14 Protection and Control in Substations and Power Networks

14.1 Introduction

Contained under the heading of protection and control in substations and power networks are all the technical aids and facilities necessary for the optimum supervision, protection, control and management of all system components and equipment in high- and medium-voltage networks. The task of the control system begins with the position message at the HV circuit-breaker and ends in complex control systems and substations for network and load management.

Fig. 14-1 gives an indication of the functions and subsystems that go to make up control technology in the context of electricity transmission and distribution.

The purpose of the secondary systems is to gather information directly at the high- and medium-voltage apparatus in the substations and to effect their on-site operation, including the maintenance of secure power supplies. Additional contacts or integral sensors establish the interface with the telecontrol system and hence with the network control facility.

Modern automation techniques can provide all the means necessary for processing and compressing information at the actual switchgear locations in order to simplify and secure normal routine operation, make more efficient use of existing equipment and quickly localize and disconnect faults in the event of trouble, thereby also relieving the burden on the communication paths and the network control centres.

Protective devices are required to safeguard the expensive equipment and transmission lines against overloads and damage by very quickly and selectively isolating defective parts of the supply network, e.g. in the event of short circuit or earth faults. They are thus a major factor in ensuring consistent operation of the network.

The purpose of network management as a subdivision of power system control is to secure the transmission and distribution of power in ever more complex supply networks by providing each control centre with a continually up-to-date and user-friendly general picture of the entire network. All essential information is sent via telecontrol links from the substations to the control centre, where it is instantly evaluated and corrective actions are taken. The growing flood of information has meant that the conventional control rooms with mimic displays as used in the past for controlling the processes directly have been virtually superseded by management systems with computers and video terminals, and are employed only to depict the network's geographical layout or for emergencies.

Load management consists in directly influencing the system load, possibly with the aid of ripple control which, acting via the normal power network, can selectively disconnect and re-connect consumers or consumer categories. On the basis of current figures and forecasts, it is possible to even out the generating plant's load curves and make better use of available power reserves.

It would be beyond the scope of this book to consider in detail all the subsystems and components relating to network control. This chapter can therefore serve only as an introduction to the complex tasks, fundamentals, problems and solutions encountered in power network control and its systems. Closer attention is paid, however, to all components and interfaces which directly concern the switching installation and the switchgear engineer, and which must be considered in the planning, erection and operation of substations.

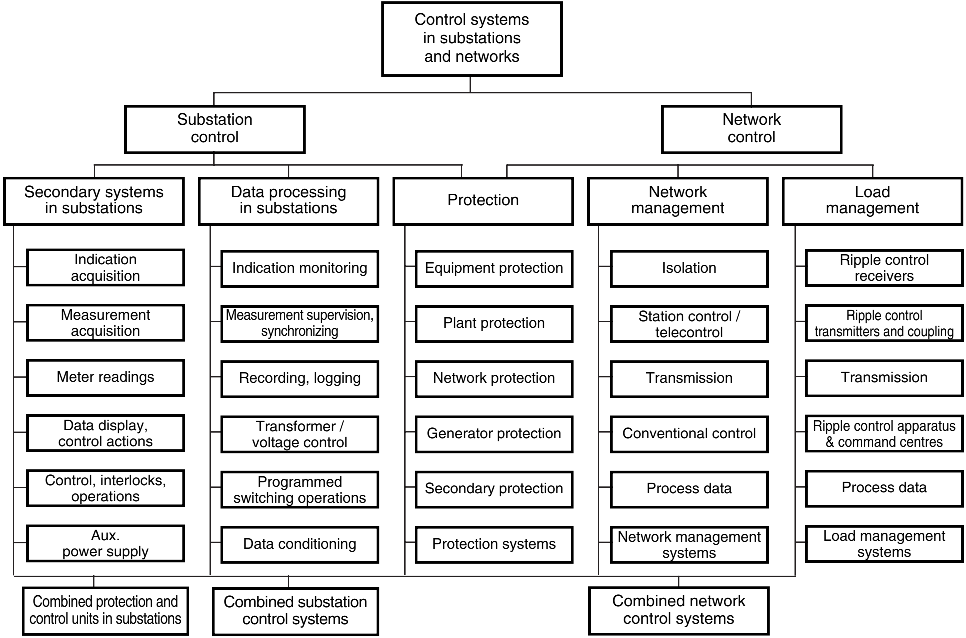


Fig. 41-1

Functions and subsystems of controls in substations and networks

14.2 Protection

Various protection devices – in systems with rated voltages > 1kV – are available to protect generators, transformers, cables, busbars and consumers. The purpose of these devices is to detect faults and isolate them selectively and quickly from the network as a whole so that the consequences of the fault are limited as much as possible. With today's high fault levels and highly integrated networks, faults have far-reaching consequences, both direct (damaged equipment) and indirect (loss of production). Protection relays must therefore act very fast with the greatest possible reliability and availability.

Relays can be divided into various categories.

A basic distinction is made with respect to function between contactor relays and measuring relays.

Other distinguishing characteristics are

- the relay's construction
  - (e.g. circuit-board relays, reed relays, miniature relays, mercury-wetted relays);
- the relay's operating principle
  - (e.g. attracted-armature relays, immersed-armature relays, moving-coil relays);
- the relay's location
  - (e.g. telephone relays, antenna relays, generator protection relays, network protection relays);
- the relay's specific function
  - (e.g. signalling relays, time-delay relays, control relays, momentary-contact relays, auxiliary relays);
- the relay's required performance
  - (e.g. heavy-current relays, high/low temperature relays, d.c. relays).

The relays used for protection purposes, together with supervisory relays, fall into the category of measuring relays, and as electronic relays become more widespread, of solid-state measuring relays. All the types of relays mentioned are used to transmit clearly defined, fast and carefully isolated indication and control signals from low-energy electronic circuits to external circuits.

14.2.1 Protection relays and protection systems

Today's standard protection relays and protection systems are in some cases still preferably static but are designed to be numerically controlled (with microprocessors). Electromechanical relays are practically never specified in new systems. They have to meet the following international specifications:

- IEC 60 255
- DIN VDE 0435-303 Electrical Relays – Static Measuring Relays (SMR)
- and the new VDE standards DIN EN 60255 – ... derived from IEC in all parts

Please also observe the

– VDEW – “Directives for static protective equipment”.

Overcurrent relays/time-overcurrent relays

Currents above an adjustable threshold value are detected in one or more phases, and interrupted after a presettable time. The release time is the same, no matter how much the threshold has been exceeded by.

(*D*efinite *T*ime *L*ag *R*elay = DTL relay)

The preference in English-speaking countries is for Inverse Definite Minimum Time Lag (IDMT) relays which respond faster to heavier currents.

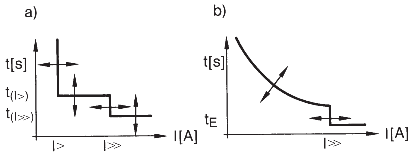


Fig. 14-2

Characteristics of overcurrent relays

a) DTL relays, two-stage
b) IDMT relays with high-current stage
I > Overcurrent stage
1 ≫ High-current stage
t_E Opening time

Overcurrent relays are used in radial networks with single infeed.

The relays are connected via a current transformer (secondary relay).

With a direction-sensing element that measures current and voltage, the relay can be made to provide directional time-overcurrent protection. They are preferably implemented with parallel lines and on the transformer undervoltage side with parallel transformer operation.

Overload relays

The temperature conditions at the protected object are simulated with the same time constant in the relays. Any load bias is taken into account by the thermal replica in the relay in accordance with the heating and cooling curves. Alarm signals or tripping commands are given if a set temperature is exceeded. The relays are built as primary or secondary relays. Secondary relays usually operate in two or more stages. Overload relays are used on machines that can overheat, such as transformers and motors, but occasionally on cables, too.

Differential relays

The currents measured at the beginning and end of the protected object are matched in phase angle and magnitude and compared in a measuring element. If a set ratio of difference current to through current is exceeded, the relay emits a tripping command.

Modern relays contain all the components needed for differential protection:
– matching transformers,
– signalling devices,
– tripping devices,
– inrush stabilization.

Differential relays are available for transformers or generators.

Differential relays for lines have a measuring element (relay) at each end. The relays must be linked to transmit protection data. Fibre-optic cables or pilot wires are available as connections. The connection must be monitored to ensure proper functioning of the protection system.

Comparative protection

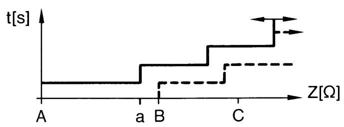
The variables measured at beginning and end of the protected item are checked to see if they are coincident (phase comparison) or of the same kind (signal comparison). These protection devices require only a few communication channels and are unaffected by interference.

Distance relays

The distance of a fault from the relay is assigned to a tripping range by measuring the impedance with reference to the fault current and voltage. In accordance with an adjustable distance/time characteristic set on the relay, the relay trips the appropriate circuit-breaker or serves as back-up protection. Distance relays operate selectively and extremely quickly in meshed networks with multiple infeed, and need no auxiliary link.

Fig. 14-3

Characteristic of a distance relay
A, B, C Stations
Station A location of relay
a = approx. 85 – 90 % of distance A–B



Auto-reclose relays

In networks with overhead lines, the auto-reclose relay interrupts 1 or 3 phases of the power feed to the faults detected by the time-overcurrent relay or distance relay and then reconnects it after an adjustable interval of about 300 ms. The arc across the fault is able to de-ionize during this time, and operation can resume without interruption. If the autoreclosure is not successful, the result will be a 3-phase definite trip.

Busbar protection

The quantities from a number of measuring points which respond in different ways to faults on the branch lines or in the busbar system are evaluated in a measuring circuit. Owing to the difficulty of obtaining measurements (transformer saturation) and the high speed needed to limit damage in the case of high short-circuit powers, electronic protection systems are used. (Measuring time approx. 2 ms, system command time approx. 10–20 ms). In static busbar protection, a breaker backup protection is frequently installed as backup protection. Additional functions are integrated into numeric busbar protection, such as overcurrent, undervoltage protection, (circuit-breaker) synchronization monitoring and, as an advantage of numeric technology, event lists, fault records, comprehensive hardware and software monitoring, test procedures (manual or automatic) etc.

Directional earth-fault relays

An indication of direction is obtained from the relative vectorial position of neutral current and neutral voltage. The side of the fault is identified by comparing the values measured in the network. Other methods of measurement are possible.

Frequency relays

If the frequency goes above or below set limits or fluctuates at an unacceptable rate (df/dt), this is detected, resulting in disconnection or load rejection.

Voltage relays

Voltage deviations are indicated, allowing the system load to be reduced as necessary.

Other protective devices used specifically with certain system components include interturn-fault relays, negative sequence relays, reverse-power relays for generators, Buchholz relays, temperature monitors, oil level indicators, oil and air flow indicators for transformers, and insulation monitoring for conductors.

14.2.2 Advantages of numeric relays

Static protection relays with discrete components have now been joined by digital relays equipped with microprocessors (µP). Digital devices of the same kind can perform control functions as well as protection duties. Users are coming to insist on their use.

Features of these relays include:

- Analogue variables are digitalized in the relay’s input circuit and calculated in the processor.
- The entered settings act on the relay’s built-in program.
- Several protective functions can be combined and executed in a single unit. All newly developed numeric protection relays are multifunction relays.
- The relays incorporate constant self-monitorlng and diagnosis.
- They can be controlled from a personal computer (PC) with menu guidance in a variety of languages.
- Logic functions allow links to external signals by way of optocoupler inputs.
- Memories for recording events and disturbances enable faults to be analysed afterwards in detail from the stored data.

Serial interfaces make them easy to integrate into control and instrumentation systems.

14.2.3 Protection of substations, lines and transformers

The basic scheme for protecting switchgear installations, lines and transformers is shown in Fig. 14-4.

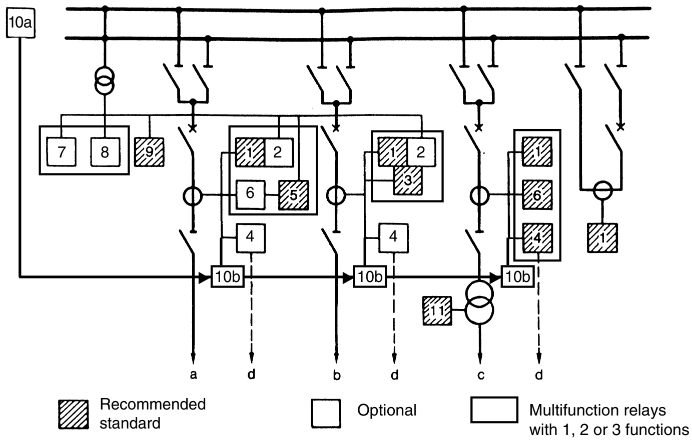


Fig. 14-4

Basic scheme of protection system for switchgear, lines and transformers:
a) Cable, b) Overhead line, c) Transformer, d) Auxiliary line
1 Overcurrent time protection, 2 Distance protection, 3 Autoreclose function, 4 Differential protection, 5 Directional ground-fault protection, 6 Overload protection, 7 Frequency monitoring, 8 Voltage monitoring, 9 Ground-fault indicator monitoring, 10 Busbar protection, 10a Central processor, 10b Bay unit, 11 Buchholz protection, temperature monitoring

14.2.4 Generator unit protection

The term generator unit protection is used when the means of protecting the generator, the main transformer and the station services transformer are combined with those for protecting the generator circuit-breaker or load disconnector.

Numerical relays are used almost exclusively with modern generator unit protection. Important factors influencing the form of the protection system within the overall electrical design concept include:

- whether the generator is switched by a circuit-breaker or a load switch,
- whether the station services transformer has two or three windings,
- the number of station services transformers,
- the method of excitation (solid-state thyristors or rotating rectifiers).

The general layout is drawn up accordingly for each individual project. As an example, Fig. 14-5 shows the single-line diagram for a unit-type arrangement with generator circuit-breaker in a large thermal power plant.

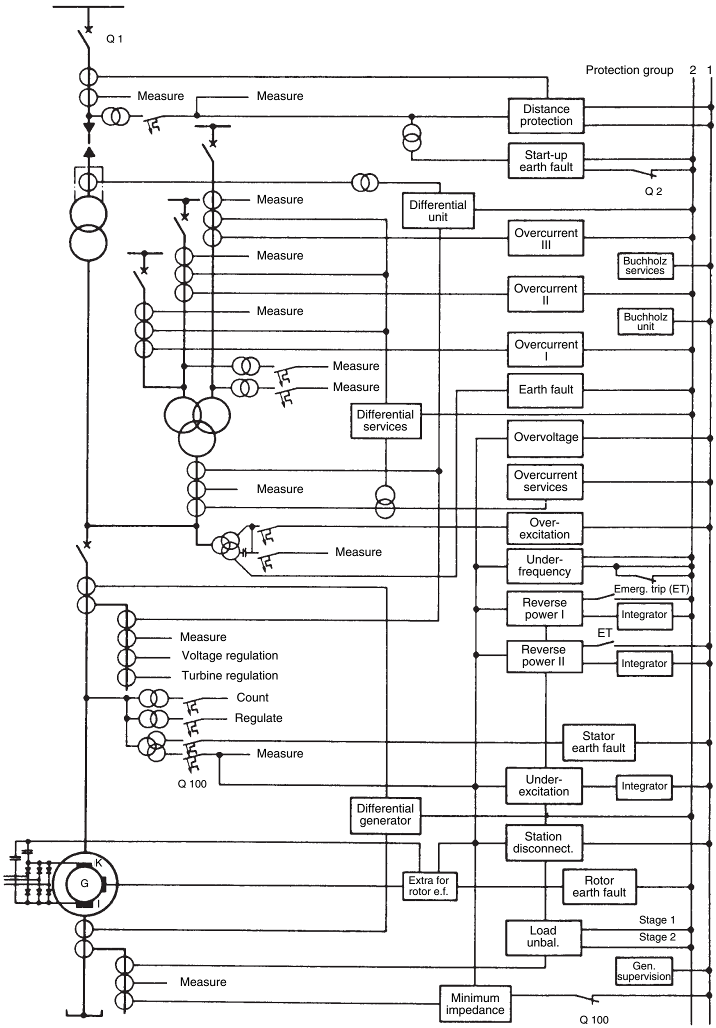


Fig. 14-5

Single-line diagram of generator unit protection system, unit connection wlth generator circuit-breaker

A function diagram shows how the individual protective devices are linked to the operating circuits. The protection device OFF commands are configured on the switching devices (for example, generator circuit-breaker, magnetic field switch, etc.) and switching systems (for example, automatic internal transfer gear) with a software matrix (component of the relays) or, in the case of larger systems, with a tripping matrix (diode matrix).The tripping schedule can then easily be modified later.

To maximize availability, the protection facilities are split into two separate and largely independent groups and installed in different cubicles. Protection systems that complement or at times may step in for each other can be assigned to both groups.

14.3 Control, measurement and regulation (secondary systems)

Secondary systems are all those facilities needed to ensure reliable operation of the primary system, e.g. a high-voltage substation. They cover the functions of controlling, interlocking, signalling and monitoring, measuring, counting, recording and protecting (see also Fig. 14-6). The power for these auxiliary functions is taken from batteries so that they continue in the event of network faults. Whereas in the past conventional techniques were used for decentralized control, e.g. from a local panel, this can now be done using substation control techniques such as ABB's PYRAMID system. Today, overall network management is undertaken by computer-assisted systems based at regional or supraregional control centres and load-dispatching stations. The interface that this necessitates, however, is moving ever closer to the process, i.e. to the primary system. How near this interface can be brought to the process depends, for example, on how practical and reliable it is to convert from electromechanical methods to electronic techniques, or whether the information to be transmitted can be provided by the process in a form which can be directly processed by the electronics.

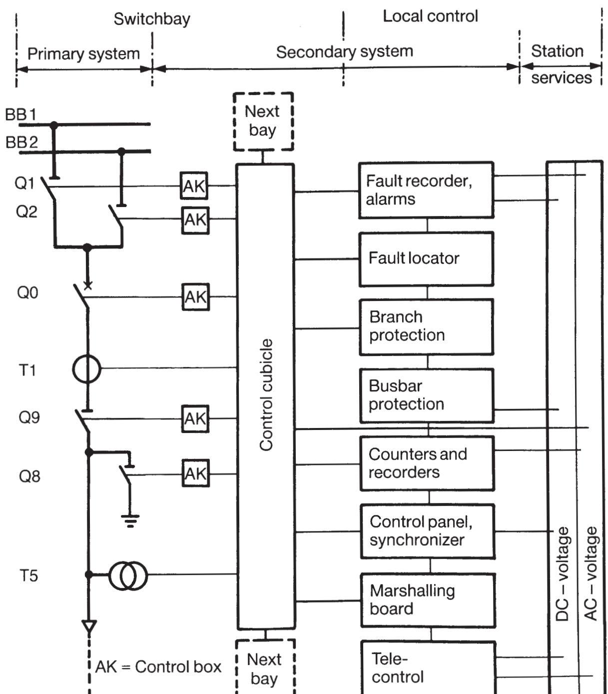


Fig. 14-6
AK = Control box
The functions of secondary systems in high-voltage switchgear installations, for coding of apparatus in primary systems see Tables 6-12 and 6-13

14.3.1 D.C. voltage supply

It is essential that the components of the secondary systems have a secure DC power supply. For HV and EHV installations, this means that the DC power supply must include redundancy (see also Fig. 14-7) so as not to be rendered inoperative by a single fault. Indeed it is advisable to provide two separate infeeds for the low-voltage three-phase network. If these infeeds are not very dependable, a diesel generator should also be provided for emergencies. The three-phase loads are connected as symmetrically as possible to the two three-phase busbars thus formed; the battery rectifiers are also connected here, one to each busbar.

If the battery equipment is suitable, the DC output from the rectifier and also the battery can be connected independently to the DC busbars, so giving greater flexibility. It is best to use 220 V and 110 V for direct control, with 60 V, 48 V and 24 V for remote control and signal circuits. With the aid of inverters, a secure AC busbar can then be created from the DC busbar if necessary.

The DC network must be carefully planned. The auxiliary circuits must be assigned to each function and branch so that only one function or one bay is affected by a fault. Faults in the signal circuit, for example, do not then influence the control circuit, and vice versa.

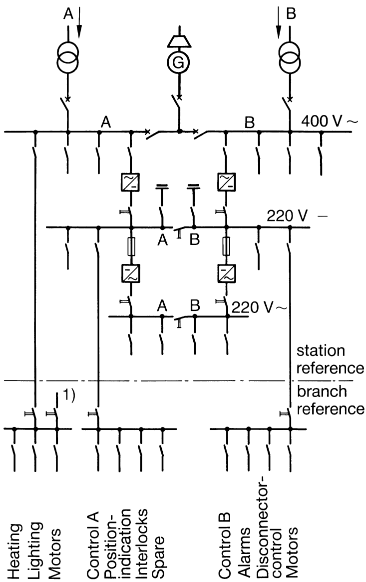


Fig. 14-7

Single-line diagram of station services power supply, A and B Independent infeeds or bus sections, 1) Connection to adjacent bay

14.3.2 Interlocking

To ensure reliable control, the high voltage switching devices within each bay, and at a higher level within the entire installation, are interlocked with respect to each other. The interlock conditions depend on the circuit configuration and status of the installation at any given time. The interlocks must in particular prevent an isolator from operating while under load. The interlock conditions must be defined according to the station layout, such as in the following example for a double busbar with branch, coupling and bus earthing switch, see Fig. 14-8.

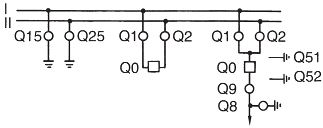


Fig. 14-8

Mimic diagram of a double busbar substation with branch, coupling and bus earthing switch

The following conditions must be satisfied in this case:

1. Disconnectors Q1, Q2 and Q9 can be operated only when breaker Q0 is open (protection against switching under load).
2. Breaker Q0 cannot be closed with disconnectors Q1, Q2 and Q9 in the intermediate position (intermediate position indication).
3. Disconnectors Q1 and Q2 are mutually interlocked so that only one can be closed at a time.
4. When the bus-tie is closed, a second bus disconnector (Q1 or Q2) belonging to the tied system can be closed. One of the two closed disconnectors can then be opened (change of bus under load).
5. Disconnectors Q1 and Q2 can be operated only if the related bus earthing switch Q15 or Q25 is open.
6. Disconnector Q9 can be operated only when earthing switch Q8 is open (taking account of other end if necessary).
7. Earthing switch Q8 can be operated only when disconnector Q9 is open (taking account of other end of outgoing line if necessary).
8. Disconnectors Q1, Q2 and Q9 can be operated only when maintenance earthing switches Q51/Q52 are open.
9. Maintenance earthing switches Q51/Q52 can be operated only when disconnectors Q1, Q2 and Q9 are open.
10. The tie-breaker Q0 can be opened only if not more than one bus isolator in each branch is closed (tie-breaker lock-in).
11. One bus earthing switch Q15 or Q25 can be operated if in the respective bus section all bus disconnectors of the corresponding bus system are open.
12. All interlocks remain active if the auxiliary power fails.
13. An interlock release switch cancels the interlock conditions. Switching operations are then the responsibility of the person authorized.

14.3.3 Control

The purpose of a control device in a switchgear installation is to change a defined actual condition into a specified desired condition.

The operating sequences of controlling, interlocking and signalling can be performed either by simple contact-type electromechanical and electromagnetic devices such as discrepancy switches, auxiliary contactors and auxiliary relays or by contact-less electronic components. Both methods allow single switching operations and programmed switching sequences up to fully automated switching routines.

With conventional control techniques, there are limits to the scope for automation. These methods are becoming less popular because of the space required, the equipment's high power consumption, wear due to constant operation, and the fixed wiring. Today they are used mainly for local control within the switching installation.

Here, the devices can be divided into those relating to:

- switching apparatus,
- branch and
- station.

The apparatus-related devices are contained in a box on the circuit-breaker or isolator. The branch-related devices are usually in a control cubicle or local relay kiosk. Station-related devices are located in central relay kiosks or in the station control building.

Because of the increasing reliability of electronic components, and also the question of interference, the tendency is for contact-type systems to be employed only for apparatus-related devices, and electronic components to be used very extensively for branch-related and station-related devices.

When drawing up the control system concept, it must be considered whether the substation is to be largely manned or unmanned, or remotely monitored and controlled. The kinds of control system can be broadly defined as follows.

Local control

Here, the controls are close to the switchgear. They are used mainly during commissioning and maintenance, often for emergencies as well. They are located on the apparatus itself or in a branch cubicle, and work independently of higher-level control systems.

Direct control

In this case, the switchgear is controlled locally from the on-site control point, where each piece of apparatus has its own control switch, etc. It may utilize the switchgear's control voltage or light-duty relays. Control from the station panel always includes indication of the switchgear's respective operating positions.

Selective control

This method is used both for on-site control and in central control rooms. It is arranged in a number of levels, so that from an operator's position one can, for instance, pick first the station, then the branch and finally the item of switchgear before initiating the actual switching operation with the "execute" button.

Both station-level and central control systems nowadays have two mutually interlocked operator positions for this purpose. Each consists of a control panel and a VDU. The interlock prevents commands being sent simultaneously from both positions to a station or branch. Certain control sequences can be pre-programmed where necessary. Light current is used for the control circuits. Feedback signals and switchgear settings are shown on the monitor. A mosaic-type display panel is sometimes provided in addition to the video screen.

Remote control

In this case, the substation is controlled from regional and central control centres, predominantly via telecontrol lines. The general trend is increasingly away from local control to remote control, so the latter warrants particular attention. For details on telecontrol, see Sections 14.5.4 and 14.5.6.

Control functions include a wide variety of different applications; representative examples are the monitoring of tripping circuits, Fig. 14-9, and the duplication of tripping circuits, Fig. 14-10.

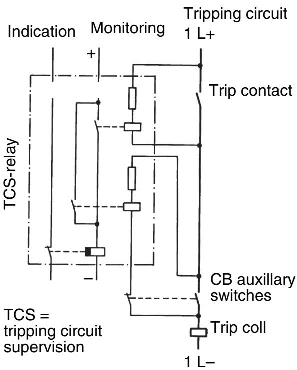


Fig. 14-9

Tripping circuit supervision for a circuit-breaker in closed and open position

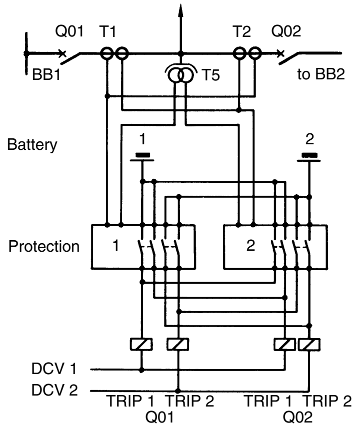


Fig. 14-10

Duplication of tripping circuits with 1½- and 2-breaker arrangement

14.3.4 Indication

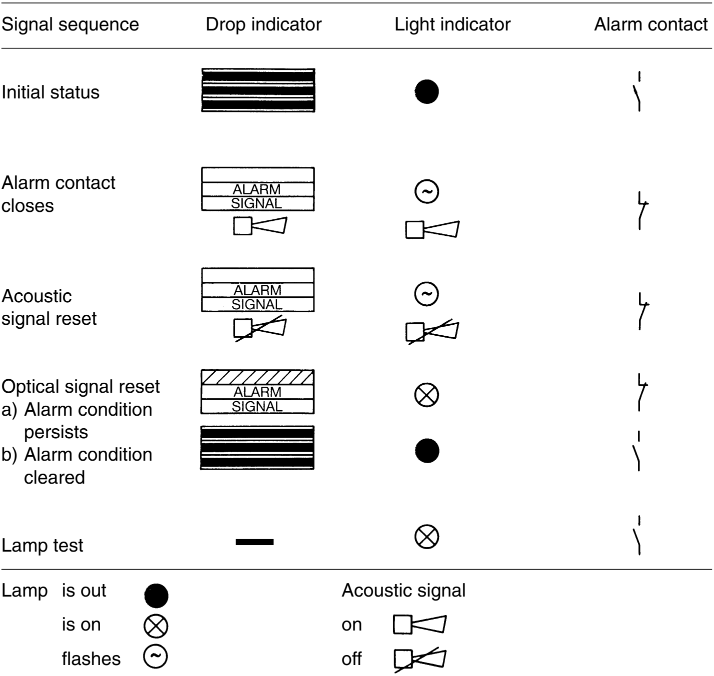
Operating personnel must be informed of faults, circuit conditions and the settings of switchgear.

Switchgear contact settings are indicated by means of position transmitters, light-emitting diodes or on a screen. The signal must not be sent until the apparatus has reached or is certain to reach its final CLOSED or OPEN position; otherwise an intermediate position must be indicated.

Incoming fault and status signals are indicated by optical and acoustic means, and often recorded, see Section 14.3.8 Recording and logging. The signals are gathered or passed on by signalling relays with floating auxiliary contacts. The relays can be electromechanical or electronic. Table 14-3 shows the standard signal sequence of drop indicator relays and light indicators.

Table 14-1

Standard signal sequence for drop indicators and light indicators



14.3.5 Measurement

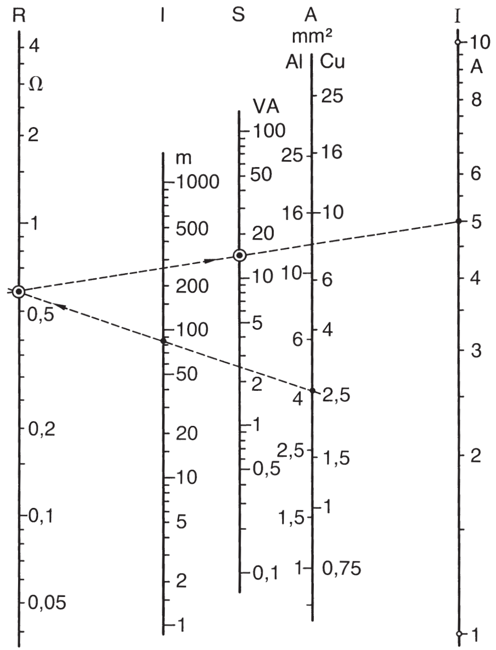
Operating a substation involves measuring, recording and evaluating a number of quantities such as currents, voltages, powers, etc. To do this, the primary system requires current and voltage transformers, which can be incorporated in the busbars or branches. What instrument transformers are necessary will depend on operating requirements, see Sections 10.5.2 to 10.5.5 on transformer selection.

Voltage transformers are useful in the branches for measurement and protection. Voltage transformers on the busbar as well are convenient for synchronizing and measurement purposes; there is then no need for simulation.

The secondary sides of current and voltage transformers must be earthed so as to avoid any risk to equipment and personnel from unacceptably high voltages.

Current transformers must not be operated with open secondary windings as the high voltages occurring at the secondary terminals are dangerous and may damage the transformer.

Current transformer circuits must be earthed at only one point. In high-voltage installations, this should be the branch control cubicle wherever possible. The standards applicable at the particular location must be observed. One must make sure that the transformer power rating is at least equal to the power consumption of the measuring devices, including the connecting lines. The dimensions of these can be determined with the aid of Fig. 14-11.



Example:

$A = 2.5\ mm^2, l_r = 85\ m$: then $R \approx 0.6\ \Omega$

$I = 5\ A, R \approx 0.6\ \Omega$: then $S \approx 15\ VA$

Fig. 14-11

Current transformer secondary lines; To determine resistance and power consumption, R = line resistance Ω, l_r = resultant line length m, S = power VA, A = line cross section mm² for Cu and Al, I = sec. transformer current A

The readings of the measurements are displayed in the control cubicles, in the on-site control room and/or at the command centre. Attention must be paid to the positioning of the instruments. With modern control systems, the readings are shown on the screen in the central control room.

The shapes, sizes and coding of switchboard instruments are summarized in Fig. 14-12. See DIN 43700 and 43701 for detailed information on standardized designs and dimensions of control panel instrumentation and measurement ranges.

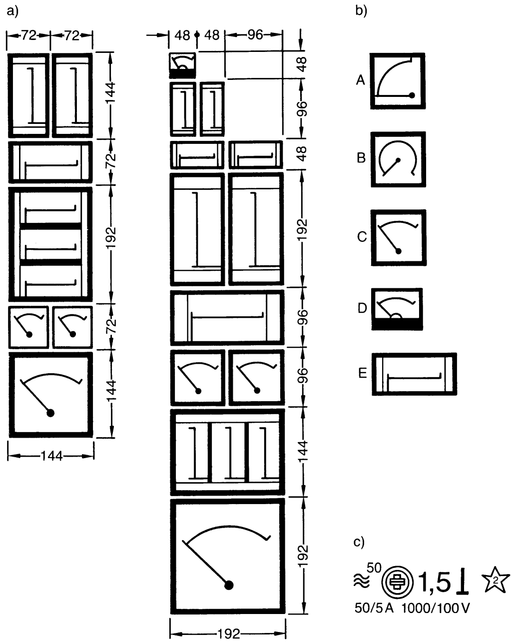


Fig. 14-12

a) Shapes, sizes, b) Scales and c) Coding of switchboard instruments (dimensions in mm):

A Quadrant scale, B Circular scale, C Sector scale, D Sector scale for tubular instruments, E Linear scale; Example of coding: c) Instrument for 3-ph. 50 Hz with 2 iron-cored el.-dyn. elements Cl. 1.5; vert. posn.; test voltage 2 kV, transf. connection: prim. current 50 A, sec. current 5 A, prim. volt. 1000 V, sec. volt. 100 V

Measuring elements and their principal applications

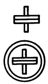
Electrical measuring instruments have a class coding. The classes are: 0.1; 0.2; 0.5; 1; 1.5; 2.5 and 5. These denote the measurement or reading error in percent, both positive and negative. They always relate to the top of the measuring range. Instruments of classes 0.1 to 0.5 are precision instruments, those above are industrial instruments.

The choice of measuring elements for the instruments is summarized in Table 14-2.

DIN EN 61010-1 (VDE 0411 Part 1), DIN EN 61010-1/A2 (VDE 0411 Part 1/A1) and DIN EN 60051; plus DIN 43781 (for recorders) are applicable for electrical instrumentation and recorders. These standards contain the most important definitions, classifications, safety and test requirements and forms of identification.

Table 14-2

Measuring elements for measuring instruments

Element	Symbol	Operating principle	Input	Application and characteristics
Moving-iron element		Two iron cores in a ring coil are magnetized with the same polarity and repel each other.	*I* –, *U* – *I* ~, *U* ~	For DC and AC currents and voltages. Greater overload capacity than other measuring elements. Much higher consumption than moving-coil elements. Scale almost linear, but can be extensively influenced. Robust.
Moving-coil element Moving-iron ratiometer (cross-coil element)	 	Coils able to rotate in the homogeneous field of a permanent magnet; variants with magnet outside or as core magnet element with permanent magnet inside the coil.	*I* –, *U* – Thermocouple, Resistance thermometer, *I* ~, *U* ~ Active power, Reactive power, Power factor	Chiefly a DC instrument. Together with rectifiers also suitable for AC; with adapters also for power measurement. Greater accuracy than all other electrical measuring elements. Low consumption. Scale almost linear. Moving-coil galvanometers are highly sensitive.[1]
Electro-dynamic element		A voltage coil is able to rotate in the homogeneous magnetic field of a fixed current winding.	Active power, Reactive power, Power factor	For power measurement with AC and DC, as quotient meter also for measuring power factor. Scale almost linear. Largely independent of frequency and curve shape. Core-less types for precision instruments, iron-cored types for industrial instruments and recorders.
Electronic element		Two electrodes in an electrostatic field move relative to each other owing to potential differences.	*U* – *U* ~	For DC and AC voltages, also high-frequency voltage.
Vibrating-reed element (reed-type frequency meter)		A row of steel reeds is induced to vibrate in the force field of an electromagnet.	Frequency	For frequencies from 7 – 1500 Hz. High, consistent measuring accuracy. Robust.
Bimetal element		A bimetal spiral indicates the mean value of prolonged loads.	*I* ~	For monitoring thermal loading of transformers and power cables. With resettable slave pointer. Scales calibrated in percent or amps. Compensated for changes in room temperature.

[1] Sensitivity and accuracy must not be confused. If an indicating instrument is required to be sensitive, this means it has to respond to small changes in the measuring variable with large scale deflections, but it does not have to be accurate.

Measuring transducers

Transducers in the field of power engineering convert input variables such as current, voltage, power and system frequency into analogue electrical output quantities, usually in the form of impressed direct current but sometimes also impressed d.c. voltage. These output quantities are then particularly suitable for subsequent measured-value processing and transmission systems.

The most important parameters, device properties, designations and tests of transducers for quantities in electrical engineering can be found in the VDE 0411 Part 1 and VDE 0411 Part 1/A1 standards mentioned above in the “Instrumentation” section. The DIN EN 50178 (VDE 0160) and the VDE/VDI Directive 2192 must also be observed.

Fig. 14-13 shows various measuring arrangements. The transducers can be single or multiple. Table 14-3 shows an overview of the typical consumption values of the most important instrumentation.

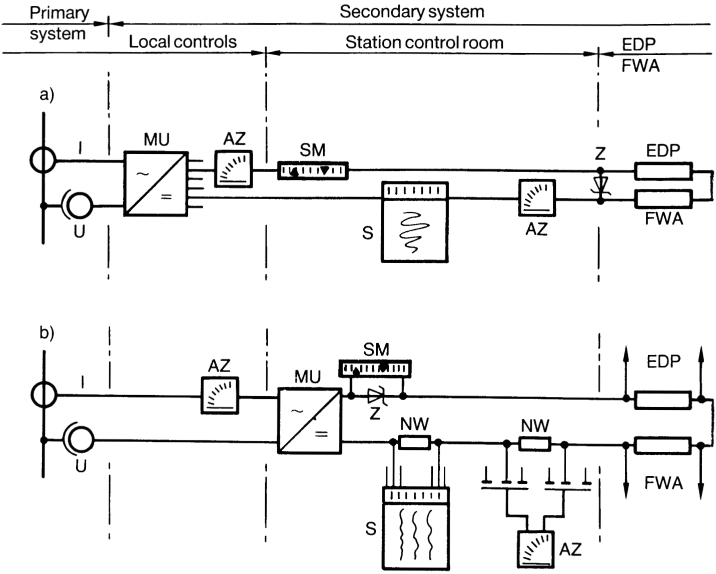


Fig. 14-13

Common measuring circuits with transducers:

a) Connection to indicating and recording instruments in the transducer output circuit for indoor stations, b) Connection to selectable instruments via shunt resistors in the transducer output circuit for outdoor stations, AZ Indicating instrument, EDP Data processing, FWA Telecontrol system, I Current, MU Transducer, NW Shunt resistor, S Recorder, SM Signal meter with maximum contact, U Voltage, Z Zener diode

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Table 14-3

Typical[1)] power consumption of measuring instruments, recorders, meters, transducers and lines

Instrument	Power consumption per Current path VA	Power consumption per Voltage path VA
Ammeter	0.3…3	—
Current recorder	5…10	—
Voltmeter	—	1.5…7
Voltage recorder	—	10…20
Voltage range recorder	—	18
Wattmeter	1…3	0.5…2
Power recorder	1.5…10	1.3…12
P.f. meter	1.5…6	0.5…3.5
P.f. meter with alternating energy direction	5…15	3.3…8
P.f. recorder	6…14	10…12
Frequency meter	—	1…3
Frequency recorder	—	10…13
Time recorder	—	0.6…3.4
Electric drive for paper feed	—	3…25
Zero-voltage indicator	—	15
Synchroscope	—	15…22
Meter (counter)	0.17…3	0.85…5
Voltage transducer	—	1…3
Current transducer	0.5…3	—
Power transducer	0.5…1	1…1.5
P.f. transducer	0.5	2.5
Multi-transducer	0.1…0.5	0.02

Power consumption of copper measuring lines for length 1 m and 5 A

1.5 mm^2	0.29 VA	6 mm^2	0.07 VA
2.5 mm^2	0.18 VA	10 mm^2	0.044 VA
4 mm^2	0.11 VA	16 mm^2	0.0011 VA

1) Instrument power consumption vary according to manufacturer. Exact values are to be found in the manufacturer's literature.

14.3.6 Synchronizing

Synchronizing is also a kind of measurement. System components cannot be connected in parallel unless their voltage curves coincide, otherwise the electrical stresses on the equipment become too high. While with direct current it is sufficient for the system components' voltage and polarity to be the same, with a.c. voltages the frequency, voltage and phase angle must match; with three-phase current so must the phase sequence.

The standard synchronizing instruments are double frequency meter, double voltmeter and synchronoscope. Digital control technology now offers the option of feeding the input signals of these instruments directly to an automatic synchronization device, which independently trips the closing operation at the right time.

When parallel switching system parts, it is sufficient to use an automatic synchronization test instrument, e.g. the Synchrocheck design of the SYNCHROTACT range from ABB, which prevents switching in asynchronous mode with non-permitted high phase difference angles or excessively high voltage differences.

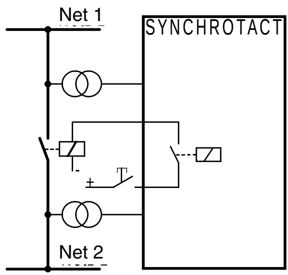

Fig. 14-14

Automatic synchronization test instrument
When paralleling conditions have been met, the contact is closed, the networks can be synchronized.

An automatic synchronization device is always recommended for parallel switching of generators with power supply units. This automatically brings the speed and voltage of the generator into a preset tolerance range using higher and lower commands. The voltage, phase angle, frequency and switch mechanical delay are taken into account to set the paralleling command to ensure that the switch contacts touch at precisely the instant the phases are the same.

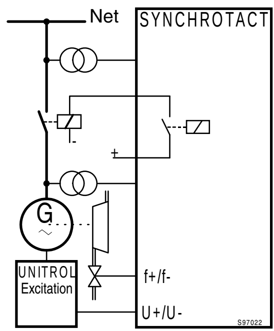

Fig. 14-15

Automatic synchronizer unit
The synchronizer device issues higher and lower commands to turbine controllers and voltage controllers. When paralleling conditions are met, the circuit-breaker is closed at the exact moment when the phases are the same.

The SYNCHROTACT automatic synchronization device in its simplest form is one single channel, which takes care of measurement, voltage, frequency balancing, monitoring and command formation with high security against faulty operation. Depending on system size and safety design, dual channel solutions are also available. Measuring, microprocessor and command relays in both channels are separate in the SYNCHROTACT dual-channel synchronization units. This independence significantly increases security against faulty operation in comparison to the single channel system.

14.3.7 Metering

General

Meters are used for determining the amounts of power supplied from the power source or distribution system to the consumer. The selection criteria are shown in Table 14-4.

In a special category are meters for billing electricity consumption. In the Federal Republic of Germany, for instance, they have to meet the requirements of the Physikalisch-Technische Bundesanstalt (PTB) and of the Deutsches Amt für Maße und Gewichte (DAMG), i.e. certified and approved. The voltage drop on the instrument transformer line of billing meters must not exceed 0.05 %.

Table 14-4

Selection criteria and alternatives for electricity meters (counters)

Criterion	Alternatives
Connection	direct or to instrument transformer
Type	electromechanical or electronic
Mounting	surface-mounted housing, live parts fixed
	flush-mounted housing, live parts fixed
	flush-mounted housing, live parts removable
	subrack, live parts on circuit boards
Current	alternating current
	three-phase in 3- and 4-wire systems loaded symmetrically and asymmetrically
Power	active and reactive consumption, incoming and outgoing[1)]
Tariff	single or two-rate tariff[2)]
Accuracy class	0.2, 0.5, 1, 2, 3
Metering system	primary system[3)]
	semi-primary system[4)]
	secondary system[5)]
Special meters	maximum-demand meters[6)]
	pulse meters[7)]
	remote meters

1) Reversal prevention is necessary where the power flow direction changes.
2) Tariff changed with separate timer or ripple control receiver.
3) The ratio of preceding transformers is accounted for in the meter reading.
4) This takes account only of the ratio of preceding voltage or instrument transformers, the readings must be multiplied by a constant.
5) This does not take account of the ratio of preceding transformers, the readings must be multiplied by a constant.
6) The maximum rate is calculated from the price per kilowatt-hour (kWh) and per kilowatt (kW).
7) These measure the power throughput and according to the units counted, emit pulses to the connected remote meters, remote summation meters or telecontrol devices.

Electronic four-quadrant meters

Electronic meters formerly almost always used multipliers, which measure only one energy variable at a time, such as the time-division multiplier or the Hall multiplier. Modern meters use the principle of digital multiplication. The measured quantities of current and voltage are digitized using high-precision A/D transducers at a sampling frequency such as 2400 Hz and are forwarded to a downstream digital signal processor (DSP). This calculates the effective, reactive and apparent power or the corresponding energies and sends energy-proportional impulses to the rate module. The advantages of this process lie in high integration of the measurement functions in the low fault rate, the high measurement stability and the option of running a full 4-quadrant measurement.

The measured values can also be immediately and flexibly processed further and derived values can be numerically determined, e.g. momentary values, averages, minimum values, maximum values, etc. Appropriate selection of the sampling frequencies also makes it possible to record the proportions of the harmonics with the preset accuracy class rating.

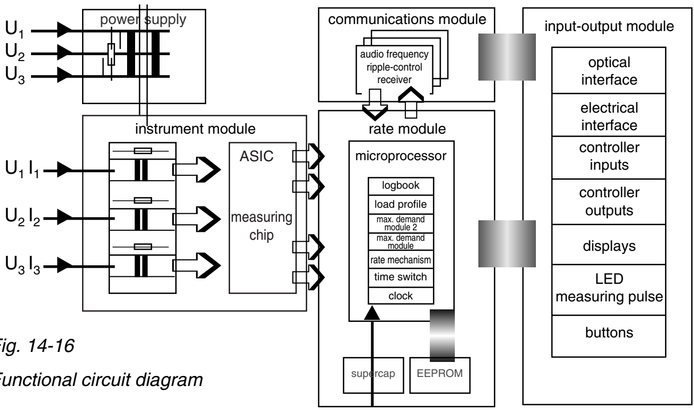

Fig. 14-16

Functional circuit diagram

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The calculated measured quantities are:

– effective power ...+P,
– effective power ...-P,
– reactive power ...(Q1, Q2, Q3, Q4 individually or combined).

Here, the effective power is derived by multiplying the current and voltage values:

$$p(t) = u(t) \cdot i(t)$$

The reactive power can be calculated from the apparent and effective power by application of the vector method:

with $S = U_{eff} \cdot I_{eff}$

follows $Q = \sqrt{S^2 - P^2}$

Because the harmonic content in the two rms values of current and voltage and are taken into account in the apparent power and in the effective power, the harmonic power is also included in the calculation of the reactive energy.

Display and control

Electronic' meters use an LC display controlled by a call button to show values. This also allows display and control by parameter-setting tools – PCs or handheld terminals – connected through appropriate interfaces e.g. 'optical interfaces'.

The display distinguishes between parameters such as the following different operating modes:

– operating display or standard display of measured values (rolling display),
– display test mode (display of the meaning of the individual display segments),
– call mode (display of all accounting-relevant registers),
– setting mode (display values/parameters that can be changed or set).

The following figure. shows the meaning of the different display segments:

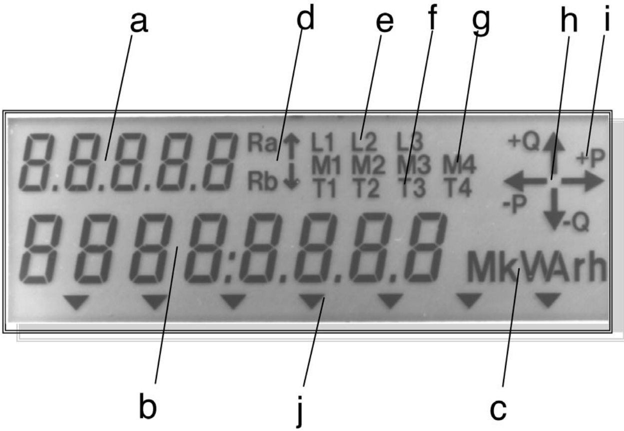

Fig. 14-17

Illustration of a display

a) 5 Segments showing the EDIS reference number (EDIS:Energy Data Identification System)

b) 8 Segments showing the measured values, with date and time

c) Unit of the measured value

d) Ra, Rb reset mark for the current month

e) Phase display L1, L2, L3

f) Current rate display (T1 - T4)

g) Current maximum display (M1 - M4)

h) Current direction of measurement, startup recognition

i) Programmed measured quantities (+ P, - P, + Q, - Q)

j) Marking arrows (left to right)

- TRE: internal ripple-control receiver active
- Clock: rate and maximum control by internal time switch
- StE: rate and maximum control by control input
- Pm: test mode/calibration mode
- Lp: load profile memory
- Par: parameter setting mode
- Set: setting mode

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Table 14-5

Possible design variations of an electronic meter:

a) Direct connection (4-wire meter; 50 Hz)

– 3 x 230/400 V	5/60 A
– 3 x 230/400 V	5/80 A
– 1 x 230/400 V	5/60 A
– 1 x 230/400 V	5/80 A

b) Instrument transformer connection (4-wire meter; 50 Hz)

– 3 x 230/400 V	5/1 A class 1
– 3 x 230/400 V	1/2 A class 0.5
– 3 x 230/400 V	5/6 A class 0.5
– 3 x 58/100 V	5/1 A class 1
– 3 x 58/100 V	1/2 A class 0.5
– 3 x 58/100 V	5/6 A class 0.5
– 3 x 63/110 V	5/1 A class 1
– 3 x 63/110 V	1/2 A class 0.5
– 3 x 63/110 V	5/6 A class 0.5

c) Instrument transformer connection
(3-wire meter, in accordance with Aron circuit; 50 Hz)

– 3 x 100 V	5/1 A class 1
– 3 x 100 V	1/2 A class 0.5
– 3 x 100 V	5/6 A class 0.5
– 3 x 110 V	5/1 A class 1
– 3 x 110 V	1/2 A class 0.5
– 3 x 110 V	5/6 A class 0.5

d) Instrument transformer connection for railway (1-wire meter; 16.66 Hz)

– 1 x 100 V	5/1 A class 1
– 1 x 100 V	1/2 A class 1

Standards for meters

The following standards must be taken into account in planning and installing DC and AC power meters:

- DIN 43850 — Electrical Meters Technical Specifications
- DIN 43854 — Sealed Terminal Cover Screws for Electrical Meters
- DIN 43855 — Electrical Meter Labels
- DIN 43856 — Electrical Meters, Multi-rate Tariff Switches, Ripple-control Receivers
Terminal Marking, Pattern Numbers, Circuit Diagrams
- DIN 43857-1... — Electrical Meters in Insulated Cases to 60 A Limit Current
- DIN 43862 — Removable Meter with Fixed Measuring Mechanism, Main Dimensions
- DIN 43863-1 — Electrical Meter, Rate Devices, General Requirements
- DIN 43864 — Electrical Meter, Current Interface for Impulse Transmission
- DIN 43860 — Supplementary Devices as per DIN 43857 Part 2, Fastening Brackets
- DIN 43861-1 — Ripple-control Receiver for Installation in Light Poles
- DIN 43861-301 — Ripple-control Receiver Transmission Protocol with Data Backup for Transmission Tasks in Ripple-control Technology
- DIN EN 60387 — Electrical Meter Symbols for AC Meters
- DIN EN 60521 — (VDE 0418 Part 12)
AC kWh Meters Class 0.5, 1 and 2
- DIN EN 60687 — (VDE 0418 Part 8)
Electronic AC kWh Meters, Class 0.2 S and 0.5 S
- DIN EN 61036 — (VDE 0418 Part 7)
Electronic AC kWh Meters, Class 1 & 2
- DIN EN 61268 — (VDE 0418 Part 20)
Electronic AC VArh Meters, Class 2 & 3
- DIN VDE 0418-4 — (VDE 0418 Part 4)
Electrical Meters, Maximum-demand Mechanisms
- DIN VDE 0418-5 — (VDE 0418 Part 5)
Electrical Meters, Duplicating Meters
- DIN EN 61037 — (VDE 0420 Part 1)
Electronic Ripple-control Receivers for Rate and Load Controllers
- DIN EN 61038 — (VDE 0419 Part 1)
Time Switches for Rate and Load Controllers
- DIN EN 61107 — Meter Content Transmission, Rate and Load Controller
Data transmission for fixed and mobile connections
- DIN EN 61142 — Meter Content Transmission, Data Exchange via Local Bus

14.3.8 Recording and logging

Event recorders

These are necessary for efficient system management and are generally supplied with information on currents, voltages, powers and events.

Sequential signalling systems, e.g. from the ABB INDACTIC® range, are available for recording events in the order in which they occur. Signals separated by as little as 1 ms are registered in the correct sequence. The event signals are normally recorded in clear text, together with the time, on printers and/or shown simultaneously on the VDU terminal. The signals can be binary or analogue. For control centres incorporating telecontrol systems and for logging routine measurements such as current, voltage, frequency power or work, there are various systems available, e.g. the S.P.I.D.E.R. family, which are intended for extensive systems with large volumes of data.

Fault recorders

As well as recording routine measurements, in the event of a fault it is also important to be able to reconstruct and have evidence of the surrounding circumstances and the timing of the disturbance. Fault recorders are used for this. They register the values and times of currents, voltages and events (e.g. breaker settings) shortly before and after the fault and react quickly to changes in nominal conditions. In this way, it is possible to analyse faults, determine their causes and avoid them in the future. The ABB INDACTIC® 65 system is suitable for recording and evaluating the course of such local faults.

Fault locators

Transmission line availability is particularly important in HV and EHV networks: it can be improved by speedily finding the site of the fault and so clearing it more quickly. Determining the distance of a fault is based on resistance measurement with the fault locator. Measurement thus has to be very fast as the time available is only from the fault’s occurrence until it is isolated. The distance of a fault can be read directly from the instrument.

When choosing these instruments, care must be taken that those for use with double-circuit lines include means of compensation. Fault locators can be in the form of the ABB “RANZA” range of separate instruments or integrated in the ABB INDACTIC 65 fault recorder.

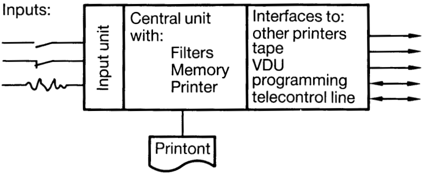
Process computers

In load-centre stations, it is also possible to install a small computer which can assume numerous functions. Some of these duties are shown in Fig. 14-18.

Fig. 14-18

Block diagram of a station computer

Outputs: position indications, alarms, system circuit status, fault sequences, routine measurements (single, per bay, per level), metering, outputs cycling or on demand



14.3.9 Automatic switching control

An automatic switching or transfer system automatically executes switching or re-routing operations under clearly defined error conditions. Controlled by measuring relays, its task is to restore a fault-free supply.

The service auxiliaries of substations include automatic transfer facilities which, if an infeed fails for example, quickly connect ties, standby transformers or start emergency diesels.

The station services equipment of thermal power plants include high-speed transfer systems to ensure a secure power supply to the motors for the boiler ancillaries. If the power supply is interrupted, the high-speed changeover equipment sees that important loads (high-voltage motors) are switched to a standby network as quickly as possible and without impairing operation, see also Section 15.2.

This technique is also used by industry, especially the chemical industry, where it is essential that processes continue without interruption.

The 15 kV systems of the German Federal Railway include automatic line testers so that the trains can keep running. A fault on the contact wire (earth fault) first trips the circuit-breaker in the substation, but the control system immediately closes it again. Only if it trips again is the line finally disconnected.

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In overhead line networks, automatic reclosure plays an important part in maintaining the power supply. Experience shows that faults in these networks are often only transitory and can be cleared if the breaker opens for a brief interval during which the arc can extinguish and the insulating distance reseal before it automatically closes again. The timing of a successful reclosing operation is shown in Fig. 14-19. As well as single fast reclosure, there is multiple slow reclosure accompanied by checks on the synchronizing conditions. Reclosure can be performed one- or three-phase, depending on type of fault and network conditions, with break times of 0.2 s to 2 s for fast reclosure and between 10 seconds and several minutes for slow reclosure. For further details, see Sections 14.2.1 and 10.4.5.

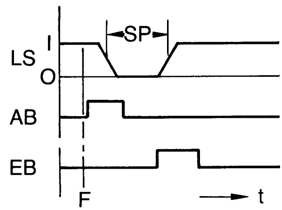


Fig. 14-19

Simplified time diagram of successful reclosure:
AB OPEN command, EB CLOSE command, LS Circuit-breaker, I Close, O Open, SP Dead interval, F Onset of fault

Automatic branch-switching control

Switching sequences executed locally can ease the load on operating personnel and the telecontrol facilities, e.g. one can program all the switching operations needed to connect a branch or change busbars. Technical expedience and economics govern the use of automatic switching and logic systems. Fig. 14-20 shows the block diagram of an automatic branch and busbar transfer facility with the ABB Procontic® system. Modern telecontrol substations such as S.P.I.D.E.R. RTU, an ABB product family, can also be programmed to execute sequences of this kind.

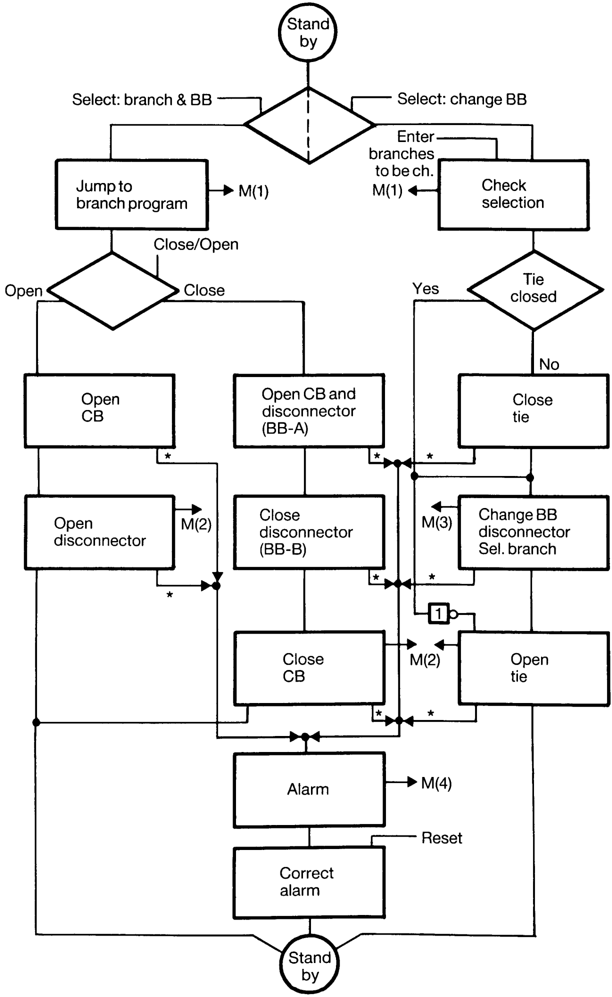


Fig. 14-20

Block diagram of an automatic branch and busbar transfer facility

** = Sequence error, CB / isolator does not operate; Signals:* M (1) *Selection confirmed,* M (2) *Program executed,* M (3) *Isolator transfer executed,* M (4) *Fault in sequence,* [1]○ *Negation*

14.3.10 Transformer control and voltage regulation

An important aspect of operating power transformers is being able to vary the ratio. This is done to match the voltage if the load fluctuates, to distribute load, to adjust active and reactive currents in interconnected systems and for voltage matching purposes with electric furnaces and rectifiers.

To obtain specified voltages on the output side, the transformer's high-voltage winding is provided with tappings (main and control windings) which are connected in different sequences according to the load. The respective winding sections are selected by means of off-load or on-load tap changers.

Off-load tap changers

Off-load tap changers are used in networks with little fluctuation in load. The tap changer covers a band of ± 5 % of the guaranteed operating voltage. The taps are changed off-load in 2 x 2 stages each of 2.5 %. This can be done only by hand directly on the transformer.

On-load tap changers

On-load tap changers are used in networks with frequent brief load fluctuations. The control range is ± 16 % max. of the guaranteed operating voltage in a total of 2 x 16 stages each of 1%. The tap changer selects the winding sections while under voltage and load. It is operated by a spring mechanism which is tensioned by means of an electric motor.

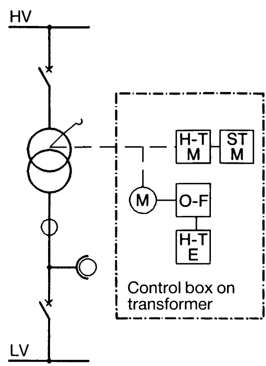
Tap changer control

1. *Local control,* Fig. 14-21
   The tap changer can be actuated directly at the transformers with the aid of a crank handle (emergency operation). Electrical local control by pushbutton is also possible. In this case, switching from one tapping to another requires a separate command. The tap changer is designed so that a single command cannot execute more than one change.

Fig. 14-21

Basic diagram of local tap changer control

H-T M	*Higher / lower, mechanical*
ST M	*Selected tapping shown mechanically*
O-F	*Local / remote selector switch*
H-T E	*Higher / lower, electrical*
M	*Drive motor*



2. *Station control / remote control,* Figs. 14-22 and 14-23
   Electrical control is also possible from the station control room or from the network command centre. Simultaneous actuation from the three locations – local / station panel / command centre – is prevented by selector switches. A pilot light on the station panel stays on while taps are being changed, indicating that a control command is being executed.

   Remote indication of the tap settings can be provided by a contact strip with resistors (e. g. 3 ohms per tap) on the changer operating mechanism, together with a DC voltage source (e. g. 6 V power adapter) and a scale instrument showing the tapping numbers.

   The station panel can also show the voltage to be maintained, as well as the selected tappings.

H-T M	*higher-lower, mechanical*
ST M	*selected tapping shown, mechanical*
O-F	*selector switch local-remote*
H-T E	*higher-lower, electrical*
M	*drive motor*
KB B	*contact strip, active*
KB UB	*contact strip, inactive*
ST E	*selected tapping shown, electrical*
V	*voltmeter*
G	*contact transmittler*
LL	*running light*

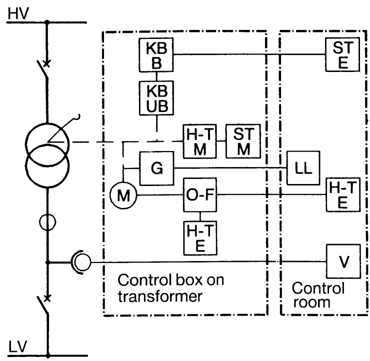


Fig. 14-22
Basic circuit diagram regulating switch for local and station control

H-T M	*higher-lower, mechanical*
ST M	*selected tapping shown, mechanical*
O-F	*selector switch local-remote*
H-T E	*higher-lower, electrical*
M	*drive motor*
KB B	*contact strip, active*
KB UB	*contact strip, inactive*
ST E	*selected tapping shown, electrical*
V	*voltmeter*
G	*contact transmittler*
LL	*running light*
MU	*measuring transducer*

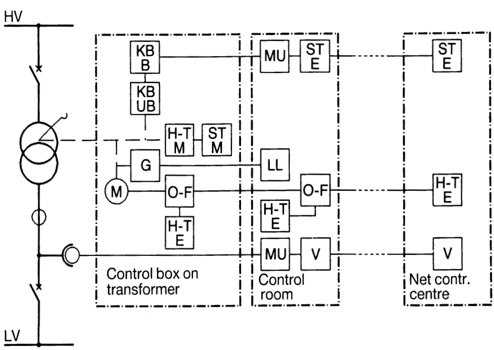


Fig. 14-23 Basic circuit diagram regulating switch for local and station and system control centre

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3. *Parallel tap changer control,* Fig. 14-24
Where several transformers are connected in parallel, the tappings must have an interlock system which is active only in parallel operation. The interlock prevents different tap settings on the paralleled transformers from giving rise to an excessive reactive current which could damage the transformers.

The interlock system operates via otherwise inactive contact strips which are allocated to the operating mechanisms of the tap changers.

If in parallel operation the tap settings are different (fault), a visual and acoustic alarm is given at the station panel.

If the transformers are equipped with automatic voltage regulation, see Fig. 14-24, the tapping interlock system is not needed. However, a measuring device is then necessary, which in parallel operation individually corrects the tappings to the minimum reactive current. In this way, transformers with differently set tappings can be operated in parallel.

The controller of only one transformer, the "master" transformer, should be active when running in parallel. This master controller, specified by means of the selector switch, then acts on the tap settings of all the transformers connected in parallel.

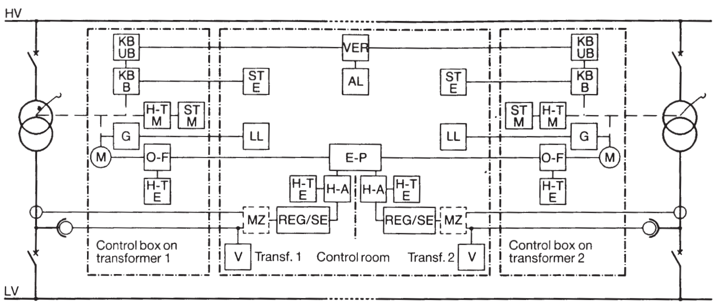


Fig. 14-24

Basic diagram of local / station / automatic parallel tap changer control

H-T M	*higher-lower, mechanical*
ST M	*selected tapping shown, mechanical*
O-F	*selector switch local-remote*
H-T E	*higher-lower, electrical*
M	*drive motor*
KB B	*contact strip, active*
KB UB	*contact strip, inactive*
ST E	*selected tapping shown, electrical*
V	*voltmeter*
G	*contact transmittler*
LL	*running light*
MZ	*measurement unit*
REG/ SE	*automatic voltage regulator and setpoint adjuster*
H-A	*selector switch, manual-auto*
E-P	*selector switch single parallel and master selector*
VER	*tapping interlock*
AL	*tapping discrepancy alarm*

4. *Automatic control*

Voltage regulation by means of tap changers can also be done automatically. The principal components of such a system are voltage regulator, setpoint adjuster, a measuring device for load-dependent setpoint correction, and for long lines, a means of compensating the voltage drop. This latter device can be contained in the voltage regulation or be installed separately. Measuring units are available for the following operating conditions:

- parallel busbar operation,
- parallel network operation,
- networks with widely varying active and reactive power components.

The choice of measuring units thus depends on the operating conditions.
The control system is connected to voltage and instrument transformers at the voltage level that needs to be held constant.
Simultaneous manual / automatic operation is prevented by selector switch.

14.3.11 Station control rooms

The control room at a substation provides close-range control and supervision. Fig. 14-25 shows the equipment layout for the generally manned control room of a large transformer substation. Besides technical performance, the design must also take account of ergonomic aspects such as clear arrangement, ease of access, lighting, freedom from glare, acoustics, climate and comfort conditions.

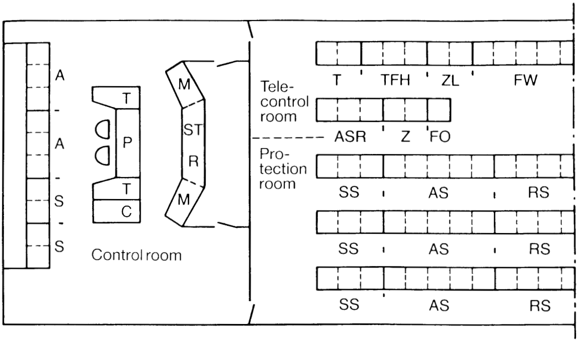


Fig. 14-25

Control room layout for a transformer substation:

A Alarms, AS Branch protection, ASR Automatic voltage regulation, C Station computer, FO Fault locator, FW Telecontrol, M Measurement, P Desk, R Mimic panel, RS Standby protection, S Fault recorder, SS Busbar protection, ST Controls, T Telephones, TFH PLC communication, Z Metering, ZL Terminal links

Further details on the design of control rooms are to be found in Section 14.5.3.

14.4 Substation control with microprocessors

14.4.1 Outline

Substation control facilities using microprocessors and serial data transfer perform all the established functions of the secondary systems in transformer and substations, i.e. on / off control, interlocking, measurement, feedback control, indication, signalling, protection (feeders and busbar) and metering etc..

But computer-aided systems offer more: process diagnostics, the creation and automation of decentralized substations, together with preliminary on-site data processing, so easing the general task of network management.

A radical feature of this new technology is its diagnostic capability, which alone has operational benefits for the user, even if he decides against the other new possibilities available.

Overall, the new technology offers

- fast fault recognition
- simple system structure
- error-free operation,

so significantly improving station availability.

14.4.2 Microprocessor and conventional secondary systems compared

With conventional secondary systems, the various functions considered in Section 14.3 are performed by separate devices (discrete components) which mostly work on the analogue principle and as a rule are of varying sophistication.

The resulting situation is as follows:

- Each task is performed by devices employing different technologies (electromechanical, electronic, solid-state or microprocessor-based).
- These discrete devices may require many different auxiliary voltages and power supply concepts.
- The links between the devices and with the switchgear require a great deal of wiring or cabling and means of matching.
- The information from the switching apparatus has to be applied separately to numerous inputs for protection, control, interlocks etc., so monitoring the interfaces is complicated.
- Checking the performance of the individual devices is accompanied by more difficult verification of overall performance.

With the new control technology for switching installations, the emphasis is on the system and its function as a whole.

Digital methods are employed for the respective functions, using programmable modules based on microprocessors.

The distinguishing features of the new technology are:

- Use of identical device components or combined devices based on microprocessors for the various tasks or functions.
- Standardized power supply and supply concept.

- Serial data transfer minimizes wiring (bus technique).
- Fibre optic cables are used near the process to reduce the cost of established adequate electromagnetic compatibility.
- Composite use made of data from the switchgear.
- Self-diagnosis with continuous function check-up, hence simpler testing of overall system and subsystem.
- Simple correct-sequence signal acquisition with a resolution of about 1 ms.
- Reduced space requirements.
- Records of station functions.

Another major innovation of the new approach is the man-machine interface (MMI). While the access interface to conventional secondary technology is switch panel- or mimic control panel-oriented with the elements of switches, buttons, lamps and analogue instrumentation, access to the new control systems is usually through a display at bay level and through monitors and keyboards at substation and system control centre level. Operation is mostly menu-guided, so no programming or computer skills are necessary.

14.4.3 Structure of computerized control systems

A substation can be divided broadly into a sector comprising the switchbays (feeders, ties, sectionalizers and earthing system) with their functions:

- Control, supervision, interlocking
- Transformer control and voltage regulation
- Bay-level automatic functions
- Indication acquisition and processing
- Measurement acquisition and processing
- Local (bay) control
- Autonomous bay protection

and a sector with higher-level, i. e. station-related, tasks such as:

- Local (station) control
- Communication link
- Connection to station auxiliaries
- Station functions
- Busbar protection.

The logic structure of the control system consequently has two hierarchical levels: the switchbay level with the bay units (BU) and the station level with the station unit (SU), see Fig. 14-26.

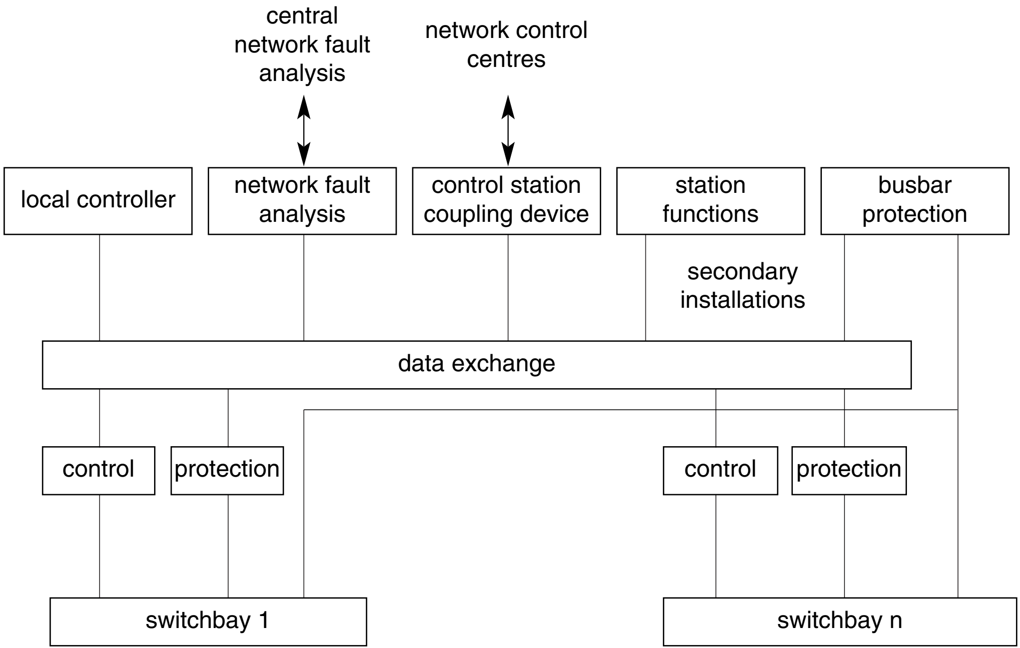


Fig. 14-26
Logic structure of computerized substation control

On the process side of the control system, the bay units are assigned accordingly to the process (switchbays). The result is that between every switchbay and the associated bay unit either a parallel connection, i.e. a direct connection between switchbay and bay unit is established for every datapoint such as position indicators and encoders for analogue values, or the data are linked to the bay unit by actuators and sensors over a process bus.

The functions performed in the bay units are basically those which require data from their associated switchbay (e.g. line protection, bay interlocks) and for which short functional loops are preferable.

The functions in the station unit, on the other hand, are those which need data from the whole station (e.g. busbar protection, priority treatment of alarms, indication of busbar voltage) or have a central function (connection to network control centre, radio time mark receiver, central operating position).

Serial links are used throughout for transferring data between bay and station units. The serial links are arranged radially. With a radial configuration serial links pass radially from the station unit to all bay units, and via these links the station unit can exchange data simultaneously with the bay units.

The ABB PYRAMID substation automation system uses a bus system for this data transmission. The radial (star) network consists of fibre-optic cables which are brought together at a star coupler (see also Section 14.4.4).

The bay and substation units are built up from modular components, or as a combined bay control and protection unit. The number of modules used depends on the required quantity of functions, the desired structure and specified aspects of system quality, such as availability. However, for safety reasons, in the high-voltage area beyond 72 kV the protection components are generally designed to operate independently of the other components of that bay unit.

Components of this new technology are also used for the self-contained protection circuits prevalent today, which provide additional information such as fault recording and fault location.

The self-contained protection devices can be of traditional or digital design, even from different manufacturers or different generations of protection equipment. In the case of conventional protection gear, parallel wiring continues to be used for the signal lines between bay and station units. Modern digital devices, on the other hand, offer the possibility of serial data transmission. To enable this, the interface is defined as per IEC 60 870-5-103 as a standard interface for serial connection of protection devices. Fig. 14-27 shows the general structure of the ABB PYRAMID control system with its decentralized function components. The star coupler ensures data communications between the autonomous subsystems.

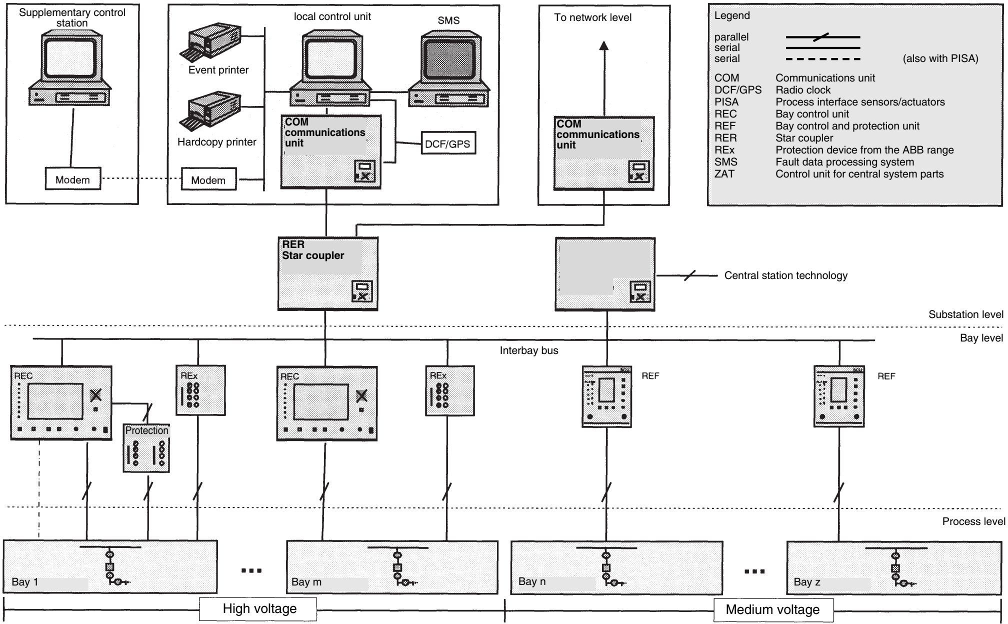
The functions are decentralized, irrespective of the bay unit’s locations and distribution.

A recommendation on “Digital Station Control Systems” by the VDEW working group for “Integrated Station Control Systems” has been in force since 1994, and a revised version is currently in preparation.

Sections 7.2.5 and 8.2.5 contain further information on computer-aided control for low-voltage and medium-voltage systems.

Fig. 14-27

Basic structure of the ABB PYRAMID control system



14.4.4 Fibre-optic cables

In modern station control systems, the links between the individual components usually carry information serially. Fibre-optic cables are used for these serial connections.

Properties and principle

Fibre-optic cables (FOC) are composed of glass or manmade filaments which by utilizing the property of total reflection are able to transmit light over long distances. They have a core with a high refractive index surrounded by cladding with a low refractive index and a mechanical protective coating (primary coating). The light is conducted by the core (subject to certain boundary conditions). Light-emitting diodes (LEDs) generally serve as the light source, but laser diodes are also used in special cases. Fig. 14-28 shows an optical transmission link.

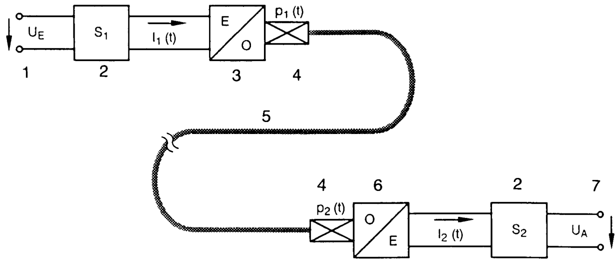


Fig. 14-28

Optical transmission technology with fibre optic cable, 1 Input, 2 Signal conditioning, 3 Electro-optical converter, 4 Connector, 5 Fibre optic cable, 6 Opto-electrical transducer, 7 Output

Their most important features regarding application in switchgear control systems are their complete immunity to electromagnetic interference and the absence of any problems with earthing and potential bonding.

Other major advantages are their large transmission bandwidth, low signal attenuation (regardless of transmission speed) and ease of handling. Fibre-optic cables are thin and flexible, and can be bent to relatively small radii.

Glass fibres differ from synthetic fibres mainly in that their attenuation is significantly lower, so the cables can be longer. On the other hand, they are not quite so convenient in practice.

Applications

The German VDEW recommendation “Integrated control and instrumentation in stations” includes many possible forms of serial links between the components of a station control system, all of which can in principle consist of fibre-optic cables. Because of their distinctive properties, however, especially their noise immunity, the main applications tend to be focused near the process itself. These are the communication links at the bay level, and the links joining components at the bay level with those at the station level.

One typical application is to connect the bay units with the higher-order star coupler at substation level.

As described earlier in Section 14.4.3 Structure of computerized control systems, the bay units of the ABB station control system communicate with each other and with the units at station level by means of a bus configuration that in physical terms comprises a star arrangement of fibre optic cables. This is an ideal combination, bringing together the advantages of the bus system, in particular the ability of all components to communicate quickly with each other, and the benefits of fibre optics. Furthermore, with this star structure, the failure of one component or its communication link has no effect on the performance of the other components.

VDEW ‘’Interface No. 6"

Applicable in Germany since 1991 is the “VDEW/ZVEI recommendation on serial interfaces for protection devices in integrated station control systems of electricity supply utilities”. This is also called “Interface No. 6”, since it bears the number 6 in the VDEW recommendation “Integrated control and instrumentation in stations”. The interface has also been included in international standards as the basis for IEC 60870-5-103.

Compliance with IEC 60870-5-103 ensures that digital bay protection equipment from different manufacturers retains connector compatibility. The specified connector corresponds to the F-SMA design in accordance with the IEC 60874-2 standard “Fibre-optic connector type F-SMA”. It has been chosen because it allows the use of both glass and synthetic fibres. The technical details of the compatible FOC transmission system can be seen in Table 14-6.

Table 14-6

Specification for the compatible fibre optic transmission system in the VDEW “6”

Characteristic	Synthetic fibre	Glass fibre 62.5/125 μm
Connector	F-SMA	F-SMA
Distance, typical	to 40 m	to 1000 m
Optical wavelength	660 nm	820 – 860 nm
Temperature range	– 5 to + 55 °C	– 5 to + 55 °C
Inserted power	min –7 dBm	min – 16 dBm
Received power	min – 20 dBm	min – 24 dBm
System reserve	min + 3 dBm	min + 3 dBm

Source: VDEW / ZVEI recommendation on serial interfaces for protection devices in integrated station control systems of electricity supply utilities. 1st edn. 1991.

14.5 Network control and telecontrol

14.5.1 Functions of network control systems

The purpose of network control systems is to operate transmission and distribution networks economically and reliably with the aid of data processing and information technology. The principal aim under normal conditions is to minimize overheads and capital costs by optimizing the utilization of the equipment, and under fault conditions to secure the supply of power at all points of the network and restore the situation to normal with interruption times kept to a minimum.

In order to achieve this, the status of the (usually extensive and closely intermeshed) network as regards topology, voltage and load must be known at all times, abnormal values must be instantly detected and signaled, and countermeasures taken. As supply systems become ever more complex, this is done at control centres which are fed by way of telecontrol links with all the information from the switchgear necessary for appraising the network's status and controlling it.

Initially, all functions were centralized in the control station. However, the increasing volume of information soon resulted in a shortage of processing capacity. The current trend is to decentralize most individual tasks at the point where they occur by implementing intelligent telecontrol stations or more powerful substation automation systems and to forward only the compressed information essential for centralized control of the overall network to the central control station for processing.

The exact duties to be performed by the network management system depend on the type and size of the network, on the nature of its main equipment and on the operational strategy adopted by the network operator.

In the supraregional network, the electricity is transported in bulk from the power stations to the load centres at voltages of 380 kV and 220 kV, or sometimes higher. This transmission network in turn supplies the distribution systems, operating at 110 kV, 60 kV, 20 kV, 10 kV and also other voltages, which carry the electricity at regional level from the interconnected network to the consumers.

The entire control and supervision of the machinery and equipment in the power plant itself, such as turbines and generators, is the province of power plant control, and so is not considered further here.

The tasks of network control begin with transmission of the electricity. For this, a *load-dispatching centre* controls the output of the power stations and the flow of power in the grid to meet the demand at any moment, aided by equivalent load curves from previous periods and according to mutual agreements with other electrical utilities, supplying the grid and large customers, together with various other parameters, in order to provide the most economical and secure service.

Network control centres monitor and control circuit status and the loading on switchgear and lines in the bulk transmission and distribution systems. When faults occur, it is possible with the aid of the high-speed data processing to obtain immediately an up-to-date picture of the network's general status and the situation at the site of the fault, then select and execute the required switching operations.

At the urban and municipal level, the supply of all forms of energy, i.e. gas, water, district heat, etc. as well as electricity, is controlled from one central multi-purpose centre.

The exact performance required from such a management system determines the equipment in the control centre. Today this consists almost exclusively of computer systems with separately assigned functions, together with colour monitors for displaylng the network and its parts. Because of the continuous increase in the scope and interconnection of the information processed in the control stations, it would no longer be possible for the control room staff to monitor and control the system without the aid of information technology. Process computers take over routine tasks from operators and quickly and safely prepare the data for processing. Central control rooms with computers and colour monitors for standard control operation and with an additional mimic diagram or large display with cumulative information for emergency operation or geographical overview are also encountered.

The internal data processing and information systems in many utilities are now networked with company data networks. This offers the option of deriving information from the system control technology for planning tasks, e.g. for network and maintenance planning, and for management information.

Practical experience shows that the designing of a new network management system calls for close cooperation between operator and supplier so that the individual parts of the system, such as data acquisition, transmission and processing, can be ideally matched to each other and to what they are required to do.

The general concept is often arrived at with the aid of joint preliminary studies, including the use of simulators, in order to make full use of today’s technology and optimize the control system to the specific requirements.

The Federation of German Electricity Companies VDEW has published a manual of recommendations[1)] on the design, construction and operation of network control centres, telecontrol and process computer systems, ripple-control systems, control rooms, auxiliary services, station control and network management. The different subjects are thoroughly dealt with in separate volumes.

These are:

0. General (overview, project management, non-technical requirements, awarding contracts)
1. Telecontrol systems (general, functions, technical requirements)
2. Ripple-control systems (basic planning, frequency planning, interactions, ripple-control receivers)
3. Process computer systems (task division in control and subcontrol rooms, functions, design of process computing systems, network database, interfaces)
4. Control engineering (task division and analysis, information input and output, control design, control room, ergonomic requirements)
5. Auxiliary equipment (backup power supply, rooms, signalling equipment, communications, equipment protection)
6. Integrated control systems in substations (design, requirements, information for the operator)

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1) Manual “Netzleitsysteme in Elektrizitätsversorgungsunternehmen (EVU) – Empfehlungen” (Network control systems in electrical utilities – Recommendations), VDEW-Verlag, 4/1994

7. NN
8. Network control systems
9. Standards, directives and recommendations

The latest supplement to this publication appeared in April 1994 as a ring binder. Some designs have in the meantime been superseded by technical progress. However, additional revisions are not proposed at present because the publisher is planning to replace the publication by various internationally coordinated documents.

The international standard on process data communication in network control systems is IEC/TC 57 “Power system control and associated communications”. The K 952 “System control technology” of the DKE is the responsible technical committee for Germany.

The results of the standardization are published internationally as parts of the IEC 60870 publication “Telecontrol equipment and systems”. In Europe, the publications are appearing from IEC 60870 as EN 60870 with the corresponding part number of the IEC document, in Germany as DIN EN 60870.

14.5.2 Control centres with process computers for central network management

With the growing trend towards centralized management of power networks and the accompanying large volume of incoming information, operating staff were subjected to an ever heavier work load until eventually they were unable to cope even under normal conditions owing to the limits on their ability to assimilate data within a given time span. In the interests of clarity and security, the information therefore has to be conditioned and condensed. The operators must be relieved of routine duties so as to be free for important tasks and decisions.

These demands can be met only by using programmable process computers. Table 14-7 lists a number of tasks that can be performed with the aid of process computers in network control centres and outstations. Although the technology has made rapid progress since this part of the recommendation (1981) was published and new solutions such as the integrated control system in the outstations have been implemented, in principle the task assignments are still generally current.

Table 14-7

Tasks for process computers in control centres and substations[1)]

1	2	3
Display and supervision of network status	**Control of switchgear and auxiliaries**	**Load management**
● Alphanumeric display of incoming data tabulated in clear text – group signals – derived single signals ● Graphic display of network and station diagrams – networks by voltage level – subnets – block diagrams of transformer and substations – station segments – station allocation lists – list of available pictures ● Additional information in selected pictures – measurements (digital or bar diag.) – setpoints and limit values – updates of switchgear settings – identification of earthed and unavailable apparatus – identification of messages to be reset locally – indication of work in progress on switchgear ● Use of colour display units – separate colour per voltage level or network section having same earthing condition ● Mimic panel as general display – geographical layout – linked node-point signals – limited additional information	● Command input via keyboards – all kinds of control command – uniform operation – independent of existing control systems ● Multiple-step commands – operator guidance functions – stepwise checking of completeness and correct sequence – command output, storage and reporting	● System load measurement and monitoring – measurement of energy at supply points – transmission as meter reading or pulse string – acquisition and storage in computer – calculation of total system load over accounting period – determination of free capacity – generation of substitute values for missing values – output via VDU or digital display – printouts of individual values ● Load management – calculation of load trends – short-range load forecasts – time-related load control ● Operation of ripple-control systems – manual commands to control unit, bypassing computer – manual commands through computer – automatic commands through computer based on calculation

1) Summary from manual "Netzleitsysteme in Elektrizitätsversorgungsunternehmen (EVU) – Empfehlungen" (Network control systems in electrical utilities – Recommendations), Section 3.1, 4/81

(continued)

Table 14-7 (continued)

Tasks for process computers in control centres and substations[1)]

4	5
Load shedding	**Documentation of events – printouts and off-line storage**
● Determination of loads to disconnect according to – time of year – day of week – time of day – system load immediately before fault – available generating capacity – network circuit status	● Printouts required for – recording events in network – later analysis of disturbances – statistical purposes – future planning
● High-speed detection of fault criteria and measurements – system frequency – unassisted power available – total system load – load of separately switchable subnets – measurements to determine transfer lines	● Clear text printouts – text summaries – clearly organized typefaces
● Shedding of load – determination of optimum reduction with computer – disconnection with minimum delay – assumption of load frequency control in subnet	● Computer tasks – essential information in most effective form – data conditioning and compression – collation of data – production of sorted reports
	● Off-line storage required for – examination and analysis of past events or operating conditions – network planning – forecasting
	● Selection of storage media – disk – tape, cassette – punched tape, cards – diskette, CD-ROM
	● Preparation for storage – conversion to most suitable form – savings of memory space

(continued)

Table 14-7 (continued)

Tasks for process computers in control centres and substations[1)]

6	7
Data acquisition and processing in substations	**Other tasks for process computers**
● Telecontrol functions ● Indication processing – collection of fault signals in real time – collection of fault signals with follow-up faults – preprocessing of data – transmission after initial sorting ● Processing of measurements and meter readings – transmission only when value alters – totals generated at substation – readings transmitted in different time cycles – supervision of limit values – generation of operating values from performance values or as pulse strings ● Commands – verification of interlock conditions – execution of programmed control actions – construction of a switching matrix ● Simplified reports – for indications and measurements – for executing switching commands ● Station control system – takes over partial tasks – complete control and monitoring	● In network operation – data reduction, e.g. earth-fault location – programmed switching operations – temperature-rise calculations for cables and transformers ● In network planning – power flow calculation – short-circuit calculation ● In load dispatching – state estimation – network security calculation – restoration of supply – load forecasting – optimization of generator output ● In statistics – measurement statistics – apparatus statistics – maintenance planning

Which of the many functions are to be incorporated in a control centre depends very much on the performance specification and financial resources at the user's disposal. Deciding the exact details must form part of the planning phase.

PC-based computer systems with fully graphic colour monitors for process control are primarily used in small and medium municipal and regional control stations, and also in station control systems. In selecting computers, great emphasis is placed on commercially available industry standards for the hardware, the operating systems and the basic software (e.g. OS/2, RMX, Windows). Networking over local area networks (LAN, Ethernet) is also important.

In addition to straight electricity control rooms for medium-voltage networks, sometimes linked to load management, this category also includes multi-purpose centres for several different types of energy, e.g. electricity, gas, district heat and water, which run in parallel on the same or multiple networked computer systems and are monitored from the same workstation.

Very exacting demands are made on the computer systems for large and complex network management facilities and for load-dispatching centres. In addition to standard system control (SCADA basic functions), more advanced tasks for network operation, load distribution, system planning and for statistical purposes must be handled here. These functions are designated as higher decision and optimization functions (HEO) or as energy management functions (EMS).

The computer hardware used consists of 32-bit computers, increasingly also 64-bit computers, with the associated storage media, teletypes, printers, graphic monitors, keyboards, etc. Front-end computers or remote terminals are used to link local substations and telecontrol lines

Multiple computer configurations with redundancy are used in medium and larger network management systems in order to increase availability and spread the work load. With the hierarchical system structure which used to be customary, computers connected in series performed different tasks such as time-critical scheduling of telecontrol lines, network management and statistical calculations. If a computer went out, others connected in parallel took over operation without interruption and with no loss of data. Now "distributed computer systems" are primarily used for this purpose. The overall system tasks are distributed over smaller computer units, which are connected in parallel to a duplicate or segmented LAN (Local Area Network) and can also operate independently of one another.

Besides the hardware, the network management system's capabilities are determined above all by the software. Preferred operating systems are the widespread and proven standards, e.g. UNIX operating systems such as ULTRIX, POSIX, HP-UX, or the industry standard operating system OSF/1. An important requirement of the application software, apart from performing all its allotted functions, is that it should be easy to use. The user must be able to manage the system without any programming skills, and with dialogue guidance easily be capable of adjustments and changes to the data and network configurations.

Control centres equipped with process computers require a number of other facilities as well. Besides air-conditioning for the computer rooms to maintain a constant atmosphere, an uninterruptible power supply is necessary to prevent data from being garbled or lost.

Chapter 3 of the VDEW manual “Netzleitsysteme in Elektrizitätsversorgungs-unternehmen (EVU)” (Network control systems in electrical utilities) contains a series of recommendations for task allocation and design of process computer systems in control stations and outstations. An important part of this chapter is also the “process for development of a network database”.

ABB provides an integrated series of network control systems for economical and reliable management of power supply networks with the S.P.I.D.E.R. system family under the Panorama integrated system solution to cover all task areas from the smallest introductory version to the largest load distributor.

The S.P.I.D.E.R. MicroSCADA system, a PC-based control system, is designed for small and medium tasks in system control and also for load management and station control systems. The S.P.I.D.E.R. SCADA system is the basis for larger network control systems. Depending on the actual application, it can be scaled up for high-performance network control systems, e.g. for higher optimization tasks to the S.P.I.D.E.R. EMS system, as a distributor network management system to S.P.I.D.E.R. DMS or in pipeline monitoring to S.P.I.D.E.R. PMS. All these systems are equipped with high-performance computers of the DEC-VAX family.

The hardware and software of all S.P.I.D.E.R. systems are made up of self-contained modules which are compatible with each other and can easily be combined to form complex, distributed network management systems. In addition, S.P.I.D.E.R. network control systems are completely separate from the switchgear itself and the telecontrol facilities. They can be adapted without difficulty to any set of requirements.

14.5.3 Control centres, design and equipment

The aim of control room design is to create the best possible man-machine interface (MMI). All the facilities must be provided for controlling and supervising technical processes and equipment from a central point located at a distance from the various installations.

The essential requirements to be met by a control room are a clear presentation of the supervised network or network segment, indication of the circuit conditions, voltages and loadings of the apparatus and linking conductors, the immediate and unambiguous signalling of abnormal circumstances and the keeping of records regularly and in response to events.

To arrive at the best possible solution for performing all the control and supervisory tasks, many different aspects have to be considered in equipping and arranging the control room. Included among these is the field of ergonomics, which is the scientific study of optimizing and standardizing the communication interface between man and process to accord with human cognitive capabilities and reactions.

An important point when designing a control room is that the equipment must be suited to its particular task, and must also take into account the limited capacity of a person to absorb information within a given length of time. All important information must be presented within the operator’s primary field of view. Here, attention must be paid to the correct arrangement of the individual functional units, such as VDU, operator’s console and signal display, and also to an appropriate and easily understood representation of the state of the system and the various controls.

These technical considerations have also given rise to recommendations on the control room's interior design. These aim to create physiological comfort by means of glare-free lighting, acoustic treatment and indoor climate, but at the same time make sure that the operating staff stay alert. Although their duties are not very demanding under normal circumstances, they must react quickly and correctly if trouble occurs. The relevant DIN, EN and IEC provisions must be observed with respect to these environmental conditions.

Further recommendations and hints on control room design are to be found in the VDEW manual "Netzleitsysteme in Elektrizitätsversorgungsunternehmen (EVU)" (Network control systems in electrical utilities). Volume 4 "Control room design" (as of 08/92) contains guidelines on all major aspects of planning and designing network control centres, including the essential considerations of

– human physiology and sensory perception,
– codification of information (e.g. as symbols),
– presentation and interrelation of information, taking into account disturbing influences such as glare, noise, etc.

The individual subsections describe the general task allocation of the control engineering, the task analysis including task assignment and functional overview for the specific application case, provide details of input of information (commands, control and display) and information output (information quantities, processing and display), provide suggestions for control procedures, on the spatial configuration of the subsystems inside the control room, on control room equipment and air-conditioning and also on the ergonomic requirements. At the end, a series of provisions and directives that must be considered in control engineering is listed.

As the control room is often seen as reflecting the image of the supply utility, this is another significant aspect to be considered in deciding the furnishings and fittings.

Up to the seventies, a large mimic panel was the principal and often also the only means of displaying a replica of the network. Owing to increasing centralization and automation together with the growing complexity of power supply systems, the mosaic-type mimic panel has lost its former importance. It certainly provides a quick overall view of the network, but limits are imposed by sheer size and the ease of recognizing details. The mosaic-type mimic panel has hence become restricted to local or other small control rooms where system layout and status can still be shown using simple systems on a manageable area and modifications to network configuration and apparatus can be made without difficulty. The mosaic panel with reset controls continues to be used as well as VDUs in larger control centres, serving to provide a less detailed overall picture, a stylized map of the network, and also back-up for the main system. More and more often batteries of projectors are found in control rooms, which are arranged in a pattern and project a seamless overview of the entire system in one large image. The active network images are taken from the computer, and video images (e.g. door monitoring) can also be incorporated into the general view. In addition to the usual means of signalling and control, the panels are also fitted with other intelligent devices for indicating faults, large-scale displays and recording.

In all medium-sized and larger control centres with process computers, the details of the network are shown on fully-graphic colour VDU terminals. With these, it is possible to prepare and display the specific up-to-date information necessary for a given switching operation or for fault analysis. All unneeded information, such as healthy branches, can be omitted. Important details can be emphasized by colour, e.g. line loadings, earth lines, etc. Signals and measurements arriving spontaneously can be presented on the screen as they occur. The video terminal thus offers a greater density of information than the same area of a mosaic panel, and at the same time more clearly, i.e. perceived faster and more reliably by the operator. Different parts of a picture can be shown on a number of adjacent screens. In another form of presentation, the picture shown on one screen sweeps across the entire network (rolling map method). Additional functions offered by the graphics monitors are image zooming, decluttering with automatic changes of the degree of detail when zooming, the windowing technique with temporary display of windows for control or help and softkeys (virtual keys) that can be shown on the edges of the display for frequently occurring functions. The image section and the equipment that is to be controlled during switching operations and input of the switching command are selected on screen, primarily using keyboards on the control panel as the input device but also “virtual keyboards” on the display or cursor positioning on the screen with a joystick, arrow keys, roller ball or mouse. Light pens and digitizing tablets with stylus are not recommended because that would require the monitors to be installed within reach of the operators. However, this does enable the change service to design images and symbols particularly quickly.

In both conventional and computerized control rooms, the process is usually controlled from a desk or console. It is important that the monitors used to depict and control the network are simple to operate and show the network in a uniform manner, especially when an extensive management system has several computers sited at various places in the network, e.g. at the control centre and at the substation. The previously process-orientated operating staff must be able to do their work easily, without the need for skilled computer specialists. In many cases, therefore, the operator receives guidance from the screen in the form of a menu showing instructions on forthcoming control actions, either in clear text or by means of icons, in much the same way as with modern personal computers.

Fig. 14-29 shows an example of a control room in a computerized regional control centre. As well as the technical facilities with 2 workstations, 4 colour terminals, mosaic-type mimic display and other input and output devices in the control room itself, one can also see some of the other amenities forming part of a large network control centre.

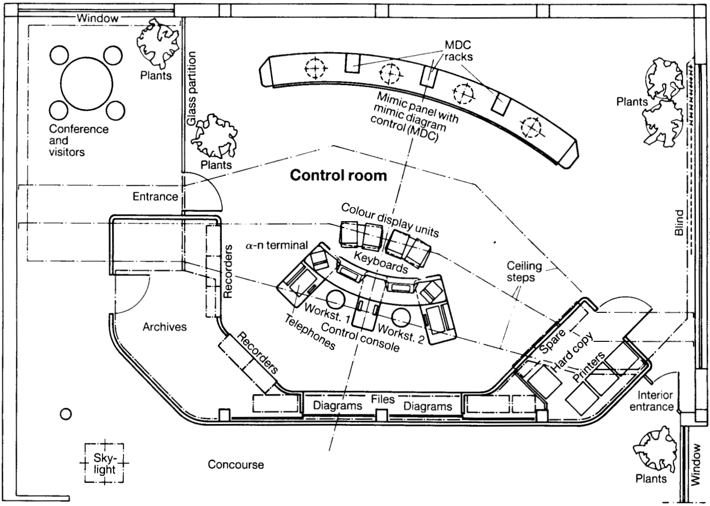


Fig. 14-29

Layout of a regional network control room

14.5.4 Telecontrol and telecontrol systems

Along with data processing, telecontrol plays a vital role in central network management. It is communications technology applied to technical processes. Its purpose is the economical and reliable transmission of data (such as switching and adjustment commands, signals and measurements) between the decentralized substations and the central control room.

At the transmitting end of a telecontrol system, the relevant information is prepared for transmission, i.e. it is coded and secured with additional redundancy so that errors due to disturbances along the transmission path can be detected at once, and spurious output data prevented. At the receiving end, the incoming information is decoded, checked and, if free from errors, sent as a command, signal or measured value to the process modules or passed to the master computer.

The IEC's TC 57 has drawn up a number of standards on telecontrol and published them as IEC 870. The results have been published in the European standard EN 60870, i.e. in the German DIN 19244. The terminology of telecontrol is defined in the "International Electrotechnical Dictionary, Part 371: Telecontrol", available in Germany under the number IEC 50, part 371.

The most important telecontrol terms can be found in the "Internationales Elektrotechnisches Wörterbuch Kapitel 371: Fernwirken" (International electrotechnical dictionary – Chapter 371: Telecontrol) as IEC publication IEC 50 (371) (1984), incorporated nationally as IEV 371 (1989), and in the associated change 1 as supplement IEC 60050 (371) dated 1997.

Also on this subject, "Begriffe der Fernwirktechnik", published as ntz-report No. 26 by VDE-Verlag GmbH, Berlin-Offenbach 1991, has been brought up to date and contains all definitions in English and German.

The growing size and complexity of power supply networks and the increased volume of information has necessitated telecontrol systems of different structures. In the case of small control centres with few substations, all the stations can still be connected directly to the control centre by their own telecontrol links, either point-to-point (the control centre communicates only with one substation) or on the multi-point principle (the control centre interrogates a number of substations one after the other for new information). For medium or large network management systems with many or distant substations, however, a hierarchically structured telecontrol network is unavoidable owing to the usually limited number of available communications channels, and also to relieve the control centre. In this case, the information from several substations, for instance, can be collected and compressed at so-called router stations or passed to telecontrol substations via additional telecontrol feeder lines.

Choosing the most suitable telecontrol system depends on its required performance. The main criteria are the volume of information and how up-to-date it needs to be, but equally important is its incorporation into the hierarchy of the control system as a whole.

Today time-division multiplex (TDM) telecontrol systems are used almost exclusively. With the TDM system the data are transmitted one after the other in the form of telegrams, a succession of pulses. Each piece of information is assigned to a certain place in the telegram. Besides the information itself, the telegram also includes address and test characters, the purpose of the latter being to prevent incorrect information from being sent.

The IEC TC 57 "Power Systems Control" and the DKE committee K.952 "Netzleittechnik" (system control technology) have been working on standardizing transmission protocols for a long time. These standards are or will be published in IEC 60870-5 (international), EN 60870-5 (European) or the DIN EN 60870-5 (German) standards series under the subject of "Telecontrol equipment and systems, Part 5 – Transmission protocols". The individual parts describe and define the following subjects:

Part -5-1: Transmission frame formats
Part -5-2: Link transmission procedures
Part -5-3: Structure of application data
Part -5-4: Definition/coding of elements
Part -5-5: Basic application functions

The main section IEC 60870-5-101 “Companion standard for basic telecontrol tasks” (1993) or EN 60870-5-101 “Application-based standard for fundamental telecontrol tasks” (1996) is particularly interesting and important for telecontrol. This standard is intended to lead to a unification of the transmission protocols of various manufacturers of telecontrol systems and to make it easier to combine different telecontrol systems in the same network control system. The protocol as per IEC 60870-5-101 is in the process of being integrated into existing or new telecontrol systems.

The December 1997 main section IEC 60870-5-103 “Companion standard for the informative interface of protection equipment” marks an important milestone for the serial connection of protection relays in substation control systems and telecontrol stations. The standard is derived from the earlier VDEW “no. 6” interface (see Section 14.4.4).

The usual transmission speeds employed for telecontrol are between 50 and 1200 Bd (baud)[1)]. In large network control systems and in special application cases, e.g. where system protection information with very short reaction time is transmitted, transmission speeds of 2400, 4800, 9600 and even 19200 Bd are also standard if permitted by the available transmission channels.

The manual “Netzleitsysteme in Elektrizitätsversorgungsunternehmen (EVU)”(Network control systems in electrical utilities) covers the subject of telecontrol in volume 1. The fundamentals of telecontrol and its different functions are defined and described, and the section “Technical conditions” contains information on environmental factors, on conditions for interfacing with switchgear and the transmission facility, on operating behaviour, power supply and general questions of design. Under “Non-technical conditions” are notes on documentation, identity coding, training, performance certification and warranties.

With the introduction of programmable central processors, telecontrol stations have been assigned not only the usual functions (input and output of information, preparation and transmission of telegrams, securing of information) but also additional decentralized processing tasks to ease the load on the control centre. The trend has since been towards incorporating the telecontrol station as an integral component of the station control system or setting it to completely and independently control all the control tasks in the substation.

Examples of functions in the outstations can be seen in column 6 of Table 14-7. A new function is the serial linking of digital protection relays to telecontrol substations and to control centres.

Additional functions at router stations are:

– compression of information,
– correlation of data to reduce volume,
– evaluation, processing and interconnection of information from underlying substations,
– information distribution to more than one control station and substation control system,
– execution of emergency action.

[1)] 1 baud = 1 digital pulse per second

Other possibilities with modern telecontrol systems are:

– interlinking of telecontrol systems of different types and makes,
– serial linking of digital protection relays and bay or substation units,
– standardization of telegrams,
– different transmission protocols to higher-order control systems,
– pre-processing of data.

The ABB Panorama design with the RTU system family has a range of modern telecontrol systems suitable for all tasks. The range extends from small systems for simple telecontrol tasks up to very large TDM systems with many additional functions at all hierarchical levels for use in complex network control systems.

The various ABB systems can be combined with each other, and also expanded from the smallest up to the very largest. For network management systems of any size, therefore, there is ABB telecontrol system suitable for every point in the communications network.

With the aid of intelligent coupling devices, it is also easy to incorporate ABB telecontrol systems in network control facilities from other suppliers, or connect 'foreign' feeder stations to the S.P.I.D.E.R. substation. The implementation of standard protocols as per IEC 60870-5-101 will make this task even easier in the future. The same applies for interconnection with station control systems in the substations, e.g. with the ABB PYRAMID control system. As an example, interfaces as per the ABB SPA bus protocol or as per the international IEC 60870-5-103 standard are offered for serial linking of protection relays or control modules.

14.5.5 Transmission techniques

Communications links are required for transmitting the telecontrol signals between the control centres and the various stations of the telecontrol network. The nature and capacity of these links also determine the maximum speed of transmission.

Audio-frequency (AF) transmission by means of voice-frequency telegraphy (VFT) or modem over the following paths is generally preferred:

Telecommunication lines or cables with copper wire or fibre-optic conductors, PLC links (power-line carrier transmission over high-voltage lines), VHF and radio relay links. Direct-current data transmission is also used for short distances (≤ 10 km), in this case usually with only low transmission speeds.

The communication channels can either be owned by the system operator or rented from the postal authority. Typical examples of transmission links belonging to the utility are telecommunication cables in the form of buried or aerial lines run along the same route in parallel with high-voltage cables or overhead power lines. Aerial cables are divided into autonomous cables, earth-conductor cables and phase cables. Other examples are multichannel radio relay links, chiefly at grid level, and PLC communication by way of the power lines themselves.

If no telecontrol transmission paths are available, current paths or data connections can be leased from Telekom. However, note that Telekom current paths must not be switched together with private telecommunication paths.

The terminal devices must be approved for this purpose[1]. Telekom guarantees a sufficient receive level for transmission on leased lines. With private lines, it may be necessary to provide repeaters, amplifiers and matching elements.

The most important provisions and recommendations for the transmission paths are presented together in Volume 1, Chap. 1.1 of the VDEW recommendations. This includes the provisions of VDE 0800 (telecommunications), VDE 0228 (influence by power systems), VDE 0816 and DIN VDE 0818 (for cables), VDE 0850 or EN 60495 and VDE 0851 (for TFH (power line telephony) and VDE 0888 or EN 187000 (fibre optics for telecommunications).

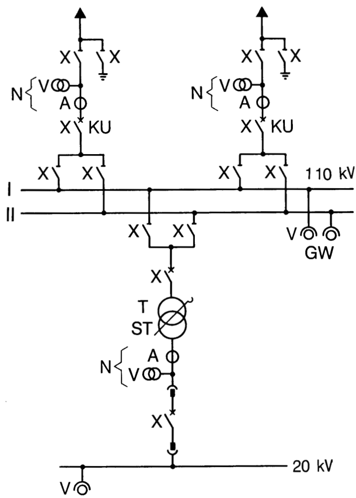
14.5.6 Technical conditions for telecontrol systems and interfaces with substations

Volume 1 of the manual “Netzleitsysteme in Elektrizitätsversorgungsunternehmen (EVU)” (Network control systems in electrical utilities) contains recommendations regarding the technical conditions that telecontrol systems have to satisfy. Described here, too, are the different interfaces, including those to the substations, and the question of power supply. In the meantime, there are various standards that are also concerned with this subject as per E DIN IEC 57(CO)21 (international IEC 60870-1-1) and E DIN IEC 57(CO)49 (international IEC 60870-1-3). The following principal conditions for interfacing with the switchgear are also taken from these source documents.

The centralized management of a network requires a variety of information from the substations relating to closed and open-loop control, measurements etc. The nature and quantity of signals, commands and measurements that need to be made available and transmitted depends among other things on the kind of supply network, its voltage level and scope of the network management system. Fig. 14-30 shows an example of the telecontrol information transmitted from a 110 / 20 kV substation[2].

Fig. 14-30

Example of the telecontrol information transmitted from a 110 / 20 kV substation, X Control action and indication, GW Limit value, A Measurement: current, V Measurement: voltage, N Power, ST Tapping, T Temperature, KU Auto-reclosure



[1] The Zentralamt für Zulassungen im Fernmeldewesen (FZZ) (central office for telecommunications approvals), Saarbrücken, is responsible for this in Germany.

[2] Taken slightly revised from the manual "Netzleitsysteme in Elektrizitätsversorgungs-unternehmen (EVU)" (Network control systems in electrical utilities), P. 1.1.2-1.

14

Interface telecontrol unit/substation

This interface carries information passing between the telecontrol equipment and the control devices in the substation. For the telecontrol equipment, there are the following 4 kinds of data input/output:

– digital inputs,
– analogue inputs,
– digital outputs,
– analogue outputs.

The classes of noise-voltage limit values and insulation requirements are shown in Tables 14-8 and 14-9. The choice of class depends on the characteristics of the switchgear.

Table 14-8

Noise-voltage limit values and insulation requirements for binary signals

	Transverse voltage	Longitudinal voltage
Operating limits	10 % power frequency volt. peak / peak referred to U_N 0.2 kV H.F. (1) 0.3 kV IMP (1)	 25 V AC 65 V DC 0.3 kV H.F. (1) 0.5 kV IMP (1)
Destruction limits class 1	+ 200 % U_N DC (2) – 125 % U_N DC (2) 200 % U_N A. (2) 0.3 kV H.F. (1) 0.5 kV IMP (1)	 0.5 kV N.F. (1) 0.5 kV H.F. (1) 1.0 kV IMP (1)
Destruction limits class 2 for telecontrol equipment with series EMI barrier	+ 200 % U_N DC (2) – 125 % U_N DC (2) 200 % U_N AC (2) 0.5 kV H.F. (1) 1.0 kV IMP (1)	 0.5 kV N.F. (1) 1.0 kV H.F. (1) 2.5 kV IMP (1)
Destruction limits class 3 for telecontrol equipment connected direct to the switchgear	+ 200 % U_N DC (2) – 125 % U_N DC (2) 200 % U_N AC (2) 1.0 kV H.F. (1) 25 kV IMP (1)	 2.5 kV N.F. (1) 2.5 kV H.F. (1) 5.0 kV IMP (1)
Insulation between inputs and/or outputs and/or earths		(a) min 1 MΩ at 500 V AC (3) (b) min 10 MΩ at 500 V AC (3) (c) min 100 MΩ at 500 V AC (3)

Notes:

(1) N.F. = System frequency (usually 50/60 Hz)
H.F. = Damped high-frequency oscillation, see IEC 60255-4
IMP = High-voltage pulse

(2) The equipment must withstand this voltage for 1 min without harm.

(3) Insulation class (a) is for normal applications. Insulation classes (b) and (c) may be used in special cases.

Table 14-9

Noise-voltage limit values and insulation requirements for analogue signals

	Transverse voltage	Longitudinal voltage
Destruction limits class 1	± 50 mA DC (2) ± 24 V DC (2) 0.2 kV H.F. (1) 0.3 kV IMP (1)	25 V AC 65 V DC 1.0 kV H.F. (1) 2.0 kV IMP (1)
Destruction limits class 2 for telecontrol equipment with series EMI barrier (4)	± 50 mA DC (2) ± 24 V DC (2) 0.5 kV H.F. (1) 1.0 kV IMP (1)	± 0.5 kV DC 0.5 kV N.F. (1) 1.0 kV H.F. (1) 2.0 kV IMP (1)
Insulation between inputs and/or outputs and/or earth		(a) min 1 MΩ at 500 V AC (3) (b) min 10 MΩ at 500 V AC (3) (c) min 100 MΩ at 500 V AC (3)

Notes:

(1) N.F. = System frequency (usually 50/60 Hz)
H.F. = Damped high-frequency oscillation, see IEC 60255-4
IMP = High-voltage pulse

(2) The equipment must withstand this voltage for 1 min without harm.

(3) Insulation class (a) is for normal applications. Insulation classes (b) and (c) may be used in special cases.

(4) The values for class 3 in Table 14-8 apply here if telecontrol equipment is connected direct to control devices at the switchgear.

General conditions for substations

In the substations, all the circuit-breakers and disconnectors to be remotely controlled must have a power operating mechanism and a floating-potential make and break contact for indicating status. Transformers, arc-suppression and charging-current shunt coils must be provided with additional floating contacts to indicate grading level and on-status. All enunciator relays working together with telecontrol devices must have a floating NO contact, and so that new changes of state can be detected the enunciator contacts must be closed only while the coil is energized. Relays for isolating against external interference must be mounted close to the telecontrol equipment. Measuring sensors are required for remote measurement.

As part of the power equipment, all these interface devices must conform to the relevant IEC standards, for instance IEC 364, and if electronic to IEC 1010.

Commands

Commands to switching devices and transformers or graded arc-suppression coils are transmitted by the telecontrol system via digital outputs as two-phase pulsed commands of ≤ 60 V DC lasting 100 to 500 ms. Single-phase and one-and-a-half-phase output arrangements should be fitted with a switching monitor in the process-side circuit. Disconnectors with longer operating times (10 – 15 sec) must be provided with additional means of automatic control or additional timing elements. Plunger-type arc suppression coils can be activated continuously or converted locally to step control. With a switching device such as a local/remote selector switch it must be possible to inhibit individual groups of commands or all commands from the telecontrol substation.

Indications

Indications are passed individually via digital inputs to the telecontrol device, although the enunciator contacts can be grouped to feed common return lines. Signals indicating switchgear settings must identify both positions. These two signals are usually obtained from a changeover contact or an NC and NO contact. With isolators that move slowly, transmission of the intermediate position is suppressed by the telecontrol system during the isolator's usual operating time. Signals in response to tripping should, wherever possible, be generated locally in each switchbay.

The signals can be continuous, of short duration or fleeting signals with times of $\geq$ 10 ms, the last two categories being stored by the telecontrol system until they are acknowledged. A DC signal voltage of 60 V should be used (48 or 24 V are also possible) so that even with considerable distances between switchyard and telecontrol station any noise voltages remain below the signal-tripping value.

Measured values

The remote measuring sensors employed to convert the process data into standardized values must have floating-potential outputs. The voltage at the output of open-circuit sensors must not exceed 100 V. They must not be damaged by short-circuits or open circuits on the output side, nor in such cases have any unacceptable effects on the primary transformers.

Buffer amplifier or lightning arresters should be provided to guard against overvoltages, particularly in high-voltage installations.

The expected input quantity for the analogue inputs of the telecontrol device is preferably an injected unipolar or bipolar direct current, also if applicable an injected DC voltage (1 mA, 2.5 mA, 5 mA, 10 mA, 20 mA, 1V, 10V). The entire measurement and transmission chain, from switchyard to control centre, should conform to accuracy class 1.

Meter readings

Metered values are fed to the telecontrol system as counting pulses or coded counter totals. The counting devices (primary coders) usually have 6 decades and BCD coding at the output. A floating input is required for the digital inputs to the telecontrol equipment.

Connecting conductors

Only insulated wires and cables may be used to connect the telecontrol equipment to the respective devices and plant components. Cables with conductors whose insulation is not moisture-proof must be suitably sealed at the ends if necessary. The wires and cables are best laid in underfloor gulleys or on trays or racks. If no gulley is available, the wiring to the apparatus must be protected with ducting, conduit, or similar. Earth wires and shielding must be connected by low-impedance joints to rails linked to the protective earth conductor. Signal lines must be routed away from power and control lines.

Power supply, premises

The telecontrol devices are usually connected to a secure power supply so that data can still be sent if the power in the switching installation should fail. This is generally a 60 V or 24 V battery (also 48 V in other countries), and occasionally a secure 220 V AC supply. The requirements for power supply for telecontrol devices are summarized in Main Section 1 of IEC 60870-2-1 or in DIN EN 60870-2-1, also in VDEW Manual Volume 1, Chap. 1.3.4. In addition, all of Chap. 5.1 “Secured power supply” of Volume 5 “Auxiliary Equipment” covers the recommendations.

In addition to electrical requirements, the premises in which telecontrol systems are installed and operated must also satisfy certain conditions.

The premises must be dry with a room temperature between 0 °C and + 55 °C, in large substations + 5 °C to + 40 °C. Generally the telecontrol equipment shall be able to operate without air-conditioning.

14.6 Load management, ripple control

14.6.1 Purpose of ripple control and load management

Ripple-control techniques enable power suppliers to control their widely dispersed consumers from a central point. The principal object of this is load management, i.e. the supply utility can influence the consumption of electricity by connecting and disconnecting suitable items such as storage heaters, hot water heaters, heat pumps etc.

Fig. 14-31 shows the uncontrolled load pattern between midnight and 3 p.m., the lines representing quarter-hourly averages.

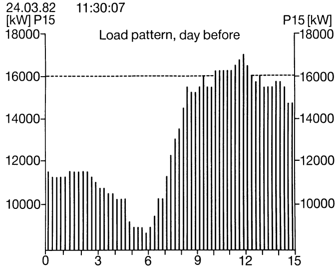


Fig. 14-31

Load pattern between midnight and 3 p.m., shown as quarter-hourly averages

Electricity consumption throughout the day can be made more even by connecting consumers when load is low- afternoons and at night – and disconnecting them at peak times – mornings, evenings. Power stations and transmission/distribution networks are loaded more uniformly. Depending on the network management policy, the system, comprising load management centre, ripple-control equipment (transmitter and coupling) and ripple-control receiver, can be operated on either the open- or closed-loop principle.

In the first case, the consumers are switched on and off according to a fixed timetable. In the second instance, the computer also measures the effective network load, calculates the trend in order to establish, in relation to a set value, the necessity for connection or disconnection, and chooses the consumers to be affected by any correction required. The system thus functions like a digital feedback circuit.

Although the principal aim is load management, the power utilities also use ripple control for other purposes, e.g. tariff control (peak rate, off-peak, special rates, etc.), controlling street lighting, neon signs or building illumination, and in special cases also fire and other alarms, and for operating switchgear where there are no telecontrol links.

14.6.2 Principle and components for ripple-control systems

Under the principle of ripple-control technology, signal voltages with frequencies of 150 to 1350 Hz must be injected briefly at a few places in the power supply system (50 or 60 Hz), in general in the substations of the distribution network, for the duration of the information transmission. The signals consist of a train of pulses in telegram form with an injection level of 1 to 5% of the system voltage. They can be received throughout the supply network, decoded by ripple-control receivers and converted into switching commands.

The telegrams have a distinctive pulse sequence for each kind of signal and are preceded by a starting pulse, while modern systems also have an interrupt pulse (Fig. 14-32).

The ripple control frequencies are determined in relation to the harmonics of the network frequency, which can assume values up to 8 %, and of neighbouring control frequencies. The middle frequencies of broad-band systems are arranged symmetrically at 33⅓ Hz intervals, for example, between the odd-numbered harmonics of the network frequency (e.g. 150 Hz, 250 Hz etc.), while those of narrow-band systems are inserted accordingly (Fig. 14-33).

Where electricity networks are inductively linked with each other through a higher order voltage level, certain regulations must be observed when operating a ripple-control system so that the ripple control facilities of adjacent supply utilities do not interfere with each other. In Germany, the Federation of German Electricity Companies (VDEW) in collaboration with the manufacturing companies has issued “Recommendations for frequency planning in ripple control installations”[1)]. These stipulate the audio frequencies and limit the residual audio frequency level in the higher-order network to a maximum of 0.3 % U_n.

1) Source: Ringbuch der Energiewirtschaft, Abschnitt 234, 3 bis 5

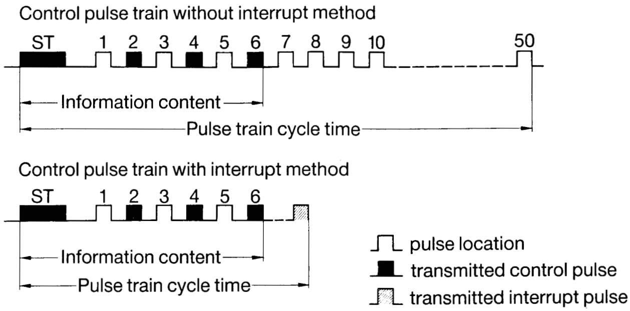


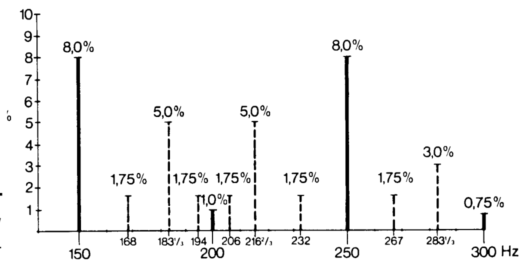
Fig. 14-32

Trains of control pulses with and without interrupt pulses
ST= starting pulse

Fig. 14-33

The harmonics of a 50 Hz network ———

Preferred ripple control frequencies - - - - - - - - -



With new installations, frequencies of 150 to 450 Hz (the bottom part of the permitted frequency band) are preferred because of better propagation conditions and a more uniform distribution of levels, i.e. reduced resonance effects due to the power transformers and compensating capacitors being connected in series. In older systems or in special cases, higher ripple-control frequencies (up to approx. 1600 Hz) may also occur.

The requisite audio frequency voltages and currents are injected into the supply network by static inverters followed by either series or parallel couplings.

Filtering out the audio frequency voltages, decoding the telegrams and then converting them into switching commands is done by ripple control receivers, which can be connected to the consumer's network (e.g. 220 V) wherever desired. Switching operations are generally controlled with the aid of ripple-control technology in low-voltage networks. If switching operations also need to be controlled in the distribution network in special cases, the ripple-control receiver is connected via voltage transformers.

The transmitter units are connected to the central load management computers by dedicated telecommunication channels, e.g. VFT channels.

New ways of operating ripple-control systems have become possible as the result of a new technique which allows the receivers to function as “remote-controlled timers”.

With this method, changeover times can be stored in the switching program or schedule, and then activated by the internal clock. The timetable can also be modified, adjusted according to temperature for instance, from the central command point.

It is then only necessary to send synchronizing signals from the command centre to the receivers, perhaps once a day, so that the receivers can continue to function independently.

The control system is thus unaffected by outside influences. In consequence, the central ripple control equipment and the power distribution network serving as the communication channel must no longer be 100 % available in order to be certain that the appropriate control action always takes place. A protocol for transmission with secured data now exists to accommodate this new approach.

The equipment of control centre, transmission equipment and receivers must therefore conform to the protocols both of conventional ripple control techniques and of data-protected transmission.

14.6.3 Ripple-control command centre

The process is controlled and monitored centrally from the load management unit.

Its main duties are:

- Execution of time- and event-based control actions according to defined time schedules.
- Display of receiver status.
- Continuous measurement of system load and calculation of load trends within a billing interval (e. g. 15 minutes).
- Determining power corrections and scheduling consumers for connection / disconnection.
- Control and monitoring of transmission equipment and of transmitted pulse trains by exchanging data with the substation controllers.
- Displaying tables and curves on video terminals.
- Printing out reports.
- The new technology also requires means of registering the time schedules stored in the decentralized receivers, supporting the second secured transmission protocol, etc.

14.6.4 Equipment for ripple control

Ripple-control systems are the equipment required for injecting the audiofrequency signals into the distribution network.

The entire system comprises an audiofrequency transmitter, which generates a constant output voltage of a defined frequency, the connection for injecting the audiofrequency voltages or currents into the distribution network at the required level values, e.g. 1.5 % of the rated system voltage, and the substation control devices. These controllers continually exchange data with the command centre, generate conventional or secured-data control telegrams, control and monitor the transmitter, keep check of the signal level and detect fault conditions. The station's status is regularly transmitted to the command centre.

Ripple-control transmitters

Ripple-control transmitters are static converters which rectify the network voltage (e. g. 50 Hz/380 V), and by triggering power semiconductors (thyristors or transistors) convert the DC voltage into audiofrequency voltages which are passed as a three-phase signal to the transmitter output.

Depending on the injection level, network structure and losses at the couplings, roughly 0.1 % of the network power is needed for the transmitters. When injecting into 12 kV and 24 kV networks, this means that outputs of 15 to 150 kVA are required and for injection into the 110 kV network outputs of 400 to 1500 kVA.

ABB RTS 400 transmitters of the S.P.I.D.E.R. LMS family have electronic current limitation and can be matched to the transient behaviour of different kinds of coupling. The same transmitters can be used for parallel and series couplings.

Coupling

The audio frequency generated by the ripple control transmitter must be superimposed over the distribution network at the required injection level and must be as loss-free as possible, and in reverse the system voltage and its harmonics must be dampened enough to prevent the transmitter from negatively influencing the process. This is the task of the coupling. A distinction is made between inductive (series) coupling and capacitive (parallel) coupling.

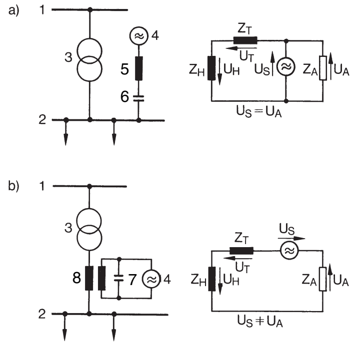
The choice of coupling technique depends on the impedance ratios due to the selected ripple control frequency, as these influence the signal and crosstalk levels. But important too, is the design of the station being fed with the injected signal, together with installation aspects (presence of high-voltage switchbays for parallel coupling) and operational considerations.

Fig. 14-34

Principle and equivalent diagrams of parallel and series coupling of ripple-control transmitters:
1 Higher-order network, 2 System being controlled, 3 Power transformer, 4 Ripple-control transmitter,

a) Parallel coupling
5 Coupling transformer
6 Coupling capacitor

b) Series coupling
7 Series capacitor
8 Instrument transformer / power transformer (for coupling)



Parallel coupling, Fig. 14-34a

Parallel coupling is preferred for higher audio frequencies. The voltage source is in this case in parallel with the ripple-control network Z_A (see equivalent diagram). The audio frequency current across the shunt of transformer Z_T and high-voltage network Z_H must however be provided in addition to the current from the ripple-controlled network.

Coupling to the 50 Hz network is effected by a series resonant circuit matched to the audio frequency. The capacitor is on the network side and almost the entire network voltage drop occurs here. The ratings of high-voltage capacitor and coupling transformer are governed by the audio frequency and the total network impedance (Z_A parallel to Z_T and Z_H) and the signal level.

Series coupling, Fig. 14-34b

Series coupling is used mainly with low frequencies where, as the equivalent diagram shows, the inductive voltage drop across transformer Z_T and high-voltage network Z_H is small compared to the network Z_A with ripple control .

The coupling is inductive, injection being via an instrument transformer or power transformer. The audio frequency transmitter output voltage is transformed to the required network injection level, e.g. 1.5 % of the system voltage, or 173 V with 20 kV/$\sqrt{3}$.

The 50 Hz network currents (instrument transformer) or 50 Hz network voltages (power transformer) are reflected back to the transmitter side. With instrument transformer injection, the transformed 50 Hz current is passed through a 50 Hz series circuit (see Fig. 14-34b), while with power transformer injection the 50 Hz reverse voltage is blocked capacitively. The instrument transformer method has the advantage over the power transformer of smaller network voltage drops, but is less suitable for higher throughput ratings.

14.6.5 Ripple control receivers

Most of the ripple control receivers installed at the consumer's end evaluate the pulse trains of a defined frequency superposed on the 50 Hz supply, and convert them into switching commands. According to IEC 1037, which covers ripple control receivers, the guaranteed functional voltage must be 0.5 % and the guaranteed non-functional voltage 0.3 %. This means that all receivers in the network must be sure to respond to audiofrequency voltages equal to or greater than 0.5 % of the network voltage, and refuse to respond to values equal to or less than 0.3 %.

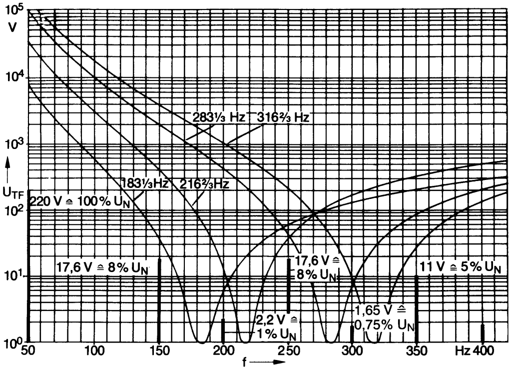


Fig. 14-35

Broad-band response characteristics of ripple-control receivers for common transmission frequencies, —— *Response characteristics of receivers,* ▬▬ *Harmonic voltage level of network, U_N Network voltage, f Audio frequency, U_{TF} Audio-frequency voltage*

The principal components of a conventional ripple control receiver are the filter module, the telegram decoding unit and the output relay stages.

The filter unit has a pass band optimized to the chosen control frequency, and must adequately suppress the unwanted frequencies, e.g. system harmonics or neighbouring control frequencies. A distinction is made between narrow-band and broad-band systems, see Fig. 14-35, i. e. filters with greater or lesser selectivity, corresponding to longer and shorter settling times, or telegrams of longer or shorter duration.

Receivers with digital filters show particularly good characteristics, suppressing system harmonics and frequencies very effectively at defined intervals of 8⅓ Hz for example, see Fig. 14-36.

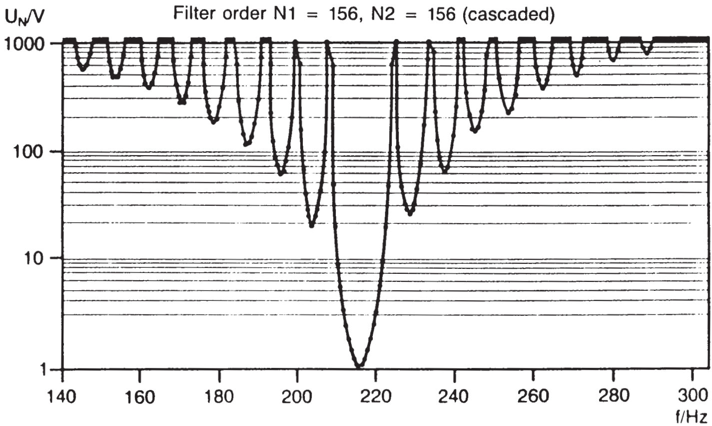


Fig. 14-36

Filter curve of a digital filter with optimum suppression of system harmonics and defined neighbouring frequencies at 8 ⅓ Hz intervals

The decoding units can evaluate telegrams generated by different ripple-control methods, e.g. Semagyr, Decabit, Ricontic, etc. Identification is by means of so-called system parameters. The telegrams are usually encoded in m-out-of-n or m-times-n codes.

New types of ripple control receiver are able to process in parallel both conventional telegrams and telegrams with data protection. This protocol is defined by a statement of block length, CRC of the block length, statements of function specification and address specification, CRC of the complete data block and an active end bit. The protocol is used for all kinds of purposes, such as transmission of switching commands, remote assignment of parameters (switching times, enabling/disabling of switching schedules, and so on) and sending synchronizing signals, etc.

Modern receivers can thus operate on the “distributed intelligence” principle and perform functions independently.

The devices are generally installed on meter panels or directly on the meter terminal cover with the use of a special terminal cover (see DIN 43861).

Technical requirements and test procedures are described in the VDE 0420 standard and must be observed.