ohm};$$

$$R_{Relay} = \frac{1.5\text{ VA}}{1\text{ A}^2} = 1.5\text{ Ohm}$$

$$R_l = \frac{2 \cdot 0.0179 \cdot 50}{6} = 0.3\text{ Ohm}$$

$$R_{BC} = R_l + R_{Relay} = 0.3 + 1.5 = 1.8\text{ Ohm}$$

$$K_{ALF} \geq \frac{1.8 + 4}{15 + 4} \cdot 25 = 7.6$$

Result:

The rated K_{ALF}-factor (10) is higher than the calculated value (7.6). Therefore, the stability criterium is fulfilled.

Fig. 11

Power System Protection
Introduction

Introduction

Siemens is one of the world's leading suppliers of protective equipment for power systems.

Thousands of our relays ensure first-class performance in transmission and distribution networks on all voltage levels, all over the world, in countries of tropical heat or arctic frost.

For many years, Siemens has also significantly influenced the development of protection technology.

- In 1976, the first minicomputer (process computer)-based protection system was commissioned: A total of 10 systems for 110/20 kV substations were supplied and are still operating satisfactorily today.
- Since 1985, we have been the first to manufacture a range of fully numerical relays with standardized communication interfaces.
  Today, Siemens offers a complete program of protective relays for all applications including numerical busbar protection.
  To date (1999), more than 150,000 numerical protection relays from Siemens are providing successful service, as standalone devices in traditional systems or as components of coordinated protection and substation control.
  Meanwhile, the innovative SIPROTEC 4 series has been launched, incorporating the many years of operational experience with thousands of relays, together with users' requirements (power authority recommendations).

SIPROTEC 3

SIPROTEC 4

Fig. 12: Numerical relay ranges of Siemens

State of the art

Mechanical and solid-state (static) relays have been almost completely phased out of our production because numerical relays are now preferred by the users due to their decisive advantages:

- Compact design and lower cost due to integration of many functions into one relay
- High availability even with less maintenance due to integral self-monitoring
- No drift (aging) of measuring characteristics due to fully numerical processing
- High measuring accuracy due to digital filtering and optimized measuring algorithms
- Many integrated add-on functions, for example, for load-monitoring and event/fault recording
- Local operation keypad and display designed to modern ergonomic criteria
- Easy and secure read-out of information via serial interfaces with a PC, locally or remotely
- Possibility to communicate with higher-level control systems using standardized protocols (open communication)

Power System Protection
Introduction

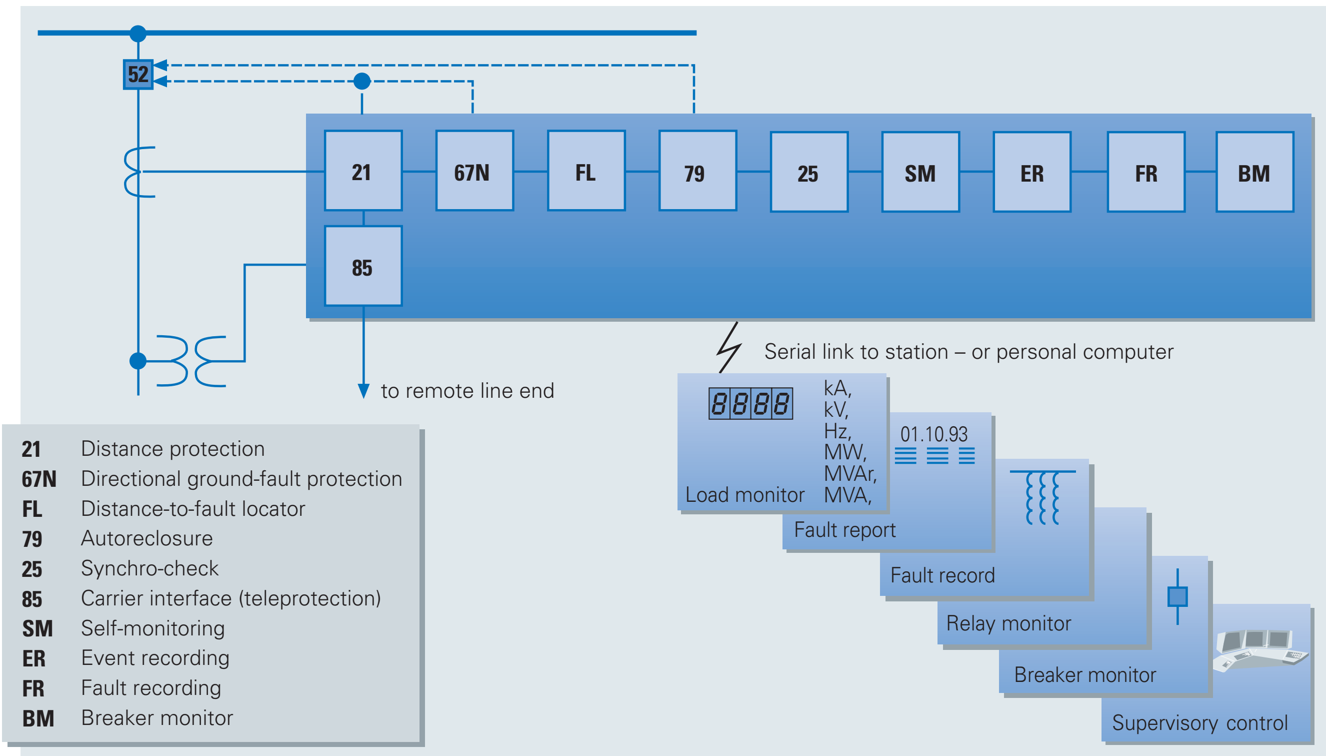


Fig. 13: Numerical relays, increased information availability

Modern protection management

All the functions, for example, of a line protection scheme can be incorporated in one unit:

- Distance protection with associated add-on and monitoring functions
- Universal teleprotection interface
- Autoreclose and synchronism check

Protection-related information can be called up on-line or off-line, such as:

- Distance to fault
- Fault currents and voltages
- Relay operation data (fault detector pick-up, operating times etc.)
- Set values
- Line load data (kV, A, MW, kVAr)

To fulfill vital protection redundancy requirements, only those functions which are interdependent and directly associated with each other are integrated in the same unit. For back-up protection, one or more additional units have to be provided.

All relays can stand fully alone. Thus, the traditional protection concept of separate main and alternate 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 towards a parameter definition procedure. The documentation is provided by the relay itself. Free allocation of LED operation indicators and output contacts provides more application design flexibility.

Measuring included

For many applications, the protective-current transformer accuracy is sufficient for operational measuring. The additional measuring c.t. was more for protection of measuring instruments under system fault conditions. Due to the low thermal withstand ability of the measuring instruments, they could not be connected to the protection c.t.. Consequently, additional measuring c.t.s and measuring instruments are now only necessary where high accuracy is required, e.g. for revenue metering.

On-line remote data exchange

A powerful serial data link provides for interrogation of digitized measured values and other information stored in the protection units, for printout and further processing at the substation or system control level.
In the opposite direction, settings may be altered or test routines initiated from a remote control center.

For greater distances, especially in outdoor switchyards, fiber-optic cables are preferably used. This technique has the advantage that it is totally unaffected by electromagnetic interference.

Off-line dialog with numerical relays

A simple built-in operator panel which requires no special software knowledge or codeword tables is used for parameter input and readout.

This allows operator dialog with the protection relay. Answers appear largely in plain-text on the display of the operator panel. Dialog is divided into three main phases:

- Input, alternation and readout of settings
- Testing the functions of the protection device and
- Readout of relay operation data for the three last system faults and the autoreclose counter.

Modern system protection management

A more versatile notebook PC may be used for upgraded protection management.

The MS Windows-compatible relay operation program DIGSI is available for entering and readout of setpoints and archiving of protection data.

The relays may be set in 2 steps. First, all relay settings are prepared in the office with the aid of a local PC and stored on a floppy or the hard disk. At site, the settings can then be downloaded from a PC into the relay. The relay confirms the settings and thus provides an unquestionable record.

Vice versa, after a system fault, the relay memory can be uploaded to a PC, and comprehensive fault analysis can then take place in the engineer's office.

Alternatively, the total relay dialog can be guided from any remote location through a modem-telephone connection (Fig. 15).

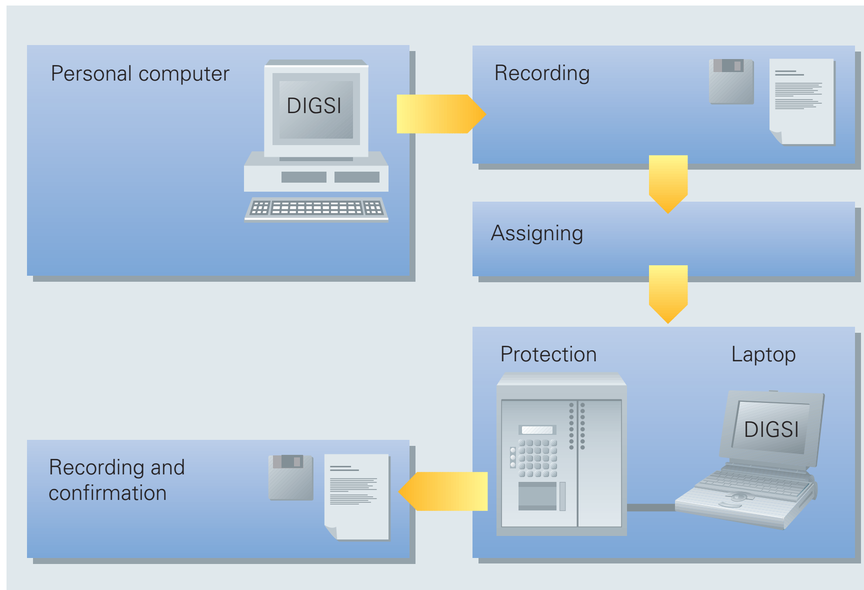


Fig. 14: PC-aided setting procedure

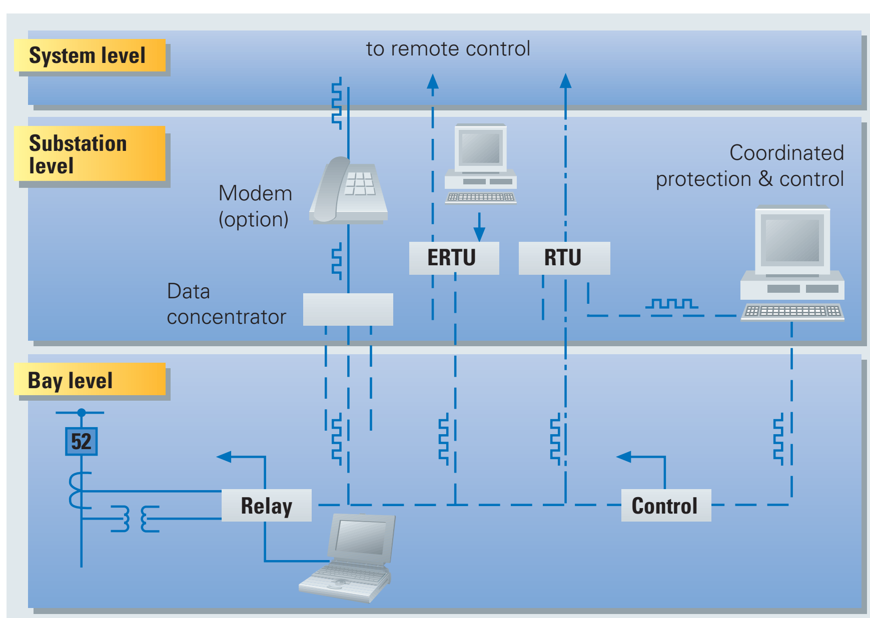


Fig. 15: Communication options

6

Relay data management

Analog-distribution-type relays have some 20–30 setpoints. If we consider a power system with about 500 relays, then the number adds up to 10,000 settings. This requires considerable expenditure in setting the relays and filing retrieval setpoints.

A personal computer-aided man-machine dialog and archiving program, e.g. DIGSI, assists the relay engineer in data filing and retrieval. The program files all settings systematically in substation-feeder-relay order.

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 protective relay itself, but are methodically carried through from current transformer circuits to tripping relay coils.

Equipment failures and faults in the c.t. circuits are immediately reported and the protective relay blocked.

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

Adaptive relaying

Numerical relays now offer secure, convenient and comprehensive matching to changing conditions. Matching may be initiated either by the relay's own intelligence or from the outside world via contacts or serial telegrams. Modern numerical relays contain a number of parameter sets that can be pretested during commissioning of the scheme (Fig. 17). One set is normally operative. Transfer to the other sets can be controlled via binary inputs or serial data link. There are a number of applications for which multiple setting groups can upgrade the scheme performance, e.g.

a) for use as a voltage-dependent control of o/c relay pickup values to overcome alternator fault current decrement to below normal load current when the AVR is not in automatic operation.

b) for maintaining short operation times with lower fault currents, e.g. automatic change of settings if one supply transformer is taken out of service.

c) for "switch-onto-fault" protection to provide shorter time settings when energizing a circuit after maintenance. The normal settings can be restored automatically after a time delay.

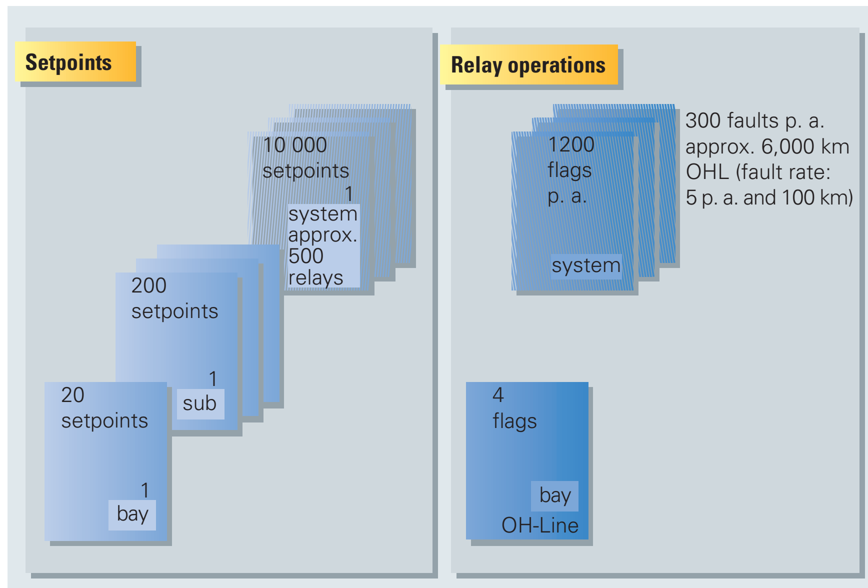


Fig. 16: System-wide setting and relay operation library

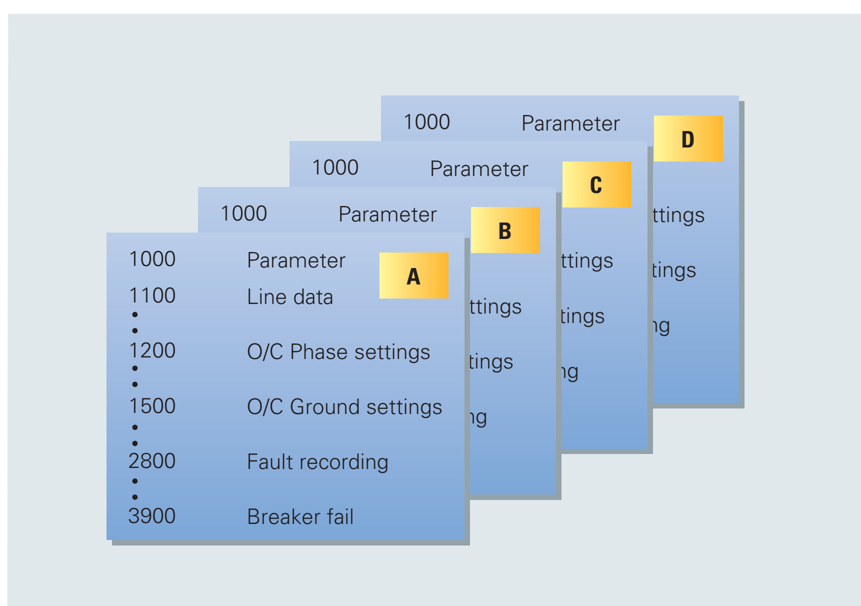


Fig. 17: Alternate parameter groups

d) for autoreclose programs, i.e. instantaneous operation for first trip and delayed operation after unsuccessful reclosure.

e) for cold load pick-up problems where high starting currents may cause relay operation.

f) for "ring open" or "ring closed" operation.

Power System Protection Relay Design and Operation

Mode of operation

Numerical protection relays operate on the basis of numerical measuring principles. The analog measured values of current and voltage are decoupled galvanically from the plant secondary circuits via input transducers (Fig. 18). After analog filtering, the sampling and the analog-to-digital conversion take place. The sampling rate is, depending on the different protection principles, between 12 and 20 samples per period. With certain devices (e.g. generator protection) a continuous adjustment of the sampling rate takes place depending on the actual system frequency.

The protection principle is based on a cyclic calculation algorithm, utilizing the sampled current and voltage analog measured values. The fault detections determined by this process must be established in several sequential calculations before protection reactions can follow.

A trip command is transferred to the command relay by the processor, utilizing a dual channel control.

The numerical protection concept offers a variety of advantages, especially with regard to higher security, reliability and user friendliness, such as:

- High measurement accuracy:
  The high utilization of adaptive algorithms produce accurate results even during problematic conditions
- Good long-term stability:
  Due to the digital mode of operation, drift phenomena at components due to ageing do not lead to changes in accuracy of measurement or time delays
- Security against over and underfunction

With this concept, the danger of an undetected error in the device causing protection failure in the event of a network fault is clearly reduced when compared to conventional protection technology. Cyclical and preventive maintenance services have therefore become largely obsolete.

The integrated self-monitoring system (Fig. 19) encompasses the following areas:

– Analog inputs
– Microprocessor system
– Command relays.

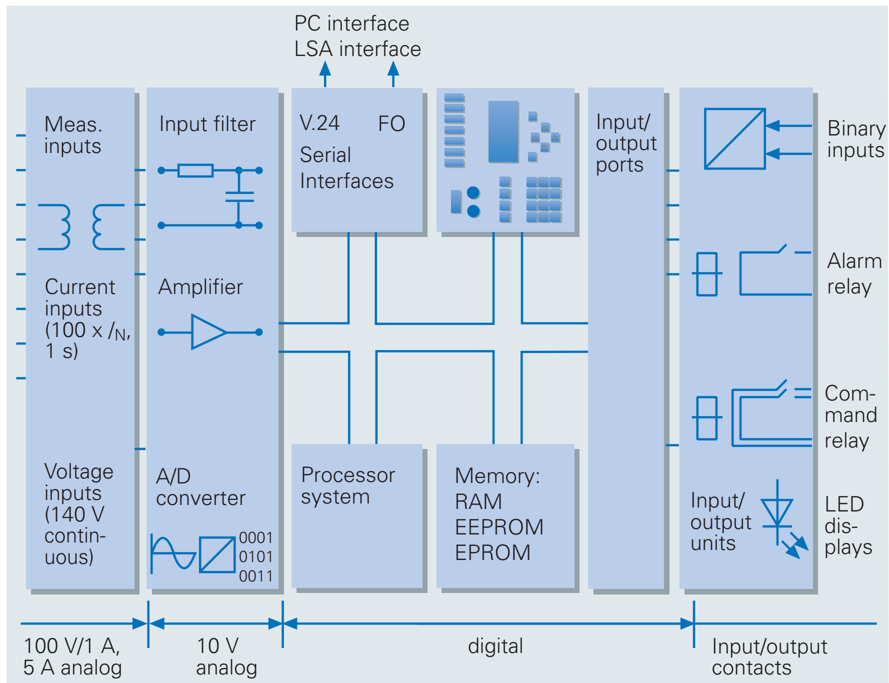


Fig. 18: Block diagram of numerical protection

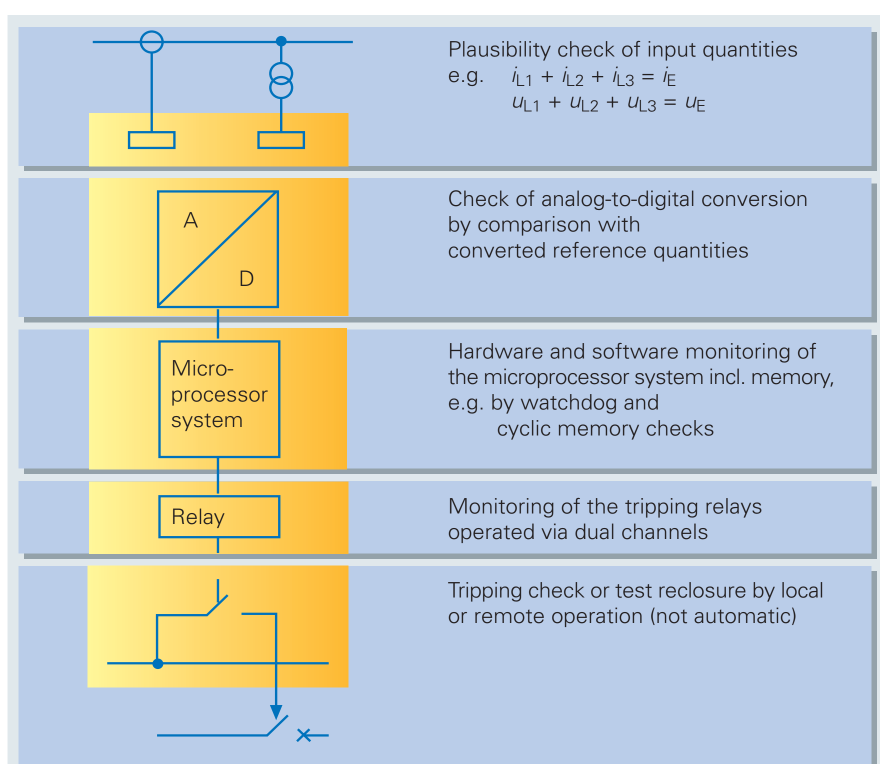


Fig. 19: Self-monitoring system

Power System Protection Relay Design and Operation

Implemented Functions

SIOPROTEC relays are available with a variety of protective functions. See relay charts (page **6**/20 and following).

The high processing power of modern numerical devices allow 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 uniformly answered. In transmission type substations, separation into independent hardware units is still preferred, whereas on the distribution level a trend towards higher function integration can be observed. Here, combined feeder relays for protection, monitoring and control are on the march (Fig. 20).

Most of the relays of this guide are standalone protection relays. The exception in the SIPROTEC 3 series is the distribution feeder relay 7SJ531 that also integrates control functions. Per feeder, only one relay package ist needed in this case leading to a considerable reduction in space und wiring.

With the new SIPROTEC 4 series (types 7SJ61, 62 and 63), 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 functions in the feeder, without compromising the reliability of the protection functions (Fig. 21).

Fig. 20: Switchgear with numerical relay (7SJ62) and traditional control

Switchgear with combined protection and control relay (7SJ63)

The following solutions are available within one relay family:

- Separate control and protection relays
- Protection relays including remote control of the feeder breaker via the serial communication link
- Combined feeder relays for protection, monitoring and control

Mixed use of the different relay types is readily possible on account of the uniform operation and communication procedures.

6

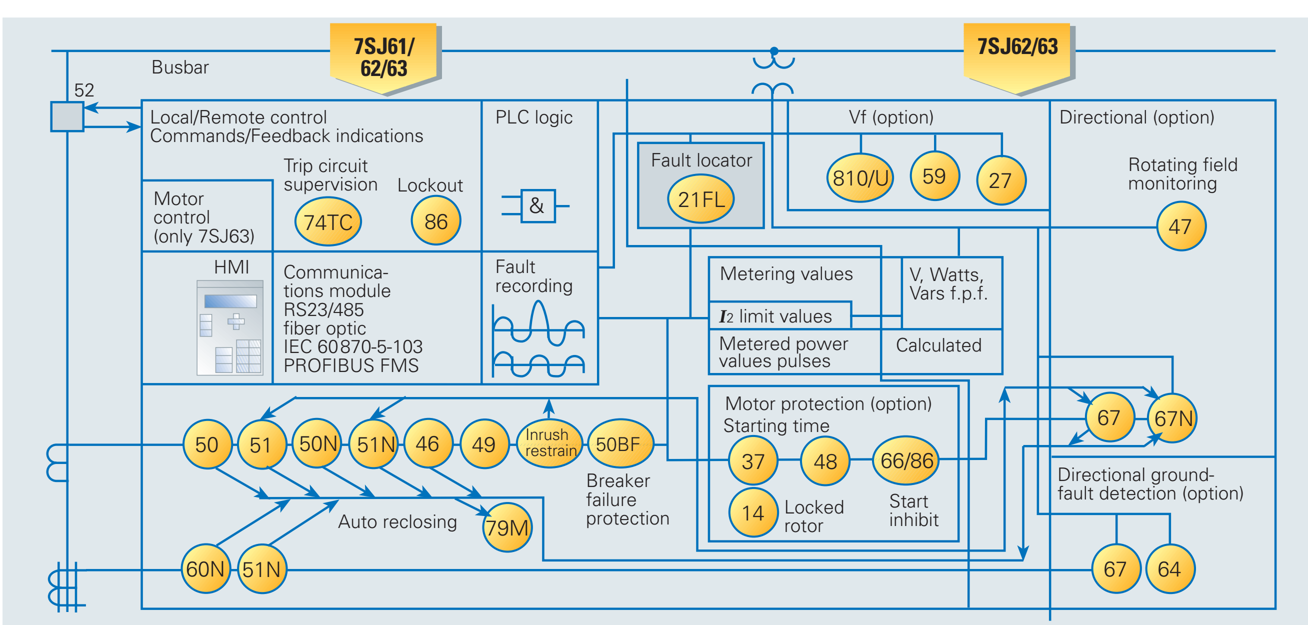


Fig. 21: SIPROTEC 4 relays 7SJ61/62/63, implemented function

Power System Protection
Relay Design and Operation

6

Integration of relays in the substation automation

Basically, Siemens numerical relays are all equipped with an interface to IEC 60870-5-103 for open communication with substation control systems either from Siemens (SINAUT LSA or SICAM, see page **6**/71 ff) or of any other supplier.

The relays of the newer SIPROTEC 4 series, however, are even more flexible and equipped with communication options.

SIPROTEC 4 relays may also be connected to the SINAUT LSA system or to a system of another supplier via IEC 60870-5-103.

But, SICAM 4 relays were originally designed as components of the new SICAM substation automation system, and their common use offers the most technical and cost benefits.

SIPROTEC 4 protection and SICAM station control, which is based on SIMATIC, are of uniform design, and communication is based on the Profibus standard.

SIPROTEC 4 relays can in this case be connected to the Profibus substation LAN of the SICAM system via one serial interface. Through a second serial interface, e.g. IEC 60 870-5-103, the relay can separately communicate with a remote PC via a modem-telephone line (Fig. 22).

Local relay operation

All operator actions can be executed and information displayed on an integrated user interface.

Many advantages are already to be found on the clear and user-friendly front panel:

- Positioning and grouping of the keys supports the natural operating process (ergonomic design)
- Large non-reflective back-lit display
- Programmable (freely assignable) LEDs for important messages
- Arrows arrangement of the keys for easy navigation in the function tree
- Operator-friendly input of the setting values via the numeric keys or with a PC by using the operating program DIGSI 4
- Command input protected by key lock (6MD63/7SJ63 only) or password
- Four programmable keys for frequently used functions >at the press of a button<

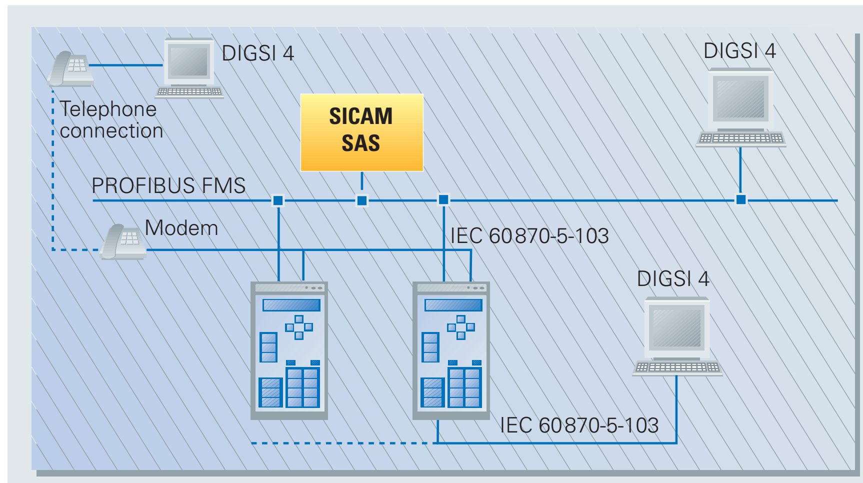
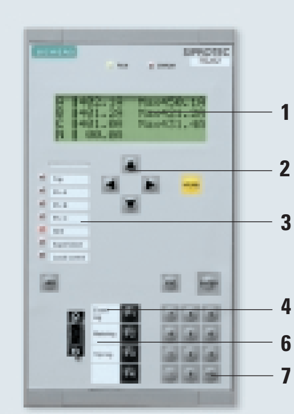
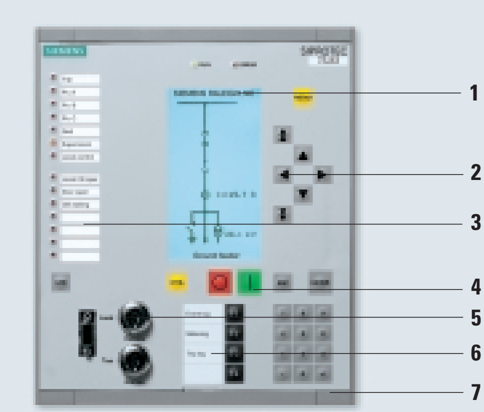


Fig. 22: SIPROTEC 4 relays, communication options





1 Large illuminated display
2 Cursor keys
3 LED with reset key
4 Control (7SJ61/62 uses function keys)
5 Key switches
6 Freely programmable function keys
7 Numerical keypad

Fig. 23: Front view of the protection relay 7SJ62

Fig. 24: Front view of the combined protection, monitoring and control relay 7SJ63

Power System Protection
Relay Design and Operation

DIGSI 4 the PC program for operating SIPROTEC 4 relays

For the user, DIGSI is synonymous with convenient, user-friendly parameterizing and operation of digital protection relays. DIGSI 4 is a logical innovation for operation of protection and bay control units of the SIPROTEC 4 family.

The PC operating program DIGSI 4 is the human-machine interface between the user and the SIPROTEC 4 units. It features modern, intuitive operating procedures. With DIGSI 4, the SIPROTEC 4 units ca be configured and queried.

- The interface provides you only with what is really necessary, irrespective of which unit you are currently configuring.
- Contextual menus for every situation provide you with made-to-measure functionality – searching through menu hierarchies is a thing of the past.
- Explorer – operation on the MS Windows 95® Standard – shows the options in logically structured form.
- Even with marshalling, you have the overall picture – a matrix shows you at a glance, for example, which LEDs are linked to which protection control function(s). It just takes a click with the mouse to establish these links by a fingertip.
- Thus, you can also use the PC to link up with the relay via star coupler or channel switch, as well via the PROFIBUS® of a substation control system. The integrated administrating system ensures clear addressing of the feeders and relays of a substation.
- Access authorization by means of passwords protects the individual functions, such as for example parameterizing, commissioning and control, from unauthorized access.
- When configuring the operator environment and interfaces, we have attached importance to continuity with the SICAM automation system. This means that you can readily use DIGSI on the station control level in conjunction with SICAM. Thus, the way is open to the SIMATIC automation world.

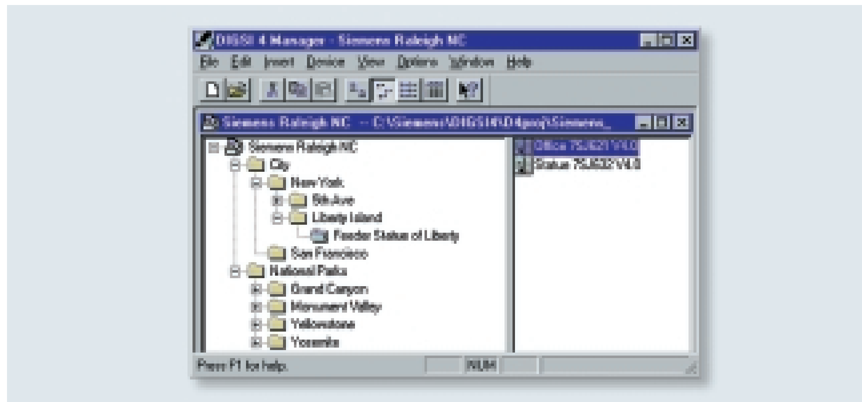


Fig. 25: Substation manager for managing of substation and device data

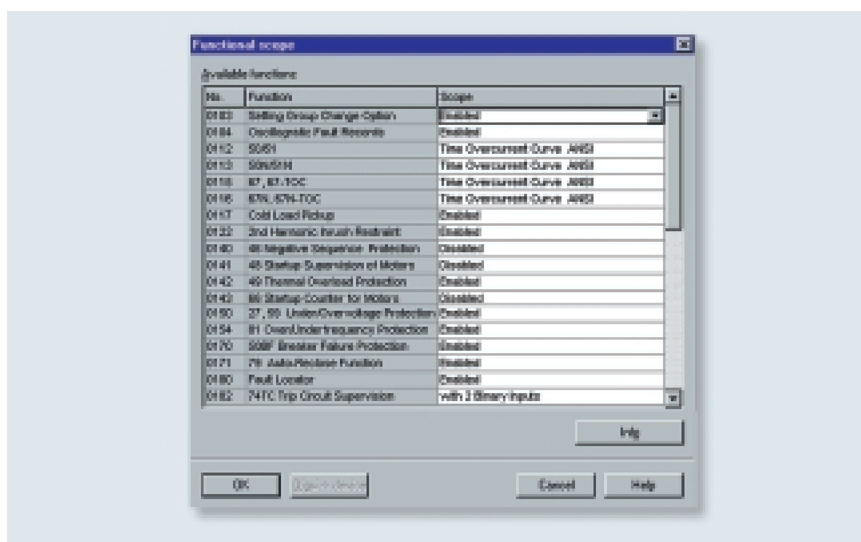


Fig. 26: Function range

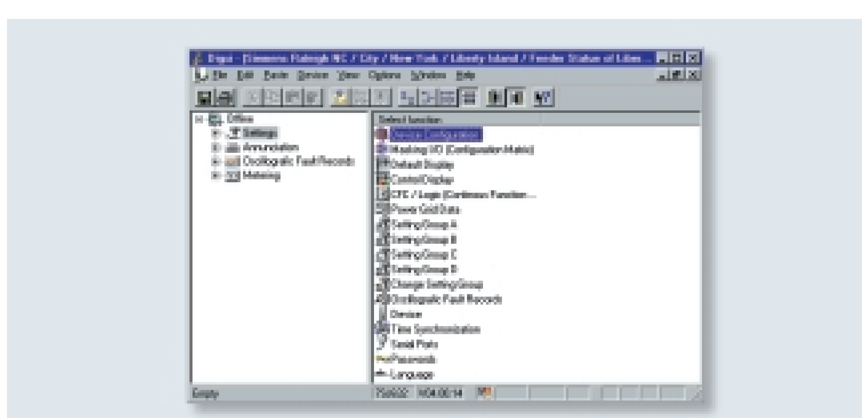


Fig. 27: Range of operational measured values

Power System Protection
Relay Design and Operation

DIGSI 4 matrix

The DIGSI 4 matrix allows the user to see the overall view of the relay configuration at a glance. For example, you can display all the LEDs that are linked to binary inputs or show external signals that are connected to the relay. And with one click of the button, connections can be switched (Fig. 28).

Display editor

A display editor is available to design the display on SIPROTEC 4 units. The predefined symbol sets can be expanded to suit the user. The drawing of a one-line diagram is extremely simple. Load monitoring values (analog values) can be placed where required (Fig. 29).

Commissioning

Special attention has been paid to commissioning. All binary inputs and outputs can be read and set directly. This can simplify the wire checking process significantly for the user.

CFC: Planning instead of programming logic

With the help of the graphical CFC (Continuous Function Chart)Tool, you can configure interlocks and switching sequences simply by drawing the logic sequences; no special knowledge of software is required. Logical elements such as AND, OR and time elements are available (Fig. 30) .

Hardware and software platform

- Pentium 133 MHz or above, with at least 32 Mbytes RAM
- DIGSI requires about 200 Mbytes hard-disk space
- Additional hard-disk space per installed protection device 2 Mbytes
- One free serial interface to the protection device (COM 1 to COM 4)
- One CD ROM drive (required for installation)
- WINDOWS 95/98 or NT 4

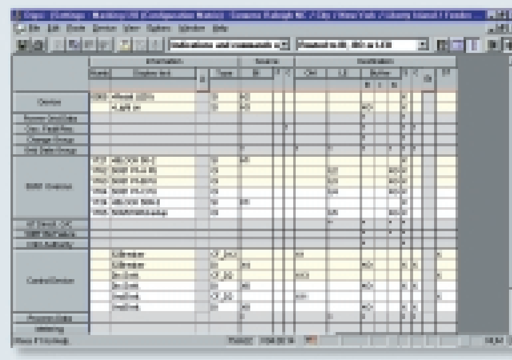


Fig. 28: DIGSI 4 allocation matrix

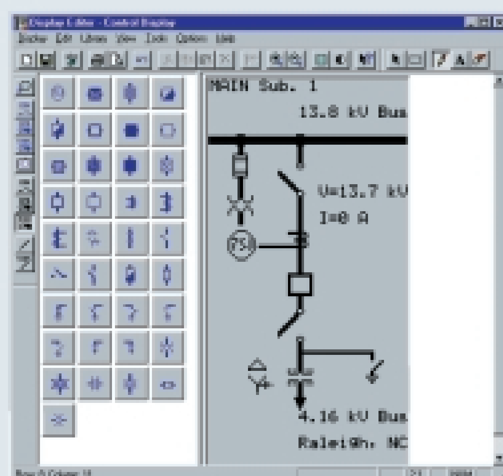


Fig. 29: Display Editor

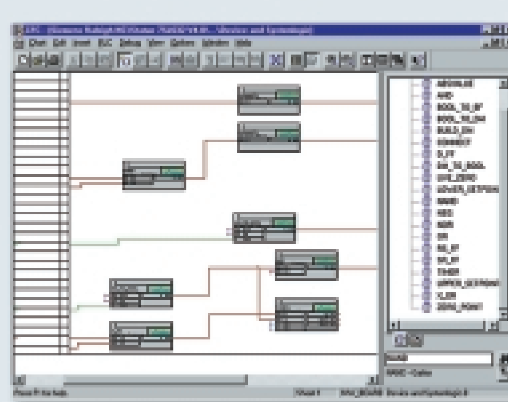


Fig. 30: CFC logic with module library

Operation of SIPROTEC 3 Relays

Most of the Siemens numerical relays belong to the series SIPROTEC 3. (Only the distribution protection relays 7SJ61/62, the combined protection and control relay 7SJ63 and the line protection 7SA522 are presently available in the version SIPROTEC 4).

Both relay series are widely compatible and can be used together in protection and control systems. SIPROTEC 3 relays however are not applicable with PROFIBUS but only with the IEC 60870-5-103 communication standard.

The operation of SIPROTEC 3 and 4 relays is very similar. Some novel features of the PC operating program DIGSI 4 like the CFC function and the graphical setting matrix are however not contained in DIGSI 3.

Operation of SIPROTEC 3 relays via integral key pad and LCD display:

Each parameter can be accessed and altered via the integrated operator panel or a PC connected to the front side serial communication interface.

The setting values can be accessed directly via 4-digit addresses or by paging through the menu. The display appears on an alphanumeric LCD display with 2 lines with 16 characters per line.

Also the rear side IEC 60870-5-103 compatible serial interface can be used for the relay dialog with a PC, when not occupied for the connection to a substation automation system. This rear side interface is in particular used for remote relay communication with a PC (see page **6**/19).

Most relays allow for the storage of several setting groups (in general 4) which can be activated via binary relay input, serial interface or operator panel.

Binary inputs, alarm contact outputs, indicating LEDs and command output relays can be freely assigned to the internal relay functions.

Fig. 31: Operation of the protection relays using PC and DIGSI 3 software program

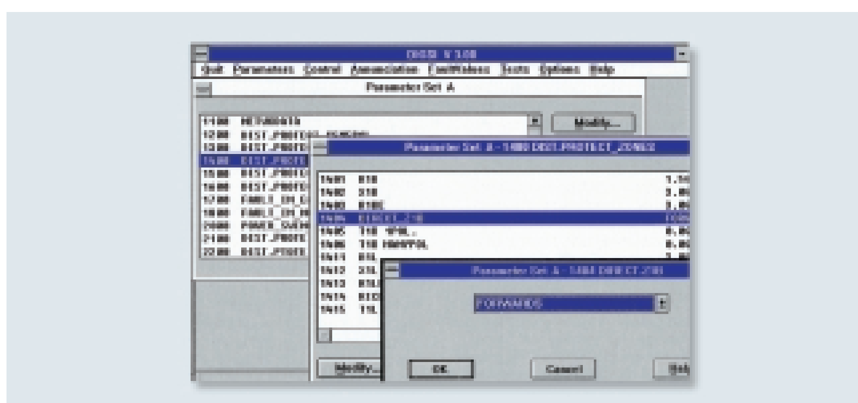


Fig. 32: Parameterization using DIGSI 3

DIGSI 3 the PC program for operating SIPROTEC 3 relays

For setting of SIPROTEC 3 relays, the DIGSI 3 version is applicable. (Figs. 31 and 32). It is a WINDOWS-based program that allows comfortable user-guided relay setting, load monitoring and readout of stored fault reports, including oscillographic fault records. It is also a valuable tool for commissioning as it allows an online overview display of all measuring values.

DIGSI comes with the program DIGRA for graphic display and evaluation of oscillographic fault records (see next page).

For remote relay communication, the program WINDIMOD is offered (option).

The DIGSI 3 program requires the following hardware and software platform:

- PC 386 SX or above, with at least 4 Mbytes Ram
- 10 Mbytes hard-disc space for DIGSI 3
- 2 to 3 Mbytes additional hard-disc space per installed protection device
- One free serial interface to the protection device (COM 1 to COM 4)
- One floppy disc drive 3.5", high density with 1.44 Mbytes or CD ROM drive for program installation
- WINDOWS version 3.1 or higher

These requirements relate to the case when DIGSI 3 is used as stand-alone version. When used together with DIGSI 4, the requirements for DIGSI 4 apply. In this case DIGSI 3 and DIGSI 4 run under the common DIGSI 4 substation manager.

Fault analysis

The evaluation of faults is simplified by numerical protection technology. In the event of a fault in the network, all events as well as the analog traces of the measured voltages and currents are recorded.

The following types of memory are available:

- 1 operational event memory
  Alarms that are not directly assigned to a fault in the network (e.g. monitoring alarms, alternation of a set value, blocking of the automatic reclose function).
- 5 fault-event histories
  Alarms that occurred during the last 3 faults on the network (e.g. type of fault detection, trip commands, fault location, autoreclose commands). A reclose cycle with one or more reclosures is treated as one fault history. Each new fault in the network overrides the oldest fault history.
- A memory for the fault recordings for voltage and current. Up to 8 fault recordings are stored. The fault recording memory is organized as a ring buffer, i.e. a new fault entry overrides the oldest fault record.
- 1 earth-fault event memory (optional for isolated or resonant grounded networks)
  Event record of the sensitive earth fault detector (e.g. faulted phase, real component of residual current).

The time tag attached to the fault-record events is a relative time from fault detection with a resolution of 1 ms. In the case of devices with integrated battery back-up clock, the operational events as well as the fault detection are assigned the internal clock time and date stamp.

The memory for operational events and fault record events is protected against failure of auxiliary supply with battery back-up supply.

The integrated operator interface or a PC supported by the programming tool DIGSI is used to retrieve fault reports as well as for the input of settings and marshalling.

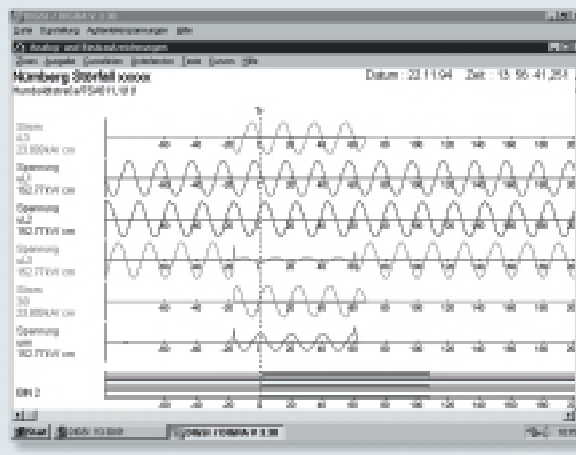


Fig. 33: Display and evaluation of a fault record using DIGSI

Evaluation of the fault recording

Readout of the fault record from the protection device by DIGSI is done by fault-proof scanning procedures in accordance with the standard recommendation for transmission of fault records.
A fault record can also be read out repeatedly. In addition to analog values, such as voltage and current, binary tracks can also be transferred and presented.

DIGSI is supplied together with the DIGRA (Digsi Graphic) program, which provides the customer with full graphical operating and evaluation functionality like that of the digital fault recorders (Oscillostores) from Siemens (see Fig. 33).

Real-time presentation of analog disturbance records, overlaying and zooming of curves and visualization of binary tracks (e.g. trip command, reclose command, etc.) are also part of the extensive graphical functionality, as are setting of measurement cursors, spectrum analysis and fault resistance derivation.

Data security, data interfaces

DIGSI is a closed system as far as protection parameter security is concerned. The security of the stored data of the operating PC is ensured by checksums. This means that it is only possible to change data with DIGSI, which subsequently calculates a checksum for the changed data and stores it with the data. Changes in the data and thus in safety-related protection data are reliably detected.

DIGSI is, however, also an open system. The data export function supports export of parameterization and marshalling data in standard ASCII format. This permits simple access to these data by other programs, such as test programs, without endangering the security of data within the DIGSI program system.

With the import and export of fault records in IEEE standard format COMTRADE (ANSI), a high-performance data interface is produced which supports import and export of fault records into the DIGSI partner program DIGRA.
This enables the export of fault records from Siemens protection units to customer-specific programs via the COMTRADE format.

Remote relay interrogation

The numerical relay range of Siemens can also be operated from a remotely located PC via modem-telephone connection.

Up to 254 relays can be addressed via one modem connection if the star coupler 7XV53 is used as a communication node (Fig. 34).

The relays are connected to the star coupler via optical fiber links.
Every protection device which belongs to a DIGSI substation structure has a unique address.

The attached relays are always listening, but only the addressed one answers the operator command which comes from the central PC.

If the relay located in a station is to be operated from a remote office, then a device file is opened in DIGSI and protection dialog is chosen via modem.
After password input, DIGSI establishes a connection to the protection device after receiving a call-back from the system.

In this way secure and timesaving remote setting and readout of data are possible.

Diagnostics and control of test routines are also possible without the need to visit the substation.

Housing and terminal system

The protection devices and the corresponding supplementary devices are available mainly in 7XP20 housings (Figs. 35 to 42). The dimension drawings are to be found on **6**/36 and the following pages. Installing of the modules in a cubicle without the housing is not permissible.

The width of the housing conforms to the 19" system with the divisions 1/6, 1/3, 1/2 or 1/1 of a 19" rack. The termination module is located at the rear of devices for panel flush mounting or cubicle mounting.

For electrical connection, screwed terminals of the SIPROTEC 3 relay series and also parallel crimp contacts are provided. For field wiring, the use of the screwed terminals is recommended; snap-in connection requires special tools.

To withdraw crimp contact terminations of the SIPROTEC 3 relay series the following tool is recommended:
Extraction tool No. 135900 (from Weidmüller, Paderbornstrasse 157, D-32760 Detmold).

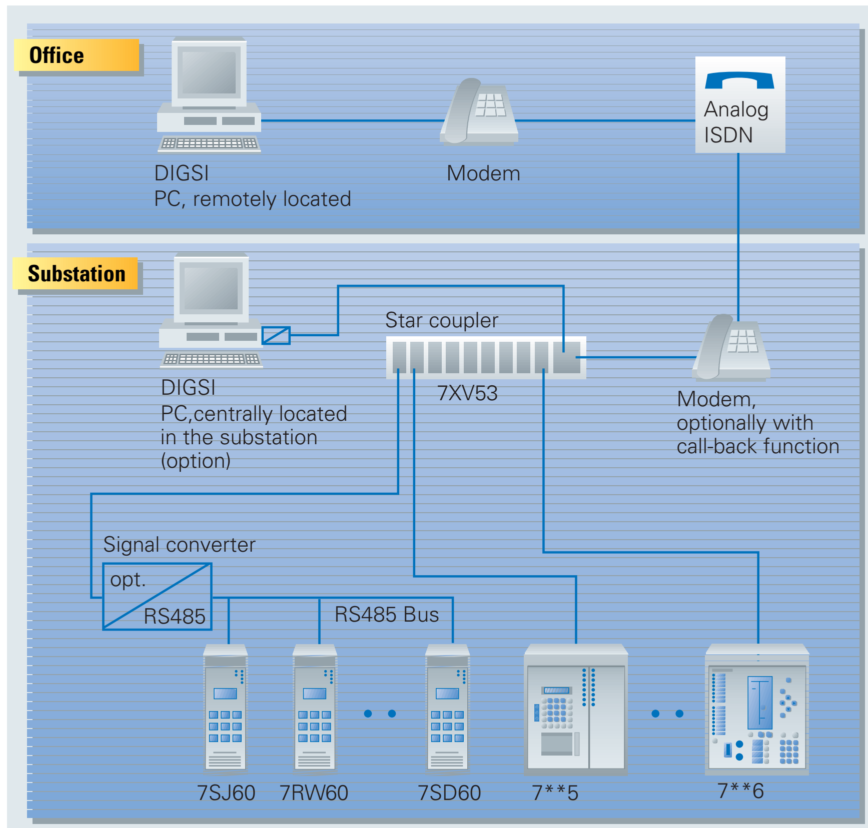


Fig. 34: Remote relay communication

The heavy-duty current plug connectors provide automatic shorting of the c.t. circuits whenever the modules are withdrawn. This does not release from the care to be taken when c.t. secondary circuits are concerned.

In the housing version for surface mounting, the terminations are wired up on terminal strips on the top and bottom of the device. For this purpose two-tier terminal blocks are used to attain the required number of terminals (Fig. 36 right).

According to IEC 60529 the degree of protection is indicated by the identifying IP, followed by a number for the degree of protection. The first digit indicates the protection against accidental contact and ingress of solid foreign bodies, the second digit indicates the protection against water. 7XP20 housings are protected against access to dangerous parts by wire, dust and dripping water (IP 51).

For mounting of devices into cubicles, the 8MC cubicle system is recommended. It is described in Siemens Catalog NV21.
The standard cubicle has the following dimensions:
2200 mm x 900 mm x 600 mm (HxWxD).
These cubicles are provided with a 44 U high mounting rack (standard height unit U = 44.45 mm). It can swivel as much as 180° in a swing frame.

The rack provides for a mounting width of 19", allowing, for example, 2 devices with a width of 1/2 x 19" to be mounted. The devices in the 7XP20 housing are secured to rails by screws. Module racks are not required (see Fig. 65b on page **6**/33).

6

SIPROTEC 3 Relay Series

SIPROTEC 3 relays come in 1/6 to 1/1 of 19" wide cases with a standard height of 243 mm.

Their size is compatible with SIPROTEC 4 relays. Therefore, exchange is always possible.

Versions for flush and surface mounting are available.

Terminations:

Flush-mounted version:

Each termination may be made via screw terminal or crimp contact. The termination modules used each contain:

4 termination points for measured voltages, binary inputs or relay outputs (max. 1.5 mm^2) or

2 termination points for measured currents (screw termination max. 4 mm^2, crimp contact max. 2.5 mm^2)

2 FSMA plugs for the fiber optic termination of the serial communication link

Surface mounted version:

Screw terminals (max. wire cross section 7 mm^2) for all wired terminations at the top and bottom of the housing

2 FMS plugs for fiber optic termination of the serial communication link at the bottom of the housing

Fig. 35c

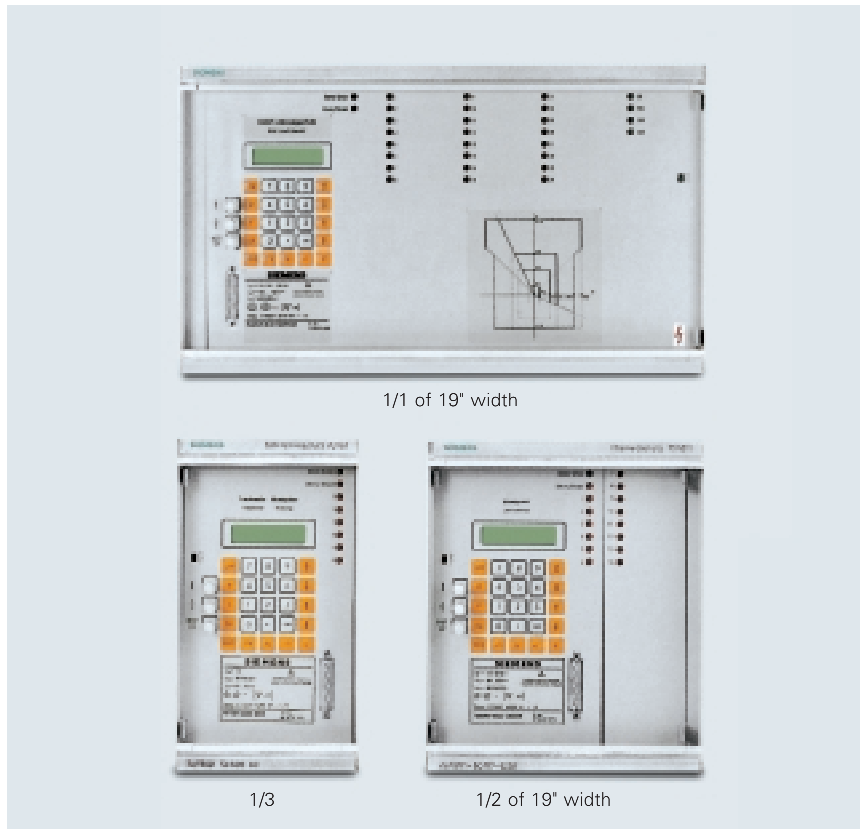


Fig. 35a/b: Numerical protection relays of the SIPROTEC 3 series in 7XP20 standard housing

Fig. 36: SIPROTEC 3 relays left: Connection method for panel flush mounting including fiber-optic interfaces;

Fig. 36 Right: Connection method for panel surface mounting

SIPROTEC 4 Relay Series

SIPROTEC 4 relays come in 1/6 to 1/1 of 19" wide cases with a standard height of 243 mm.

Their size is compatible with SIPROTEC 3 relays. Therefore, compatible exchange is always possible.

All wires (cables) are connected at the rear side of the relay via ring tongue terminals.

A special relay version with loose cable-connected operator panel (Fig. 42) is also available. It allows for example installation of the relay itself in the low-voltage compartment and of the operator panel separately in the door of the switchgear.

In this version voltage terminals are of the plug-in type. Current terminals are again screw-type.

Terminations:

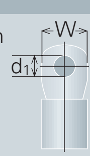
Standard relay version with screw terminals:	
Current terminals:	
Connection ring cable lugs	W_{max} = 12 mm d_1 = 5 mm 
Wire size	2.7 – 4 mm^2 (AWG 13–11)
Direct connection	Solid conductor, flexible lead, connector sleeve
Wire size	2.7 – 4 mm^2 (AWG 13–11)
Voltage terminals:	
Connection ring cable lugs	W_{max} = 10 mm d_1 = 4 mm
Wire size	1.0 – 2.6 mm^2 (AWG 17–13)
Direct connection	Solid conductor, flexible lead, connector sleeve
Wire size	0.5 – 2.5 mm^2 (AWG 20–13)
Special relay version (Fig. 42) with plug-in terminals:	
Current terminals:	
Screw type as above	
Voltage terminals:	
2-pin or 3-pin	0.5 – 1.0 mm^2
connectors	0.75 – 1.5 mm^2
Wire size	1.0 – 2.5 mm^2

Fig. 37

Fig. 38: 1/6 of 19"

Fig. 39: 1/3 of 19"

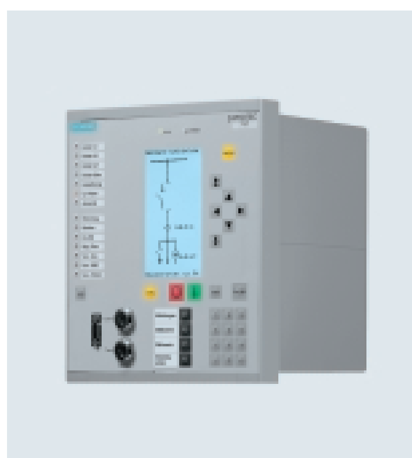


Fig. 40: 1/2 of 19"

Fig. 41: SIPROTEC 4 relay case versions

Fig. 42: SIPROTEC 4 combined protection, control and monitoring relay 7SJ63 with separate operator panel

Power System Protection
Relay Selection Guide

Relay Selection Guide

ANSI No.*	Description	7SA511	7SA513	7SA522	7SD600	7SD502	7SD503	7SD511	7SD512	7SJ511	7SJ512	7SJ531	7SJ60	7SJ61	7SJ62	7SJ63	7SJ551	7VH80	7UT512	7UT513	7SS50/52	7VH83	7UM511	7UM512	7UM515	7UM516
Protection functions / Type		Distance		Pilot wire differential				Fiber-optic current comparison		Overcurrent							Motor protection	Differential					Generator protection			
14	Zero speed and underspeed dev.	–	–	–	–	–	–	–	–	–	–	■	–	–	–	–	■	–	–	–	–	–	–	–	–	–
21	Distance protection, phase	■	■	■	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■
21N	Distance protection, ground	■	■	■	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
24	Overfluxing	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	–
25	Synchronism check	■	■	■	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
27	Undervoltage	–	–	–	–	–	–	–	–	–	–	■	–	–	■	■	■	–	–	–	–	–	■	■	■	–
27/59/81	U/f protection	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	–
32	Directional power	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	–	–	■
32F	Forward power	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	■	–	■
32R	Reverse power	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	■	–	■
37	Undercurrent or underpower	–	–	–	–	–	–	–	–	–	–	■	–	■	■	■	■	–	–	–	–	–	–	■	–	–
40	Field failure	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	–	–	–
46	Load unbalance, negative phase sequence overcurrent	–	–	–	–	–	–	–	–	–	–	■	■	■	■	■	■	–	–	–	–	–	■	■	–	■
47	Phase sequence voltage	■	■	■	–	–	–	–	–	–	–	–		–	■	■	–	–	–	–	–	–	–	–	–	–
48	Incomplete sequence, locked rotor, failure to accelerate	–	–	–	–	–	–	–	–	–	–	■	■	■	■	■	■	–	–	–	–	–	–	–	–	–
49	Thermal overload	■	–	–	–	■	■	■	■	■	■	■	■	■	■	■	■	–	■	■	–	–	■	–	–	–
49R	Rotor thermal protection	–	–	–	–	–	–	–	–	–	–	■	■	■	■	■	■	–	–	–	–	–	–	–	–	–
49S	Stator thermal protection	–	–	–	–	–	–	–	–	–	–	■	■	■	■	■	■	–	–	–	–	–	■	–	–	–
50	Instantaneous overcurrent	–	–	–	–	–	–	–	–	■	■	■	■	■	■	■	■	–	■	■	–	–	■	–	–	–
50N	Instantaneous ground fault overcurrent	–	–	–	–	–	–	–	–	■	■	■	■	■	■	■	■	–	–	–	–	–	–	–	–	–
51G	Ground overcurrent relay	–	–	–	–	–	–	–	–	–	–	■	■	■	■	■	■	–	■	–	–	–	–	■	■	–

* ANSI/IEEE C 37.2: IEEE Standard Electrical Power System Device Function Numbers

Fig. 43a

6

Power System Protection Relay Selection Guide

ANSI No.*	Description	Distance: 7SA511	7SA513	7SA522	Pilot wire differential: 7SD600	7SD502	7SD503	Fiber-optic current comparison: 7SD511	7SD512	Overcurrent: 7SJ511	7SJ512	7SJ55	7SJ531	7SJ60	7SJ61	7SJ62	7SJ63	Motor protection: 7SJ551	Differential: 7VH80	7UT512	7UT513	7SS50/52	7VH83	Generator protection: 7UM511	7UM512	7UM515	7UM516
51GN	Stator ground-fault overcurrent	–	–	–	–	–	–	–	–	–	–	–	■	–	–	–	–	■	–	–	–	–	–	■	■	■	–
51	Overcurrent with time delay	–	–	–	–	■	■	■	■	■	■	–	■	■	■	■	■	■	–	■	■	–	–	■	■	–	■
51N	Ground-fault overcurrent with time delay	■	■	■	–	–	–	■	■	■	–	–	■	■	■	■	■	■	–	–	–	–	–	■	■	–	–
59	Overvoltage	–	■	■	–	–	–	–	–	–	–	–	■	–	–	■	■	■	–	–	–	–	–	■	■	■	–
59N	Residual voltage ground-fault protection	–	–	–	–	–	–	–	–	–	■	–	■	–	–	■	■	–	–	–	–	–	–	■	–	■	■
64R	Rotor ground fault	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	■	■	–
67	Directional overcurrent	–	–	–	–	–	–	–	–	–	■	–	■	–	–	■	■	–	–	–	–	–	–	–	–	–	–
67N	Directional ground-fault overcurrent	■	■	–	–	–	–	–	–	–	■	–	■	–	–	■	■	■	–	–	–	–	–	–	–	–	–
67G	Stator ground-fault, directional overcurrent	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	–	–
68/78	Out-of-step protection	■	■	■	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■
79	Autoreclose	■	■	■	–	–	–	–	■	–	■	■	■	■	■	■	■	–	–	–	–	–	–	–	–	–	–
81	Frequency relay	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	■	–	–	–	–	–	–	■	■	■	–
85	Carrier interface	■	■	■	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
86	Lockout relay, start inhibit	–	–	–	–	–	–	–	–	–	–	–	■	–	■	■	■	■	–	–	–	–	–	–	–	–	–
87G	Differential protection, generator	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	■	–	–	–	–	–	–
87T	Differential protection, transf.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	■	–	–	–	–	–	–
87B	Differential protection, bus-bar	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	■	–	–	–	–
87M	Differential protection, motor	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	■	–	■	–	–	–	–
87L	Differential protection, line	–	–	–	■	■	■	■	■	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
87N	Restricted earth-fault protection	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	■	–	■	–	–	–	–	–	–
92	Voltage and power directional rel.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
50BF	Breaker failure	–	■	■	–	–	–	–	–	■	■	–	■	–	■	■	■	–	–	–	–	■	–	–	–	–	–

* ANSI/IEEE C 37.2: IEEE Standard Electrical Power System Device Function Numbers

Fig. 43b

6

Power System Protection
Relay Selection Guide

Relay Selection Guide

ANSI No.*	Description	Autoreclose + Synchronism check 7VK512	Synchronizing 7VE51	Breaker failure 7SV512	Breaker failure 7SV600	Voltage, Frequency 7RW600
24	Overfluxing	–	–	–	–	■
25	Synchronism check	■	–	–	–	–
	Synchronizing	–	■	–	–	–
27	Undervoltage	–	–	–	–	■
27/59/ 81	U/f protection	–	–	–	–	■
50BF	Breaker failure	–	–	■	■	–
59	Overvoltage	–	–	–	–	■
79	Autoreclose	■	–	–	–	–
81	Frequency relay	–	–	–	–	■

* ANSI/IEEE C 37.2: IEEE Standard Electrical Power System Device Function Numbers

Fig. 43c

Power System Protection
Relay Portraits

Relay portraits

Siemens manufactures a complete series of numerical relays for all kinds of protection application.

The series is briefly portrayed on the following pages.

7SJ600

Universal overcurrent
and overload protection

- Phase-segregated measurement and indication (Input 3 ph, I_E calculated)
- All instantaneous, i.d.m.t. and d.t. characteristics can be set individually for phase and ground faults
- Selectable setting groups
- Integral autoreclose function (option)
- Thermal overload, unbalanced load and locked rotor protection
- Suitable for busbar protection with reverse interlocking
- With load monitoring, event and fault memory

7SJ602*

Universal overcurrent
and overload protection

Functions as 7SJ600, however additionally:

- Fourth current input transformer for connection to an independent ground current source (e.g. core-balance CT)
- Optical data interface as alternative to the wired RS485 version (located at the relay bottom)
- Serial PC interface at the relay front

*) Commencement of delivery planned for end of 1999

Fig. 44: 7SJ600/7SJ602

Fig. 45: 7SJ511/512

7SJ511

Universal overcurrent protection

- Phase-segregated measurement and indication (3 ph and E)
- I.d.m.t and d.t. characteristics can be set individually for phase and ground faults
- Suitable for busbar protection with reverse interlocking
- With integral breaker failure protection
- With load monitoring, event and fault memory
- Inrush stabilization

7SJ512

Digital overcurrent-time protection
with additional functions

Same features as 7SJ511, plus:

- Autoreclose
- Sensitive directional ground-fault protection for isolated, resonant or high-resistance grounded networks
- Directional module when used as directional overcurrent relay (optional)
- Selectable setting groups
- Inrush stabilization

Power System Protection
Relay Portraits

7SJ61

Universal overcurrent
and overload protection with
control functions

- Phase-segregated measurement and indication (input 3 ph and E)
- All instantaneous, i.d.m.t. and d.t. characteristics can be set individually for phase and ground faults
- Selectable setting groups
- Inrush stabilization
- Integral autoreclose function (option)
- Thermal overload, unbalanced load and locked rotor protection
- Suitable for busbar protection with reserve interlocking
- With load monitoring, event and fault memory
- With integral breaker failure protection
- With trip circuit supervision

Control functions:

- Measured-value acquisition (current)
- Limit values of current
- Control of 1 C.B.
- Switchgear interlocking isolator/C.B.

7SJ62

Digital overcurrent and overload protection with additional functions
Features as 7SJ61, plus:

- Sensitive directional ground-fault protection for isolated, resonant or high-resistance grounded networks
- Directional overcurrent protection
- Selectable setting groups
- Over and undervoltage protection
- Over and underfrequency protection
- Distance to fault locator (option)

Control functions:

- Measured-value acquisition (voltage)
- P, Q, cos φ and meter-reading calculation
- Measured-value recording
- Limit values of I, V, P, Q, f, cos φ

Fig. 46: 7SJ61/7SJ62

Fig. 47: 7SJ551

7SJ551

Universal motor protection
and overcurrent relay

- Thermal overload pretection
  - separate thermal replica for stator and rotor based on true RMS current measurement
  - up to 2 heating time constants for the stator thermal replica
  - separate cooling time constants for stator and rotor thermal replica
  - ambient temperature biasing of thermal replica
- Connection of up to 8 RTD sensors ground elements
- Real-Time Clock: last 3 events are stored with real-time stamps of alarm and trip data

Power System Protection
Relay Portraits

Combined feeder protection and control relay 7SJ63

Line protection

- Nondirectional time overcurrent
- Directional time overcurrent
- IEC/ANSI and user definable TOC curves
- Overload protection
- Sensitive directional ground fault
- Negative sequence overcurrent
- Under/Overvoltage
- Under/Overfrequency
- Breaker failure
- Autoreclosure
- Fault locator

Motor protection

- Thermal overload
- Locked rotor
- Start inhibit
- Undercurrent

Control functions

- Control up to 5 C.B.
- Switchgear interlocking isolator/C.B.
- Key-operated switching authority
- Feeder control diagram
- Status indication of feeder devices at graphic display
- Measured-value acquisition
- Signal and command indications
- P, Q, cos φ and meter-reading calculation
- Measured-value recording
- Event logging
- Switching statistics
- Switchgear interlocking
- 2 measuring transducer inputs

I/O Capability

	7SJ631	7SJ632/3	7SJ635/6
Binary inputs	11	24/20	37/33
Contact outputs	8+Life	11+Life	14+Life
Motor control outputs	0	4(2)	8(4)
Control of switching devices	3	5	5
Cases	1/2 of 19"	1/1 of 19"	1/1 of 19"

Fig. 48

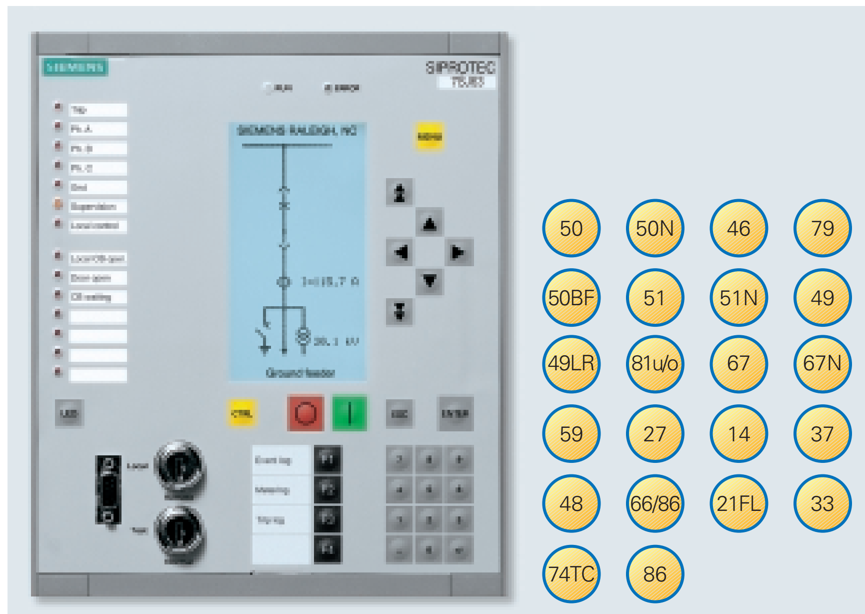


Fig. 49: 7SJ63

Combined feeder protection and control relay 7SJ531

Line protection

- Nondirectional time overcurrent
- Directional time overcurrent
- IEC/ANSI and user-definable TOC curves
- Overload protection
- Sensitive directional ground fault
- Negative sequence overcurrent
- Under/Overvoltage
- Breaker failure
- Autoreclosure
- Fault locator

Motor protection

- Thermal overload
- Locked rotor
- Start inhibit
- Undercurrent

Control functions

- Measured-value acquisition
- Signal and command indications
- P, Q, cos φ and meter-reading calculation
- Measured-value recording
- Event logging
- Switching statistics
- Feeder control diagram with load indication
- Switchgear interlocking

Fig. 50: 7SJ531

Power System Protection
Relay Portraits

7SA511

Line protection with distance-to-fault locator

Universal distance relay for all networks, with many additional functions, including

- Universal carrier interface (PUTT, POTT, Blocking, Unblocking)
- Power swing blocking or tripping
- Selectable setting groups
- Sensitive directional ground-fault determining for isolated and compensated networks
- High-resistance ground-fault protection for grounded networks
- Single and three-pole autoreclose
- Synchrocheck
- Thermal overload protection for cables
- Free marshalling of optocoupler inputs and relay outputs
- Line load monitoring, event and fault recording
- Selectable setting groups

7SA510

Line protection with distance-to-fault locator

(Reduced version of 7SA511)

Universal distance protection, suitable for all networks, with additional functions, including

- Universal carrier interface (PUTT, POTT, Blocking, Unblocking)
- Power swing blocking and/or tripping
- Selectable setting groups
- Sensitive directional ground-fault determining for isolated and compensated networks
- High-resistance ground-fault protection for grounded networks
- Thermal overload protection for cables
- Free marshalling of optocoupler inputs and relay outputs
- Line load monitoring, event and fault recording
- Three-pole autoreclose

Fig. 51: 7SA511

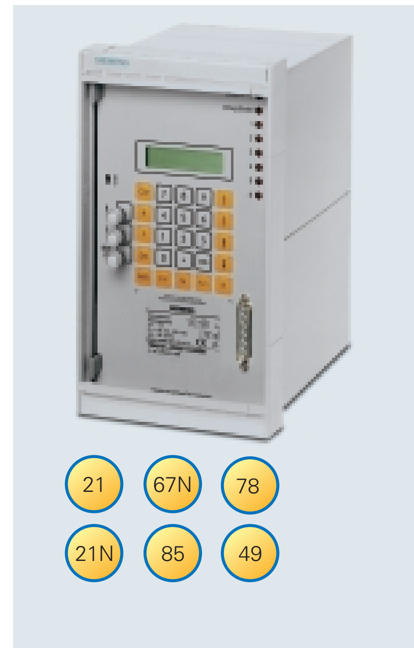


Fig. 52: 7SA510

Power System Protection Relay Portraits

7SA522

Full scheme distance protection with add-on functions

- Quadrilateral or MHO characteristic
- Sub-cycle operating time
- Universal teleprotection interface (PUTT, POTT, Blocking, Unblocking)
- Weak infeed protection
- Power swing blocking/tripping
- High-resistance ground-fault protection (time delayed or as directional comparison scheme)
- Overvoltage protection
- Switch-onto-fault protection
- Stub bus O/C protection
- Single and three-pole multi-shot auto-reclosure*)
- Synchro-check*)
- Breaker failure protection*)
- Trip circuit supervision
- Fault locator w./w.o. parallel line compensation
- Oscillographic fault recording
- Voltage phase sequence

Fig. 53: 7SA522

7SA513

Transmission line protection with distance-to-fault locator

- Full scheme distance protection, with operating times less than one cycle (20 ms at 50 Hz), with a package of extra functions which cover all the demands of extra-high-voltage applications
- Suitable for series-compensated lines
- Universal carrier interface (permissive and blocking procedures programmable)
- Power swing blocking or tripping
- Parallel line compensation
- Load compensation that ensures high accuracy even for high-resistance faults and double-end infeed
- High-resistance ground fault protection
- Backup ground-fault protection
- Overvoltage protection
- Single and three-pole autoreclose
- Synchrocheck option
- Breaker failure protection
- Free marshalling of a comprehensive range of optocoupler inputs and relay outputs
- Selectable setting groups
- Line load monitoring, event and fault recording
- High-performance measurement using digital signal processors
- Flash EPROM memories

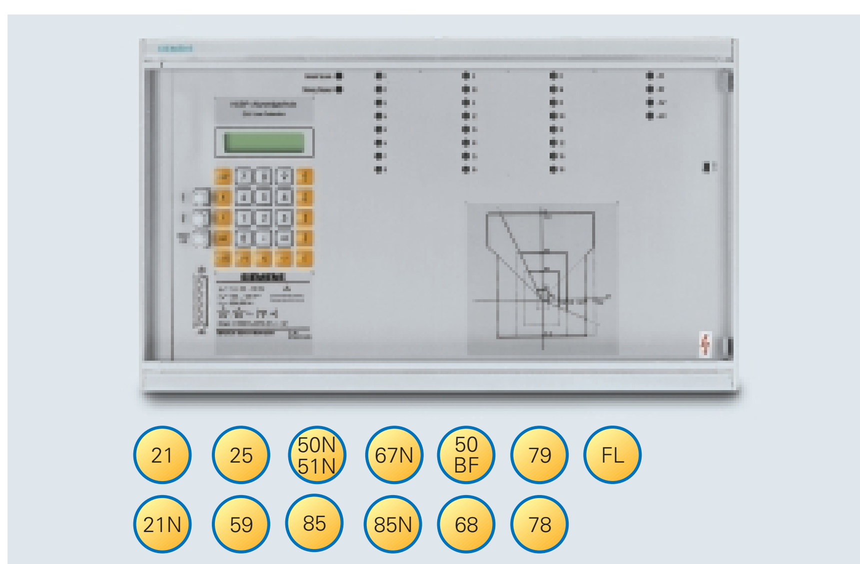


Fig. 54: 7SA513

*) available with Version 4.1 (Commencement of delivery planned for Oct. 1999)

Power System Protection
Relay Portraits

7SD511

Current-comparison protection
for overhead lines and cables

- With phase-segregated measurement
- For serial data transmission (19.2 kbits/sec)
  - with integrated optical transmitter/ receiver for direct fiber-optic link up to approx. 15 km distance
  - or with the additional digital signal transmission device 7VR5012 up to 150 km fiber-optic length
  - or through a 64 kbit/s channel of available multipurpose PCM devices, via fiber-optic or microwave link
- Integral overload and breaker failure protection
- Emergency operation as overcurrent backup protection on failure of data link
- Automatic measurement and correction of signal transmission time, i.e. channel-swapping is permissible
- Line load monitoring, event and fault recording

7SD512

Current-comparison protection
for overhead lines and cables

with functions as 7SD511, but additionally with autoreclose function for single and three-pole fast and delayed autoreclosure.

7SD502

- Pilot-wire differential protection for lines and cables (2 pilot wires)
- Up to about 25 km telephone-type pilot wire length
- With integrated overcurrent back-up and overload protection
- Also applicable to 3-terminal lines (2 devices at each end)

7SD503

- Pilot-wire differential protection for lines and cables (3 pilot wires)
- Up to about 15 km pilot wire length
- With integrated overcurrent back-up and overload protection
- Also applicable to 3-terminal lines (2 devices at each end)

Fig. 55: 7SD511

Fig. 56: 7SD512

Fig. 57: 7SD502/503

Power System Protection
Relay Portraits

7SD600

Pilot wire differential protection for lines and cables (2 pilot wires)

- Up to about 10 km telephone-type pilot wire length
- Connection to an external current summation transformer
- Pilot wire supervision (option)
- Remote trip command
- External current summation transformer 4AM4930 to be ordered separately

Fig. 58: 7SD600

7UT512

Differential protection for machines and power transformers

with additional functions, such as:

- Numerical matching to transformer ratio and connection group (no matching transformers necessary)
- Thermal overload protection
- Backup overcurrent protection
- Measured-value indication for commissioning (no separate instruments necessary)
- Load monitor, event and fault recording

7UT513

Differential protection for three-winding transformers

with the same functions as 7UT512, plus:

- Sensitive restricted ground-fault protection
- Sensitive d.t. or i.d.m.t. ground-fault-o/c-protection

Fig. 59: 7UT512

Fig. 60: 7UT513

Power System Protection
Relay Portraits

Fig. 61: 7SS50

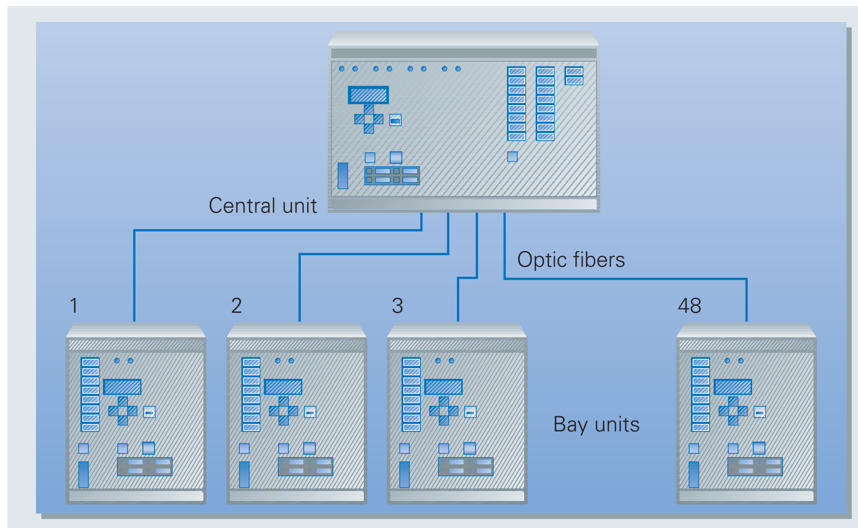


Fig. 62: 7SS52

7SS50

Numerical busbar and breaker failure protection

- With absolutely secure 2-out-of-2 measurement and additional check zone, each processed on separate microprocessor hardware
- Mixed current measurement
- With fast operating time (< 15 ms)
- Extreme stability against c.t. saturation
- Completely self-monitoring, including c.t. circuits, isolator positions and run time
- With integrated circuit-breaker failure protection
- With commissioning-friendly aids (indication of all feeder, operating and stabilizing currents)
- With event and fault recording
- Designed for single and multiple busbars, up to 8 busbar sections and 32 bays

7SS52

Distributed numerical busbar and breaker failure protection

- With absolutely secure 2-out-of-2 measurement and additional check zone, each processed on separate microprocessor hardware
- Phase-segregated measurement
- With fast operating time (< 15 ms)
- Extreme stability against c.t. saturation
- Completely self-monitoring, including c.t. circuits, isolator positions and run time
- With integrated 2-stage circuit-breaker failure protection

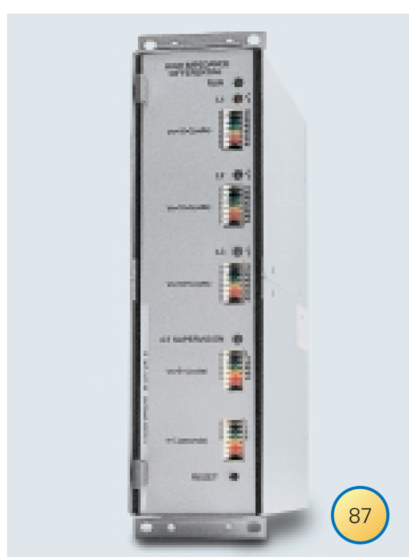


Fig. 63: 7VH83

- With commissioning-friendly aids (indication of all feeder, operating and stabilizing currents)
- With event and fault recording
- Designed for single and multiple busbars, up to 12 busbar sections and 48 bays

7VH80

High impedance differential relay

- Single-phase type
- Robust solid-state design

Fig. 64: 7VH80

- Inrush stabilized through filtering
- Fast operation: 15 ms (I > 5 x setting)
- Optionally, external voltage limiters (varistor)

7VH83

High impedance differential relay

- Three-phase type
- Robust solid-state design
- Integral buswire supervision
- Integral c.t. shorting relay
- Inrush stabilized through filtering
- Fast operation: 21 ms (I > 5 x setting)
- Optionally, external voltage limiters (varistors)

Power System Protection
Relay Portraits

7UM511/12/15/16

Multifunctional devices
for machine protection

- With 10 protection functions on average, with flexible combination to form complete protection systems, from the smallest to the largest motor generator units (see Fig. 66)
- With improved measurement methods based on Fourier filters and the evaluation of symmetrical components (fully numeric, frequency compensated)
- With load monitoring, event and fault recording

See also separate reference list for machine protection.

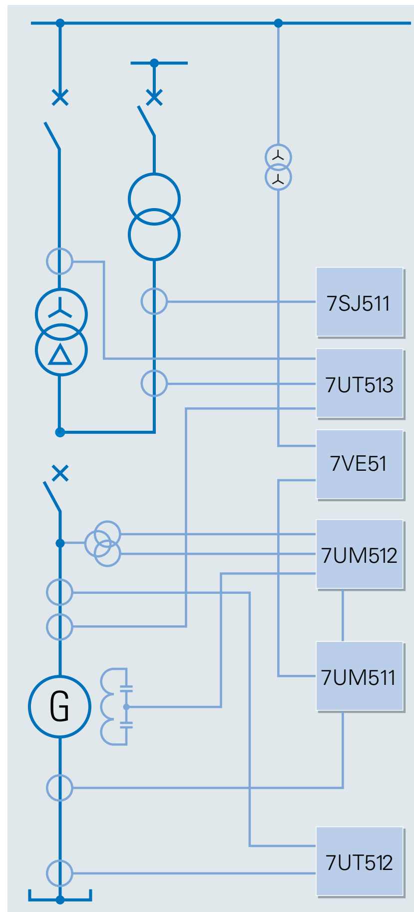
Order No. E50001-U321-A39-X-7600

7VE51

Paralleling device

for synchronization of generators and networks

- Absolutely secure against spurious switching due to duplicate measurement with different procedures
- With numerical measurand filtering that ensures exact synchronization even in networks suffering transients
- With synchrocheck option
- Available in two versions: 7VE511 without, 7VE512 with voltage and frequency balancing



7SJ511	51	
7UT513	87T	
7VE51	25	Synchronizing
7UM512	59N 64R 46	
7UM511	81u 59 32 40 49	
7UT512	87G	

Fig. 65a: Numerical protection of a generating unit (example). Single-line diagram.

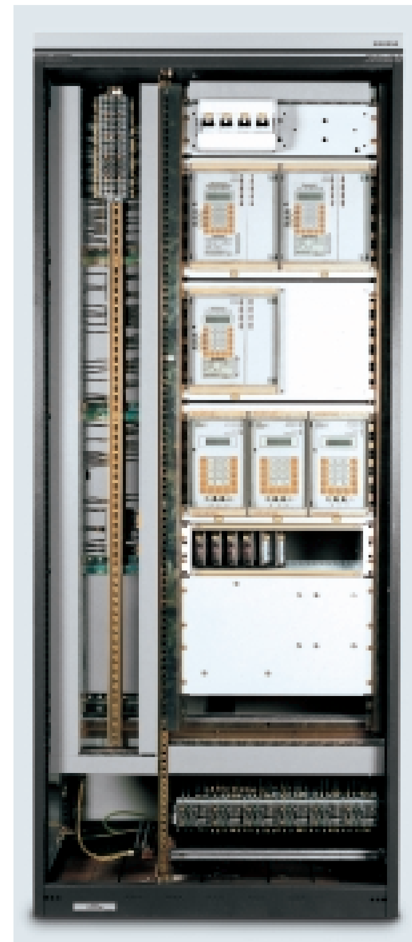


Fig. 65b: Numerical protection of a generating unit (example). Cubicle design.

Power System Protection
Relay Portraits

Fig. 66

Numerical generator protection
Protection functions

ANSI No.*	Function	Relay	7UM511	7UM512	7UM515	7UM516
51	Overcurrent	I>, t(+U<)	■	■		
		I_E>, t	■2)			
		I>>, t	■			
51, 37	Overcurrent/Undercurrent	I $^{>}$<, t		■		
49	Thermal overload	I^2t	■			
46	Load unbalance	I_2/I_n>, t	■	■		■
		$(I_2/I_n)^2$ t	■	■		■
87	Differential protection	ΔI_G>				
		ΔI_T>				
		ΔI_g>				
59	Overvoltage	U>, t	■	■	■	
		U>>, t	■	■	■	
27	Undervoltage	U>, t	■			
		t = f(U<)			■	
	U< with frequency evaluation	U(f)<, t		■		
	Direct voltage	$U_=$ $^{>}$<, t		■		
59GN	Stator	U_E >,t	■6)	■	■	■
	ground fault protection <90%	U_E + I_E>,t		■		
53GN	Stator	R_E <,t			■	
	ground fault protection 100%					
	Interturn fault protection	U_W >,t			■	
81o	Overfrequency	f>	■3)	■4)	■3)	
81u	Underfrequency	f<	■3)	■4)	■3)	
3Z	Reverse power	(–P)>, t	■	■7)		■
	Forward power1)	(+P)>, t	■			■
40	Underexcitation (field failure)	ϑ>, t	■	■7)		
	protection	ϑ_1 + U_e>, t	■			
64R	Rotor	R_E<, t(f_N)		■		
	ground fault protection	R_E<, t(1Hz)			■	
		I_E>, t(f_N)	■2)			
24	Overexcitation	U/f >, t			■	
	protection	$(U/f)^2$ t			■	
21	Impedance protection	Z<, t				■
78	Out-of-step protection	ϑ(Z) >, n				■
87N	Restricted ground fault prot.	ΔI_E				
	Trip control inputs	t, trip	4	4	4	4
	Trip circuit monitoring		2	2	2	2

* ANSI/IEEE C 37.2: IEEE Standard Electrical Power System Device Function Numbers

1) for special applications
2) I_E> sensitive stage, suitable for rotor or stator earth fault protection
3) altogether 4 frequency stages, to be used as either f> or f<
4) altogether 4 frequency stages, to be used as either f> or f<
5) tank protection
6) evaluation of displacement voltage
7) 1 stage

6

Power System Protection
Relay Portraits

7VK512

Autoreclose and check-synchronism relay

Highly flexible autoreclose relay with or without check-synchronism function. Available functions include:

- Single or/and three-pole auto-reclosure
- Up to 10 autoreclose shots
- Independently settable dead times and reclaim time
- Sequential fault recognition
- Check-synchronism or dead line/dead bus charging
- Selectable setting groups
- Event and fault recording (voltage inputs)

7SV512

Breaker failure protection relay

- Variable and failsafe breaker failure protection (2-out-of-4 current check, 2-channel logic and trip circuits)
- Phase selective for single and three-pole autoreclosure
- Reset time < 10 ms (sinusoidal current)
  < 20 ms worst case
- "No current" condition control using the breaker auxiliary contacts
- Integral end fault protection
- Selectable setting groups
- Event and fault recording

7SV600

Breaker failure protection relay

- Phase selective for single and three-pole autoreclosure
- Reset time < 10 ms (Sinusoidal current)
  < 20 ms worst case
- "No current" condition control using the breaker auxiliary contacts
- Selectable setting groups
- Event and fault recording
- Lockout of trip command

7RW600

Voltage and Frequency Relay

- Intelligent protection and monitoring device
- Two separate voltage measuring inputs
- Applicable as two independent single-phase units or one multiphase unit (positive sequence voltage)
- High-set and low-set voltage supervision U>>, U>, U<
- 4-step frequency supervision f><
- 4-step rate of change of frequency supervision df/dt>
- All voltage, frequency and df/dt steps with separate definite time delay setting
- Overfluxing (overexcitation) protection U/f (t) as thermal model, U/f >> (DT delay)
- Voltage and frequency indication
- Fault recording (momentary or RMS values)
- RS485 serial interface for connection of a PC or coordination with control systems

Fig. 67: 7RW600

Fig. 68: 7SV600

Power System Protection
Relay Dimensions

Case 7XP20 for relays 7SJ600, 7RW600, 7SD600, 7SV600

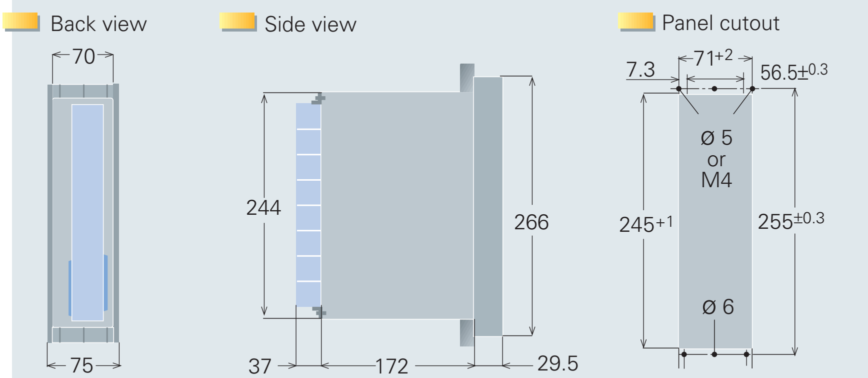


Fig. 69

Case 7XP2030-2 for relays 7SD511, 7SJ511/12, 7SJ531, 7UT512, 7VE51, 7SV512, 7SK512

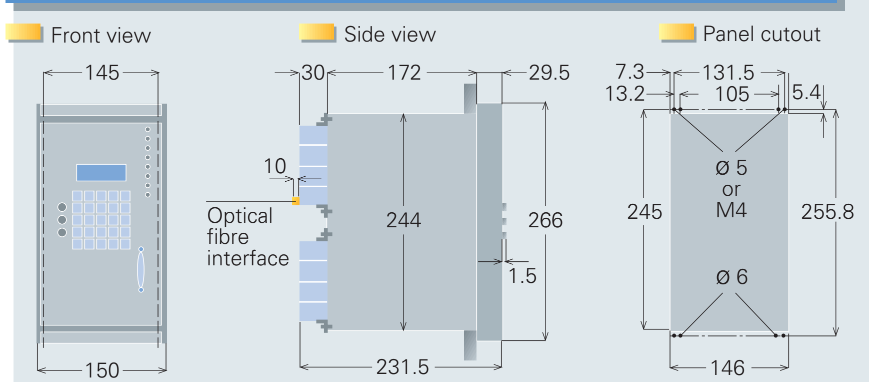


Fig. 70

Case 7XP2040-2 for relays 7SA511, 7UT513, 7SD512, 7UM5**, 7VE512, 7SD502/503

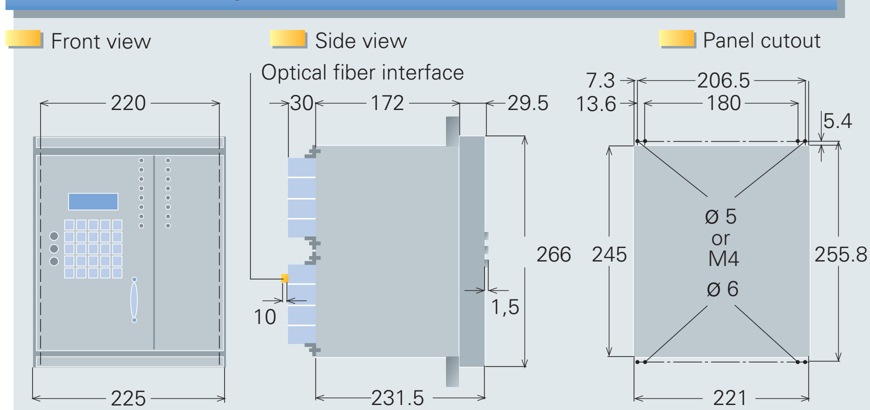


Fig. 71

All dimensions in mm.

Power System Protection Relay Dimensions

Case 7XP2020-2 for relay 7VH83

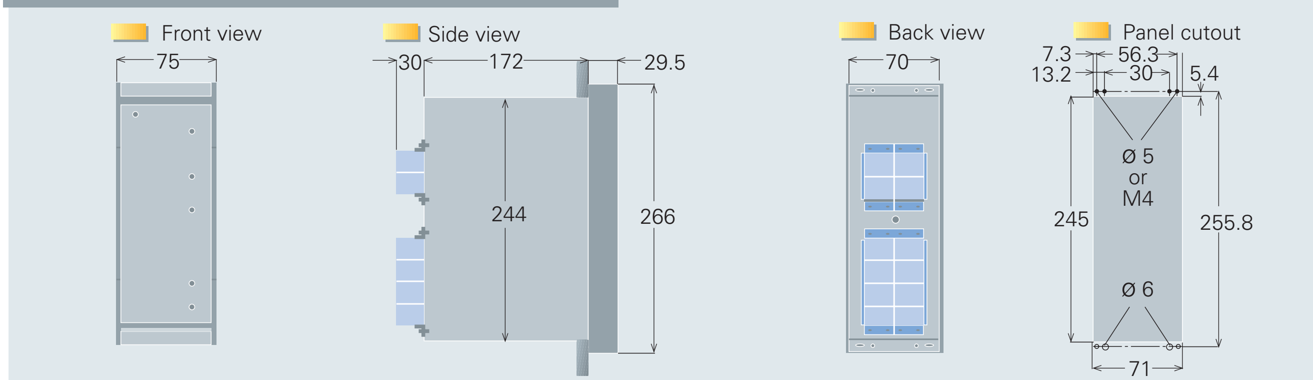


Fig. 72

Case 7XP2010-2 for relay 7VH80, 7TR93

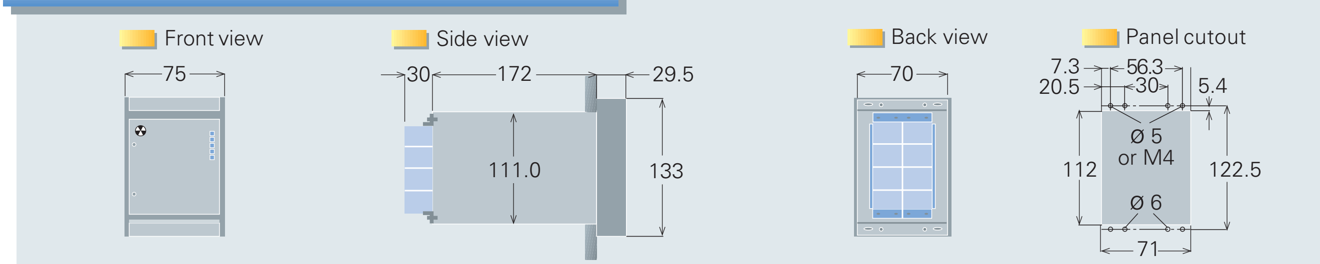


Fig. 73

Case for relay 7SJ551

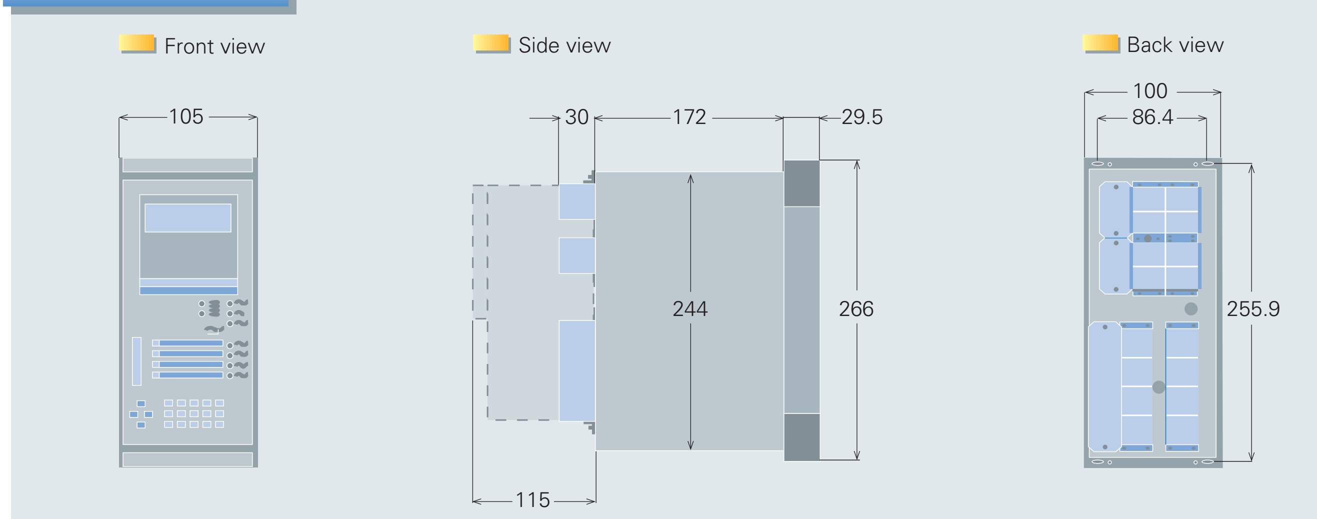


Fig. 74

Power System Protection
Relay Dimensions

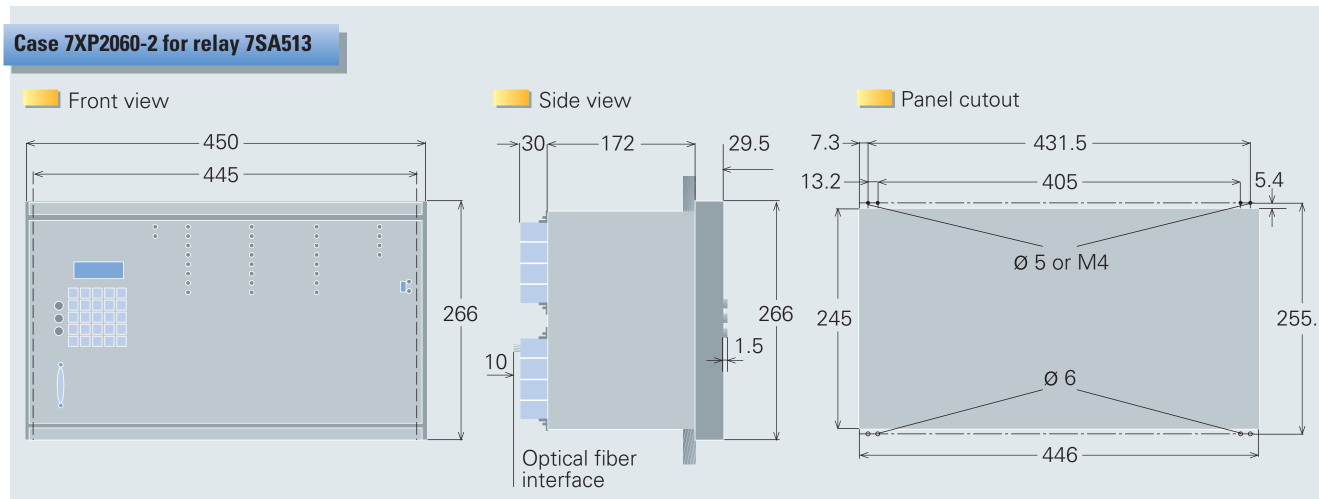


Fig. 75

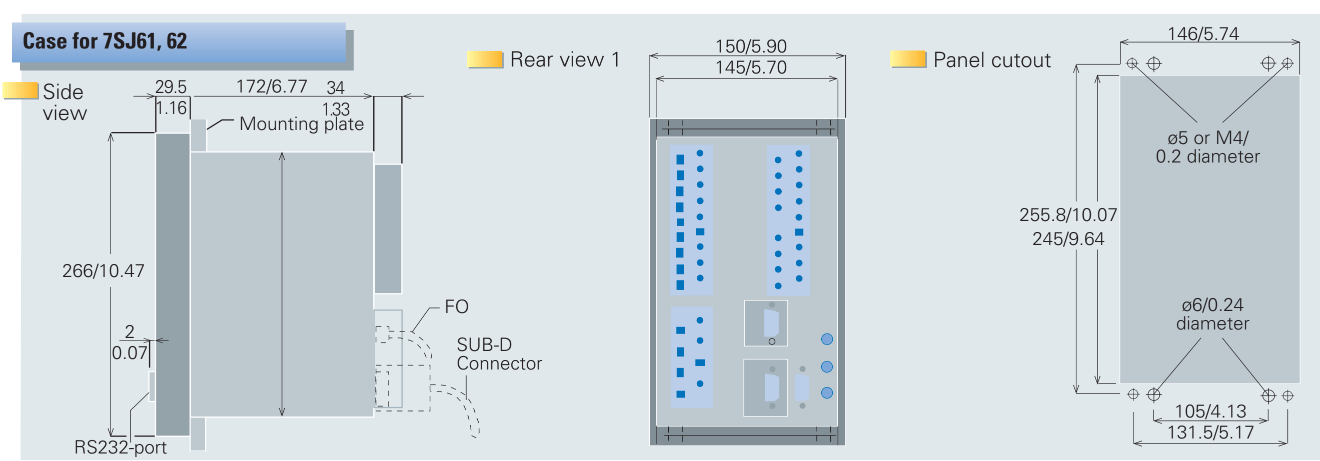


Fig. 76a

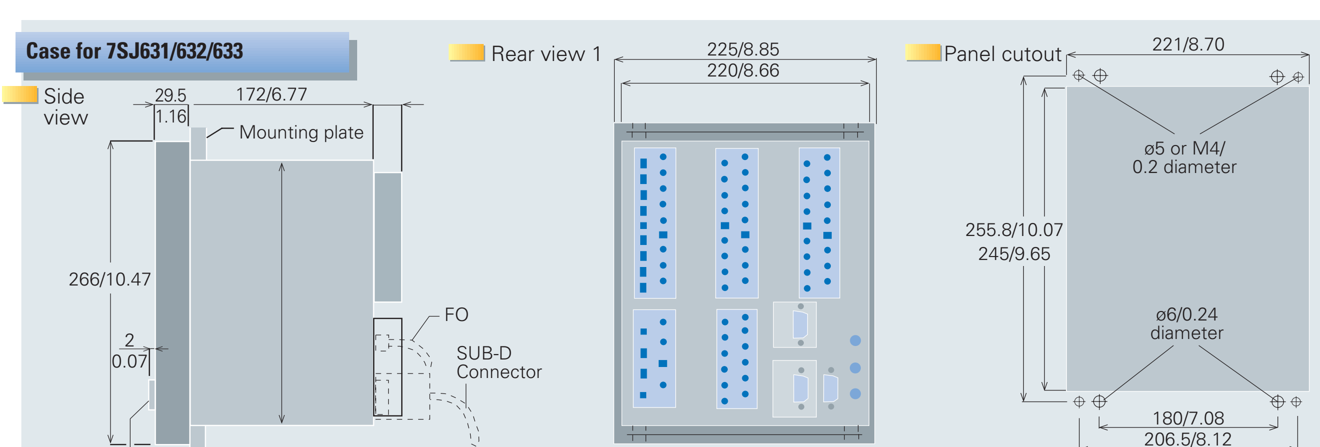


Fig. 76b

All dimensions in mm.

Power System Protection Relay Dimensions

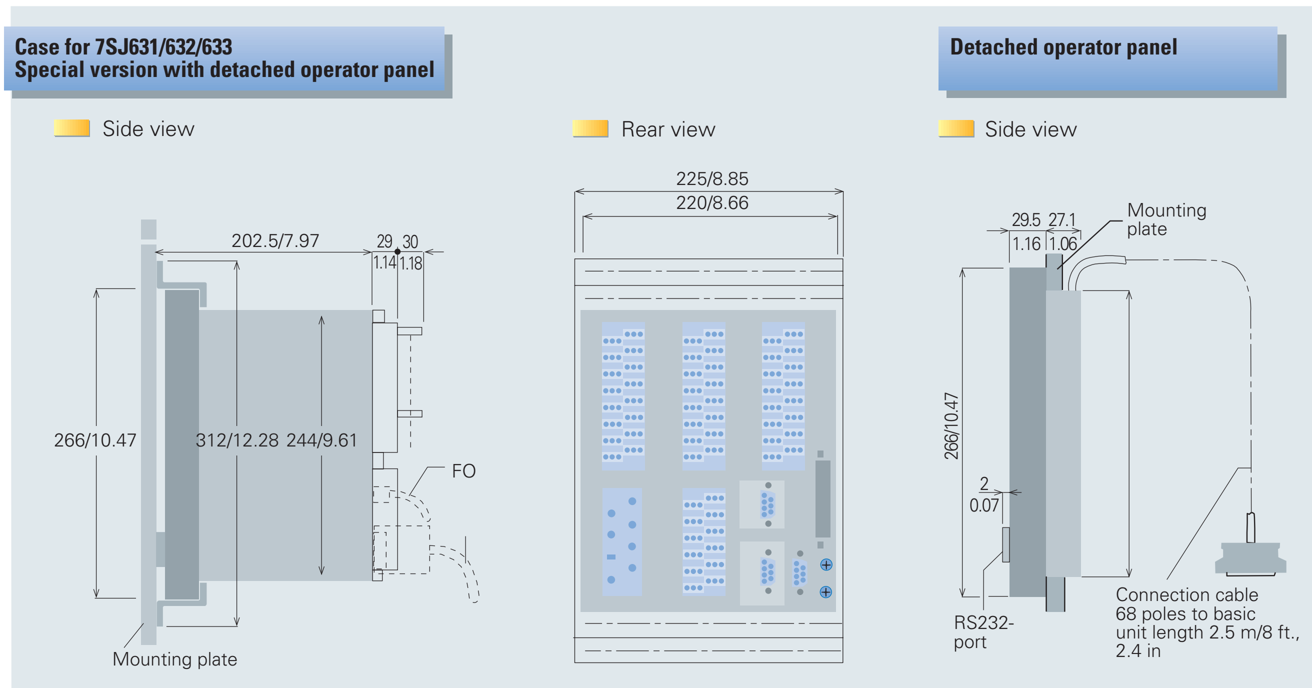


Fig. 77: 7SJ63, 1/2 surface mounting case (only with detached panel, see Fig. 42, page ***6****/21)*

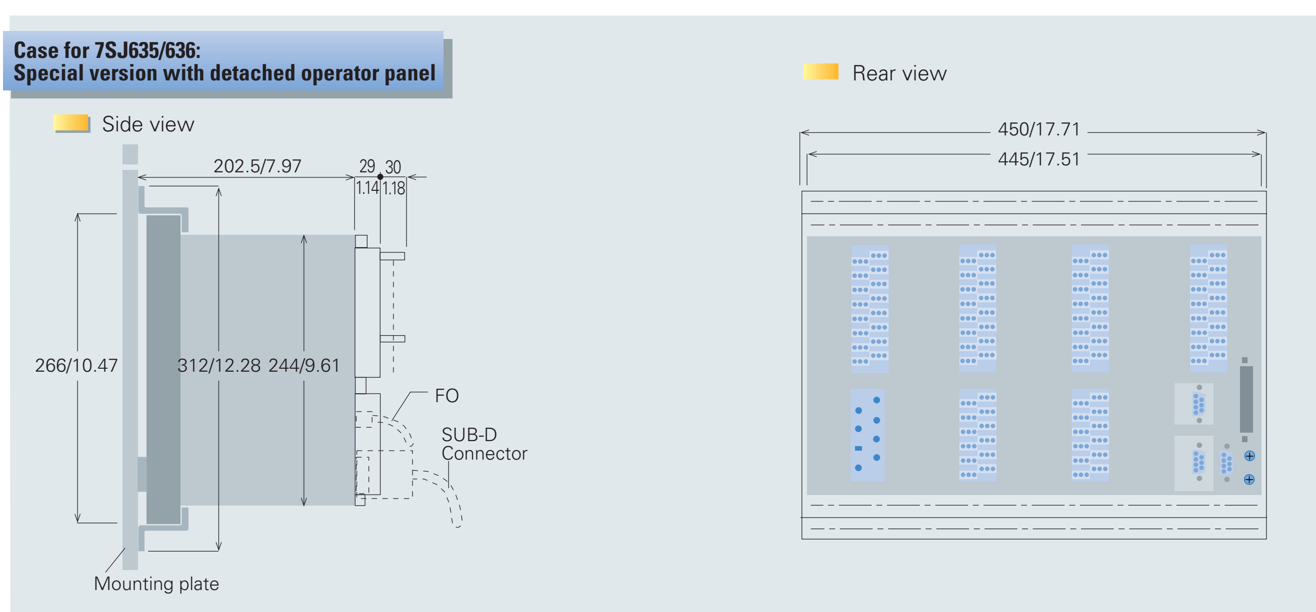


Fig. 78: 7SJ63, 1/1 surface mounting case (only with detached panel, see Fig. 42, page ***6****/21)*

All dimensions in mm.

Power System Protection
Relay Dimensions

7XR9672 Core-balance current transformer (zero sequence c.t.)

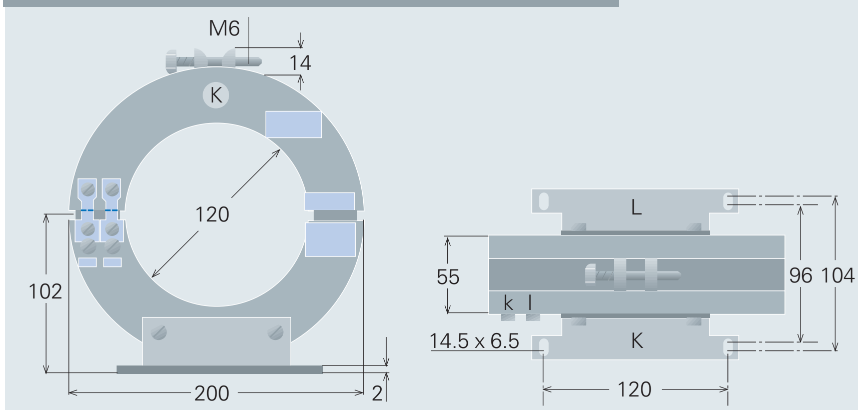


Fig. 79

7XR9600 Core-balance current transformer (zero sequence c.t.)

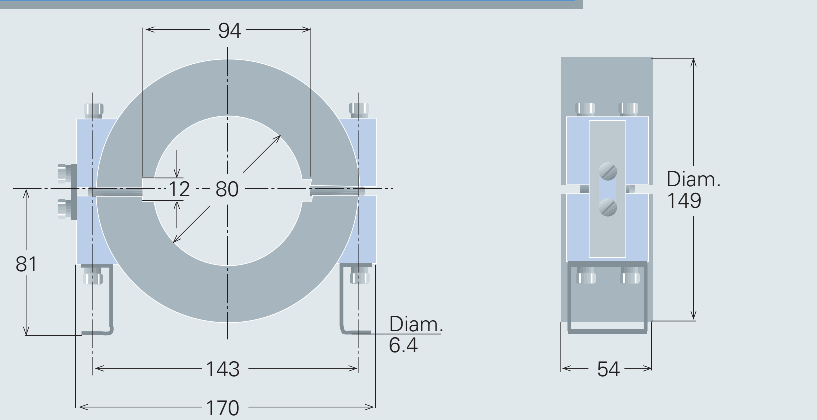


Fig. 80

Power System Protection
Relay Dimensions

4AM4930 Current summation transformer for relay 7SD600

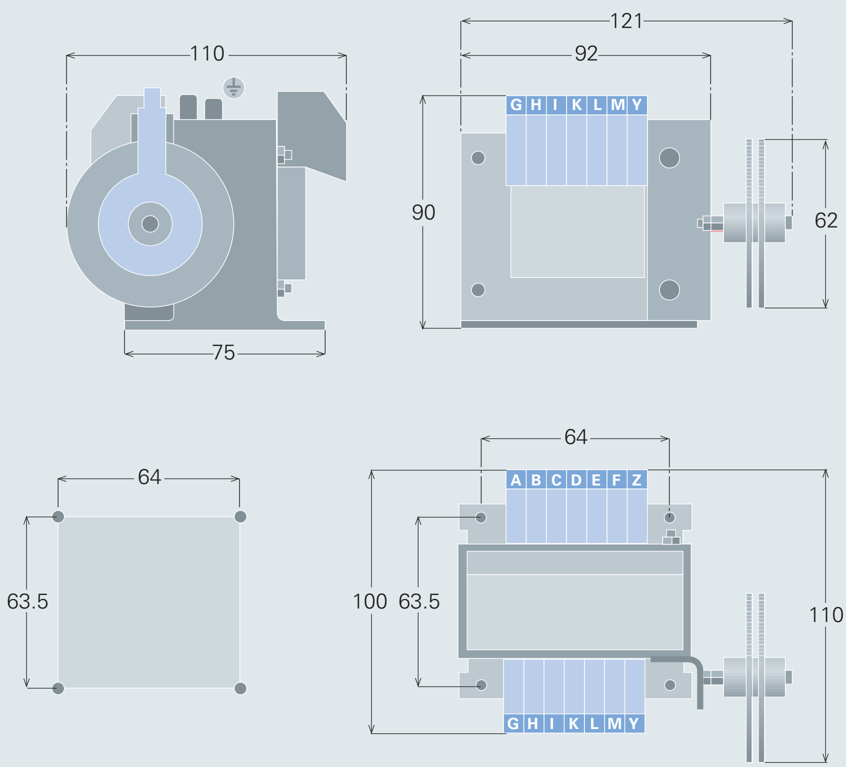


Fig. 81

Power System Protection
Typical Protection Schemes

Application group	Circuit number	Circuit equipment protected	Page
Cables and overhead lines	**1**	Radial feeder circuit	**6**/43
	2	Ring main circuit	**6**/43
	3	Distribution feeder with reclosers	**6**/44
	4	Parallel feeder circuit	**6**/44
	5	Cable or short overhead line with infeed from both ends	**6**/45
	6	Overhead lines or longer cables with infeed from both ends	**6**/45
	7	Subtransmission line	**6**/46
	8	Transmission line with reactor	**6**/48
	9	Transmission line or cable (with wide band communication)	**6**/49
	10	Transmission line, breaker-and-a-half terminal	**6**/49
Transformers	**11**	Small transformer infeed	**6**/51
	12	Large or important transformer infeed	**6**/51
	13	Dual infeed with single transformer	**6**/52
	14	Parallel incoming transformer feeder	**6**/52
	15	Parallel incoming transformer feeder with bus tie	**6**/53
	16	Three-winding transformer	**6**/53
	17	Autotransformer	**6**/54
	18	Large autotransformer bank	**6**/54
Motors	**19**	Small and medium-sized motors	**6**/55
	20	Large HV motors	**6**/55
Generators	**21**	Smallest generator < 500 kW	**6**/56
	22	Small generator, around 1 MW	**6**/56
	23	Large generator > 1 MW	**6**/57
	24	Large generator >1 MW feeding into a network with isolated neutral	**6**/57
	25	Generator-transformer unit	**6**/59
Busbars	**26**	Busbar protection by o/c relays with reverse interlocking	**6**/60
	27	High-impedance differential busbar protection	**6**/61
	28	Low-impedance differential busbar protection	**6**/61

Fig. 82

Power System Protection
Typical Protection Schemes

1. Radial feeder circuit

Notes:

1) Autoreclosure 79 only with O.H. lines.
2) Negative sequence o/c protection 46 as sensitive backup protection against unsymmetrical faults.

General hints:

– The relay at the far end (D) gets the shortest operating time.
Relays further upstream have to be time-graded against the next downstream relay in steps of about 0.3 seconds.
– Inverse-time curves can be selected according to the following criteria:
– Definite time:
source impedance large compared to the line impedance, i.e. small current variation between near and far end faults
– Inverse time:
Longer lines, where the fault current is much less at the end of the line than at the local end.
– Very or extremely 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 provide also higher stability on service restoration (cold load pick-up and transformer in rush currents)

2. Ring main circuit

General hints:

– Operating time of overcurrent relays to be coordinated with downstream fuses of load transformers.
(Preferably very inverse time characteristic with about 0.2 s grading-time delay
– Thermal overload protection for the cables (option)
– Negative sequence o/c protection 46 as sensitive protection against unsymmetrical faults (option)

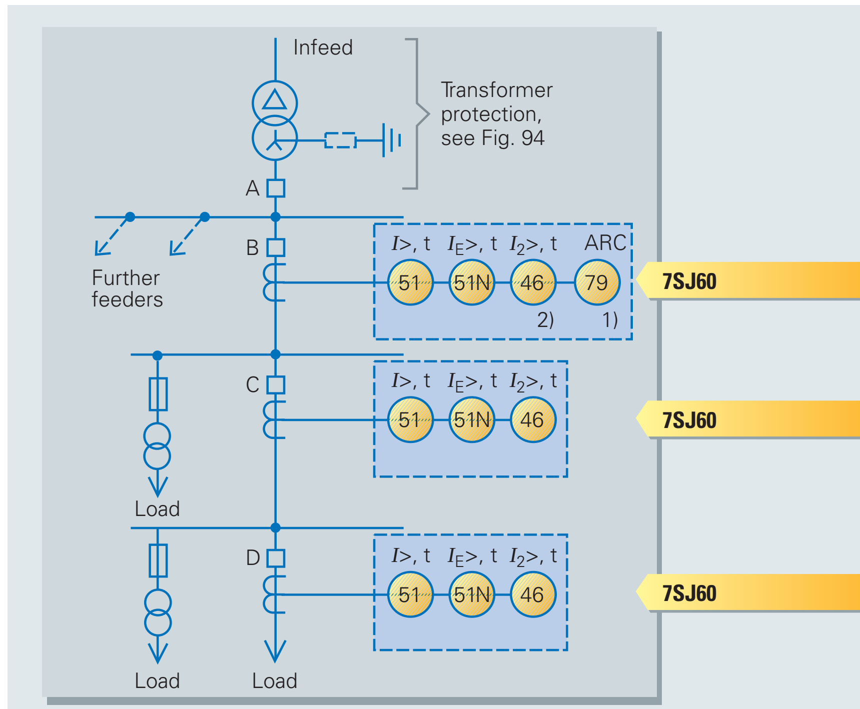


Fig. 83

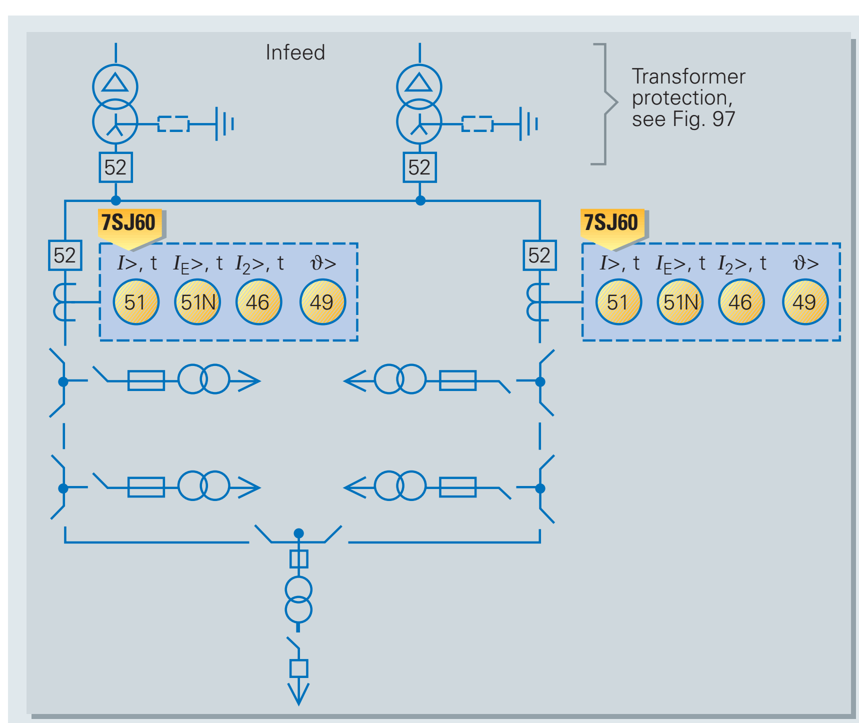


Fig. 84

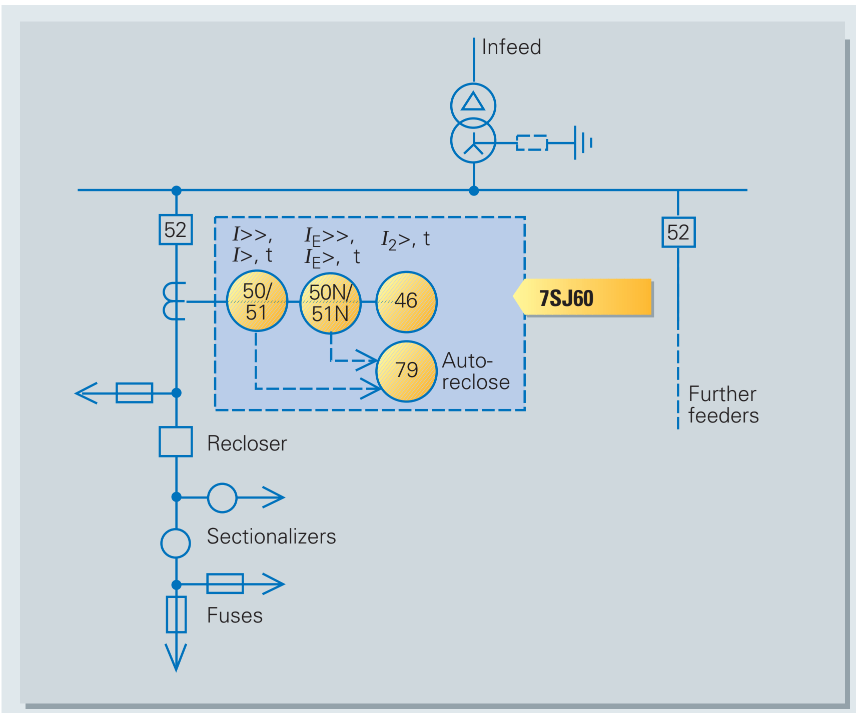


Fig. 85

3. Distribution feeder with reclosers

General hints:

– The feeder relay operating characteristics, delay times and autoreclosure cycles must be carefully coordinated with downstream reclosers, sectionalizers and fuses.
The instantaneous zone 50/50N 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 autoreclosure is initiated in this case.
Further time delayed tripping and reclosure steps (normally 2 or 3) have to be graded against the recloser.
– The o/c relay should automatically switch over to less sensitive characteristics after longer breaker interruption times to enable overriding of subsequent cold load pick-up and transformer inrush currents.

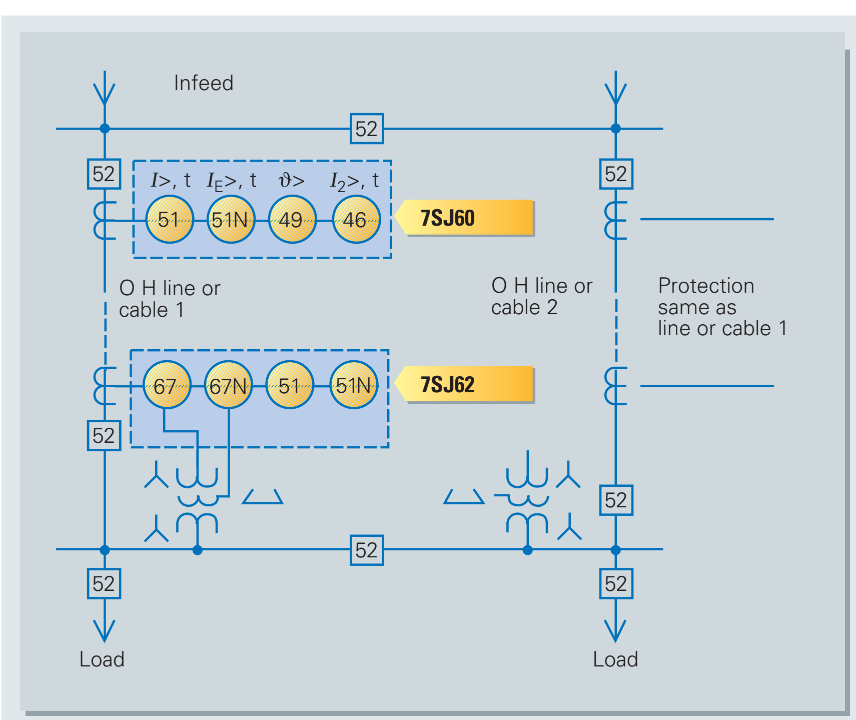


Fig. 86

4. Parallel feeder circuit

General hints:

– This circuit is preferably used for the interruption-free supply of important consumers without significant backfeed.
– The directional o/c protection 67/67N trips instantaneously for faults on the protected line. This allows the saving of one time-grading interval for the o/c-relays at the infeed.
– The o/c relay functions 51/51N have each to be time-graded against the relays located upstream.

5. Cables or short overhead lines with infeed from both ends

Notes:

1) Autoreclosure only with overhead lines
2) Overload protection only with cables
3) Differential protection options:
   – Type 7SD511/12 with direct fiber-optic connection up to about 20 km or via a 64 kbit/s channel of a general purpose PCM connection (optical fiber, microwave)
   – Type 7SD600 with 2-wire pilot cables up to about 10 km
   – Type 7SD502 with 2-wire pilot cables up to about 20 km
   – Type 7SD503 with 3-wire pilot cables up to about 10 km.
4) Functions 49 and 79 only with relays 7SD5**. 7SD600 is a cost-effective solution where only the function 87L is required (external current summation transformer 4AM4930 to be ordered separately)

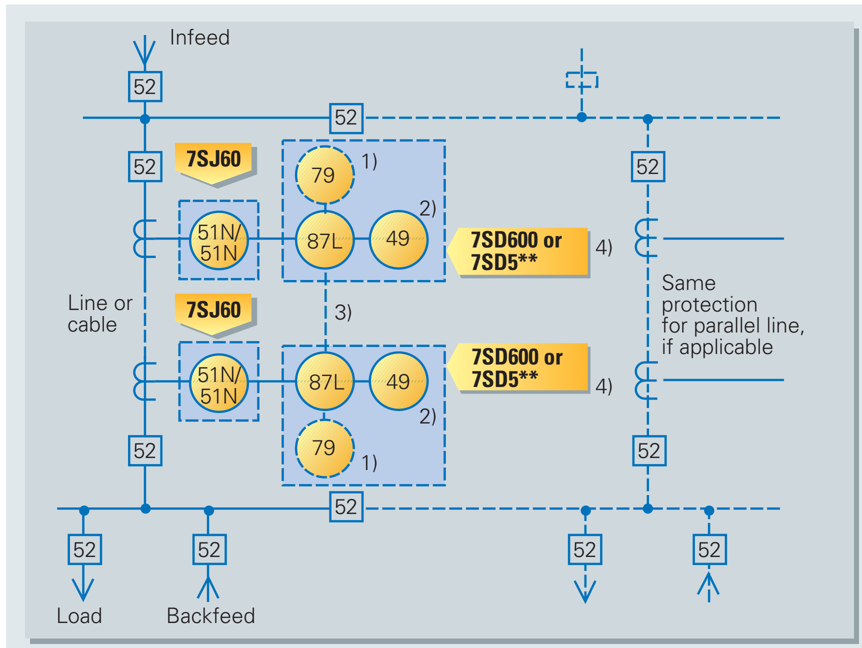


Fig. 87

6. 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, microwave or optical fiber (to be provided separately). The teleprotection supplement is only necessary if fast fault clearance on 100% line length is required, i.e. second zone tripping (about 0.3 s delay) cannot be accepted for far end faults.
2) Directional ground-fault protection 67N with inverse-time delay against high-resistance faults
3) Single or multishot autoreclosure 79 only with overhead lines
4) Reduced version 7SA510 may be used where no, or only 3-pole autoreclosure is required.

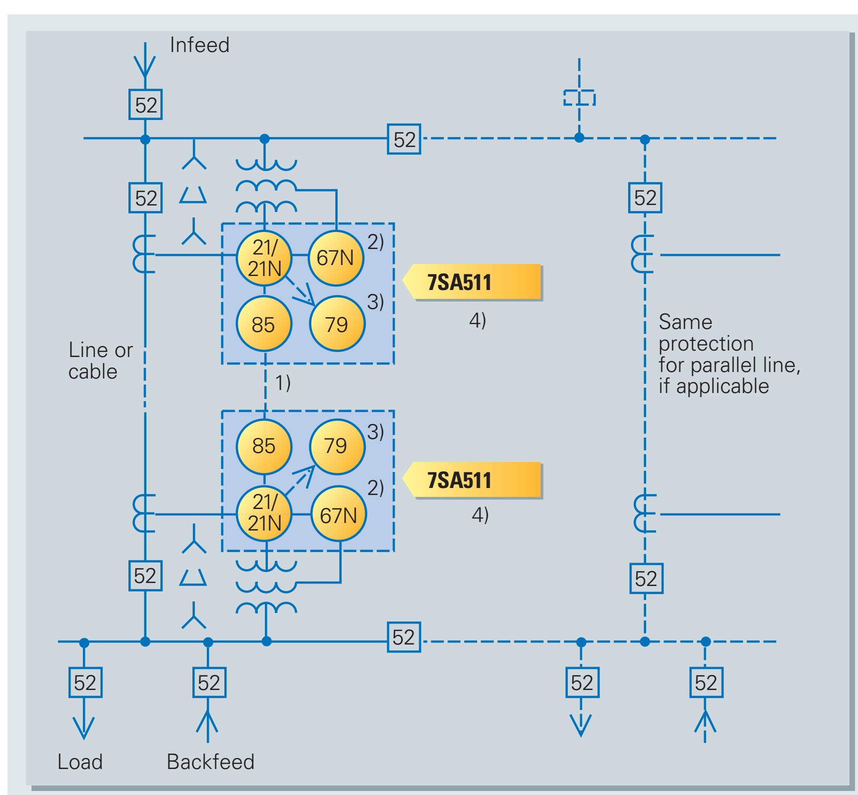


Fig. 88

6

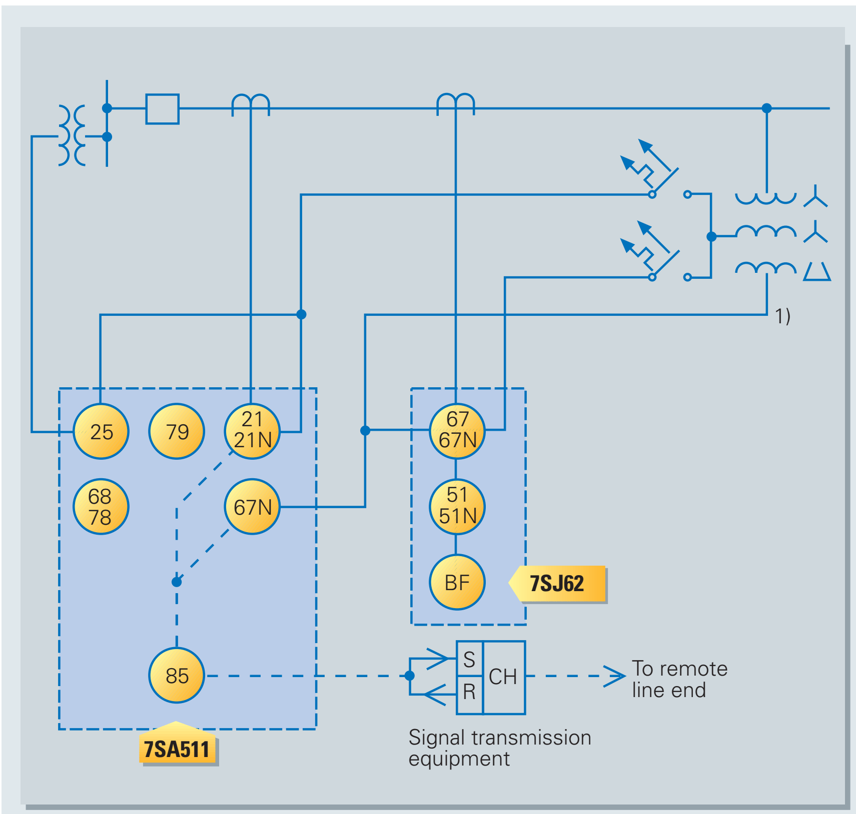


Fig. 89

7. Subtransmission line

Note:

1) Connection to open delta winding if available. Relays 7SA511 and 7SJ512 can, however, also be set to calculate the zero-sequence voltage internally.

General hints:

– Distance teleprotection is proposed as main, and time graded directional O/C as backup protection.
– The 67N function of 7SA511 provides additional high-resistance ground fault protection. It can be used in a directional comparison scheme in parallel with the 21/21N-function, but only in POTT mode. If the distance protection scheme operates in PUTT mode, 67N is only available as time-delayed function.
– Recommended 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).

Power System Protection
Typical Protection Schemes

Application criteria for frequently used teleprotection schemes

		Permissive underreaching transferred tripping (PUTT)	Permissive overreaching transferred tripping (POTT)	Blocking	Unblocking
Preferred application	**Signal transmission:**	Secure and dependable channel: ■ Frequency shift power line carrier (phase-to-phase HF coupling to the protected line, better HF coupling to a parallel running line to avoid sending through the fault) ■ Microwave, in particular digital (PCM) ■ Fiber optic cables		■ Dependable channel (only with external faults) ■ Amplitude modulated ON/OFF power line carrier (same frequency can be used at all terminals)	Applicable only with ■ Frequency shift power line carrier
	Line configuration:	Normally used with medium and long lines (7SA511/513 relays allow use also with short lines due to their independent X and R setting of all distance zones).	■ Short lines in particular when high fault resistance coverage is required ■ Multi-terminal and tapped lines with intermediate infeed effects	All kinds of line (Preferred US practice)	EHV lines
Advantages:		■ Simple method ■ Tripping of underreaching zone does not depend on the channel (release signal from the remote line end not necessary). ■ No distance zone or time coordination between line ends necessary, i.e. this mode can easily be used with different relay types.	■ No distance zone overreaching problems, when applied with CCVTs on short lines ■ Applicable to extreme short lines below the minimum zone setting limit ■ No problems with the impact of parallel line coupling.	← same as for POTT	← same as for POTT
Drawbacks:		■ Parallel, teed and tapped lines may cause underreach problems. Careful consideration of zero-sequence coupling and intermediate infeed effects is necessary. ■ Not applicable with weak infeed terminals.	■ Distance zone and time coordination with remote line end relays necessary ■ Tripping depends on receipt of remote end signal (additional independent underreaching zone of 7SA511/513 relays avoids this problem). ■ Weak infeed supplement necessary	← same as for POTT Except that a weak infeed supplement is **not** necessary No continuous on-line supervision of the channel possible!	Same as for POTT, however, loss of remote end signal does not completely block the protection scheme. Tripping is in this case released with a short time delay of about 20 ms (unblocking logic).

Fig. 90

8. Transmission line with reactor

Note:

1) 51G only applicable with grounded 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 ground fault protection using one 7VH80 high-impedance relay.

General hints:

– Distance relays are proposed as main 1 and main 2 protection. Duplicated 7SA513 is recommended for long (>100 km) and heavily loaded lines or series-compensated lines and in all cases where extreme short operating times are required due to system stability problems.
  7SA513 as main 1 and 7SA511 as main 2 can be used in the normal case.
– Operating time of the 7SA513 relay is in the range of 15 to 25 ms dependent on the particular fault condition, while the operating time of the 7SA511 is 25 to 35 ms respectively.
  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 signalling via optical fibres).
  Teleprotection schemes based on 7SA513 and 7SA511 have therefore operating times in the order of 40 ms and 50 ms each. With state-of-the-art two-cycle circuit breakers, fault clearing times well below 100 ms (4 to 5 cycles) can normally be achived.
– Dissimilar carrier schemes are recommended for main 1 and main 2 protection, for example PUTT, and POTT or Blocking/Unblocking
– Both 7SA513 and 7SA511 can practise selective single-pole and/or three-pole tripping and autoreclosure.
  The ground current directional comparison protection 67N of the 7SA513 relay uses phase selectors based on symmetrical components. Thus, single pole autoreclosure can also be practised with high-resistance faults.
  The 67N function of the 7SA511 relay should be used as time delayed directional O/C backup in this case.
– The 67N functions are provided as high-impendance fault protection. 67N of the 7SA513 relay is normally used with an additional channel as separate carrier scheme. Use of a common channel with distance protection is only possible in the POTT mode. The 67N function in the 7SA511 is blocked when function 21/21N picks up. It can therefore only be used in parallel with the distance directional comparison scheme POTT using one common channel. Alternatively, it can be used as time-delayed backup protection.

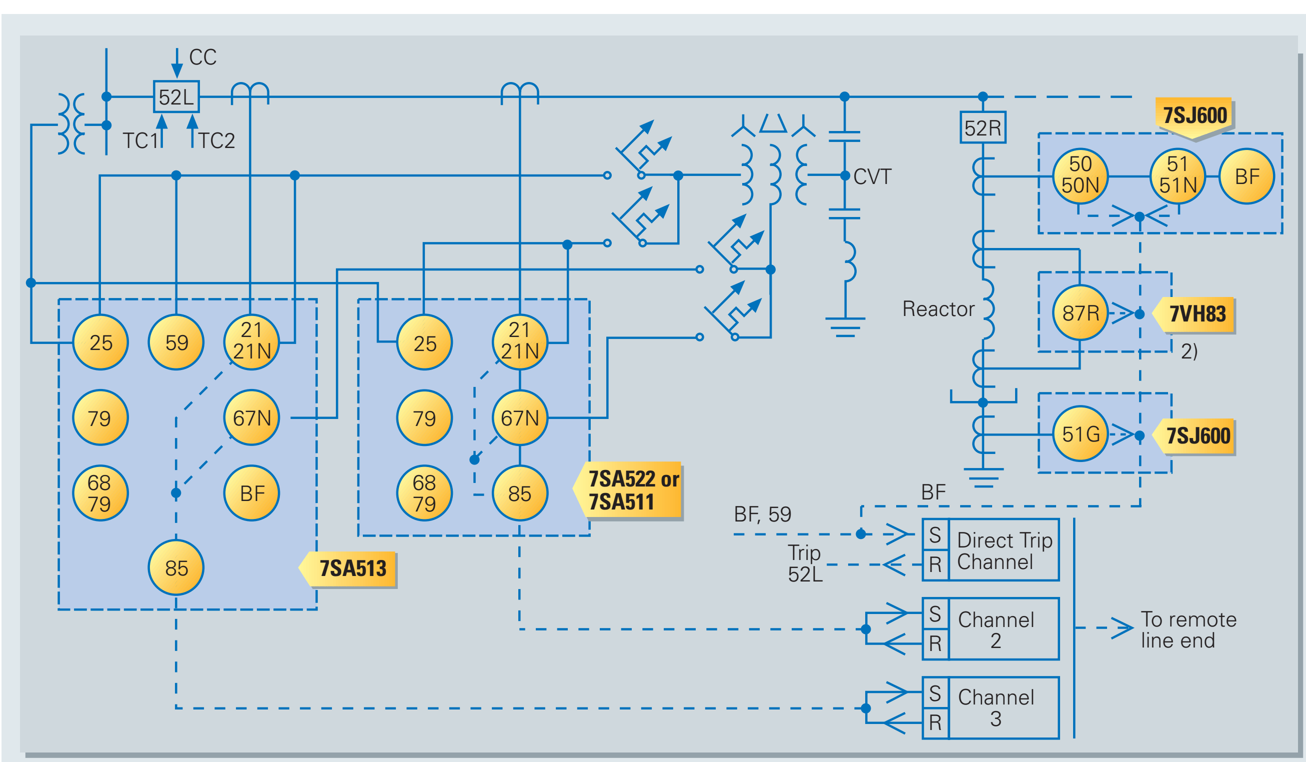


Fig. 91

Power System Protection
Typical Protection Schemes

9. Transmission line or cable (with wide band communication)

Note:

1) Overvoltage protection only with 7SA513

General hints:

– Digital PCM coded communication (with n x 64 kBit/s channels) between line ends is now getting 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 unit-type current comparison protection 7SD511/12 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 further a current-only protection that does not need VT connection. For this reason, the adverse effects of CVT transients are not applicable.
This makes it in particular suitable for double and multicircuit lines where complex fault situations can occur.
Pilot wire protection can only be applied to short lines or cables due to the inherent limitation of the applied measuring principle. The 7SD511/12 can be applied to lines up to about 20 km in direct relay-to-relay connection via dedicated optical fiber cores (see also application 5), and also to much longer distances up to about 100 km by using separate PCM devices for optical fiber or microwave transmission.
The 7SD511/512 then uses only a small part (64 kBit/s) of the total transmission capacity being in the order of Mbits/s.

– The unit protection 7SD511 can be combined with the distance relay 7SA513 or 7SA511 to form a redundant protection system with dissimilar measuring principles complementing each other. This provides the highest degree of availability. Also, separate signal transmission ways should be used for main 1 and main 2 protection, e.g. optical fiber or micro-wave, and power line carrier (PLC).
  1. The criteria for selection of 7SA513 or 7SA511 are the same as discussed in application 8.
     The current comparison protection has a typical operating time of 25 ms for faults on 100% line length including signalling time.

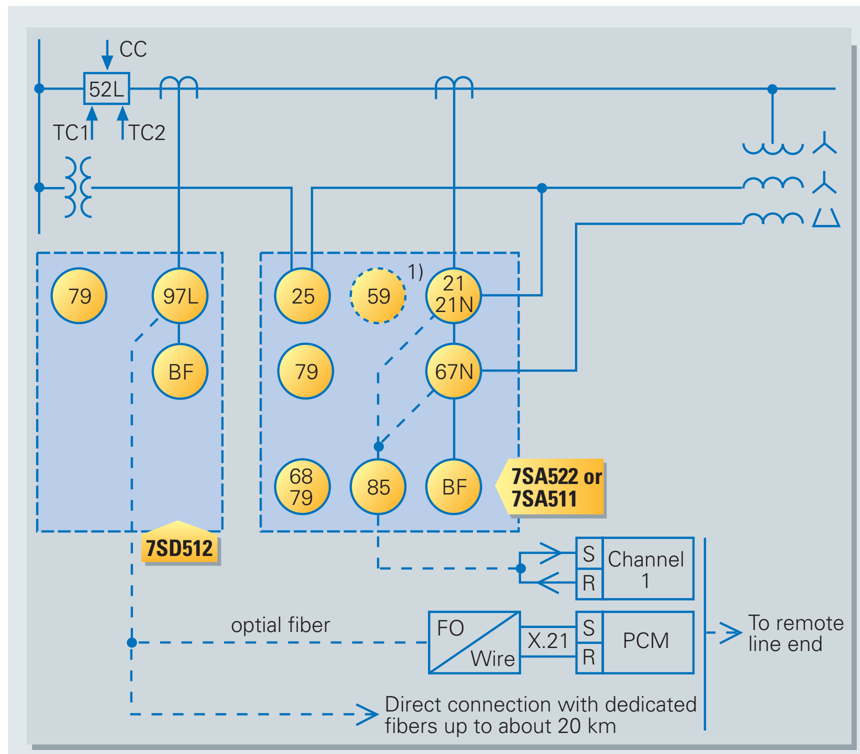


Fig. 92

10. Transmission line, breaker-and-a-half terminal

Notes:

1) When the line is switched off and the line 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 ground fault protection (67N) under this condition via an auxiliary contact of the line isolator. Instead, a stand-by overcurrent function (50/50N, 51/51N) is released to protect the remaining stub between the breakers ("stub" protection).

2) Overvoltage protection only with 7SA513

General hints:

– 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 current 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 breakers. Live-tank 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 breaker has opened. Consequently, final fault clearing by cascaded tripping has to be accepted in this case.
The 7SV512 relay provides the necessary end fault protection function and trips the breakers of the remaining infeeding circuits.

– For the selection of the main 1 and main 2 line protection schemes, the comments of application examples 8 and 9 apply.

– Autoreclosure (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 case of a line fault, both adjacent breakers have to be tripped by the line protection. The sequence of automatic reclosure of both breakers or, alternatively, the automatic reclosure of only one breaker and the manual closure of the other 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 breakers of one line (or transformer feeder).

– The voltages for synchrochecking have to be selected according to the breaker and isolator positions by a voltage replica circuit.

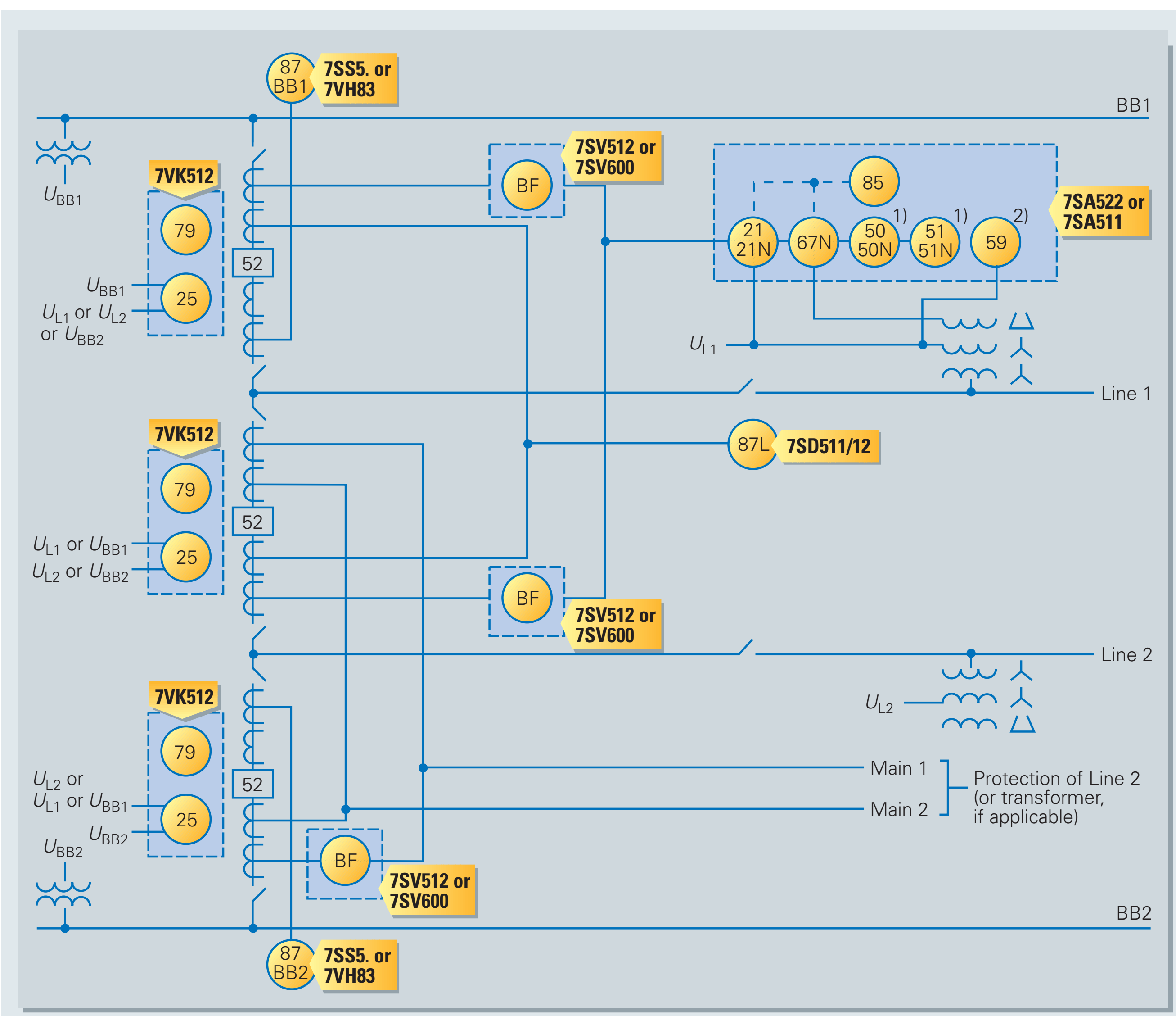


Fig. 93

11. Small transformer infeed

General hints:

– Ground-faults on the secondary side are detected by current relay 51G which, however, has to be time-graded against downstream feeder protection relays. The restricted ground-fault relay 87N can optionally be provided to achieve fast clearance of ground faults in the transformer secondary winding.
  Relay 7VH80 is of the high-impedance type and requires class X CTs with equal transformation ratio.
– Primary breaker and relay may be replaced by fuses.

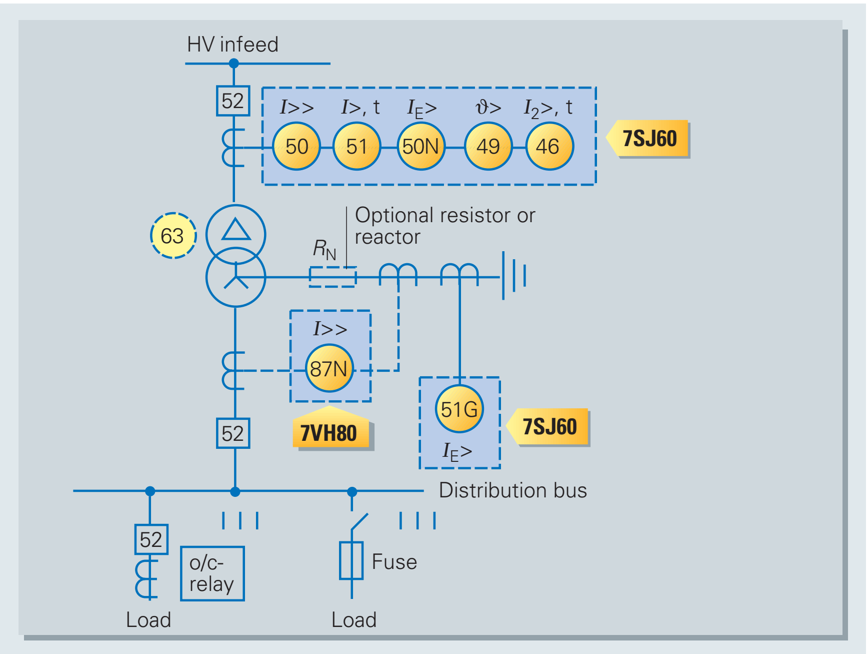


Fig. 94

12. Large or important transformer infeed

Notes:

1) Three winding transformer relay type 7UT513 may be replaced by two-winding type 7UT512 plus high-impedance-type restricted ground-fault relay 7VH80. However, class X CT cores would additionally be necessary in this case. (See small transformer protection)
2) 51G may additionally be provided, in particular for the protection of the neutral resistance, if provided.
3) Relays 7UT512/513 provide numerical ratio and vector group adaption. Matching transformers as used with traditional relays are therefore no longer applicable.

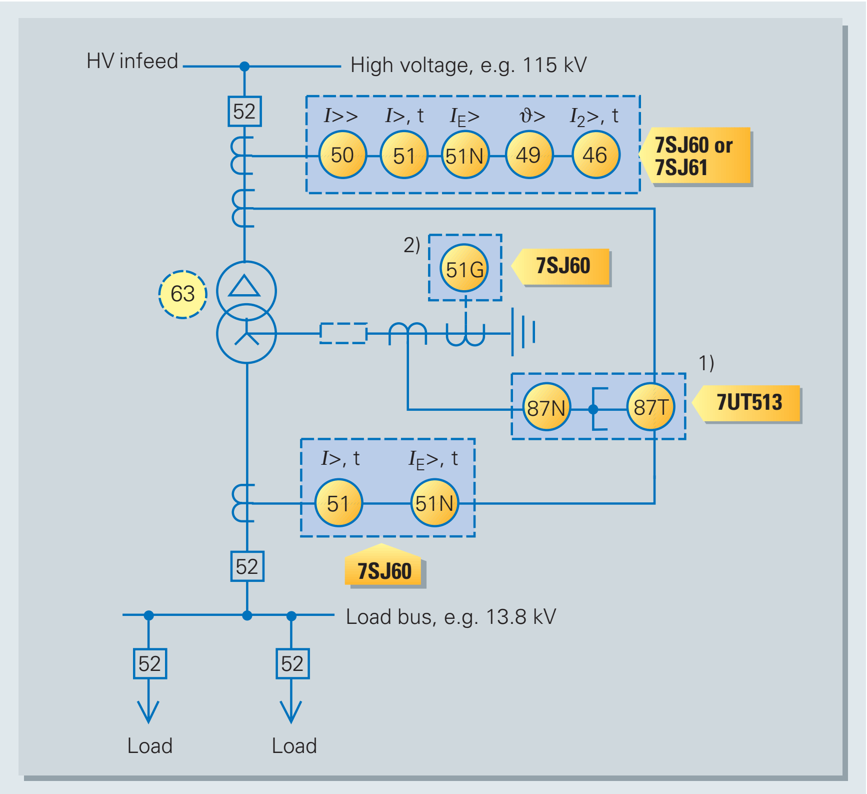


Fig. 95

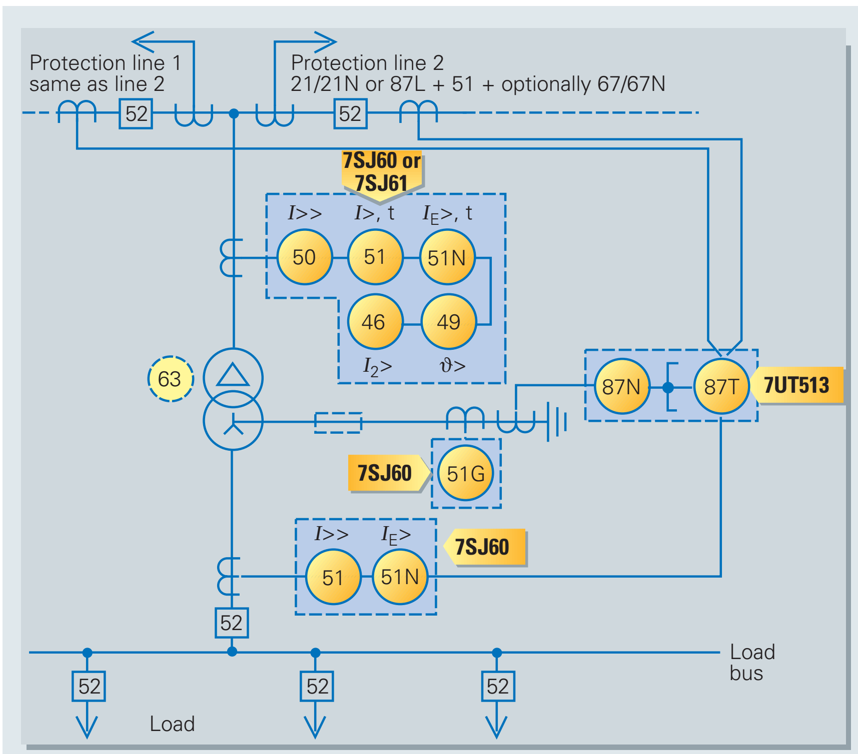


Fig. 96

13. Dual-infeed with single transformer

Notes:

1) Line CTs are to be connected to separate stabilizing inputs of the differential relay 87T in order to assure stability in case of line through-fault currents.
2) Relay 7UT513 provides numerical ratio and vector group adaption. Matching transformers, as used with traditional relays, are therefore no longer applicable.

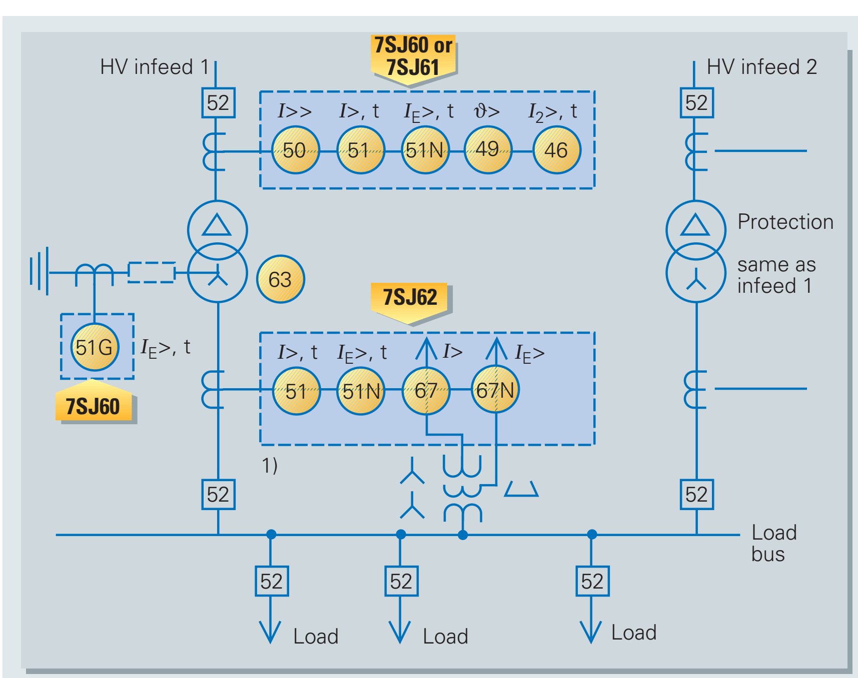


Fig. 97

14. Parallel incoming transformer feeders

Note:

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

15. Parallel incoming transformer feeders with bus tie

Note:

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

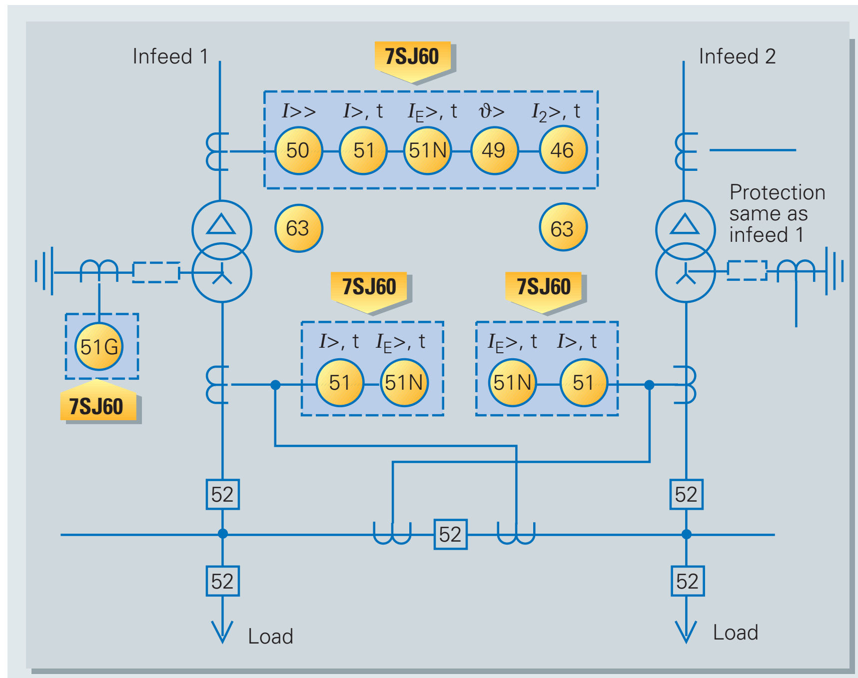


Fig. 98

16. Three-winding transformer

Notes:

1) The zero-sequence current must be blocked from entering the differential relay by a delta winding in the CT connection on the transformer sides with grounded winding neutral. This is to avoid false operation with external ground faults (numerical relays provide this function by calculation). About 30% sensitivity, however, is then lost in case of internal faults.
   Optionally, the zero-sequence current can be regained by introducing the winding neutral current in the differential relay (87T). Relay type 7UT513 provides two current inputs for this purpose.
   By using this feature, the ground fault sensitivity can be upgraded again to its original value.
2) Restricted ground fault protection (87T) is optional. It provides back-up protection for ground faults and increased ground fault sensitivity (about 10% I_N, compared to about 20 to 30% I_N of the transformer differential relay).
   Separate class X CT-cores with equal transmission ratio are additionally required for this protection.

General hint:

– In this example, the transformer feeds two different distribution networks with cogeneration. Restraining differential relay inputs are therefore provided at each transformer side.
  If both distribution networks only consume load and no through-feed is possible from one MV network to the other, parallel connection of the CTs of the two MV transformer windings is admissible allowing the use of a two-winding differential relay (7UT512).

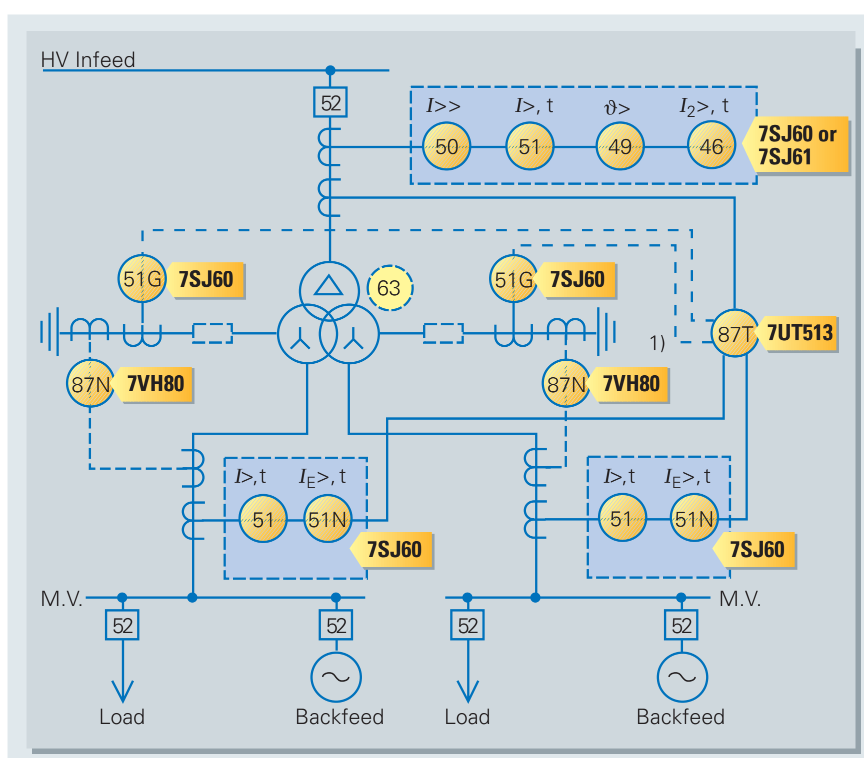


Fig. 99

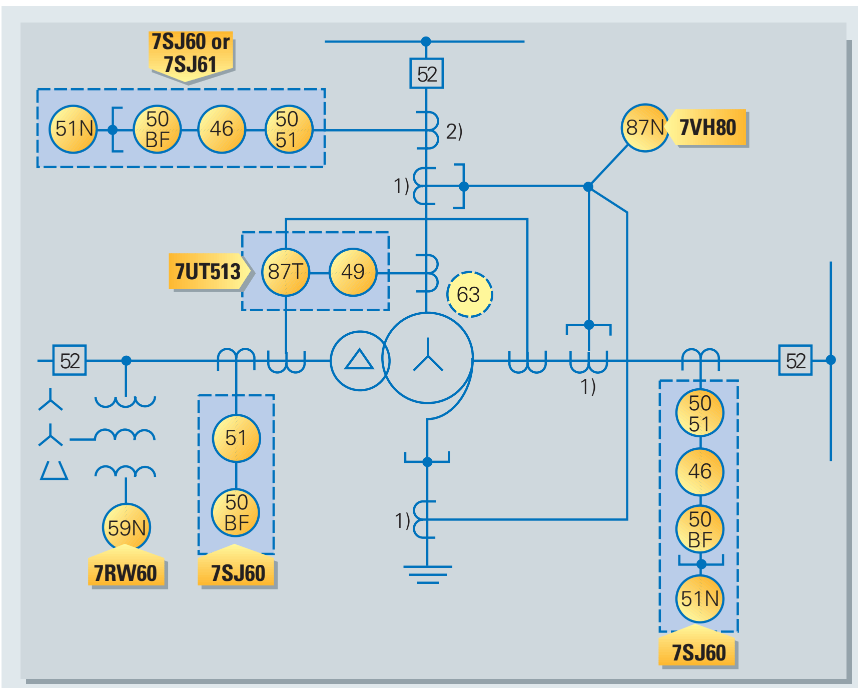


Fig. 100

17. Autotransformer

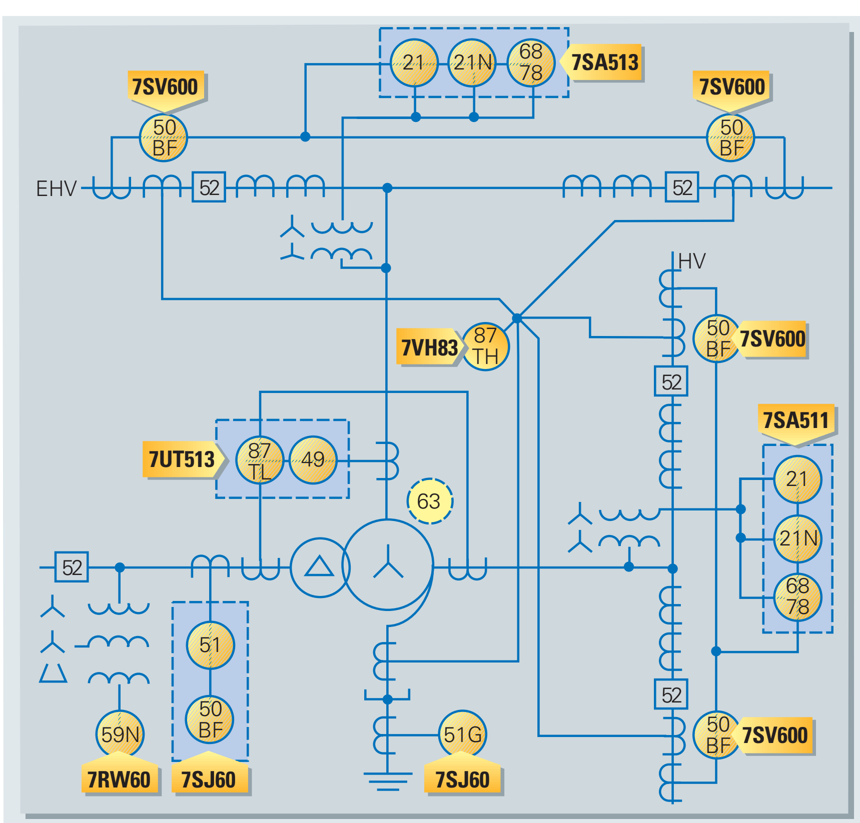
Notes:

1) 87N high-impedance protection requires special class X current transformer cores with equal transmission ratio.
2) The 7SJ60 relay can alternatively be connected in series with the 7UT513 relay to save this CT core.

General hint:

– Two different protection schemes are provided:
87T is chosen as low-impedance three-winding version (7UT513). 87N is a single-phase high-impedance relay (7VH80) connected as restricted ground fault protection. (In this example, it is assumed that the phaseends of the transformer winding are not accessible on the neutral side, i.e. there exists a CT only in the neutral grounding connection.)

6



18. Large autotransformer bank

General hints:

– The transformer bank is connected in a 1½ breaker arrangement.
Duplicated differential protection is proposed:
Main 1: Low-impedance differential protection $87T_L$ (7UT513) connected to the transformer bushing CTs.
Main 2: High-impedance overall differential protection $87T_H$ (7VH83). Separate class X cores and equal CT ratios are required for this type of protection.
– Back-up protection is provided by distance relays (7SA513 and 7SA511), 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 network with isolated neutral.

Fig. 101

Power System Protection Typical Protection Schemes

19. Small and medium-sized motors < about 1 MW

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

General hint:

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

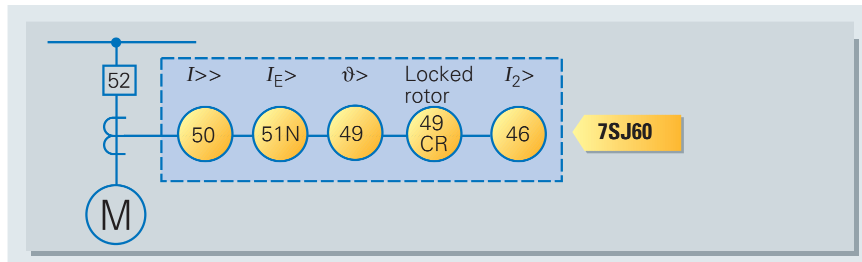


Fig. 102a

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

Notes:

1) Window-type zero sequence CT.
2) Sensitive directional ground-fault protection 67N only applicable with infeed from isolated or Peterson-coil-grounded network.
(For dimensioning of the sensitive directional ground fault protection, see also application circuit No. 24)
3) If 67G ist not applicable, relay 7SJ602 can be applied.

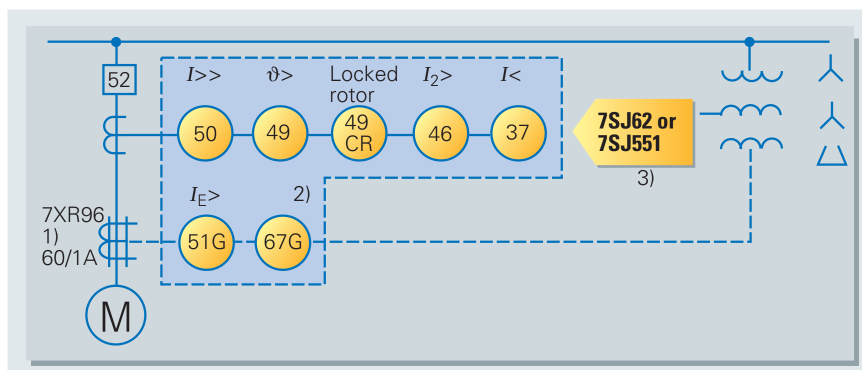


Fig. 102b

20. Large HV motors > about 1 MW

Notes:

1) Window-type zero sequence CT.
2) Sensitive directional ground-fault protection 67N only applicable with infeed from isolated or Peterson-coil-grounded network.
3) This function is only needed for motors where the runup time is longer than the safe stall time t_E.
According to IEC 79-7, the t_E-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 temperature to the limiting temperature.
A separate speed switch is used to supervise actual starting of the motor. The motor breaker is tripped if the motor does not reach speed in the preset time. The speed switch is part of the motor delivery itself.
4) Pt100, Ni100, Ni120
5) 49T only available with relay type 7SJ5
6) High impedance relay 7VH83 may be used instead of 7UT12 if separate class x CTs. are provided at the terminal and star-point side of the motor winding.

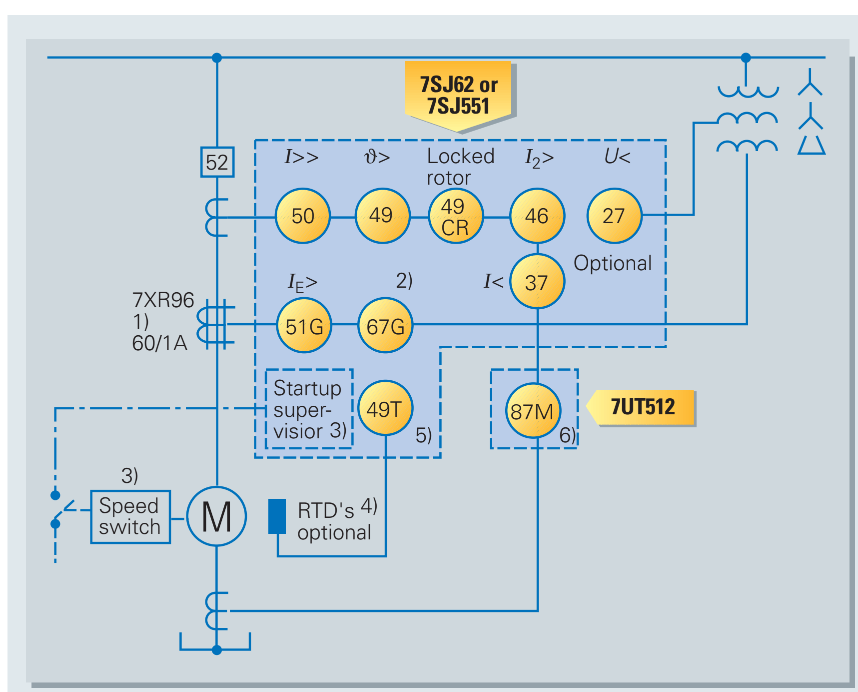


Fig. 103

21. Smallest generators < 500 kW

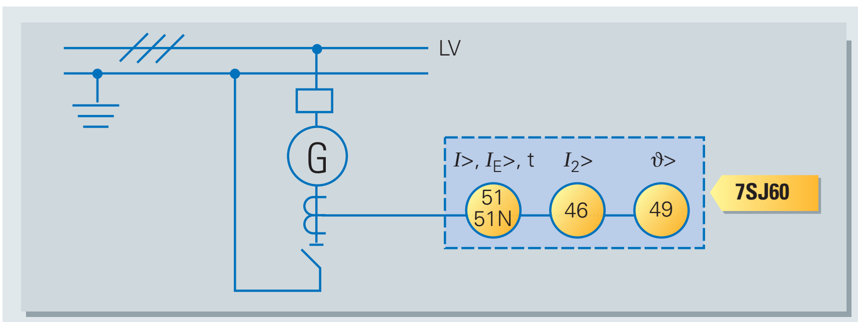


Fig. 104a: With solidly grounded neutral

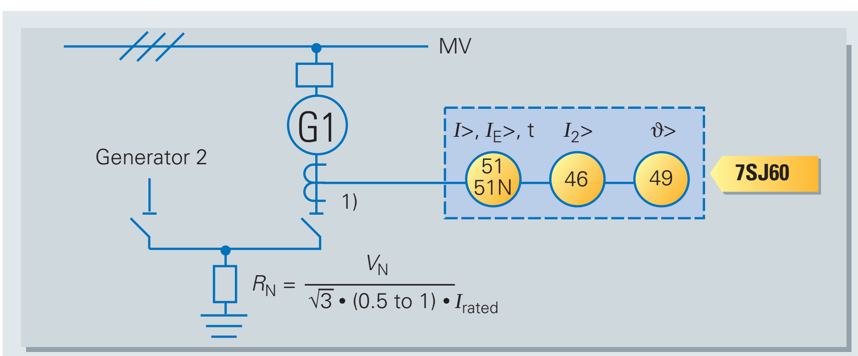


Fig. 104b: With resistance grounded neutral

Note:

1) If a window-type zero-sequence CT is provided for sensitive ground fault protection, relay 7SJ602 with separate ground current input can be used (similar to Fig. 102b of application example 19b).

22. Small generator, typically 1 MW

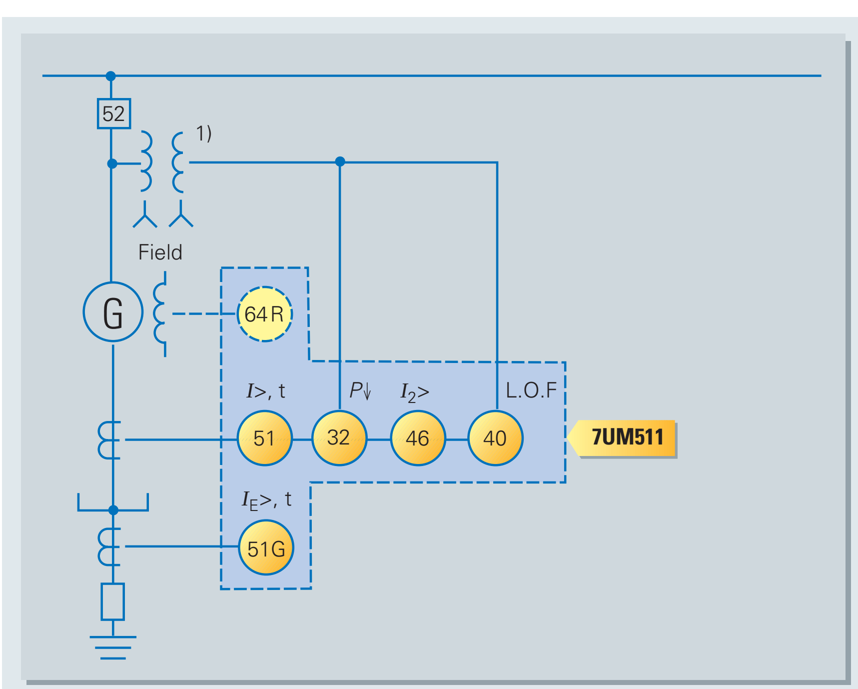


Fig. 105

Note:

1) Two CTs in V connection also sufficient.

Power System Protection Typical Protection Schemes

23. Smallest generators > 1 MW

Notes:

1) Functions 81 und 59 only required where prime mover can assume excess speed and voltage regulator may permit rise of output voltage above upper limit.
2) Differential relaying options:
   – 7UT512: Low-impedance differential protection 87
   – 7UT513: Low-impedance differential 87 with integral restricted ground-fault protection 87G
   – 7VH83: High-impedance differential protection 87 (requires class X CTs)
3) 7SJ60 used as voltage-controlled o/c protection.
   Function 27 of 7UM511 is used to switch over to a second, more sensitive setting group.

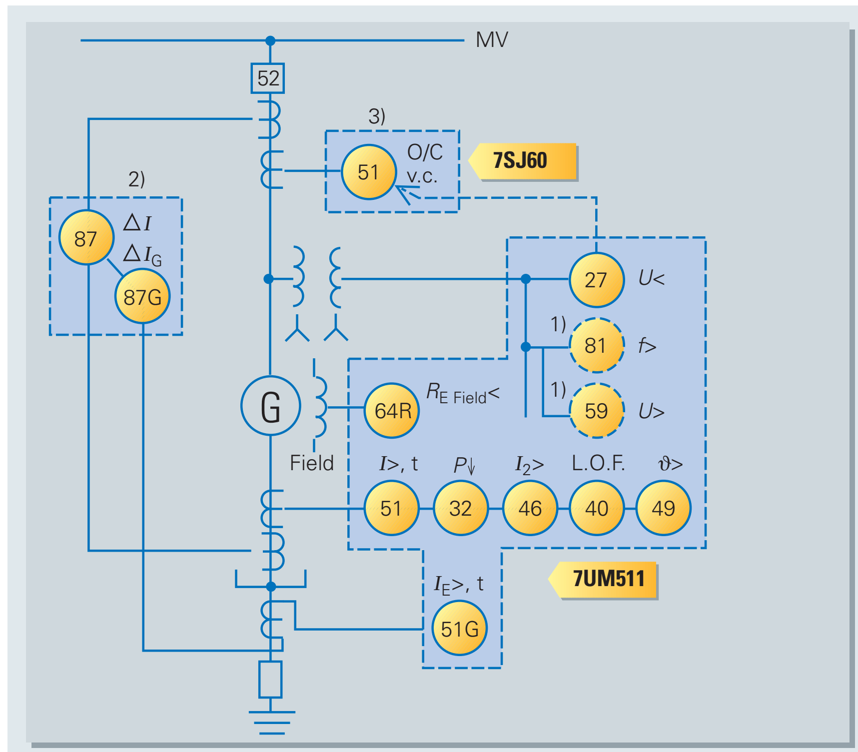


Fig. 106

24. Large generator > 1 MW feeding into a network with isolated neutral

General hints:

– The setting range of the directional ground fault protection 67G in the 7UM511 relay is 2 – 100 mA. Dependent on the current transformer accuracy, a certain minimum setting is required to avoid false operation on load or transient rush currents:

Relay ground current input connected to:	Minimum relay setting:	Comments:
Core-balance c.t. 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	1A CT: ca. 50 mA 5A CT: ca. 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 current (≤ 2 mA)	2 – 3‰ of secondary rated CT current $I_{n\,SEC}$: 10 – 15 mA with 5A CTs	1A CTs are not recommended in this case

Fig. 107

Power System Protection
Typical Protection Schemes

– In practice, efforts are generally made to protect about 90% of the machine winding, measured from the machine terminals. The full ground 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.
For the most sensitive setting of 2 mA, we need therefore 20 mA secondary ground current, corresponding to (60/1) x 20 mA = 1.2 A primary.
This current may be delivered by the network ground capacitances if enough cables are contained. In this case, the directional ground fault protection (67G) has to be set to reactive power measurement (U x I x sin w).
If sufficient capacitive ground current is not available, a grounding transformer with resistive zero-sequence load can be installed as ground current source at the station busbar. The 67G function has in this case to be set to active (wattmetric) power measurement (U x I x cosw).
The smallest standard grounding transformer TGAG 3541 has a 20 s short time rating of P_G = 27 kVA.

In a 5kV network, it would deliver:

$$I_{G\,20s} = \frac{\sqrt{3} \times P_G}{U_N} = \frac{\sqrt{3} \times 27{,}000VA}{5000V} = 9.4\ \mathrm{A}$$

corresponding to a relay input current of 9.4 A x 1/60 = 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 500V open-delta winding of the grounding transformer would then have to be designed for $R_G = U_{SEC}^2 / P_G$ = 500 V² / 27,000 VA = 9.26 Ohm (27 KW, 20 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 $(1-\frac{12}{78})$ = 85%.

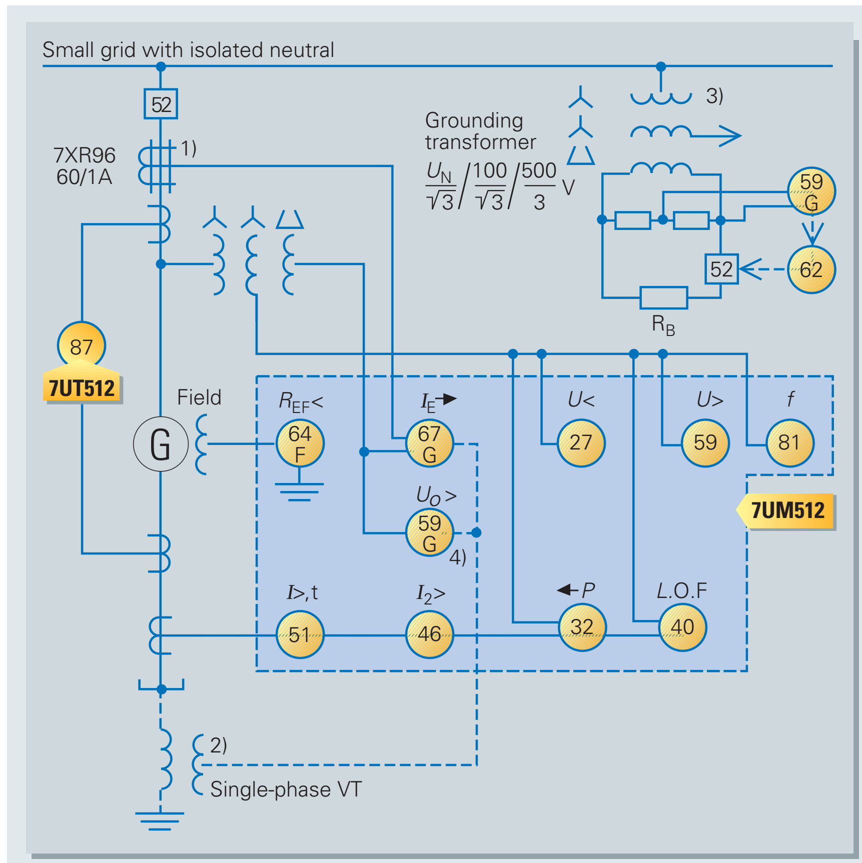


Fig. 108

Notes:

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 single-phase VT at the machine neutral could be used as zero-sequence polarizing voltage.
3) The grounding transformer is designed for a short-time rating of 20 seconds. To prevent overloading, the load resistor is automatically switched off by a time-delayed zero-sequence voltage relay (59G + 62) and a contactor (52).
4) During the startup time of the generator with open breaker, the grounding source is not available. To ensure ground fault protection during this time interval, an auxilliary contact of the breaker can be used to change over the directional ground fault relay function (67G) to a zero-sequence voltage detection function (59G) via a contact converter input.

Power System Protection
Typical Protection Schemes

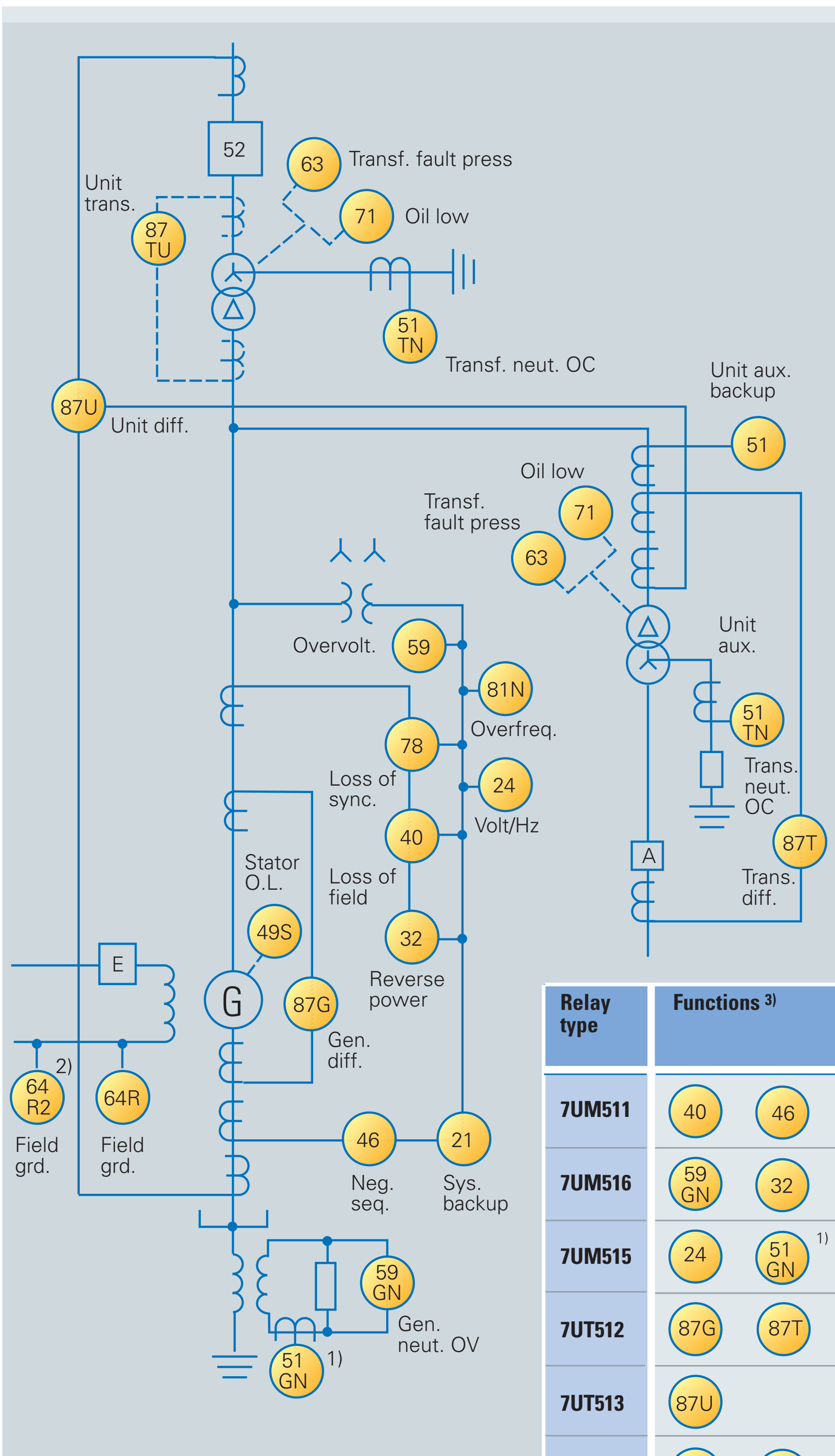


Fig. 109

25. Generator-transformer unit

Notes:

1) 100% stator ground-fault protection based on 20 Hz voltage injection
2) Sensitive field ground-fault protection based on 1 Hz voltage injection
3) Only used functions shown, further integrated functions available in each relay type (see "Relay Selection Guide", Fig. 43).

Relay type	Functions 3)	Number of relays required
7UM511	40 46 59 81N 49 64R	1
7UM516	59 GN 32 21 78	1
7UM515	24 51 GN 1) 64 R2 2)	1
7UT512	87G 87T and optionally 87 TU	2 optionally 3
7UT513	87U	1
7SJ60	51N 51	3

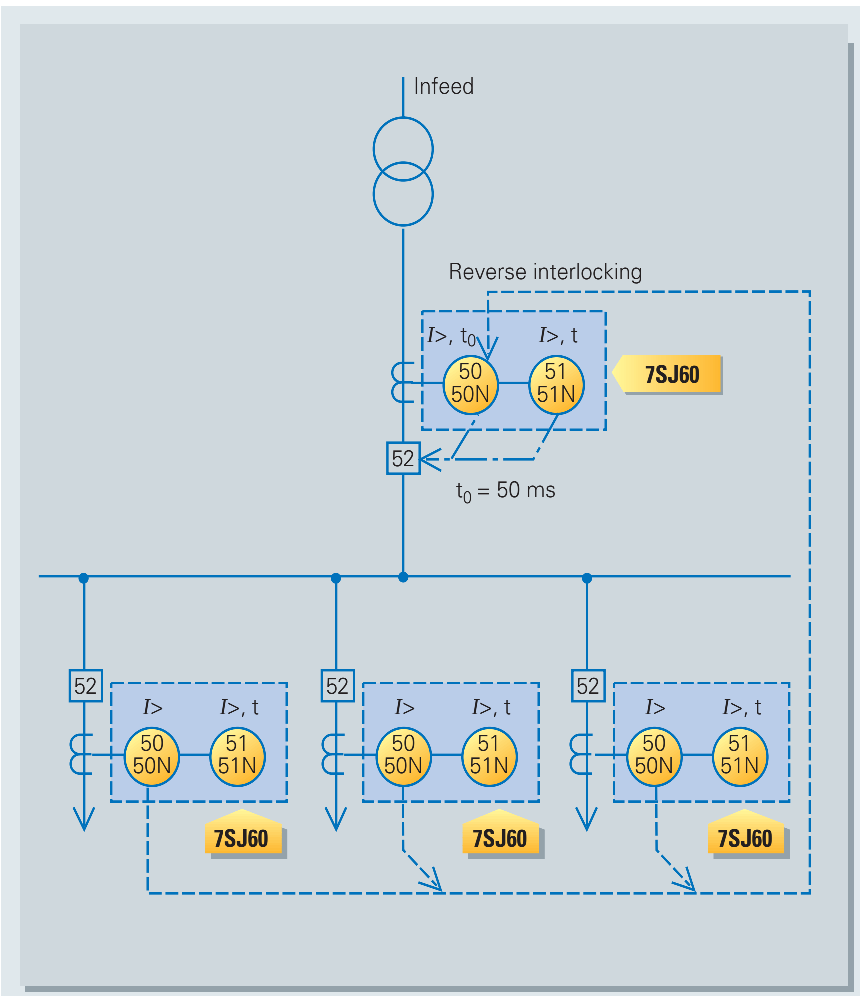


Fig. 110

26. Busbar protection by O/C relays with reverse interlocking

General hint:

Applicable to distribution busbars without substantial (< 0.25 x I_N) backfeed from the outgoing feeders

Power System Protection
Typical Protection Schemes

27. High impedance busbar protection

General hints:

- Normally used with single busbar and 1 1/2 breaker schemes
- Requires separate class X current transformer cores. All CTs must have the same transformation ratio

Note:

1) A varistor is normally applied accross the relay input terminals to limit the voltage to a value safety below the insulation voltage of the secondary circuits (see page **6**/70).

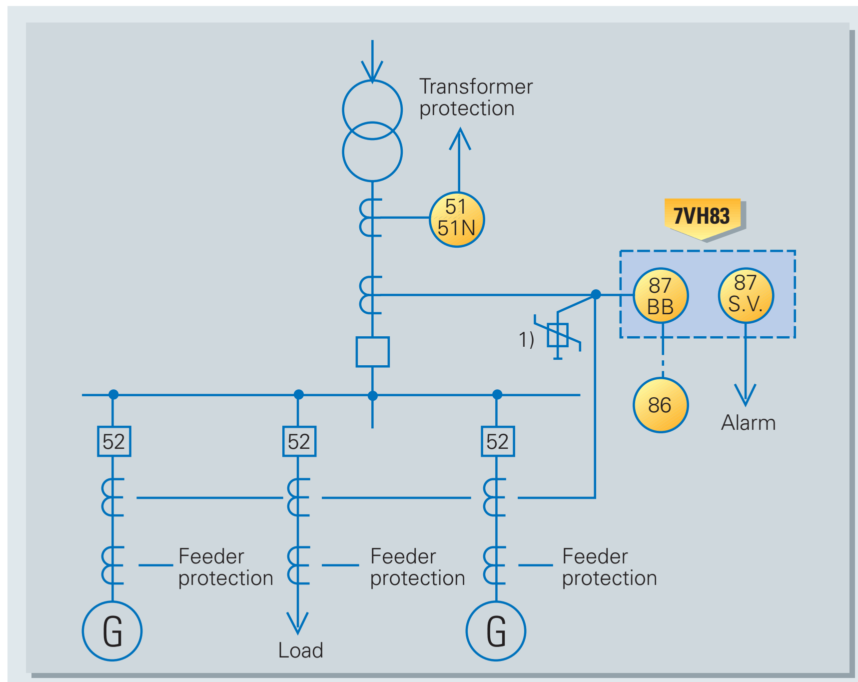


Fig. 111

28. Low-impedance busbar protection

General hints:

- Preferably used for multiple busbarschemes where an isolator replica is necessary
- The numerical busbar protection 7SS5 provides additional breaker failure protection
- CT transformation ratios can be different, e.g. 600/1 A in the feeders and 2000/1 at the bus tie
- The protection system and the isolator replica are continuously self-monitored by the 7SS5
- Feeder protection can be connected to the same CT core.

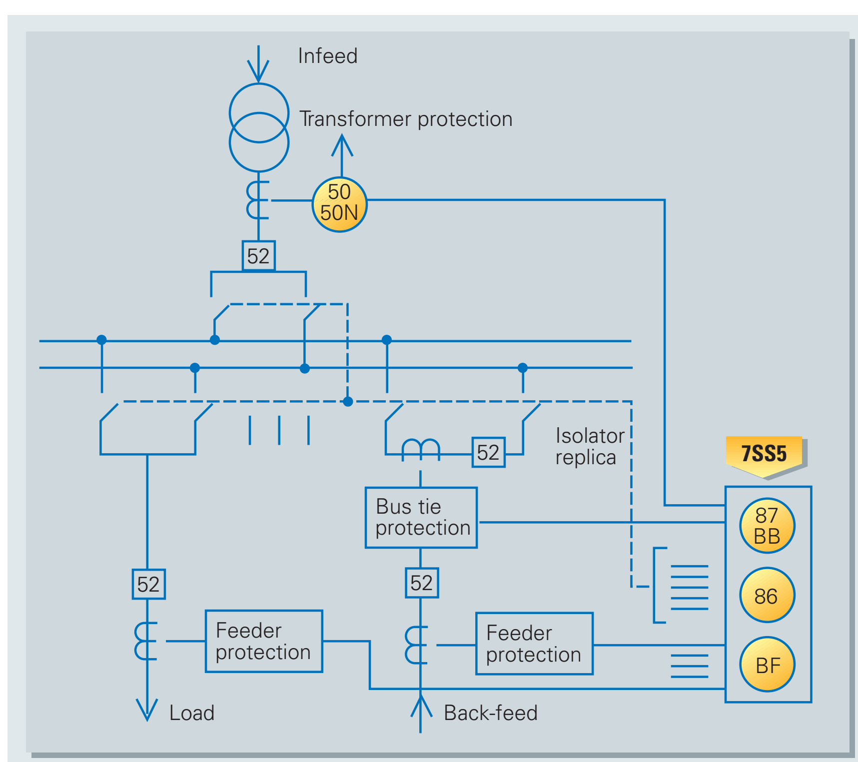


Fig. 112

Protection coordination

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

Sensivity

Protection should be as sensitive as possible 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.

Phase-fault relays

The pick-up values of phase o/c relays are normally set 30% above the maximum load current, provided that sufficient short-circuit current is available.
This practice is recommmended in particular 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 10% lower setting.
Feeders with high transformer and/or motor load require special consideration.

Transformer feeders

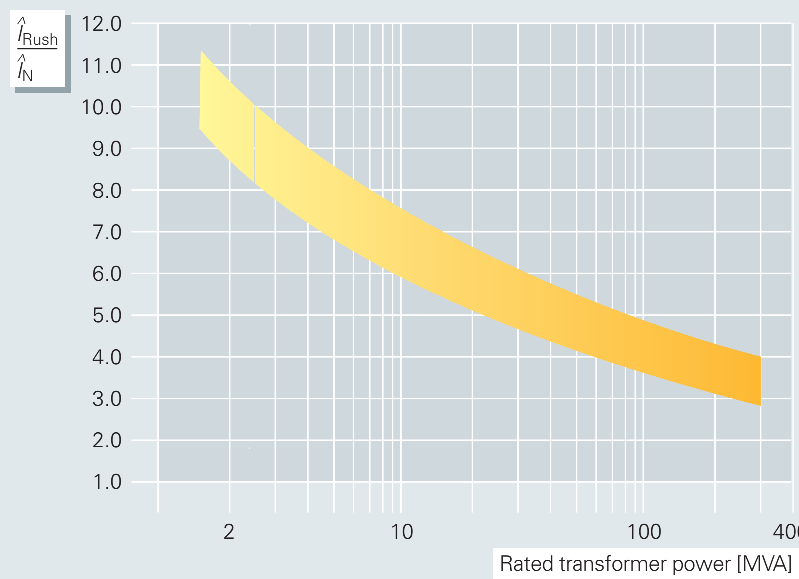
The energizing of transformers causes inrush currents that may last for seconds, depending on their size (Fig. 113).

Selection of the pickup current and assigned time delay have to be coordinated so that the rush current decreases below the relay o/c reset value before the set operating time has elapsed.
The rush current typically contains only about 50% fundamental frequency component.
Numerical relays that filter out harmonics and the DC component of the rush current can therefore be set more sensitive. The inrush current peak values of Fig. 113 will be nearly reduced to one half in this case.

Ground-fault relays

Residual-current relays enable a much more sensitive setting, as load currents do not have to be considered (except 4-wire circuits with single-phase load). In solidly and low-resistance grounded systems a setting of 10 to 20% rated load current is generally applied.

Peak value of inrush current



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. 113: Transformer inrush currents, typical data

High-resistance grounding requires much more sensitive setting in the order of some amperes primary.
The ground-fault current of motors and generators, for example, should be limited to values below 10 A in order to avoid iron burning.

Residual-current relays in the star point connection of CTs can in this case not be used, in particular with rated CT primary currents higher than 200 A. The pickup value of the zero-sequence relay would in this case be in the order of the error currents of the CTs.

A special zero-sequence CT is therefore used in this case as ground current sensor. The window-type current transformer 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 Peterson-coil-grounded networks where very low ground currents occur with single-phase-to-ground faults. Settings of 20 mA and less may then be required depending on the minimum ground-fault current.
Sensitive directional ground-fault relays (integrated in the relays 7SJ512, 7SJ55 and 7SA511) allow settings as low as 5 mA.

Power System Protection
Protection Coordination

Differential relays (87)

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

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

Instantaneous o/c protection (50)

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

Motor feeders

The energizing of motors causes a starting current of initially 5 to 6 times rated current (locked rotor current).
A typical time-current curve for an induction motor is shown in Fig. 114.
In the first 100 ms, a fast decaying assymetrical inrush current appears additionally. With conventional relays it was current practice to set the instantaneous o/c step for 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 fast 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 adaption is to be made by setting of the pickup value and the thermal time constant, using the data supplied by the motor manufacturer. Further, the locked-rotor protection timer has to be set according to the characteristic motor value.

Time grading of o/c 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).

This is shown in Fig. 116 by the example of definite time o/c relays.
The overshoot times takes into account the fact that the measuring relay continues to operate due to its inertia, even when the fault current is interrupted. This may

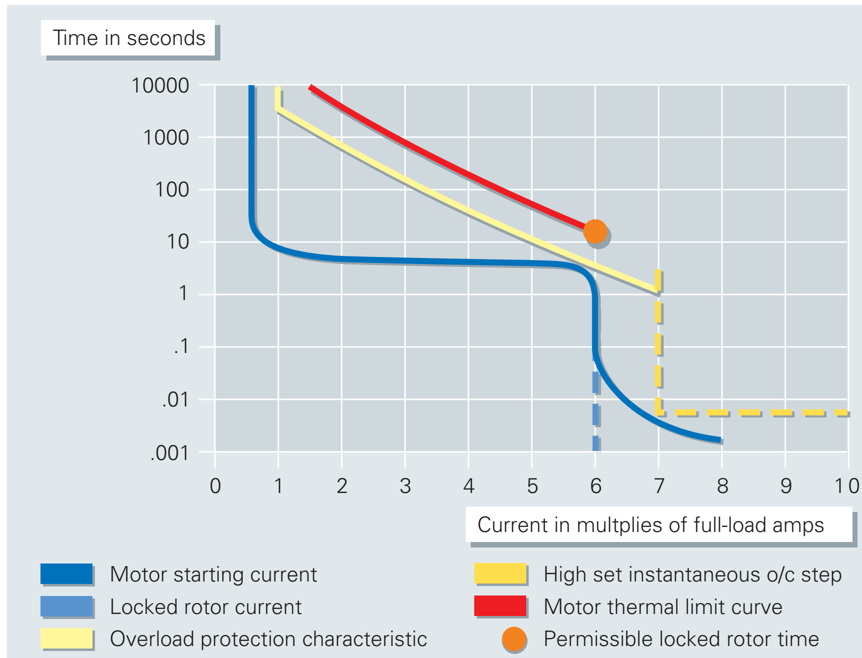


Fig. 114: Typical motor current-time characteristics

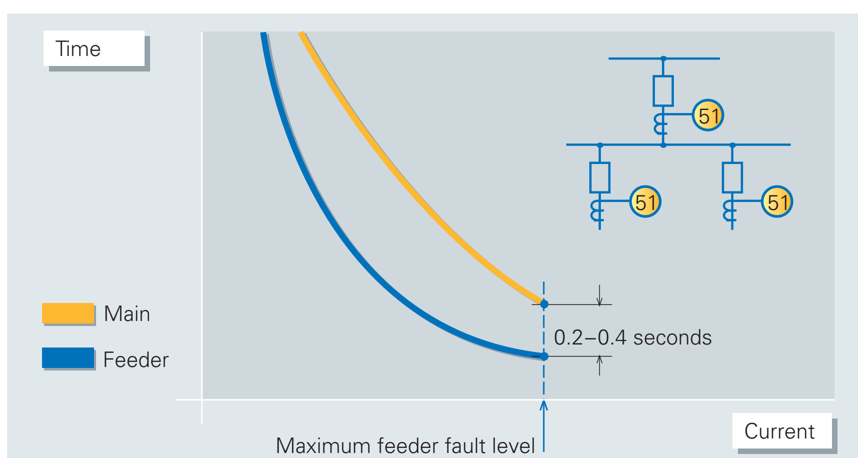


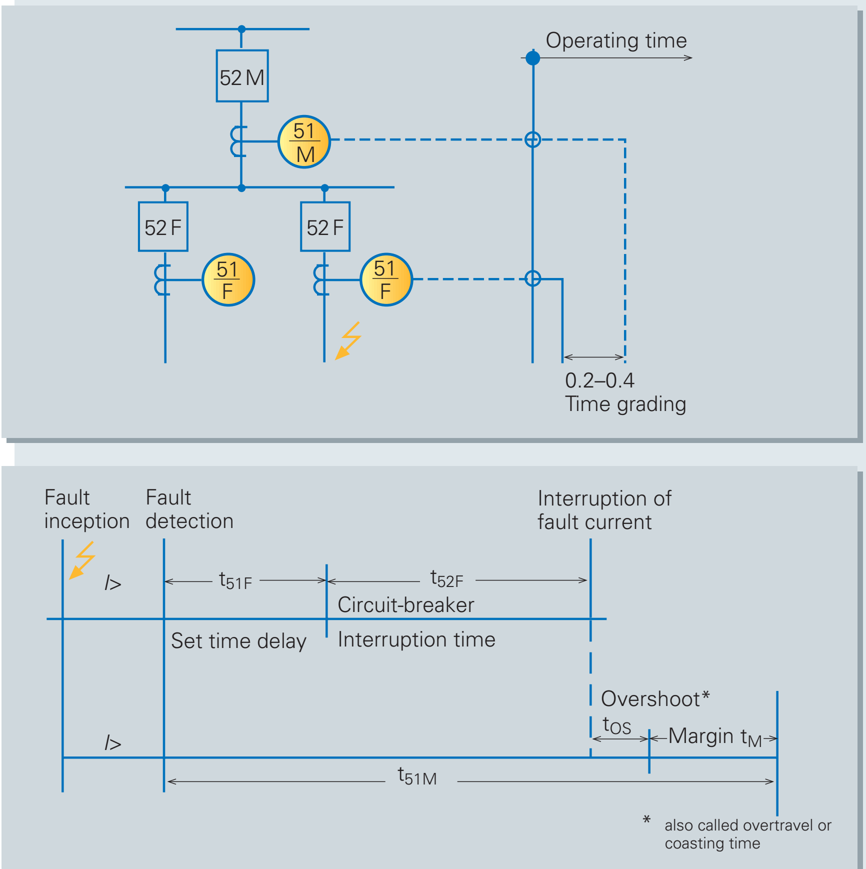
Fig. 115: Coordination of inverse-time relays

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, the same rules apply in principle 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. 115).

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



$$t_{51M} - t_{51F} = \underbrace{t_{52F} + t_{OS} + t_M}_{\text{Time grading } t_{TG}}$$

Example 1

Mechanical relays: t_{OS} = 0.15 s
Oil circuit-breaker t_{52F} = 0.10 s
Safety margin for measuring errors, etc.: t_M = 0.15

$$\mathbf{t_{TG} = 0.10 + 0.15 + 0.15 = 0.40\ s}$$

Example 2

Numerical relays: t_{OS} = 0.02 s
Vacuum breaker: t_{52F} = 0.08 s
Safety margin: t_M = 0.10 s

$$\mathbf{t_{TG} = 0.08 + 0.02 + 0.10 = 0.20\ s}$$

Fig. 116: Time grading of overcurrent-time relays

Power System Protection
Protection Coordination

Calculation example

The feeder configuration of Fig. 117 and the assigned load and short-circuit currents are given.
Numerical o/c relays 7SJ60 with normal inverse-time characteristic are applied.
The relay operating times dependent on current can be taken from the diagram or derived from the formula given in Fig. 118.

The I_P/I_N settings shown in Fig. 117 have been chosen to get pickup values safely above maximum load current.
This current setting shall be lowest for the relay farthest downstream. The relays further upstream shall each have equal or higher current setting.
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 related to 13.8 kV is 523 A.
  This results in 7.47 for I/I_P at the o/c relay in location C.
- With this value and $T_P = 0.05$ we derive from Fig. 118 an operating time of $t_A = 0.17$ s

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

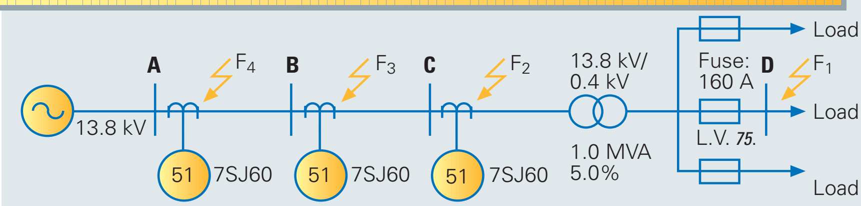
- Current tap: $I_P/I_N = 0.7$
- Time multipler: $T_P = 0.05$

Station B:

The relay in B has a back-up 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, we obtain an operating time of 0.11 s (I/I_P = 19.9).
We assume that no special requirements for short operating times exist and can therefore choose an average time grading interval of 0.3 s. The operating time of the relay in B can then be calculated:

- $t_B = 0.11 + 0.3 = 0.41$ s
- Value of $I_P/I_N = \dfrac{1395\text{ A}}{220\text{ A}} = 6.34$
  see Fig. 117.
- With the operating time 0.41 s and $I_P/I_N = 6.34$, we can now derive $T_P = 0.11$ from Fig. 118.

Example: Time grading of inverse-time relays for a radial feeder



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	4500	400/5	1.0	400	11.25
B	170	2690	200/5	1.1	220	12.23
C	50	1395	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. 117

The setting values for the relay at station B are herewith

- Current tap: $I_P/I_N = 1.1$
- Time multiplier $T_P = 0.11$

Given these settings, we can also check the operating time of the relay in B for a close-in fault in F3:
The short-circuit current increases in this case to 2690 A (see Fig. 117). The corresponding I/I_P value is 12.23.

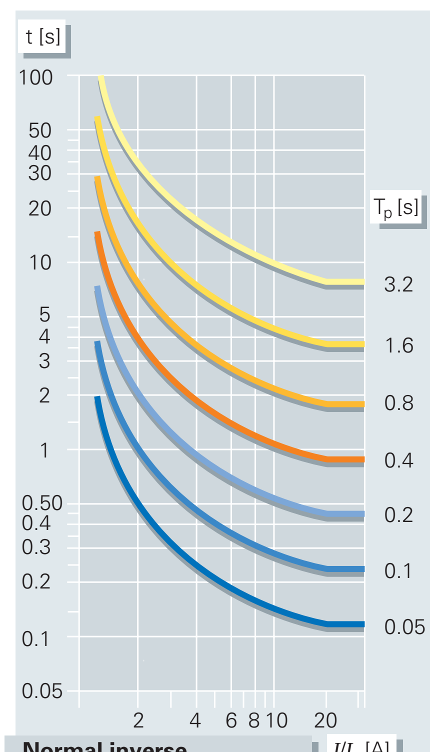
- With this value and the set value of $T_P = 0.11$ we obtain again from Fig. 118 an operating time of 0.3 s.

Station A:

- We add the time grading interval of 0.3 s and find the desired operating time $t_A = 0.3 + 0.3 = 0.6$ s.

Following the same procedure as for the relay in station B we obtain the following values for the relay in station A:

- Current tap: $I_P/I_N = 1.0$
- Time multiplier: $T_P = 0.17$
- For the close-in fault at location F4 we obtain an operating time of 0.48 s.



Normal inverse

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

Fig. 118: Normal inverse time-characteristic of relay 7SJ60

Power System Protection
Protection Coordination

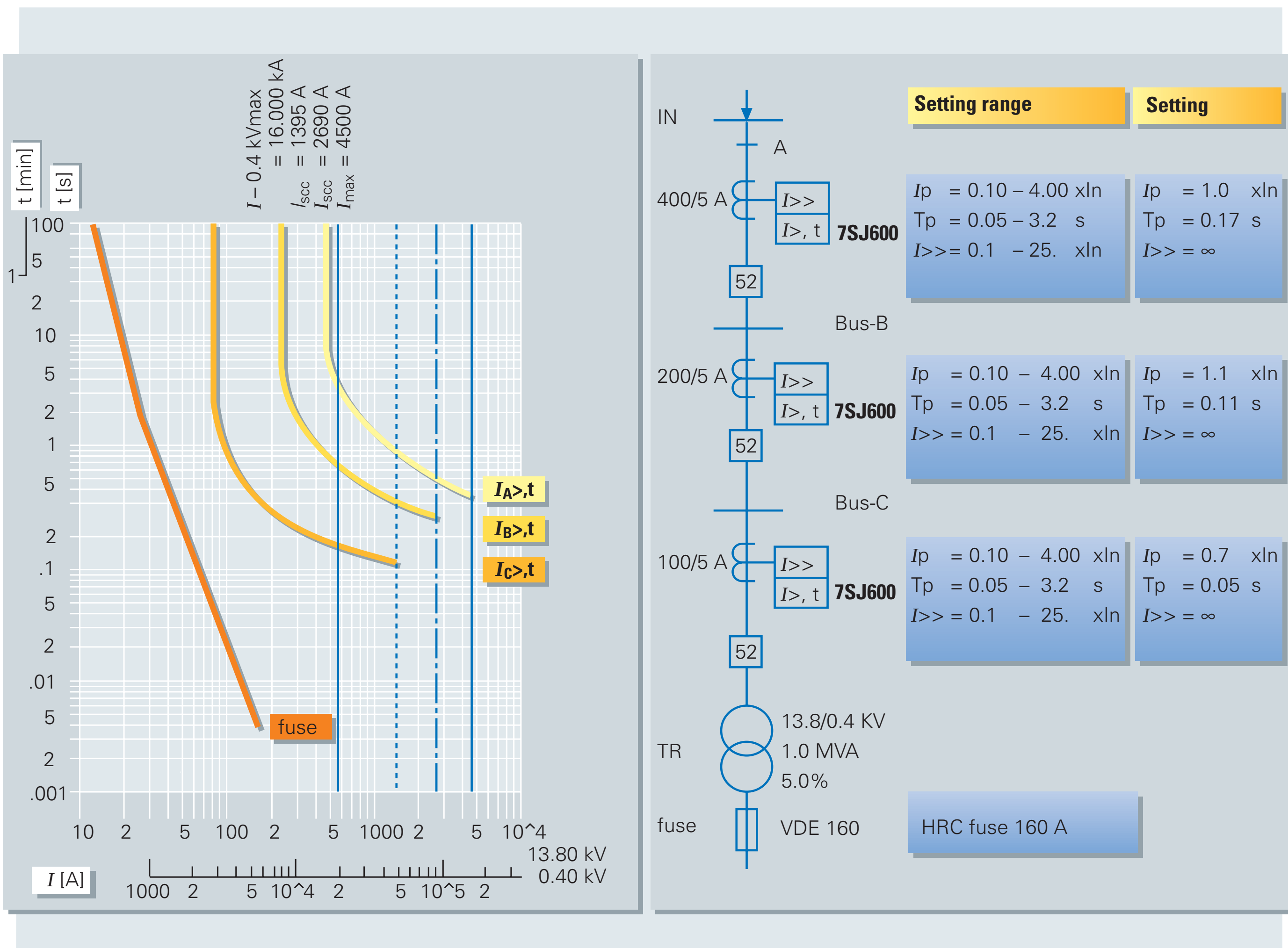


Fig. 119: O/c time grading diagram

The normal way

To prove the selectivity over the whole range of possible short-circuit currents, it is normal practice to draw the set operating curves in a common diagram with double log scales. These diagrams can be manually calculated and drawn point by point or constructed by using templates.
Today computer programs are also available for this purpose. Fig. 119 shows the relay coordination diagram for the example selected, as calculated by the Siemens program CUSS (computer-aided protective grading).

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 o/c relays with fuses and low-voltage trip devices

The procedure is similar to the above described grading of o/c relays. Usually a time interval between 0.1 and 0.2 seconds is sufficient for a safe time coordination. Very and extremely inverse characteristics are often more suitable than normal inverse curves in this case. Fig. 120 shows typical examples.
Simple consumer-utility interrupts use a power fuse on the primary side of the supply transformers (Fig. 120a).
In this case, the operating characteristic of the o/c relay at the infeed has to be coordinated with the fuse curve.
Very inverse characteristics may be used with expulsion-type fuses (fuse cutouts) while extremly 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 o/c relays with one inverse time and two definite-time zones can be closely adapted (Fig. 120b).

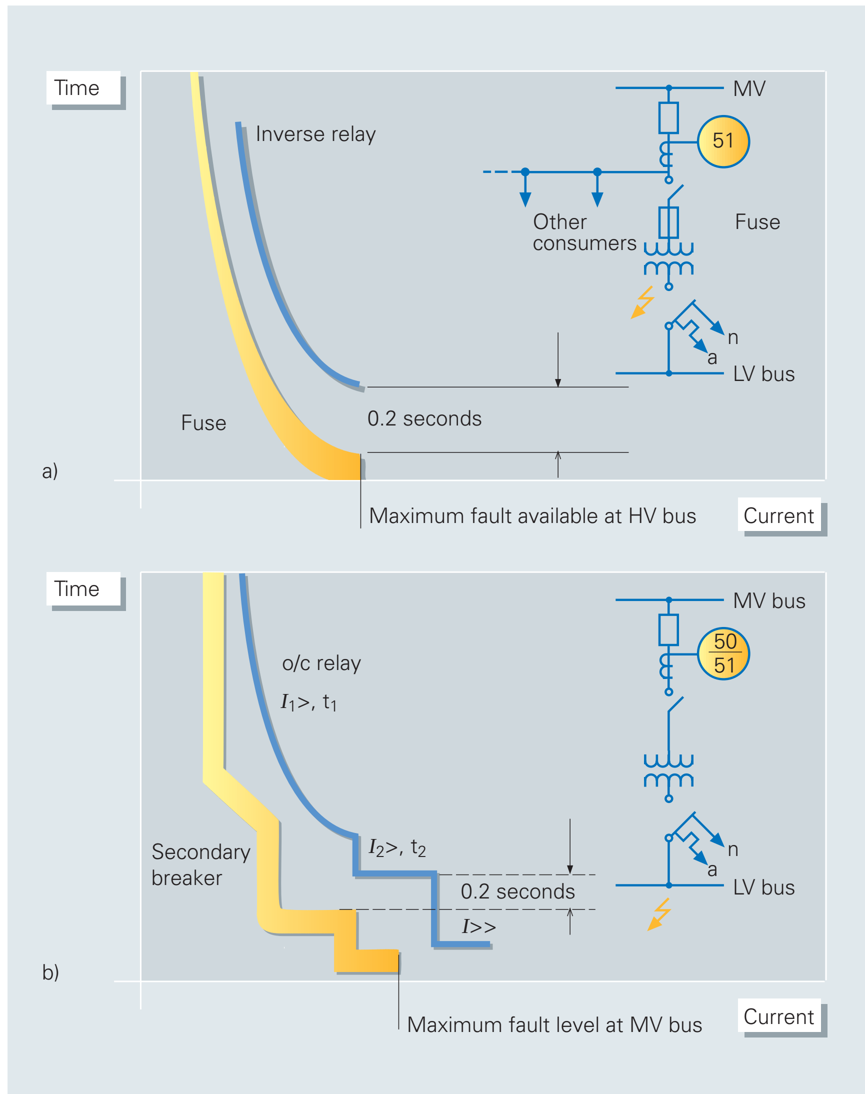


Fig. 120: Coordination of an o/c relay with an MV fuse and a low-voltage breaker trip device

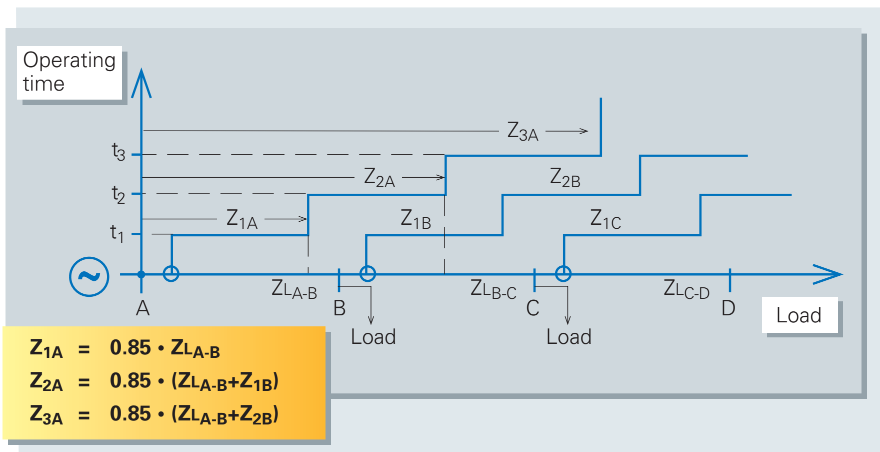


Fig. 121: Grading of distance zones

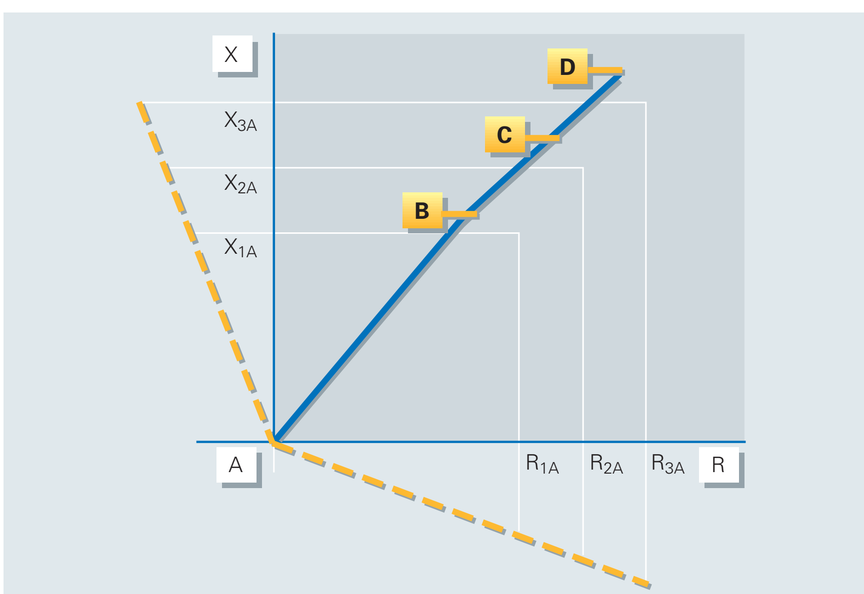


Fig. 122: Operating characteristic of Siemens distance relays 7SA511 and 7SA513

Coordination of distance relays

The reach setting of distance times 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%. Further, the line parameters are normally only calculated, not measured. This is a further source of errors.

A setting of 80–85% 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 reach setting may also 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 has always to be considered (Fig. 121).

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

Grading of zone times

The first zone normally operates undelayed. For the grading of the time intervals of the second and third zones, the same rules as for o/c relays apply (see Fig. 116).

For the quadrilateral characteristics (relays 7SA511 and 7SA513) only the reactance values (X values) have to be considered for the reach 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:

$$R_{Arc} = \frac{l_{Arc} \times 2_{kV/m}}{I_{scc\ Min}}$$

l_{Arc} = arc length in m
$I_{scc\ Min}$ = minimum short-circuit current

Fig. 123

- Typical settings of the ratio R/X are:
  - Short lines and cables (≤ 10 km): R/X = 2 to 10
  - 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 underreach distance zones without the need for signaling links depends on the shortest settable relay reactance.

$$X_{Primary\ Minimum} = X_{Relay\ Min} \times \frac{VT_{ratio}}{CT_{ratio}}\ [\mathrm{Ohm}]$$

$$l_{min} = \frac{X_{Prim.Min}\ [\mathrm{Ohm}]}{X'_{Line}\ [\mathrm{Ohm/km}]}\ [\mathrm{km}]$$

Fig. 124

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

Breaker failure protection setting

Most digital relays of this guide provide the 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 from outside 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 needs auxiliary relays which add a small time delay (BFT) to the overall fault clearing time.
This is in particular the case with 1-and-1/2-breaker or ring bus arrangements where a separate breaker failure relay (7SV600 or 7SV512) is used per breaker (see application example 10).

The deciding criterion of BF protection time coordination is the reset time of the current detector (50BF) which must not be exceeded under any condition of current interruption. The reset times specified in the Siemens digital relay manuals are valid for the worst-case condition: interruption of a fully offset short-circuit current and low current pick-up setting (0.1 to 0.2 times rated CT current).
The reset time is 1 cycle for EHV relays (7SA513, 7SV512) and 1.5 to 2 cycles for distribution type relays (7SJ***).
Fig. 126 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.

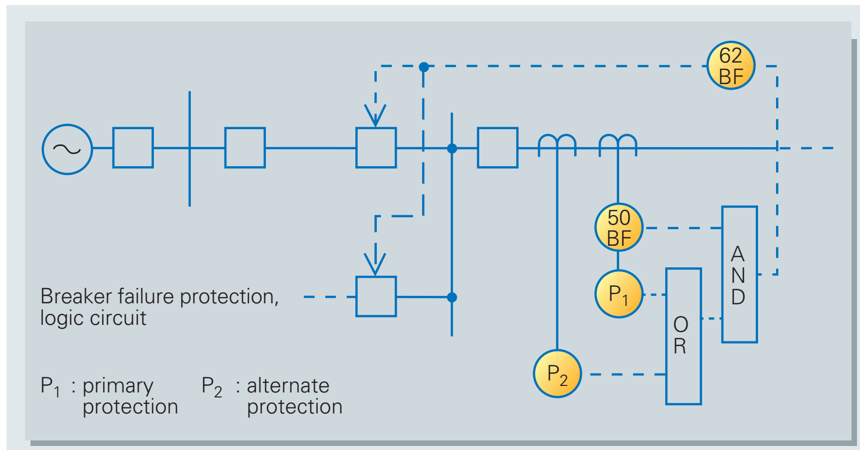


Fig. 125

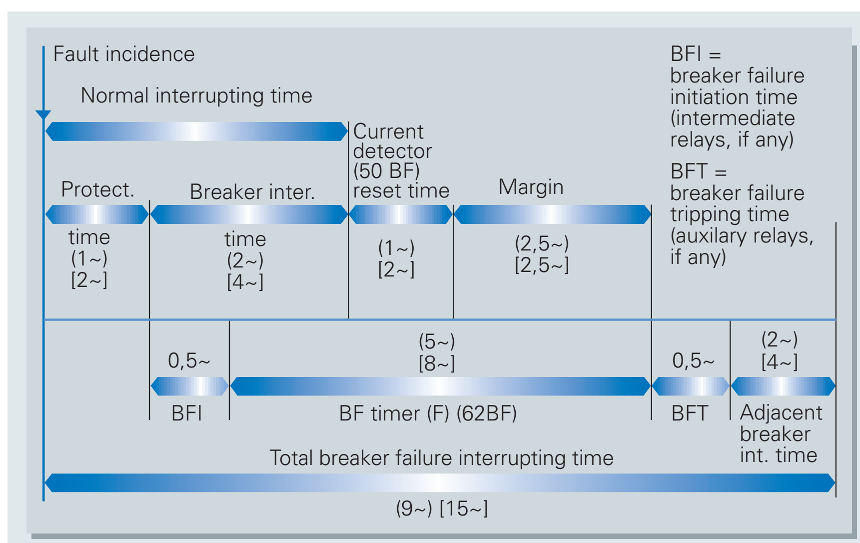


Fig. 126

High-impedance differential protection: Verification of design

The following design data must be established:

CT data

The CTs must all have the same ratio and should be of low leakage flux design according to Class TPS of IEC 44-6 (Class X of BS 3938). The excitation characteristic and the secondary winding resistance are to be provided by the manufacturer.
The knee-point voltage of the CT is required to be designed at least for two times the relay pick-up voltage to assure dependable operation with internal faults.

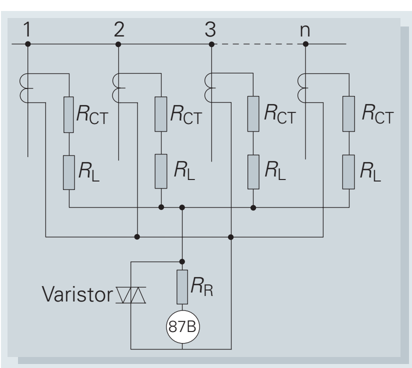


Fig. 127

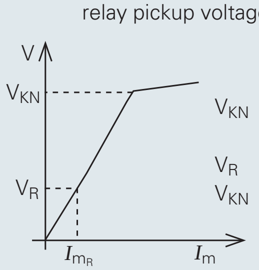
Sensitivity:

$I_{Fmin} = N \cdot (I_{Rset} + I_{var} + n \cdot I_{mR})$

Stability:

$I_{FThrough\,max} < N \cdot \frac{R_R}{R_L + R_{CT}} \cdot I_{Rset}$

N = CT ratio
I_{Rset} = Set relay pickup current
I_{Var} = Varistor spill current
I_{m_R} = CT magnetizing current at relay pickup voltage



V_{KN} = CT knee point voltage
$V_R = R_R \cdot I_{Rset}$
$V_{KN} \geq 2 \cdot V_R$

Fig. 128

Differential relay

The differential relay must be a high-impedance relay designed as sensitive current relay (7VH80/83: 20 mA) with series resistor. If the series resistor is integrated in the relay, the setting values may be directly calibrated in volts, as with the relays 7VH80/83 (6 to 60 V or 24 to 240 V).

Sensitivity

For the relay to operate in case of an internal fault, the primary current must reach a minimum value to supply the set relay pickup current ($I_{R\text{-}set}$), the varistor leakage current (I_{var}) and the magnetizing currents of all parallel-connected CTs ($n \cdot I_{mR}$).
Low relay voltage setting and CTs with low magnetizing demand therefore increase the protection sensitivity.

Voltage limitation by a varistor is required if:

$$V_{Rmax} = 2\sqrt{2V_{KN}(V_F - V_{KN})} > 2\text{kV}$$

$$\text{with } V_F = \frac{I_{Fmax\,Through}}{N}(R_{CT} + 2 \cdot R_L + R_R)$$

Fig. 129

Calculation example:

Given: $n = 8$ feeders
$N = 600/1$ A
$V_{KN} = 500$ V
$R_{CT} = 4$ Ohm
$I_{mR} = 30$ mA (at relay setpoint)
$R_L = 3$ Ohm (max.)
$I_{Rset} = 20$ mA
$R_R = 10$ kOhm
$I_{Var} = 50$ mA (at relay setpoint)

Sensitivity:

$I_{Fmin} = N \cdot (I_{Rset} + I_{var} + n \cdot I_{mR})$

$I_{Fmin} = \frac{600}{1} \cdot (0.02 + 0.05 + 8 \cdot 0.03)$

$I_{Fmin} = 186$ A (31% I_N)

Stability:

$I_{FmaxThrough} < N \cdot \frac{R_R}{R_L + R_{CT}} \cdot I_{Rset}$

$I_{Fmax\,Through} < \frac{600}{1} \cdot \frac{10{,}000}{3+4} \cdot 0.02$

$I_{Fmax\,Through} < 17$ kA ($28 \cdot I_N$)

Fig. 130

Stability with external faults

This check is made by assuming an external fault with maximum through-fault current and full saturation of the CT in the faulted feeder. The saturated CT ist then only effective with its secondary winding resistance R_{CT}, and the appearing relay voltage V_R corresponds to the voltage drop of the infeeding currents (through-fault current) at R_{CT} and R_L. The current at the relay must under this condition safely stay below the relay pickup value.
In practice, the wiring resistances R_L may not be equal. In this case, the worst condition with the highest relay voltage (corresponding to the highest relay 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 to enhanced through-fault stability, but, also to higher CT magnetizing and 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% I_N is normal for motor and transformer differential protection, or for restricted ground-fault protection.
With busbar protection a pickup value ≥ 50 % IN is normally applied.
An increased pickup value can be achieved by connecting a resistor in parallel to the relay.

Varistor

Voltage limitation by a varistor is needed if peak voltages near or above the insulation voltage (2 kV) are to be expected. A limitation to 1500 V rms is then recommended.
This can be checked for the maximum internal fault current by applying the formula shown for $V_{R\text{-}max}$.
A restricted ground-fault protection may normally not require a varistor, but, a busbar protection in general does.
The electrical varistor characteristic can be expressed as $V = K \cdot I^B$. K and B are the varistor constants.

Relay setting V rms	K	B	Varistor type
≤125	450	0.25	600A/S1/S256
125–240	900	0.25	600A/S1/S1088

Fig. 131

Local and Remote Control
Introduction

State-of-the-art

Modern protection and substation control uses microprocessor technology and serial communication to upgrade substation operation, to enhance reliability and to reduce overall life cycle cost.

The traditional conglomeration of often totally different devices such as relays, meters, switchboards and RTUs is replaced by a few multifunctional, intelligent devices of uniform design. And, instead of extensive parallel wiring (centralized solution, Fig. 132), only a few serial links are used (decentralized solution, Fig. 133).

Control of the substation takes place with menu-guided procedures at a central VDU workplace.

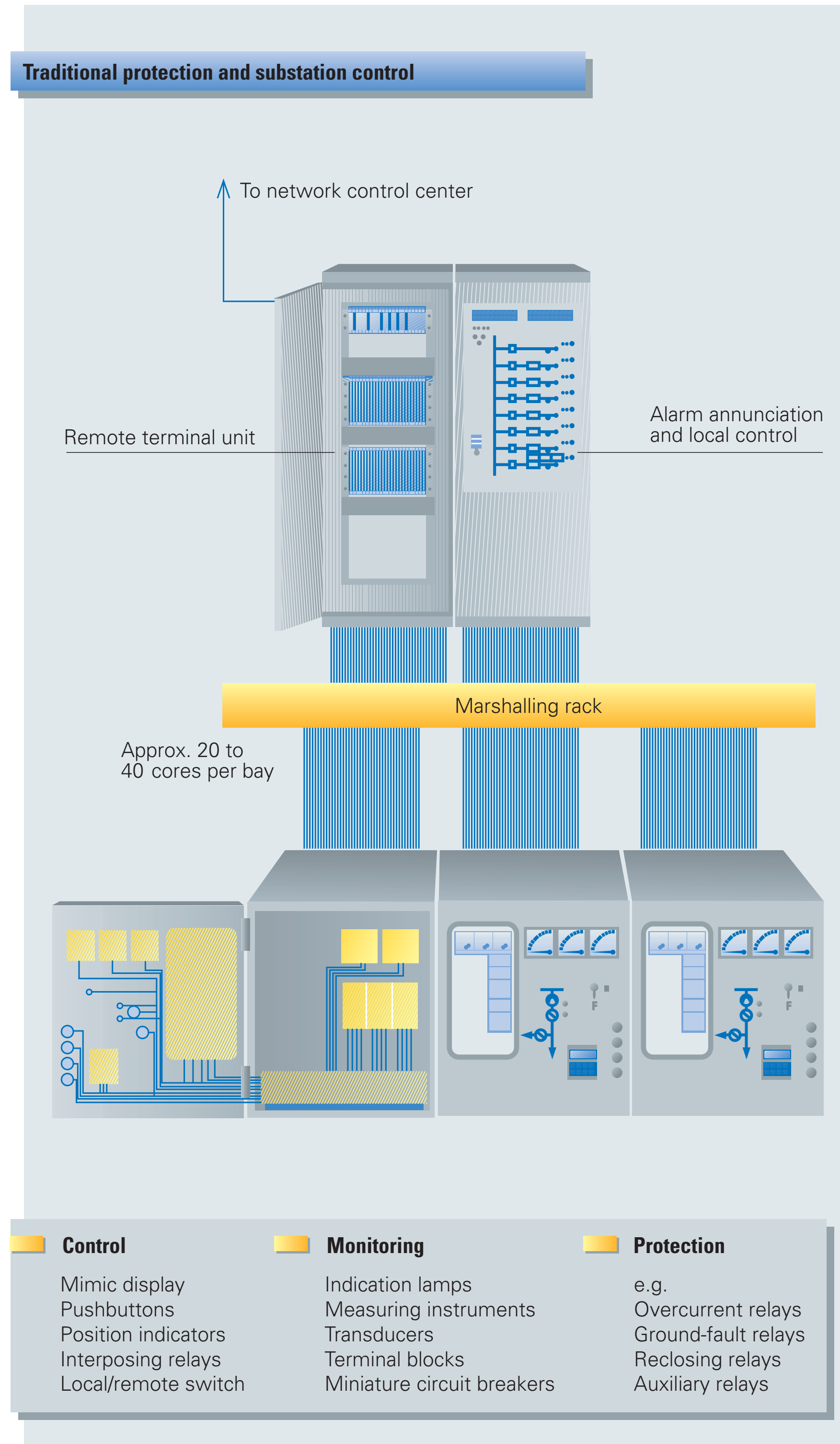


Fig. 132: Central structure of traditional protection and control

Local and Remote Control Introduction

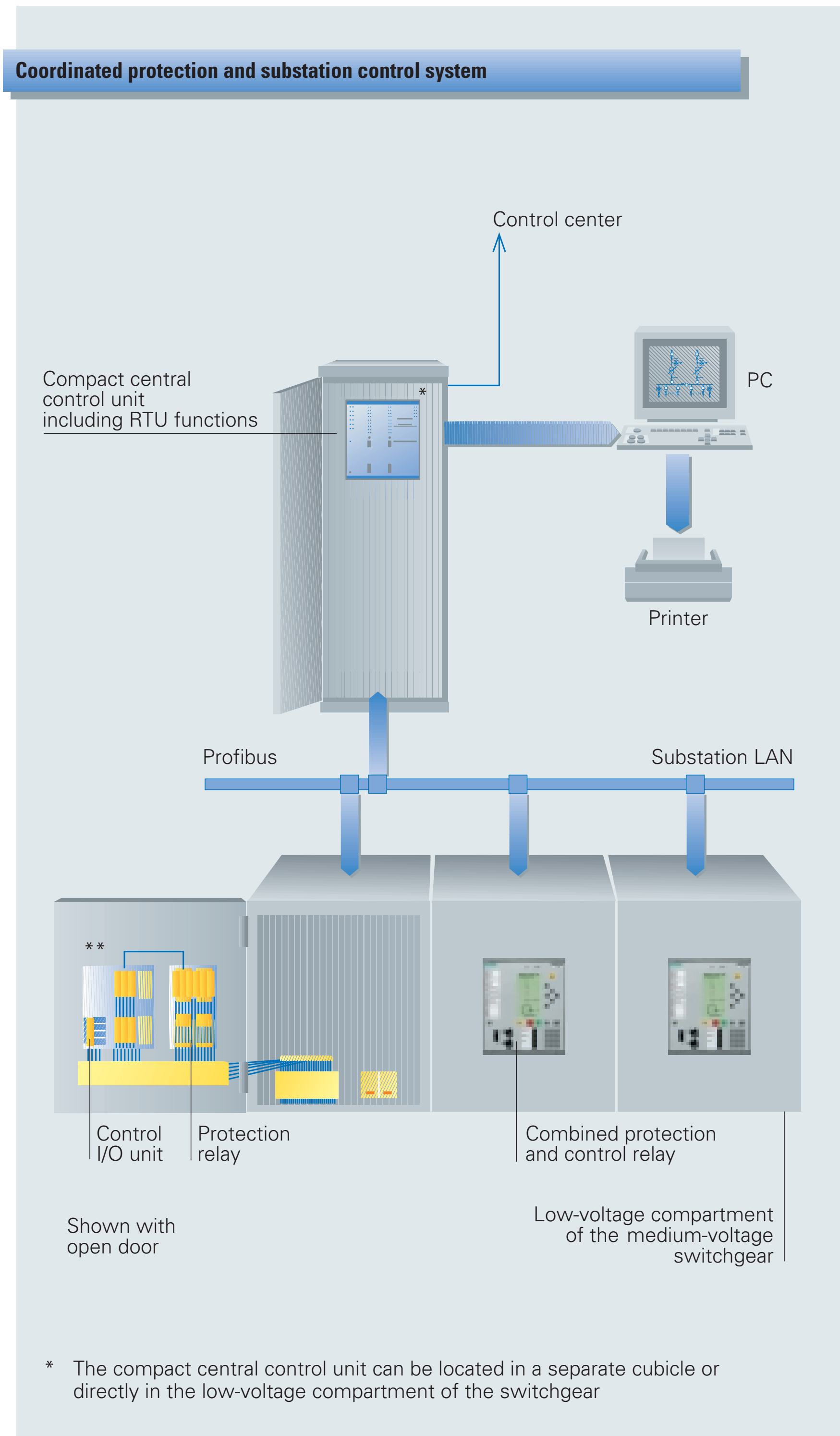


Fig. 133: Decentralized structure of modern protection and control

Local and Remote Control Introduction

Substation control and protection system

For numerical substation control and protection system applications, two different systems are available:

- SINAUT LSA
- SICAM

By virtue of their different functions and specific advantages, the two systems cover different applications. This means that it is possible to configure an optimum system for every application.

SINAUT LSA is typically used primarily for medium-voltage and high-voltage applications in power supply utilities.

The principal use for SICAM products is currently in medium-voltage applications for power suppliers and industry.

Other features in which they differ are summarized in Fig. 134.

SINAUT LSA substation control system

Since 1986, SINAUT LSA systems have proved themselves in practice in over 1500 substations. The SINAUT LSA substation automation system was the first digital system to have integrated all the following functions in a single equipment family:

- Telecontrol
- Local Control
- Monitoring
- Automation and
- Protection

SINAUT LSA has significantly extended the scope of performance and functionality of conventional secondary equipment. It is design and operation-friendly to a very considerable extent.

SINAUT LSA is a system matched to requirements – from the hardware to the PC tools – and is tailored in optimum form to the function of numerical substation control and protection systems.

Fig. 134 shows the principal application aspects of the SINAUT LSA substation control and protection system in comparison with the SICAM systems.

SICAM Substation Automation System

Units of the SICAM family have been in service since 1996. The SICAM system is based on SIMATIC*) and PC standard modules. SICAM possesses an open communication system with standardized interfaces. Thus, SICAM is a flexible system capable of uncomplicated further development.

*)Siemens PLCs and Industrial Automation Systems.
For detailed information see: Catalog ST 70,
Siemens Components for Totally Integrated Automation.

The SICAM family offers of the following options:

- SICAM SAS, the substation automation system with the following features:
  - Principal function: substation automation
  - Decentralized and centralized process connection
  - Local control and monitoring with archive function
  - Communication with the System Control Center
- SICAM RTU, the telecontrol system with central process connection and the following features:
  - Principal function: information communication
  - Central process connection
  - PLC functions
  - Communication with Control Center
- SICAM PCC, the PC-based Substation Control System with the following features:
  - Principal function: local substation supervision and control
  - Decentralized process connection
  - LAN/WAN communication with IEC 60870-6 TASE.2
  - Flexible communication
  - Linkage to Office® products.

Principal application aspects of SINAUT LSA and SICAM

	SINAUT LSA Central and decentral connection	SICAM SAS	RTU	PCC
Telecontrol data concentrator (connection of telecontrol remote stations)	+++			++
Telecontrol communication via WAN with TCP/IP		+	+	+++
Telecontrol communication using standard protocols IEC 870-5-101, DNP3.0, SINAUT 8FW	+++	+++	+++	
Supplementing of project-specific telecontrol protocols	+	++	++	+++
Supply of existing telecontrol protocols	+++	+	+	+
IED link using IEC 870-5-103	+++	+++		++
IED link using DNP3.0		+++		+++
Expansion of existing SINAUT LSA substations	+++	++(1)	++(1)	
Expansion of existing SICAM substations		+++	+++	+++
Incorporation in SIMATIC automation solutions	+	+++	+++	+
Linkage of PROFIBUS DP-IEDs		+++	++	++
Addition of project-specific IED protocols		+	+	+++
Uncomplicated, low-cost design	+	++	+++	+++

(1) Linkage as telecontrol remote station
IED – Intelligent Electronic Device

+++ Ideally suitable
++ Very suitable
+ Suitable

Fig. 134: Table shows the principal application aspects of the SICAM and SINAUT LSA system families.

6

Local and Remote Control
SINAUT LSA – Overview

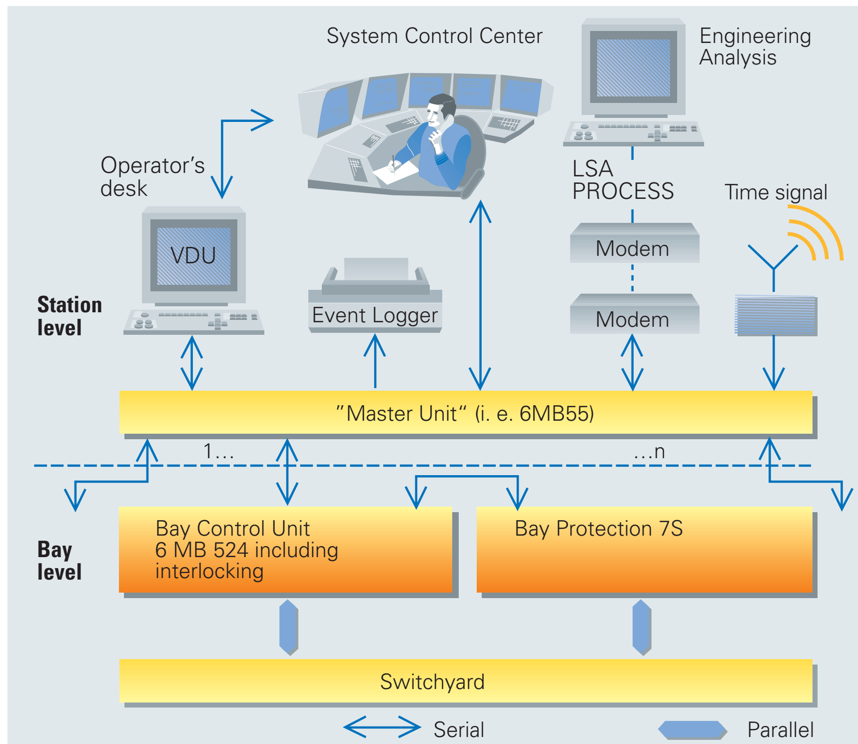


Fig. 135: Distributed structure of coordinated protection and control system SINAUT LSA

Technical proceedings

The first coordinated protection and substation control system SINAUT LSA was commissioned in 1986 and continuously further developed over subsequent years. It now features the following main characteristics:

- Coordinated system structure
- Optical communication network (star configuration)
- High processing power (32-bit µP technology)
- Standardized serial interfaces and communication protocols
- Uniform design of all components
- Complete range of protection and control functions
- Comprehensive user-software support packages.

Currently (1999) over 1500 systems are in successful operation on all voltage levels up to 400 kV.

System structure and scope of functions

The SINAUT LSA system performs supervisory local control, switchgear interlocking, bay and station protection, synchronizing, transformer tap-changer control, switching sequence programs, event and fault recording, telecontrol, etc.
It consists of the independent subsystems (Fig. 135):

- Supervisory control 6MB5**
- Protection 7S***

Normally, switchgear interlocking is integrated as a software program in the supervisory control system. Local bay control is implemented in the bay-dedicated I/O control units 6MB524.
For complex substations with multiple busbars, however, the interlocking function can also be provided as an independent backup system (System 8TK).

Communication and data exchange between components is performed via serial data links. Optical-fiber connections are preferred to ensure EMI compatibility.
The communication structure of the control system is designed as a hierarchical star configuration. It operates in the polling procedure with a fixed assignment of the master function to the central unit. The data transmission mode is asynchronous, half-duplex, protected with a hamming distance d = 4, and complies with the IEC Standard 60870-5.
Each subsystem can operate fully in stand-alone mode even in the event of loss of communication.

Data sharing between protection and control via the so-called informative interface according to IEC 60870-5-103 is restricted to noncritical measuring or event recording functions. The protection units, for example, deliver r.m.s. values of currents, voltages, power, instantaneous values for oscillographic fault recording and time-tagged operating events for fault reporting.
Besides the high data transmission security, the system also provides self-monitoring of individual components.
The distributed structure also makes the SINAUT LSA system attractive for refurbishment programs or extensions, where conventional secondary equipment has to be integrated.
It is general practice to provide protection of HV and EHV substations as separate, self-contained relays that can communicate with the control system, but function otherwise completely independently.
At lower voltage levels, however, higher integrated solutions are accepted for cost reasons.
For distribution-type substations combined protection and control feeder units (e.g. 7SJ63) are available which integrate all necessary functions of one feeder, including: local feeder control, overcurrent and overload protection, breaker-failure protection and metering.

Supervisory control

The substation is monitored and controlled from the operator's desk (Fig. 136). The VDU shows overview diagrams and complete details of the switchgear including measurands on a color display. All event and alarm annunciations are selectable in the form of lists. The control procedure is menu-guided and uses mouse and keyboard. The operation is therefore extremely user-friendly.

Automatic functions

Apart from the switchgear interlocking provided, a series of automatic functions ensure effective and secure system operation. Automatic switching sequences, such as changing of busbars, can be user-programmed and started locally or remotely. Furthermore, the synchronizing function has been integrated into the system software and is available as an option.

Local and Remote Control
SINAUT LSA – Overview

The synchronizing function runs on the relevant 6MB524 bay control units. The performance of these functions corresponds to modern digital stand-alone units. The advantages of the integrated solution, however, are:

- External auxiliary relay circuits for the selection of measurands are no longer applicable.
- Adaptive parameter setting becomes possible from local or remote control levels.

High processing power

The processing power of the central control unit has been enormously increased by the introduction of the 32-bit μP technology. This permits, on the one hand, a more compact design and provides, on the other hand, sufficient processing reserve for the future introduction of additional functions.

Static memories

A decisive step in the direction of user friendliness has been made with the implementation of large nonvolatile Flash EPROM memories. The system parameters can be loaded via a serial port at the front panel of the central unit. Bay level parameters are automatically downloaded.

Analog value processing

The further processing of raw measured data, such as the calculation of maximum, minimum or effective values, with assigned real time, is contained as standard function.
A Flash EPROM mass storage can optionally be provided to record measured values, fault events or fault oscillograms.The stored information can be read out locally or remotely by a telephone modem connection. Further data evaluation (harmonic analysis, etc.) is then possible by means of a special PC program (LSA PROCESS).

Compact design

A real reduction in space and cost has been achieved by the creation of compact I/O and central units. The processing hardware is enclosed in metallic cases with EMI-proof terminals and optical serial interfaces. All units are type tested according to the latest IEC standards.
In this way, the complete control and protection equipment can be directly integrated into the MV or HV switchgear (Fig. 137, 138).

Fig. 136: Digital substation control, operator desk. Control of a 400 kV substation (double control unit)

Fig. 137: Switchgear-integrated control and protection

Fig. 138: View of a low-voltage compartment

Switchgear interlocking and local control

With the introduction of the bay control unit 6MB524, the switchgear interlocking and the local control function have been integrated completely into the SINAUT LSA station control system. That means that there is no technical need for an additional switchgear interlocking like the 8TK system, because the SINAUT LSA system has the same reliability according to the testing of interlocking conditions. However, the 8TK system is still available for the case that an interlocking system with seperate hardware and software is required.

The interlocking function ensures fail-safe switching and personal safety down to the lowest control level, i.e. directly at the switchpanel, even when supervisory control is not available.
The bay control unit 6MB524 uses codewords to protect the switchgear from unauthorized operation. With these codewords, the authorization for local switching and unlocked local switching can be reached. The bay-to-bay interlocking conditions are checked in the SINAUT LSA central unit. Each 6MB524 bay control unit has an optical fiber link to this central unit.

Local and Remote Control
SINAUT LSA – Overview

Numerical protection

A complete range of fully digital (numerical) relays is available (see chapter Power System Protection **6**/8 and following pages).
They all have a uniform design compatible with the control units (Fig. 139). This applies to the hardware as well as to the software structure and the operating procedures. Metallic standard cases, IEC 60255-tested, with EMI-secure terminals, ensure an uncomplicated application comparable to mechanical relays. The LCD display and setting keypad are integrated. Additionally a RS232 port is provided on the front panel for the connection of a PC as an HMI.
The rear terminal block contains an optical-fiber interface for the data communication with the SINAUT LSA control system.
The relays are normally linked directly to the relevant I/O control unit at the bay level. Connection to the central control system unit is, however, also possible.
The numerical relays are multifunctional and contain, for example, all the necessary protection functions for a line feeder or transformer. At higher voltage levels, additional, main or back-up relays are applied.
The new relay generation has extended memory capacity for fault recording (5 seconds, 1 ms resolution) and nonvolatile memory for important fault information.

The serial link between protection and control uses standard protocols in accordance with IEC 60870-5-103.
In this way, supplier compatibility and interchangeability of protection devices is achieved.

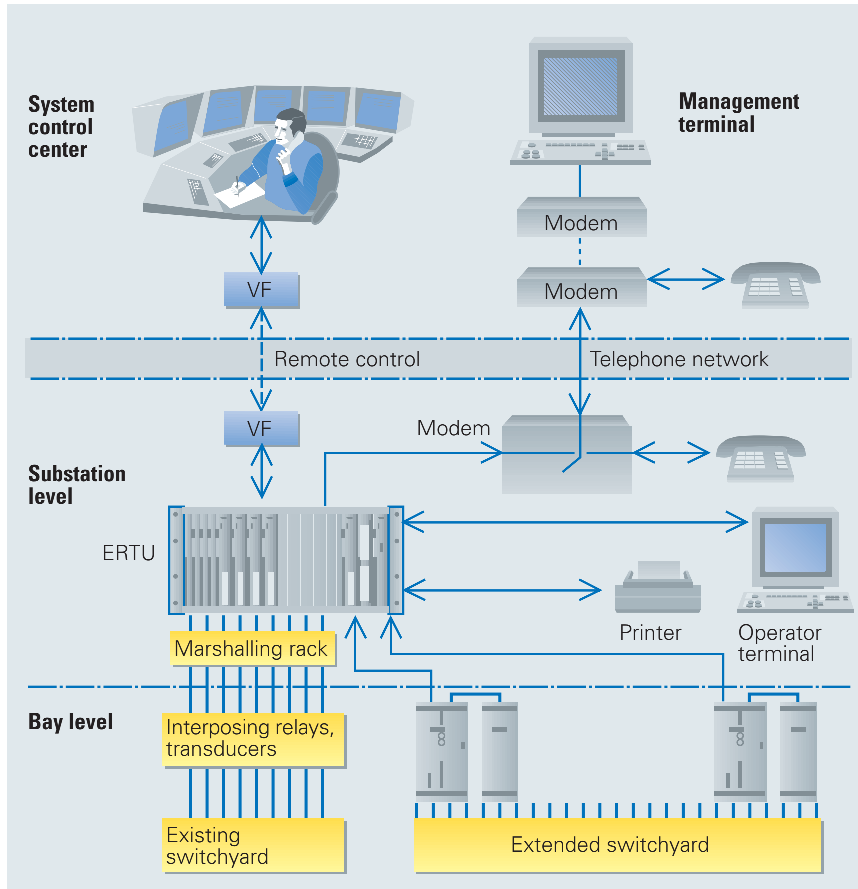


Fig. 140: Enhanced remote terminal unit 6MB55, application options

Fig. 139: Numerical protection, standard design

Enhanced remote terminal units

For substations with existing remote terminal units, an enhancement towards the decentralized SINAUT LSA performance level is feasible.
The telecontrol system 6MB55 replaces outdated remote terminal units (Fig. 140).
Conventional RTUs are connected to the switchgear via interposing relays and measuring transducers with a marshalling rack as a common interface.
The centralized version SINAUT LSA can be directly connected to this interface. The totally parallel wiring can be left in its original state.
In this manner, it is possible to enhance the RTU function and to include substation monitoring and control with the same performance level as the decentralized SINAUT LSA system.
Upgrading of existing substations can thus be achieved with a minimum of cost and effort.

Communication with control centres

The SINAUT LSA system uses protocols that comply with IEC Standard 60870-5. In many cases an adaption to existing proprietary protocols is necessary, when the system control center has been supplied by another manufacturer.
For this purpose, an extensive protocol library has been developed (approx. 100 protocol variants). Further protocols can be provided on demand.

Local and Remote Control
SINAUT LSA – Overview

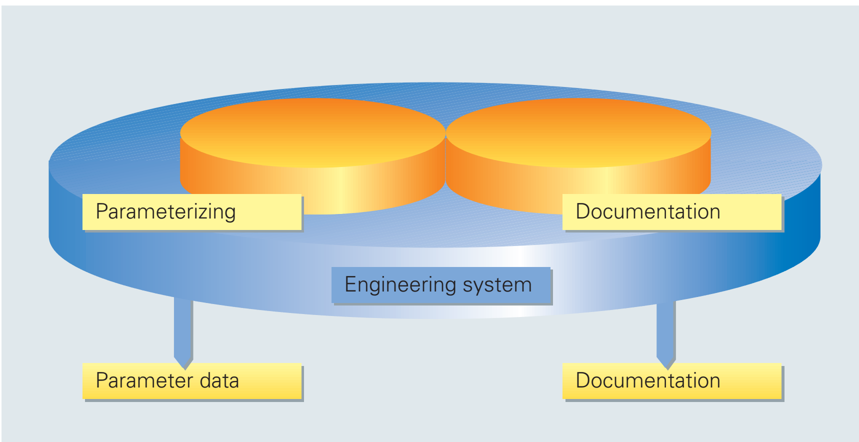


Fig. 141: Engineering system LSATOOLS

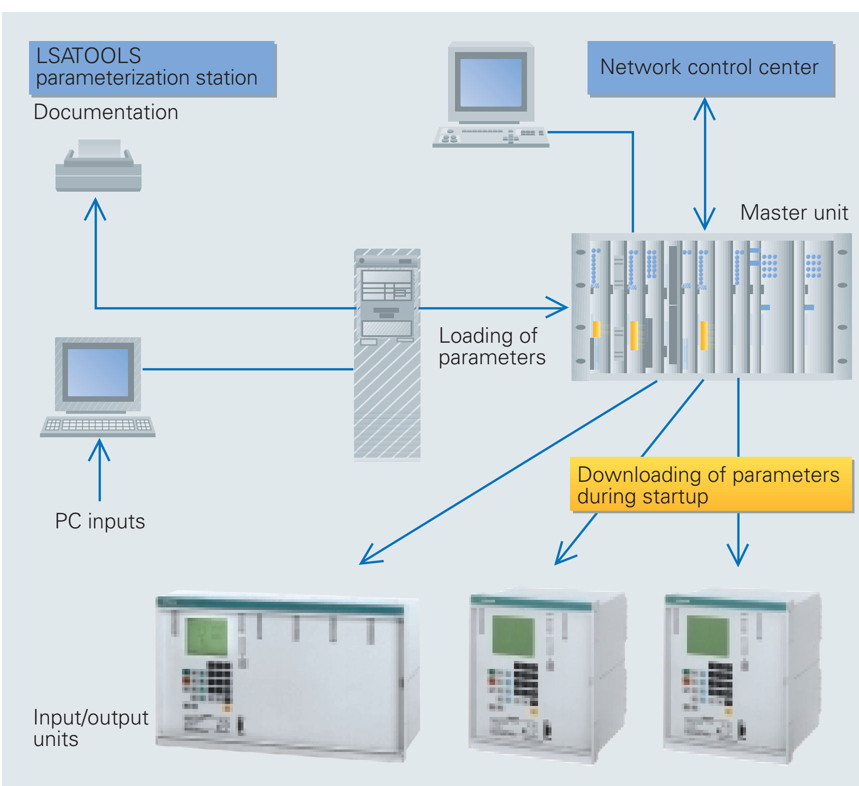


Fig. 142: PC-aided parameterization of SINAUT LSA with LSATOOLS and downloading of parameters

Engineering system LSATOOLS

In parallel with the upgrading of the central unit hardware, a novel parameterizing and documentation system LSATOOLS has been developed. It uses modern graphical presentation management methods, including pull-down menus and multiwindowing.
LSATOOLS enables the complete configuration, parameterization and documentation of the system to be carried out on a PC workstation. It ensures that a consistent database for the project is maintained from design to commissioning (Fig. 141).

The system parameters, generated by LSATOOLS, can be serially loaded into the Flash EPROM memory of the central control unit and will then be automatically downloaded to the bay level devices (Fig. 142).
Care has been taken to ensure that changes and expansions are possible without requiring a complete retest of the system. Because of the object-oriented structure of LSATOOLS, it is easily possible for the system engineer to add new bays with all necessary information.

Local and Remote Control
SINAUT LSA – Distributed Structure

In the SINAUT LSA substation control system the functions can be distributed between station and bay control levels.
The **input/output devices** have the following tasks on the bay control level:

- Signal acquisition
- Acquisition of measured values and metering data
- Monitoring the execution of control commands, e.g. for
  - Control of switchgear
  - Transformer tap changing
  - Setting of Peterson coils

  Data processing, such as
  - Limit monitoring of measured values, including initiation of responses to limit violations
  - Calculation of derived operational measured values (e.g. P, Q, cos φ) and/or operational parameters (for example r.m.s. values, slave pointer) from the logged instantaneous values for current and voltage
  - Deciding how much information to transmit to the control master unit in each polling cycle
  - Generation of group signals and deriving of signals internally, e.g. from self-monitoring
- Switchgear-related automation tasks
  - Switching sequences in response to switching commands or to process events
  - Synchronization
- Local control and operation (only bay control unit 6MB524):
  - Display of actual bay status (single line diagram)
  - Local control of circuit-breaker and disconnectors
  - Display of measurement values and event recording
- Transmission of data from numerical protection relays to the control master unit
- Local display of status and measured values.

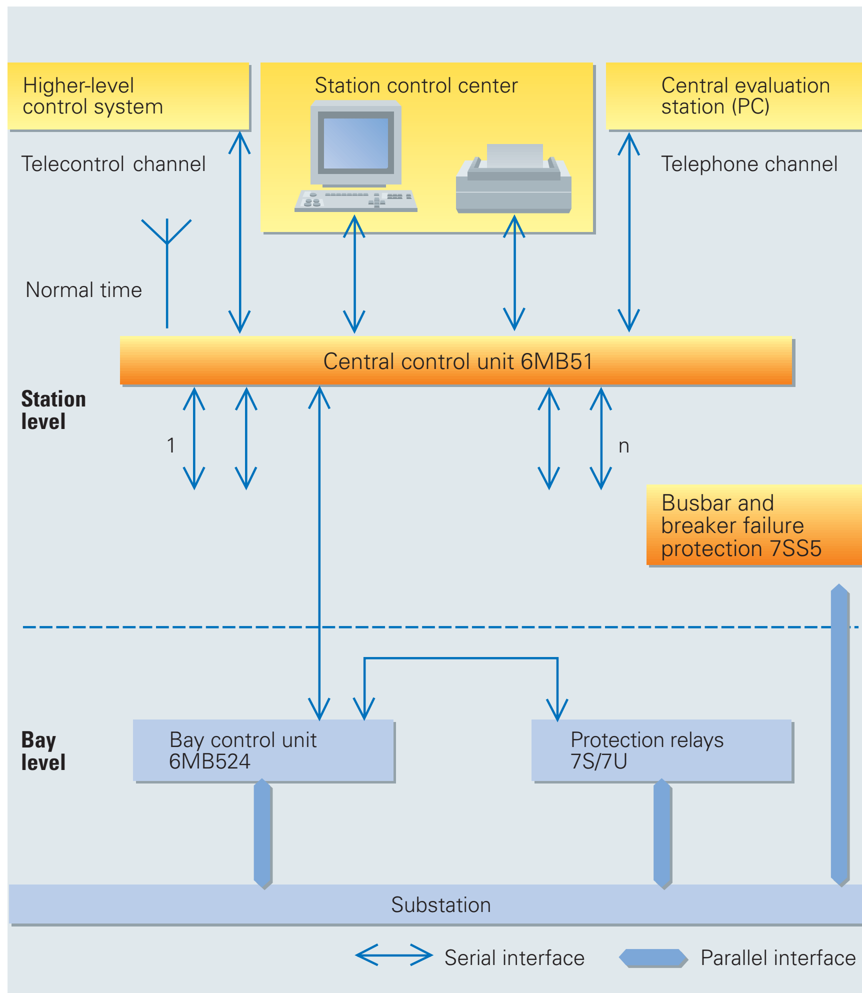


Fig. 143: SINAUT LSA protection and substation control system system

Input/output devices

A complete range of devices is available to meet the particular demands concerning process signal capacity and functionality (see Fig. 149). All units are built up in modern 7XP20 housings and can be directly installed in the low-voltage compartments of the switchgear or in separate cubicles.
The smallest device 6MB525 is designed as a low-cost version and contains only control functions. It is provided with an RS485-wired serial interface and is normally used for simple distribution-type substations together with overcurrent/overload relays 7SJ60 and digital measuring transducers 7KG60. (see application example, Fig. 165).
All further bay control devices contain an optic serial interface for connection to the central control unit, and an RS232 serial interface on the front side for connection of an operating PC. Further, integral displays for measuring values and LEDs for status indication are provided.

Minicompact device 6MB525

It contains signal inputs and command outputs for substation control. Analog measuring inputs, where needed, have to be provided by additional measuring transducers, type 7KG60. Alternatively, the measuring functions of the numerical protection relays can be used. These can also provide local indication of measuring values.
The local bay control is intended to be performed by the existing, switchgear-integrated mechanical control.

Compact devices 6MB522/523

They provide a higher number of signal inputs and outputs, and contain additional measuring functions. One measuring value or other preprocessed information can be displayed on the 2-row, 16-character alphanumeric display.
If local control is required, the bay control unit 6MB524 is the right choice.

Local and Remote Control
SINAUT LSA – Distributed Structure

Bay control unit 6MB524

This bay control device can be delivered in five versions, depending on the peripheral requirements.
It provides all control and measuring functions needed for switchgear bays up to the EHV level.
Switching status, measuring values and alarms are indicated on a large graphic display. Measuring instruments can therefore be widely dispensed with.
Bay control is, in this case, performed by the integrated keypad. The synchronizing function is included in the software.

Combined protection
and control device 7SJ531

This fully integrated device provides all protection, control and measuring functions for simple line/cable, motor or transformer feeders. Protection includes overcurrent, overload and ground-fault protection, as well as breaker-failure protection, autoreclosure and motor supervision functions (see page **6**/27).
Only one unit is needed per feeder. Space, assembly and wiring costs can therefore be considerably reduced.
Measured value display and local bay control is performed in the same way as with the bay control unit 6MB524 with a large display and a keypad.

Combined protection and control devices 7SJ61, 7SJ62, 7SJ63 and bay control unit 6MD63 (SIPROTEC 4 series)

These new SIPROTEC 4 devices have been available since December 1998. With a large graphical display and ergonomically designed keypad, they offer new possibilities for bay control and protection. Via the IEC 60870-5-103 interface, connection to the substation control system SINAUT LSA is handled. The protection devices include overcurrent, over/undervoltage and motor protection functions (see page **6**/27).
The smaller 7SJ61 and 7SJ62 devices are delivered with an alphanumerical display with 4 lines of text for displaying of measurement values, alarms, metering values and status of switching devices.
The 7SJ63 and 6MD63 units include a large illuminated graphic display for a clearly visible single-line diagram of the switchgear, alarm lists, measured and metered values as well as status messages. With the integrated key switches, the user authorization is regulated.
For complete description of the new SIPROTEC 4 devices, refer to the protection chapter (page **6**/8).

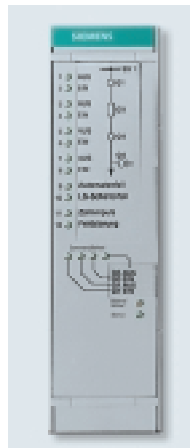


Fig. 144: Minicompact I/O device 6MB525

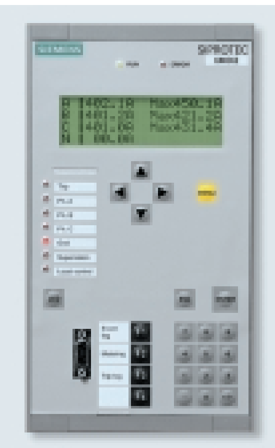


Fig. 145: Compact I/O device 6MD62

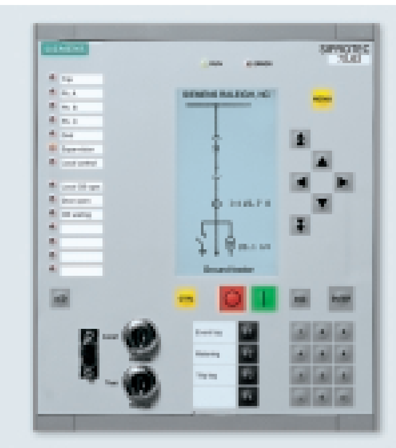


Fig. 146: Combined protection and control device 7SJ63

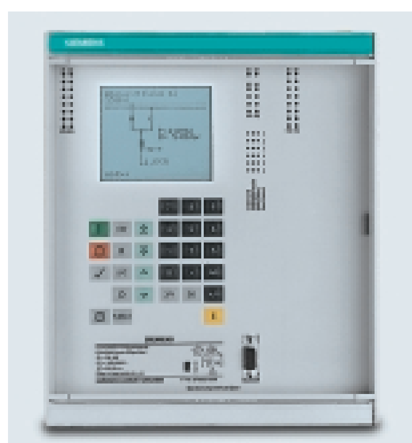


Fig. 147: Compact I/O unit with local (bay) control 6MB5240-0

Fig. 148: Combined protection and control device 7SJ531

Local and Remote Control
SINAUT LSA – Distributed Structure

Design	Type	Commands		Signal inputs		Analog inputs		Components
		Double	Single	Double	Single	Direct connection to transformer	Connection to measure transducer	
Minicompact[1]	6MB525	2	–	6	–	–	–	Double commands and alarms configurable also as "single"
Compact[1]	6MB523	1	–	3	5	1 x I	–	For simple switchgear cubicles with one switching device
	6MB522-0	3	1	3	5	2 x U, 1 x I	2	
	6MB522-1	6	2	6	10	3 x U, 3 x I	–	
	6MB522-2	6	2	6	10	4 x U, 2 x I	2	with P, Q calculation
Compact with local (bay) control and large display	6MB5240-0	4	1	8	–	2 x U, 1 x I	1	High-end bay control for HV and EHV Double commands and alarms also usable as "single"
	-1	6	1	12	–	3 x U, 3 x I	2	
	-2	8	2	16	–	3 x U, 3 x I	2	
	-3	20	5	40	–	9 x U, 6 x I	5	
	-4	12	3	24	–	6 x U, 3 x I	2	
Combined control and protection device with local (bay) control	7SJ531	1	–	–	–	3 x U, 3 x I		Double commands and alarms also usable as "single"
Compact with local bay control (SIPROTEC 4 design with large graphic display)[2]	6MD631	4	–	5	1	4 x I, 3 x U	–	Bay control units in new design, optimized for medium-voltage switchgear with $1^1/_2$-pole control (max. 7 switching devices). 2-pole control also possible (max. 4 switching devices). Double commands and alarms also usable as "single"
	6MD632	5 + 4[3]	1	12	–	4 x I, 3 x U	–	
	6MD633	5 + 4[3]	1	10	–	4 x I, 3 x U	2	
	6MD634	3 + 4[3]	–	10	–	–	–	
	6MD635	7 + 8[3]	–	18	1	4 x I, 3 x U	–	
	6MD636	7 + 8[3]	–	16	1	4 x I, 3 x U	2	
	6MD637	4 + 8[3]	1	16	1	–	–	
Combined control and protection device with local bay control (SIPROTEC 4 design with large graphic display)[2]	7SJ610	–	4	–	3	4 x I	–	Combined control and protection devices. 7SJ61 and 7SJ62 with 4 line text display, 7SJ63 with graphic display. Optimized for $1^1/_2$-pole control (max. 7 switching devices). 2-pole switching is also possible (max. 4 switching devices). Double commands and alarms also usable as "single"
	7SJ612	–	6	–	11	4 x I	–	
	7SJ621	–	8	–	7	4 x I, 3 x U	–	
	7SJ622	–	7	–	11	4 x I, 3 x U	–	
	7SJ631	4	–	5	1	4 x I, 3 x U	–	
	7SJ632	5 + 4[3]	1	12	–	4 x I, 3 x U	–	
	7SJ633	5 + 4[3]	1	10	–	4 x I, 3 x U	2	
	7SJ635	7 + 8[3]	–	18	1	4 x I, 3 x U	–	
	7SJ636	7 + 8[3]	–	16	1	4 x I, 3 x U	2	

[1] Local (bay) control has to be provided separately if desired. In distribution-type substations, mechanical local control of the switchgear may be sufficient.
[2] Control of switching devices: $1^1/_2$ -pole; 2-pole control possible
[3] Second figure is number of heavy duty relays

Fig. 149: Standardized input/output devices with serial interfaces

Local and Remote Control
SINAUT LSA – Distributed Structure

The 6MB51 control master unit

This unit lies at the heart of the 6MB substation control system and, with its 32-bit 80486 processor, satisfies the most demanding requirements.
It is a compact unit inside the standard housing used in Siemens substation secondary equipment.
The 6MB51 control master unit manages the input/output devices, controls the interaction between the control centers in the substation and the higher control levels, processes information for the entire station and archives data in accordance with the parameterized requirements of the user.
Specifically, the control master unit coordinates communication

- to the higher network control levels
- to the substation control center
- to an analysis center located either in the station or connected remotely via a telephone line using a modem
- to the input/output devices and/or the numerical protection units (bay control units)
- to lower-level stations.

This is for the purpose of controlling and monitoring activities at the substation and network control levels as well as providing data for use by engineers.

Other tasks of the control master unit are

- Event logging with a time resolution of 1 or 10 ms
- Archiving of events, variations in measured values and fault records on mass-storage units
- Time synchronization using radio clock (GPS, DCF77 or Rugby) or using a signal from a higher-level control station
- Automation tasks affecting more than one bay:
  - Parallel control of transformers
  - Synchronizing (measured value selection)
  - Switching sequences
  - Busbar voltage simulation
  - Switchgear interlocking
- Parameter management to meet the relevant requirements specification
- Self-monitoring and system monitoring.

System monitoring primarily involves evaluating the self-monitoring results of the devices and serial interfaces which are coordinated by the control master unit.
In particular, in important EHV substations, some users require redundancy of the control master unit. In these cases, two control master units are connected to each other via a serial interface. System monitoring then consists of mutual error recognition and, if necessary, automatic transfer of control of the process to the redundant control master unit.

The SINAUT LSA station control center

The standard equipment of the station control center includes

- The PC with color monitor and LSAVIEW software package for displaying
  - Station overview
  - Detailed pictures
  - Event and alarm lists
  - Alarm information
- A printer for the output reports

The operator can access the required information or initiate the desired operation quickly and safely with just a few keystrokes.

Fig. 150: Compact control master unit 6MB513 for a maximum of 32 serial interfaces to bay control units. Extended version 6MB514 for 64 serial interfaces to bay control units (double width) additionally available

Fig. 151: SINAUT LSA PC station control center with function keyboard

Local and Remote Control
SINAUT LSA – Local Control Functions

Local control functions

Tasks of local control

The Siemens SINAUT LSA station control system performs at first all tasks for conventional local control:

- Local control of and checkback indications from the switching devices
- Acquisition, display and registration of analog values
- Acquisition, display and registration of alarms and fault indications in real time
- Measurement data acquisition and processing
- Fault recording
- Transformer open-loop and closed-loop control
- Synchronizing/paralleling

Unlike the previous conventional technology with completely centralized processing of these tasks and complicated parallel wiring and marshalling of process data, the new microprocessor-controlled technology benefits from the distribution of tasks to the central control master unit and the distributed input/output units, and from the serial data exchange in telegrams between these units.

Tasks of the input/output unit

The input/output unit performs the following bay-related tasks:

- Fast distributed acquisition of process data such as indications, analog values and switching device positions and their preprocessing and buffering
- Command output and monitoring
- Assignment of the time for each event (time tag)
- Isolation from the switchyard via heavy-duty relay contacts
- Run-time monitoring
- Limit value supervision
- Paralleling/synchronizing
- Local control and monitoring

Analog values can be input to the bay control unit both via analog value transducers and by direct connection to CTs and VTs. The required r.m.s. values for current and voltage are digitized and calculated as well as active and reactive power. The advantage is that separate measuring cores and analog value transducers for operational measurement are eliminated.

Control master unit

The process data acquired in the input/output unit are scanned cyclically by the control master unit. The control master unit performs further information processing of all data called from the feeders for station tasks "local control and telecontrol" with the associated event logging and fault recording and therefore replaces the complicated conventional marshalling distributor racks. Marshalling is implemented under microprocessor control in the control master unit.

Serial protection interface

All protection indications and fault recording data acquired for fault analysis in protection relays are called by the control master unit via the serial interface.
These include instantaneous values for fault current and voltage of all phases and ground, sampled with a resolution of 1 ms, as well as distance-to-fault location.

Serial data exchange

The serial data exchange between the bay components and the control master unit has important economic advantages. This is especially true when one considers the preparation and forwarding of the information via serial data link to the control center communication module which is a component of the control master unit. This module is a single, system-compatible microprocessor module on which both the telecontrol tasks and telegram adaptation to telegram structures of existing remote transmission systems are implemented. This makes the station control independent of the telecontrol technology and the associated telegram structure used in the network control center at a higher level of the hierarchy.

Station control center

The peripheral devices for operating and visualization (station control center) are also connected to the control master unit. The following devices are part of the station control center:

- A color VDU with a function keyboard or mouse for display, control, event and alarm indication,
- A printer for on-line logging (event list),
- Mass storage.

Switchyard overview diagram

A switchyard single-line diagram can be configured to show an overview of the substation. This diagram is used to give the operator a quick overview of the entire switchyard status and shows, for example, which feeders are connected or disconnected. Current and other analog values can also be displayed.
Information about raised or cleared operational and alarm indications is also displayed along the top edge of the screen.
It is not possible to perform control actions from the switchyard overview. If the operator wants to switch a device, he has to select a detailed diagram, say "110 kV detailed diagram". If the appropriate function key is pressed, the 110 kV detailed diagram (Fig. 153) appears. This display shows the switching state of all switching devices of the feeders.

Function field control

In the menu of the function fields, it is possible, for example, to select between control switching devices and tap changing. The control diagram shows details of station components and allows control and defining of display properties or functions (e.g. change in color/flashing). Furthermore, the popup diagram window can be opened from here, where switching operations with control elements are performed.

The configured switching operation works as follows:

- Selecting the switch: A click with the left mouse button on the switch symbol opens the popup window for command output
- Output of the command. On clicking the operate button in the popup window the command is output

The color of the switch symbol depends on the state. If the command is found to be safe after a check has been made for violations of interlock conditions, the switching device in question is operated. In the case where a mouse is available, the appropriate device is selected by the usual mouse operation.

Once the switching command has been executed and a checkback signal has been received, the blinking symbol changes to the new actual state on the VDU.
In this way, switching operations can be performed very simply and absolutely without error. If commands violate the interlock conditions or if the switch position is not adopted by a switching device, for example, because of a drive fault, the relevant fault indications or notes are displayed on the screen.

Local and Remote Control
SINAUT LSA – Local Control Functions

Event list

All events are logged in chronological order. The event list can be displayed on the VDU whenever called or printed out on a printer or stored on a mass-storage medium. Fig. 153 shows a section of this event list as it appears on the VDU.
The event list can also be incorporated in the detailed displays. The bay-related events can therefore also be shown in the detailed displays.

Example event list (Fig. 154)

The date can be seen in the left-hand area and the events are shown in order of priority. Switching commands and fault indications are displayed with a precision of up to 1 ms and events with high priority and protection indications after a fault-detection are shown with millisecond resolution.
A command that is accepted by the control system is also displayed. This can be seen by the index "+" of the command (OP), otherwise "OP–" would appear.
If the switchgear device itself does not execute the command, "FB–" (checkback negative) indicates this. "FB+" results after successful command execution. The texts chosen are suggestions and can be parameterized differently.
The event list shows that a protection fault-detection (general start GS) has occurred with all the associated details. The real time is shown in the left-hand column and the relative time with millisecond precision in the right-hand column, permitting clear and fast fault analysis. The fault location, 17 km in this case, is also displayed.
The lower section of the event list shows examples of raised (RAI) and cleared (CLE) alarm indications, such as "voltage transformer miniature-circuit-breaker tripped". This fault has been remedied as can be seen from the corresponding cleared indication. The letter S in the top line, called the indication bar, indicates that a fault indication has been received that is stored in a separate "warning list".

Example alarm list (Fig. 155)

When the alarm list is selected, it is displayed on the VDU. In this danger alarm concept a distinction is made between cleared and raised and between acknowledged and unacknowledged indications. Raised indications are shown in red, cleared indications are green (similar to the fast/slow blinking lamp principle).
The letter Q is placed in front of an indication that has not yet been acknowledged. Indications that are raised and cleared and acknowledged are displayed in white in the list.

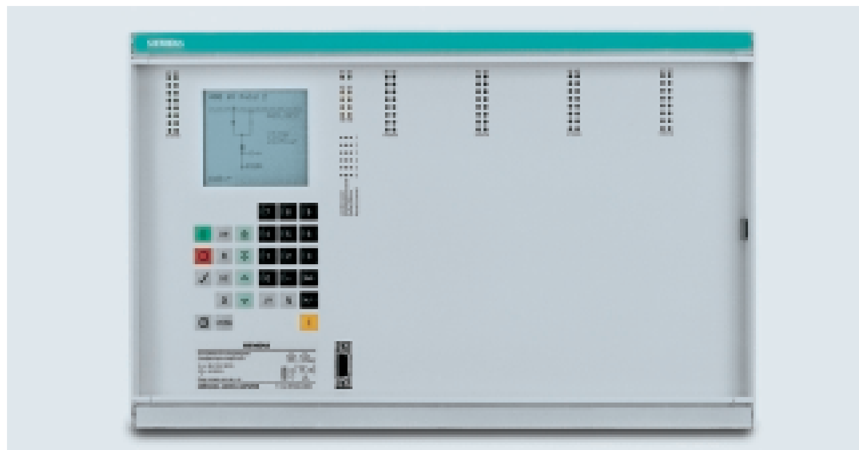


Fig. 152a: Compact I/O unit with local (bay) control, extended version 6MB5240-3

This system with representation in the alarm list therefore supersedes danger alarm equipment with two-frequency blinking lamps traditionally used with conventional equipment.
As stated above, all events can also be continuously logged in chronological order on the associated printer, too. The appearance of this event list is identical to that on the VDU. The alarm list can also be incorporated in the detailed displays. The bay-related alarms can therefore also be shown in the detailed displays.

Mass storage

It is also possible to store historic fault data, i.e. fault recording data and events on mass-storage medium.
It can accept data from the control master units and stores it on Flash EPROMs. This static memory is completely maintenance-free when compared to floppy or hard disc systems. 8Mbyte of recorded data can be stored. The locally or remotely readable memory permits evaluation of the data using a PC. This personal computer can be set up separately from the control equipment, e.g. in an office. Communication then takes place via a telephone-modem connection.
In addition to fault recording data, operational data, such as load-monitoring values (current, voltage, power, etc.) and events can be stored.

Local bay control (Fig.152a, Fig. 152b)

With the 6MB524 bay control units, local control and monitoring directly in the bay is possible. The large graphic display can show customer-specific single-line diagrams. A convenient menu-guided operation leads the user to the display of measurands, metering values, alarm lists and status messages. The keypad design with 6 colors supports the operator for quick and secure operation. User authorization is handled via password, for example unlocked switching.

The new SIPROTEC4 devices also allow local bay control. At the 7SJ63 and 6MD63 devices, a large graphic display and an ergonomic keypad assist the operator in control of the switching devices and read out messages, measurements and metering values. In the 7SJ61 and 7SJ62 protection units, the user interface consists of a 4-line text display. These smaller units also make it possible to control the feeder circuit-breaker.
All SIPROTEC4 devices are parameterized with the operating program DIGSI4.

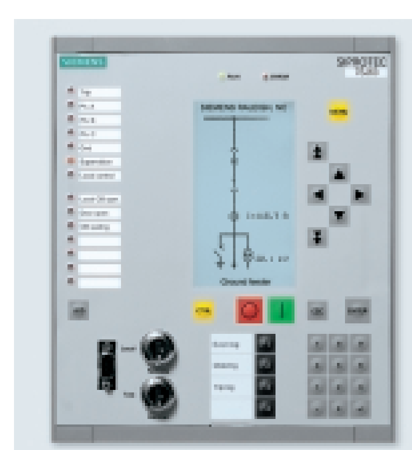


Fig. 152b: 6MD63 bay control unit

Local and Remote Control
SINAUT LSA – Local Control Functions

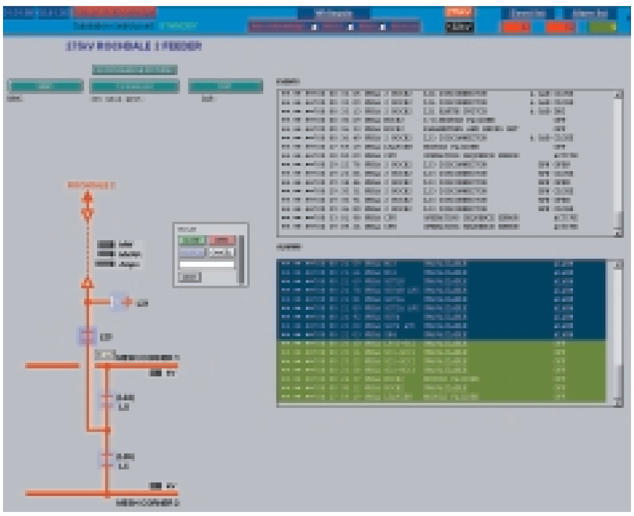


Fig. 153: SINAUT LSA substation control, example: overview picture

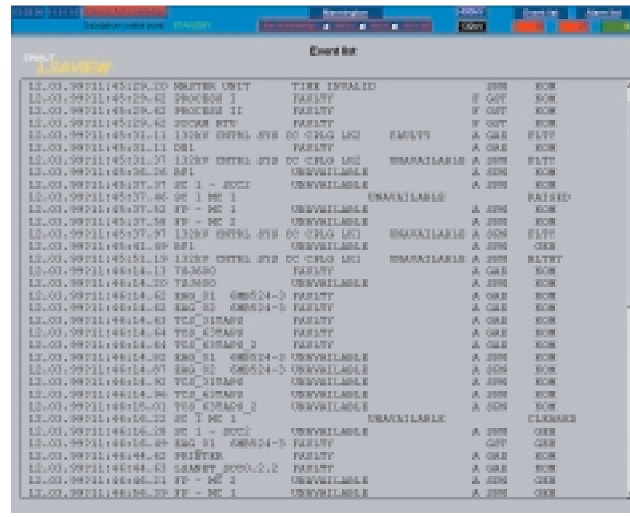


Fig. 154: SINAUT LSA substation control, example: event list

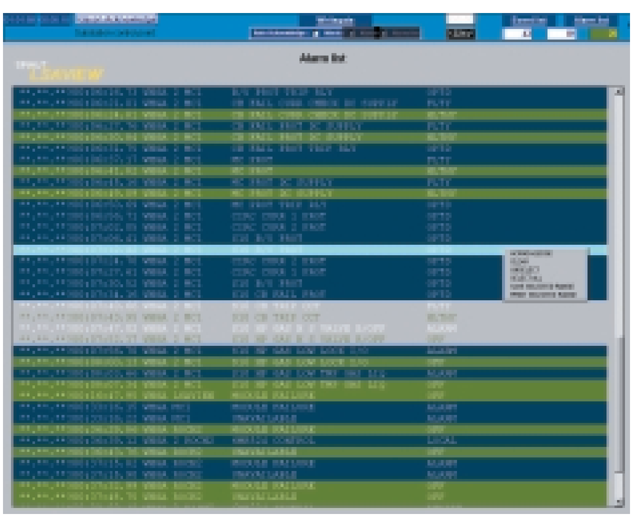


Fig. 155: SINAUT LSA substation control, example: alarm list

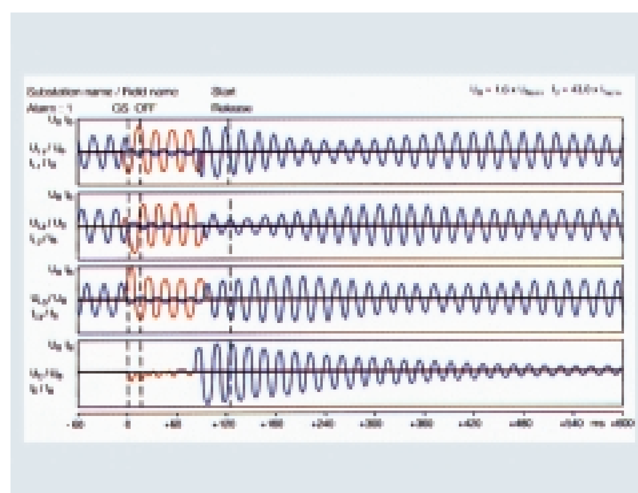


Fig. 156: 6MB substation control system, example: fault recording

6

Example fault recording (Fig. 156)

After a fault, the millisecond-precision values for the phase currents and voltages and the ground current and ground voltage are buffered in the feeder protection. These values are called from the numerical feeder protection by the control master unit and can be output as curves with the program LSAPROCESS (Fig. 156).
The time marking 0 indicates the time of fault detection, i.e. the relay general start (GS). Approx. 5 ms before the general start, a three-phase fault to ground occurred, which can be seen by the rise in phase currents and the ground current.

12 ms after the general start, the circuit breaker was tripped (OFF) and after further 80 ms, the fault was cleared.
After approx. 120 ms the protection reset. Voltage recovery after disconnection was recorded up to 600 ms after the general start.

This format permits quick and clear analysis of a fault. The correct operation of the protection and the circuit breaker can be seen in the fault recording (Fig. 156).
The high-voltage feeder protection presently includes a time range of at least 5 seconds for the fault recording.

The important point is that this fault recording is possible in all feeders that are equipped with the microprocessor-controlled protection having a serial interface according to IEC 60870-5-103.

Local and Remote Control
SINAUT LSA – Application Examples

Application examples

The flexible use of the components of the Coordinated Protection and Substation Control System SINAUT LSA is demonstrated in the following for some typical application examples.

Application in high-voltage substations with relay kiosks

Fig. 157 shows the arrangement of the local components. Each two bays (line or transformer) are assigned to one kiosk. Each bay has at least one input/output unit for control (bay control unit) and one protection unit. In extra-high voltage, the protection is normally doubled (main and back-up protection).

Local control is performed at the bay units (6MB524) using the integrated graphic display and keypad.

Switchgear interlocking is included in the bay control units and in the central control unit.

The protection relays are serially connected to the bay control unit by optical-fiber links.

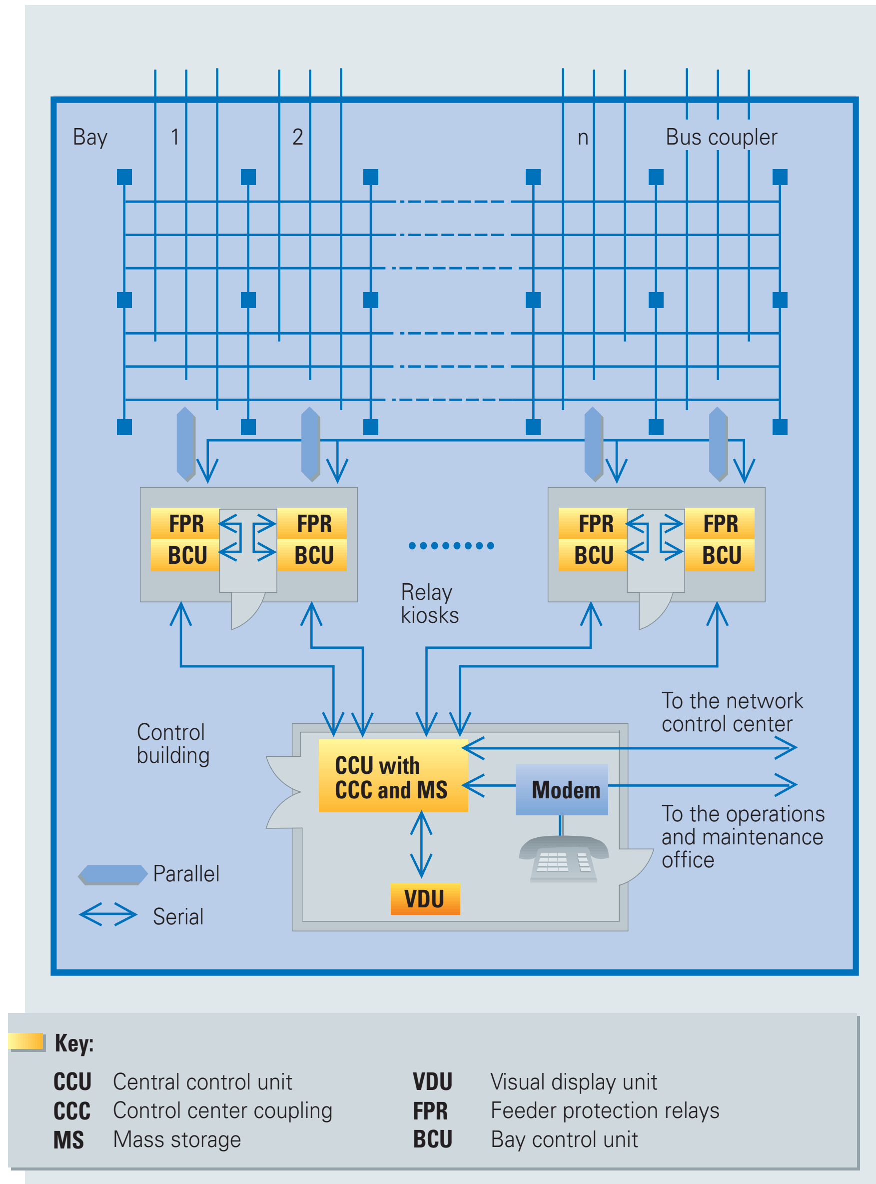


Fig. 157: Application example of outdoor HV or EHV substations with relay kiosks

Local and Remote Control
SINAUT LSA – Application Examples

In extremely important substations, mainly extra-high voltage, there exists a doubling philosophy. In these substations, the feeder protection, the DC supply, the operating coils and the telecontrol interface are doubled. In such cases, the station control system with its serial connections, and the master unit with the control center coupling can also be doubled.
Both master units are brought up-to-date in signal direction. The operation management can be switched over between the two master units (Fig. 158).

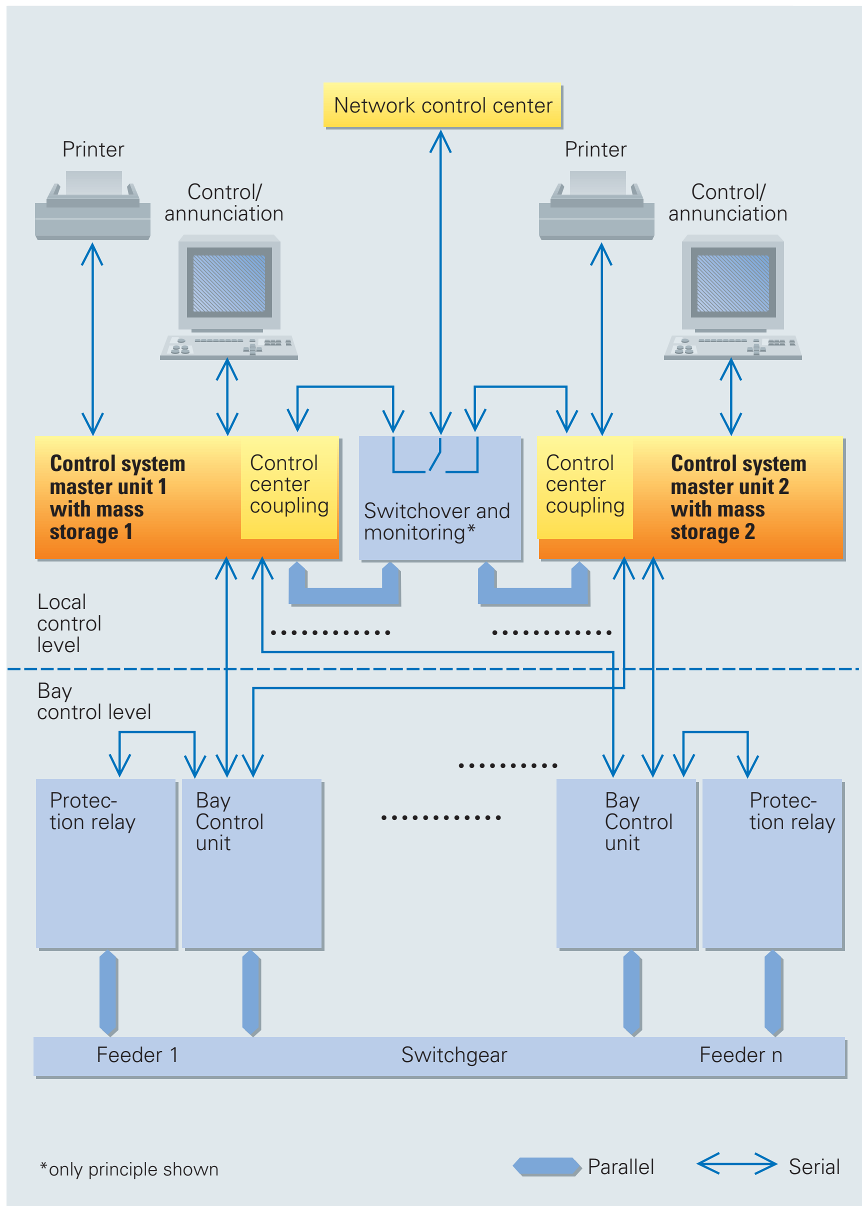


Fig. 158: System concept with double central control

Local and Remote Control
SINAUT LSA – Application Examples

Application in indoor high-voltage substations

The following example (Fig. 159) shows an indoor high-voltage substation. All decentralized control system components, such as bay control unit and feeder protection are also grouped per bay and installed close to the switchgear. They are connected to the central control unit in the same way as described in the outdoor version via fiber-optic cables.

Application in medium-voltage substations

The same basic arrangement is also applicable to medium-voltage (distribution-type) substations (Fig. 160 and 161).
The feeder protection and the compact input/output units are, however, preferably installed in the low-voltage compartment of the feeders (Fig. 160) to save costs.
There is now a trend to apply combined control and protection units. The relay 7SJ63, for example, provides protection and measurement, and has integrated graphic display and keypad for bay control. Thus, only one device is needed per cable, motor or O H line feeder.

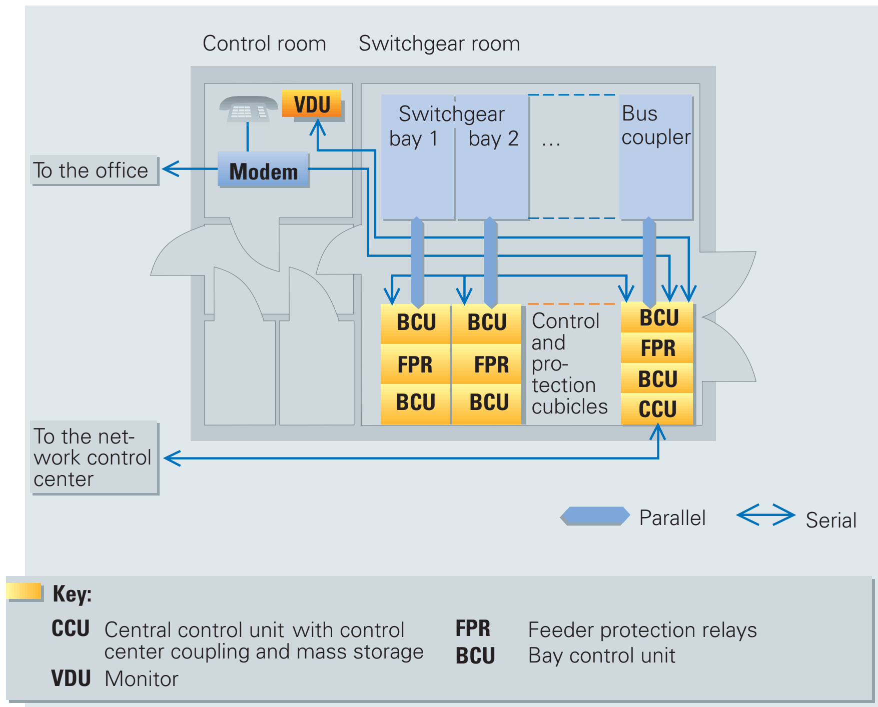


Fig. 159: Typical example of indoor substations with switchgear interlocking system

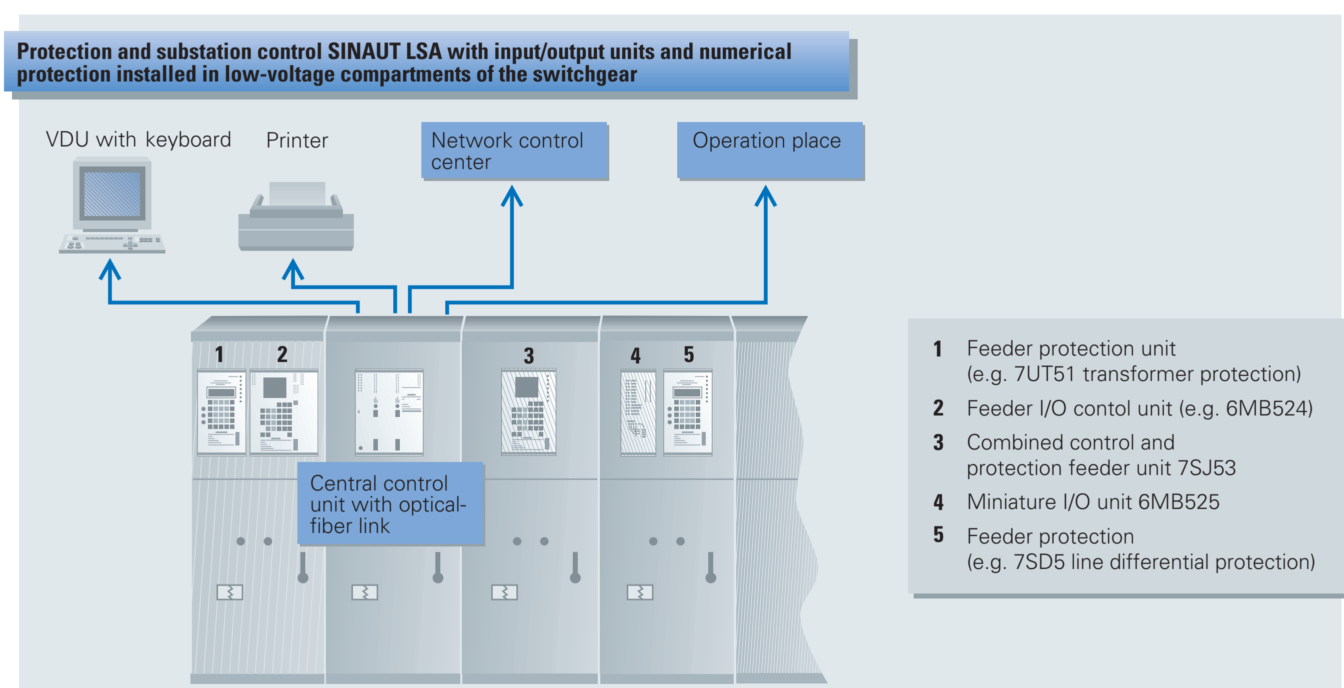


Fig. 160: Protection and substation control system SINAUT LSA for a distribution-type substation

Local and Remote Control
SINAUT LSA – Application Examples

Fig. 162 shows an example for the most simple wiring of the feeder units.
The voltages between the bay control unit and the protection can be paralleled at the bay control unit because the plug-in modules have a double connection facility.
The current is connected in series between the devices. The current input at the bay control unit is dimensioned for 100xI_N, 1 s (protection dimensioning).
The plug-in modules have a short-circuiting facility to avoid opening of CT circuits.
The accuracy of the operational measurements depends on the protection characteristics. Normally, it is approx. 2% of I_N.
If more exact values are required, a separate measuring core must be provided.
The serial interface of the protection is connected to the bay control unit.
The protection data is transferred to the control central unit via the connection between the bay control unit and the central unit. Thus, only one serial connection to the central unit is required per feeder.

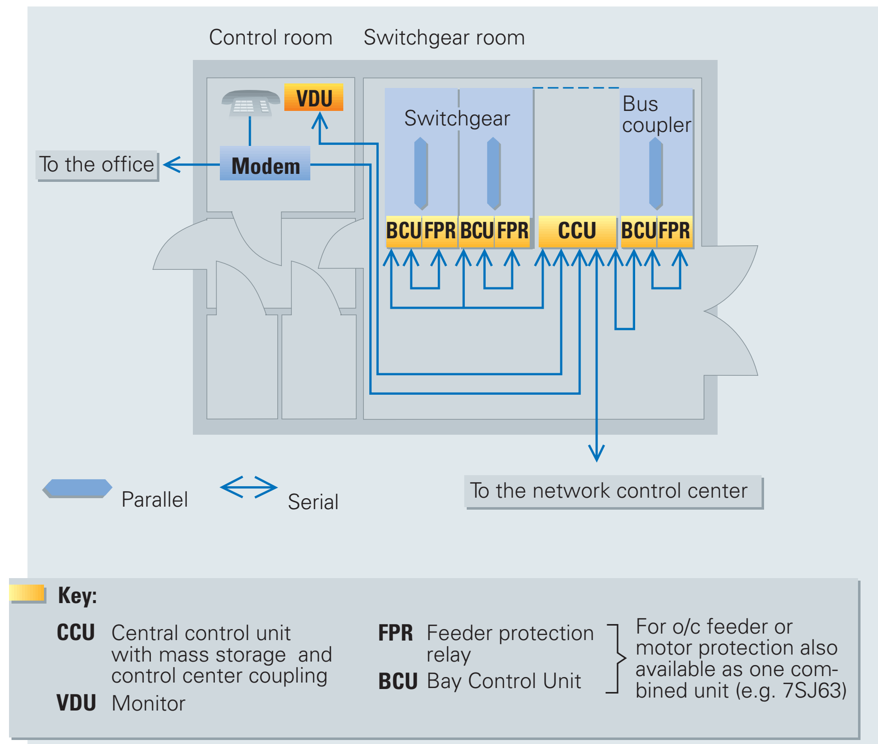


Fig. 161: Application example of medium-voltage switchgear

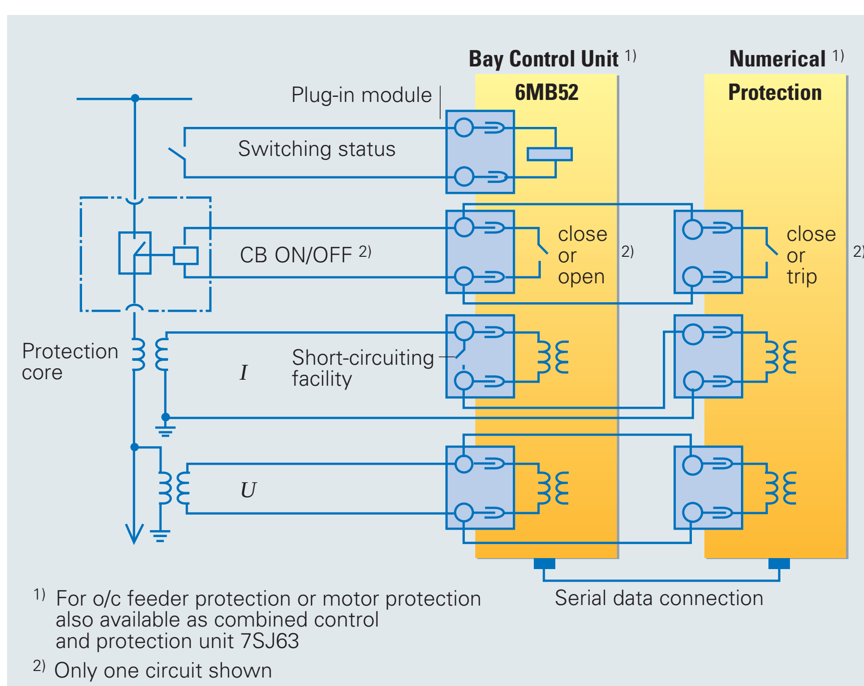


Fig. 162: Principle wiring diagram of the medium-voltage feeder components

Local and Remote Control
SINAUT LSA – Application Examples

System configuration

The system arrangement depends on the type of substation, the number of feeders and the required control and protection functions. The basic equipment can be chosen according to the following criteria:

Central control master unit

has to be chosen according to the number of bay control units to be serially connected:

- 6MB513 for a maximum of 32 serial interfaces
- 6MB514 for a maximum of 64 serial interfaces

At the most 9 more serial interfaces are available for connection of data channels to load dispatch centers, local substation control PCs, printers, etc.

Substation control center

It normally consists of a PC with keyboard and a mouse, color monitor, LSAVIEW software and a printer for the output of reports. For exact time synchronization of 1 millisecond accuracy, a GPS or DCF77 receiver with antenna may be used.

Bay control units

Normally, a separate bay control unit is assigned to every substation bay. The type has to be selected according to the following requirements:

- Number of command outputs:
  that means the sum of circuit breakers, isolators and other equipment to be centrally or remotely controlled. The stated double commands are normally provided for double-pole ("+" and "–") control of trip or closing coils.
  Each double-pole command can be separated into two single-pole commands where stated (Fig. 149, page **6**/80).
- Number of digital signal inputs:
  as the sum of alarms, breaker and isolator positions, tap changer positions, binary coded meter values, etc, to be acquired, processed or monitored. Position monitoring requires double signal inputs while single inputs are sufficient for normal alarms.
- Number of analog inputs:
  depends on the number of voltages, currents and other analog values (e.g. temperatures) to be monitored. Currents (rated 1 A or 5 A) or voltages (normally rated 100 to 110 V) can be directly connected to the bay control units. No transducers are required. Numerical protection relays also acquire and process currents and voltages.
  They can also be used for load monitoring and indication (accuracy about 2% of rated value). In this way, the number of analog inputs of the bay control units can be reduced. This is often practised in distribution-type substations.

The device selection is discussed in the following example.

Example:
Substation control configuration

Fig. 163 shows the arrangement of a typical distribution-type substation with two incoming transformers, 10 outgoing feeders and a bus tie.

The required inputs and outputs at bay level are listed in Fig. 164 for the incoming transformer feeders and in Fig. 165 for the outgoing line feeders, the bus tie and the VT bay.
Each bay control unit is connected to the central control unit via fiber-optic cables (graded index fibers).
The o/c relays 7SJ60, the minicompact I/O units 6MB5250 and the measuring transducers 7KG60 each have RS 485 communication interfaces and are connected to a bus of a twisted pair of wires.

An RS485 converter to fiber-optic is therefore additionally provided to adapt the serial wire link to the fiber-optic inputs of the central unit.
Recommendations for the selection of the protection relays are given in the section System Protection (**6**/8 and following pages).
The selection of the combined control/protection units 7SJ531 or 7SJ63 is recommended when local control at bay level is to be provided by the bay control unit. The low-cost solution 7SJ60 + 6MB5250 should be selected where switchgear integrated mechanical local control is acceptable.

Typical distribution-type substation

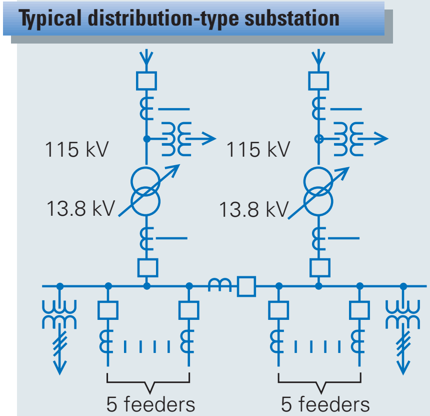
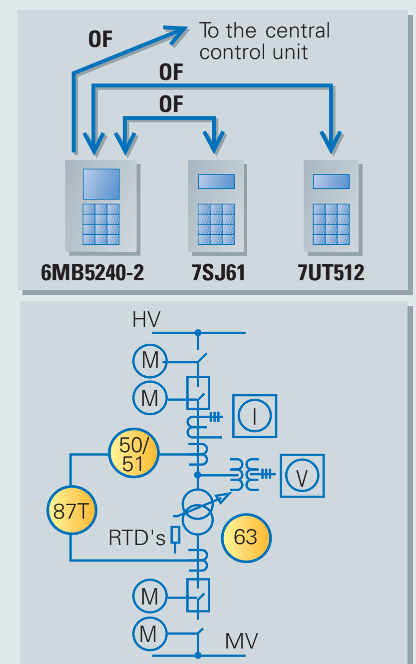


Fig. 163: Typical distribution-type substation

Incoming transformer bays



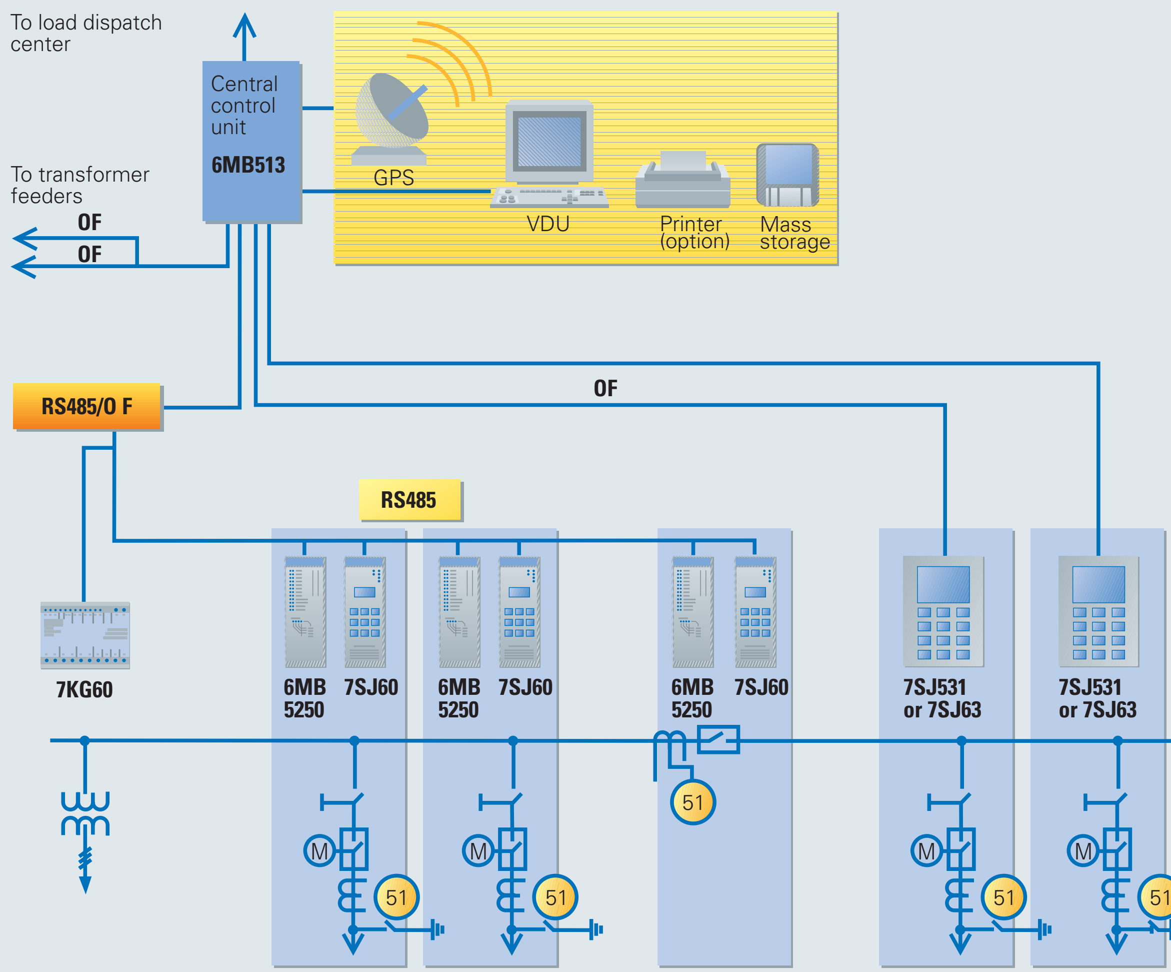
Data acqusition	
1 x DSI	Isolator HV side
1 x DSI	Circuit-breaker HV side
1 x DSI	Isolator MV side
1 x DSI	Circuit-breaker MV side
8 x DSI	Transformer tap-changer positions
1 x SSI	Alarm Buchholz 1
1 x SSI	Alarm Buchholz 2
3 x V, 3 x J, 8 x ϑ	Measuring values

Control	
2 x DCO	Isolator HV side
2 x DCO	Circuit-breaker HV side
2 x DCO	Isolator MV side
2 x DCO	Circuit-breaker MV side
2 x SCO	Tap changer, higher, lower
1 x SCO	Emergency trip

SSI	Single signal input
DSI	Double signal input
DCO	Double command
SCO	Single command

Fig. 164: Typical I/O signal requirements for a transformer bay

Local and Remote Control
SINAUT LSA – Application Examples



Voltage transformer-bay	Per feeder		Bus tie		Per feeder	
–	1 x DSI	Isolator	–		1 x DSI	Isolator
–	1 x DSI	Grounding switch	–		1 x DSI	Grounding switch
–	1 x DSI	Circuit-breaker	1 x DSI	Circuit-breaker	1 x DSI	Circuit-breaker
–	5 x SSI	5 alarms	9 x SSI	9 alarms	5 x SSI	5 alarms
1 x 7KG60	Load currents are taken from the protection relays				Measuring values (3 x V, 3 x I) from protection	
Control						
–	2 x DCO	Circuit-breaker	2 x DCO	Circuit-breaker	2 x DCO	Circuit-breaker

Fig. 165: Typical I/O signal requirements for feeders of a distribution-type substation

Local and Remote Control SINAUT LSA – Centralized (RTU) Structure

Enhanced remote terminal units 6MB551

The 6MB55 telecontrol system is based on the same hardware and software modules as the 6MB51 substation control system. The functions of the inupt/output devices have been taken away from the bays and relocated to the central unit at station control level. The result is the 6MB551 enhanced remote terminal unit (ERTU).

Special plug-in modules for control and acquisition of process signals are used instead of the bay dedicated input/output devices:

- Digital input (32 DI)
- Analog input (32 AI grouped, 16 AI isolated)
- Command output (32 CO) and
- Command enabling

These modules communicate with the central modules in the same frame via the internal standard LSA bus. The bus can be extended to further frames by parallel interfaces.
The 6MB551 station control unit therefore has the basic structure of a remote terminal unit but offers all the functions of the 6MB51 substation control system such as:

Communication

- to the higher network control levels
- to an analysis center located either in the station or connected remotely via a telephone line using a modem
- to the bay control unit and/or the numerical protection units (bay control units)
- to lower-level stations (node function).

This is for the purpose of controlling and monitoring activities at the substation and network control levels as well as providing data for system planning and analysis.

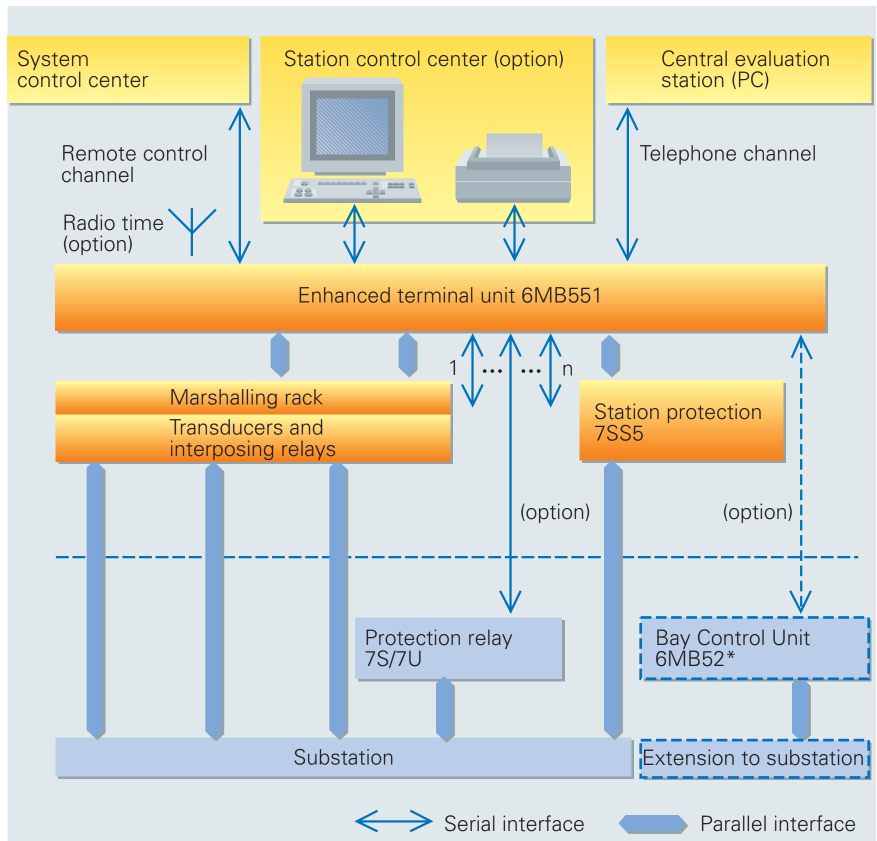


Fig. 166: Protection and substation control system LSA 678 for a distribution-type substation

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Local and Remote Control
SINAUT LSA – Centralized (RTU) Structure

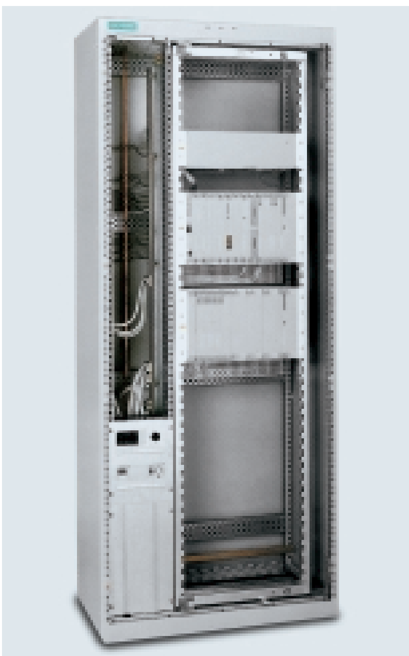


Fig. 167: 6MB551 enhanced remote terminal unit, installed in an 8MC standard cubicle with baseframe and expansion frame

Other tasks of the enhanced RTU are

- Event logging with a time resolution of 1 or 10 ms
- Archiving of events, variations in measured values and fault records on mass storage units
- Time synchronization using radio clock (GPS, DCF77 or Rugby) or using a signal from a higher-level control station
- Automation tasks affecting more than one bay:
  - Parallel control of transformers
  - Synchronizing (measured value selection)
  - Switching sequences
  - Busbar voltage simulation
  - Switchgear interlocking
- Parameter management to meet the relevant requirements specification
- Self-monitoring and system monitoring.
- Up to 96 serial fiber-optic interfaces to distributed bay control units
- Up to 5 expansion frames.

Configuration including signal I/O modules can be parameterized as desired.
Up to 121 signal I/O modules can be used (21 per frame minus one in the baseframe for each expansion frame, i.e. totally 6 x 21 – 5 = 121).

The 6MB551 station control unit can therefore be expanded from having simple telecontrol data processing functions to assuming the complex functionality of a substation control system.
The same applies to the process signal capacity. In one unit, more than 4 000 data points can be addressed and, by means of serial interfacing of subsystems, this figure can be increased even further.

The 6MB551 station control unit simplifies the incorporation of extensions to the substation by using the decentralized 6MB52* bay control units for the additional substation bays.

These distributed input/output devices can then be connected via serial interface to the telecontrol equipment. Additional parameterization takes care of their actual integration in the operational hierarchy.

The 6MB551 RTU system is also available as standard cubicle version SINAUT LSA COMPACT 6MB5540. The modules and the bus system have been kept; the rack design and the connection technology, however, have been cost-optimized (fixed rack only and plug connectors).
This version is limited to a baseframe plus one extension frame with altogether 33 I/O modules, and a maximum of 5 serial interfaces for telecontrol connection without communication to bay control units or numerical protection units.

Local and Remote Control
SINAUT LSA – Remote Terminal Units

Remote terminal units (RTUs)

The following range of intelligent RTUs are designed for high-performance data acquisition, data processing and remote control of substations. The compact versions 6MB552/553 of SINAUT LSA are intended for use in smaller substations.

Fig. 168: 6MB552 compact RTU for medium process signal capacity

Fig. 169: SINAUT LSA COMPACT 6MB5540 remote terminal unit installed in a cubicle

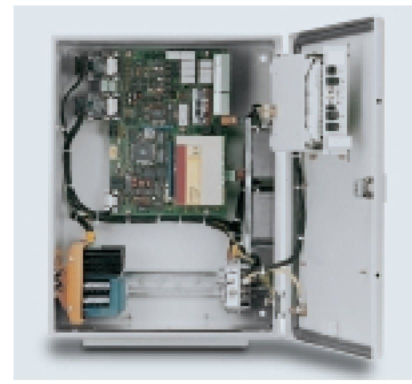


Fig. 170: 6MB5530-0 minicompact RTU for small process signal capacity

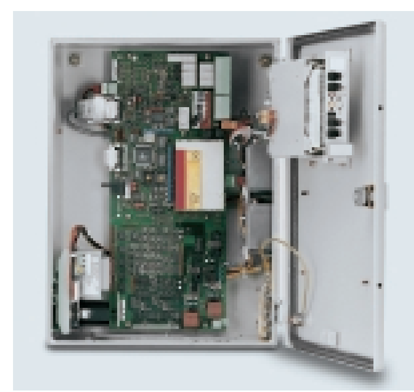


Fig. 171: 6MB5530-1 remote terminal unit (RTC) with cable-shield communication

Design	Type	Single commands	Alarm inputs	Analog inputs	Serial ports to control centers	Serial ports to bay units
Minicompact RTU*	6MB5530-0A 6MB5530-0B 6MB5530-0C	8 8 8	8 24 32	– 8 –	1	–
Remote terminal unit with cable shield communication (RTC)	6MB5530-1A 6MB5530-1C	8 8	8 32	– –	1 additional gateway	–
Compact RTU	6MB552-0A 6MB552-0B 6MB552-0C 6MB552-0D	32[1]/8 32[1]/8 32[1]/8 8	72 40 104 136	32 16[2] – –	1 Option 2	7

* Further 3 minicompact RTUs can be serially connected in cascade for extension (maximum distance 100 m)
1) With switching-current check
2) Potential-free

Fig. 172: Remote terminal units, process signal volumes

Local and Remote Control
SINAUT LSA – Remote Terminal Units

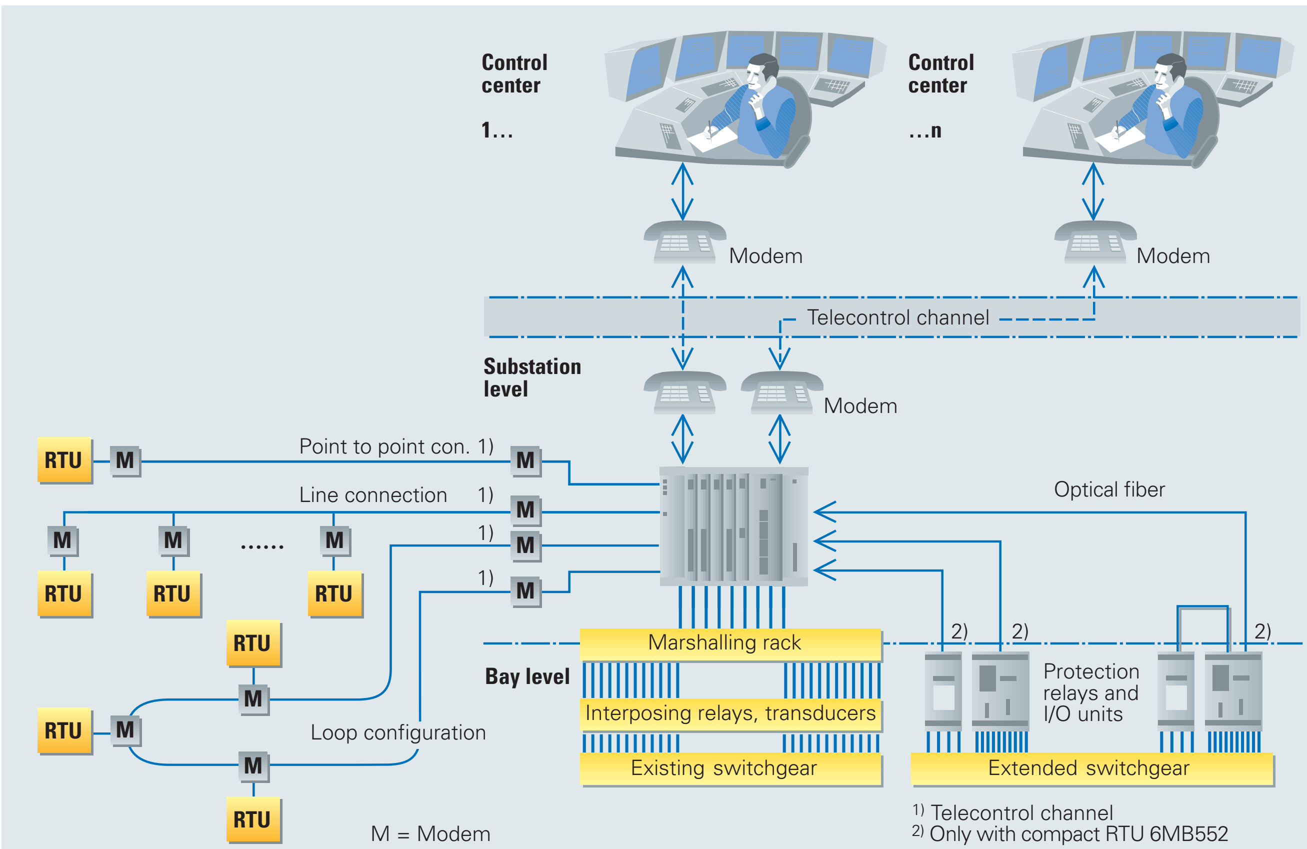


Fig. 173: RTU interfaces

RTU interfaces

The described RTUs are connected to the switchgear via interposing relays and measuring transducers (± 2.5 to ± 20 mA DC) (Fig. 173). Serial connection of numerical protection relays and control I/O units is possible with the compact RTU type 6MB552.
The communication protocols for the serial connection to system control centers can be IEC standard 870-5-101 or the Siemens proprietary protocols 8FW.
For the communication with protection relays, the IEC standard 870-5-103 is implemented.

Besides these standard protocols, more than 100 legacy protocols including derivatives are implemented for remote control links up to system control centers and down to remote substations (see table overleaf).

Fig. 174: VF coupler with ferrite core 35 mm

Local and Remote Control
SINAUT LSA – Remote Terminal Units

List of implemented legacy protocols:

- ADLP 180
- ANSI X3.28
- CETT 20
- CETT 50
- DNP3.0
- DUST 3964R (SINAUT 8-FW-data structure)
- EFD 300
- EFD 400
- F4F
- FW 535
- FW 537
- Geadat 90
- Geadat 81GT
- GI74
- Granit
- Harris 5000
- IDS
- IEC 60870-5-101
- IEC 870-5-BAG
- IEC 870-5-VEAG
- Indactic 21
- Indactic 23
- Indactic 33
- Indactic ZM20
- LMU
- Modbus
- Netcon 8830
- RP570
- SAT 1703
- SEAB 1F
- SINAUT 8-FW
- SINAUT HSL
- SINAUT ST1
- Telegyr 709E
- Telegyr 809
- Tracec 130
- Ursatron 8000
- Wisp+

Cable-shield communication

The minicompact RTU can be delivered in a special version for communication via cable shield (Type 6MB5530-1).
It does not need a separate signaling link. The coded voice frequency (9.4 and 9.9 kHz) is coupled to the cable shield with a special ferrite core (35 mm or 100 mm window diameter) as shown in Fig. 174.
The special modem for cable-shield communication is integrated in the RTU.
Fig. 175 shows as an example the structure of a remote control network for monitoring and control of a local supply network.

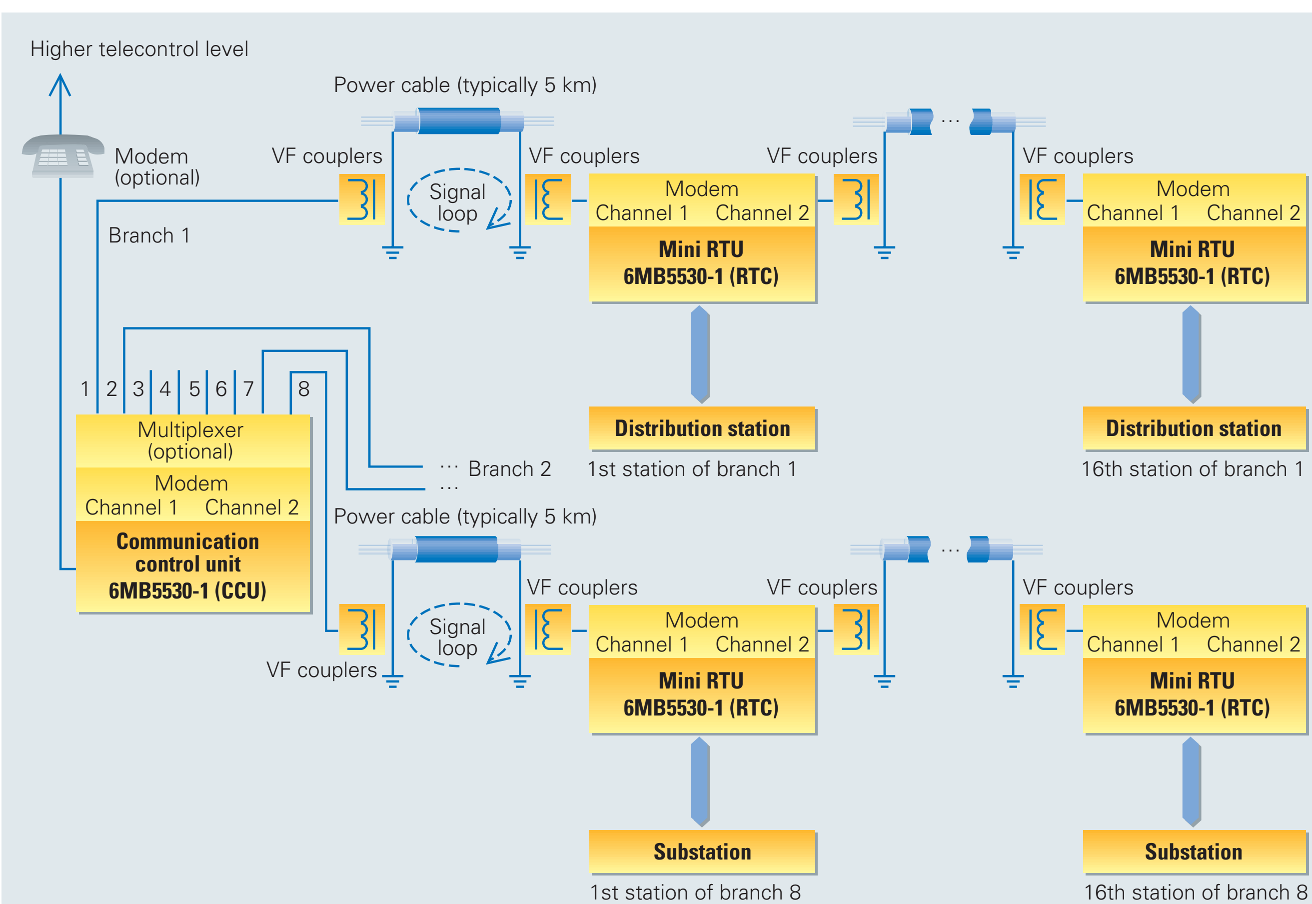


Fig. 175: Remote control network based on remote terminal units with cable-shield communication

Local and Remote Control SICAM – Overview

SICAM is an equipment family consisting of products for digital power automation. The system is continuous, from the system control center, through the information technology, to the bay protection and control units.

The SICAM System is based on SIMATIC*) and PC standard modules. SICAM is thus an open system with standardized interfaces, readily lending itself to further development.

The SICAM family consists of the following individual systems (see Fig. 176):

- SICAM RTU, the telecontrol system with the following features
  - Principal function: information transfer
  - Central process connection
  - PLC functions
  - Communication with control center
- SICAM SAS, the decentralized automation system
  - Principal function: substation automation
  - Decentralized and centralized process connection
  - Local operation and monitoring with archiving functions
  - Communication with the control center
- SICAM PCC, the PC-based Station Control System with the following features
  - Principal function: Substation supervision and control
  - Decentralized process connection
  - LAN/WAN communication with IEC 60870-6 TASE.2
  - Flexible communication
  - Linkage to Office® products

*) Siemens PLCs and Industrial Automation Systems (see Catalog ST70)

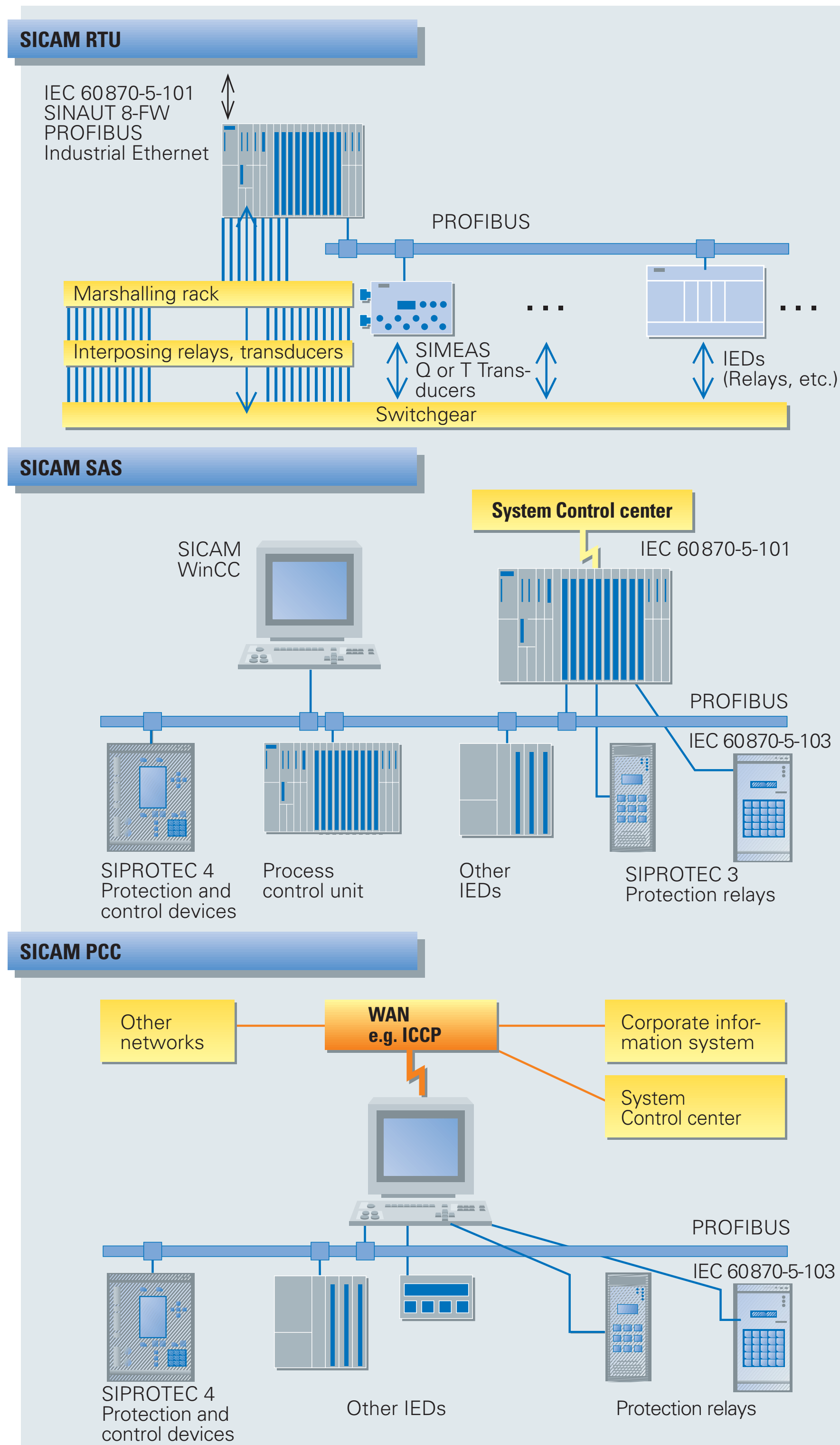


Fig. 176: The SICAM family

6

Local and Remote Control
SICAM RTU – Design

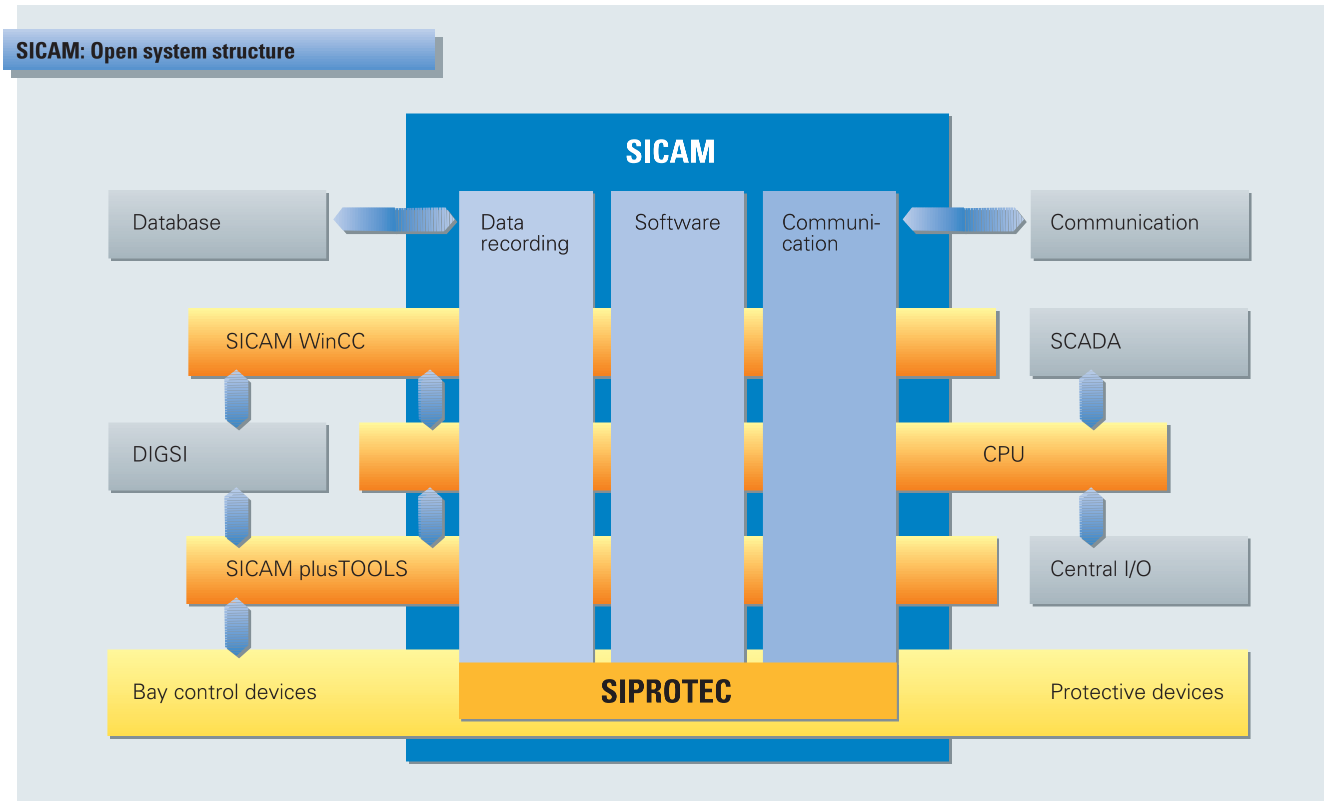


Fig.177: SICAM system structure

SICAM RTU 6MD201 Enhanced Remote Terminal Unit

Overview

The SICAM RTU Remote Terminal Unit is based on the SIMATIC S7-400, a powerful PLC version of the Siemens product range for industrial automation. The SIMATIC S7-400 has been supplemented by the addition of modules and functions so as to provide a flexible, efficient remote terminal unit. Based on worldwide used SIMATIC S7-400, it is possible to add project-specific automation functions to the existing telecontrol functions.

The SIMATIC S7-400 System has been expanded to include the following properties:

- All-round isolation of all connections with 2.5 kV electric strength
- Heavy duty output contacts (10 A, 150 VDC, 240 AC) on external relay module (type LR with up to 16 command relays)
- CT and VT graded measuring value acquisition via serially connected numerical transducers SIMEAS Q or T (see page **6**/132)
- Acquisition of short-time event signals with 1 ms resolution and real-time stamping
- Preprocessing of information acquired (e.g. double indications, metered values)
- Fail-safe process control (e.g., 1-out-of-n check, switching current check)
- Secure long-distance data transmission using the IEC 60870-5-101 or SINAUT 8-FW protocol
- Remote diagnostic capability

The open and uniform system structure is illustrated in Fig. 177, showing the essential modules.

A variety of SICAM equipment family products are available depending on the different requirements and applications.

The individual system modules are described in detail in the sections below.

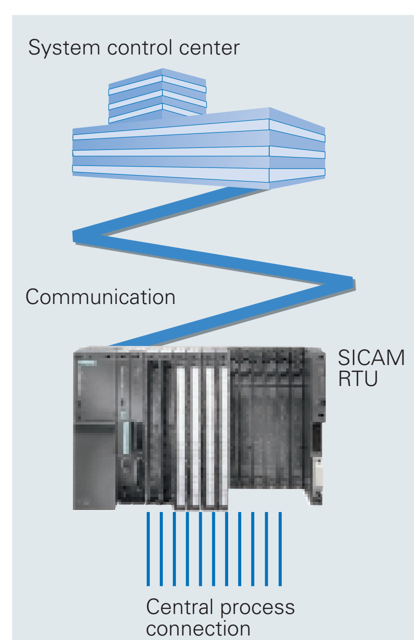


Fig. 178: SICAM RTU remote terminal unit

Local and Remote Control SICAM RTU – Design

System architecture

The SICAM RTU is a modular system. It is suitable for substation sizes from approximately 300 up to 2048 data points.
The SICAM RTU consists of the:

- SICAM S7-400 basic rack with its extension facilities and
- Any S7-400 CPU (412 to 477, with/without PROFIBUS connection). As standard CPU, the CPU 412 or CPU 413 is used.

To supplement the SIMATIC S7-400 modules, telecontrol-specific modules have been developed in order to fulfill the required properties and functions, such as for example electric insulation strength and time resolution.

These are the following modules:

- Power supply
  - Voltage range from 19 V–72 V DC
  - 88 V–288 V AC/DC
- Process input and output modules
  - Digital input DI (32 inputs) for status indications, counting pulses, bit patterns and transformer tap settings
    • voltage ranges:
    24–60 V DC
    110–125 V DC
  - Analog input AI (32 analog inputs grouped, 16 AIR (analog inputs isolated) for currents (0.5 mA–24 mA) and voltages (0.5 V–10 V)
  - Command output (32 CO) for commands and digital setpoints
    • voltage range: 24–125 V DC
  - Command release (8 DI, 8 DO) for local inputs and outputs and monitoring of command output circuits
    • voltage ranges:
    24–60 V DC
    110–125 V DC
- Communication module
  - Telecontrol processor TP1 for communication with the system control center with protocols IEC 60870-5-101 and SINAUT 8-FW and as time signal receivers for DCF77 or GPS reception.

The Power Supply and the I/O modules can also be used in SICAM SAS.

Fig. 179: SICAM mounting rack

6

Local and Remote Control
SICAM RTU – Design

Construction

The SICAM RTU is based on the SIMATIC S7-400. The construction of the SICAM RTU is therefore, as is the case with SIMATIC, highly compact, straightforward and simple to operate:

- All connections are accessible from the front. Therefore, no swivel frame is necessary.
- The modules are enclosed and therefore extremely rugged.
- Plugging and unplugging of modules is possible while in operation; therefore maintenance work can be carried out in a minimum of time (reduced MTTR).
- Direct process connection is effected by means of self-coding front plug connectors of screw-in or crimp design.
- During configuration, no module slot rules have to be observed; the SICAM RTU permits free module fitting.
- No forms of setting are necessary on the modules; replacement can be carried out in a minimum of time.

Dependent on configuration level and customer requirements, there are two housing variants:

- a floor-mounting cabinet and
- a wall-mounting cabinet.

Both housing variants are optimized for the SICAM RTU; they are of flexible modular construction. Thus, for example, provision is made for installation of accessories to provide a cost-effective rack system.

Fig. 180a: SICAM RTU wall-mounting cabinet

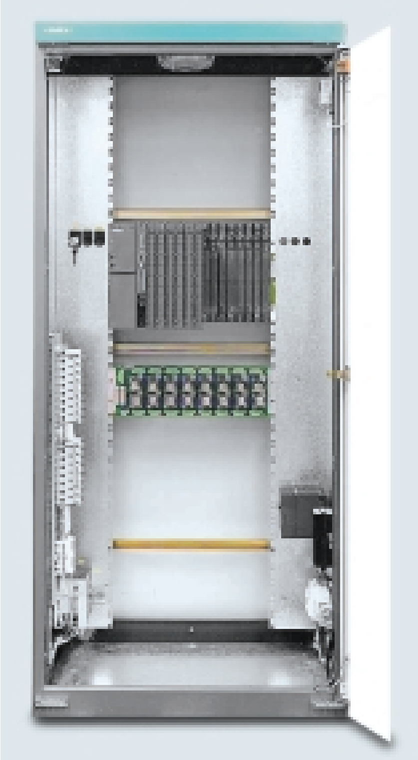


Fig. 180b: SICAM RTU floor-mounting cabinet

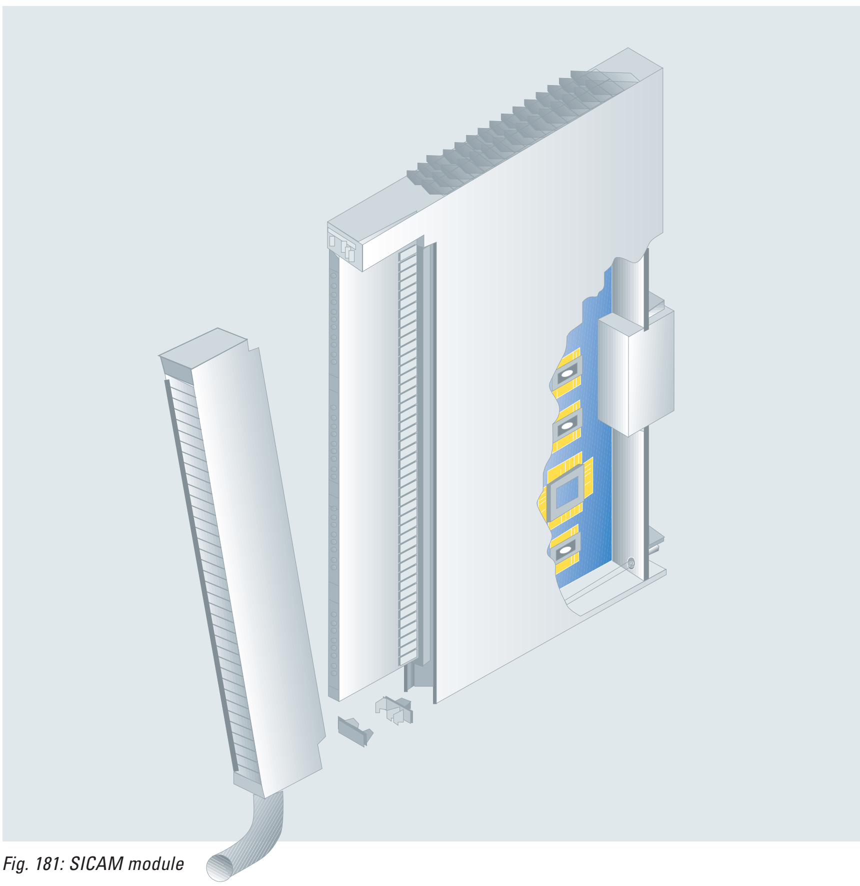


Fig. 181: SICAM module

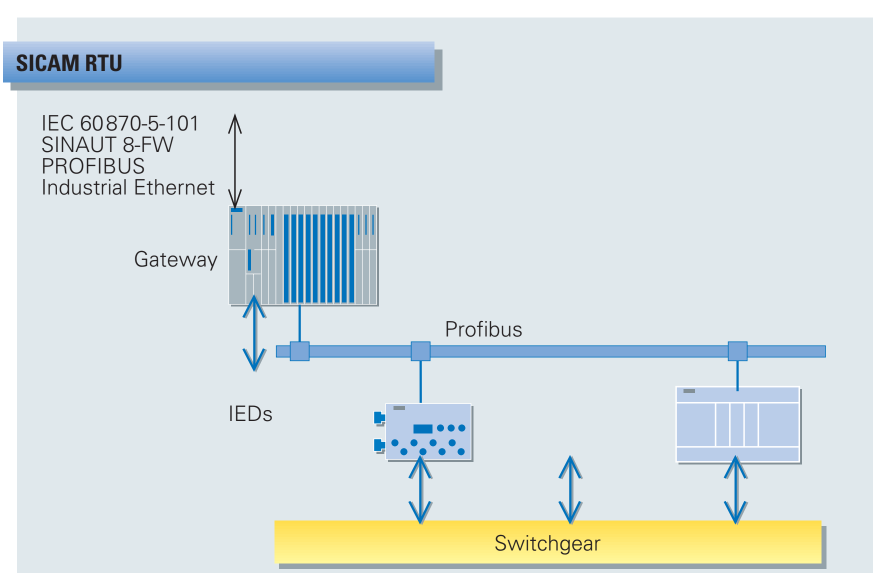


Fig. 182: Gateway: PROFIBUS – IEC 60870-5-101

SICAM Modules

SICAM RTU modules have been developed to be SIMATIC-compatible and can therefore be used in a standard SIMATIC S7-400, for example for the following applications:

- Acquisition of status indications with a resolution of 1 ms and an accuracy of ± 2 ms
- Time synchronization of the SIMATIC CPU to within an accuracy of ± 2 ms
- An analog input module with 32 channels with current or voltage inputs
- Use of modules with 2.5 kV electric insulation strength in order to save interposing relays

The modules are used for example in hydro-power plants for acquisition of fault events via digital input with a resolution of 1 ms and relaying them to a power station system, for example via an Industrial Ethernet.

The other application is the use of the communication module TP1 in a SIMATIC NET - IEC 60870-5-101 gateway. Fig. 182 shows an example of a PROFIBUS gateway.

Local and Remote Control
SICAM RTU – Functions

SICAM RTU functions

SICAM RTU possesses telecontrol functions, such as:

- Alarm acquisition and processing, including:
  - Single point information
  - Double point information
  - Bit patterns
  - Transformer taps
  - Metering pulses
- Measured value acquisition and processing, including:
  - parameterizable current inputs in ranges from 0.5 mA–24 mA
  - parameterizable voltage inputs in ranges from 0.5 V–10 V
- Fail-safe command output, including:
  - Single commands
  - Double commands
  - Bit pattern outputs
  - Transformer tap change control
  - Pulse commands
  - Continuous commands
- Telecontrol communication with a maximum of two system control centers with different telecontrol messages, with the standardized IEC 60870-5-101 and/or with the worldwide proven SINAUT 8-FW protocol.

In addition to the standard RTU functions, the SICAM RTU provides additional functions, such as:

- Efficient operation mode control with 15 priorities and various send lists, such as:
  - Spontaneous lists with/without time
  - Scan lists for measured values, metered values or status indications
  - Cyclic lists
  - Time-controlled lists

With the aid of this mode control system, it is possible to optimize the data flow between remote terminal unit and system control center.

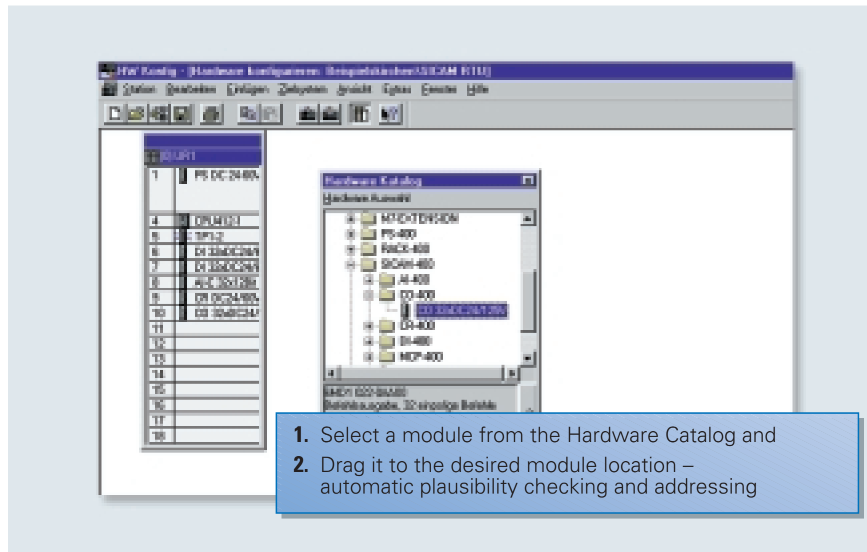


Fig. 183: plusTOOLS for SICAM RTU, hardware configuration

- Time synchronization via DCF or GPS receiver on the TP1 module.
  The SIMATIC CPU is synchronized to within an accuracy of 1 ms.
- Serial interface to a maximum of two control centers.
  In addition to selection of the telecontrol protocols IEC 60870-5-101 and SINAUT 8-FW, the scope of status indications, measured values and commands per control center per interface can be configured, with separate telecontrol protocols, different process data, different message addresses and different modes.
- Can be extended up to 4096 information points
- Comprehensive remote diagnostic facilities locally or in remote form with the aid of the SIMATIC TeleService.
- Output of analog setpoints via the S7-400 AO module (1500 kV insulated)
- SICAM RTU is maintenance-free and requires no fan cooling
- The variety of available module types with wide-range inputs is kept to a minimum; the value ranges are parameterizble.

Engineering

The SICAM RTU is designed such that all telecontrol functions are parameterizable. Comprehensive Help texts assist the operator during configuration. The following configuration steps are carried out with the aid of the intuitive-operation program plusTOOLS for SICAM RTU:

- Creation of hardware configuration, SIMATIC modules and SICAM modules
- Setting of module parameters on the SIMATIC modules and SICAM modules
- Assignment of process data to the message addresses
- Assignment of message addresses to the message lists in the mode control system, stipulation of send priorities.
- Checking of all parameters for plausibility.
- Loading of parameters into a non-volatile flash EPROM of the CPU.

Fig. 183 shows as an example the mask for hardware configuration.

Local and Remote Control
SICAM RTU – Functions

Automation functions

The SICAM RTU is based on the SIMATIC S7-400. Therefore, all modules of the SIMATIC S7-400 System can be used in a SICAM RTU: For example, a CPU 413-DP with PROFIBUS connection or the communication processor CP 441, e.g. for connection of a Modbus device.

If additional functions are to be introduced project-specifically by S7 PLC means, these can be integrated with the aid of the internal API Interface (Application Program Interface). Thus, for example, the data received via the CP 441 can be processed internally and sent via the TP1 to the system control center.

The following functions can for example be implemented:

- Initiate functions by commands from the system control center
- Derive commands as a function of measured value changes (e.g. load shedding when a frequency drop has been measured)
- Connection of an operator panel to the serial system interface (Fig. 184a/b)
- Connection of decentralized peripherals via the PROFIBUS DP

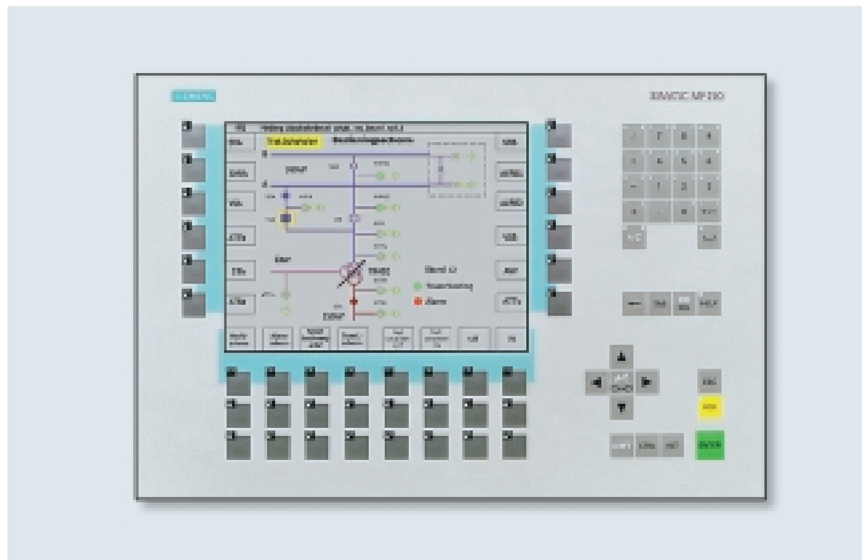


Fig. 184a: Operator Panel

Fig. 184b: Operator Panel mounted in a cubicle door

Local and Remote Control
SICAM MRTU/microRTU

SICAM MRTU 6MD202/6MD203 Small Remote Terminal Unit

Overview

Supplementary to the SICAM RTU, the following small remote terminal units are available for low-level upgrades:

- SICAM microRTU 6MD203 up to 50 process inputs/outputs
- SICAM miniRTU 6MD202 up to 300 process inputs/outputs

The two remote terminal units are based on the SIMATIC S7-200.

Supplementary to the SIMATIC modules, a "SICAM TCM" communication module has been developed for the SICAM miniRTU. The TCM module is installed in a S7-214 housing.

The SICAM micro and miniRTUs provide small remote terminal units which handle the process data and communicate by means of an assured IEC 60870-5-101 telecontrol protocol with the system control center. The SICAM miniRTU makes it possible to supplement project-specific functions.

Both units possess the following advantages of the SIMATIC S7-200 System in terms of construction:

- Compact design
- Quick mounting by snapping onto a hat rail
- Low power consumption
- Extensive range of expansion modules
  - Digital inputs
  - Relay outputs
  - Electronic outputs
  - Analog inputs
  - Analog outputs
- Connection of expansion modules by means of plug-in system
- Connection of process signals by means of screw terminals
- Automatic recognition of upgrade level

Fig. 185: SICAM microRTU

SICAM microRTU 6MD203

For the SICAM microRTU, it is possible to use an S7-214 or an S8-216 CPU. The PPI interface is used for loading the programs and the parameters and also for communication with the system control center. The standardized transmission protocol IEC 60870-5-101 has been implemented. Unbalanced mode has been chosen as traffic mode because small remote terminal units are generally operated in partyline (that is to say polling) mode.

The SICAM microRTU performs the following functions:

- Acquisition and processing of a maximum of 24 single point items of information
- Acquisition and processing of metering pulses (maximum 20 Hz) for a maximum of 4 metered values
- Acquisition of a maximum of 12 measured values
- Command output as pulse or persistent command for a maximum of 14 digital outputs
- Transmission of data (priority-controlled) spontaneously or on demand in half duplex mode
- Transmission rate: 300–9600 bit/sec

Parameterizing takes place with STEP7 MicroWIN. All parameters are preset; they only have to be adapted slightly. The parameters are loaded locally from the PC.

For transmission, there is a gradable V.23 hat-rail-mounted modem with an RS-485 interface. The transmission rate is 1200 bit/sec.

Local and Remote Control SICAM miniRTU

SICAM miniRTU 6MD2020

Overview

The SICAM miniRTU differs from a SICAM microRTU in the following respects:

- Volume of data: 300 instead of 50 information points
- Clock control: messages with time stamp are possible
- An integrated V.21 modem is available
- Project-specific additions can be introduced via the API interface

The SICAM miniRTU is a small, efficient modular remote terminal unit with a wide range of functions. The SICAM miniRTU can be upgraded from a configuration level of 14 digital inputs up to a medium-sized terminal with a maximum of 300 process points.

For the SICAM miniRTU, it is possible to use the S7-200 CPUs 27-214 or S7-216. In addition, the TCM (telecontrol module) communication module is required. The TCM incorporates an RS-232 interface for communication with the system control center; this implements the entire message interchange. The standard transmission protocol is implemented: IEC 60870-5-101, unbalanced mode. IEC 60870-5-101 balanced mode and SINAUT 8-FW point-to-point traffic are in preparation.

Fig. 186 illustrates a minimum configuration level of a SICAM miniRTU with an S7-214 CPU. Fig. 187 shows in diagrammatic form a maximum configuration level with 3 S7-200 CPUs.

Fig. 186: SICAM miniRTU with TCM and S7-214 CPU

Functions

The SICAM miniRTU performs the following functions or incorporates the following features:

- Acquisition and processing of single point and double point information. Transmission with or without time in message.
- Acquisition and processing of metering pulses (maximum 20 Hz). Re-storing by means of internal timer or by means of message from the system control center. Transmission with or without time in message.
- Acquisition and processing of measured values, threshold processing, threshold matchable by means of message. Transmission with or without time in message.
- Command output as pulse commands with 1-out-of-n monitoring and command release. Persistent command output is possible.
- Analog setpoint output.
- Bit-by-bit assignment of process information to processing functions
- Clock control with synchronization by message from system control center

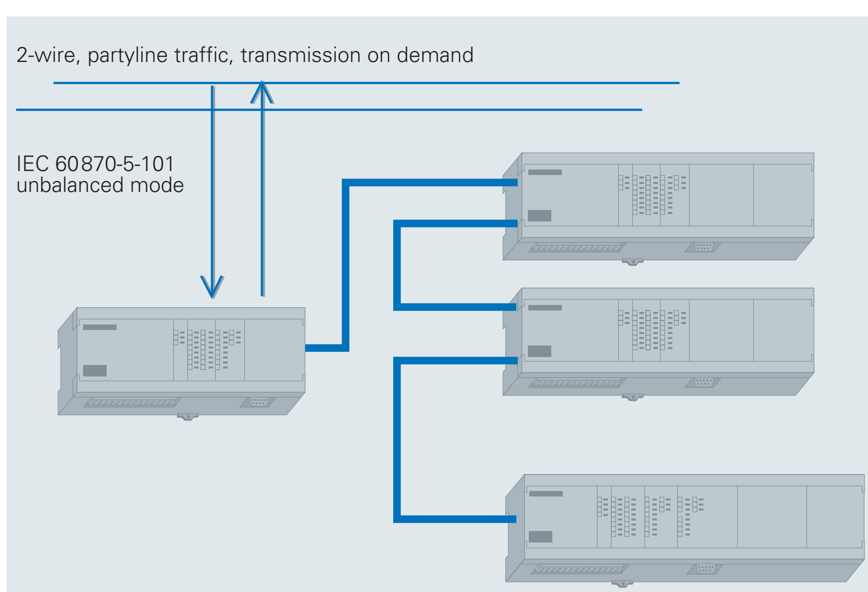


Fig. 187: SICAM miniRTU with TCM and three S7-214 CPUs

6

Communication

Communication with the system control center is carried out by the SICAM miniRTU with the TCM communicaton module. A gradable V.21 modem is already integrated in the TCM, so that the SICAM miniRTU can be used directly.

Other communication characteristics are:

- Transmission speed of 300–9600 bit/sec. adjustable
- Mode control with 15 priorities which can be freely assigned
- Different send lists for:
  – Spontaneous mode
  – Polling mode
  – Cyclic mode

Linkage of small remote transmission units generally takes place by means of transmission on demand. The lines with the remote transmission units are compressed with the aid of a data concentrator and are relayed to the system control center. Fig. 188 shows an example of configuration.

Rail-mounted modems with RS-232 interface are available for transmission with an external modem:

- Gradable V.23 modem with 1200 bit/sec transmission speed
- Dedicated line modem – V.32 modem – with a transmission speed of 9600 bit/sec.

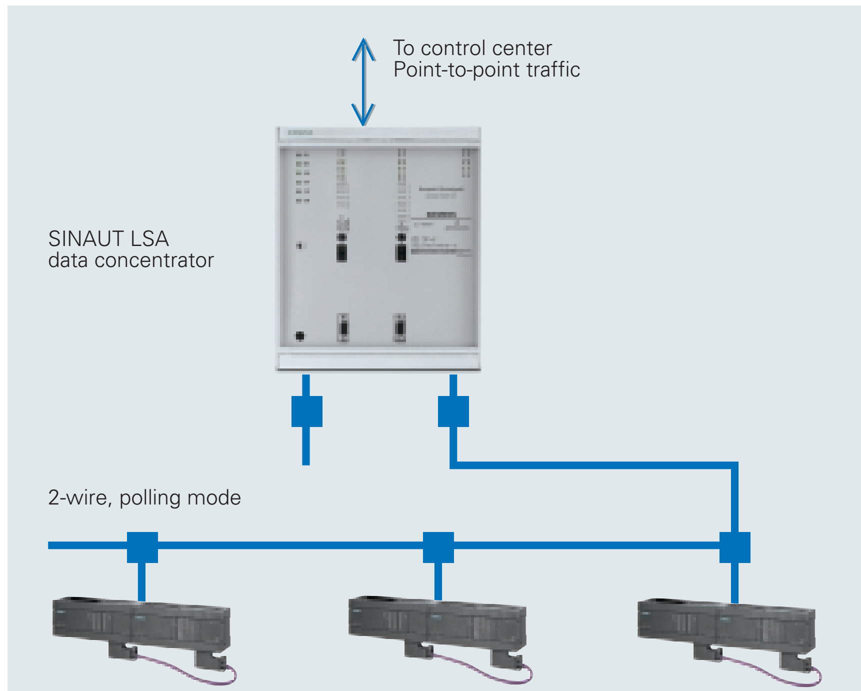


Fig. 188: SICAM miniRTU, typical configuration

Project-specific expansion options

In the SICAM miniRTU, an API interface (Application Program Interface) is available. Project-specific programs can thus be upgraded. Access by the API interface to communication is supported by the system. That is to say, the information from the control center can be processed in the user program; information derived in the user program can be remotely controlled. Examples of this are:

- Formation of group alarms,
- Transmitting internally formed measured values or metered values to the control center,
- Initiating functions by means of commands from the control center,
- Influencing of alarm processing, for example filtering, relaying via API,
- Activating PROFIBUS link on an S7-215.

Local and Remote Control
SICAM miniRTU

Engineering

Parameterizing is effected with the plus-TOOLS program for miniRTU. The program can be run on Windows 95, 98 or NT 4.

Parameterizing takes place operator-guided by means of menus. Extensive help texts facilitate operation. Figs. 190 and 191 illustrate as examples the mask for hardware configuration and the mask for assignment of message addresses.

The parameters are checked for plausibility prior to loading. They are loaded in non-volatile form from the PC into the flash EPROM of the TCM. All parameters of a SICAM miniRTU can be read locally with the PC. For this purpose, the parameter set of the station to be read out does not have to be present on the PC. Modification and reloading is possible.

Design	RTU Type	Single point information [1]	Single commands [1]	Analog inputs	Analog outputs	Serial ports to CC
SICAM RTU	6MD201	typical up to 2048 maximum: 4096				2
SICAM miniRTU	6MD202	192 [2]	192 [2]	36 [2]	12 [2]	1
SICAM microRTU	6MD203	24	16	12	4	1

[1] Processing of double point information and double commands is also possible. The table is intended solely to represent the number of connection points.
[2] Maximum values; note combination options!

Fig. 189: Remote terminal units, process signal volumes

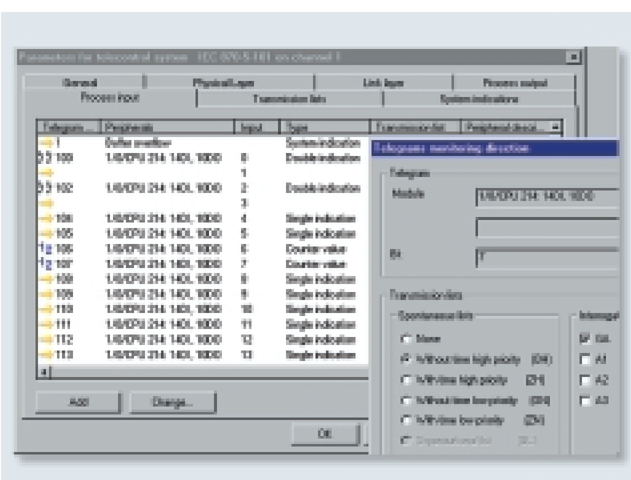


Fig. 190: plusTOOLS, generation of hardware configuration

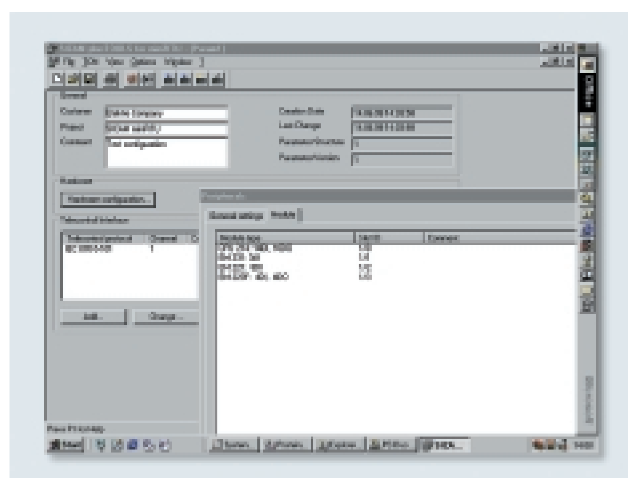


Fig. 191: plusTOOLS, parameterizing of communication

Local and Remote Control
SICAM SAS – Overview

SICAM SAS Overview

In order to assure security of supply, the substation automation system must be capable in normal operation of real-time acquisition and evaluation of a large volume of individual items of information.

In the event of a fault, additional information is required to assist rapid fault diagnosis. Graphic display functions, logs and curve evaluations are aids suitable for this purpose. The SICAM SAS substation control and protection system provides a system solution for efficient implementation of these functions.

SICAM SAS is designed as an open-type system which, based on international standards, provides simple interfaces for integration of additional bay control units or new transmission protocols, as well as interfaces for implementation of project-specific automation functions.

Field of application

SICAM SAS is used in power transmission and distribution for automation of medium-voltage and high-voltage substations.

It is used wherever:

- Distributed processes are to be monitored and controlled.
- Functions previously available on a higher control level are being decentralized and implemented locally.
- High standards of electric insulation strength and electromagnetic compatibility are demanded.
- A real-time capability system is required.
- Reliability is very important.
- Communication with other control systems must be possible.

Fig.192: SICAM SAS components: SICAM SC Substation Controller, SIPROTEC 4 relays and 6MB525 bay control units

Functions

SAS assumes the following functions in a substation:

- Monitoring
- Data exchange with and operation of serially connected protection devices and other IEDs
- Local and remote control with interlock
- Teleindication
- Automation
- Local processing and display
- Archiving and logging

SICAM SAS – Structure

System architecture

The typical configuration of a SICAM SAS consists of:

- SICAM SC Substation Controller
- Connection to higher-level system control centers
- Connection to bay level
- Bay control units, protection relays or combined control and protection bay units.
- Configuration PC with SICAM plusTOOLS
- Operation and monitoring with SICAM WinCC

The modular construction of the system permits a wide range of combination options within the scope of the system limits.

In the SICAM SC substation controller, the SICAM I/O modules can be used for alternative central connection of process inputs and outputs (see description of the SICAM RTU).

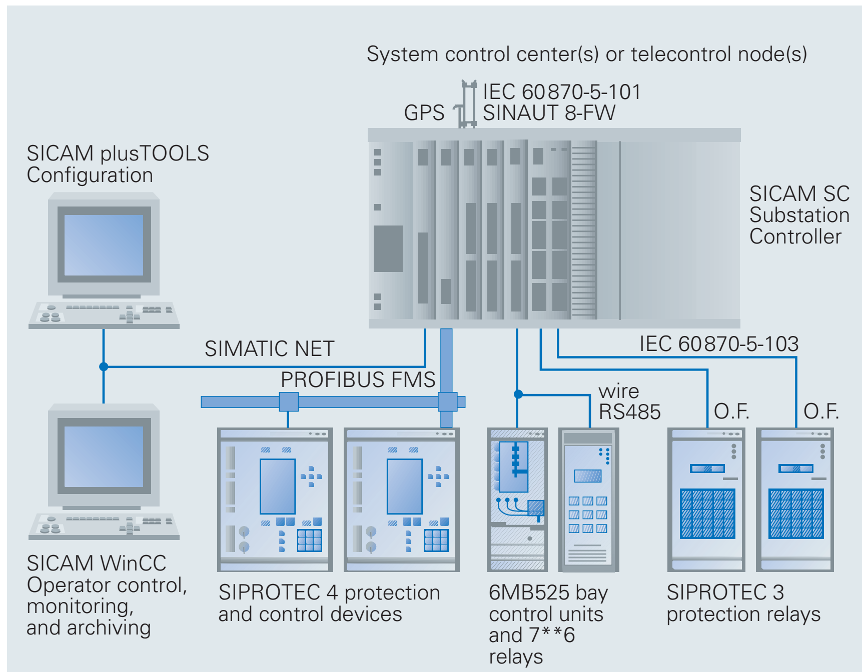


Fig. 193: Typical configuration of a SICAM SAS

6

Local and Remote Control
SICAM SAS – SC Substation Controller

SICAM SC Substation Controller

The SICAM SC is an open-type, modular construction telecontrol and substation controller. The specific functions of a telecontrol system are combined with those of a programmable automation system (PLC).

Standard functions of the automation system and control and protection-specific applications, such as real-time processing, fail-safe command output or telecontrol functions, combine to form a rugged, future-oriented hardware system.

The basis of the SICAM SC is formed by the SIMATIC M7-400 family of systems. In order to meet the increased requirements of telecontrol and substation control technology for electric insulation strength, you now have at your disposal a wide range of modules and devices to supplement the SIMATIC standard modules. The communication processors of the system support the IEC 60870-5-101, SINAUT 8FW, IEC 60870-5-103, PROFIBUS FMS, PROFIBUS DP and Industrial Ethernet communication protocols.

Hardware

The hardware of the SICAM Substation Controller is based on the standard modules of the SIMATIC S7/M7-400 automation system and on additional modules which have been developed for the special requirements of control and protection.

The following modules form the basic complement of the SICAM SC:

- Power Supply
- SIMATIC M7-400 CPU (Pentium processor)
- MCP (Modular Communication Processor)

The MCP module is the function module which supports the communication functions, such as telecontrol connection to higher-level system control centers, e.g. with the IEC 60870-5-101 protocol, and serial connection of bay control units by means of the IEC 60870-5-103 protocol. In addition, it is in SICAM SAS the time master, to which can be connected time signal receivers for DCF77 or GPS.

Additionally available for the MCP are the XC2 (eXtension Copper 2 interfaces) and XF6 (eXtension Fiber optic 6 interfaces) extension modules for additional communication interfaces to higher-level system control centers and bay control units (IEC 60870-5-103).

In addition, the following modules can be used for supplementary functions in the SICAM SC:

- For central process connection: SICAM I/O modules (see description of the SICAM RTU) and SIMATIC 400 Standard I/O modules (see Siemens Catalog ST 70)
- For connection of bay control units via Profibus DP and FMS: SIMATIC 400 communication processor modules
- For connection to SICAM WinCC: SIMATIC 400 modules for Profibus FMS and Industrial Ethernet

Construction

Like the SICAM RTU, the SICAM SC is based on the SIMATIC 400. Consequently, the statements on construction of the SICAM RTU are also applicable to the SICAM SC.

Software

The bases of the run-time system (SICAM RTC for SAS) in the SICAM SC are to be found both on the M7-CPU and on the MCP module real-time operating systems for event-controlled program execution. Among other things, this assures an essential requirement for control applications: State change of information may not be lost or remain unnoticed in critical situations (→ alarm surge).

System security

SICAM SAS fulfills to a very considerable extent the reliability and security requirements imposed on a substation control and protection system. In the case of all electronic devices incorporated in the SAS SICAM System, special attention has been paid to electromagnetic compatibility.

Interruption of power supply

The SICAM SAS System is designed to be maintenance-free, that is to say no backup batteries are required for restart after mains failure.

Safety functions

Hardware self-test: On startup and cyclically in the background.
General check: At start of the transfer time system and creep mode in background.

Communication

Errors in data transmission due to electromagnetic effects, earth potential differences, ageing of components and other sources of interference and noise on the transmission channels are reliably detected. The safety measures of the protocols provide protection from:

- Bit and message errors
- Information loss
- Unwanted information
- Separation or interference of assembled items of information

Priority-controlled message initialization

Messages initiated by events are initialized quickly (priority-controlled).

Failure indication

The failure status is derived in case of:

- Contact chatter
- Signalling-circuit voltage failure
- Module out of order

A telecontrol malfunction group alarm can be parameterized from individual pieces of information, for example:

- MCB trip
- Voice-frequency telegraphy error
- Channel error
- No signalling-circuit voltage
- Module out of order
- Buffer overflow

Measured value capturing

- Live zero monitoring (4–20 mA)

Command output

Safe command output, i.e.

- Destination monitoring (1-out-of-n)
- Switching current check
- Interference voltage monitoring
- Determination of the coil resistance

The SICAM SC system provides the following five operating modes, thus allowing the user to take into account different safety requirements for process output:

- 1-pole command output
- $1^1/_2$-pole command output
- 2-pole command output
- $1^1/_2$-pole command output with separate command release through CR module
- 2-pole command output with separate command release through CR module

By combining the CO module with the CR module, a single error (in case of $1^1/_2$-pole command output) in the command output circuit results in the command not being executed.

Through the test and monitoring measures provided by the CR module, which make it possible to distribute the command output circuit to two independent modules, high requirements are met.

System capacity

The maximum configuration of the SICAM SC substation controller consists of:

- 1 baseframe with 7 to 11 free module locations, dependent on choice of MCP communication link and
- Maximum of 6 expansion racks, each with 14 free module locations

Thus, you have available a maximum of 95 free module locations which you can equip for example with 95 I/O modules or a further 4 MCP(4) communication assemblies and 75 I/O modules. For connection of bay control units via PROFIBUS FMS, up to 4 CP443-5 base communication processors can be plugged into the baseframe. Each CP443-5 requires one module location. For connection of PROFIBUS DP devices, an interface module is used which is plugged into a module shaft of the CPU module. Connection to Industrial Ethernet can be implemented via the CP443-1 communication processor and will then require one module location. Alternatively, you can also however use the CP1401 interface module which is plugged into a module shaft of the CPU module.

Under these conditions, it is possible to implement up to a maximum of 3040 items of information to a SICAM SC via centralized process connection. With the use of bay control units – linked to the SICAM SC via MCP communication assemblies or PROFIBUS – it is possible for up to 10,000 items of information to be managed, for decentralized process connection.

Interfaces

The variability and expansion capability of a substation control and protection system depends primarily on its outward interfaces. SICAM SAS supports international standards, such as PROFIBUS, the IEC 60870 5-101 telecontrol protocol or the IEC 60870-5-103 relay communication protocol and thus assures optimum flexibility of substation planning.

The SICAM communication modules of the SICAM SC are equipped with serial interfaces (parameterizable as RS232 or as RS422/485) and with optical fiber links. They are combined, according to application, to form MCP communication assemblies which consist of the MCP communication processor and XC2 and/or XF expansion modules.

Local and Remote Control
SICAM SAS – SC Substation Controller

Telecontrol interfaces

Via the serial interfaces of the MCP communication processor and the XC2 expansion modules, one can connect the SICAM SC to a maximum of three higher-level system control centers.

The telecontrol interfaces are operated with the IEC 60870-5-101 or SINAUT 8FW transmission protocols and are parameterizable as RS232, RS422/RS485 or optical fiber interfaces.

Bay control unit interfaces

For connection of decentralized items of information via bay control interfaces, various options are available:

- A maximum of 4 CP 443-5 base modules for connection of bay control units with PROFIBUS FMS interface. One can connect a maximum of 48 devices (SIPROTEC 4, 6MB525) per module; the total number in the design may not however exceed 96 devices.
- One IF964-DP interface module for connection of a maximum of 20 SU200 bay control units and/or SIMEAS measuring transducers via PROFIBUS DP. For all other bay control units with PROFIBUS DP interface, the upper limit of 127 devices will apply.
- A maximum of 4 MCP(4) communication assemblies, each consisting of one MCP communication processor and 4 XF6 expansion modules with optical fiber interfaces for a maximum of 96 bay control units (IEC 60870-5-103).
- A maximum of 1 MCP (1) communication assembly (consisting of 1 MCP communication processor and 1 XC2 expansion module) and 1 MCP communication assembly (consisting of 1 MCP communication processor) for a maximum of 186 bay control units via a maximum of 6 RS485 lines (IEC 60870-5-103).

Combinations of the above examples are possible, but the quantity of 10,000 information points should not be exceeded.

MPI interface

On the CPU module is located 1 MPI interface (token ring multipoint-capability bus structure) for design, parameterizing, diagnostics.

Time signal reception

The MCP communication processor possesses an interface for receipt of an external time signal. Time synchronization is effected by means of DCF77 or GPS.

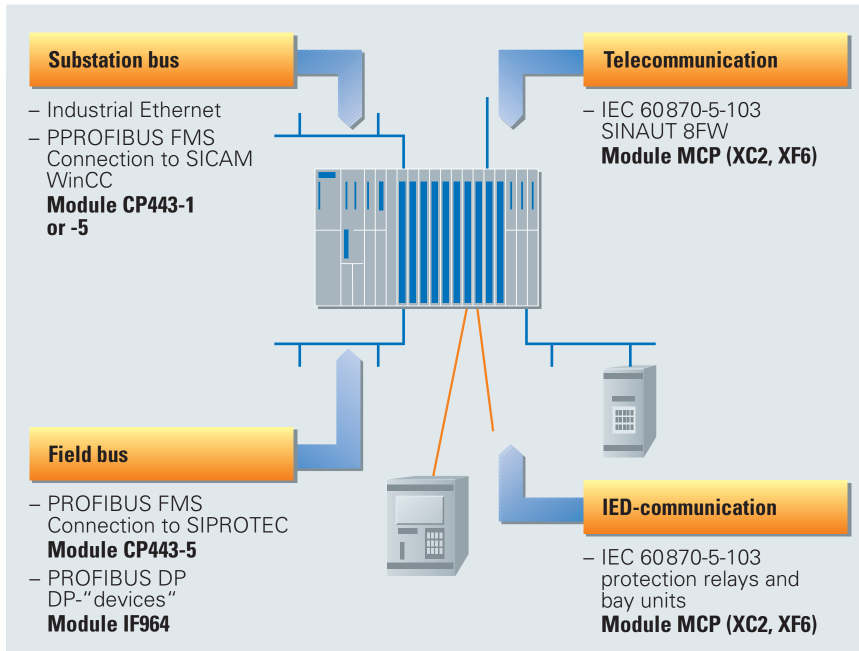


Fig. 194: SICAM SC communication interfaces

Design tools

Design of the SICAM SC is carried out with SICAM plusTOOLS which is based on the SIMATIC basic modules: STEP7, SIMATIC CFC and Borland C/C++.

Process visualization

For visualization and control of the process, SICAM WinCC is used; this is based on SIMATIC WinCC.

Expandability

SICAM has been designed for a new generation of devices and function modules for the automation of substations in power supply.

SICAM integrates complementary and compatible product lines and is the logical continuation of proven, available modules.

By virtue of its open system concept, SICAM SAS is adaptable to the growing demands of the future. System expansion and further development are readily possible.

Bay control units

In the design and parameterizing of subdevice connections, SICAM plusTOOLS accesses databases which describe the interface complement of the devices. Creation of a new protection unit type with IEC 60870-5-103 transmission protocol is made possible by the parameterizer in SICAM plusTOOLS.

Protocols

Telecontrol and field bus protocols will in future be incorporated in modular fashion by means of an expansion interface.

SIMATIC modules

Within SICAM SAS, it is possible to use the SIMATIC Standard I/O modules (see Siemens Catalog ST70, Siemens Components for Totally Integrated Automation.)

Local and Remote Control
SICAM SAS – Bay Control Units

Bay control units

Serial connection of distributed bay control units allows access to extensive detailed information about your switchgear in the substation control and protection system.

For this purpose, SICAM SAS offers bay control units with differing scope of information and function. The range extends, according to requirements, from pure bay control units and protection relays on the one hand, to combined devices on the other hand which provide the bay protection and control functions in a single unit. SICAM SAS supports bay control units with IEC 60870-5-103, PROFIBUS FMS and PROFIBUS DP interface.

6MB525 Mini Bay Unit

(see description of SINAUT LSA)

This low-end unit with its limited range of information is preferably used in single-busbar substations. It can be connected via RS485 with IEC 60870-5-103 or via PROFIBUS FMS to the SICAM SC.

7SJ531 Combined
Bay Control and Protection Unit

(see description of SINAUT LSA and Power System Protection)

The 7SJ531 possesses, in addition to protection functions, the facility for controlling a switching device (also remotely). It can be integrated in the SICAM SAS with IEC 60870-5-103 via optical fiber link.

Design	Type	Commands Double	Commands Single	Signal inputs Double	Signal inputs Single	Analog inputs: Direct connection to transformer	Analog inputs: Connection to measure transducer	Components
Compact bay control unit (SIPROTEC 4 design with large graphic display) 1)	6MD631	4	–	5	1	4 x I, 3 x U	–	Bay control units in new design, optimized for medium voltage switchgear with $1^1/_2$-pole control (max. 7 switching devices). 2-pole control is also possible (with max. 4 switching devices). Double commands and alarms also usable as "single"
	6MD632	5 + 4 2)	1	12	–	4 x I, 3 x U	–	
	6MD633	5 + 4 2)	1	10	–	4 x I, 3 x U	2	
	6MD634	3 + 4 2)	–	10	–	–	–	
	6MD635	7 + 8 2)	–	18	1	4 x I, 3 x U	–	
	6MD636	7 + 8 2)	–	16	1	4 x I, 3 x U	2	
	6MD637	4 + 8 2)	1	16	1	–	–	
Combined control and protection device with local bay control 1)	7SJ610	–	4	–	3	4 x I	–	Combined control and protection devices. 7SJ61 and 7SJ62 with 4 line text display, 7SJ63 with graphic display. Optimized for $1^1/_2$ pole control (max.7 switching devices). 2-pole control is also possible (with max. 4 switching devices). Double commands and alarms also usable as "single"
	7SJ612	–	6	–	11	4 x I	–	
	7SJ621	–	8	–	7	4 x I, 3 x U	–	
	7SJ622	–	7	–	11	4 x I, 3 x U	–	
	7SJ631	4	–	5	1	4 x I, 3 x U	–	
	7SJ632	5 + 4 2)	1	12	–	4 x I, 3 x U	–	
	7SJ633	5 + 4 2)	1	10	–	4 x I, 3 x U	2	
	7SJ635	7 + 8 2)	–	18	1	4 x I, 3 x U	–	
	7SJ636	7 + 8 2)	–	16	1	4 x I, 3 x U	2	

1) $1^1/_2$-pole control; 2-pole control possible
2) Second figure is number of heavy duty relays

Fig. 195: Survey of bay units

Local and Remote Control
SICAM SAS – Bay Control Units

SIPROTEC 4

(see description of Power System Protection)

The 7SJ63 and the 6MD63 are designed for larger volumes of information and thus are also suitable for use in duplicate-busbar substations.
SIPROTEC 4 units are preferably connected to the SICAM SAS via PROFIBUS FMS. Connection via IEC 60870-5-103 with reduced functionality (compared to the use of PROFIBUS FM) is also possible.

The SIPROTEC 4 7SJ61 and 7SJ62 relays can also be used via Profibus FMS and IEC 60870-5-103 in SICAM SAS. These two units support control of the feeder circuit-breaker.

Protective relays (V3 type)

By means of IEC 60870-5-103, all SIPROTEC 3 protective relays (see Power System Protection, page **6**/8), and also protection relays of other manufacturers supporting IEC 60870-5-103 can be connected to the SICAM SC substation controller.

Other bay control units

In addition, the following can be connected to the SICAM SC:

- SIMEAS T transducer via IEC 60870-5-103
- SIMEAS Q Power Quality via PROFIBUS DP
- Maschinenfabrik Reinhausen transformer tap voltage controllers (for example VC100, MK30E) via IEC 60870-5-103
- Eberle transformer tap voltage controller (RegD) via IEC 60870-5-103
- SU200 bay control unit for high-voltage use via PROFIBUS DP
- Decentralized peripherals via PROFIBUS DP (for example ET200)

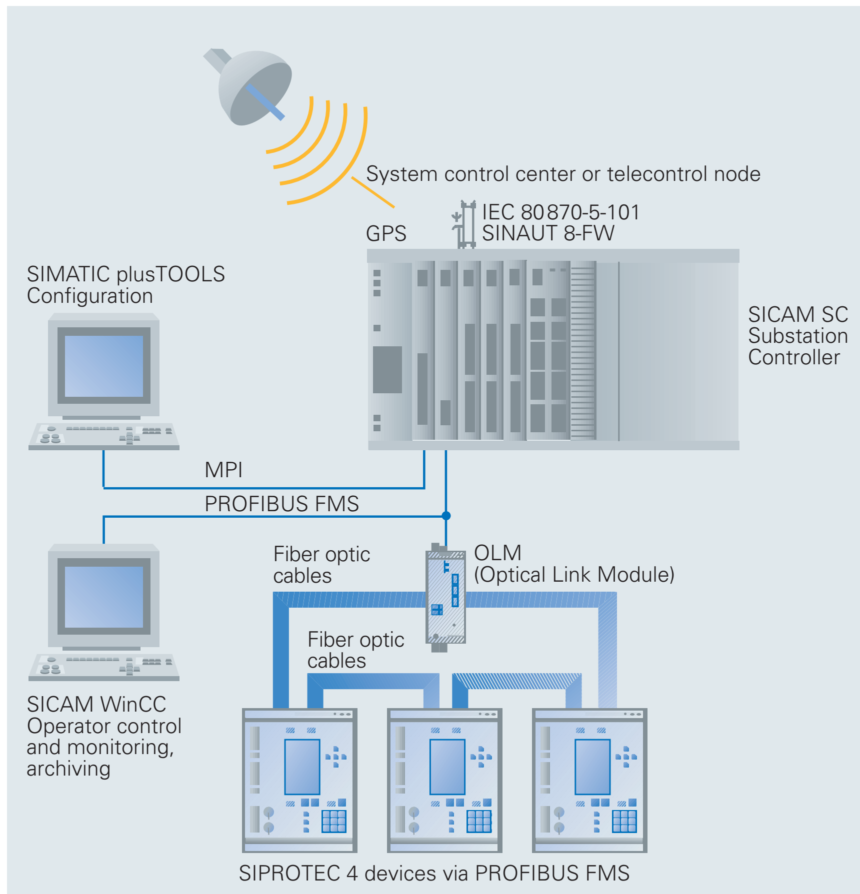


Fig.196: SICAM SAS, connection of SIPROTEC 4 bay control units via PROFIBUS FMS and optical fiber

6

Local and Remote Control
SICAM SAS – Human-Machine Interface

SICAM WinCC

In the SICAM SAS substation automation system, SICAM WinCC is the human-machine interface HMI between the user and the computer-assisted monitoring and control system.
For efficient system management, numerous single information items must be displayed quickly and clearly.
The state of the substation must be displayed and logged correctly at all times. Important indications, along with measured and metered values of past time periods must be archived in such a way that they are available for specific evaluation in the form of curves or tables at any time.
The SICAM WinCC human-machine interface meets these requirements for efficient system management and also provides the user with numerous options for individual design of the system user interface and numerous open interfaces for implementing operation-specific functions. The windowing technique of SICAM WinCC makes it easier to work with. In designing the graphic displays, the user has every degree of freedom and also has the support of a pool of predefined substation automation symbols such as switchgear, transformers or bay devices.
SICAM WinCC consists of the WinCC process visualization system and SICAM software components.

- WinCC
  WinCC offers standard function modules for graphical display, for messaging, archiving and reporting. Its powerful process interface, fast display refresh and reliable data archiving function assure high availability.
  S7-PMC serves as a basis for a chronological messaging and archiving of data.
- SICAM components
  They consist of:
  – SICAM symbol library,
  – SICAM message management expansion,
  – SICAM wizards,
  – SICAM processing functions and
  – SICAM Valpro, (Measured/ Metered Value Processing Unit)

SICAM symbol library

The SICAM symbol library contains switchgear, bay devices, transformers and other object templates for bay representations which are typical for substation control and protection systems. One can use them for designing detail images. The symbols are selected from the library and placed in a detail image using the Drag & Drop function. The symbols are dynamized. Thus, for example, there are several different views of a circuit-breaker which visualize the ON, OFF or fault position switching states.

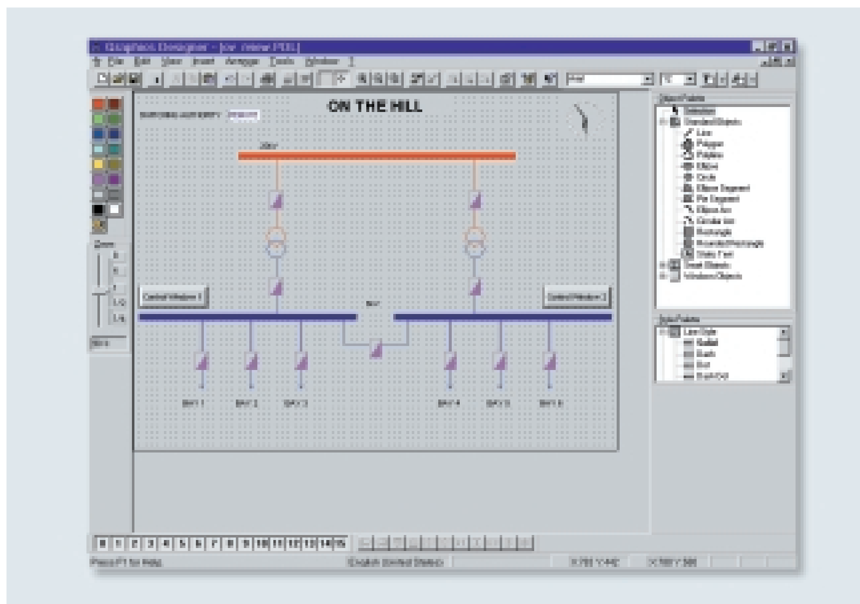


Fig. 197: Overview diagram in Graphics Designer

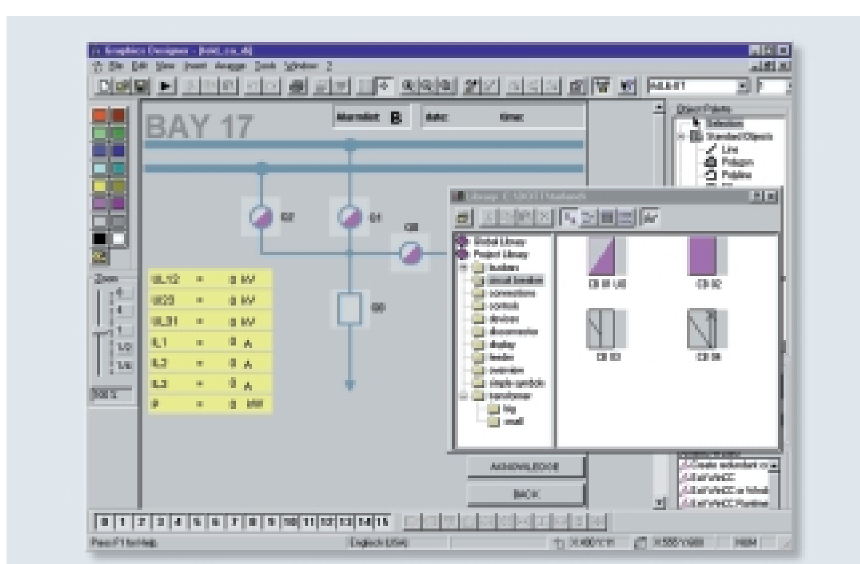


Fig. 198: Selecting a circuit-breaker from the symbol library

Local and Remote Control
SICAM SAS – Human-Machine Interface

SICAM message management expansion

The SICAM message management expansion ensures a chronological messaging and archiving of data. On the basis of S7-PMC, the SICAM Format DLL evaluates the data and assigns the corresponding messages to them. Based on this, a millisecond resolution of all events is given and for every event not only the state of indication itself is available, but also additional information without the need for additional parameterizing effort.
For message assignment, the format DLL recurs to the WinCC text libary. You can adapt the texts contained in the text library to meet your project-specific requirements.

SICAM wizards

The SICAM wizards assist the user in creating a new WinCC project. The following tasks are carried out with help of the wizards:

- Creating SICAM structure types:
  The Create SICAM tag structure types wizard helps the user to generate the structure types for structured tags which are necessary in a SICAM system.
  Structure types are needed for importing tags from SICAM plusTOOLS.
- Taking over tags from SICAM plusTOOLS:
  The Import SICAM tags wizard helps to import tags from SICAM plusTOOLS into SICAM WinCC.
  This function allows the user to visualize information, i.e. to represent it in process diagrams, configured and parameterized with SICAM plusTOOLS.
- Creating the SICAM message management:

  The SICAM message management wizard helps the user to generate a message management system under WinCC which meets the specific requirements of a substation automation system.
  In addition to a message archive, the SICAM message management includes the following templates: event list, alarm list and protection message list.
  Each of these lists always contains message blocks, message window templates, message line formats, message classes, message sequence reports, layouts and texts.

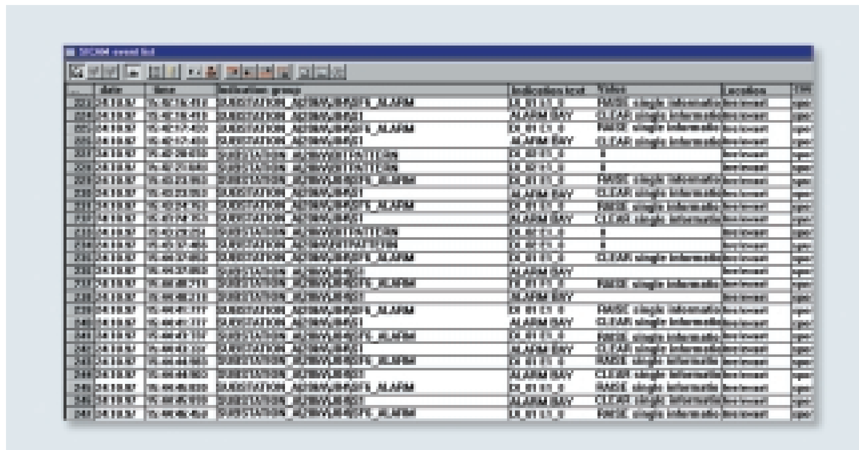


Fig.199: SICAM WinCC event list

- Taking over messages from SICAM plusTOOLS:
  The Import SICAM messages wizard helps the user to import messages from SICAM plusTOOLS into WinCC.
  This function allows the user to report information in the message management system which was configured and parameterized with SICAM plusTOOLS. This function allows the user to visualize information from SICAM plusTOOLS under WinCC, i.e. to use it in process diagrams.
- Creating the SICAM archiving system:
  The Create SICAM archives wizard helps generation of an archiving system under WinCC. The SICAM WinCC archiving system consists of:
  – a sequence archive for measured values and
  – a sequence archive for metered values.

One can import metered values und measured values from SICAM plusTOOLS into this archiving system.

- Integrating the SICAM symbol library:
  The Import SICAM libary wizard helps the user to load the SICAM symbol library into the current project. One can use the symbol library for designing individual detail images.

Local and Remote Control
SICAM SAS – Engineering Tools

SICAM Valpro

Curve and tabular display of archived measured values and metered values is carried out by means of the SICAM Valpro program. Valpro provides the facility for using archived values for various evaluation purposes, without altering them in the archive. The user decides at the time of evaluation (in a dialog) which values should be displayed in which raster. In addition to the variables to be displayed, he specifies the time range, the color and if necessary the mathematical function to be carried out. One can have totals, averages, maximums, minimums or the power factor formed and displayed. The calculation interval can be individually specified. Stored presets can be altered at any time.

Engineering System SICAM plus TOOLS

With SICAM plusTOOLS, a versatile and powerful system solution is available, which supports the user efficiently in configuring and parameterizing the SICAM SAS (SICAM Substation Automation System). SICAM plusTOOLS is based on Windows 95 and Windows NT. Thus the user moves within a familiar system environment and can recur to the well-known, convenient functionality of the Windows technique.

SICAM plusTOOLS allows a flexible procedure when configuring and parameterizing a station, while providing consequent user guidance at the same time.

Plausibility checks allow only operations and combinations which are permissible in the respective context.

- Permissible input variables are displayed in drop-down lists or scroll boxes.
- The Drag & Drop function makes it easy to group, separate or move data.
- Context-sensitive help texts explain the text boxes and the permissible input variables.
- Copy functions on different levels optimize the configuration procedure.
- Help texts which are organized according to topics explain the configuration.

The SICAM plusTOOLS Software Package

The SICAM plusTOOLS configuration system is divided into individual, function-specific applications.

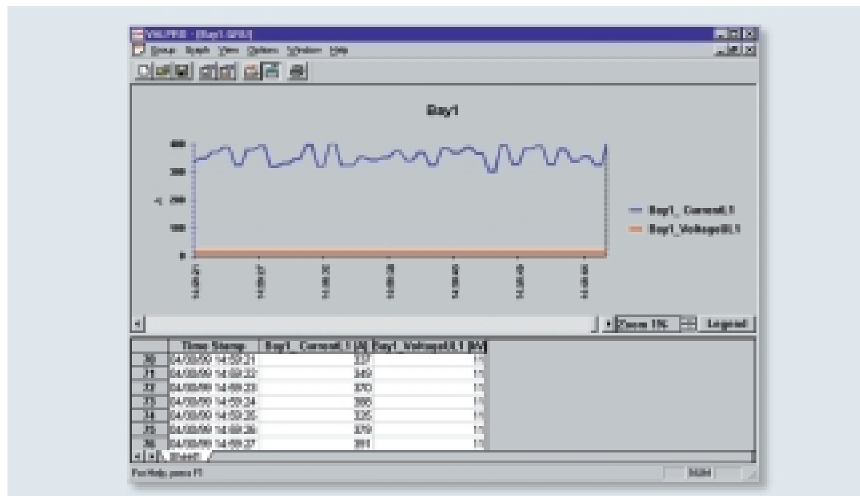


Fig. 200: Example of curve evaluation using Valpro

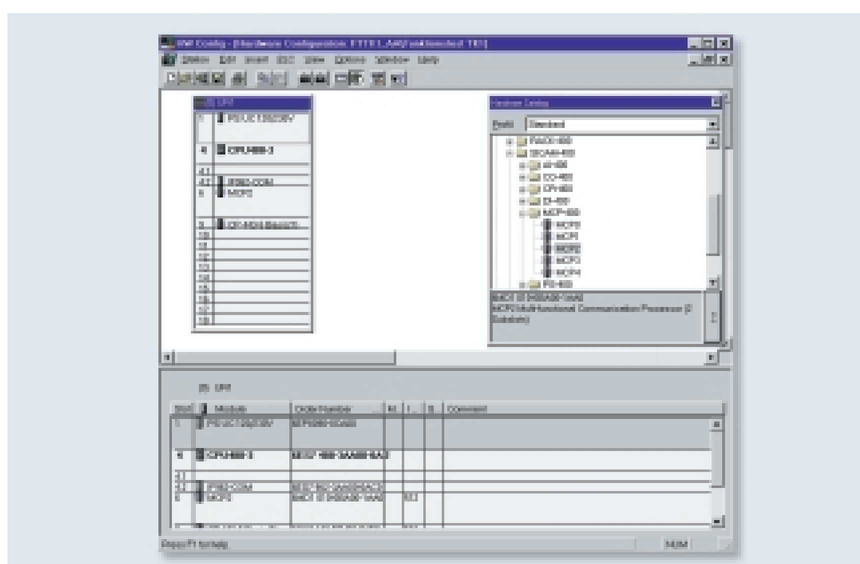


Fig. 201: Hardware Configuration of a demo station

SIMATIC Manager

The SIMATIC Manager is the platform of SICAM plusTOOLS. With the help of the SIMATIC Manager, the user defines and manages the project and calls the individual applications.
The project structure is created automatically in the course of the configuration procedure. The data areas are organized in separate containers.
In the navigation window of the SIMATIC Manager, the project structure is represented similar to a Windows 95 directory tree. Each container corresponds to a folder on the respective hierarchical level.

Hardware Configuration

The Hardware (HW) Configuration application serves for configuring the modules and their parameters. The configuration is represented as a table on the screen. The user chooses the components from a Hardware Catalog and places them into the hardware configuration window using Drag & Drop or double-clicks. The tabs for parameterizing the modules are already filled with the default values, which can be modified by the user.

Local and Remote Control
SICAM SAS – Engineering Tools

COM IED

The COM IED application (Communication to Intelligent Electronic Devices) serves for configuring the connection of bay devices in control and monitoring direction.

The bay devices are imported into COM IED with their maximum information volume from an IED Catalog using Drag & Drop. The information volume can be reduced later. If SIPROTEC 4 bay units with Profibus FMS communication are used, then the information parameterized with DIGSI 4 will be taken over automatically.

COM TC

The COM TC application manages all parameters which are related to the information exchange with higher-level control centers. The telegrams are configured separately for control and monitoring direction. For the transmission of the telegrams in monitoring direction, these are assigned to priority-specific and type-specific lists. The list types are provided in a Telecontrol List Catalog and are copied into COM TC using Drag & Drop.

CFC

In the SICAM SAS System, automation functions, such as:

- Bay-related and cross-bay interlocks
- Switching sequences (busbar changes, etc.)
- Status indication and command derivatives (group indications, load shedding, etc.)
- Measured value and metered value processing (limit value processing, comparative functions, etc.)

are projected graphically with the CFC (Continuous Function Chart).

The scope of supply of SICAM plusTOOLS includes a comprehensive library of SICAM SAS components. The designer makes his selection from this library, positions the selected component by Drag and Drop on his worksheet and interconnects the components required for its function to one another and to the process signals.

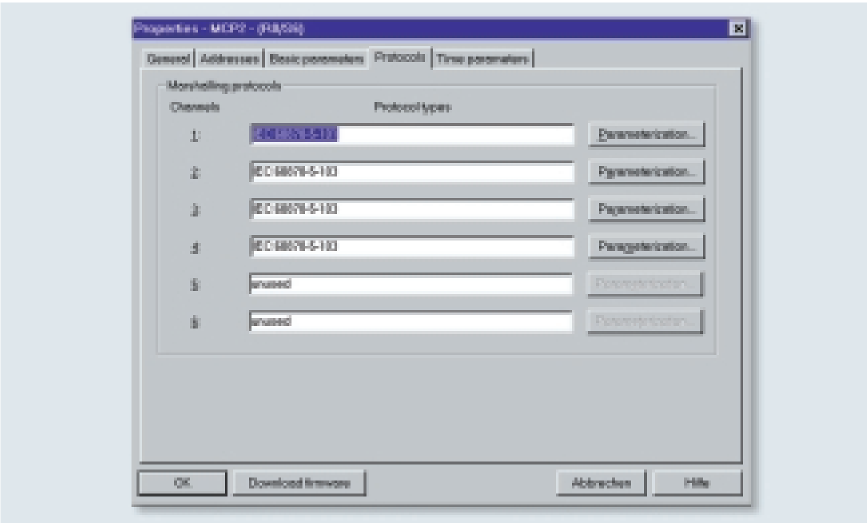


Fig. 202: MCP Parameterizing

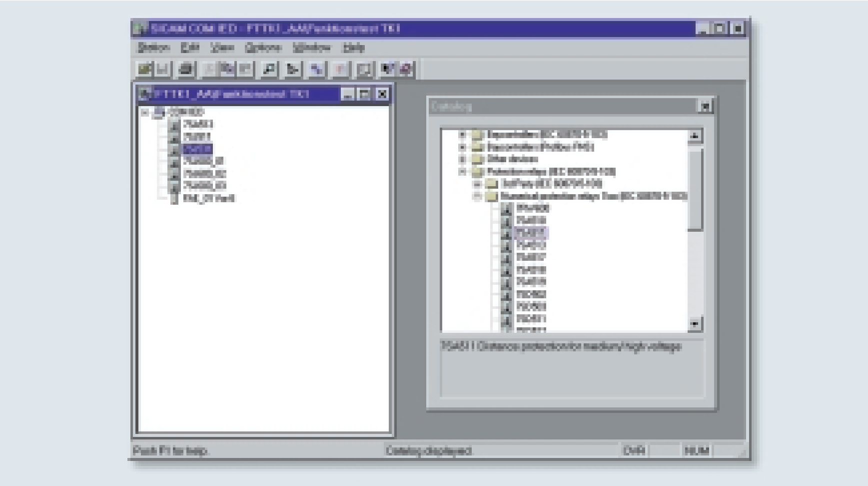


Fig. 203: COM IED and bay units catalog

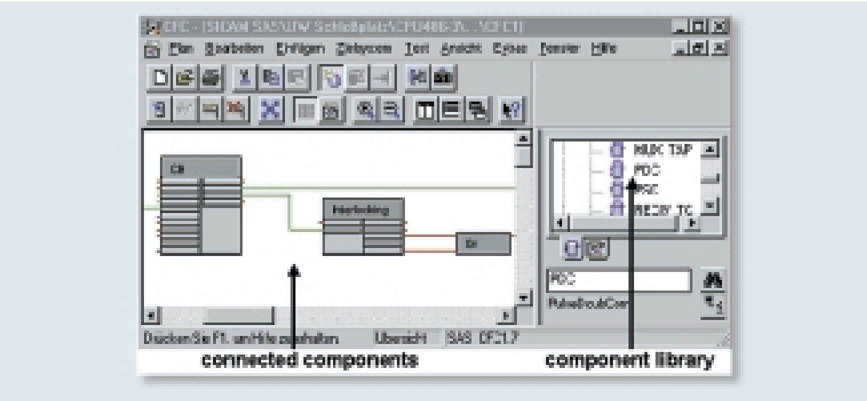


Fig. 204: CFC with Component Library

Local and Remote Control
SICAM PCC – System Design

Introduction

Changing requirements

The ongoing deregulation of the power supply industry has been creating a competitive environment with new challenges for the utilities:

- The liberalized production, transmission and distribution of electrical power call for more flexible operation of the power system resulting in more complex control, metering and accounting procedures.
- The deregulated system structure requires the extension of load and quality of supply monitoring, as well as event and disturbance recording, to control the business processes and to care for liability cases.
- Operation data that has traditionally been used only within a given utility must now be shared by a number of players in various locations, such as utilities, independent power producers, system operators and metering or billing companies. More effective data acquisition, archiving and communication is therefore needed.
- Competition requires that costs have to be reduced wherever possible. The optimization of processes has consequently been given high priority. System automation and in particular distribution automation including automatic meter reading and customer load control can therefore be observed as the future trend.

The SICAM PCC meets these requirements by integrating modern PC-technology and open communication.

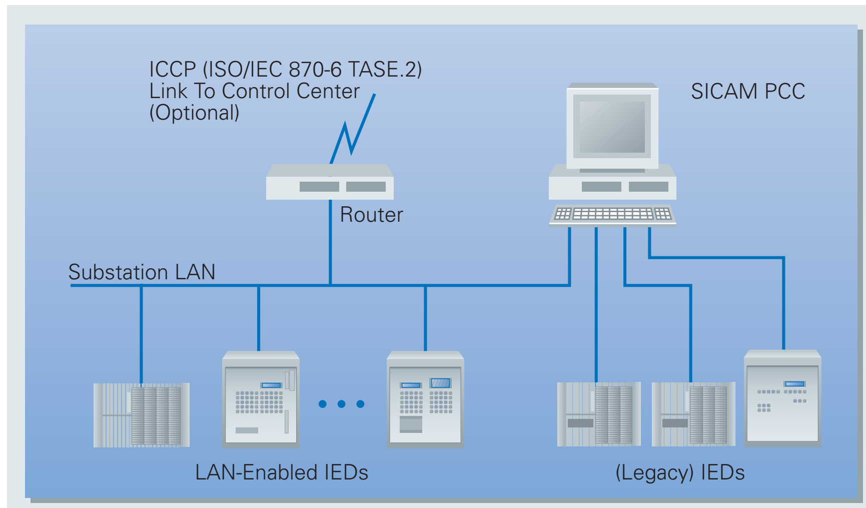


Fig. 205: Sample Substation with SICAM PCC

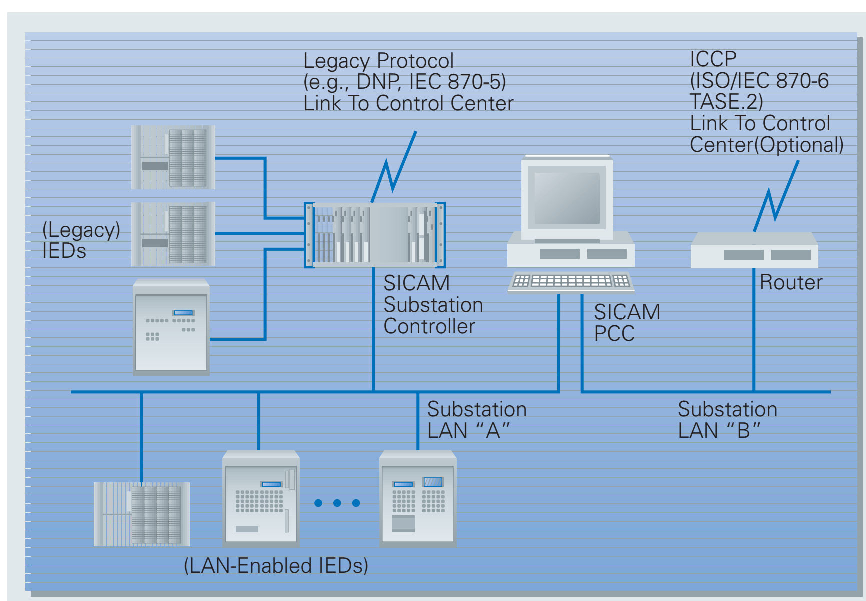


Fig. 206: Sample Substation with SICAM PCC and SICAM SC

Some Typical Configurations

PC-Based Substation Automation

Fig. 203 illustrates a typical configuration employing the SICAM PCC. The components of such a configuration include:

- SICAM PCC.
- Substation LAN.
- One or more LAN Enabled Intelligent Electronic Devices (IEDs).
- One or more legacy IEDs, connected to the PCC in a star configuration.
- One or more RTUs.
- ICCP communications to a Control Center (optional).
- Siemens' SICAM WinCC Human Machine Interface (HMI) (optional component of SICAM PCC).

Local and Remote Control
SICAM PCC – System Design

A PLC can be added

This, of course, is not the only way in which the SICAM PCC may be used in a substation configuration. Fig. 206 illustrates a slightly more complex substation configuration which includes both the SICAM PCC and the SICAM Substation Controller (SC)[1]. The SICAM Substation Controller is an advanced Programmable Logic Controller (PLC) (see **6**/109 and following pages).

Open-ness

A product is not "open" just because its manufacturer decides to publish the specifications of a proprietary communications protocol. A product is really open if it supports standard and de facto industry standard communications.

There was a time, not so very long ago, when vendors of substation and control center equipment offered only proprietary solutions. The designer and maintainer of substations was forced to choose among a number of options, many – in fact almost all-of which would force the designer to use a proprietary communications protocol. After the choice, either the future options became very limited or one was forced to deal with the problem of installing protocol gateways. With SICAM, those days are over. SICAM, and specifically the SICAM PCC, are designed with "open-ness" as a primary design consideration. Siemens' goal in designing this product line is to provide the tools and features which enable the user to design and upgrade the substations the way he wants.

The sample configuration diagrams shown are not meant to illustrate all the possible configurations using the PCC and other components of the SICAM product line. Rather, they show that the components of the SICAM product line are designed so that users may take a "building block" approach to designing or upgrading their substations.

[1] In PCC version 2.0, WinCC is required for configurations in which there is communication between PCC and the SICAM Substation Controller.

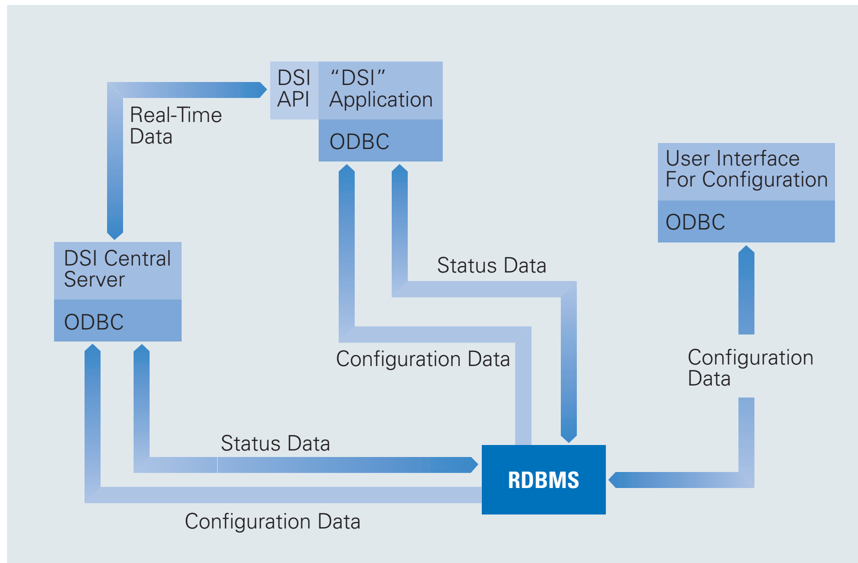


Fig. 207: DSI with RDBMS

PCC At A Glance

Platform

The SICAM PCC executes on Intel-based hardware running the Microsoft Windows NT operating system (Version 4.0 and above). Siemens chose this platform because it offers an effective combination of low hardware and software cost, ease of use, scalability, flexibility, and easy access to support.

Distributed Architecture & Database

The SICAM PCC uses a high-performance data distribution subsystem for distribution of real-time data among system components. The data distribution subsystem permits distribution of applications across multiple computers to address performance, physical connectivity and redundancy requirements. This means that if a configuration contains more devices than can physically be connected to a single computer, one can distribute the system across multiple computers. Or, if the applications require more processing power than can be provided by a single computer, one can solve the problem by adding additional computers to the system and distributing the processing load.

In designing the PCC, the data distribution subsystem was combined with a standard third-party RDBMS. The PCC architecture uses the RDBMS to do what an RDBMS does best – organize and store data.

The architecture uses the data distribution subsystem to augment the RDBMS to meet those data distribution performance requirements which the RDBMS cannot address.

The presence of both the data distribution subsystem and the RDBMS is largely transparent to the average user. However, for designers and programmers who wish to interface to the PCC infrastructure, Siemens publishes full details of the Applications Programming Interface (API) provided by the data distribution system, including all details of the RDBMS data model used by SICAM PCC.

DSI (Distributed System Infrastructure) is a simple data distribution switch which operates in conjunction with a standard RDBMS. While DSI does have some characteristics of a database, it lacks certain others, so it is not referred to as a database.
DSI allows distributed applications to share data in a consistent, efficient (i.e. high-performance) manner.

There are three basic components which make up DSI:

- A central application called the DSI central server.
- A collection of interface functions which make up the DSI API.
- A data model which describes the RDBMS tables used to store the configuration and status information used by DSI and applications which interface to DSI.

6

Local and Remote Control
SICAM PCC – System Design

Interfacing to Other Systems

The PCC is designed to be an effective integration platform by including support for both modern and legacy communications protocols.

The SICAM PCC does several things to simplify the task of interfacing to other systems:

- The interface to PCC's data distribution subsystem is fully externalized and documented. All interfaces are available for use by customers or third parties in developing software (including gateways) to interface to the PCC. Siemens provides a Software Development Kit which can automatically generate the basis for a working application, as well as the user interface windows to configure it.
  PCC's DB Gateway feature allows you to use familiar RDBMS tools and techniques to exchange data with the PCC. DB Gateway provides a bidirectional mechanism which may be used to insert data into the real-time data distribution system via the RDBMS. That is, one can write an object into the RDBMS using, for example, SQL statements. DB Gateway will retrieve that object from the RDBMS and enter it into the real-time data distribution stream for distribution to other components of the system. Similarly, one can configure DB Gateway to accept data objects from the real-time data distribution stream and write them into the RDBMS. The user can then read them using RDBMS tools and techniques. All of this can be done with almost no knowledge of the internals of the PCC architecture – all one needs to know is which RDBMS table to read and/or which to write.
  Fig. 208 illustrates the position of Device Master in the architecture. In this picture, it is easy to visualize a protocol module which is isolated from other system components while at the same time has full access to all system services required.
- Version 2.0 of PCC makes available a set of ActiveX controls which can be embedded into an ActiveX container application. This feature is included as a "proof of concept" feature to explore the scope of the ability to embed a real-time value from PCC's data distribution subsystem into a "web" document.

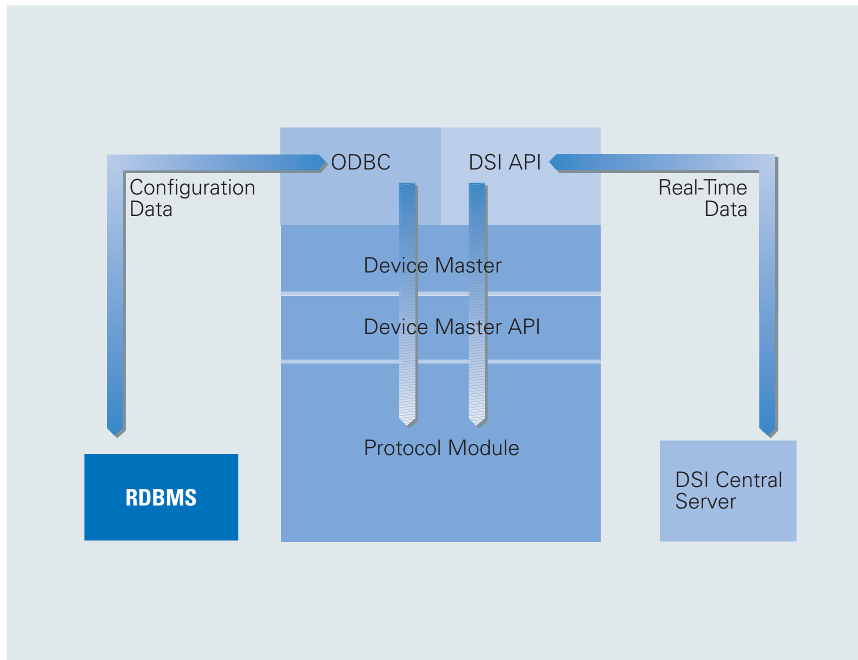


Fig. 208: Device Master

"Enterprise" Protocols

Siemens is the acknowledged leader in delivering ICCP solutions. The PCC's full-featured ICCP implementation allows communication with any system which supports this popular protocol. PCC's ICCP currently supports Conformance Blocks 1, 2, 5, and 8.

Whenever a power system disturbance occurs or even during normal operations, it is very useful to be able to collect a log of changes in one or more data objects. Many modern field devices (e.g. relays, meters, etc.) allow collection of this type of data within the device itself. However, many others do not. PCC's Sequence of Events Logger option allows collection and storage to the RDBMS of any data objects processed by PCC's data distribution subsystem. Data may be collected either periodically or "on event". Since data are stored into the RDBMS, they may be retrieved for analysis using standard RDBMS tools and techniques.

"Legacy" Protocols

Perhaps the largest problem the user will tackle in attempting to upgrade and automate existing substations arises from the large number of communications protocols used by existing equipment in those substations. Many of these devices simply will not talk to each other. Many of them will not talk to the control center. Even if a completely new substation is built, one may face this problem because the choice of devices may be limited by the suite of protocols which are supported by the existing SCADA or EMS system.

A primary design consideration in the PCC is the ability to support legacy[1)] protocols. The ability to support these protocols has been enhanced by a PCC feature called **Device Master.** It allows Siemens (and third parties) to develop protocol modules in much less time than would be required for a traditional system. This means that more protocols can be made available more quickly and at reduced cost.

[1)] "Legacy", when used to refer to communications protocols, is an euphemism for "old and proprietary".

6

Local and Remote Control
SICAM PCC – System Design

Data Conditioning

The SICAM PCC includes the feature **Data Normalization** (or simply **Normalization**) which provides a simplified method by which **normalize procedures** may be associated with data objects. These normalize procedures perform transformations on data objects as they enter and leave PCC's data distribution subsystem. The types of transformation which may be performed include (but are not limited to): jitter suppression, deadband calculations, linear transformation, and curve-based transformation. In addition, custom procedures can be developed and added to the system to perform any type of calculation and data transformation. Up to 16 normalization procedures may be concatenated and applied to a single data object. PCC's user interface provides a simple, intuitive way to create custom normalization procedures and associate normalization procedures with individual data objects or groups of data objects.

Human-Machine Interface.

Frequently, it is desirable for personnel working in a substation to have access to HMI displays. If an HMI is available in the substation, costs can be reduced by eliminating or reducing the size of local control panels and the wiring associated with them. Additionally, well-designed HMI displays can reduce the risk of error by presenting data and controls in a logical schematic representation – interlocks can be included to prevent certain operations or to "remind" personnel to follow certain procedures.

If an HMI is used in a substation automation and integration system like the PCC, it is important to ensure that the HMI integrates well into the system. The HMI must be integrated in such a way that it does not become a performance "bottleneck". The HMI must not be the "center" of the substation automation architecture. No HMI offers a sufficient level of data distribution performance to allow it to be used as the "center" of the architecture. Another strong consideration in integrating an HMI is to ensure that whoever has the job of configuring the system is not required to enter data a number of times. Nor should the HMI require the user to become a computer programmer.

The PCC's optional HMI Gateway provides a pathway through which data are exchanged between PCC's data distribution subsystem and the HMI. Point and click methods are used to select data objects which are to be exchanged with the HMI. If one adds, for example, a new meter to the substation and one wants to place some data from that meter on an HMI one-line display, only a few mouse clicks are required to perform the task. Typing the name of a data object is at no time required. Definition of data objects may be performed either via PCC's user interface or from within the HMI.

The recommended HMI is the WinCC product from Siemens. While WinCC is a superior product, it is recognized that some customers have "standardized" on another product. The Siemens HMI Gateway however is designed to simplify customization to meet these requirements.

Local and Remote Control
SICAM PCC – User Interface

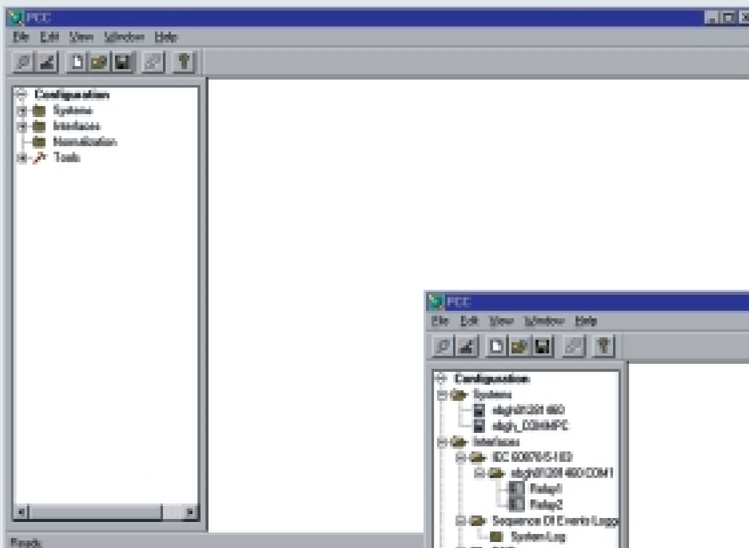


Fig. 209: PCC Main Configuration Window

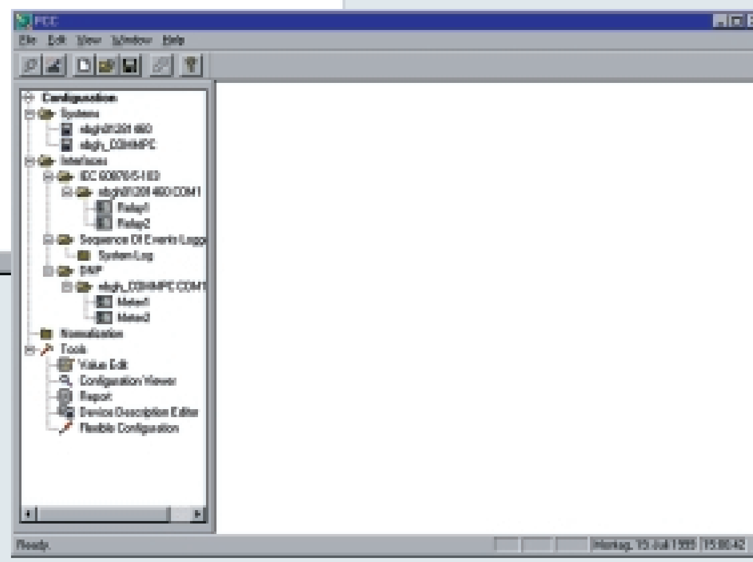


Fig. 210: PCC Configuration Window – Distributed System

User Interface

The user interface used to configure and operate the PCC is very much influenced by *de facto* industry standards. Specifically, the user interface has a ”look and feel” established by Microsoft’s Windows 95. The great popularity of Windows 95 made this an easy decision. The choice of a Windows 95 ”look and feel” means that the user interface is familiar to anyone who has used Windows 95 software. The PCC development team has worked with Siemens human factors engineers to make the user interface as intuitive as possible.

The PCC’s user interface is divided into two parts:

- User Interface for Configuration, also called the PCC Configuration Manager.
- User Interface for Operation, also called the PCC Operations Manager.

User Interface for Configuration

The PCC user interface is started just like any other Windows 95 or Windows NT 4.0 program:

1. Click on the **Start** button of the taskbar.
2. Select **Programs** from the menu which appears.
3. Select the **SICAM PCC** folder from the menu which then appears.
4. Double-click on **SICAM PCC**.

Now a window appears like shown in Fig. 209.

It looks like the Windows Explorer of Windows 95 and Windows NT 4.0. On the left is a navigation window. At the top is a menu bar and a tool bar. The navigation window can be undocked and then resized or moved around on your screen.

The navigation window has four elements:

- A **Systems** folder: By opening this folder, one sees an icon for each computer in the PCC configuration.
- An **Interfaces** folder: By opening this folder, one sees the interfaces which are configured on the PCC.
- A **Normalization** folder: By opening this folder, one is able to create custom normalize procedures.
- A **Tools** icon: By opening this, one sees a number of tools which may be used in configuration mode.

Fig. 210 illustrates the PCC main window (configuration mode) with several folders open. In this case, the system is a distributed configuration with two computers.

Local and Remote Control
SICAM PCC – User Interface

When the user wishes to work with an interface or device, it is done by double-clicking on the device he wishes to work with. For example, Fig. 211 shows the PCC user interface after double-clicking on **Meter1** (a relay which speaks the DNP 3.0 protocol). As one can see in this illustration, a new window has appeared on the right-hand side of the PCC main window. In this case, the new window contains a tabbed display which may be used to select and rename data objects from **Meter1**.

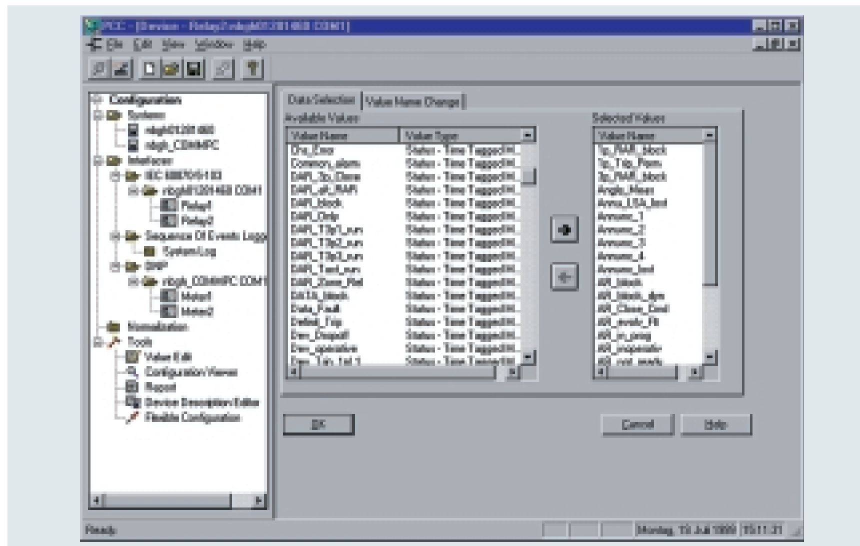


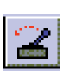
Fig. 211: Working with an Existing Device

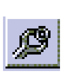
If a mistake is made…

The user can change interface and device parameters by double-clicking on the appropriate folders and / or icons. For example, by a double-click on the icon for a device, windows appear which are almost identical to those used to initially configure the device. By working with these windows, one can make any necessary changes to the PCC configuration.

User Interface for Operation

The user interface for operation is very much like what has already been shown. One can switch between two modes by clicking on toolbar buttons:

 selects configuration mode.

 selects operational mode.

The user interface in operational mode looks like the illustration in Fig. 212.

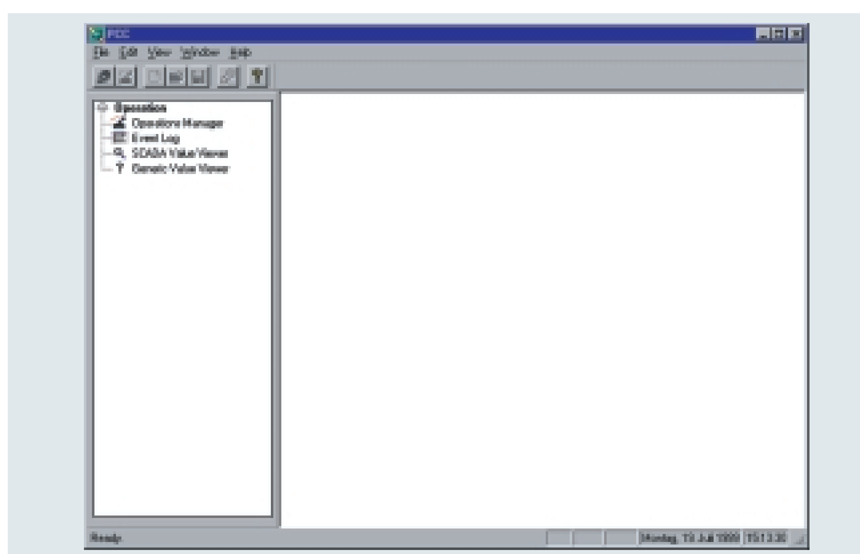


Fig. 212: User Interface (Operation Mode)

Navigation in operational mode is just like configuration mode. The items displayed on the navigation tree are very similar.

- **Operations Manager**: By double-clicking on this, the Operations Manager is opened which allows the user to view and control the status of the software and devices which make up the PCC system.
- **Event Log**: This is a tool which opens the Windows NT event log viewer. It is used to examine messages which PCC software places in the event log.
- **SCADA Value Viewer**: This is a tool which allows the user to examine data which is being distributed by PCC's data distribution subsystem. Using this tool, one can verify that changes which occur in a device are being correctly communicated throughout the system.
- **Generic Value Viewer**: This is a tool which allows the user to view details of complex data types used within PCC. Like the SCADA Value Viewer, it can also be used to view data being distributed by PCC's data distribution subsystem. It can also be used to introduce manual changes in data for debugging, testing, and checkout.

The PCC's Operations Manager displays are built automatically during system configuration. The configuration mode to add a new interface or device will appear on the Operations Manager display the next time the Operations Manager is started.

For those who want to customize their display, the PCC user interface provides an interactive tool for customizing colors and text on status indicators.

Local and Remote Control
SICAM PCC – Application Example

Application example for Sicam PCC

The example shows the application of SICAM PCC to a large industrial power supply system with distributed substations. (Fig. 213)
Remote substation 1 has been built completely new. In the existing substation 2 only the secondary equipment has been refurbished. Control of both substations takes place at the operator workstation in substation 2. The operator workstation in substation 2 is only used in special cases for local control (maintenance, emergency control).

Substation 1:

Consists of two half-bars, each with 2 incoming cable bays and 8 outgoing feeder bays.
The incoming feeder bays are all equipped with a bay control unit 6MD63 for command output, data acquisition and local bay control. In addition, cable differential protection 7SD600 and overcurrent protection relays 7SJ600 are also provided.
The outgoing feeders each have a combined protection and control relay 7SJ63, providing overcurrent protection and bay-related measuring, data acquisition and control functions.
The SICAM PCC station serves in this substation predominantly as data concentrator and communication node for the distributed bay units. The connection of the bay units is established by a copper-based multi-drop link (RS 485 bus) according to the IEC 870-5-103 standard.

Substation 2:

Combined protection and control relays 7SJ63 are used in this substation in all feeder bays. Connection to the substation control system SICAM PCC is again established with the wired RS485-bus as in substation 1.
The SICAM PCC, located in the control room of this substation, is designed as a full server and uses WinCC as operating and monitoring tool. The data concentrator SICAM PCC of substation 1 is connected to this common SICAM PCC control station in substation 2 via an optical fiber network using the network-capable protocol IEC 60870-6 TASE.2.

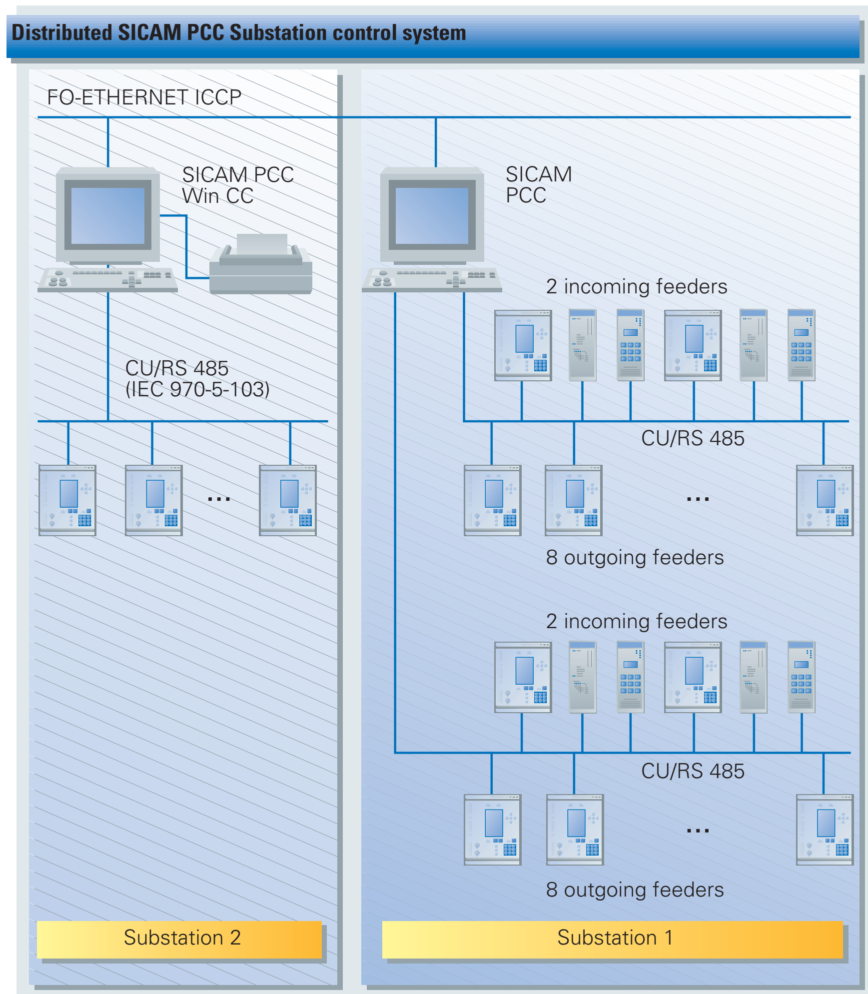


Fig. 213: System Configuration

This configuration provides numerous facilities for expansion. Thus, for example, it is possible to expand bays in each of the remote stations and to link the devices on the bay level necessary for protection and control via Profibus or IEC 60 870-5-103 to the existing PCC. Additional devices can also be connected to the control room PCC. For expansion of a complete remote station, it is possible for example to use a further Device Interface Processor as SICAM PCC, to which in turn devices on the bay level are connected. For expansion of the operating and monitoring function, it is possible, instead of the Single-User WinCC System, to use for example a WinCC Client Server System with several operator terminals. This system offers redundancy as an option.

Local and Remote Control Device Dimensions

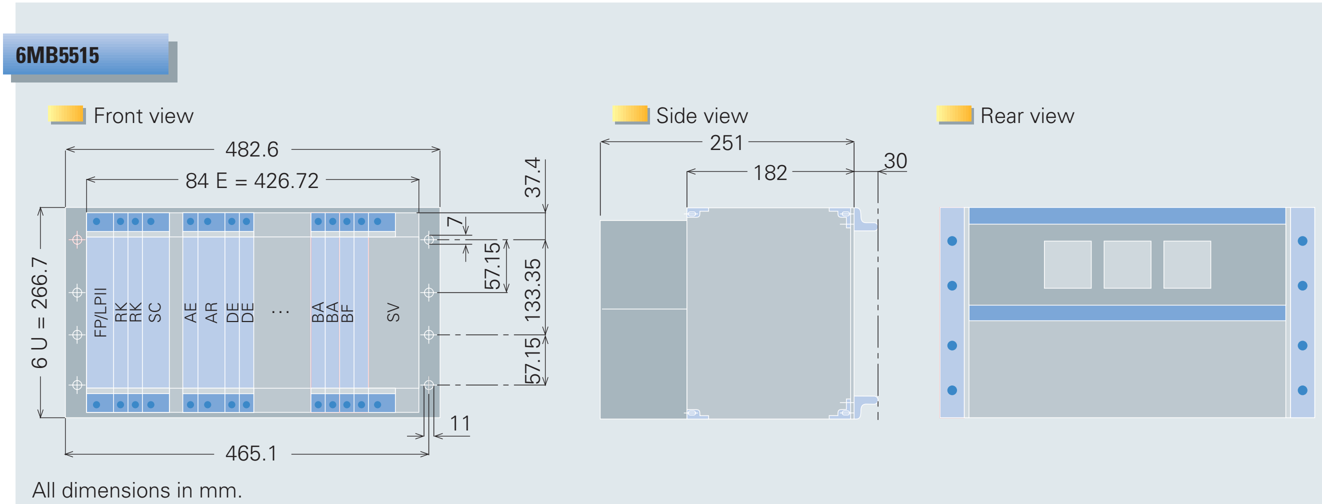


Fig. 214: Enhanced RTU 6MB551

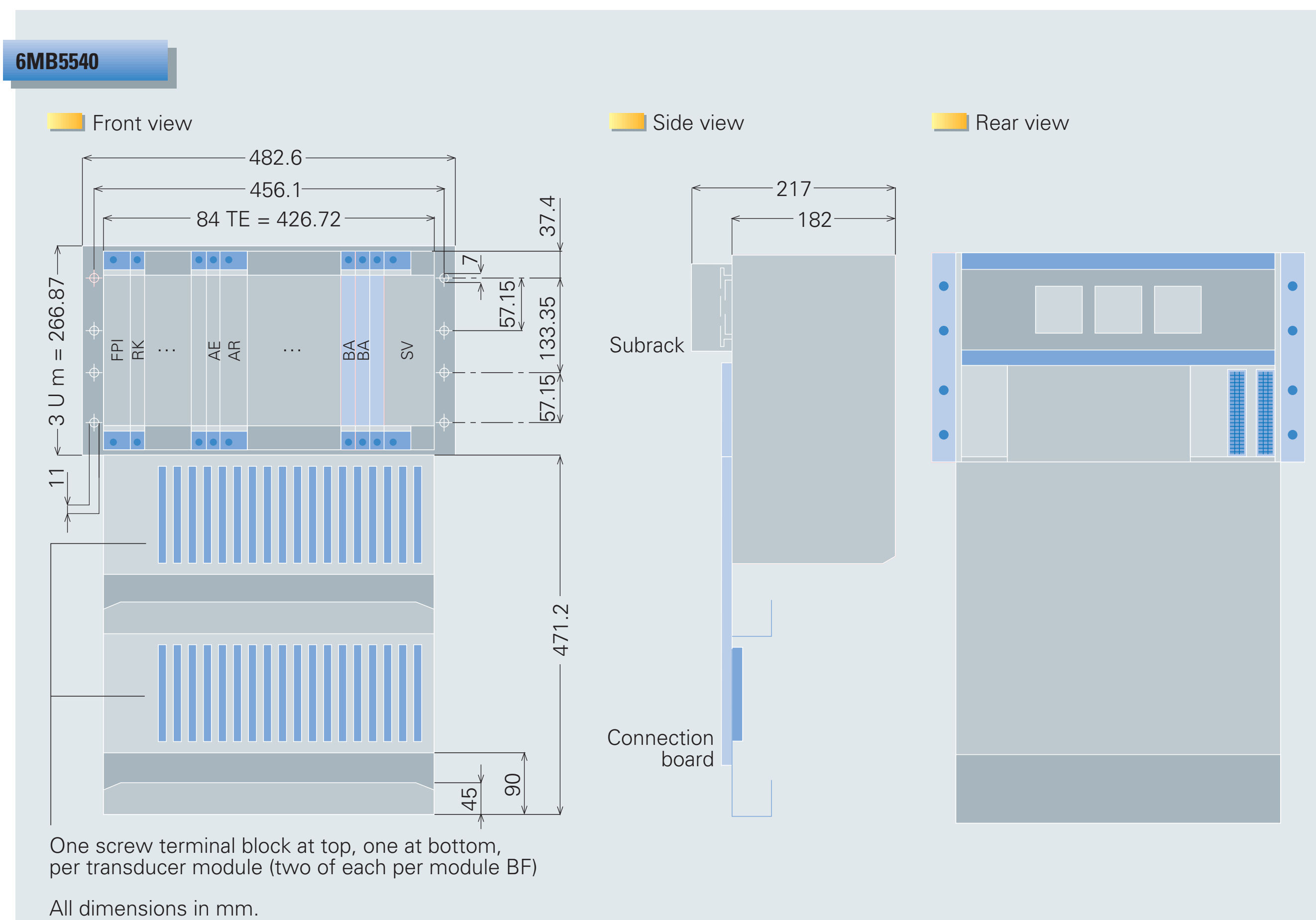
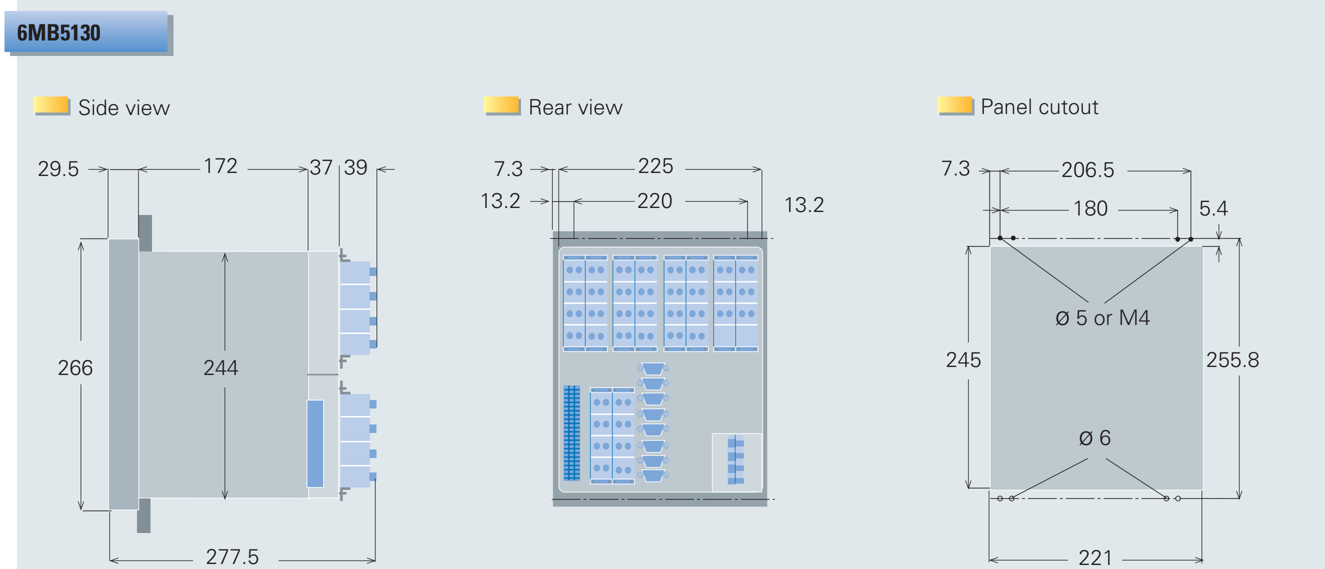


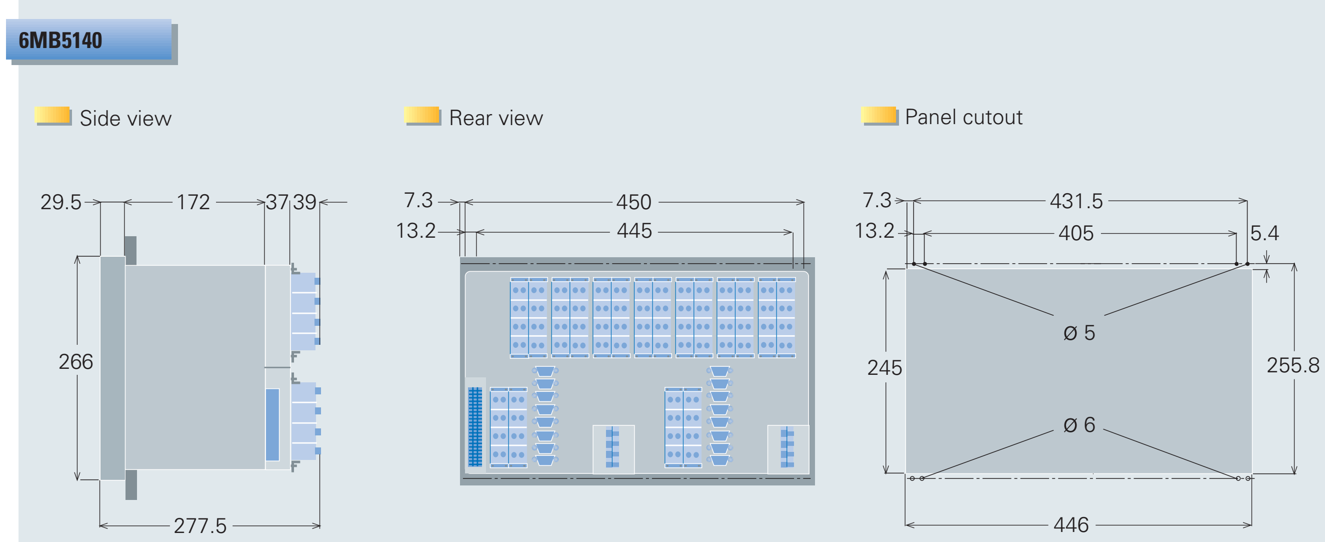
Fig. 215: SINAULT LSA COMPACT 6MB5540, basic frame

Local and Remote Control Device Dimensions



All dimensions in mm.

Fig. 216: Compact central control unit 6MB513

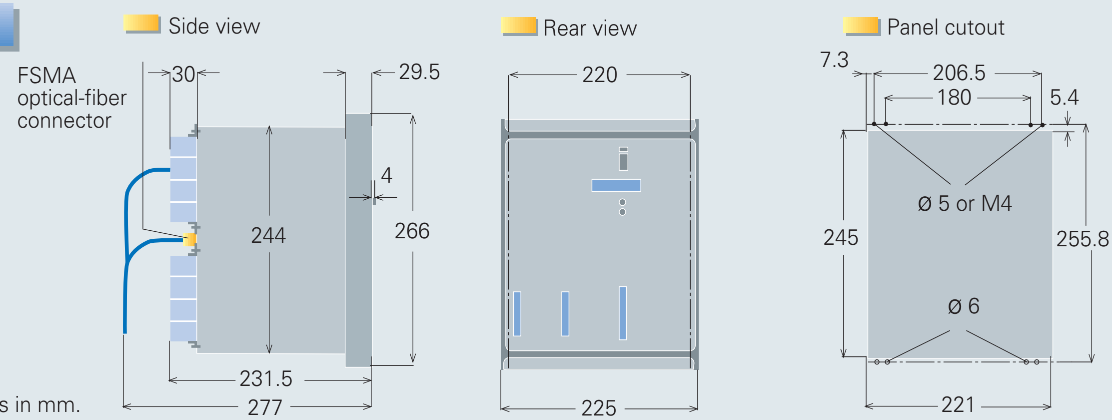


All dimensions in mm.

Fig. 217: Compact central control unit 6MB514

Local and Remote Control Device Dimensions

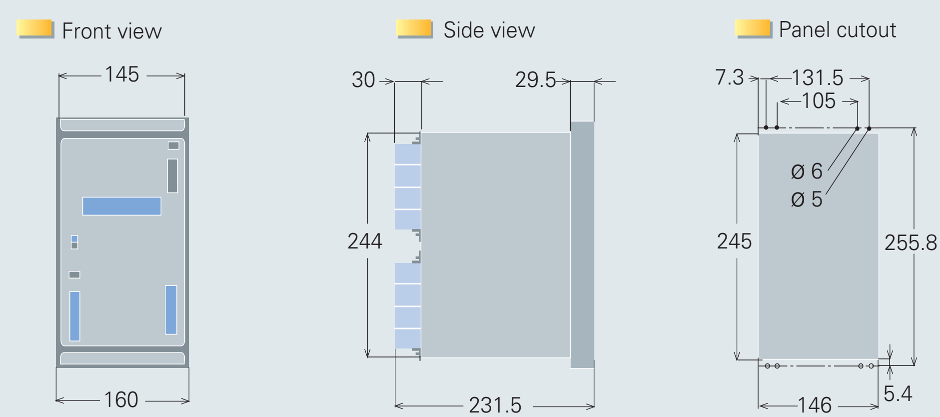
6MB522



All dimensions in mm.

Fig. 218: Compact input/output device 6MB522

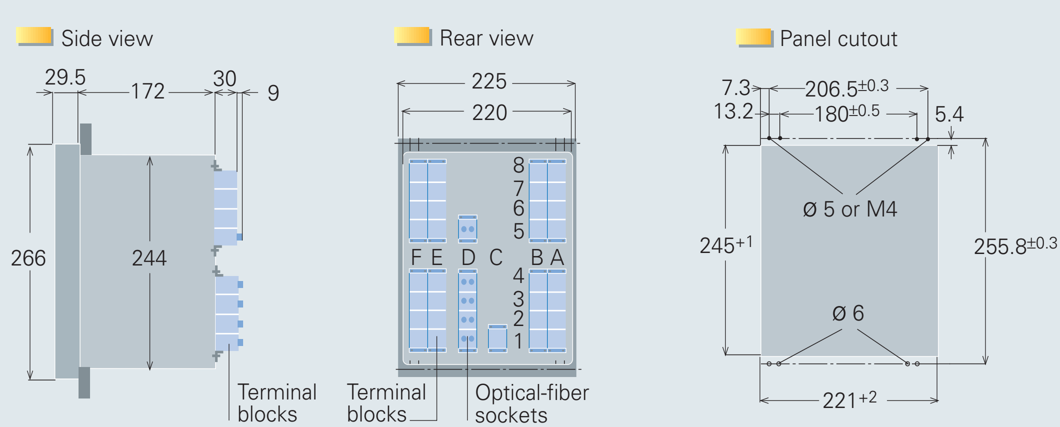
6MB523



All dimensions in mm.

Fig. 219: Compact input/output device 6MB523

6MB524-0, 1, 2



All dimensions in mm.

Fig. 220: Compact I/0 unit with local (bay) control 6MB524-0,1,2

Local and Remote Control Device Dimensions

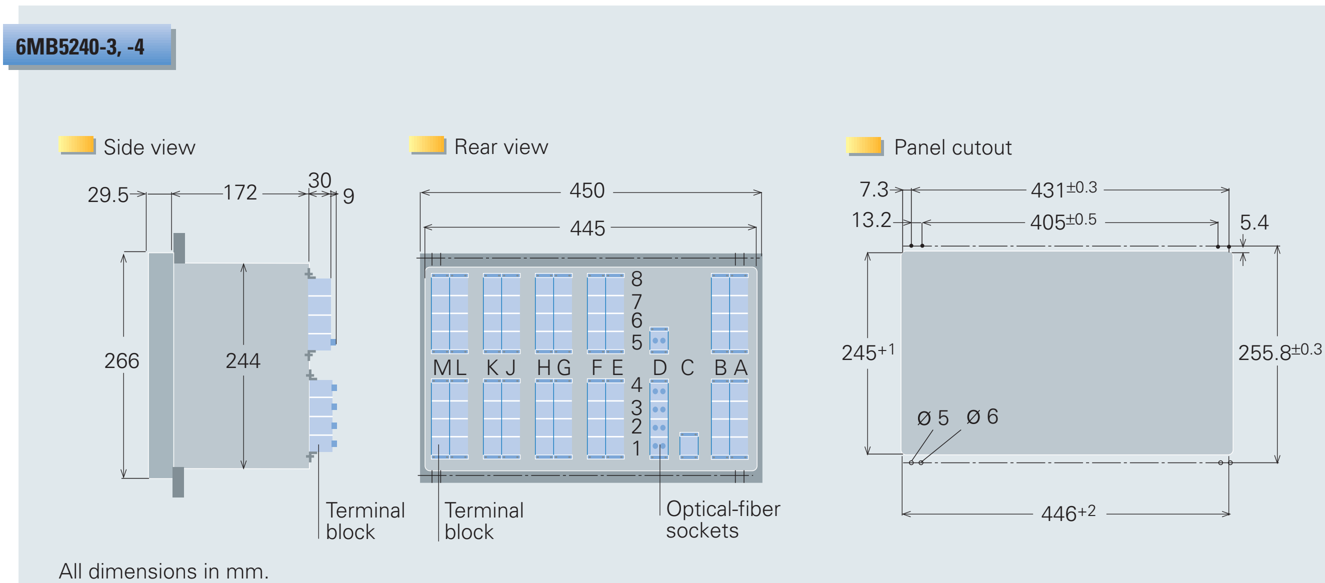


Fig. 221: Compact I/O unit with local (bay) control, extended version 6MB5240-3

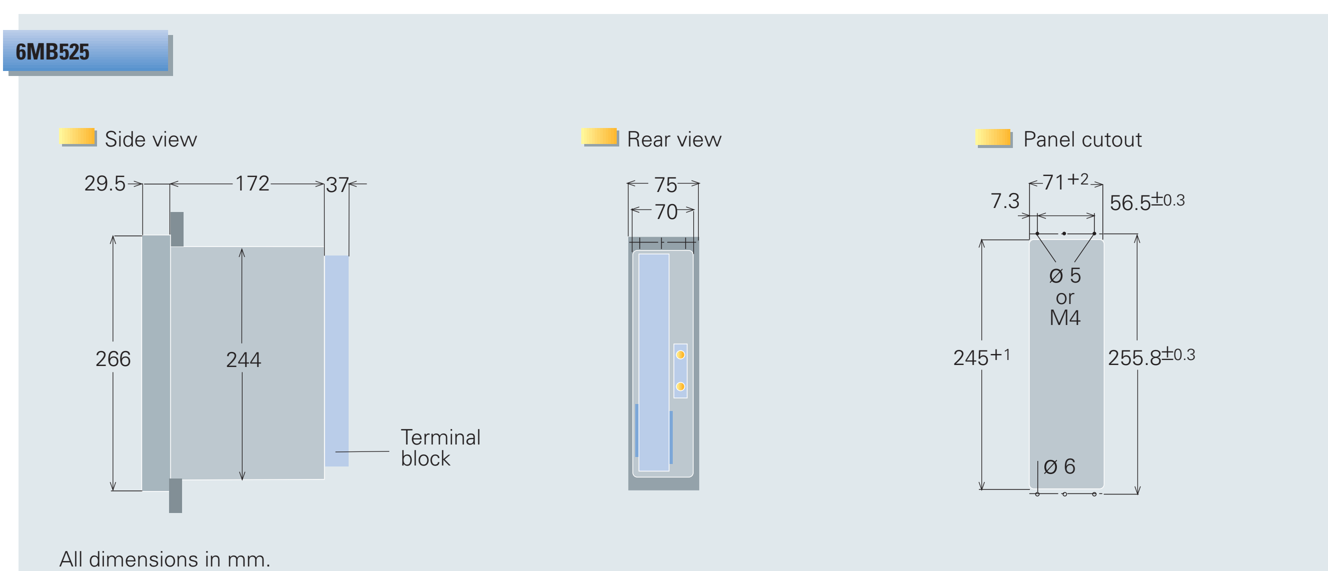


Fig. 222: Minicompact I/O device 6MB525

Local and Remote Control Device Dimensions

Case for 6MD631/632/633/634/637

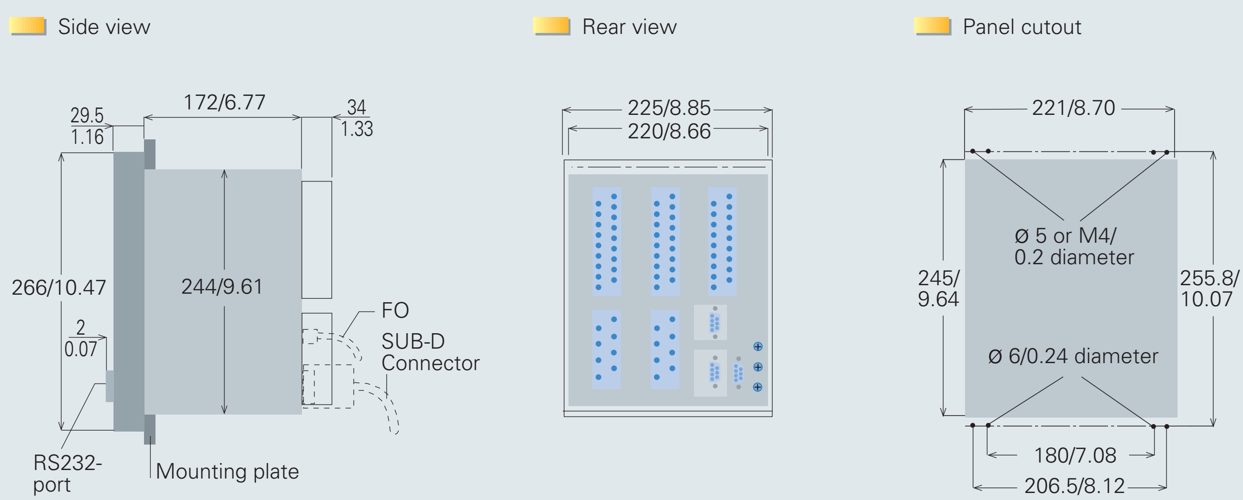
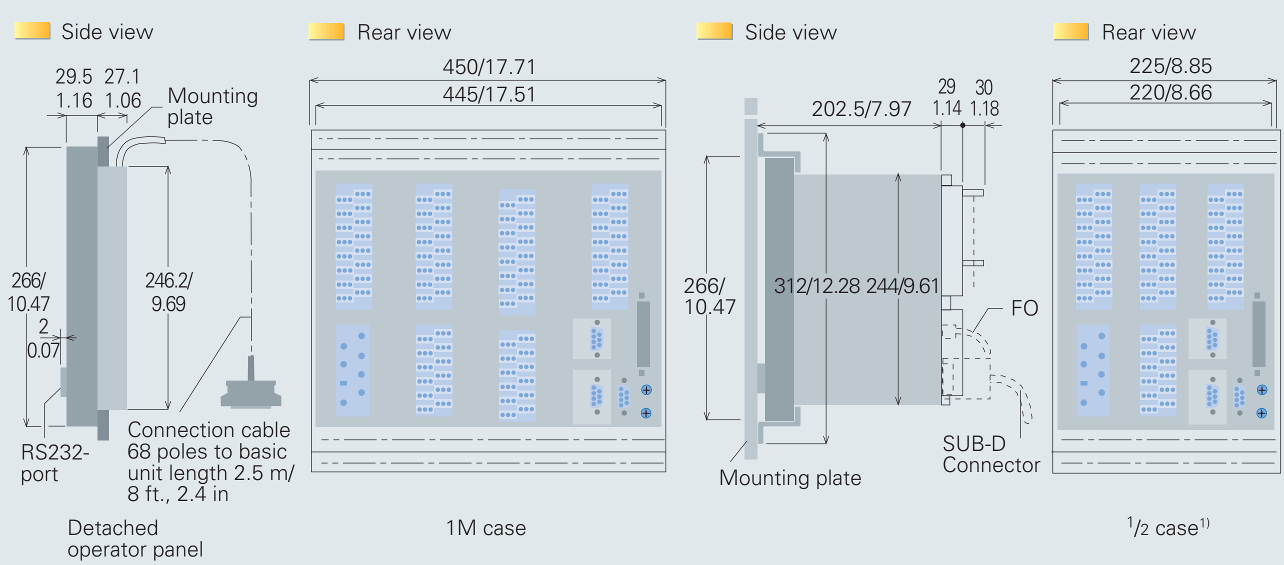


Fig. 223: 6MD63 in 1/2 flush-mounting case for surface mounting with detachable operator panel

Case for 6MD63



1) applicable to 6MD631/632/633/634/637
1) applicable to 6MD635/636

*Fig. 224: 6MD63 in 1/2 and 1/1 surface mounting case (only with detached operator panel, see Fig. 42, page **6**/21)*

Local and Remote Control Device Dimensions

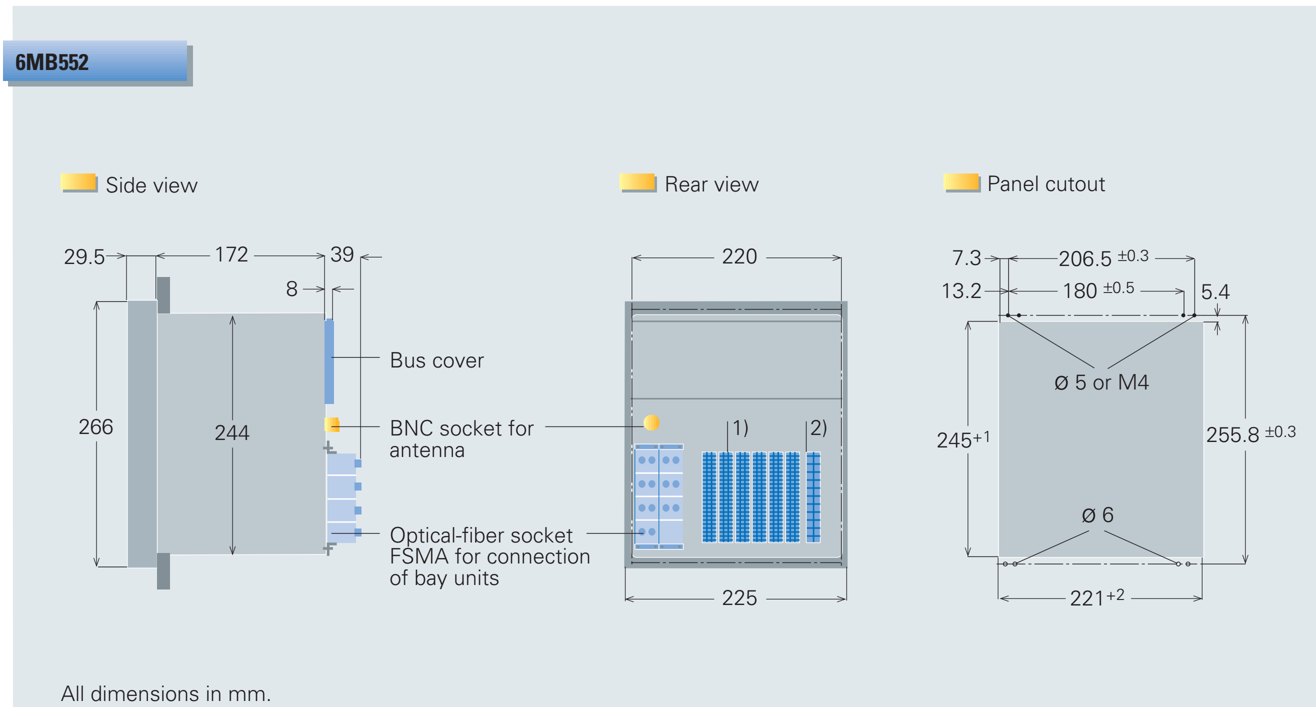


Fig. 225: Compact RTU 6MB552 in 7XP20 housing

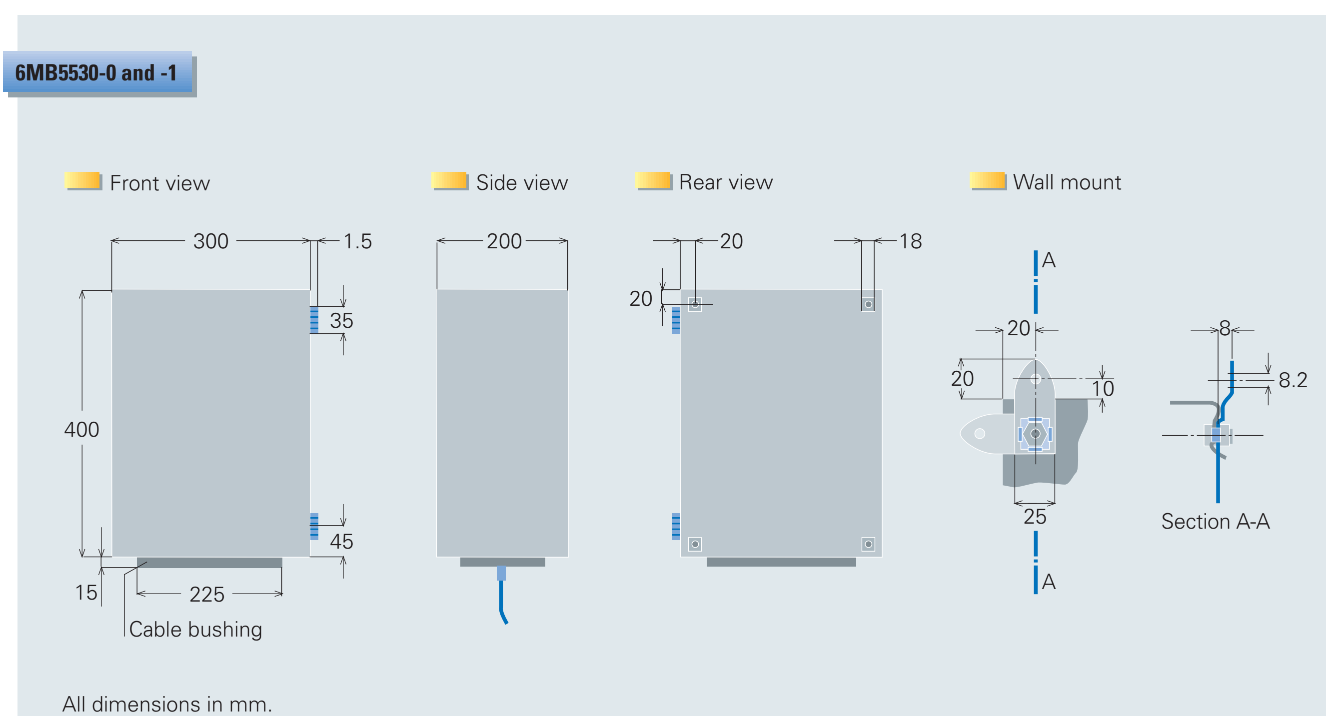


Fig. 226: Minicompact RTU 6MB5530

Power Quality
Measuring, Recording, Compensation

Introduction

For more than 100 years, electrical energy has been a product, measured, for example, in kilowatt-hours, and its value was determined by the amount of energy supplied. In addition, the time of day could be considered in the price calculation (cheap night current, expensive peak time tariffs) and agreements could be made on the maximum and minimum power consumption within defined periods. The latest development shows an increased tendency to include the aspect of voltage quality into the purchase orders and cost calculations. Previously, the term "quality" was associated mainly with the reliable availability of energy and the prevention of major deviations from the rated voltage. Over the last few years, however, the term of voltage quality has gained a completely new significance. On the one hand, devices have become more and more sensitive and depend on the adherence to certain limit values in voltage, frequency and waveshape; on the other hand, these quantities are increasingly affected by extreme load variations (e.g. in steelworks) and non-linear consumers (electronic devices, fluorescent lamps).

Power Quality standards

The specific characteristics of supply voltage have been defined in standards which are used to determine the level of quality with reference to

- frequency
- voltage level
- waveshape
- symmetry of the three phase voltages.

These characteristics are permanently influenced by accidental changes resulting from load variations, disturbances from other machines and by the occurrence of insulation faults. In contrast to usual commodity trade, the quality of voltage depends not only on the individual supplier but, to an even larger degree, on the customers.

The IEC series 1000 and the standards IEEE 519 and EN 50160 describe the compatibility level required by equipment connected to the network, as well as the limits of emissions from these devices. This requires the use of suitable measuring instruments in order to verify compliance with the limits defined for the individual characteristics as laid down in the relevant standards.
If these limit values are exceeded, the polluter may be requested to provide for corrective action.

Competitive advantage though power quality

In addition to the requirements stated in standards, the liberalization of the energy markets forces the utilities to make themselves stand out against their competitors, to offer energy at lower prices and to take cost-saving measures. These demands result in the following consequences for the supplier:

- The energy tariffs will have to reflect the quality supplied.
- Customers polluting the network with negative effects on power quality will have to expect higher power rates – "polluter-must-pay" principle.
- Cost saving through network planning and distribution is different from today's practice in network systems, which is oriented towards the customers with the highest power requirements.

The significant aspect for the customer is that non-satisfying quality and availability of power supply may cause production losses resulting in high costs or leading to poor product quality.

Examples are in particular

- Semiconductor industry
- Paper industry
- Automotive industry (welding processes)
- Industries with high energy requirements

Siemens offers a wide range of products including different types of recording equipment, as well as systems for active quality improvement.

Power Quality Measuring and Recording

The SIMEAS T Measuring Transducer

SIMEAS T is a new generation of measuring transducers for quantities present in electrical power supply systems. The compact housings are mounted to a standard rail with the help of a snap-on mechanism. Depending on the specific application, the devices are available with or without auxiliary power supply or can be provided with a multi-purpose measuring transducer which can be configured according to individual requirements.

Applications

- Electrical isolation and conditioning of electrical measurands for further processing.
- Industrial plants, power plants and substations.
- Easy-to-instal, space-saving device.

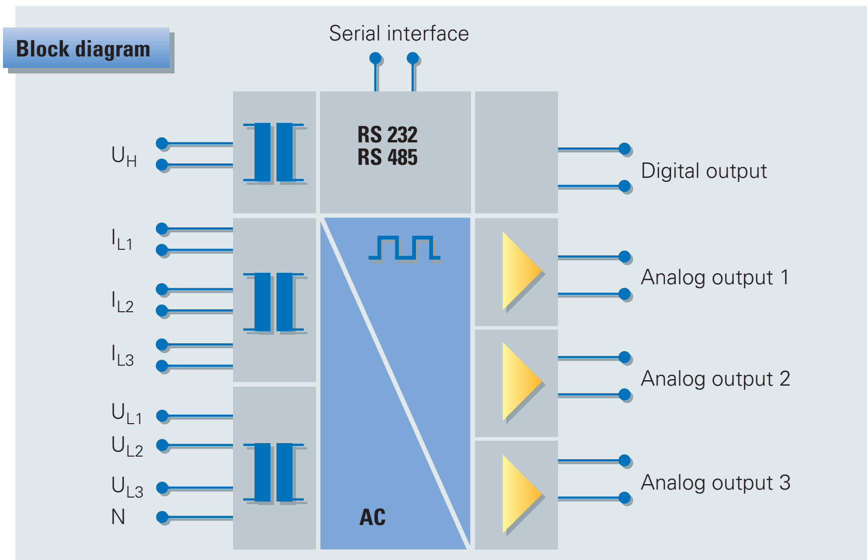


Fig. 227: Measuring transducer 7KG60, block diagram

Fig. 228: Measuring transducer 7KG60

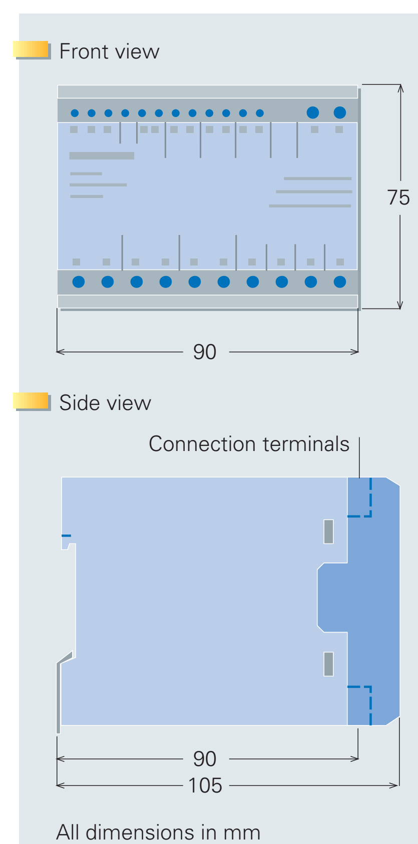


Fig. 229: Measuring transducer 7KG60, dimensions

Power Quality Measuring and Recording

Functions

Conversion of the measured values into analog or digital values suitable for systems in the fields of automatic control, energy optimization and operational control.

Special features

- Minimum dimensions,
- Short delivery time, standard types delivered ex-warehouse,
- Complies with all relevant standards,
- High-capacity output signals,
- Electrical isolation at high test voltage,
- Suitable to extend the beginning and end of the measuring range,
- Design variants for true r.m.s measurement.

Additional features of the multi-purpose measuring transducers:

- Acquisition of up to 16 measurands,
- Connection to any type of single-phase or three-phase systems, 16 2/3, 50, 60 Hz,
- 3 electrically isolated outputs, ±10 V and ± 20 mA,
- 1 binary output,
- Type of network, measurand, measuring range, etc. can be freely programmed,
- V.28 or RS 485 serial interface for configuration and output of the measured values.

Measurands

- AC voltage,
- AC current,
- Extension of the measuring range is possible.

Additional features of the multi-purpose measuring transducer:

- AC voltage and current,
- Active, reactive and apparent power, power factor, phase angle,
- System frequency,
- Energy pulses,
- Limit-value monitoring.

Special features of the parameterizable multi-purpose measuring transducer

Input quantities

- 3 voltage inputs for 0–346 V, up to 600 V line-to-line voltage in the three-phase system,
- 3 current inputs for 0–10 A.

Outputs

- 3 isolated outputs for ± 20 mA or ±10 V and smaller values,
- 1 contact, definable for error or limit indication or as energy pulse,
- 1 serial interface type RS 232C (V.28) or, as an option, type RS 485 for connection to a personal computer for configuration and data transmission.

Types of connection

- Single-phase,
- Three-wire three-phase current with constant/balanced load,
- Three-wire three-phase current with any load,
- Four-wire three-phase current with constant/balanced load,
- Four-wire three-phase current with any load,
- Connected either directly or via external transformer.

Measured and calculated quantities

- R.m.s. values of the line-to-line and star voltages,
- R.m.s. value of the zero sequence voltage,
- R.m.s. value of the line-to-line currents,
- R.m.s. value of the zero sequence current,
- Active and reactive power of the single phases and the sum thereof,
- Power factors of the single phases and the sum thereof,
- Total apparent power,
- Active energy, incoming supply at the single phases and the sum thereof (pulses),
- Active energy, exported supply at the single phases and the sum thereof (pulses),
- Reactive energy, inductive, at the single phases and the sum thereof (pulses),
- Reactive energy, capacitive, at the single phases and the sum thereof (pulses), Line frequency.

Alarm contact

- Violation of the min./max. limits for voltage, current, active power, reactive power, frequency,
- Violation of the min. limit for power factor,
- Functional error.

Serial interface

Standard-type RS 232 C (V.28) interface for connection to a personal computer for configuration, calibration and transfer of the measured values; an RS 485-type serial interface is available with an additional bus function according to IEC 60870-5-103.

Auxiliary power

Two versions: 24 to 60 V DC and 110 to 250 V DC, as well as 100 to 230 V AC.

Characteristic line with breakpoint

The start and end periods of the analog outputs can be extended according to requirements. This enables enlarging of the display of the operating range of voltages, while the less interesting overcurrent range can be compressed.

Configuration and adjustment

With the help of a personal computer connected to the serial interface, the type of network, the measurands and the output signals can be configured to suit the individual situation. The SIMEAS PAR software program enables easy adjustment of the devices to different requirements. Since only one type needs to be kept on stock, the user can benefit from the advantages of reduced storage costs and easier project planning and ordering procedures. The software also supports and facilitates the adjustment of the transducers.

Data output with SIMEAS T PAR

SIMEAS T PAR can also be used to continuously collect the data of 12 measurands from the transducer and to display them both graphically and numerically on the screen. These data can then be saved or printed.

Bus operation with IEC protocol

The transducer is suitable for the acquisition of up to 43 measurands and for the monitoring of up to 39 measurands. With three analog outputs and one contact output only part of these data can be transferred. With the help of the RS 485 serial interface which uses the IEC 60870-5-103 protocol, however, any number of measured data can be transmitted to a central unit (e.g. LSA or PC). As this protocol restricts the number of data units to 9 or 16 measuring points, the function parameters for file transfer can be assigned in such a way as to bypass this restriction and to load any desired number of data.

Power Quality
Measuring and Recording

SIMEAS T PAR parameterization software

Description

By means of the SIMEAS T PAR software, SIMEAS T transducers with an RS232 or an RS485 interface can be parameterized or calibrated swiftly and easily. Measured quantities can be displayed on the PC online via a graphical meter or can be recorded and stored over a period of up to one week.

SIMEAS T PAR was designed for installation on a commercially available PC or laptop with the MS-DOS operating system. It is operated via the MS-Windows V3.1 or Windows 95 graphical user interface by PC mouse and keyboard. Operating instructions can be created by printing the "Help" file. Communication with the transducer is achieved by means of a cable (optionally available) connected via the interface that is available on every PC or laptop. For units featuring an RS232 interface, use the connecting cable 7KG6051-8BA or, for units featuring an RS485 interface, use the converter 7KG6051-8EB/EC. Three mutually independent program sections can be called up.

Parameterization

Parameterization serves to set the transducer to the required measured quantities, measuring ranges and output signals etc. Users are able to parameterize the transducer themselves in only a few steps.

Entry of the data in the windows provided is clear and simple, supported with "Help" windows.

Parameterization is also possible without the transducer. After storage of the data under a separate name, the transducers can be adjusted with the "Send file" command. They can also be reparameterized online during operation.

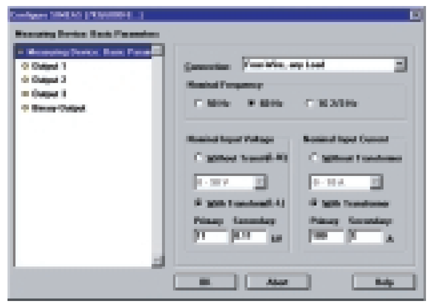


Fig. 230: Parameterization of the basic parameters

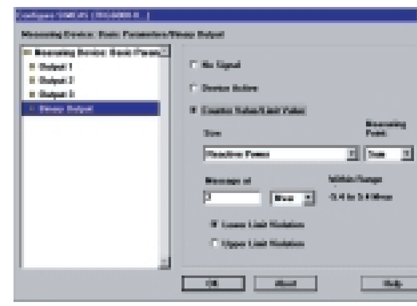


Fig. 231: Parameterization of the binary output

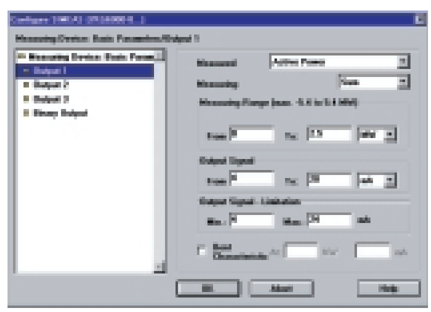


Fig. 232: Parameterization of an analog output

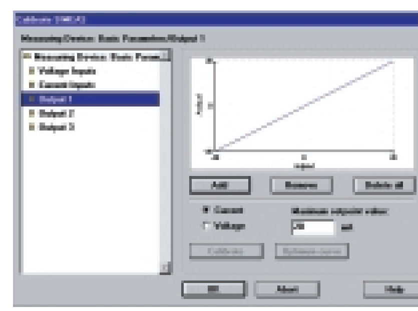


Fig. 233: Calibrating an analog output

Features

- Extremely simple and straightforward operation
- Storage of parameterization data under a user-defined name even without the transducer
- Parameters are sent to transducers even after installation on the site
- When "Receive" is selected, the transducer's parameters are read into the "Parameterization window", can be modified and can be sent back by selecting "Send"
- Entered data is subjected to an extensive plausibility check and a message and "Help" are displayed in the event of invalid inputs
- A parameterization list with the specific connection diagram of the transducer can be printed
- A self-adhesive data plate can be printed and affixed to the transducer, including a possibility of entering three lines of text containing the name and location etc.
- When units featuring an RS485 interface are chosen, an additional window is available for entry of the bus parameters

Calibration

As the transducer features neither setting potentiometers nor other hardware controls, it is calibrated easily by means of the SIMEAS T PARA software, by selection of the "Calibrate" function.

Generally, all the transducers are already calibrated and factory-set when delivered.

Recalibration of the transducers is normally only necessary after repairs or in the event of readjustment.

It goes without saying that the windows and graphical characteristics displayed in the "Calibrate" program can be operated with ease.

Here also, the test setup and explanations of how to operate the programm are provided in "Help" windows.

Features

- Sealed for life design
- Calibration without tools or special devices
- No test field environment is needed

Current inputs, voltage inputs and the individual analog outputs can be calibrated independently of one another.

Power Quality
Measuring and Recording

Fig. 234: Measured value display with 3 measured quantities

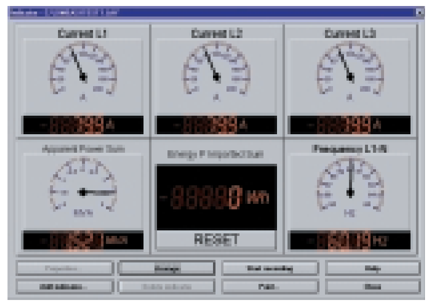


Fig. 235: Measured value display with 6 measured quantities

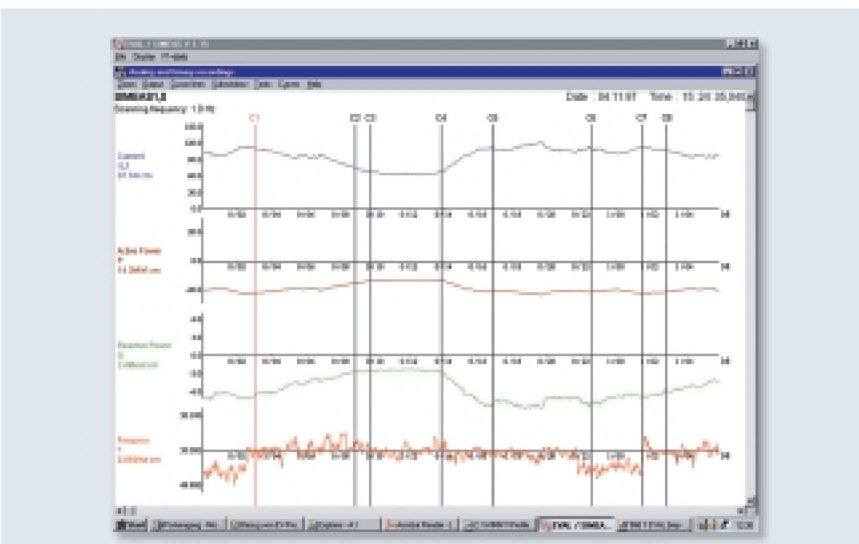


Fig. 236: SIMEAS EVAL, overview recorded values

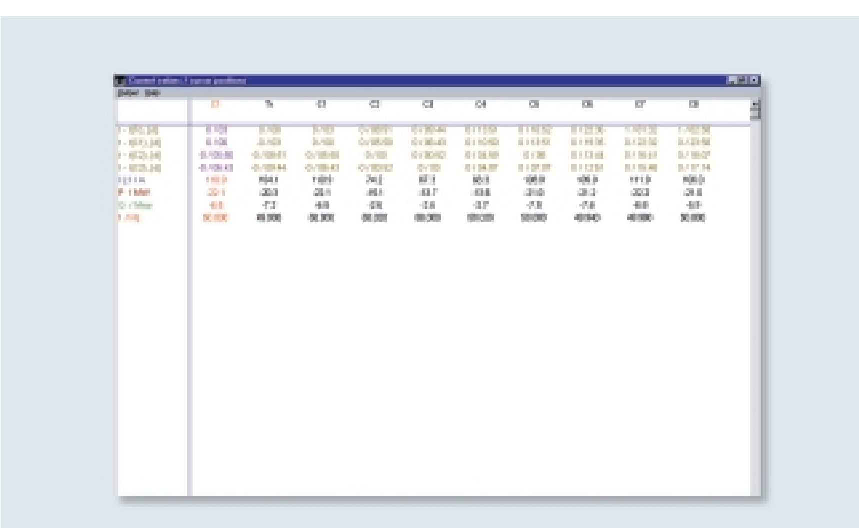


Fig. 237: After setting cursors in the overview, the affiliated measurements and times are displayed in the table

Reading out data

With graphical instruments, all measured quantities calculated in the transducer and power quantities can be displayed online on a PC or laptop, and either in analog form or digitally.

To improve the resolution of the graphics, users can freely choose the number of instruments on the screen and can freely assign the measured quantity and measuring range.

These are selected and assigned independently of the unit's analog outputs.

Displayed measured values can be stored, printed or recorded for the EVAL evaluation software.

Features

- Online measurements in the system with high accuracy
- The meters for the 3 analog outputs with the appropiate measuring range appear automatically when the program part is called up
- Easy addition or modification of meters with measured quantity and measuring range
- Selection of measured quantities independently of the analog outputs
- Storage of the layout under a file name
- Printing of the instantaneous values of the displayed measured quantities
- Recording and storage of measured values for the EVAL evaluation software

SIMEAS EVAL evaluation software

Description

With a PC or a notebook with the SIMEAS T PAR software installed on it, up to 25 measured quantities can be displayed and recorded online with the SIMEAS T digital transducer. A maximum of one week can be recorded. Every second, one complete set of measured values is recorded with time information. The complete recording can then be saved under a chosen name.

Using the SIMEAS EVAL evaluation software, the stored values can then be edited, evaluated and printed in the form of a graphic or a table (Figs. 236 to 238).

Power Quality
Measuring and Recording

SIMEAS EVAL is a typical Windows program, i.e. it is completely Windows-oriented and all functions can be operated with the mouse or keyboard.

SIMEAS EVAL is installed together with SIMEAS T PAR and is started by double clicking on the EVAL icon. A window containing the series of measurements recorded by SIMEAS T PAR is displayed for selection.

Features

- Automatic diagram marking
- Graphic or tabular representation
- Sampling frequency: 1 s
- A measured value from the table can be dragged to the graphic by simply right-clicking it
- Add your own text to graphics
- Select measured quantities and the measuring range
- Easy zooming with automatic adaption of the diagram captions on the X and Y axes
- Up to 8 cursors can be set or moved anywhere
- Tabular online display of the chosen cursor positions with values and times
- Characteristics can be placed over one another for improved analysis
- The sequence of displayed measured quantities can be selected and modified
- The complete recording or edited graphic can be printed, including a possibility of selecting the number of curves on each sheet
- The table can be printed with measured values and times pertaining to the cursor positions.

Information for SIMEAS T Project Planning

The transducer is suitable for low-voltage applications, 400 V three-phase and 230 V single-phase voltages, (max. measuring 600 L-L) and currents of 1, 5, 10 A (max. measurement 12 $A_{r.m.s}$), either directly or via current transformers, as well as for connection to voltage transformers of

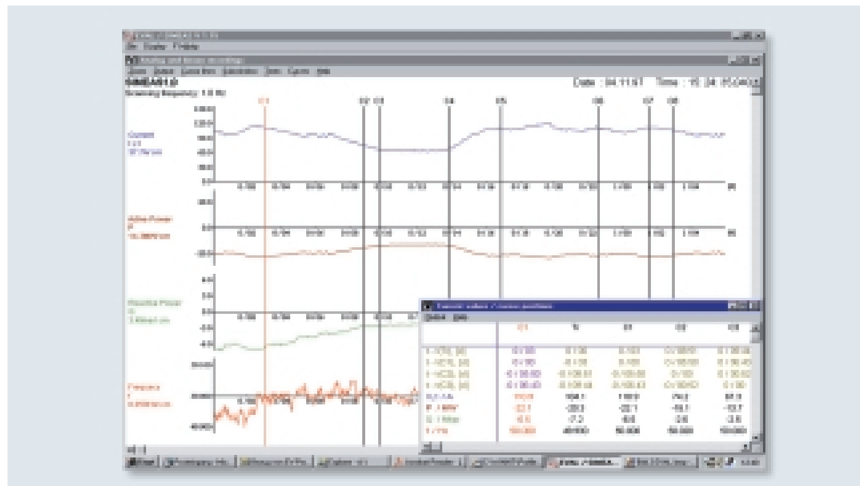


Fig. 238: When a cursor is moved by the mouse, the measured values and times in the table are adapted automatically

$1000\sqrt{3}$, $110\sqrt{3}$, $200\sqrt{3}$. The devices can be pre-configured at the factory according to customer requirements or configuration can be performed by the customer himself. The latter possibility facilitates and considerably reduces the customer's expense for storage and spare parts service. All usual variants of connection (two, three or four-wire systems, constant/balanced or any/unbalanced load 16 2/3, 50, 60 Hz) can be configured according to individual requirements.

Please note that two different types are available which differ in their types of interface: V.28 (RS 232C) and RS 458. The standard interface (V.28) is used for configuration. It enables loading of the measured values to a personal computer, whereby only one transducer can be connected to a computer. Both versions are operated with the SIMEAS PAR software. The RS 485 enables connection to a bus, i.e. up to 31 transducers can be connected to a central device (e.g. PC) simultaneously. Data transmission is based on IEC 60 870-5-103 protocol.

The type of power supply is to be specified when ordering, either 24..60 V DC or 100..230 V AC/DC. Please note that analog output 1 and the serial interface use the same potential and can be operated simultaneously only under certain conditions.

Power Quality
Measuring and Recording

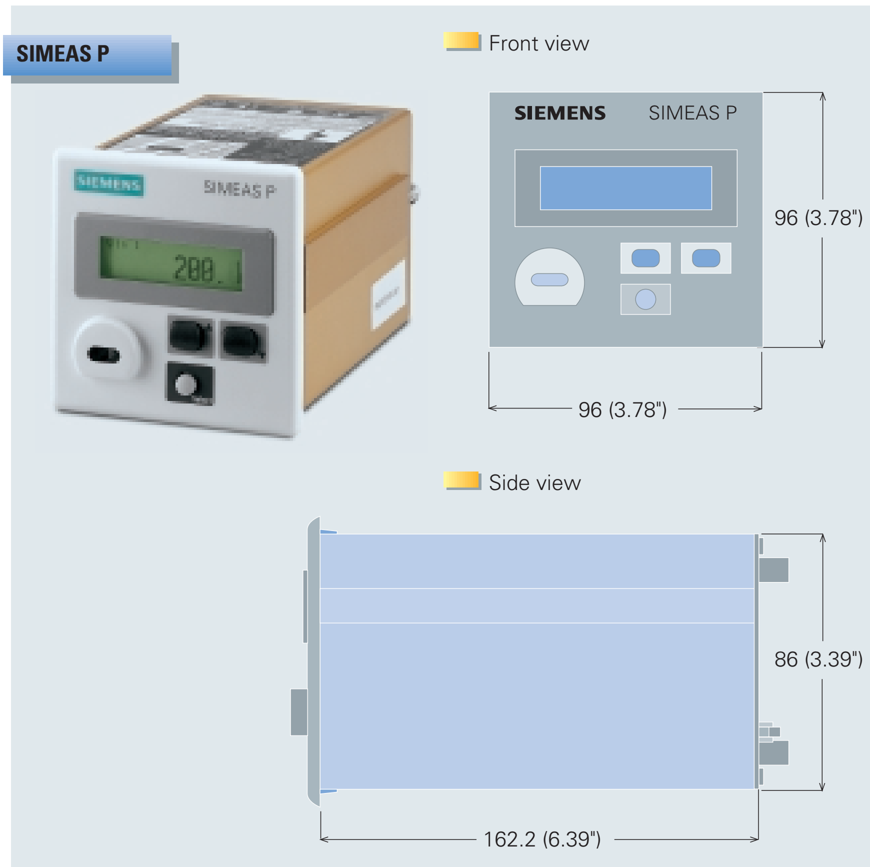


Fig. 239: Power Meter SIMEAS P, views and dimensions

Power Meter SIMEAS P

The SIMEAS P power meter is suitable for panel mounting. The digital multi-function display can replace any measuring devices usually required for a three-phase feeder. Furthermore, it offers a variety of additional functions. The optional equipment with a PROFIBUS enables centralized access to the measured values.

Application

All systems used for the generation and distribution of electrical power. The device can be easily installed for stationary use.

Functions

Measuring instrument for all relevant measurands of a feeder. Combination of several measuring instruments in one unit.

Special features

Dimensions for panel mounting according to DIN (front frame 96 x 96 mm). Integrated PROFIBUS as optional equipment. Data output is effected via the Profibus.

Measuring inputs

- 3 voltage inputs up to 347 V (L-E), 600 V (L-L),
- 3 current inputs for 5 A rated current, measuring range up to 10 A with an overload of 25%.

Communication

- LCD display with background illumination,
- Simultaneous display of four measuring values,
- Parameter assignment by using the keys on the front panel,
- 1 serial interface type RS 485 for connection to the Profibus (option).

Auxiliary power

Two versions: 24 to 60 V DC and 85 to 240 V AC/DC.

Measured and calculated quantities

- R.m.s. values of the line-to-ground or line-to-line voltages and the mean value,
- R.m.s. values of the line-to-line currents and the mean value,
- Line frequency,
- Power factor (incl. sign),
- Active, reactive and apparent power, separately for each phase and as a whole, imported supply,
- Total harmonic distortion (THD) for voltage and currents, separately for each phase, up to the 15th **harmonic order**,
- Unbalanced voltage and current, Active and reactive power (import, export), total sum, difference,
- Apparent power, total sum,
- Minimum and maximum values of most quantities.

Basic Function

Display of the measured quantities and transfer to the Profibus.

Information for Project Planning

The SIMEAS P can be delivered in different designs varying with regard to the measuring voltage, auxiliary voltage, line frequency and type of terminals. It is always designed for four-wire connection at any load. The measuring voltages are:

- 120 V, 277 V, 347 V L-N for screw clamps, up to max. 277 V for self-clamping contacts.
- The basic rated current value is 5 A; fully controlled it is 10 A.

Two variants are to be considered for the auxiliary voltage: standard version and 85–240 V AC/DC and, as an option 20–60 V DC.

The standard version of the device can be used only for the display of the different measurands. Communication with a centralized system is possible only in connection with the Profibus which can be ordered as optional equipment.

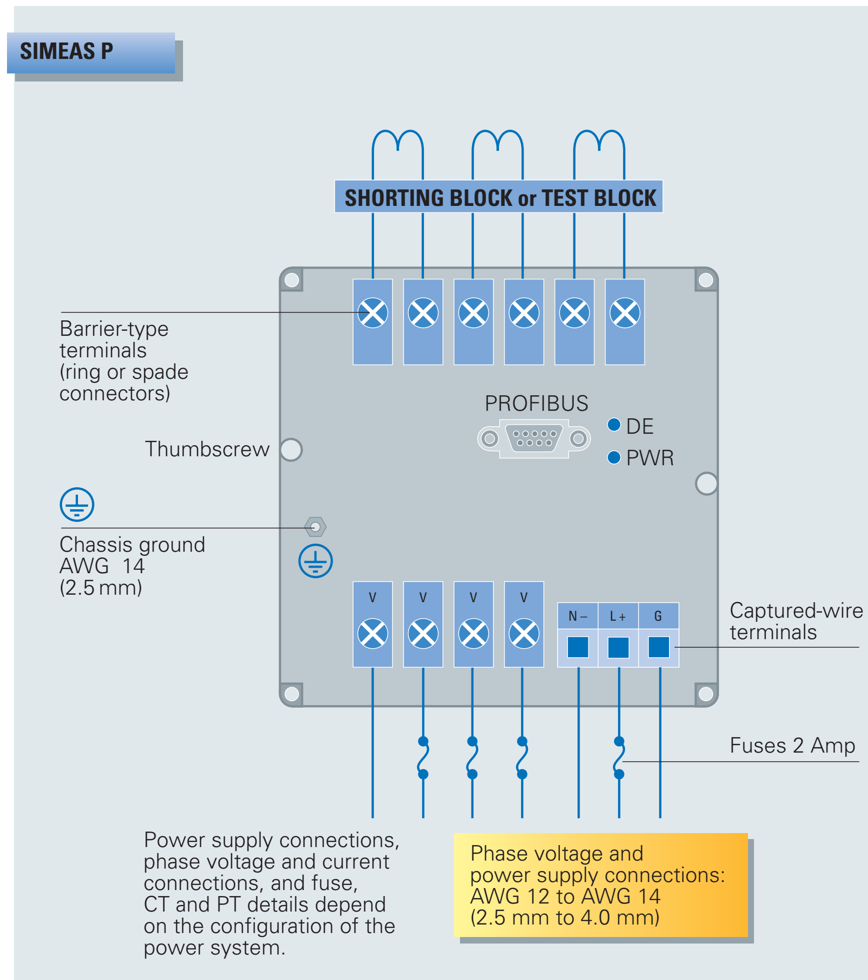


Fig. 240: Power Meter SIMEAS P, back panel diagram

Power Quality Measuring and Recording

The SIMEAS Q Quality Recorder

SIMEAS Q is a measuring and recording device which enables monitoring of all characteristics related to the voltage quality in three-phase systems according to the specifications defined in the standards EN 50160 and IEC 61000. It is mounted on a standard rail with the help of a snap-on mechanism.

Application

Medium and low-voltage systems.
The device requires only little space and can be easily installed for stationary use.

Functions

Instrument for network quality measurement. All relevant measurands and operands are continuously recorded at freely definable intervals or, if a limit value is violated, the values are averaged. This enables the registration of all characteristics of voltage quality according to the relevant standards. The measured values can be automatically transferred to a central computer system at freely definable intervals via a standardized PROFIBUS DP interface and at a transmission rate of up to 1.5 Mbit/s.

Special features

- Cost-effective solution.
- Comprehensive measuring functions which can also be used in the field of automatic control engineering.
- Minimum dimensions.
- Integrated PROFIBUS DP.
- The integrated clock can be synchronized via the PROFIBUS. Configuration and data output via PROFIBUS DP.

Measuring inputs

3 voltage inputs, 0–280 V,
3 current inputs, 0–6 A.

Fig. 241: The SIMEAS Q quality recorder

Communication

- 2 optorelays as signaling output, available either for
  – device in operation,
  – energy pulse,
  – signaling the direction of energy flow (import, export),
  – value below min. limit for cos φ,
  – pulse indicating a voltage dip,
- 3 LEDs indicating the operating status and PROFIBUS activity,
- 1 RS 485 serial interface for connection to the PROFIBUS.

Auxiliary power

Two versions: 24 to 60 V DC and 110 to 250 V DC, as well as 100 to 230 V AC.

Measured and calculated quantities

- R.m.s. values of the line-to-ground or line-to-line voltages,
- R.m.s. values of the line-to-line currents,
- Line frequency (from the first voltage input),
- Active, reactive and apparent power, separately for each phase and as a whole,
- Harmonics for voltages and currents up to the 40th order,
- Total harmonic distortion (THD), voltages and currents of each phase,
- Unbalanced voltage and current in the three-phase system,
- Flicker irritability factor.

Averaging intervals

- Voltages and currents from 10 ms to 60 min.,
- Other quantities from 1s to 60 min.

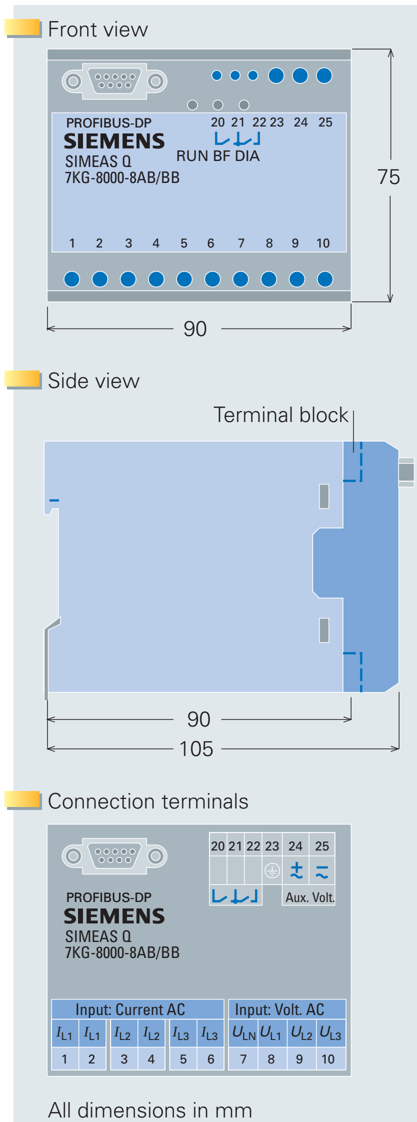


Fig. 242: The SIMEAS Q quality recorder, dimension drawings

Power Quality
Measuring and Recording

Operating modes

- Continuous measurement with definable averaging intervals,
- Event-controlled measurement with definable averaging intervals.

Storage capacity

Up to 20,000 measured and calculated values. Parameters for the measuring points can be freely defined. The PROFIBUS DP enables quick loading of the measured values, so that the apparently small storage capacity is absolutely sufficient. Assuming a usual parameter setting with regard to the measuring points and averaging intervals for quality monitoring, the storage capacity will last for seven days in case of a PROFIBUS failure.

Basic Functions

In the course of continuous measurement, the selected measuring data are stored in the memory or transferred directly via the PROFIBUS. The averaging interval can be selected separately for the different measurands.

In the event-controlled mode of operation, the data will be stored only if a limit value has been violated within an averaging interval.

Apart from the mean values, the maximum and minimum values within an averaging interval can be stored, with the exception of flicker irritability factors and the values from energy measurement.

Parameter assignment and adjustment of the device are performed via the Profibus interface.

Information for SIMEAS Q Project Planning

Up to 400 V (L-L), the device is connected directly, or, if higher voltages are applied, via a external transformer. The rated current values are 1 and 5 A (max. 6 A can be measured) without switchover. Communication with the device is effected via PROFIBUS DP or, as an option, via modem (telephone network).

Auxiliary voltage is available in two variants: 24 to 60 V DC and 110 to 250 V DC or 100 to 230 V AC.

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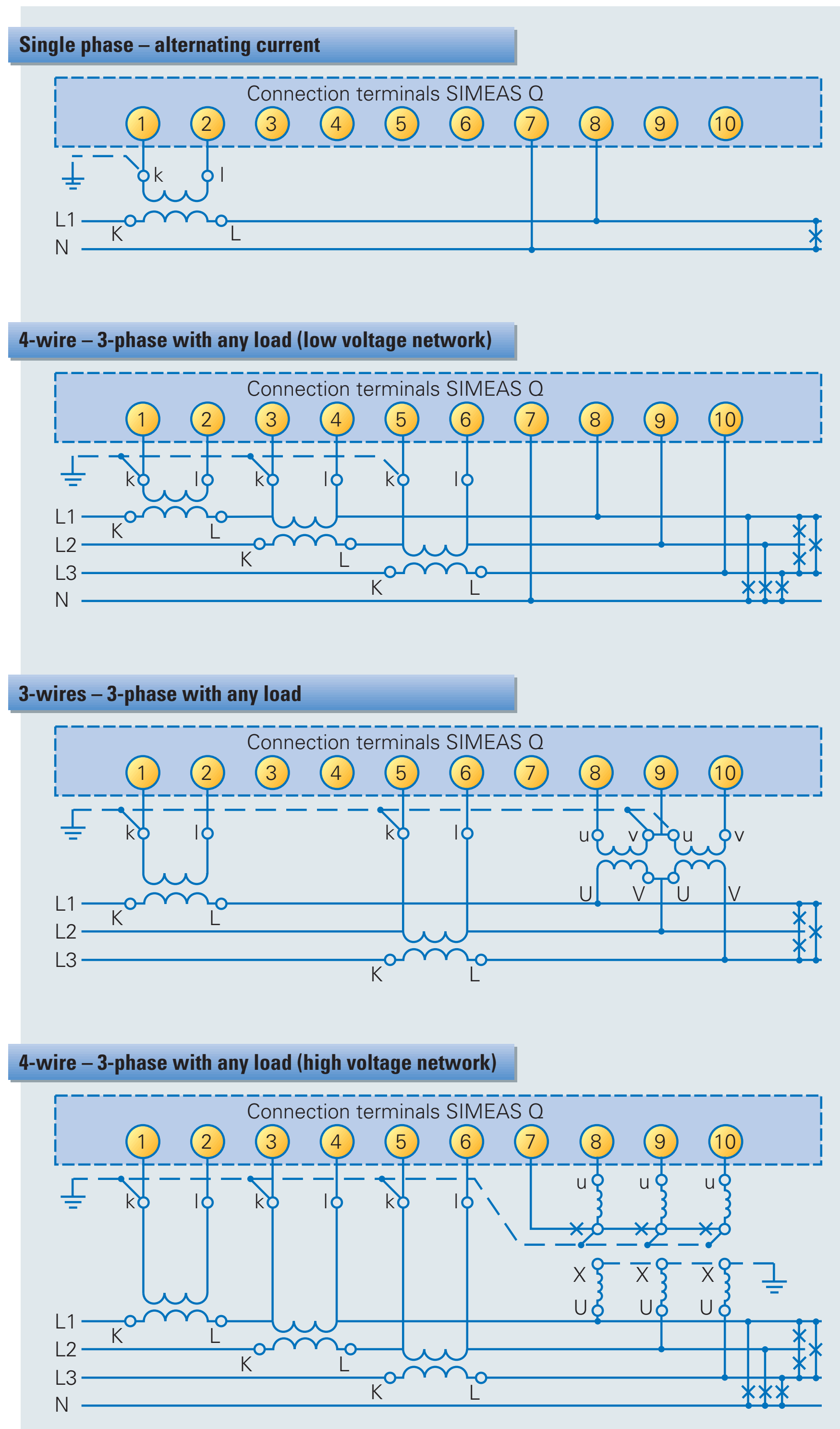

Fig. 243: SIMEAS Q connection terminals

Power Quality
Measuring and Recording

The SIMEAS N Quality Recorder

SIMEAS N is a measuring and recording device which is used to monitor all characteristics referring to the voltage quality in three-phase systems in compliance with the requirements stated in the EN 50160 and IEC 1000 Standards.

Application

Medium and low-voltage systems, laboratories, test bays. Portable device for mobile use.

Functions

Device for network quality measurement. The measurands and operands are continuously recorded over definable intervals; in case of limit violations, the values will be averaged. This enables the recording of all characteristics relevant to voltage quality. In addition, this multi-purpose device can be used for general measurement tasks in the field of AC power engineering.

Special features

Comprehensive measuring functions. A lockable cover protects the terminals against accidental contact. The operator access can be password-protected. Clamp-on probes with an error correction function facilitate connection. A back-up battery stores the measured data in case of voltage failure. The integrated battery-backed real-time clock will be usable until the year 2097.

Output of the measured values via integrated thermal printer, floppy disk or serial interface.

Measuring inputs

- 4 voltage inputs, 0–460 V,
- 3 of these inputs with additional transient acquisition ±2650 V_{peak} at a sampling rate of 2 MHz,
- 4 voltage/current inputs, voltage 0–460 V/clamp-on probe or transducer.

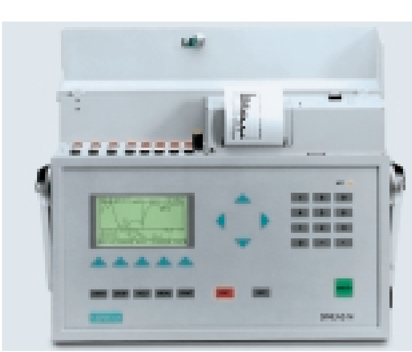

Fig. 244: SIMEAS N Quality Recorder

Communication

- 1 input for trigger signal,
- 1 contact as alarm output,
- 1 integrated thermal printer,
- 1 3.5" floppy disk drive, 1.44 MB for parameters and data storage,
- 1 serial interface type RS 232C (V.24) for connection to a personal computer for configuration and data transmission.

Measured and calculated quantities

- R.m.s. values of voltages, AC, AC+DC, DC,
- Peak voltage values during transient measurement,
- R.m.s values of currents, AC, AC+DC, DC (depending on transducer or clamp-on probes),
- Voltage dips and voltage cutoffs,
- Overvoltages,
- System frequency,
- Active, reactive and apparent power, 1- to 3 phases,
- Phase angle,
- Harmonics of voltages and currents up to the 50^{th} order,
- Total harmonic distortion (THD), voltages and currents, unweighted or weighted inductively or capacitively,
- Unbalanced voltage and current in the three-phase system.

Connection types

- Single phase,
- Four-wire three-phase current.

Measurands and operands, available as an option

- Direction of harmonics,
- Flicker measurement,
- Digital storage oscilloscope.

Operating modes

- Continuous measurement with display at one-second intervals,
- Continuous measurement with data storage,
- Event-controlled measurement with data storage.

Storage capacity

Up to 500,000 measured and calculated values; various options for defining the measuring points.

Function

Continuous measurement without storage roughly corresponds to the function of a multimeter. The selected values to be measured are continuously displayed and the whole screen content including the graphic illustrations can be printed on the integrated thermal printer by key command. This operating mode is used to check correct connection of the device and is suitable for general measurement tasks. Monitoring of the network quality is effected by continuously calculating and storing the mean values of the measured quantities. In the storage mode, the averaging interval can be configured individually from one period of the system voltage up to several months. Two types of storage modes can be selected, either linear mode (stops when the memory is full) or overwrite mode (the oldest data will be overwritten by the new information).

With the help of the OSCOP Q program, the measuring data can be transmitted to a personal computer for detailed analysis.

Information for Project Planning

The basic version of the device is fully capable of simultaneous acquisition of up to 55 measurands.

The voltage range of 400 V +15% is suitable for connection to 400 V three-phase systems. Clamp-on probes (10, 100 and 1000 A) for current measurement are available. The connection of a transducer is possible, if a resistor provides a voltage drop of 1 V nominal value.

The device can also be delivered for high-speed processing which enables simultaneous acquisition of up to 186 different measurands.

Optional functions which can be added at a later date by software installation:

- Power measurement of individual harmonics and their direction in order to identify the cause.
- Extension of the device functions for use as an additional three-channel digital oscilloscope.
- Flicker measurement according to IEC 60868.

Power Quality
Measuring and Recording

Recording Equipment

The SIMEAS R Fault and Digital Recorder

Application

- Stand-alone stationary recorder for extra-high, high and medium-voltage systems.
- Component of secondary equipment of power stations and substations or industrial plants.

Functions

Fault recorder, digital recorder, frequency/power fault recorder, power quality recorder, event recorder.

All functions can be performed simultaneously and are combined in one unit with no need for additional devices to carry out the different tasks.

Special features

- The modular design enables the realization of different variants starting from systems with 8 analog and 16 binary inputs up to the acquisition of data from any number of analog and binary channels.
- Clock with time synchronization using GPS or DCF77.
- Data output via postscript printer, remote data transmission with a modem via the telephone line, connection to LAN and WAN.

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Fig. 245: SIMEAS R Systems are used in power plants …

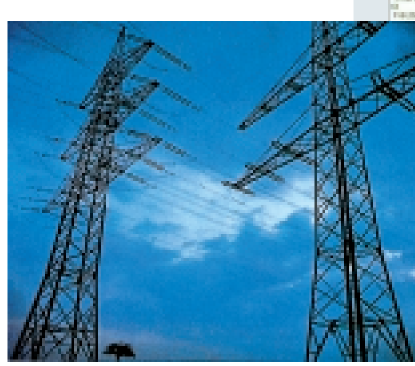

Fig. 246: … and to monitor transmission lines

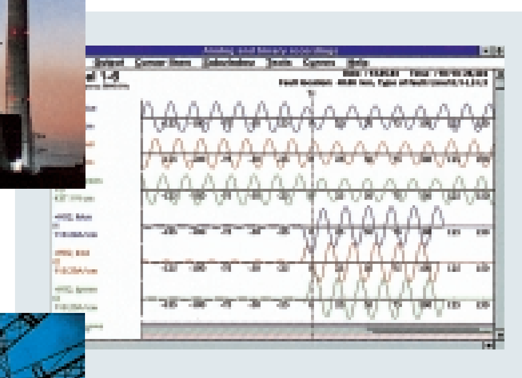

Fig. 247: Fault record

Fault Recording (DFR)

This function is used for the continuous monitoring of the AC voltages and currents, binary signals and direct voltages or currents with a high time resolution. If a fault event, e.g. a short-circuit, occurs, the specific fault will be registered including its history. The recorded data are then archived and can either be printed directly in the form of graphics or be transferred to a diagnosis system which can, for example, be used to identify the fault location.

Fault detection is effected with the help of trigger functions. With analog quantities this refers to

- exceeding the limit values for voltage, current and unbalanced load (positive and negative phase sequence system).
- falling below the limit values for voltage, current and unbalanced load (positive and negative phase sequence system).
- limit values for sudden changes in up or downward direction.

Monitoring of the binary signals includes

- signal status (high, low)
- status changes

Power Quality
Measuring and Recording

Logical triggers

Logical triggers can be defined by combining any types of trigger event (analog or binary). They are used to avoid undesired recording by increasing the selectivity of the trigger function. The device can distinguish between different causes of a fault, e.g. between a voltage dip caused by a short-circuit (low voltage, high current) which needs to be recorded, and the disconnection of a feeder (voltage low, current low) which does not need to be recorded.

Sequential control

An intelligent logic operation is used to make sure that each record refers to the actual duration of the fault event. This is to prevent continuous violation of a limit value (e.g. undervoltage) from causing permanent recording and blocking of the device.

Analog measurands

16-bit resolution for voltages and DC quantities and 2 x 16-bit resolution for AC voltages.
The sampling frequency is 256 times the period length, i.e. 12.8 kHz at 50 Hz and 15.36 kHz at 60 Hz for each channel.

A new current transformer concept enables a measuring range between 0.5 mA and 400 $A_{r.m.s.}$ with tolerances of <0.2% at <7 $A_{r.m.s.}$ and <1% at >7 $A_{r.m.s}$. Furthermore, direct current is registered in the range above 7 A; this enables a true image of the transient DC component in the short-circuit current.

Binary signals

The sampling frequency at the binary inputs is 2 kHz.

Data compression

For best utilization of the memory space and for high-speed remote transmission the data can be compressed to as little as 2% of their original size.

Fault diagnosis

Performed with the OSCOP P software package.

Digital Recording (DR)

This function is used for the continuous registration of the mean values of the measurands at intervals which can be freely defined (min. interval is one period). The main function of this device is the continuous recording of quantities at the feeders and to make these values available for the analysis of the network quality.

In single-phase and three-phase systems, the following measurands are recorded:

- R.m.s. values of voltages and currents
- Active power, phase-segregated and overall
- Reactive power, phase-segregated and overall (displacement or total reactive power)
- Power factor, phase-segregated and overall
- Frequency
- Positive and negative sequence voltage and current
- Weighted and unweighted total harmonic distortion (THD)
- 5 th to 50 th harmonics (depending on the averaging time)
- DC signals, e.g. from transducers

Depending on the individual network configuration, a three or four-wire connection is used.

Frequency/Power Recording (FPR)

This function uses the same principle as a fault recorder. It continuously monitors the gradient of the frequency and/or power of one or more three-phase feeders. If major deviations are detected, e.g. caused by the outage of a power plant or when great loads are applied, the profile of the measurands will be recorded including their history. The recorder is also used for the registration of power swings.

Measurands

- Frequency of one of the voltages, (limit of error ±1 mHz)
- Active power, reactive power (reactive displacement power), (limit of error ≤ 0.2%)
- Power factor

Averaging interval

A value between 1 and 250 periods of the network frequency can be selected.

History

Depends on the averaging interval;
10 s times the averaging periods.

Automatic power analysis

With the help of the OSCOP software package (see The OSCOP P) a power analysis of a station can be created automatically.

Sequence of Event (SOE) Recording

Each status change occurring at the binary inputs is registered with a resolution of 0.5 ms and is then provided with a time stamp indicating the time information from the year down to the millisecond.

200 status changes per second can be stored for each group of 32 inputs. The mass memory of the device can be configured according to requirements (a 5 MB memory, for example, enables the storage of approx. 120,000 status changes). Modules for signal voltages between 24 and 250 V are available.

The time-synchronous output enables the combined representation with analog curves, e.g. of alarm and command signals together with the course of relay voltages and currents. With the help of the OSCOP P program, the event signals can however also be displayed in the form of a text list in chronological order. The use of a separate sequence of event recorder will no longer be required.

Fig. 248: SIMEAS R for 8 analog and 16 binary inputs, 1/2 19'' design

Power Quality
Measuring and Recording

The OSCOP P Evaluation Program

The OSCOP P software package is suitable for use in personal computers provided with the operating systems MS WINDOWS 95/98 or WINDOWS NT. It is used for remote transmission, evaluation and archiving (database system) of the data received from a SIMEAS R or OSCILLOSTORE and from digital protection devices. The program includes a parameterization function for remote configuration of SIMEAS R and OSCILLOSTORE units.

The program enables fully-automated data transmission of all recorded events from the acquisition units to one or more evaluation stations via dedicated line, switched line or a network; the received data can then be immediately displayed on a monitor and/or printed (Fig. 249).

The OSCOP P program is provided with a very convenient graphical evaluation program for the creation of a time diagram with the curve profiles, diagrams of the r.m.s. values or vector diagrams (Fig. 252).

The individual diagrams can, of course, be adjusted to individual requirements with the help of variable scaling and zoom functions. Records from different devices can be combined in one diagram. The different quantities measured can be immediately calculated by marking a specific point in a diagram with the cursor (impedance, reactance, active and reactive power, harmonics, peak value, r.m.s. value, symmetry, etc.).

Additional diagnosis modules can be used to perform an automatic analysis of fault events and to identify the fault location. The program also supports server/client structures.

Information for Project Planning with SIMEAS R

The secondary components of high or medium-voltage systems can either be accommodated in a central relay room or in the feeder dedicated low-voltage compartments of switchgear panels. For this reason, the SIMEAS R system has been designed in such a way as to allow both centralized or decentralized installation.

The acquisition unit can be delivered in two different widths, either $^{1}/_{2}$ 19" or 19" (full width). The first version is favorable if measurands of only one feeder are to be considered (8 analog and 16 binary signals). This often applies to high-voltage plants where each feeder is provided with an extra relay kiosk for the secondary equipment. In all other cases, the full-width version of 19" is more economical, since it enables the processing of up to 32 analog and 64 binary signals. The modular structure with a variety of interface modules (DAUs) provides a maximum of flexibility. The number of DAUs which can be integrated in the acquisition system is unlimited.

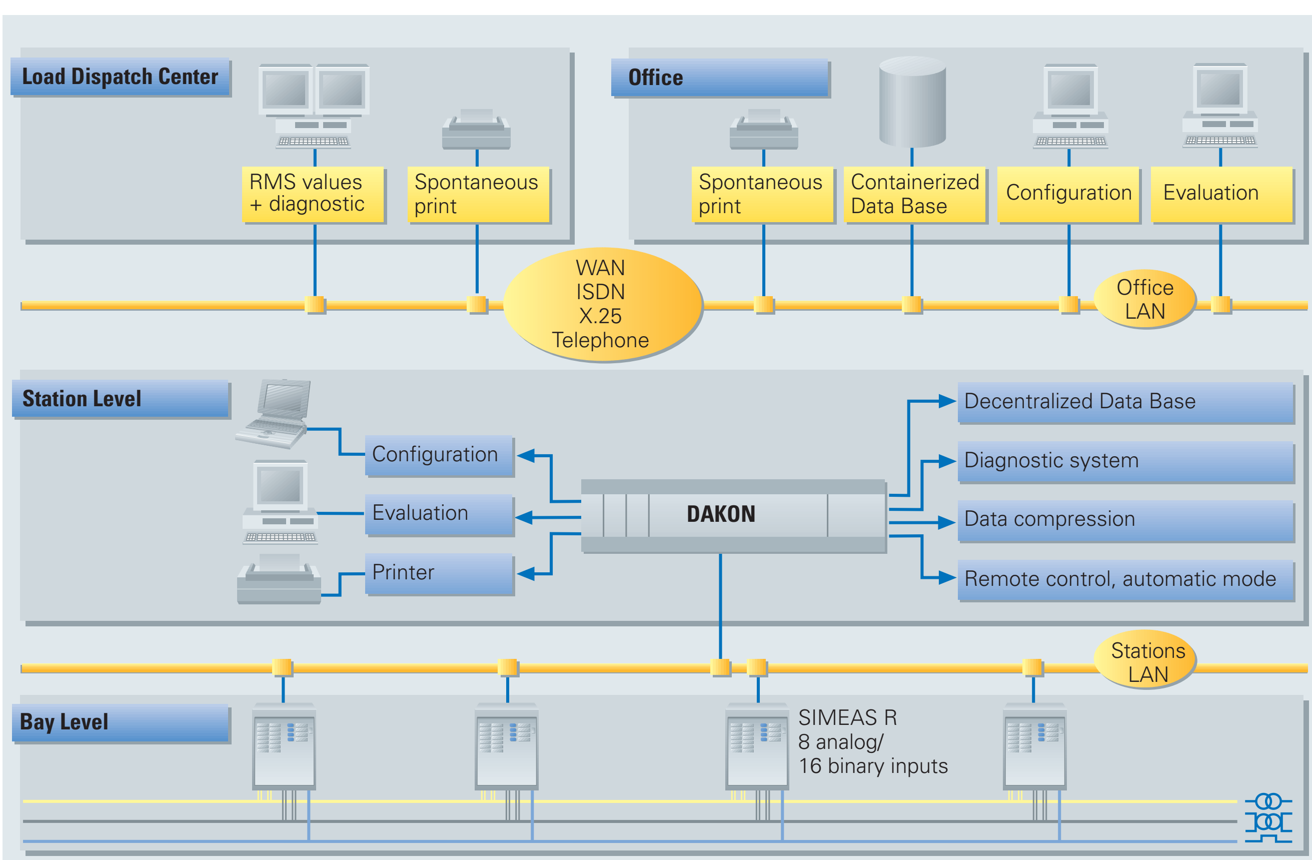

Fig. 249: Example of a distributed recording system realized with SIMEAS R recorders and data central unit DAKON

Power Quality
Measuring and Recording

With the help of a DAKON, several devices can be interlinked and automatically controlled. In addition, digital protection devices of different make can be connected to the DAKON.

The voltage inputs are designed for direct connection to low-voltage networks or to low-voltage transformers. Current inputs are suitable for direct connection to current transformers (I_N = 1 or 5 A). All inputs comply with the relevant requirements for protection devices acc. to IEC 60 255. The binary inputs are connected to floating contacts.

Data transmission is preferably effected via telephone network or WAN (Wide Area Network). If more than one SIMEAS R is installed, we recommend the use of a DAKON (data concentrator). The DAKON creates connection with the OSCOP P evaluation program, e.g. via the telephone network. Moreover, the DAKON automatically collects all information registered by the devices connected and stores these data on a decentralized basis, e.g. in the substation. The DAKON performs a great variety of different functions, e.g. it supports the automatic fax transmission of the data. A database management system distributes the recorded data to different stations either automatically or on special command.

Fig. 250: Rear view of a SIMEAS R unit with terminals for the signals and interfaces for data transmission

Use of the interface modules

DAU Type	Measurands	Application
VCDAU	4 AC voltages, 4 AC currents, 16 binary signals	Monitoring of voltages and currents of three-phase feeders or transformers including the signals from protective equipment. All recorder functions can be run simultaneously.
VDAU	8 AC voltages, 16 binary signals	Monitoring of busbar voltages
CDAU	8 AC currents, 16 binary signals	Monitoring of feeder and transformer currents or currents at the infeeds and couplings of busbars
DDAU	8 DC currents or 16 binary signals	For monitoring of quantities received from measuring transducers and telecontrol units, 20 mA or 1 and 10 V.
BDAU	16 binary signals	Event recording of alarm signals, disconnector status signals, circuit-breaker monitoring

Fig. 251: Use of the data acquisition units

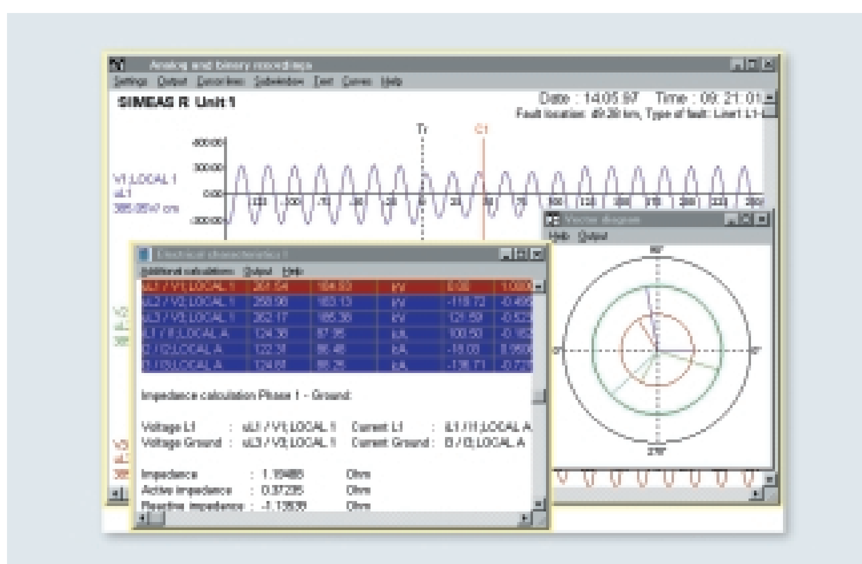

Fig. 252: OSCOP P Program, evaluation of a fault record

Compensation – Introduction Power Quality

Compensations Systems

Many consumers of electrical energy (transformers, engines, fluorescent lamps) may cause a number of different problems: reactive displacement power, non-linear loads (rectifiers, transformers), resulting in distorted waveshapes. Harmonics are generated and, finally, an unbalanced load at the three phases leads to increased apparent power and thus to increased power consumption. This is accompanied by higher conduction losses, which require the installation of lines and operating equipment suitable for higher capacities and at higher costs than actually necessary. The cost for power rates in relation to the apparent power and distortion should also be considered. In many cases it is favorable to perform compensation of the undesired components.

Siemens offers two different systems for the compensation of reactive power and of harmonics – SIPCON T and SIPCON DVR/ DSTATCOM – both suitable for three-phase LV systems up to a rated voltage of 690 V. The latter system is available in designs also capable of compensating short-term voltage dips and surges, as well as load unbalances.

- SIPCON T
  Passive systems using switched capacitors or capacitors with permanent wiring.
- SIPCON DVR / DSTATCOM
  Active systems using IGBT converters for quick and continuous operation.

The use of SIPCON can enable energy suppliers worldwide to provide the end consumer with distinctive quality of supply. As it is now possible with this technology to supply "Premium Energy", an energy supplier can formulate differing tariffs for his product – electrical energy – so that he will stand out from his competitors.

For industry, especially in the case of complex manufacturing processes (such as for example in the semiconductor industry) "Premium Energy" is an absolute necessity. SIPCON is capable of effectively suppressing system perturbation, such as for example harmonics. Here as well, tariff changes are to be expected worldwide in the future. Investigations in Europe have shown that the increase in harmonics is imposing a particular strain on systems. Such harmonics occur through the operation of variable speed drives, of rectifiers – for example in electroplating – and of induction furnaces or wind power plants. In private houses, the principal loads are single-phase, such as TV sets and personal computers. With the aid of selective recording of weaknesses in the electrical system and subsequent use of the SIPCON Power Conditioner, it will be possible to improve system loading and to significantly rationalize the high capital investment necessary for system expansion.

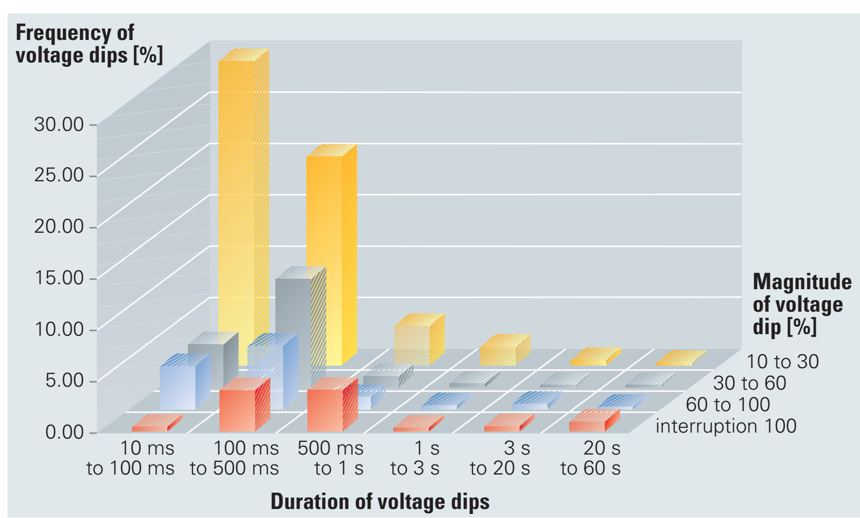

Fig. 253: Frequency and duration of voltage dips

Fig. 254: Active compensation system (Power Conditioner DSTATCOM)

Power Quality
Passive Compensation – Power Factor Correction

The SIPCON T Passive Filters and Compensation Systems

All consumers based on an electromagnetic operation principle (e.g. motors, transformers, fluorescent lamps with series reactors) require a lagging reactive power. This leads to an increase in the amount of apparent power and consequently in current. The supply of reactive power from the mains leads to additional load applied to the operating equipment which, as a result, needs to be configured for higher capacities than actually required. The higher current is accompanied by an increased power loss. However, the required reactive power can also be generated close to the consumer with the help of capacitors which prevent the above mentioned disadvantages. When selecting the capacity it is general practice to calculate with a power factor of 0.9 or higher.
Compensation can be effected according to three different principles: individual correction, group correction and centralized correction.

Individual Correction

This type of compensation is reasonable for consumers with high capacities, constant load and long operating times. (Fig. 255).

- The capacitor is installed close to the operating equipment. The lower current flows already in the line from the busbar to the consumer.
- The capacitor and the consumer are turned on and off together; an additional switch is not required.

When selecting the type of capacitors please note that in the case of induction motors, the reactive power supplied by the capacitor must not exceed approx. 90% of the motor reactive power in idle operation. Otherwise, disconnection might cause self-excitation by the resonance frequency, since the motor and the capacitor form a resonant circuit. This effect may lead to high overvoltages at the terminals and affect the insulation of the operating equipment. As a general rule, the following values should be considered for the capacitor:

- Approx. 35% of the motor power at ≥ 40 kW,
- Approx. 40% of the motor power from 20 to 39 kW,
- Approx. 50% of the motor power at < 20 kW.

Under unfavorable conditions, adherence to this rule may lead to a power factor smaller than 0.9. In this case, centralized correction should be performed additionally.

Group Correction

A group of consumers, e.g. motors or fluorescent lamps, operated by one common switch, can be compensated with one single capacitor (Fig. 256).

Centralized Correction

The solution for correcting the power factor for a great number of small consumers with varying power consumption is a centralized compensation principle (Fig. 257) using switched capacitor modules and a controller. The low losses of the capacitors allows them to be integrated directly in the switchboards or distributors.

A programmable controller is used to monitor the power factor and to switch the capacitors according to the reactive-power flow.

The devices for group correction differ in their power and in their number of switching steps. For example, a unit with 250 kVA can be switched in steps of 50 kVA.
We recommend the use of units suitable for switching between five and twelve steps.

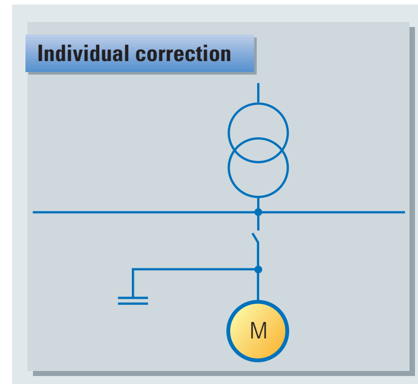

Fig. 255: Individual correction

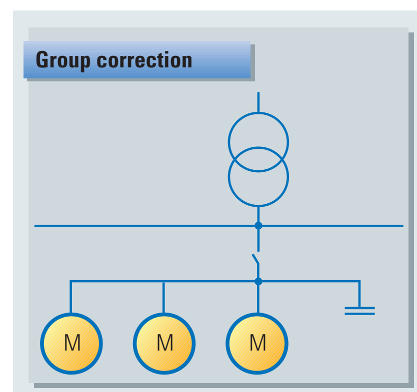

Fig. 256: Group correction

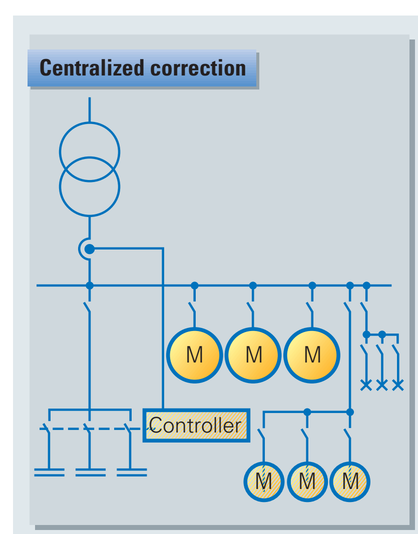

Fig. 257: Centralized correction

Power Quality
Passive Compensation – Power Factor Control

Fig. 258: SIMEAS C Power Factor Controller

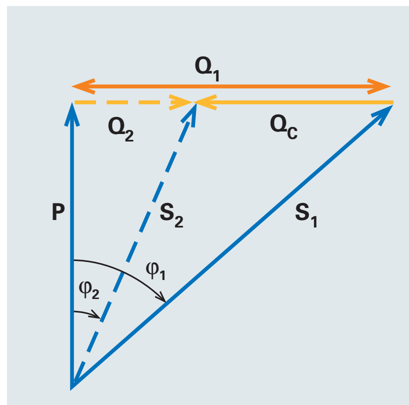

Fig. 259: Effect of compensation

Two examples

1 Uncompensated system, rated voltage 400 V

Active power P_a	550 kW
Power factor $\cos\varphi_1$	0.6
Apparent power S_1	920 kVA
Current I_1	1330 A

$$S_1 = \frac{P_a}{\cos\varphi_1} = \frac{550\text{ kW}}{0.6} = 920\text{ kVA}$$

$$I_1 = \frac{S_1}{\sqrt{3}\cdot U} = \frac{920\text{ kVA}}{\sqrt{3}\cdot 400\text{ V}} = 1330\text{ A}$$

2 Compensated system, rated voltage 400 V

Power factor $\cos\varphi_2$	0.9
Capacitor power Q_C	470 kvar
Apparent power S_2	610 kVA
Current I_2	880 A

$$Q_C = P_a(\tan\varphi_1 - \tan\varphi_2)$$

$$S_2 = \frac{P_a}{\cos\varphi_2} = \frac{550\text{ kW}}{0.9} = 610\text{ kVA}$$

$$I_2 = \frac{S_2}{\sqrt{3}\cdot U} = \frac{610\text{ kVA}}{\sqrt{3}\cdot 400\text{ V}} = 880\text{ A}$$

The correction of the power factor from $\cos\varphi_1 = 0.6$ to $\cos\varphi_2 = 0.9$, results in a 34% reduction in apparent power transmitted. Line losses can be reduced by 56%.

$$\frac{S_1 - S_2}{S_1} = 0.34$$

$$\frac{I_1^2 - I_2^2}{I_1^2} = 0.56$$

Fig. 260: Examples of power factor control

The SIMEAS C Power Factor Controller

The centralized correction principle is effected with the help of a controller. This unit is designed for panel mounting (front frame dimensions 144 x 144 mm according to DIN) in the door of the compensation equipment. It is connected to L1, L2 and L3 of the mains voltage; the current is taken from a current transformer in L1 rated 1 A or 5 A.

All capacitor modules connected are switched stepwise in such a way as to enable best approximation to the setpoint value of the power factor. Defined waiting periods prevent excessive switching operations and ensure that the capacitor will be discharged properly before the next connection. Two setpoints ($\cos\varphi_1$ and $\cos\varphi_2$) can be specified separately to enable different modes for day and night time.

Each capacitor module is operated by contactors which are controlled by means of six contacts. A further contact is used for error indication. One input for a floating contact is used to select one of the two setpoints for the power factor. Apart from the control function, the device also offers a great amount of information on the status of the supply system. It shows:

- Setpoint $\cos\varphi_1$,
- Setpoint $\cos\varphi_2$ (e.g. night operation),
- Line current,
- Voltages,
- Active power in kW,
- Apparent power in kVA,
- Actual reactive power in kvar,
- Deviation of the reactive power from the setpoint value,
- Reactive power of the activated capacitors,
- Harmonics of voltage U5,
- Harmonics of voltage U7,
- Harmonics of voltage U11,
- Harmonics of current U5,
- Harmonics of current U7,
- Harmonics of current U11.

A fiber-optic interface is accessible at the rear of the device. On request, a cable suitable for the conversion of optical pulses into RS 232C (V.2) signals can be supplied. This cable enables connection to a personal computer which can be used to program the controller and to read out parameters, as well as the measured values.

Selecting the Capacitor Power

When defining the capacitor power for a system, the active power P and the power factor cos φ_1 of the system have to be considered. In order to upgrade cos φ_1 to cos φ_2, the following applies to the power Q_C of the capacitor:

$$Q_C = P_a \cdot (\tan\varphi_1 - \tan\varphi_2)$$

Fig. 261

The diagram in Fig. 259 shows how the apparent power S_1 – caused by active power P_a and reactive power Q_1 – is reduced to the value S_2 by the capacitor power Q_C. When taking into account that the current is proportional to the apparent power, whereby the loss caused by the current increases by the power of two, the saving is remarkable. This result is possibly supported by a lower energy tariff to be paid.

With systems in the planning stage we can assume that the reactive load is caused mainly by induction motors. These motors operate with an average power factor of ≥ 0.7. Increasing the power factor to 0.9 requires a capacitor power of approx. 50% of the active power.

In present industrial plants, the required capacitor power can be determined on the basis of the energy bill, provided the plant is equipped with an active and reactive energy meter.

$$Q_C = \frac{E_r - (E_a \cdot \tan\varphi_2)}{t}$$

E_r = reactive energy (kvarh)
E_a = active energy (kWh)
t = operating time in hours over the accounting period
$\tan\varphi_2$ = calculated from the setpoint value for $\cos\varphi_2$

Fig. 262

If no reactive energy meters are installed, the required data can be determined with the help of a reactive power recorder.

Correction of the Power Factor in Networks with Harmonics

Consumers with non-linear resistors, i.e. with non-sinusoidal power consumption, cause a distorted voltage waveshape. However, all waveshapes are made up of sine curves the frequencies of which are integer multiples of the system frequency – the harmonics. When using capacitors for power factor correction, the capacity of these capacitors and the inductivity of the network (supplying transformer) form a series resonant circuit.
The two impedances of the resonance frequency are the same and cancel each other out; the relatively low active resistance, however, causes current peaks which may possibly lead to the tripping of protection devices. This may occur if the resonance frequency equals or is close to the frequency of a present harmonic.

This effect can be corrected by the use of capacitor units equipped with an inductor. These inductors are designed in such a way that the resonance frequency in combination with the network inductivity falls below the fifth harmonic. With all higher harmonics, the capacitor unit is then inductive which excludes the generation of resonances.

We recommend use of these inductor-capacitor units in all cases where more than 20% of the power is caused by harmonics-generating equipment.

Compensation in Networks with Ripple Control

Ripple control is effected by superimposing the network voltage with signals of a frequency between 160 and 1350 Hz. Since the capacitor conductance is rising in a linear manner in relation to the frequency, these signals can be practically short-circuited. For this reason, the influence of the compensation measures should be considered and, if inadmissible, it should be corrected. VDEW (German Utility Board) has issued a recommendation on this subject, where the impedance factor α has been defined as the ratio of the network impedance to that of the compensation equipment at the frequency of the ripple control signal.

The practical consequence is that in networks without harmonics and with ripple control frequencies of less than 250 Hz, capacitors without inductors can be used to correct the power factor at a capacity of up to 35% of the apparent transformer power. In this case, follow-up measurements can be omitted.

Ripple control frequencies	Reactor/capacitor ratio p
< 250 Hz	14%
> 250 Hz	≥ 7%
> 350 Hz	≥ 5%

Fig. 263: Types of compensation for different ripple control frequencies

Only in cases with a higher capacitor power should the power supply companies be consulted for an agreement on the use of audio frequency hold-offs. With frequencies greater than 250 Hz, capacitor powers without audio frequency hold-off are admissible only up to 10 kvar. If the capacitor power exceeds this value, audio frequency hold-offs are to be integrated. This refers mainly to parallel resonant circuits which are connected to the capacitors in series and which show a high impedance in their resonance frequency.

In networks where harmonics are clearly present, inductor-capacitor units should be used for compensation in any case. The specific type of compensation equipment is to be selected with consideration of the ripple control frequency. Fig. 263 shows some guide values for this procedure.

Compensation of Harmonics

The continuous progress in power semiconductor technology has resulted in an increased use of controlled rectifiers and frequency converters, e.g. for variable-speed drives. The common and characteristic feature of these devices is their non-sinusoidal power consumption. This leads to distortion of the network voltage, i.e. it contains harmonics. This distortion is then forced upon other consumers connected to the same network and will also have an effect on higher voltage levels. This disadvantage may lead to operational failures and cause a higher apparent power in the network. In order to keep to the limit values as specified in the EN 50160 standard, filtering may become necessary.

Passive Compensation – Harmonics Filter

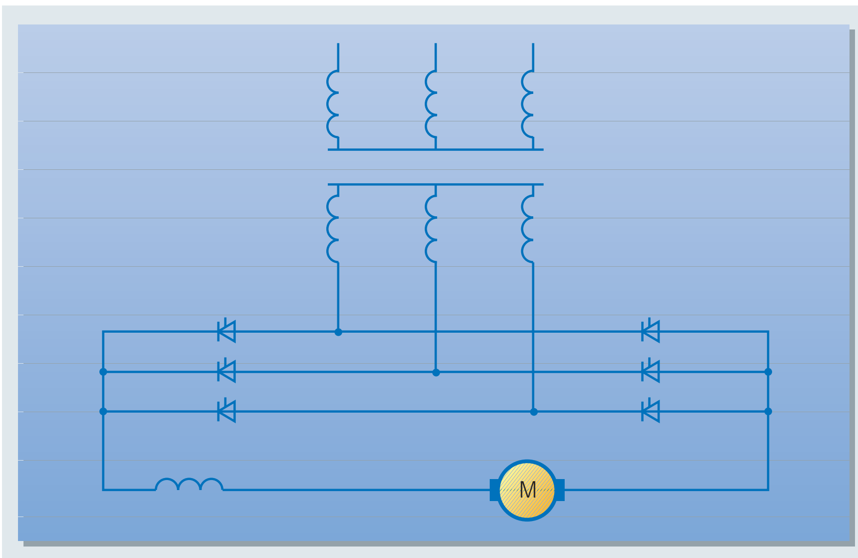

Fig. 264: Three-phase bridge circuit

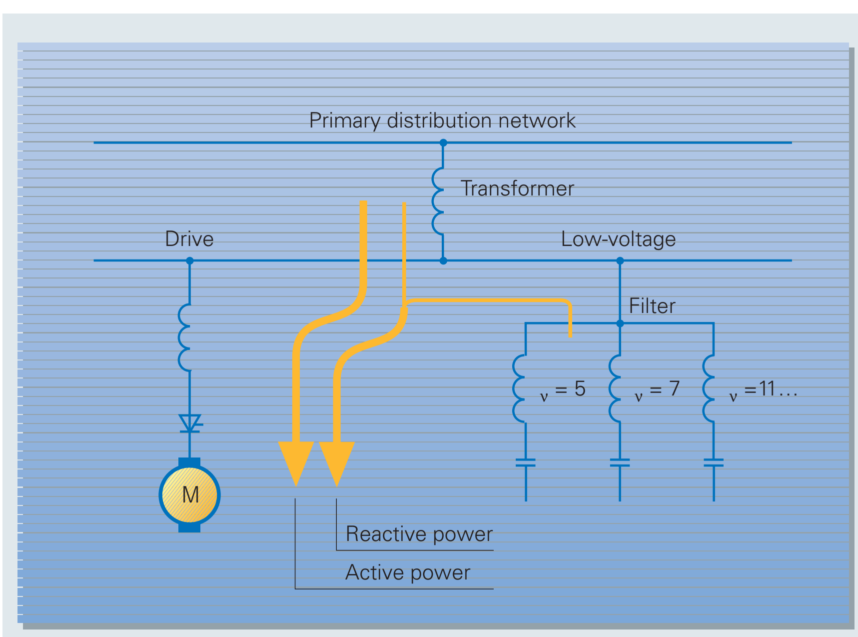

Fig. 265: Correction of the power factor with the help of filters

The following example shows the harmonics present in a typical three-phase, fully-controlled, bridge-circuit rectifier (Fig. 264).

$$\nu = 6 \cdot k \pm 1, \qquad k = 1, 2, 3, \ldots$$

Fig. 266

The amplitude of the currents decreases inversely to the increase of the order number, ideally, in a linear manner in relation to the frequency:

$$I_\nu = \frac{1}{\nu} \cdot I_1$$

Fig. 267

Actually, the values are often slightly higher, since the DC current is not completely smoothed. Harmonics of the fifth, seventh, eleventh and thirteenth order may show amplitudes which need to be reduced; harmonics of a higher order can usually be neglected.

The effect of harmonic currents on the system can be reduced considerably by the use of filters. This is effected by generating a series resonant circuit from a capacitor and an inductor which is then adjusted exactly to the corresponding frequency for each harmonic to be absorbed. The two impedances cancel each other out, so that the remaining ohmic resistance is reduced to a negligible amount, compared to the network impedance. The harmonic currents are absorbed to a large extent; the rest remains present in the supply network. This results in a lower voltage distortion and a considerable increase in voltage quality.

Referring to the fundamental component, the filters form a capacitive load. This supports the general reactive power compensation. This measure enables the corresponding equipment to be designed for lower capacities (Fig. 265).

Power Quality
Passive Compensation – Selection Guide

Help for Selection

Siemens offers capacitors with and without reactors, suitable for single-phase and three-phase systems for reactive powers between 5 and 100 kvar and for nominal voltages between 230 and 690 V. These capacitors are suitable for the compensation of constant reactive power.

Type Series 4RB

MKK Power Capacitors for fixed compensation without reactors, ratings 5 to 25 kvar. The three-phase capacitors can be directly connected at the load. Discharge resistor 4RX92 are to be connected in parallel.

Type Series 4RD

MKK power capacitors for fixed compensation without reactors, mounted in a protective housing or on a plate. Ratings 5 to 100 kvar. Discharge resistors included.

Type Series 4RY

Complete small systems without reactors for the automatic stepwise control of the power factor with and without integrated audio frequency hold-off in different housings and at different ratings. The units are equipped with a BLR-CC controller suitable for 8 switching steps. Without audio frequency hold-off, the capacity ranges from 10 to 100 kvar, with hold-off from 12 to 50 kvar. The nominal voltage for both versions is 400 V, the frequency is 50 Hz.

Larger, fully-equipped systems without reactors are delivered in cabinets. The ratings of these systems range from 37.5 up to 500 kvar for nominal values between 230 V and 690 V and frequencies between 50 and 60 Hz. With these systems the SIMEAS C controller for operation in six switching steps is used. This controller optimizes the switching sequence for constant use of the capacitors. For voltages of 400 V, systems with ratings between 75 and 300 kvar and with an integrated audio frequency hold-off are available.

Type Series 4RY56

Capacitor modules without reactors between 20 and 100 kvar for installation in racks of 600 or 800 mm in width.

Type Series 4RF56

Reactor-capacitor modules from 5 to 100 kvar for installation in racks of 600 or 800 mm in width.

Type Series 4RF6

Fixed reactor-capacitor units for stationary compensation in networks with a non-linear load percentage of more than 20% related to the supply transformer apparent power rating. Voltages between 400 and 690 V, rating from 5 to 50 kvar. Reactor/capacitor ratios: 5.67%, 7% or 14%.

Type Series 4RF14

Passive, adjusted filter circuits for the absorption of harmonics. Voltages from 400 to 690 V, rating from 29 to 195 kvar. In the course of project planning, the customer will be requested to specify the currents of the generated harmonics, the harmonic content in the higher-level network and the short-circuit reactance at the connecting point.

Type Series 4RF1

Fully-equipped compensation systems with reactor suitable for 400 to 690 V, with a capacitor rating up to 800 kvar and with additional reactors for a total rating up to 1000 kvar. The controller function is realized by SIMEAS C.

Version	Reactor/capacitor ratio
4RF16	5.67%
4RF17	7%
4RF18	8%
4RF19	14%

Fig. 268

Type Series 4RF3

Fully-equipped compensation systems with reactors suitable for 400 to 525 V (and also for other voltages on request) for ratings between 200 and 400 kvar. Special feature: audio frequency blocking and simultaneous filtering of harmonics. The controller function is realized by SIMEAS C.

For technical data of SIPCON T Passive Filters and Compensation Systems see Power Quality Catalog SR 10.6

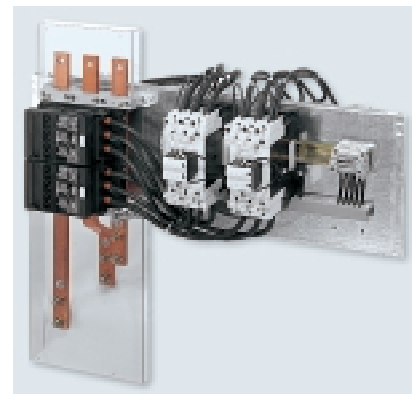

Fig. 269: 4RY56 Capacitor module 100 kvar, switchable as 2 x 50 kvar module for cable connection

Fig. 270: 4RY19 power factor correction unit in sheet-steel wall cabinet, 50 kvar

Fig. 271: 4RF1 power factor correction unit 250 kvar (5 x 50 kvar) in a cabinet 2275 x 625 mm

Power Quality
Passive Compensation – Selection Guide

Flowcharts

The flowcharts can be used as a reference when selecting the suitable compensation equipment with regard to the individual preconditions of the specific network.

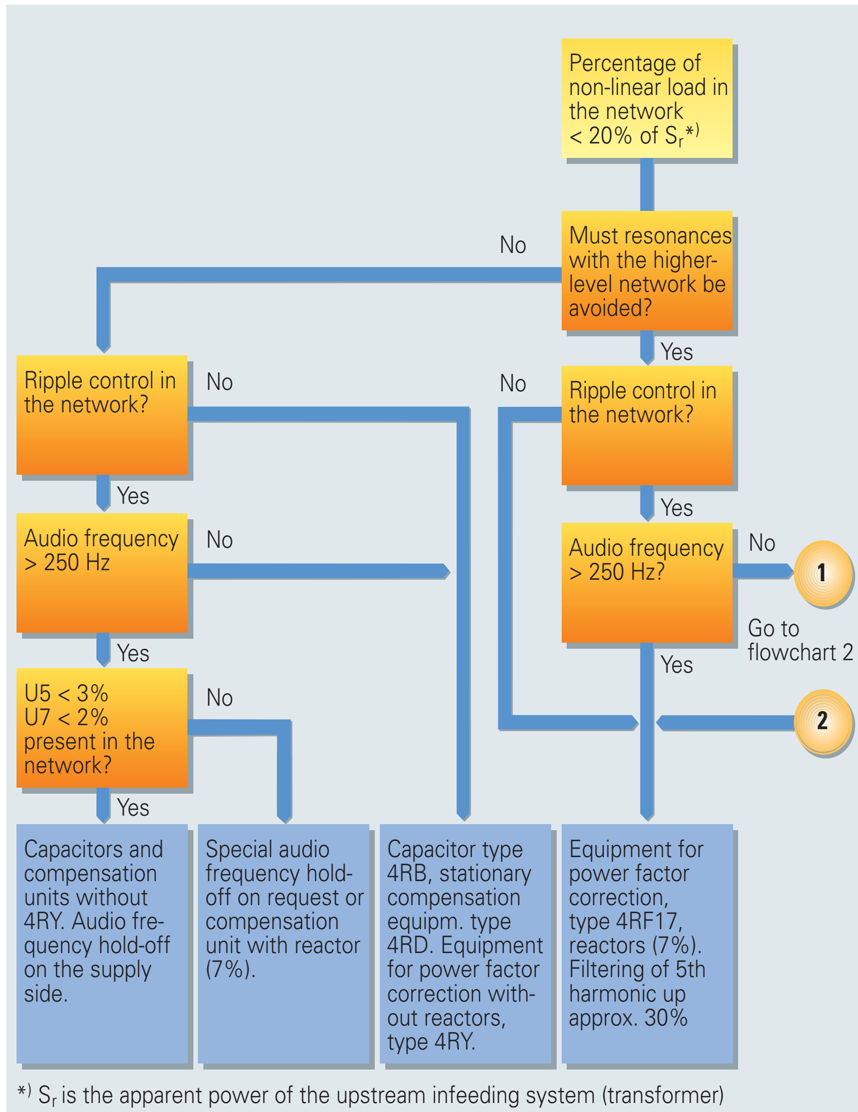

Fig. 272: Flowchart 1: Power factor correction for low, non-linear load

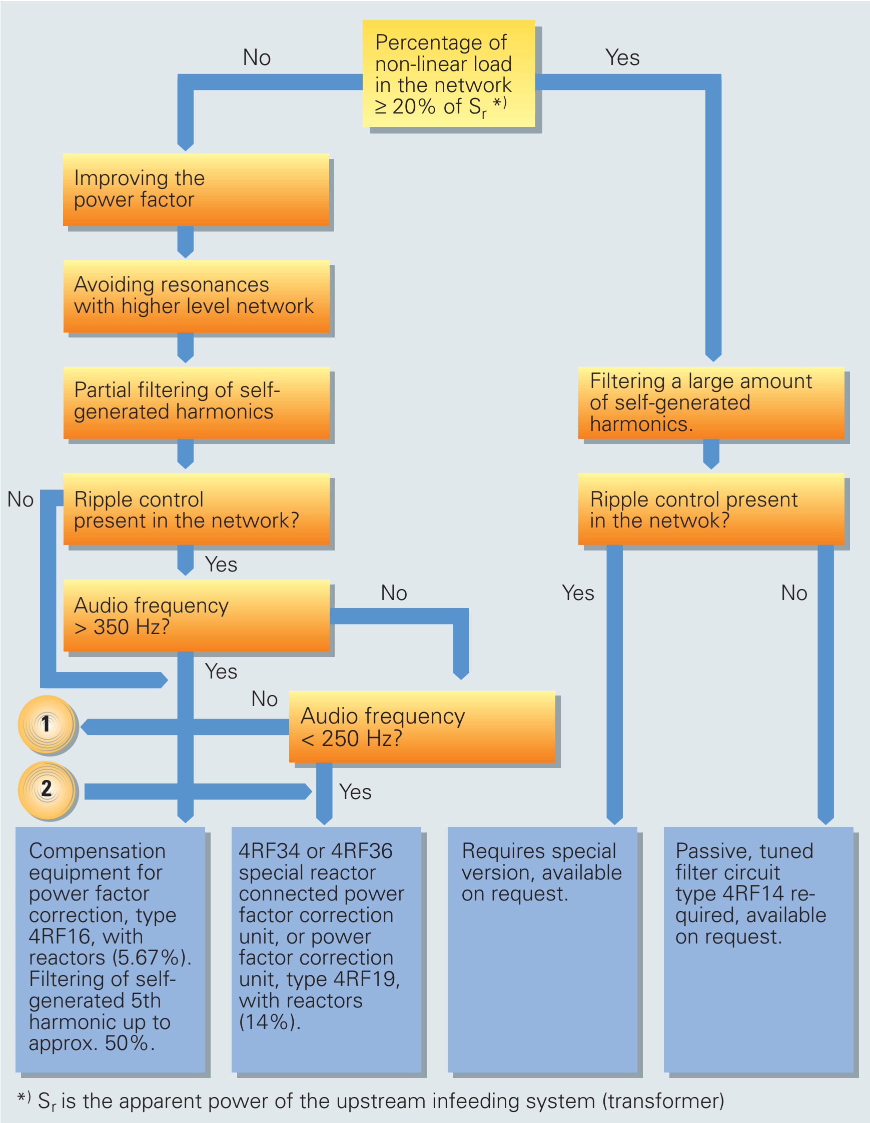

Fig. 273: Flowchart 2: Power factor correction for large non-linear load

SIPCON-DVR/SIPCON-DSTATCOM Active Filter and Compensation Systems

A great number of industrial processes based on the supply of electrical energy require a high degree of reliability in power supply, including the constancy of the voltage applied and the waveshape. A short-time voltage failure or voltage dip may cause the destruction of a component presently being processed in an NC machine or of a whole production lot in the semiconductor, chemical or steel industry. In the automotive and semiconductor industries, for example, the cost incurred by these losses may quickly accumulate to millions of dollars. In return, some production processes cause unacceptable perturbations in the supply network resulting from voltage dips (rolling mills), flickers and asymmetries (steel mills).

Correction is possible with the help of active compensation systems. These systems are capable of absorbing harmonics and of compensating voltage dips, reactive power, imbalance in the three-phase system and flicker problems. Their characteristic features go far beyond the capabilities of passive systems (e.g. SIPCON T) and offer great advantages when compared with other applications. The function principle is based on a pulse-width modulated, three-phase bridge-circuit rectifier, as used for example in variable-speed drives. The switching elements – IGBTs (insulated gate bipolar transistors) – are controlled by means of pulses of a certain length and phase angle. These pulses initiate charging and discharging of a capacitor, used as an energy store, at periodical intervals in order to achieve the desired effect of influencing the current flow direction. The control function is performed by means of a microprocessor-based, programmable control unit.

Advantages of Active Compensation Equipment

- No capacitance, in order to exclude the generation of undesired resonances.
- Reactive power and harmonics are treated independently of each other; the compensation of harmonics has no effect on the power factor and vice versa.
- The audio frequency ripple control levels remain unaffected.
- Stepless control avoids sudden changes and enables compensation at any degree of accuracy.
- Most rapid reaction to load changes with a minimum delay.
- No overvoltages caused by switching operations.
- The equipment protects itself against overload.
- The functions will not be affected by ageing of the power capacitors.
- The user can re-configure the system at any time; this greatly enhances flexibility, even if the specific tasks have changed.

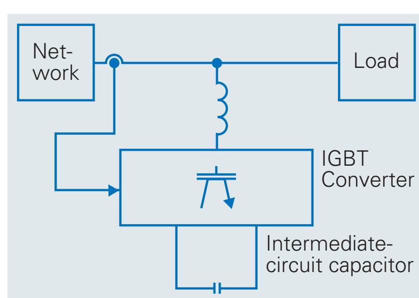

Fig. 274: DSTATCOM

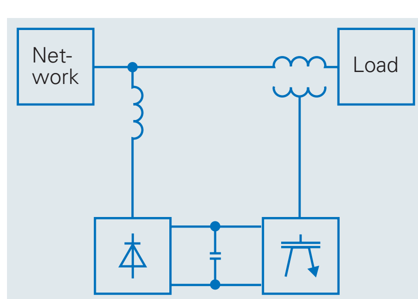

Fig. 275: DVR

There are two systems available, the DVR (Dynamic Voltage Restorer) and the DSTATCOM (Distributed Static Compensator) which differ in their specific design and application. DSTATCOM is designed for parallel and the DVR for serial connection.

The DSTATCOM is connected to the network between the incoming supply line and the consumer or a group of consumers as shown in Fig. 274. The compensation unit functions as a current source and sink. Correction includes all network characteristics related to the reactive power. The DSTATCOM is used to compensate load reactions on the network.

Connection of the DVR requires some more effort, since the system is to be looped into the line (Fig. 275) in series connection. In this connection, the DVR can influence the line current flow which enables a complete compensation of voltage dips as occurring, for example, in the event of short-circuits in the network. The DVR improves the voltage quality of the supply system.

The DSTATCOM Compensation Equipment

The DSTATCOM is used to compensate reactive power, harmonics, unbalanced load and flickers caused by a consumer. The current supplied from the network is measured and modified by injecting corrective current in such a way as to prevent violation of the limit values defined for reactive power and for specific harmonics flowing to the supply system; flicker problems can also be reduced. The power required for this compensation is derived from the intermediate-circuit capacitor which is simultaneously re-charged with line current. This line current is also used to correct the network current. Apart from the comparatively low losses, no active power flow occurs. The DSTATCOM reduces or fully compensates perturbations on the network caused by the consumer.

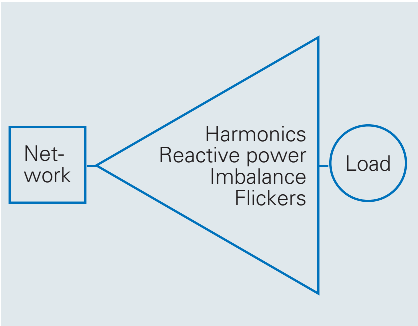

Fig. 276: Load perturbations are compensated

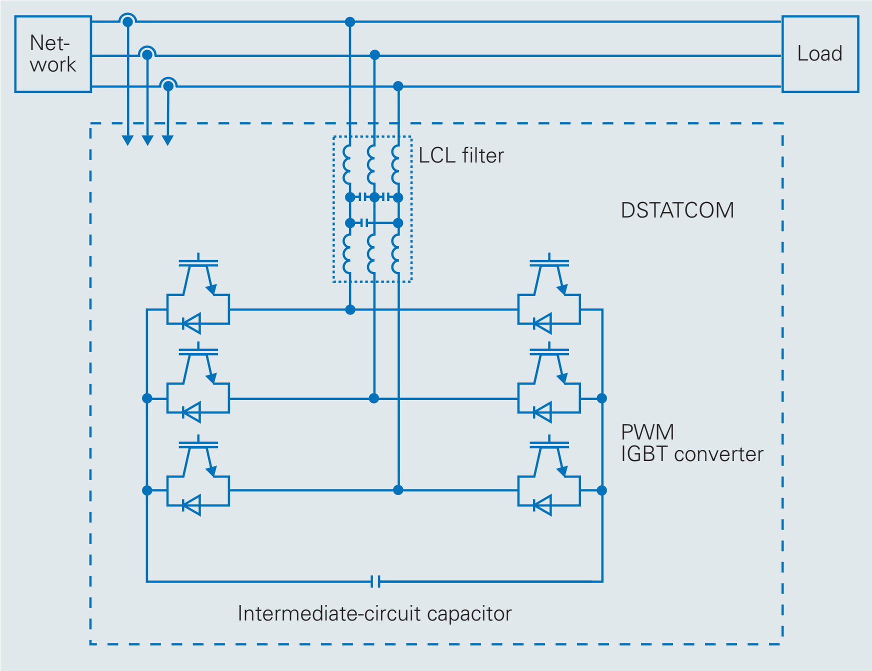

Fig. 277: Basic diagram of the DSTATCOM

Function Principle

The DSTATCOM unit measures the current applied to the supply side and injects a corrective current which compensates load perturbations in the supply system or reduces them to the admissible amount. Since no capacitors are used for correction, the risk of resonances, as with passive systems, can be neglected. Inductors are not required.

The signals from the audio frequency ripple control systems are not affected. The use of audio frequency hold-offs can be omitted.

The DSTATCOM is available in two control variants: control variant 1 for standard operation and variant 2 for flicker mode.

Fig. 277 shows the basic diagram of the system. The IGBT rectifier bridge is connected to the network via an LCL filter. The impedance of the inductivity causes the pulse-width modulated voltage to impress a current into the network and absorb components of higher frequency. With the help of capacitors, the filter effect will be improved. DC voltage is applied to the intermediate-circuit capacitor which is adjusted according to its specific function. The current is measured on the network side with the result that the correcting functions improve the network current and reduce the load reactions on the system.

Application of Variant 1

This is the standard design used to fulfill the tasks as described below. All functions can be performed simultaneously; they are carried out completely independently and do not affect each other, as occurs when using solutions with passive components (capacitors).

DSTATCOM protects itself against overload by limiting the current. The individual tasks can be allocated to different priority levels. In case of overload, the tasks with the lowest priority will then be skipped and the device will use its full capacity for the other tasks. The control functions with the highest priority level will be the last ones remaining active.

In this operating mode the DSTATCOM shows excellent dynamic behavior. Within only a few network periods, the system will reach the setpoint value. Operating variant 1 is used for:

- Absorption of Harmonics
  A maximum of 4 harmonics up to the 13th order, e.g. 5, 7, 11 and 13, are compensated. The remaining residual current can be adjusted. This option avoids excessive system load, since the increasing effect of correction causes a decline in the internal resistance for the corresponding frequency. In return, the load-caused current will considerably increase and with it the losses, which might result in a system overload. Therefore, it is reasonable to correct the harmonics only up to the limit specified by the supplier.
- Reactive Power Compensation
  Reactive power compensation, i.e. correction of the power factor, is possible for both inductive and capacitive loads. The continuous control principle avoids switching peaks and deviations which might occur when switching from one step to the next.
- Correction of Unbalanced Load
  Loads in single and two-phase connection cause voltage imbalance in the three-phase system which may also have negative effects on other consumers. Especially three-phase motors may then be exposed to overheat.
  An active load can be symmetrized by means of a Steinmetz compensator. While this compensator can correct only constant loads, the SIPCOM is capable of adjusting its correction dynamically to the load, even if this load is changing quickly.

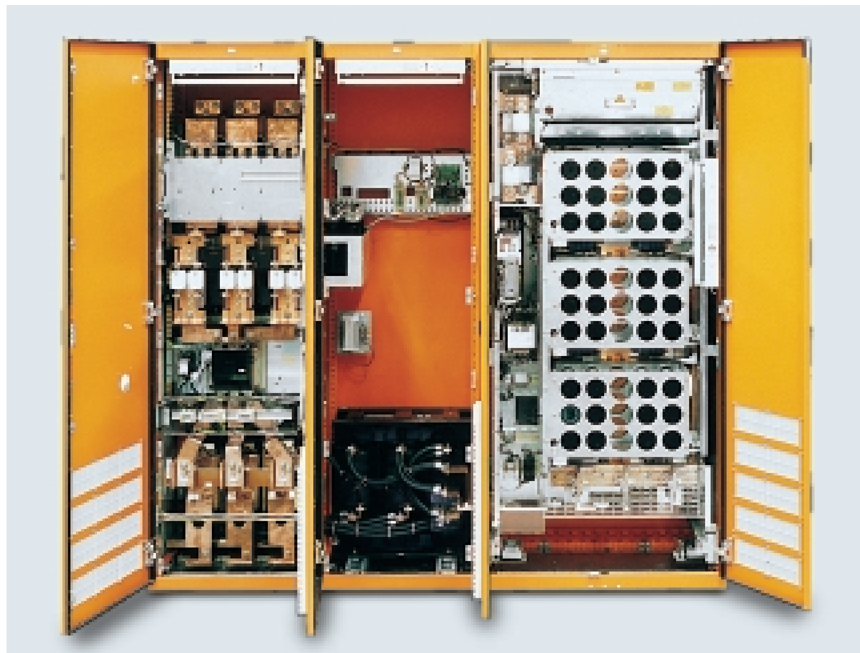

Fig. 278: Example: SIPCON DSTATCOM LV

Applications of Variant 2

Variable loads require an even quicker reaction than can be realized with variant 1. Therefore, variant 2 has been optimized in such a way as to enable reactive power compensation and load balancing within the shortest time. Possible applications of this variant are:

- Reduction of flickers
  Heavy load surges as occurring, for example, in welding machines, presses or during the startup of drives, may cause voltage line drops. Fluorescent lamps react to these voltage drops with variations in their brightness, called flickers. The reactive components of the load current have usually a greater effect in this case. The DSTATCOM can be operated in the flicker mode which provides an optimized reaction within the shortest time in order to reduce these voltage variations to a large extent. The delay time of the system is only 1/60 of the period length and control is completed within one network period.

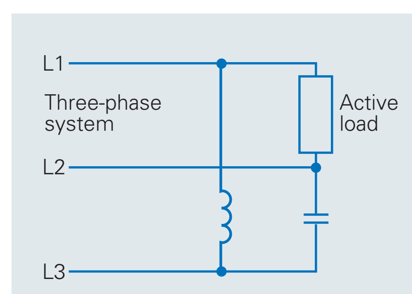

Fig. 279: Steinmetz compensator

- Correction of unbalanced load conditions
  The DSTATCOM is suitable to fully correct unbalanced loads of the three phases. Until now, this was achieved with the help of stepwise controlled inductors and capacitors, but now correction can be performed continuously and very precisely. The quick reaction of the DSTATCOM in the flicker mode enables control within only one network period. Consumers in single or two-phase connection, such as welding devices, will no longer affect symmetry.

Power Quality
Active Compensation

Information for Project Planning

When selecting a DSTATCOM, three aspects should be considered:

1. The nominal voltage.
   Nominal voltages of 400 V, 525 V, 690 V and for medium-voltage applications up to 20 kV.
2. The supply current I_{SN} required by the DSTATCOM.
3. The type of application.
   Application can be broken down into three types of different tasks (Fig. 280).

100% use for the filtering of harmonics	The whole nominal current of the DSTATCOM can be used for the filtering of harmonics. Reactive power compensation and load balancing can also be performed. This function should be used if the device is mainly used for the filtering of harmonics
50% use for the filtering of harmonics	Only 50% of the DSTATCOM nominal current is used for the filtering of harmonics. The remaining current can be used for reactive power compensation and load balancing.
Flicker mode	Instead of harmonics filtering, the whole nominal current is used to perform highly dynamic reactive power compensation and load balancing. Compared with other control variants, the dynamic behavior is many times better.
Required nominal current	The required nominal current for the DSTATCOM is calculated as the geometrical sum of the required partial currents according to the following formula:

$$I_{SN} = \sqrt{I_1^2 + I_5^2 + I_7^2 + I_{11}^2 + I_{13}^2}$$

I_1 = Reactive component of the fundamental current component

$I_5 \ldots I_{13}$ = Current harmonics

Fig. 280: Application modes of DSTATCOM

SIPCON can be used for the generation of either capacitive or inductive reactive current. Since the latter can usually be neglected as regards reactive power compensation, the working point of the DSTATCOM can be displaced by means of fixed compensation with the help of traditional compensation (SIPCON T). The power of the DSTATCOM can thus be almost doubled. (Fig. 281).

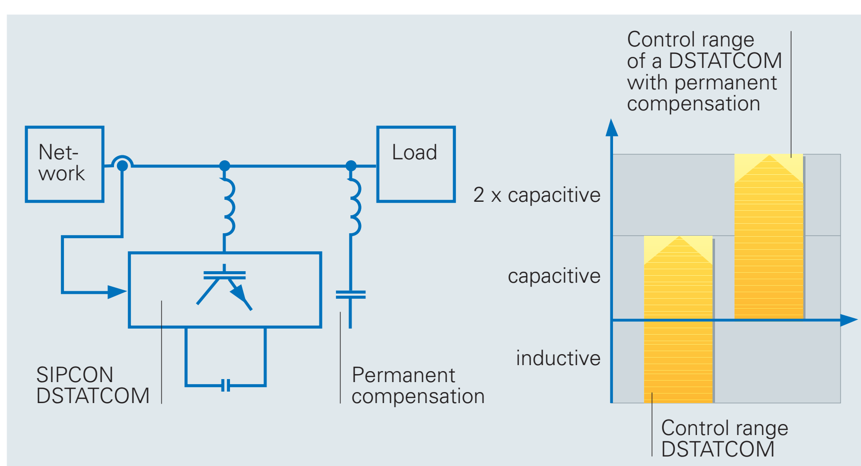

Fig. 281: Displaced control range

Power Quality
Active Compensation

The DVR Compensation Equipment

The DVR unit is used to correct interfering influences from the supply network on the consumer. Short-time and even longer voltage dips, harmonics and unbalanced load may cause considerable damage to sensitive consumers. The DVR has been designed for the compensation of such faults in order to improve the quality in power supply and to prevent production loss and damage.

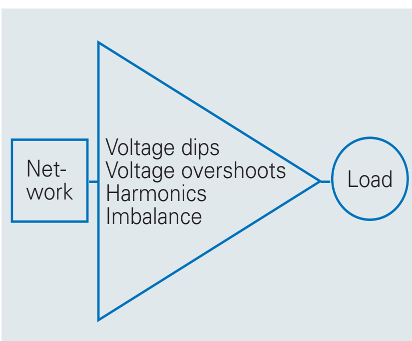

Fig. 282: Improving the quality in power supply

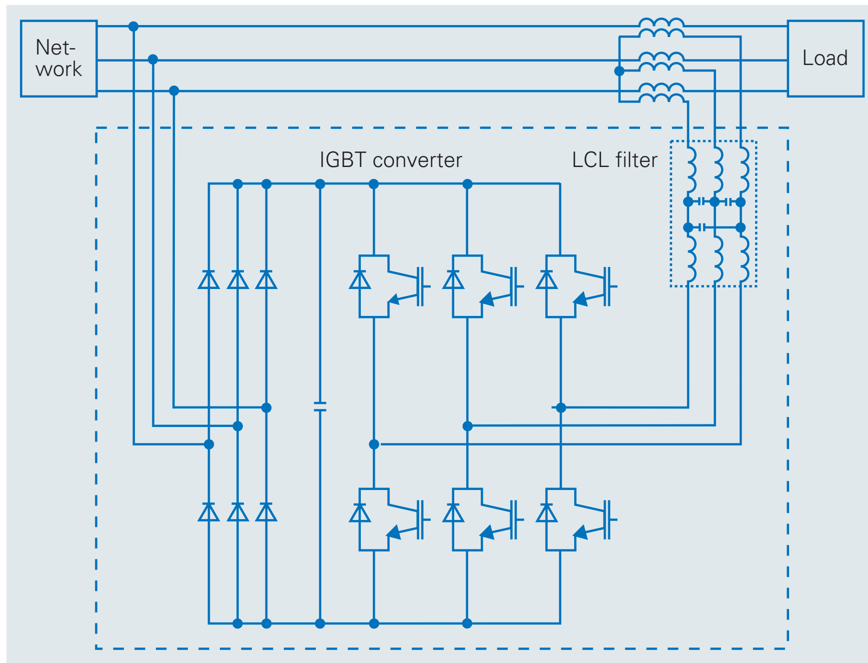

Fig. 283: Block diagram – DVR

6

Function Principle

The DVR is used as a voltage source which is integrated in the feeder line between the supply system and the consumer in series connection. The voltage applied to the consumer is measured and if it deviates from the ideal values, the missing components will be injected, so that the consumer voltage remains constant. Apart from the prevention of voltage dips, the DVR is also used to correct overvoltages and unsymmetries. The highly dynamic system is capable of realizing the full compensation of voltage dips within a period of 2 to 3 milliseconds.

The signals from audio frequency ripple control systems are not affected. An audio frequency hold-off is not required.

Application

The DVR is basically used to improve the quality of the voltage supplied by the power supply system.

- Correction of voltage variations
  Remote short-circuits in the supply network occasionally result in voltage dips of different strength and of a duration of only few tenths of a second. In weak networks it may also occur that the usual voltage limits cannot be held over a long period of time or that sensitive consumers require smaller tolerances than offered by the power supply company.
  With the DVR, single, two and three-phase voltage dips up to a certain intensity can be compensated independently of their duration. Additional power is taken from the rectifier part from the network, even if the voltage is too low; this power is then supplied to the series transformer on the load side via the converter. The value of the nominal power of the DVR is reciprocal to the voltages to be corrected. Statistics show that most of the short-time voltage dips have a residual voltage of at least 70 to 80%. The power to be generated by the DVR must be sufficient to compensate the missing part.
- Compensation of unbalanced load
  The DVR can be used to inject a positive phase-sequence voltage which enables the compensation of imbalance in the supply voltage in order to avoid excessive temperatures of three-phase machines.
- Absorption of harmonics
  The quick-action control of the DVR enables elimination of harmonics by correcting distortions of the voltage waveshape. Since the system can be configured for different tasks, it can also be used to process harmonics of the fifth, seventh, eleventh and thirteenth order, either separately or as a whole.

Information for Project Planning

In contrast to the principle of SIPCON DSTATCOM, which corrects the reactive power only for the parallel-connected load, the whole load current flows through the DVR system. Therefore, all preconditions and marginal conditions are to be considered to enable correct configuration. Basically, the following points should be taken into account:

- Fault characteristics:
  What kind of network faults are to be corrected (single, two or three-phase) and up to which residual voltage value and fault duration shall correction become effective.
- Load:
  Nominal value of the apparent power, type of load, e.g. what types of drive, resistance load, etc. are to be supplied with the help of the DVR.
- Corrective behavior:
  What degree of accuracy is to be observed for the voltage on the load side.

It will often be sufficient if the DVR supplies only part of the nominal load. To ensure correct project planning, a Siemens expert should be consulted.

Further information:

www.powerquality.de