SIPROTEC

Differential Protection
7UT6

V4.0

Manual

7UT613
7UT633
7UT635

C53000–G1176–C160–1

Siemens Aktiengesellschaft Buch-Nr. C53000–G1176–C160–1

Preface

Aim of This Manual

This manual describes the functions, operation, installation, and commissioning of the device. In particularly, you will find:

- Description of the device functions and setting facilities → Chapter 2,
- Instruction for installation and commissioning → Chapter 3,
- List of the technical data → Chapter 4,
- As well as a compilation of the most significant data for experienced users in the Appendix.

General information about design, configuration, and operation of SIPROTEC® devices are laid down in the SIPROTEC® 4 system manual, order no. E50417–H1176–C151.

Target Audience

Protection engineers, commissioning engineers, persons who are involved in setting, testing and service of protection, automation, and control devices, as well as operation personnel in electrical plants and power stations.

Applicability of this Manual

This manual is valid for SIPROTEC® 7UT6 differential protection; firmware version 4.0.

Indication of Conformity

This product complies with the directive of the Council of the European Communities on the approximation of the laws of the member states relating to electromagnetic compatibility (EMC Council Directive 89/336/EEC) and concerning electrical equipment for use within specified voltage limits (Low-voltage Directive 73/23/EEC).

This conformity has been proved by tests conducted by Siemens AG in accordance with Article 10 of the Council Directive in agreement with the generic standards EN 60000–6–2 and EN 50082 (for EMC directive) and the standards EN 60255-6 (for low-voltage directive).

This product is designed and manufactured for application in industrial environment.

The product conforms with the international standards of IEC 60255 and the German specification VDE 0435.

Further Standards

IEEE C37.90.*.

Additional Support

Should further information be desired or should particular problems arise which are not covered sufficiently for the purchaser's purpose, the matter should be referred to the local Siemens representative.

Training Courses

Individual course offerings may be found in our Training Catalogue, or questions may be directed to our training center. Please contact your Siemens representative.

Instructions and Warnings

The warnings and notes contained in this manual serve for your own safety and for an appropriate lifetime of the device. Please observe them!

The following terms are used:

DANGER
indicates that death, severe personal injury or substantial property damage will result if proper precautions are not taken.

Warning
indicates that death, severe personal injury or substantial property damage can result if proper precautions are not taken.

Caution
indicates that minor personal injury or property damage can result if proper precautions are not taken. This particularly applies to damage on or in the device itself and consequential damage thereof.

Note
indicates information about the device or respective part of the instruction manual which is essential to highlight.

Warning!

Hazardous voltages are present in this electrical equipment during operation. Non-observance of the safety rules can result in severe personal injury or property damage.

Only qualified personnel shall work on and around this equipment after becoming thoroughly familiar with all warnings and safety notices of this manual as well as with the applicable safety regulations.

The successful and safe operation of this device is dependent on proper handling, installation, operation, and maintenance by qualified personnel under observance of all warnings and hints contained in this manual.

In particular the general erection and safety regulations (e.g. IEC, DIN, VDE, EN or other national and international standards) regarding the correct use of hoisting gear must be observed. Non-observance can result in death, personal injury or substantial property damage.

QUALIFIED PERSONNEL

For the purpose of this instruction manual and product labels, a qualified person is one who is familiar with the installation, construction and operation of the equipment and the hazards involved. In addition, he has the following qualifications:

- Is trained and authorized to energize, de-energize, clear, ground and tag circuits and equipment in accordance with established safety practices.

- Is trained in the proper care and use of protective equipment in accordance with established safety practices.
- Is trained in rendering first aid.

Typographic and Symbol Conventions

The following text formats are used when literal information from the device or to the device appear in the text flow:

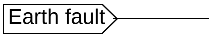
`Parameter names`, i.e. designators of configuration or function parameters which may appear word-for-word in the display of the device or on the screen of a personal computer (with operation software DIGSI®), are marked in bold letters of a monospace type style.

`Parameter options`, i.e. possible settings of text parameters, which may appear word-for-word in the display of the device or on the screen of a personal computer (with operation software DIGSI®), are written in italic style, additionally.

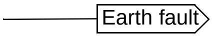
“`Annunciations`”, i.e. designators for information, which may be output by the relay or required from other devices or from the switch gear, are marked in a monospace type style in quotation marks.

Deviations may be permitted in drawings and tables when the type of designator can be obviously derived from the illustration.

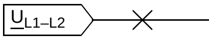
The following symbols are used in drawings:



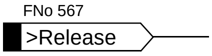
device-internal logical input signal



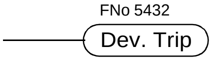
device-internal logical output signal



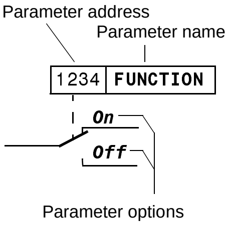
internal input signal of an analogue quantity



external binary input signal with function number Fno

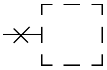


external binary output signal with function number Fno

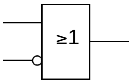


example of a parameter switch designated **`FUNCTION`** with the address 1234 and the possible settings ***`On`*** and ***`Off`***

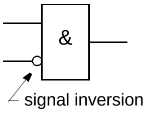
Besides these, graphical symbols are used according to IEC 60617–12 and IEC 60617–13 or similar. Some of the most frequently used are listed below:



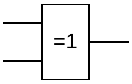
Input signal of an analogue quantity



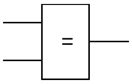
OR gate



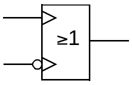
AND gate



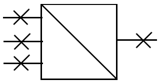
Exclusive-OR gate (antivalence): output is active, if only *one* of the inputs is active



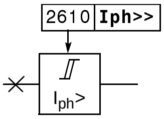
Coincidence gate (equivalence): output is active, if *both* input are active or inactive at the same time



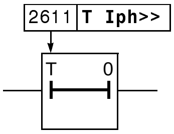
Dynamic inputs (edge-triggered)
above with positive, below with negative edge



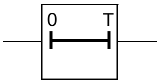
Formation of one analogue output signal from a number of analogue input signals (example: 3)



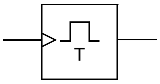
Limit stage with setting address and parameter designator (name)



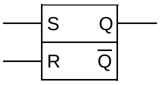
Timer (pickup delay T, example adjustable)
with setting address and parameter designator (name)



Timer (dropout delay T, example non-adjustable)



Dynamic triggered pulse timer T (monoflop)



Static memory (RS-flipflop) with setting input (S), resetting input (R), output (Q) and inverted output ($\overline{Q}$)

Furthermore, the graphic symbols according IEC 60617–12 and IEC 60617–13 or similar are used in most cases.

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Table of Contents

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Introduction

1

The SIPROTEC® 4 devices 7UT6 are introduced in this chapter. An overview of the devices is presented in their application, features, and scope of functions.

1.1 Overall Operation

The numerical differential protection device SIPROTEC® 7UT6 is equipped with a powerful microcomputer system. This provides fully numerical processing of all functions in the device, from the acquisition of the measured values up to the output of commands to the circuit breakers. Figure 1-1 shows the basic structure of a 7UT613, as an example for a three-winding power transformer.

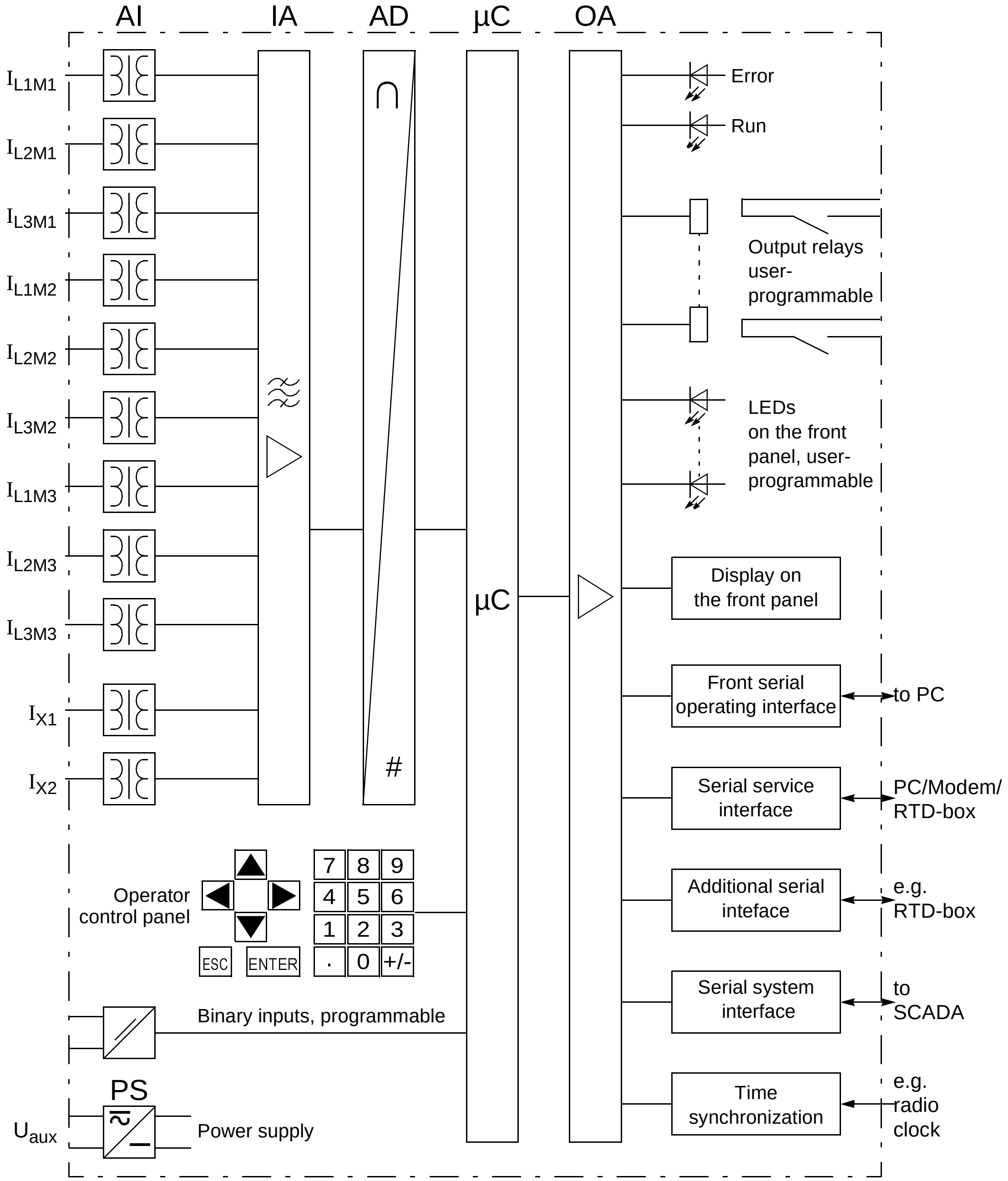


Figure 1-1 Hardware structure of the numerical differential protection 7UT6 — Example of a 7UT613 for a three-winding transformer with 3 measuring locations M1, M2 and M3, with 2 single-phase auxiliary inputs X1 and X2

Analog Inputs

The analog inputs “AI” transform the currents and voltages derived from the instrument transformers and match them to the internal signal levels for processing in the device. Depending on the version, the device comprises 12 current inputs (7UT613 and 7UT633) up to 16 current inputs (7UT635). Three current inputs are provided for the input of the phase currents at each end (= measurement location) of a three-phase protected object, further single-phase inputs (auxiliary inputs I_X) may be used for any desired current, e.g. the earth current measured between the starpoint of a transformer winding and ground or a further single-phase measured current. One or two inputs may be designed for highly sensitive current detection thus allowing, for example, the detection of small tank leakage currents of power transformers or reactors, or — with an external series resistor — processing of a voltage (e.g. for high-impedance unit protection).

The versions 7UT613 and 7UT633 can be provided with 4 voltage inputs. 3 of them may be connected to the phase-to-earth voltages. A further, single-phase, voltage input (auxiliary input U_4) is suitable for connection of a single-phase voltage, which may be the displacement voltage (open delta) or any other voltage as desired. Of course, the differential protection does not require any measured voltages. However, voltages can be connected to the device in order to use the integrated overexcitation protection which calculates the induction level in power transformers or shunt reactors. Voltage connection allows also to measure, display, transmit, and supervise voltages and further quantities derived from these, like power, power factor, induction.

The analog signals are then routed to the input amplifier group “IA”.

The input amplifier group “IA” ensures a high impedance termination for the measured signals. It contains filters which are optimized in terms of band width and speed with regard to the signal processing.

The analog/digital converter group “AD” provides a multiplexer, analog/digital converters and memory modules for the data transfer to the microcomputer system “µC”.

Microcomputer System

Apart from processing the measured values, the microcomputer system “µC” also executes the actual protection and control functions. In particular, the following are included:

- Filtering and conditioning of measured signals.
- Continuous supervision of measured signals.
- Monitoring of the pickup conditions of the individual protection functions.
- Conditioning of the measured signals, i.e. conversion of currents according to the connection group of the protected power transformer (when used for transformer differential protection) and matching of the current amplitudes.
- Formation of the differential and restraint quantities.
- Frequency analysis of the phase currents and restraint quantities.
- Calculation of the RMS-values of the currents for thermal replica and scanning of the temperature rise of the protected object.
- Interrogation of threshold values and time sequences.
- Processing of signals for the logic functions.
- Processing of user-definable logical functions.
- Reaching trip command decisions.

- Checking an issuing commands for switching devices.
- Storage of fault messages, fault annunciations as well as oscillographic fault data for system fault analysis.
- Calculation and display/indication of measured values and further values derived from these.
- Operating system and related function management such as e.g. data recording, real time clock, communication, interfaces etc.

The information is provided via output amplifier “OA”.

Binary Inputs and Outputs

The microcomputer system obtains external information through binary inputs such as remote resetting or blocking commands for protective elements. The “µC” issues information to external equipment via the output contacts. These outputs include, in particular, trip commands to circuit breakers and signals for remote annunciation of important events and conditions.

Front Elements

Light emitting diodes (LEDs) and a display screen (LCD) on the front panel provide information such as targets, measured values, messages related to events or faults, status, and functional status of the 7UT6.

Integrated control and numeric keys in conjunction with the LCD facilitate local interaction with the 7UT6. All information of the device can be accessed using the integrated control and numeric keys. The information includes protective and control settings, operating and fault messages, and measured values (see also SIPROTEC® System Manual, order-no. E50417–H1176–C151). The settings can be modified as are discussed in Chapter 2.

Using integrated switchgear control functions, the control of circuit breakers and other equipment is possible from the 7UT6 front panel.

The versions 7UT61 provide a 4-line alphanumerical display on the front plate, the versions 7UT63 have a graphical display. The latter also contain elements for local control and key-operated switches.

Serial Interfaces

A serial **operator** interface (PC port) on the front panel is provided for local communications with the 7UT6 through a personal computer. Convenient operation of all functions of the device is possible using the SIPROTEC® 4 operating program DIGSI®.

A separate serial **service** interface is provided for remote communications via a modem, or local communications via a substation master computer that is permanently connected to the 7UT6. DIGSI® is required.

All 7UT6 data can be transferred to a central master or main control system through the serial **system** (SCADA) interface. Various protocols and physical arrangements are available for this interface to suit the particular application.

Another interface is provided for the **time synchronization** of the internal clock via external synchronization sources.

Via additional interface modules further communication protocols may be created.

The **service** interface may be used, alternatively, for connection of a RTD-box in order to process external temperatures, e.g. in overload protection. Optionally, an **additional** interface can be available for the RTD-box.

Power Supply

The 7UT6 can be supplied with any of the common power supply voltages. Transient dips of the supply voltage which may occur during short-circuit in the power supply system, are bridged by a capacitor (see Technical Data, Subsection 4.1.2).

1.2 Applications

The numerical differential protection system 7UT6 is a fast and selective short-circuit protection for transformers of all voltage levels, for rotating machines, for series and shunt reactors, or for short lines and mini-busbars with 2 to 5 feeders (dependent on version). It can also be used as a single-phase protection for busbars with up to 9 or 12 feeders (dependent on version). The individual application can be configured, which ensures optimum matching to the protected object.

The device is also suited for two-phase connection and for use in traction systems with 16,7 Hz rated frequency.

A major advantage of the differential protection principle is the instantaneous tripping in the event of a short-circuit at any point within the entire protected zone. The current transformers limit the protected zone at the ends towards the network. This rigid limit is the reason why the differential protection scheme shows such an ideal selectivity.

For use as transformer protection, the device is normally connected to the current transformer sets which separate the power transformer from the remaining power system. The phase displacement and the interlinkage of the currents due to the winding connection of the transformer are matched in the device by calculation algorithms. The earthing conditions of the starpoint(s) can be adapted to the user's requirements and are automatically considered in the matching algorithms. Furthermore, it is possible to combine the currents flowing via different current transformer sets to the same winding of the power transformer by internal calculation.

For use as generator or motor protection, the currents in the starpoint leads of the machine and at its terminals are compared. Similar applies for series reactors.

Short lines or mini-busbars with 3 or up to 5 ends or feeders (dependent on version) can be protected either. "Short" means that the connections from the CTs to the device do not cause an impermissible burden for the current transformers.

For transformers, generators, motors, or shunt reactors with earthed starpoint, the current between the starpoint and earth can be measured and used for highly sensitive earth fault protection.

The 9 or 12 standard current inputs of the device (dependent on version) allow for a single-phase protection for busbars with up to 9 or 12 feeders. One 7UT6 is used per phase in this case. Alternatively, (external) summation transformers can be installed in order to allow a busbar protection for up to 6 or 12 feeders with *one* single 7UT6 relay.

If not all analog inputs are needed for the differential protection of the protected object, the remaining inputs can be used for different, independent protection or measurement tasks. If, for example, a 7UT635 (with 5 three-phase current inputs) is intended for protection of a three-winding power transformer, the 2 remaining sets of current inputs can be used for time overcurrent protection of another object, e.g. an auxiliaries system circuit.

One or two additional current inputs can be designed for very high sensitivity. This may be used e.g. for detection of small leakage currents between the tank of transformers or reactors and earth thus recognizing even high-resistance faults. Voltage measurement is also possible with an external dropper resistor.

For transformers (including auto-transformers), generators, and shunt reactors, a high-impedance unit protection system can be formed using 7UT6. In this case, the currents of all current transformers (of equal design) at the ends of the protected zone feed a common (external) high-ohmic resistor the current of which is measured using a high-sensitive current input of 7UT6.

The device provides backup time overcurrent protection functions for all types of protected objects. The functions can be enabled for any side or measuring location.

A thermal overload protection is available for any type of machine. This can be complemented by the evaluation of the hot-spot temperature and ageing rate, using an external RTD-box to allow for the inclusion of the oil temperature.

An unbalanced load protection enables the detection of unsymmetrical currents. Phase failures and negative sequence currents which are especially dangerous for rotating machines can thus be detected.

The versions with measured voltage inputs provide an overexcitation protection for the detection of increased induction in objects with shunt reactance like power transformers or power shunt reactors. This protection monitors the ratio U/f which is proportional to the magnetic flux Φ or the induction B in the iron core. It enables to detect imminent iron saturation which may occur in power stations, e.g. after (full) load shedding or decrease in frequency.

A version for 16,7 Hz two-phase application is available for traction supply (transformers or generators) which provides all functions suited for this application (differential protection, restricted earth fault protection, overcurrent protection, overload protection).

A circuit breaker failure protection checks the reaction of one circuit breaker after a trip command. It can be assigned to any of the sides or measuring locations of a protected object.

1.3 Features

- Powerful 32-bit microprocessor system.
- Complete numerical processing of measured values and control, from sampling and digitizing of the analog input values up to tripping commands to the circuit breakers.
- Complete galvanic and reliable separation between internal processing circuits of the 7UT6 and external measurement, control, and power supply circuits because of the design of the analog input transducers, binary inputs and outputs, and the DC/DC or AC/DC converters.
- Suited for power transformers, generators, motors, reactors, or smaller busbar arrangements; applicable also for short lines with multiple terminals and power transformers with multiple windings.
- Simple device operation using the integrated operator panel or a connected personal computer running DIGSI®.

Differential Protection for Transformers

- Current restraint tripping characteristic.
- Stabilized against in-rush currents using the second harmonic.
- Stabilized against transient and steady-state error currents caused e.g. by overexcitation of transformers, using a further harmonic: optionally the third or fifth harmonic.
- Insensitive against DC offset currents and current transformer saturation.
- High stability also for different current transformer saturation.
- High-speed instantaneous trip on high-current transformer faults.
- Independent of the conditioning of the starpoint(s) of the power transformer.
- High earth-fault sensitivity by processing of the starpoint current of an earthed transformer winding.
- Integrated matching of the transformer connection group.
- Integrated matching of the transformation ratio including different rated currents of the transformer windings.

Differential Protection for Generators and Motors

- Current restraint tripping characteristic.
- High sensitivity.
- Short tripping time.
- Insensitive against DC offset currents and current transformer saturation.
- High stability also for different current transformer saturation.
- Independent of the conditioning of the starpoint.

Differential Protection for Mini-Busbars and Short Lines

- Current restraint tripping characteristic.
- Short tripping time.
- Insensitive against DC offset currents and current transformer saturation.

- High stability also for different current transformer saturation.
- Monitoring of the current connections with operation currents.

Busbar Protection

- Single-phase differential protection for up to 6 or 9 or 12 feeders (depending on version and connection facilities) of a busbar.
- Either one relay per phase or one relay connected via interposed summation current transformers.
- Current restraint tripping characteristic.
- Short tripping time.
- Insensitive against DC offset currents and current transformer saturation.
- High stability also for different current transformer saturation.
- Monitoring of the current connections with operation currents.

Restricted Earth Fault Protection

- Earth fault protection for earthed transformer windings, generators, motors, shunt reactors, or starpoint formers (neutral reactors).
- Short tripping time.
- High sensitivity for earth faults within the protected zone.
- High stability against external earth faults using the magnitude and phase relationship of through-flowing earth current.

High-Impedance Unit Protection

- Highly sensitive fault current detection using a common (external) burden resistor.
- Short tripping time.
- Insensitive against DC offset currents and current transformer saturation.
- High stability with optimum matching.
- Suitable for earth fault detection on generators, motors, shunt reactors, and transformers, including auto-transformers, with or without earthed starpoint.
- Suitable for any voltage measurement (via the resistor current) for application of high-impedance unit protection.

Tank Leakage Protection

- For power transformers or reactors the tank of which is installed isolated or high resistive against ground.
- Monitoring of the leakage current flowing between the tank and ground.
- Can be connected via a “normal” current input of the device or the special highly sensitive current input (3 mA smallest setting).

Time Overcurrent Protection for Phase Currents and Residual Current

- Two definite time delayed overcurrent stages for each of the phase currents and the residual (threefold zero sequence) current can be assigned to any of the sides of the protected object or any measuring location.
- Additionally, one inverse time delayed overcurrent stage for each of the phase currents and the residual current.

- Selection of various inverse time characteristics of different standards is possible, alternatively a user defined characteristic can be specified.
- All stages can be combined as desired; different characteristics can be selected for phase currents on the one hand and residual current on the other.
- External blocking facility for any desired stage (e.g. for reverse interlocking).
- Instantaneous trip when switching on a dead fault with any desired stage.
- Inrush restraint using the second harmonic of the measured currents.
- Dynamic switchover of the time overcurrent parameters, e.g. during cold-load start-up of the power plant.

Time Overcurrent Protection for Earth Current

- Two definite time delayed overcurrent stages for the earth current connected at a 1-phase current input (e.g. current between starpoint and earth).
- Additionally, one inverse time delayed overcurrent stage for the earth current.
- Selection of various inverse time characteristics of different standards is possible, alternatively a user defined characteristic can be specified.
- The stages can be combined as desired.
- External blocking facility for any desired stage (e.g. for reverse interlocking).
- Instantaneous trip when switching on a dead fault with any desired stage.
- Inrush restraint using the second harmonic of the measured current.
- Dynamic switchover of the time overcurrent parameters, e.g. during cold-load start-up of the power plant.

Single-Phase Time Overcurrent Protection

- Two definite time delayed overcurrent stages can be combined as desired.
- For any desired single-phase overcurrent detection.
- Can be assigned to a “normal” current input or a highly sensitive current input.
- Suitable for detection of very small current (e.g. for high-impedance unit protection or tank leakage protection, see above).
- Suitable for detection of any desired AC voltage using an external series resistor (e.g. for high-impedance unit protection, see above).
- External blocking facility for any desired stage.

Unbalanced Load Protection

- Processing of the negative sequence current of any desired side of the protected object or 3-phase measuring location.
- Two definite time delayed negative sequence current stages and one additional inverse time delayed negative sequence current stage.
- Selection of various inverse time characteristics of different standards is possible, alternatively a user defined characteristic can be specified.
- The stages can be combined as desired.

Thermal Overload Protection

- Thermal replica of current-initiated heat losses.
- True RMS current calculation.

- Can be assigned to any desired side of the protected object.
- Adjustable thermal warning stage.
- Adjustable current warning stage.
- Alternatively evaluation of the hot-spot temperature according to IEC 60354 with calculation of the reserve power and ageing rate (by means of external resistance temperature detector via RTD-box).

Overexcitation Protection

Evaluation of the voltage/frequency ratio U/f which is proportional to the flux or induction of the shunt reactance of a power transformer or power shunt reactor.

Adjustable warning and tripping stage (with definite time lag).

Standard inverse time tripping characteristics or user defined characteristic with replica of the thermal stress.

Circuit Breaker Failure Protection

- Monitoring of current flow through each breaker pole of the assigned side of the protected object.
- Monitoring of the breaker position possible (if breaker auxiliary contacts or feedback information available).
- Initiation by each of the internal protection functions.
- Initiation by external trip functions possible via binary input.
- Single-stage or two-stage delay.
- Short reset and overshoot times.

External Direct Trip

- Tripping of either circuit breaker by an external device via binary inputs.
- Inclusion of external commands into the internal processing of information and trip commands.
- With or without trip time delay.

Processing of External Information

- Combining of external signals (user defined information) into the internal information processing.
- Pre-defined transformer annunciations for Buchholz protection and oil gassing.
- Transmission to output relays, LEDs, and via the serial system interface to a central computer station.

User Defined Logic Functions (CFC)

- Freely programmable linkage between internal and external signals for the implementation of user defined logic functions.
- All usual logic functions.
- Time delays and measured value set point interrogation.

Commissioning; Operation

- Disconnection of a single side or measuring location for maintenance work; the side or location concerned is excluded from processing by the differential protection system, without affecting the rest of the protection system.
- Comprehensive support facilities for operation and commissioning.

- Indication of all measured values, amplitudes and phase relation.
- Indication of the calculated differential and restraint currents.
- Integrated help tools can be visualized by means of a standard browser: Phasor diagrams of all currents of all sides an measuring locations of the protected object are displayed as a graph.
- Connection and direction checks as well as interface check.

Monitoring Functions

- Monitoring of the internal measuring circuits, the auxiliary voltage supply, as well as the hard- and software, resulting in increased reliability.
- Supervision of the current transformer secondary circuits by means of symmetry and rotation checks.
- Supervision of the voltage transformer secondary circuits (if available) by means of symmetry, sum, and rotation checks.
- Check of the consistency of protection settings as to the protected objects and the assignment of the current inputs: blocking of protection functions in case of inconsistent settings which could lead to a malfunction.
- Trip circuit supervision is possible.
- Broken wire supervision for the secondary CT circuits with fast phase segregated blocking of the differential protection system and unbalanced load protection in order to avoid malfunction.

Further Functions

- Battery buffered real time clock, which may be sychronized via a synchronization signal (e.g. DCF77, IRIG B via satellite receiver), binary input or system interface.
- Continuous calculation and display of measured quantities on the front of the device. Indication of measured quantities of all sides of the protected object.
- Fault event memory (trip log) for the last 8 network faults (faults in the power system), with real time stamps (ms-resolution).
- Fault recording memory and data transfer for analog and user configurable binary signal traces with a maximum time range of approximately 5 s.
- Switching statistics: counter with the trip commands issued by the device, as well as record of the fault current and accumulation of the interrupted fault currents;
- Communication with central control and data storage equipment via serial interfaces through the choice of data cable, modem, or optical fibres, as an option. Different transmission protocols are available.

■

Functions

2

This chapter describes the numerous functions available on the SIPROTEC® 7UT6 relay. The setting options for each function are explained, including instructions to determine setting values and formulae where required.

2.1 General

A few seconds after the device is switched on, the default display appears in the LCD. In the 7UT6 measured values are displayed.

Configuration settings (Subsection 2.1.1) can be entered using a PC and the software program DIGSI® and transferred via the operating interface on the device front, or via the serial service interface. Operation via DIGSI® is described in the SIPROTEC® 4 System Manual, order no. E50417–H1176–C151. Entry of password No. 7 (for setting modification) is required to modify configuration settings. Without the password, the settings may be read, but cannot be modified and transmitted to the device.

The function parameters, i.e. settings of function options, threshold values, etc., can be entered via the keypad and display on the front of the device, or by means of a personal computer connected to the front or service interface of the device running the DIGSI® software package. The level 5 password (individual parameters) is required.

In this general section, you make the basic decisions about the correct interaction between your power system, the measuring locations (CTs), the analog connections and the protection function of the device. Because of the comprehensive range of features provided by the devices of the 7UT6 family, this section is quite extensive. In fact, the parameters discussed in it provide the device with the fullest possible information on the system to be protected, including the measuring locations (i.e. the current and voltage transformers) and the settings for those protection functions which will be active in the device.

In a first step (Subsection 2.1.1) you specify which type of system element you want to protect, since the scope of additional features offered varies depending on the type of main protected object. You also choose the protection functions that you want to use for the intended application; part of the functions implemented in the device may be unnecessary, useless or even impossible in the concrete case.

In a next step (Subsection 2.1.2) you describe the topology of the protected object. i.e. the arrangement of the protected object, its sides (windings for transformers, sides for generators/motors, ends for lines, feeders for busbars), and the measuring locations which will provide the respective measured values.

After entering some general power system data (frequency, phase sequence), you inform the device of the properties of the main protected object; this is described in Subsection 2.1.3. Object properties include the nominal data and (in the case of transformers) the starpoint conditioning, vector group and, where applicable, the auto-connected winding.

Subsection 2.1.3 also deals with the CT data which must be set to ensure that the currents acquired at the various measuring locations are evaluated in the device with the correct scale factor.

The above information is sufficient to describe the protected object to the device's main protection function, i.e. the differential protection. For the other protection functions, you select in Subsection 2.1.4 which measured values will be processed by them and in which way.

The circuit breaker data are set in Subsection 2.1.5.

Subsection 2.1.8 describes setting groups and how they are used.

Finally, Subsection 2.1.9 contains some general data which are independent of the protection functions.

2.1.1 Configuration of the Scope of Functions

General

The 7UT6 relay contains a series of protective and additional functions. The scope of hardware and firmware is matched to these functions. Furthermore, commands (control actions) can be suited to individual needs of the protected object. In addition, individual functions may be enabled or disabled during configuration, or interaction between functions may be adjusted. Functions not to be used in the actual device can thus be masked out.

Example for the configuration of the scope of functions:
7UT6 devices should be intended to be used for busbars and transformers. Overload protection should only be applied on transformers. If the device is used for busbars this function is set to ***Disabled*** and if used for transformers this function is set to ***Enabled***.

The available function are configured ***Enabled*** or ***Disabled***. For various functions, a choice may be presented between several options which are explained below.

Functions configured as ***Disabled*** are not processed by the 7UT6. There are no messages, and associated settings (functions, limit values, etc.) are not displayed during detailed settings.

Note:

Available functions and default settings are depending on the ordering code of the relay (see ordering code in the Appendix A.1 for details).

Determination of Functional Scope

Configuration settings may be entered using a PC and the software program DIGSI® and transferred via the operating interface on the device front, or via the serial service interface. Operation via DIGSI® is described in the SIPROTEC® 4 system manual, order number E50417–H1176–C151 (Section 5.3).

Entry of password No. 7 (for setting modification) is required to modify configuration settings. Without the password, the settings may be read, but cannot be modified and transmitted to the device.

Special Cases

Many of the settings are self-explanatory. The special cases are described below. Appendix A.4 includes a list of the functions with the suitable protected objects.

If the setting group change-over function is to be used, the setting in address 103 **Grp Chge OPTION** must be set to ***Enabled***. In this case, it is possible to apply up to four different groups of settings for the function parameters. During normal operation, a convenient and fast switch-over between these setting groups is possible. The setting ***Disabled*** implies that only one function parameter setting group can be applied and used.

The definition of the protected object (address 105 **PROT. OBJECT**) is decisive for the applicable setting parameters and for the assignment of the inputs and outputs of the device to the protection functions. This object is defined as the main protected object which is intended to be protected by the differential protection. It should be mentioned here that further parts of the power plant can be protected by other part functions if not all measured current inputs of the device are necessary for the differential protection of the main protected object.

The settings for the protected object and the following protection functions are independent of the way how the protection function act on the protected object and which measuring locations (current transformers) are available. This latter topic is covered by Subsection 2.1.2. “Topology of the Protected Object (Power System Data 1)”.

- For normal power transformers with isolated windings set **PROT. OBJECT** = ***3 phase transf.*** regardless of the number of windings, the connection group (winding interconnection) and the earthing conditions of the starpoint(s). This is even valid if a neutral earthing reactor is situated within the protected zone (cf. Figure 2-29, page 88). If the differential protection shall cover a generator or motor and a block connected power transformer (also with more than 2 windings), the protected object is declared as ***3 phase transf.***, too.
- The option ***Autotransf.*** is selected for auto-transformers, regardless whether the auto-transformer provides one or more further isolated windings. This option is also applicable for shunt reactors if current transformers are installed at both sides of the connection points (cf. Figure 2-35 right graph, page 92).
- For a ***1 phase transf.***, the phase input L2 is not connected. This option is suited especially to single-phase power transformers with 16,7 Hz (traction transformers).
- Equal setting is valid for generators and motors. The option ***Generator/Motor*** also applies for series reactors and shunt reactors which latter are equipped with current transformers at both terminal sides.
- Select the option ***3ph Busbar*** if the device is used for mini-busbars. The maximum number of feeders is determined by the number of three-phase measurement inputs of the device. 7UT613 and 7UT633 provide 3, 7UT635 allows 5 three-phase measurement inputs. This setting applies also for short lines which are terminated by sets of current transformers at each terminal. “Short” means that the current transformer leads between the CTs and the device do not form an impermissible burden for the CTs.
- The device can be used as single-phase differential protection for busbars, either using one device per phase or one device connected via external summation CTs. Select the option ***1ph Busbar*** in this case. The maximum number of feeders is determined by the number of single-phase measurement inputs of the device (7UT613 and 7UT633 allow 6 or 9, 7UT635 allows 12 single-phase measurement inputs for this purpose).

Note that the restricted earth fault protection (address 113 **REF PROT.**) cannot be applied for busbars or auto-transformers (address 105 **PROT. OBJECT** = ***3ph Busbar*** or ***1ph Busbar*** or ***Autotransf.***).

To select the type of characteristics according to which the phase overcurrent time protection is to operate use address 120 **DMT/IDMT Phase**. If it is only used as definite time overcurrent protection (DMT), set ***Definite Time***. In addition to the definite time overcurrent protection an inverse time overcurrent protection may be configured, if required. The latter operates according to an IEC characteristic (***TOC IEC***), to an ANSI characteristic (***TOC ANSI***) or to a user-defined characteristic. In the latter case the trip time characteristic (***User Defined PU***) or both the trip time characteristic and the reset time characteristic (***User def. Reset***) are configured. For the characteristics please refer to the Technical Data (Section 4.4).

The type of characteristics used for the zero sequence (residual) overcurrent time protection can be set in address 122 **DMT/IDMT 3I0**. The same options are available as for the phase overcurrent protection. However, for zero sequence overcurrent protection the settings may be different from the settings selected for phase overcurrent protection. This protection function always acquires the residual current $3I_0$, i.e. the sum of the corresponding phase currents, of the supervised measuring location which may be different from that of the phase overcurrent protection. Note that the zero sequence overcurrent protection is not possible on single-phase protected objects (address 105 **PROT. OBJECT** = ***1 phase transf.*** or ***1ph Busbar***).

There is another earth current time overcurrent protection which is independent from the before-described zero sequence overcurrent protection. This protection, to be configured in address 124 **DMT/IDMT Earth**, acquires the current connected to a single-phase current measuring input. In most cases, it is the starpoint current of an earthed starpoint (for transformers, generators, motors or shunt reactors). For this protection you may select one of the characteristic types, the same way as for the phase time overcurrent protection, no matter which characteristic has been selected for the latter.

A single-phase definite-time overcurrent protection **DMT 1PHASE** for different user-requirements is available in address 127. This protection function is very well suited e.g. for highly sensitive tank leakage protection (see also Subsection 2.7.3) or high-impedance unit protection (see also Subsection 2.7.2). A high-sensitivity current input can be used for this purpose (cf. Subsection 2.1.2 under header margin “High-Sensitivity Auxiliary 1-phase Measuring Locations”.

In address 140 **UNBALANCE LOAD** the unbalanced load protection supervises the negative sequence current. The trip time characteristics can be set to definite time (***Definite Time***), additionally operate according to an IEC characteristic (***TOC IEC***) or to an ANSI characteristic (***TOC ANSI***). Note that this protection is not applicable on single-phase protected objects (address 105 **PROT. OBJECT** = ***1 phase transf.*** or ***1ph Busbar***).

In address 142 **THERM. OVERLOAD** you can select between two methods of overload detection:

- Overload protection with thermal replica according to IEC 60255-8 (***thermal replica***),
- Overload protection with calculation of hot-spot temperature and the aging rate according to IEC 60354 (***IEC354***).

The first method is characterized by its easy handling and a low number of setting values. The second method requires detailed knowledge about the protected object, the environment it is located in and cooling. The latter one is useful for transformers with incorporated temperature detectors (RTD = Resistance Temperature Detector). For more information see also Section 2.9. Note that the overload protection is not applicable for single-phase busbar protection (address 105 **PROT. OBJECT** = ***1ph Busbar***).

If overload protection with calculation of hot-spot temperature is used according to IEC 60354 (address 142 **THERM. OVERLOAD** = ***IEC354***), at least one RTD-box must be connected to the service interface or additional interface. The RTD-box informs the device about the temperature of the coolant. The interface is set in address 190 **RTD-BOX INPUT**. The possible interfaces are dependent on the version of 7UT6 (cf. Ordering Information and Accessories in Appendix A). ***Port C*** is available in all versions. The number of resistance temperature detectors and the way the RTD-box(es) transmit information is set in address 191 **RTD CONNECTION**: ***6 RTD simplex*** or ***6 RTD HDX*** (with 1 RTD-box) or ***12 RTD HDX*** (with 2 RTD-boxes). This must comply with the settings at the RTD-box(es).

Note: The temperature measuring point relevant for the calculation of the hot-spot temperature must be fed via the first RTD-box.

Note that the overexcitation protection (address 143 **OVEREXC. PROT.**) requires measured voltage connections. Furthermore, this protection is not applicable for single-phase busbar protection (address 105 **PROT. OBJECT** = ***1ph Busbar***).

Note that the circuit breaker failure protection set in address 170 **BREAKER FAILURE** and the measured value supervision in address 181 **M.V. SUPERV** are not applicable for single-phase busbar protection (address 105 **PROT. OBJECT** = ***1ph Busbar***).

For the trip circuit supervision select in address 182 **Trip Cir. Sup.** whether it shall operate with 2 (***2 Binary Inputs***) or only 1 binary input (***1 Binary Input***). The inputs have to be isolated.

2.1.1.1 Setting Overview

Note: Depending on the type and version of the device it is possible that addresses are missing or have different default settings.

Addr.	Setting Title	Setting Options	Default Setting	Comments
103	Grp Chge OPTION	Disabled Enabled	Disabled	Setting Group Change Option
105	PROT. OBJECT	3 phase Transformer 1 phase Transformer Autotransformer Generator/Motor 3 phase Busbar 1 phase Busbar	3 phase Transformer	Protection Object
112	DIFF. PROT.	Disabled Enabled	Enabled	Differential Protection
113	REF PROT.	Disabled Enabled	Disabled	Restricted earth fault protection
117	COLDLOAD PICKUP	Disabled Enabled	Disabled	Cold Load Pickup
120	DMT/IDMT Phase	Disabled Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Disabled	DMT / IDMT Phase
122	DMT/IDMT 3I0	Disabled Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Disabled	DMT / IDMT 3I0

Addr.	Setting Title	Setting Options	Default Setting	Comments
124	DMT/IDMT Earth	Disabled Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Disabled	DMT / IDMT Earth
127	DMT 1PHASE	Disabled Enabled	Disabled	DMT 1Phase
140	UNBALANCE LOAD	Disabled Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI	Disabled	Unbalance Load (Negative Sequence)
142	THERM. OVERLOAD	Disabled using a thermal replica according IEC354	Disabled	Thermal Overload Protection
143	OVEREXC. PROT.	Disabled Enabled	Disabled	Overexcitation Protection (U/f)
170	BREAKER FAILURE	Disabled Enabled	Disabled	Breaker Failure Protection
180	DISCON.MEAS.LOC	Disabled Enabled	Disabled	Disconnect measurment location
181	M.V. SUPERV	Disabled Enabled	Enabled	Measured Values Supervision
182	Trip Cir. Sup.	Disabled with 2 Binary Inputs with 1 Binary Input	Disabled	Trip Circuit Supervision
186	EXT. TRIP 1	Disabled Enabled	Disabled	External Trip Function 1
187	EXT. TRIP 2	Disabled Enabled	Disabled	External Trip Function 2
190	RTD-BOX INPUT	Disabled Port C Port D	Disabled	External Temperature Input
191	RTD CONNECTION	6 RTD simplex operation 6 RTD half duplex operation 12 RTD half duplex operation	6 RTD simplex operation	Ext. Temperature Input Connection Type

2.1.2 Topology of the Protected Object (Power System Data 1)

Measured Value Inputs

The devices of the 7UT6-family comprise various types with different function facilities and different hardware scope which latter determines the number of available analog inputs. Dependent on the ordering type, the following analog inputs are provided:

Table 2-1 Analog measuring inputs

Type	For 3-phase Protected Objects 1)			For Busbar 1-phase			Voltage 3-phase	Voltage 1-phase
	Current 3-phase 1)	Current (auxiliary)		Current 1-phase	Current (auxiliary)			
		1-phase	sensitive 3)		1-phase	sensitive 3)		
7UT613	3	3	1	9 2)	3	1	1	1
7UT633	3	3	1	9 2)	3	1	1	1
7UT635	5	1	1	—	—	—	—	—
	4	4	2	12	4	2	—	—

1) also for single-phase power transformers applicable
2) with interposed summation CTs (I_N = 0.1 A) max. 6 inputs
3) reconnectable, included in the number of 1-phase inputs

Terminology

The large variety of connection facilities of the device requires to create an exact image of the topology of the protected object. The device must be informed in which way the measured quantities derived from the measured value inputs of the device have to be processed by the different protection functions.

The topology of the protected object comprises the totality of all information: how the protected object (or several objects) is arranged, which current transformer sets supply the currents flowing into the protected object(s), and which voltages (if available) are measured at which location of the protected object. Thus, the result of the topological consideration is a complete replica of the protected object(s) with all available measuring locations. It will be decided on a later stage (Subsection 2.1.4) which measured quantities should be used by which protection functions.

Distinction must be made between the main protected object and further objects: The main protected object is that to which the main protection function, i.e. the differential protection, is applied. This is the power transformer, generator, motor, etc. as stated under address 105 **PROT. OBJECT**.

The main protected object has 2 or more sides. The sides of a power transformer are the winding terminals, a generator or motor is terminated by the terminal side and the starpoint side. In case of combined objects like generators and transformers in unit connection the sides are the exterior terminals. In case of busbars the feeders form the sides. The expression “side” is applied exclusively to the main protected object.

The currents flowing into the protected object are taken from the measuring locations. These are represented by the current transformers which limit the protected zone. They may be or may not be identical with the sides. Differences between measurement locations and sides arise, for example, if a power transformer winding (= 1 side) is fed from 2 galvanically connected lead wires via 2 sets of current transformers (measuring locations).

The measuring locations which feed a side of the main protected object are the assigned measuring locations. If a 7UT6 device provides more 3-phase current inputs than are needed for the main protected object, the remaining measuring locations are named non-assigned measuring locations. These can be used for other protection, supervision, and measuring purposes which process 3-phase currents, e.g. restricted earth fault protection, time overcurrent protection, unbalanced load protection, overload protection, or simply for display of measured values. The non-assigned measuring locations give currents of a further protected object.

Depending on the device version, 1 to 4 single-phase auxiliary current inputs are available for processing of further 1-phase currents. These can be used for processing of 1-phase currents, e.g. the earth current between a winding starpoint and earth, or the leakage current between a transformer tank and earth. These can also be assigned to the main protected object or non-assigned. If they are assigned to a side of the main protected object, they can be processed by the differential protection (example: inclusion of the starpoint current into the differential current); non-assigned 1-phase measuring locations can be processed by other protection functions (example: detection of a tank leakage current by the single-phase overcurrent protection. They can either be combined with other non-assigned 3-phase measuring locations (example: restricted earth fault protection on a further protected object, i.e. different from the main protected object.

Figure 2-1 illustrates the terminology on an example. Note that the example is not practicable in this arrangement as it contains more connections than possible; it serves only for clarification of the terminology.

The main protected object is a two-winding transformer YNd with an earthed starpoint at the Y-side. Side **S1** is the upper voltage side (Y), side **S2** is the lower voltage side (d). This definition of the sides for the main protected object (and only for it) is the basis for the formation of the differential and restraint currents used in the differential protection.

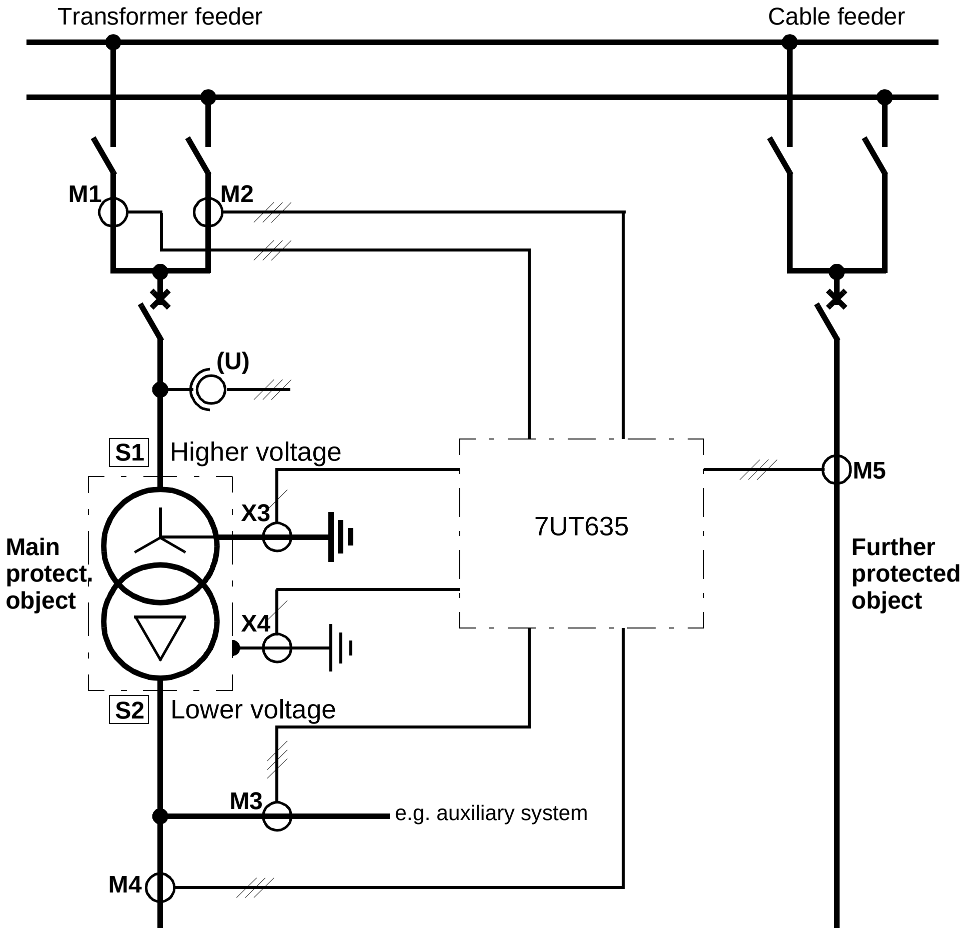
For the side S1 two measuring locations are provided, **M1** and **M2**. The currents measured at these locations are associated with side S1, their sum flows from the terminals of side 1 into the protected zone of the main protected object. The position of the busbar disconnectors is irrelevant in this case. Likewise, the polarity of the currents is not yet considered under topology aspects.

At the lower voltage side, the side S2 has two measuring locations because of its branch point to the auxiliaries system circuit: **M3** and **M4**. The sum of these currents flows into the terminals of the lower voltage side (S2) of the main protected object.

The four measuring locations M1 to M4 are assigned to the sides of the main protected object, i.e. they are assigned measuring locations. They are the basis for the measured value processing of three-phase currents for the differential protection. The same applies basically to single-phase transformers, except that in this case only two phases of the measuring currents from the measuring locations are connected.

The measuring location **M5** is not assigned to the main protected object but to the cable feeder, which is not related in any way to the transformer. This means that M5 is not assigned. The currents provided by this measuring location can be used for other protection functions, e.g. can form an overcurrent protection of the cable feeder.

In three-phase busbar protection, there is no distinction between measuring locations and sides; both are equivalent to busbar feeders.



Sides:

S1 Higher voltage side of the main protected object (power transformer)

S2 Lower voltage side of the main protected object (power transformer)

Measuring locations 3-phase, assigned:

M1 Measuring location, assigned to the main protected object, side 1

M2 Measuring location, assigned to the main protected object, side 1

M3 Measuring location, assigned to the main protected object, side 2

M4 Measuring location, assigned to the main protected object, side 2

Measuring locations 3-phase, non-assigned:

M5 Measuring location, not assigned to the main protected object

Auxiliary measuring locations, 1-phase:

X3 Measuring location, assigned to the main protected object, side 1

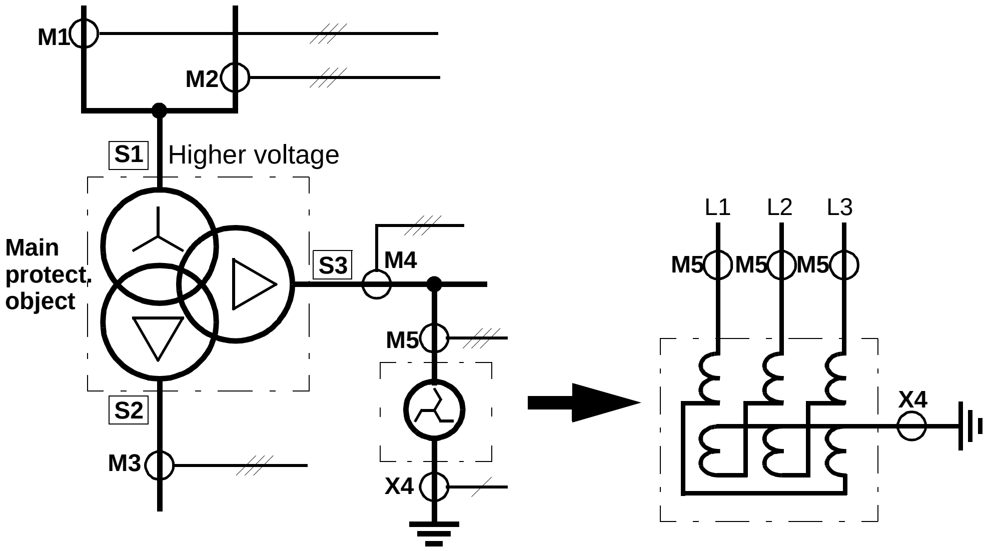
X4 Measuring location, not assigned to the main protected object

Figure 2-1 Example for the terminology of a topology

The auxiliary measuring location **X3** provides the transformer starpoint current. It is assigned to side 1 of the main protected object as an assigned measuring location. This measuring location can be used by the differential protection function for the formation of the differential current. For restricted earth fault protection operating at the higher voltage winding, it can supply the starpoint current of side 1.

The auxiliary measuring location **X4** is not assigned to the main protected object because the differential protection does not need it. It is a non-assigned measuring location which is used to detect the tank earth fault current and to feed it via the single-phase measuring input IX4 to the single-phase overcurrent protection used for tank leakage protection. Although tank leakage protection is in a general sense part of the transformer protection, X4 is not assigned to the main protection function because single-phase overcurrent protection is an autonomous protection function without any relation to a specific side.

Figure 2-2 shows an example of a topology which has in addition to the main protected object (the three-winding transformer) another protected object (the neutral reactor) with a three-phase measuring location and a 1-phase auxiliary measuring location assigned to it. Whilst in the main protected object one side can be fed by multiple measuring locations (this is the case for the higher voltage side S1 of the transformer, which is fed by M1 and M2), no sides are defined for the further protected object. Nevertheless other protection functions (not the differential protection) can act on it, such as the overcurrent protection (3-phase on M5), the earth overcurrent protection (1-phase on X4), or the restricted earth fault protection, which compares the triple of the zero sequence current from M5 with the earth current at X4.



Sides:
S1 Higher voltage side of the main protected object (power transformer)
S2 Lower voltage side of the main protected object (power transformer)
S3 Tertiary winding side of the main protected object (power transformer)

Measuring locations 3-phase, assigned:
M1 Measuring location, assigned to the main protected object, side 1
M2 Measuring location, assigned to the main protected object, side 1
M3 Measuring location, assigned to the main protected object, side 2
M4 Measuring location, assigned to the main protected object, side 3

Measuring locations 3-phase, non-assigned:
M5 Measuring location, not assigned to the main protected object, associated with the neutral reactor

Auxiliary measuring locations, 1-phase:
X4 Measuring location, not assigned to the main protected object, associated with the neutral reactor

Figure 2-2 Topology of a three-winding transformer as main protected object and a neutral reactor arranged outside of the protected zone as a further protected object; right hand three-phase illustration of the neutral reactor

Determining the Topology

You have to determine the topology of the main protected object and further objects (if applicable). The following clarifications are based on the examples given above and the terminology defined above. Further examples will be given where needed. The necessary and possible settings depend on the type of main protected object as defined during configuration according to Subsection 2.1.1.

Measuring locations for a single-phase power transformer are treated like 3-phase measuring locations: From the point of view of measured value conditioning, the single-phase transformer is handled as a three-phase transformer with missing phase L2.

Note:

If you will have changed the protected object according to Subsection 2.1.1, you will have to check and re-adjust all topological data.

Note:

When configuring the topology proceed exactly in the order given below. Some of the following settings and setting possibilities depend on settings performed before. In DIGSI® you can edit the setting sheets from the left tab to the right.

At first, number the sides of the main protected object consecutively, next number the measuring locations, beginning with those for the main object, then for the remaining. In the example (Figure 2-1), there are 2 sides **S1** and **S2**, the 5 measuring locations are **M1** to **M5**.

The following sequence of sides is advised:

- For power transformers, start with the higher voltage side, as well for generator/transformer units or motor/transformer units.
- For auto-transformers, the auto-connected winding must be declared as side 1 and side 2, further taps shall follow (if applicable), then a delta winding (if applicable). side 5 is not permitted here.
- For generators, start with the terminal side.
- For motors and shunt reactors, start with the current supply side.
- For series reactors, lines, and busbars, there is no preferred side.

Side determination plays an important role for the of all following settings.

Proceed numbering the measuring locations, beginning with those which are assigned to the main protected object. Take the order of side numbering, next the non-assigned measuring locations (if used). Refer also to Figure 2-1.

Proceed numbering the auxiliary measuring locations (1-phase), again in the order: assigned locations and then further (if used).

Note:

The determination of the sides and measuring locations is imperative for all further setting steps. It is also important that the currents from the measuring locations (current transformers) are connected to the associated analog current inputs of the device: The currents from **M1** must be fed to the current inputs $I_{L1\mathbf{M1}}$, $I_{L2\mathbf{M1}}$, $I_{L3\mathbf{M1}}$, etc. (I_{L2M1} is omitted for single-phase power transformers)!

The topological data can be altered only with a PC using DIGSI$^{®}$.

Global Data for 3-Phase Measuring Locations

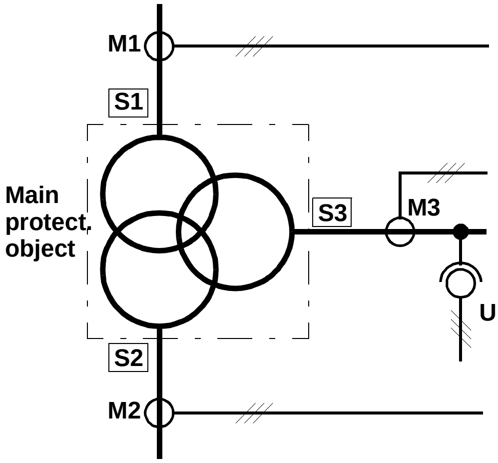
Determine the total number of 3-phase current measuring locations (= connected current transformer sets) which are connected to the device. Enter this number in address 211 **No Conn.MeasLoc**. 7UT613 and 7UT633 allow a maximum number of 3, 7UT635 a maximum of 5 measuring locations. The examples in Figures 2-1 and 2-2 contain ***5*** measuring locations each.

The number of 3-phase measuring locations assigned to the main protected object are set in address 212 **No AssigMeasLoc**. Of course, this number cannot be higher than that of address 211. The difference **No Conn.MeasLoc** – **No AssigMeasLoc** is the number of non-assigned measuring locations. Both examples in the figures 2-1 and 2-2 show ***4*** assigned 3-phase measuring locations **M1** to **M4** of a total of 5 measuring locations. **M5** is a non-assigned measuring location.

The number of sides associated with the main protected object is set in address 213 **NUMBER OF SIDES**. In the example of Figure 2-1, the main protected object is a power transformer with 2 windings; the number of sides is ***2***, namely **S1** and **S2**. In the example of Figure 2-2, the main protected object is a power transformer with 3 windings; the number of sides is ***3***. In case of an auto-transformer, a maximum of 4 sides is permissible (see below).

Of course, the number of sides can be equal to the number of measuring locations (but never greater). The example in Figure 2-3 shows a three-winding power transformer with one set of current transformers at each side. In this example: **No AssigMeasLoc** = ***3*** and **NUMBER OF SIDES** = ***3***.

No distinction between sides and measuring locations is made in case of a busbar. Both correspond to the feeders. Therefore, address 213 is missing if the protected object is a ***3ph Busbar*** (address 105 **PROT. OBJECT**).



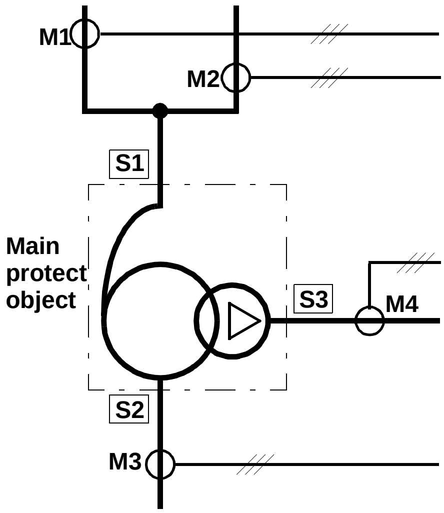
Sides:
S1 Higher voltage side of the main protected object (power transformer)
S2 Lower voltage side of the main protected object (power transformer)
S3 Tertiary winding side of the main protected object (power transformer)

Measuring locations 3-phase, assigned:
M1 Measuring location, assigned to the main protected object, side 1
M2 Measuring location, assigned to the main protected object, side 2
M3 Measuring location, assigned to the main protected object, side 3

Figure 2-3 Example of a topology on a three-winding transformer

Special Considerations on Auto-Transformers

As mentioned above, the auto-connected windings on auto-transformers must always be defined as side 1 and side 2. A third side may be present if the compensation winding is dimensioned as power winding (tertiary winding) and accessible. Figure 2-4 shows an example with ***3*** sides and ***4*** assigned measuring locations.



Sides:

S1	Higher voltage side of the main protected object (auto-transformer)
S2	Lower voltage side of the main protected object ((auto-transformer)
S3	Tertiary winding side (accessible compensation winding) of the main protected object

Measuring locations 3-phase, assigned:

M1	Measuring location, assigned to the main protected object, side 1
M2	Measuring location, assigned to the main protected object, side 1
M3	Measuring location, assigned to the main protected object, side 2
M4	Measuring location, assigned to the main protected object, side 3

Figure 2-4 Topology of an auto-transformer with a compensation winding which is used as tertiary winding

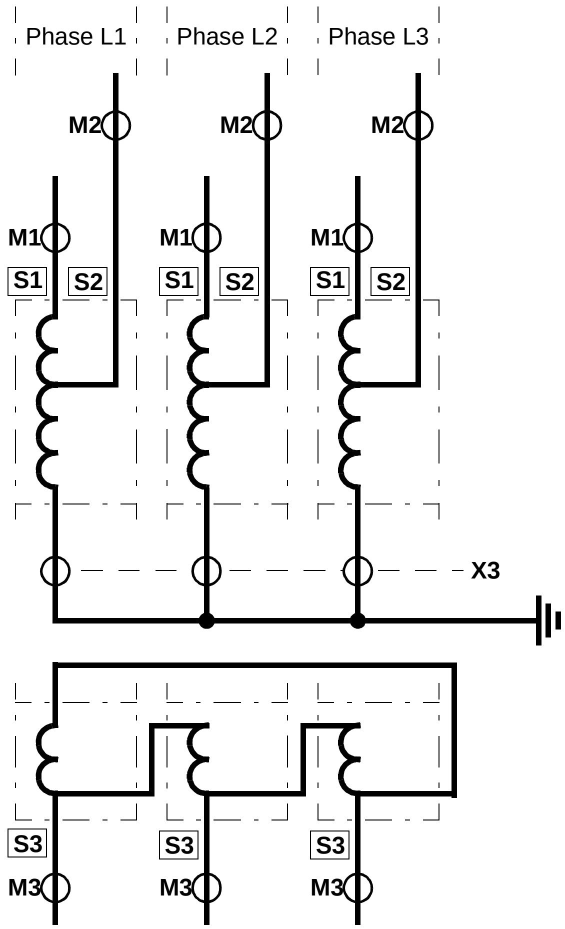
A further tap of the winding can also be used as the third side. Be aware that the numbering sequence always starts with the auto-connected winding: full winding, taps, and then accessible delta winding if required.

Auto-Transformer Banks

If three single-phase auto-transformers are arranged as a power transformer bank the connections of the starpoint leads are accessible and often provided with current transformers. Two possibilities exist for this power transformer arrangement:

Differential protection over the entire power transformer bank (Figure 2-5):

Firstly, you can build up a normal transformer differential protection system over the entire transformer bank. Figure 2-5 shows an illustration where a phase-discriminative diagram is used in order to clarify the different currents. In this example we have ***3*** sides and ***3*** assigned 3-phase measuring locations: The auto-connected winding terminals form the sides **S1** (full winding) and **S2** (tap) with the assigned 3-phase measuring locations M1 and M2. Of course, you can connect the sum of the three currents measured in the starpoint leads to an auxiliary 1-phase current input of the device (illustrated dotted) in order to use it for time overcurrent protection. The accessible and power-capable compensation winding is defined as Side **S3**.



Sides:
S1 Higher voltage side of the auto-connected winding of the main protected object
S2 Lower voltage side (tap) of the auto-connected winding of the main protected object
S3 Tertiary winding side (accessible compensation winding) of the main protected object

Measuring locations 3-phase, assigned:
M1 Measuring location, assigned to the main protected object, side 1
M2 Measuring location, assigned to the main protected object, side 2
M3 Measuring location, assigned to the main protected object, side 3

Auxiliary 1-phase measuring location, assigned to the main object (current sum of the CT set):
X3 Measuring location, assigned to the main protected object, side 1 and 2

Figure 2-5 Topology of a transformer bank consisting of 3 single-phase auto-transformers with compensation winding dimensioned as accessible tertiary winding

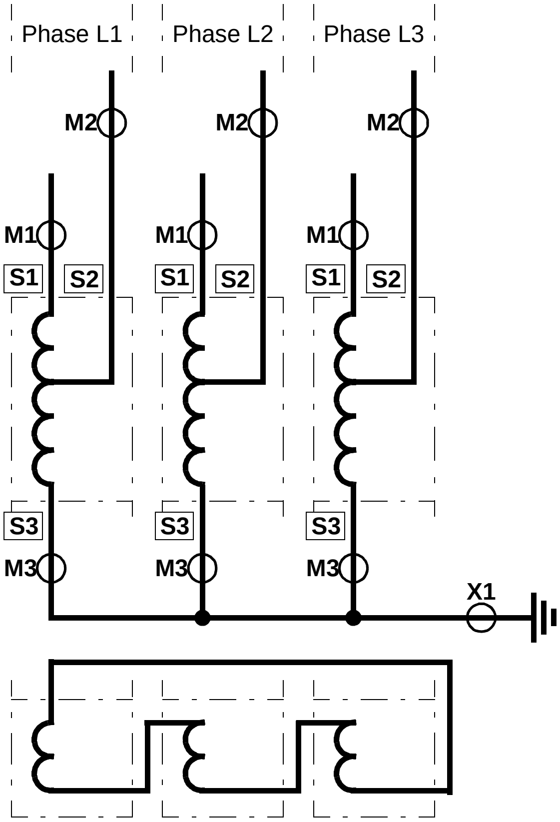
Current comparison protection over each individual winding (Figure 2-6):

Alternatively, you can build up a current comparison protection over each of the three windings of the auto-transformer bank (Figure 2-6). Besides the auto-connected winding terminals of the sides **S1** (full winding) and **S2** (tap) with the assigned 3-phase measuring locations **M1** and **M2**, one more side **S3** is defined at the starpoint terminals with the 3-phase measuring location **M3**. In this way, a current comparison protection can be realized over each of the three transformer windings, i.e. each phase.

Such a current comparison is more sensitive concerning 1-phase earth faults in one of the transformers. This has a certain importance considering that 1-phase earth faults are the most probable faults in such banks.

On the other hand, the compensation winding cannot and must not be included into this protection even if it is accessible and equipped with current transformers. This application variant is based on the current law in that all currents flowing in to a winding must total to zero.

The further current transformer X1 in Figure 2-6 is not necessary. In order to realize a time overcurrent protection for earth faults in this arrangement, you can feed the sum of the three currents measured at M3 to a auxiliary 1-phase current input of the device. A connection example for an arrangement where the 3-phase measured currents of measuring location M3 is used for current comparison as well as for a 1-phase auxiliary current input is shown in the Appendix, Section A.3, in Figure A-16.



Sides:

S1	Higher voltage side of the auto-connected winding of the main protected object
S2	Lower voltage side (tap) of the auto-connected winding of the main protected object
S3	Starpoint side of the auto-connected winding of the main protected object

Measuring locations 3-phase, assigned:

M1	Measuring location, assigned to the main protected object, side 1
M2	Measuring location, assigned to the main protected object, side 2
M3	Measuring location, assigned to the main protected object, side 3

Auxiliary 1-phase measuring location, assigned to the main object:

X1	Measuring location, assigned to the main protected object, side 1 and 2

Figure 2-6 Topology of a transformer bank consisting of 3 single-phase auto-transformers; topology definitions for a current comparison protection for each phase

Global Data for 1-phase Busbar Protection

If the device is used as busbar protection, either as single-phase protection or as three-phase protection via external summation transformers, you set the number of feeders of the busbar in address 216 **NUMBER OF ENDS**. The minimum number is ***3***. (With less feeders it would not make sense to use the 7UT613.)

The maximum number of feeders is ***9*** with 7UT613 and 7UT633, ***12*** with 7UT635. If interposed summation transformers with I_N = 0.1 A are used, the maximum number is ***6*** with 7UT613 and 7UT633.

Assignment of 3-phase Measuring Locations

After determination of the global data, the 3-phase measuring locations must be assigned to the sides of the main protected object. Only few meaningful combinations are possible for this assignment because of the condition that always **NUMBER OF SIDES** ≤ **No AssigMeasLoc** ≤ **No Conn.MeasLoc** and that a protected object provides at least 2 sides. In order to exclude impossible combinations at all, only those addresses of the following lists are requested which correspond to the global settings of addresses 211, 212, and 213. Furthermore, only meaningful setting options appear.

If the global data are implausible, the device does not find any meaningful combination of assignment possibilities. In this case you will find address 230 **ASSIGNM. ERROR** which shows one of the following options:

- ***No AssigMeasLoc*** the number of assigned measuring locations is implausible;
- ***No of sides*** the number of sides is implausible.

This parameter cannot be changed. It merely informs you about the implausibility of the global settings. If it appears recheck carefully the addresses 211, 212, and 213 and correct the settings.

There seems to be a large variety of assignment parameters. But, in the actual case, only *one* address will be visible: the address which corresponds to the above mentioned number of sides and assigned measuring locations. The measuring location and side are separated by a comma, e.g. ***3M,2S*** means 3 assigned measuring locations at 2 sides.

Only the combinations possible for the number of measuring locations and sides appear as setting options. The measuring locations of the same side are connected by a "**+**" sign; the side sequence by a comma. In the following, all possibilities are explained.

Address 220 **ASSIGNM. 2M,2S** appears if you have stated **2** assigned measuring locations (address 212) at **2** sides (address 213). Only one option is possible:

- ***M1,M2***, i.e. the 2 measuring locations are assigned: M1 to side S1, M2 to side S2.

Since no other possibilities exist there are no further options.

Address 221 **ASSIGNM. 3M,2S** appears if you have stated **3** assigned measuring locations (address 212) at **2** sides (address 213). The following options are possible:

- ***M1+M2,M3***, i.e. the 3 measuring locations are assigned: M1 and M2 to side S1, M3 to side S2.
- ***M1,M2+M3***, i.e. the 3 measuring locations are assigned: M1 to side S1, M2 and M3 to side S2.

Address 222 **ASSIGNM. 3M,3S** appears if you have stated **3** assigned measuring locations (address 212) at **3** sides (address 213). Only one option is possible:

- ***M1,M2,M3***, i.e. the 3 measuring locations are assigned: M1 to side S1, M2 to side S2, M3 to side S3. This corresponds to the examples in Figures 2-3, 2-5, and 2-6.

The further assignment possibilities can only occur in 7UT635 since 7UT613 and 7UT633 provide a maximum of 3 three-phase current inputs (cf. Table 2-1).

Address 223 **ASSIGNM. 4M,2S** appears if you have stated **4** assigned measuring locations (address 212) at **2** sides (address 213). The following options are possible:

- ***M1+M2,M3+M4***, i.e. the 4 measuring locations are assigned: M1 and M2 to side S1, M3 and M4 to side S2. This corresponds to the example in Figure 2-1 (M5 is not assigned there).
- ***M1+M2+M3,M4***, i.e. the 4 measuring locations are assigned: M1 and M2 and M3 to side S1, M4 to side S2.
- ***M1,M2+M3+M4***, i.e. the 4 measuring locations are assigned: M1 to side S1, M2 and M3 and M4 to side S2.

Address 224 **`ASSIGNM. 4M,3S`** appears if you have stated **4** assigned measuring locations (address 212) at **3** sides (address 213). The following options are possible:

- ***`M1+M2,M3,M4`***, i.e. the 4 measuring locations are assigned: M1 and M2 to side S1, M3 to side S2, M4 to side S3. This corresponds to the examples in Figures 2-2 and 2-4.
- ***`M1,M2+M3,M4`***, i.e. the 4 measuring locations are assigned: M1 to side S1, M2 and M3 to side S2, M4 to side S3.
- ***`M1,M2,M3+M4`***, i.e. the 4 measuring locations are assigned: M1 to side S1, M2 to side S2, M3 and M4 to side S3.

Address 225 **`ASSIGNM. 4M,4S`** appears if you have stated **4** assigned measuring locations (address 212) at **4** sides (address 213). Only one option is possible:

- ***`M1,M2,M3,M4`***, i.e. the 4 measuring locations are assigned: M1 to side S1, M2 to side S2, M3 to side S3, M4 to side S4.

Address 226 **`ASSIGNM. 5M,2S`** appears if you have stated **5** assigned measuring locations (address 212) at **2** sides (address 213). The following options are possible:

- ***`M1+M2+M3,M4+M5`***, i.e. the 5 measuring locations are assigned: M1 and M2 and M3 to side S1, M4 and M5 to side S2.
- ***`M1+M2,M3+M4+M5`***, i.e. the 5 measuring locations are assigned: M1 and M2 to side S1, M3 and M4 and M5 to side S2.
- ***`M1+M2+M3+M4,M5`***, i.e. the 5 measuring locations are assigned: M1 and M2 and M3 and M4 to side S1, M5 to side S2.
- ***`M1,M2+M3+M4+M5`***, i.e. the 5 measuring locations are assigned: M1 to side S1, M2 and M3 and M4 and M5 to side S2.

Address 227 **`ASSIGNM. 5M,3S`** appears if you have stated **5** assigned measuring locations (address 212) at **3** sides (address 213). The following options are possible:

- ***`M1+M2,M3+M4,M55`***, i.e. the 5 measuring locations are assigned: M1 and M2 to side S1, M3 and M4 to side S2, M5 to side S3.
- ***`M1+M2,M3,M4+M5`***, i.e. the 5 measuring locations are assigned: M1 and M2 to side S1, M3 to side S2, M4 and M5 to side S3.
- ***`M1,M2+M3,M4+M5`***, i.e. the 5 measuring locations are assigned: M1 to side S1, M2 and M3 to side S2, M4 and M5 to side S3.
- ***`M1+M2+M3,M4,M5`***, i.e. the 5 measuring locations are assigned: M1 and M2 and M3 to side S1, M4 to side S2, M5 to side S3.
- ***`M1,M2+M3+M4,M5`***, i.e. the 5 measuring locations are assigned: M1 to side S1, M2 and M3 and M4 to side S2, M5 to side S3.
- ***`M1,M2,M3+M4+M5`***, i.e. the 5 measuring locations are assigned: M1 to side S1, M2 to side S2, M3 and M4 and M5 to side S3.

Address 228 **`ASSIGNM. 5M,4S`** appears if you have stated **5** assigned measuring locations (address 212) at **4** sides (address 213). The following options are possible:

- ***`M1+M2,M3,M4,M5`***, i.e. the 5 measuring locations are assigned: M1 and M2 to side S1, M3 to side S2, M4 to side S3, M5 to side 5.
- ***`M1,M2+M3,M4,M5`***, i.e. the 5 measuring locations are assigned: M1 to side S1, M2 and M3 to side S2, M4 to side S3, M5 to side S4.

- ***M1,M2,M3+M4,M5***, i.e. the 5 measuring locations are assigned: M1 to side S1, M2 to side S2, M3 and M4 to side S3, M5 to side S4.
- ***M1,M2,M3,M4+M5***, i.e. the 5 measuring locations are assigned: M1 to side S1, M2 to side S2, M3 to side S3, M4 and M5 to side S4.

Address 229 **ASSIGNM. 5M,5S** appears if you have stated **5** assigned measuring locations (address 212) at **5** sides (address 213). Only one option is possible:

- ***M1,M2,M3,M4,M5***, i.e. the 5 measuring locations are assigned: M1 to side S1, M2 to side S2, M3 to side S3, M4 to side S4, M5 to side S5.

Assignment of the Sides with Auto-Transformers

If auto-transformers are protected the additional question arises how the sides of the protected object are to be handled by the main protection function, the differential protection. As mentioned above (margin heading “Special Considerations on Auto-Transformers”), various possibilities exist how the sides of the auto-transformer are defined. Further information is necessary in order to achieve an exact replica of the auto-transformer. The following addresses appear only in case the main protected object is an auto-transformer (address 105 **PROT. OBJECT** = ***Autotransf.*** according to Subsection 2.1.1).

Address 241 **SIDE 1** must be assigned to an ***auto-connected*** winding (primary tap as recommended above). This is imperative and, therefore, cannot be changed.

Address 242 **SIDE 2** of the auto-transformer must equally be assigned to an ***auto-connected*** (secondary tap as recommended above). This is imperative and, therefore, cannot be changed.

For the sides 3 and 4, alternatives exist. If the auto-transformer provides another tap the side thereof is declared as ***auto-connected***.

Regarding Figure 2-5, side 3 is a tertiary winding meaning an accessible and load-capable compensation winding. In this example the setting would be:
Address 243 **SIDE 3** = ***compensation*** winding (= tertiary winding).

In the example of Figure 2-6, side S3 is facing the earthing electrode of the transformer starpoint. Here:
Address 243 **SIDE 3** = ***earth.electrode***.

In summary we can say: the sides S1 and S2 are imperatively assigned to the connections of the auto-connected winding. For **SIDE 3** and **SIDE 4** you have to select the option corresponding to the topology: ***auto-connected*** (for another tap of the auto-connected winding), ***compensation*** (for an accessible and load-capable compensation winding) or ***earth.electrode*** (for the earthed side of the auto-connected windings).

Note:

If you have chosen the option ***earth.electrode*** for either side, the differential protection will automatically perform a current comparison over each of the 3 windings. This is especially sensitive concerning 1-phase earth faults in one of the windings. But the compensation winding cannot and must not be included into this protection even if it is accessible and equipped with current transformers.

Assignment of Auxiliary 1-phase Measuring Locations

Each of the possible auxiliary (1-phase) current inputs must now be assigned in the addresses 251 to 254. The number of auxiliary inputs depends on the device type (cf. Table 2-1). In the 7UT635, the inputs IX1 to IX3 are only available as auxiliary 1-phase measuring inputs if they are not needed for a fifth 3-phase measuring location, i.e. if only four (or less) 3-phase measuring locations are needed.

The auxiliary inputs can be assigned to a side or a measuring location, or they can remain non-assigned. If you have assigned exactly one measuring location to a side, this side is equivalent to the measuring location.

Single-phase auxiliary measured currents are used in the following cases:

1. In differential protection, to include the starpoint current of an earthed transformer winding (either directly or via a neutral earthing reactor in the protected zone);
2. In restricted earth fault protection, to compare the starpoint current of an earthed winding (transformer, generator, motor, shunt reactor, neutral earthing reactor) with the zero sequence current from the phase currents;
3. In earth fault overcurrent protection, to detect the earth fault current of an earthed winding or neutral earthing reactor;
4. In single-phase overcurrent protection, to detect any 1-phase current;
5. For operational limit monitoring tasks and/or display of measured values.

1st case: It is essential to assign the 1-phase input to *that* side of the main protected object whose incoming phase currents are to be compared with the earth fault current. Make sure that you assign the 1-phase input to the correct side. In the case of transformers, this can only be a side with an earthed starpoint (directly or via a neutral earthing reactor in the protected zone).

In the example shown in Figure 2-1, the auxiliary measuring location **X3** must be assigned to side **S1**. Once the device has been informed of this assignment, the current measured at current input IX3 will be reliably interpreted as the current flowing to the starpoint of the higher voltage winding (side 1).

2nd case: For this case, the same considerations apply as for the 1st case. In the case of generators, motors or shunt reactors, select the terminal side. You can also use in the 2nd case a measuring location that is *not* assigned to the main protected object. In the example shown in Figure 2-2, you can use the restricted earth fault protection for the neutral reactor: The auxiliary measuring location X4 is in this case assigned to the measuring location M5. This informs the device that the measured values of the non-assigned measuring location M5 (3-phase) must be compared with the measured value of the auxiliary measuring location X4 (1-phase).

3rd case: Here again, the auxiliary measuring location must be assigned to *that* side whose earth fault current is to be processed. You can also use a measuring location that is not assigned to the main protected object. Please note that this auxiliary measuring location will provide not only the measured value for the earth fault overcurrent protection but also circuit breaker information (current flow and manual-close detection) from the corresponding 3-phase measuring location.

If the current used by the earth fault overcurrent protection is not to be assigned to a specific side or 3-phase measuring location you can either proceed as described in the 4th and 5th case.

4th and 5th case: In these cases you set the parameter for the assignment of the auxiliary measuring location to ***conn/not assig.*** (connected but not assigned). The auxiliary measuring location is then assigned to neither a specific side of the main protected object nor to any other 3-phase measuring location. These protection and measuring functions do not need any information on their assignment to a 3-phase measuring location because they process exclusively the corresponding 1-phase current.

General advice: If you want to use a 1-phase auxiliary measuring location both for a function as per the 3rd to 5th case *and* for the 1st or 2nd case, you must assign it as described in the 1st and 2nd case.

If the device is equipped with a 1-phase measuring input but you do not need it, leave the setting ***Not connected*** unchanged.

Of the addresses described in the following paragraphs, only those available in your device will be displayed. Please keep in mind

- that in the 7UT613 and 7UT633 only the auxiliary inputs IX1 to IX3 are available, and that they can be assigned to not more than 3 sides or 3-phase measuring locations;
- that in the 7UT635 the auxiliary inputs IX1 to IX3 cannot be assigned to the measuring location M5, since in this device *either* M5 *or* IX1 to IX3 are available.

Address 251 **AUX. CT IX1** determines which side of the main protected object or which 3-phase measuring location the 1-phase measuring input IX1 is assigned to. Set here the side or measuring location, or no assignment at all, as described above.

Address 252 **AUX. CT IX2** determines which side of the main protected object or which 3-phase measuring location the 1-phase measuring input IX2 is assigned to. Set here the side or measuring location, or no assignment at all, as described above.

Address 253 **AUX. CT IX3** determines which side of the main protected object or which 3-phase measuring location the 1-phase measuring input IX3 is assigned to. Set here the side or measuring location, or no assignment at all, as described above.

Address 254 **AUX. CT IX4** determines which side of the main protected object or which 3-phase measuring location the 1-phase measuring input IX4 is assigned to. Set here the side or measuring location, or no assignment at all, as described above.

High-Sensitivity Auxiliary 1-phase Measuring Locations

Depending on the version, the devices of the 7UT6 family are equipped with 1 or 2 further high-sensitivity measuring inputs which can detect currents as low as 3 mA present at the input. These inputs can be used for single-phase overcurrent protection.

The single-phase definite time overcurrent protection is suited e.g. for high-sensitivity tank leakage protection (cf. Subsection 2.7.3), or for a high-impedance unit protection (cf. Subsection 2.7.2) where a high-sensitivity measuring input is used.

If you want to use such a high-sensitivity current measuring input, you can specify this to the device at the addresses 255 and 256.

In 7UT613 and 7UT633, input IX3 can be used as a high-sensitivity input. Set address 255 **AUX CT IX3 TYPE** to ***sensitiv input*** if you want to use IX3 as a high-sensitivity input; otherwise leave the setting ***1A/5A input*** unchanged.

In 7UT635, input IX3 can be used as a high-sensitivity input, provided that it is not used for a 5th three-phase measuring location, i.e. that only 4 three-phase measuring locations are needed. In this case you set address 255 **AUX CT IX3 TYPE** to ***sensitiv input*** if you want to use IX3 as a high-sensitivity input.

Input IX4 is always available as a single-phase input in the 7UT635; it can be set at address 256 **AUX CT IX4 TYPE** to ***sensitiv input*** or ***1A/5A input***.

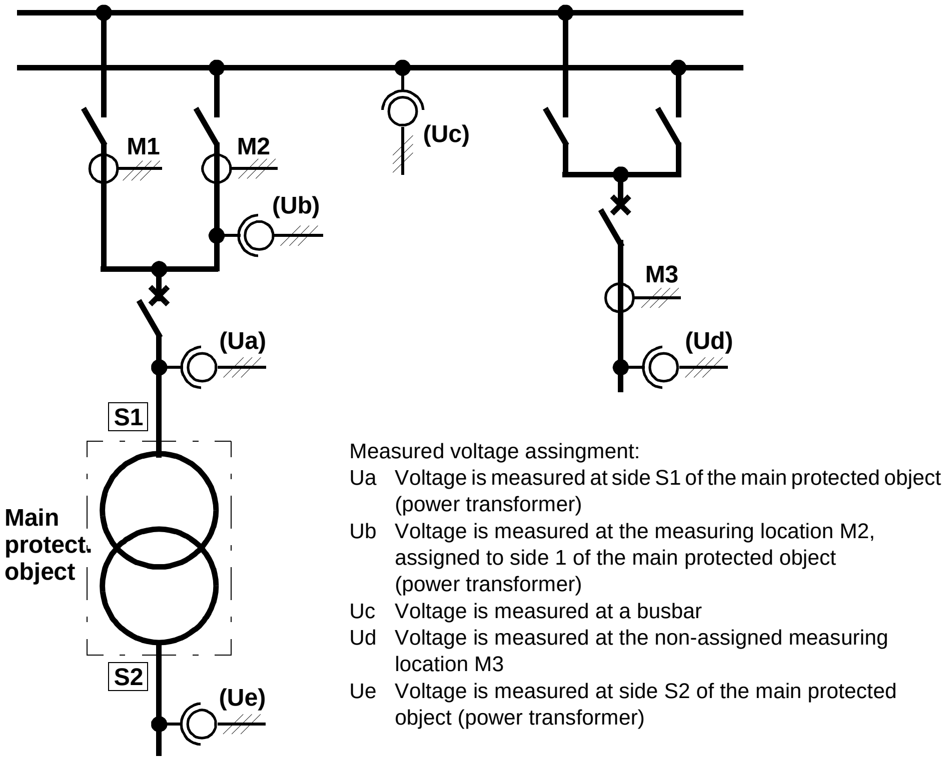
Assignment of Voltage Measuring Inputs

The 7UT613 and 7UT633 (not the 7UT635) can be provided with voltage measuring inputs (cf. Table 2-1). The 3-phase set of voltage inputs and the 4th voltage input can each be assigned to one side or one measuring location, or to the busbar voltage (for busbar protection).

Figure 2-7 shows the various possible voltage assignments (which, of course cannot occur all at the same time in practice). Address 261 must be set `VT SET`.

- For voltage measurement at **Ua** the voltages are measured on ***`Side 1`*** of the main protected object.
- For voltage measurement at **Ub** the voltages are measured at ***`Measuring loc.2`*** which is assigned to side 1 of the main protected object.
- For voltage measurement at **Uc** the voltages are measured at the ***`Busbar`*** (only possible in busbar protection).
- For voltage measurement at **Ud** the voltages are measured at ***`Measuring loc.3`*** which is not assigned to the main protected object.
- For voltage measurement at **Ue** the voltages are measured on ***`Side 2`*** of the main protected object.

As these examples show, you can select sides, busbars, assigned or non-assigned measuring locations. In 1-phase busbar protection, voltages can only be measured on the ***`Busbar`***.



Measured voltage assingment:

Ua	Voltage is measured at side S1 of the main protected object (power transformer)
Ub	Voltage is measured at the measuring location M2, assigned to side 1 of the main protected object (power transformer)
Uc	Voltage is measured at a busbar
Ud	Voltage is measured at the non-assigned measuring location M3
Ue	Voltage is measured at side S2 of the main protected object (power transformer)

Figure 2-7 Examples of measured voltage assignment

In practice, the voltage assignment depends therefore on the voltages which the device is intended to receive and process. Of course, voltage transformers must be installed at the appropriate locations and connected to the device.

If the voltage transformers represented as **Ua** do not exist in your system, you can, for instance, use the voltages at ***Measuring loc.2*** (represented as **Ub**), as they are electrically identical (assuming that the circuit breaker is closed). The device then assigns the voltage automatically to side 1 and calculates the power of the side from this voltage and the current of side S1, which is the sum of the currents from the measuring locations M1 and M2.

If no voltages are connected, set ***Not connected***.

If the overexcitation protection is used, you must choose (and connect) a voltage that is suitable for overexcitation protection. For transformers it must be a non-regulated side, since a proportional relationship between the quotient U/f and the iron core induction B is found only there. If in Figure 2-7, for instance, the winding on side 1 is provided with a voltage controller, your must select ***Side 2***.

If you do not use the overexcitation protection, you select the voltages which you want to display or transfer as operational measured values during operation, or on the basis of which you want to calculate the power.

For the 1-phase voltage measurement input U4, you can select likewise at address 262 **VT U4** a side or measuring location — regardless of the assignment of the 3-phase voltage inputs. This measuring input is frequently used for the displacement voltage, measured at the e-n windings of the voltage transformer set, but you can also use it for detection of any other measured voltage. In this case, set **VT U4** to ***conn/ not assig.***. If no voltage is needed at the 1-phase voltage input, set ***Not connected***.

As different connections are possible, you must now specify to the device how the connected 1-phase voltage should be interpreted. This is done at address 263 **VT U4 TYPE**. Set ***Udelta transf.*** if the voltage assigned acc. to address 262 is a displacement voltage. It can also be any phase-to-earth voltage (e.g. ***UL1E transform.***), or a phase-to-phase voltage (e.g. ***UL12 transform.***). If U4 is connected to a voltage which is assigned to no side or measuring location, set ***Ux transformer***.

2.1.3 General Power System Data (Power System Data 1)

General

The device requires some plant and power system data in order to be able to adapt its functions accordingly, dependent on the actual application. The data required include for instance rated data of the substation and the measuring transformers, polarity and connection of the measured quantities, if necessary features of the circuit breakers, and others. Furthermore, there is a number of settings associated with several functions rather than a specific protection, control or monitoring function. These data can only be changed from a PC running DIGSI® and are discussed in this Subsection.

Rated Frequency

The rated frequency of the power system is set under address 270 **Rated Frequency**. The available rated frequencies are ***50 Hz***, ***60 Hz***, or ***16,7 Hz***.

Phase Sequence

Address 271 **PHASE SEQ.** is used to establish the phase sequence. The preset phase sequence is ***L1 L2 L3*** for clockwise phase rotation. For systems with counter-clockwise phase rotation, set ***L1 L3 L2***. This setting is irrelevant for single-phase application.

Clockwise ***L1 L2 L3***   Counter-clockwise ***L1 L3 L2***

Figure 2-8 Phase sequence

Temperature Unit

The temperature of the hot-spot temperature calculation can be expressed in degrees ***Celsius*** or ***Fahrenheit***. If overload protection with hot-spot temperature is used, set the desired temperature unit in address 276 **TEMP. UNIT**. Otherwise this setting can be ignored. Changing temperature units does not mean that setting values which are linked to these temperature units will automatically be converted. They have to be re-entered into their corresponding addresses.

Object Data with Transformers

Transformer data are required if the device is used as differential protection for transformers, i.e. if the following was set with the configuration of the protection functions (Subsection 2.1.1, margin heading “Special Cases”): **PROT. OBJECT** (address 105) ***3 phase transf.*** or ***Autotransf.*** or ***1 phase transf.***. In cases other than that, these settings are not available.

Please observe the definition of the sides which you have performed during setting of the topology of the main protected object, as above-mentioned (Subsection 2.1.2, margin heading “Determining the Topology” and subsequent margins). Generally, side 1 is the reference winding having a current phase angle of 0° and no vector group indicator. Usually this is the higher voltage winding of the transformer.

The object data is information about each of the sides of the protected object as defined in topology statements in Subsection 2.1.2. Object data of sides which are not assigned in the topology are not requested in the following. They will be entered at a later date (margin “Object Data for Further Protected Objects”).

The device needs the following information on Side 1:

- The primary rated voltage U_N in kV (phase-to-phase) under address 311 **UN-PRI SIDE 1**.
- The primary rated apparent power of the winding **SN SIDE 1** under address 312. Note that the power ratings of the windings of power transformers with more than 2 windings may differ. Here, the rating of the winding assigned to side 1 is decisive. The power must always be entered as a primary value, even if the device is generally configured in secondary values. The device calculates the rated current of the protected winding from this power.
- The starpoint condition under address 313 **STARPNT SIDE 1**: ***Solid Earthed*** or ***Isolated***. If the starpoint is earthed via a current-limiting equipment (e.g. low-resistive) or via a Petersen-coil (high-reactive, resonant), or via a surge arrester, set ***Solid Earthed***, too. The starpoint is treated as ***Solid Earthed*** either if a starpoint former (neutral earthing reactor) is installed within the protected zone of the winding.
- The mode of interconnection of the transformer windings under address 314 **CONNECTION S1**. If side 1 is that of the higher voltage side of the transformer, this is normally the capital letter of the vector group according to IEC: ***Y*** or ***D***. For autotransformers and single-phase transformers, only ***Y*** is permitted.

If the transformer winding is regulated then the actual rated voltage of the side is not used as UN but rather the voltage which corresponds to the average current of the regulated range. The following applies:

$$U_N = 2 \cdot \frac{U_{max} \cdot U_{min}}{U_{max} + U_{min}} = \frac{2}{\frac{1}{U_{max}} + \frac{1}{U_{min}}}$$

where U_{max}, U_{min} are the voltages at the limits of the regulated range.

Calculation example:

Transformer	YNd5
	35 MVA
	110 kV/20 kV
	Y-winding with tap changer ±20 %

This results for the regulated winding (110 kV) in:

maximum voltage	U_{max} = 132 kV
minimum voltage	U_{min} = 88 kV

Setting voltage (address 311)

$$\text{UN-PRI SIDE 1} = \frac{2}{\frac{1}{U_{max}} + \frac{1}{U_{min}}} = \frac{2}{\frac{1}{132\text{ kV}} + \frac{1}{88\text{ kV}}} = 105.6\text{ kV}$$

For Side 2, the same considerations apply as for the side 1: The primary rated voltage U_N in kV (phase-to-phase) under address 321 **UN-PRI SIDE 2**, the starpoint condition under address 323 **STARPNT SIDE 2**. Observe strictly the assignment of the side according to the topological definitions in Subsection 2.1.2.

The primary rated apparent power **SN SIDE 2** under address 322 is that of the side 2. Note that the power rating of the windings of power transformers with more than 2 windings may differ. The power must always be entered as a primary value, even if the device is generally configured in secondary values. The device calculates the rated current of the protected side from this power.

The mode of connection (address 324 **CONNECTION S2**) and the vector group numeral (address 325 **VECTOR GRP S2**) must match the transformer data of the transformer windings at side 2. The vector group numeral states the phase displacement of side 2 against the reference winding, side 1. It is defined according to IEC as the multiple of 30°. If the higher voltage side is the reference (side 1), you may take the data directly from the vector group designation. For instance, for a transformer Y**d5** is 324 **CONNECTION S2** = ***D*** and 325 **VECTOR GRP S2** = ***5***. Every vector group from 0 to 11 can be set provided it is possible (for instance, Yy, Dd and Dz allow only even, Yd, Yz and Dy allow only odd numerals). For the auto-connected winding of autotransformers and for single-phase transformers, only ***Y 0*** is permissible.

If not the higher voltage side is used as reference winding (side 1) it must be considered that the vector group changes: e.g. a Yd**5** transformer is regarded from the lower voltage side as Dy**7** (Figure 2-9).

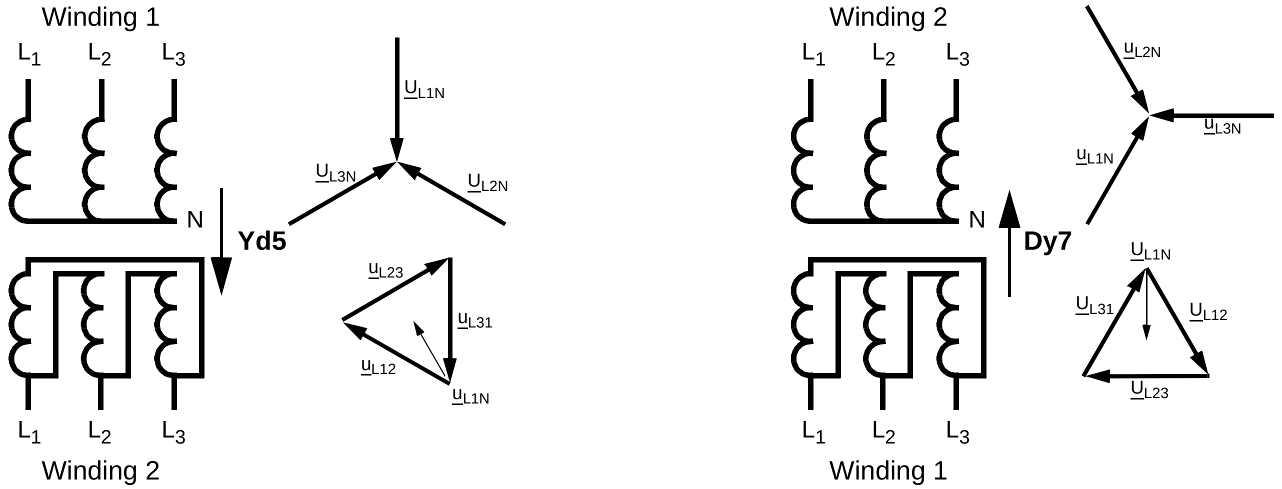


Figure 2-9 Change of the transformer vector group if the lower voltage side is the reference side — example

If the power transformer includes more than 2 windings or assigned sides, similar considerations apply for the further windings (Side 4 and 5 only with 7UT635). If you have declared the starpoint connections of an auto-transformer bank as a separate side in order to establish a current comparison protection for each of the windings (refer also to Figure 2-6 and the respective notes under “Auto-Transformer Banks”), no settings will be presented for this side as they would have no meaning for this application.

For the winding assigned to Side 3, the following data are relevant:
Address 331 **UN-PRI SIDE 3** the primary rated voltage (consider regulating range),
Address 332 **SN SIDE 3** the primary rated apparent power,
Address 333 **STARPNT SIDE 3** the starpoint conditioning,
Address 334 **CONNECTION S3** the winding connection mode
Address 335 **VECTOR GRP S3** the vector group numeral.

For the winding assigned to Side 4 (if applicable), the following data are relevant:
Address 341 **UN-PRI SIDE 4** the primary rated voltage (consider regulating range),
Address 342 **SN SIDE 4** the primary rated apparent power,
Address 343 **STARPNT SIDE 4** the starpoint conditioning,
Address 344 **CONNECTION S4** the winding connection mode,
Address 345 **VECTOR GRP S4** the vector group numeral.

For the winding assigned to Side 5 (if applicable), the following data are relevant:
Address 351 **UN-PRI SIDE 5** the primary rated voltage (consider regulating range),
Address 352 **SN SIDE 5** the primary rated apparent power,
Address 353 **STARPNT SIDE 5** the starpoint conditioning,
Address 354 **CONNECTION S5** the winding connection mode,
Address 355 **VECTOR GRP S5** the vector group numeral.

The device automatically computes from the these data of the protected transformer and its windings the current-matching formulae which are required to match the vector group and the different rated winding currents. The currents are converted such that the sensitivity of the protection always refers to the power rating of the transformer; this is the maximum of the winding ratings. No circuity is required for matching of the vector group and no manual calculations for converting of rated current are normally necessary.

Object Data with Generators, Motors or Reactors

Using the 7UT6 for protection of generators or motors, the following must have been set when configuring the scope of functions (see Subsection 2.1.1, address 105): **PROT. OBJECT** = ***Generator/Motor***. These settings also apply for series and shunt reactors if a complete set of current transformers is connected to both sides. In cases other than that, these settings are not available.

With address 361 **UN GEN/MOTOR** you inform the device of the primary rated voltage (phase-to-phase) of the machine to be protected.

The primary rated power **SN GEN/MOTOR** (address 362) is the direct primary rated apparent power of the machine. The power must always be entered as a primary value, even if the device is generally configured in secondary values. The device calculates the rated current of the protected object and its sides from this power and the rated voltage. This is the reference for all referred values.

Object Data with Mini-Busbars or Short Lines (3-phase)

These data are only required if the device is used for differential protection of mini-busbars or short lines. When configuring the scope of functions (see Subsection 2.1.1, address 105) the following must have been set: **PROT. OBJECT** = ***3ph Busbar***. In cases other than that, these settings are not available.

With address 370 **UN BUSBAR** you inform the device of the primary rated voltage (phase-to-phase). This setting is important for voltage-dependent protection functions (such as overexcitation protection). It also influences the display of the operational measured values.

The feeders of a busbar may be rated for different currents. For instance, an overhead line may be able to carry higher load than a cable feeder or a transformer feeder. You can define a primary rated current for each side (= feeder) of the protected object. These ratings may differ from the rated currents of the associated current transformers which latter will be entered at a later stage (current transformer data). Figure 2-10 shows an example for a busbar with 3 feeders.

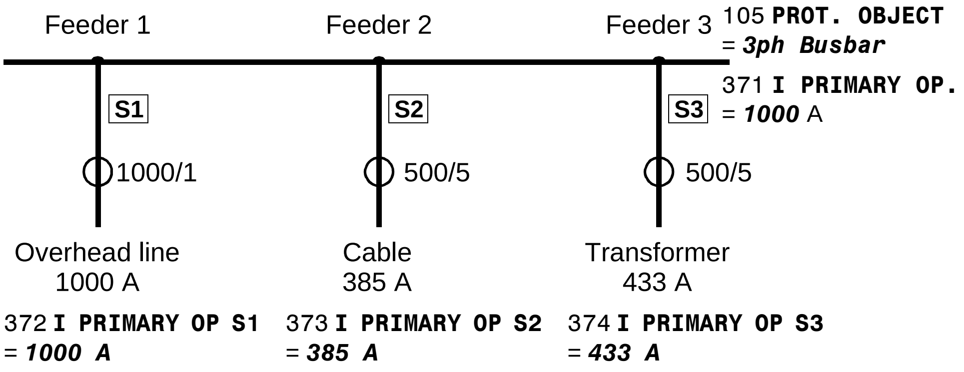


Figure 2-10 Rated current of the sides of a busbar with 3 feeders

Additionally, a rated current for the entire busbar can be determined. The currents of all measuring locations assigned to the main object are converted such that the values of the differential protection are referred to this nominal current of the main protected object, here the busbar. If the current rating of the busbar is known, set this rated current in address 371 **I PRIMARY OP BB**. If no rated current of the busbar is defined you should select the highest of the rated currents of the sides (= feeders). In Figure 2-10, the nominal object current would be 1000 A.

The object data concern only data of the protected main object as defined in the topology according to Subsection 2.1.2. No data of the sides which are not assigned are requested here. Such data are entered at a later stage (margin header “Object Data for Further Protected Objects”).

Under Address 372 **I PRIMARY OP S1**, set the rated primary current of the feeder 1. As mentioned above, the sides and the assigned measurement locations are identical for busbars.

The same considerations apply for the further sides:
address 373 **I PRIMARY OP S2** for side (feeder) 2,
address 374 **I PRIMARY OP S3** for side (feeder) 3,
address 375 **I PRIMARY OP S4** for side (feeder) 4,
address 376 **I PRIMARY OP S5** for side (feeder) 5.

Addresses 375 and 376 are omitted in 7UT613 and 7UT633 since these versions allow only for 3 sides.

Object Data with Busbars (1-phase Connection) with up to 6 or 9 or 12 Feeders

These busbar data are only required if the device is used for single-phase busbar differential protection. When configuring the protection functions (see Subsection 2.1.1, address 105) following must have been set: **PROT. OBJECT** = ***1ph Busbar***. In cases other than that, these settings are not available. 7UT613 and 7UT633 allow up to 9, 7UT635 up to 12 feeders. If interposed summation transformers with 0.1 A rated output are used, 7UT613 and 7UT633 allow 6 feeders.

With address 370 **UN BUSBAR** you inform the device of the primary rated voltage (phase-to-phase). This setting has no effect on the protective functions but influences the displays of the operational measured values.

The feeders of a busbar may be rated for different currents. For instance, an overhead line may be able to carry higher load than a cable feeder or a transformer feeder. You can define a rated current for each feeder of the protected object. These ratings may differ from the rated currents of the associated current transformers which latter will be entered at a later stage (current transformer data). Figure 2-10 shows an example of a busbar with 3 feeders.

Additionally, a rated current for the entire busbar can be determined. The currents of all measuring locations assigned to the main object are converted such that the values of the differential protection are referred to this nominal current of the main protected object, here the busbar. If the current rating of the busbar is known, set this rated current in address 371 **I PRIMARY OP.**. If no rated current of the busbar is defined you should select the highest of the rated currents of the sides (= feeders). In Figure 2-10, the nominal object current would be 1000 A.

Under Address 381 **I PRIMARY OP 1**, set the rated primary current of feeder 1.

The same considerations apply for the further feeders:
address 382 **I PRIMARY OP 2** for feeder 2,
address 383 **I PRIMARY OP 3** for feeder 3,
address 384 **I PRIMARY OP 4** for feeder 4,
address 385 **I PRIMARY OP 5** for feeder 5,
address 386 **I PRIMARY OP 6** for feeder 6,
address 387 **I PRIMARY OP 7** for feeder 7,
address 388 **I PRIMARY OP 8** for feeder 8,
address 389 **I PRIMARY OP 9** for feeder 9,
address 390 **I PRIMARY OP 10** for feeder 10,
address 391 **I PRIMARY OP 11** for feeder 11,
address 392 **I PRIMARY OP 12** for feeder 12.

Addresses 387 to 392 are omitted in 7UT613 and 7UT633 with summation transformers or 390 to 392 otherwise since these versions allow only for 6 or 9 feeders.

If one 7UT6 is used per phase, set the same rated current and voltage of a feeder for all three devices. For the identification of the phases for fault annunciations and measured values each device is to be informed on the phase it is assigned to. This is to be set in address **PHASE SELECTION**, address 396.

Object Data for Further Protected Objects

The object data described in the previous paragraphs relate to the main protected object whose sides and measuring locations have been assigned according to Subsection 2.1.2. If you have defined further protected objects in your topology, a number of non-assigned measuring locations will be left. The rated values of these are requested now.

The considerations concerning rated voltages and current are the same as for the main protected object. Only those of the following addresses will appear during setting which relate to the non-assigned measuring locations, according to the set topology. Since the main protected object provides at least 2 measuring locations (differential protection would make no sense with fewer), M1 and M2 will never appear here.

Address 403 **I PRIMARY OP M3** requests the nominal primary operating current at the measuring location M3 provided this is not assigned to the main protected object.

Address 404 **I PRIMARY OP M4** requests the nominal primary operating current at the measuring location M4 provided this is not assigned to the main protected object.

Address 405 **I PRIMARY OP M5** requests the nominal primary operating current at the measuring location M5 provided this is not assigned to the main protected object.

Addresses 404 and 405 cannot appear in 7UT613 and 7UT633 since these versions allow only 3 measuring locations.

Voltage data have only a meaning in 7UT613 or 7UT633 if the device is equipped with voltage inputs. In case the 3-phase voltage inputs relate to the main protected object the nominal voltages have already been set. But, if 3-phase voltage measurement is intended at a measuring location which is not assigned to the main protected object, e.g. in address 261 **VT SET** a non-assigned ***Measuring loc.3*** is selected, then you have to enter the nominal voltage of this measuring location in address 408 **UN-PRI M3**. This is a precondition for correct display and transmission of measured values (voltages, powers). Similar considerations apply for address 409 **UN-PRI U4**.

Current Transformer Data for 3-phase Measuring Locations

The rated primary operational currents for the protected object and its sides derive from the object data before-described. The data of the current transformer sets at the sides of the protected object generally differ slightly from the object data before-described. They can also be completely different. Currents have to have a clear polarity to ensure correct function of the differential protection and restricted earth fault protection as well as for correct display of operational measure values.

Therefore the device must be informed about the current transformer data. For 3-phase protected objects, this is done by entering rated currents and the secondary starpoint position of the current transformer sets.

In address 512 **IN-PRI CT M1** the rated primary current of the current transformer set of measuring location M1 is set, In address 513 **IN-SEC CT M1** the rated secondary current. Please make sure that the sides were defined correctly (see Subsection 2.1.2, margin heading “Assignment of 3-phase Measuring Locations”, page 28). Please also make sure that the rated secondary transformer currents match the setting for the rated currents of the device (see also Subsection 3.1.3.3, margin heading “Input/Output Board C-I/O-2 (7UT613 or 7UT633)”, “Input/Output Board C-I/O-9 (All Versions)”, and “Input/Output Board C-I/O-9 (7UT635 only)”. Otherwise the device will calculate incorrect primary data, and malfunction of the differential protection may occur.

Indication of the starpoint position of the current transformers determines the polarity of the currents. To inform the device of the starpoint position in relation to the measuring location 1, use address 511 **STRPNT->OBJ M1** (starpoint versus object at measuring location M1. Figure 2-11 shows some examples for this setting.

Similar applies for the further measuring locations (assigned or non-assigned to the main protected object). Only those addresses will appear during setting which are available in the actual device version.

Address 521 **STRPNT->OBJ M2** starpoint position of CTs for measuring location M2,
Address 522 **IN-PRI CT M2** prim. rated current of CTs for measuring location M2,
Address 523 **IN-SEC CT M2** sec. rated current of CTs for measuring location M2.

Address 531 **STRPNT->OBJ M3** starpoint position of CTs for measuring location M3,
Address 532 **IN-PRI CT M3** prim. rated current of CTs for measuring location M3,
Address 533 **IN-SEC CT M3** sec. rated current of CTs for measuring location M3.

Address 541 **STRPNT->OBJ M4** starpoint position of CTs for measuring location M4,
Address 542 **IN-PRI CT M4** prim. rated current of CTs for measuring location M4,
Address 543 **IN-SEC CT M4** sec. rated current of CTs for measuring location M4.

Address 551 **STRPNT->OBJ M5** starpoint position of CTs for measuring location M5,
Address 552 **IN-PRI CT M5** prim. rated current of CTs for measuring location M5,
Address 553 **IN-SEC CT M5** sec. rated current of CTs for measuring location M5.

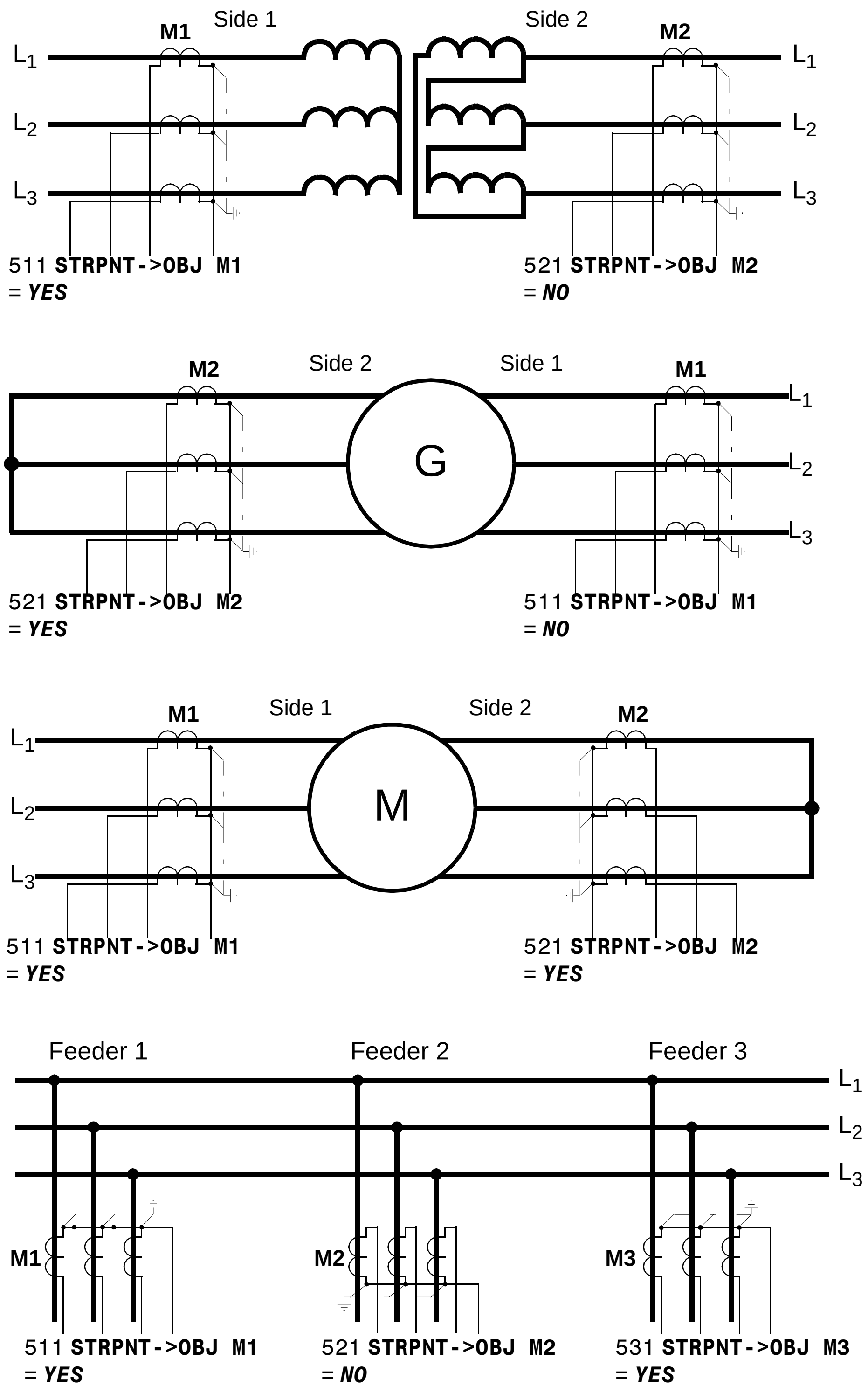


Figure 2-11 Position of the CT starpoints — examples

If the device is applied as transverse differential protection for generators or motors, special considerations must be observed for the CT connections: In a healthy operational state all currents flow into the protected object, i.e. in contrast to the other applications. Therefore you have to set a “wrong” polarity for *one* of the current transformer sets. The part windings of the machine windings correspond to the “sides”.

Figure 2-12 gives you an example: Although the starpoints of both current transformer sets are looking towards the protected object, the opposite setting is to be selected for “side 2”: **STRPNT->OBJ M2** = ***NO***.

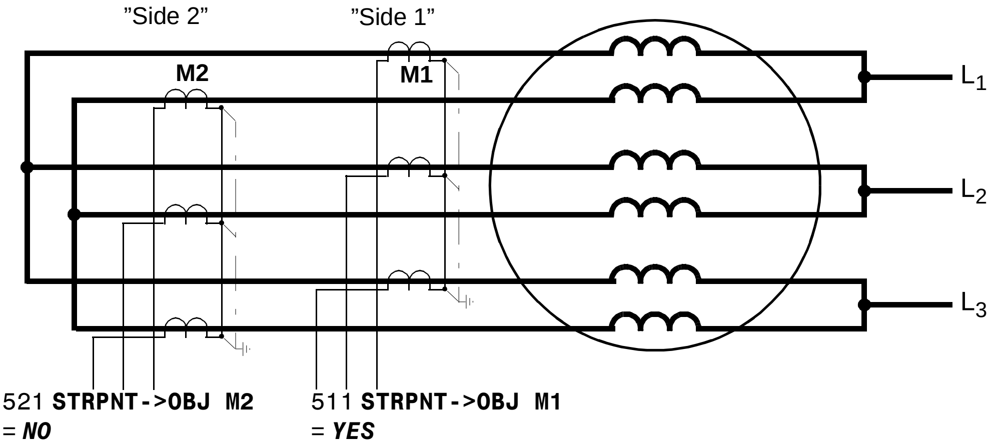


Figure 2-12 Definition of current direction for transverse differential protection - example

Current Transformer Data for 1-phase Busbar Protection

The operational nominal currents of each feeder already have been set under margin heading “Object Data with Busbars (1-phase Connection) with up to 6 or 9 or 12 Feeders” (page 40). The feeder currents are referred to these nominal feeder currents. But, the rated currents of the current transformers may differ from the nominal feeder currents. Therefore, the device must be informed about the current transformer data, too. In Figure 2-13 the rated CT currents are 1000 A (Feeder 1), 500 A (Feeder 2 and 3).

If rated currents have already been matched by external equipment (e.g. by matching transformers), the rated current value, used as a base value for the calculation of the external matching transformers, is to be indicated uniform. Normally, it is the rated operational current. The same applies if external summation transformers are used.

Indicate the rated primary transformer current for each feeder. The interrogation only applies to data of the number of feeders determined during the configuration according to 2.1.2 under margin “Global Data for 1-phase Busbar Protection” (address 216 **NUMBER OF ENDS**).

For rated secondary currents please make sure that rated secondary transformer currents match with the rated currents of the corresponding current input of the device. Rated secondary currents of a device can be matched according to 3.1.3.3 (see margin heading “Input/Output Board C-I/O-2 (7UT613 or 7UT633)”, “Input/Output Board C-I/O-9 (All Versions)”, and “Input/Output Board C-I/O-9 (7UT635 only)”). If summation transformers are used, the rated current at the outgoing side is usually 100 mA. For rated secondary currents a value of ***0.1*** A is therefore set for all feeders.

Indication of the starpoint position of the current transformers determines the polarity of the current transformers. Set for each feeder if the starpoint is looking towards the busbar or not. Figure 2-13 shows an example of 3 feeders in which the transformer starpoint in feeder 1 and feeder 3 are looking towards the busbar, unlike feeder 2.

If external interposed transformers are used, it is presumed that these are connected with correct polarity.

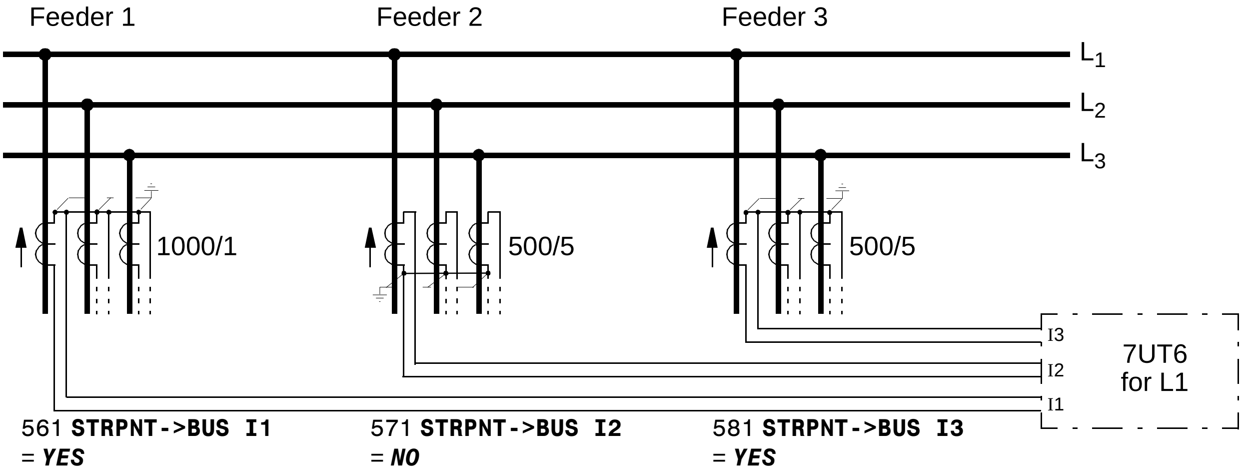


Figure 2-13 Position of the CT starpoints — example for phase L1 of a busbar with 3 feeders

Hereinafter the parameters for the individual feeders:
Address 561 **STRPNT->BUS I1** = CT starpoint versus busbar for feeder 1,
Address 562 **IN-PRI CT I1** = rated primary CT current for feeder 1,
Address 563 **IN-SEC CT I1** = rated secondary CT current for feeder 1.

Address 571 **STRPNT->BUS I2** = CT starpoint versus busbar for feeder 2,
Address 572 **IN-PRI CT I2** = rated primary CT current for feeder 2,
Address 573 **IN-SEC CT I2** = rated secondary CT current for feeder 2.

Address 581 **STRPNT->BUS I3** = CT starpoint versus busbar for feeder 3,
Address 582 **IN-PRI CT I3** = rated primary CT current for feeder 3,
Address 583 **IN-SEC CT I3** = rated secondary CT current for feeder 3.

Address 591 **STRPNT->BUS I4** = CT starpoint versus busbar for feeder 4,
Address 592 **IN-PRI CT I4** = rated primary CT current for feeder 4,
Address 593 **IN-SEC CT I4** = rated secondary CT current for feeder 4.

Address 601 **STRPNT->BUS I5** = CT starpoint versus busbar for feeder 5,
Address 602 **IN-PRI CT I5** = rated primary CT current for feeder 5,
Address 603 **IN-SEC CT I5** = rated secondary CT current for feeder 5.

Address 611 **STRPNT->BUS I6** = CT starpoint versus busbar for feeder 6,
Address 612 **IN-PRI CT I6** = rated primary CT current for feeder 6,
Address 613 **IN-SEC CT I6** = rated secondary CT current for feeder 6.

For 7UT613/7UT633 with 1-phase connection without summation transformers and for 7UT635:

Address 621 **STRPNT->BUS I7** = CT starpoint versus busbar for feeder 7,
Address 622 **IN-PRI CT I7** = rated primary CT current for feeder 7,
Address 623 **IN-SEC CT I7** = rated secondary CT current for feeder 7.

Address 631 **STRPNT->BUS I8** = CT starpoint versus busbar for feeder 8,
Address 632 **IN-PRI CT I8** = rated primary CT current for feeder 8,
Address 633 **IN-SEC CT I8** = rated secondary CT current for feeder 8.

Address 641 **STRPNT->BUS I9** = CT starpoint versus busbar for feeder 9,
Address 642 **IN-PRI CT I9** = rated primary CT current for feeder 9,
Address 643 **IN-SEC CT I9** = rated secondary CT current for feeder 9.

For 7UT635:

Address 651 **STRPNT->BUS I10** = CT starpoint versus busbar for feeder 10,
Address 652 **IN-PRI CT I10** = rated primary CT current for feeder 10,
Address 653 **IN-SEC CT I10** = rated secondary CT current for feeder 10.

Address 661 **STRPNT->BUS I11** = CT starpoint versus busbar for feeder 11,
Address 662 **IN-PRI CT I11** = rated primary CT current for feeder 11,
Address 663 **IN-SEC CT I11** = rated secondary CT current for feeder 11.

Address 671 **STRPNT->BUS I12** = CT starpoint versus busbar for feeder 12,
Address 672 **IN-PRI CT I12** = rated primary CT current for feeder 12,
Address 673 **IN-SEC CT I12** = rated secondary CT current for feeder 12.

Current Transformer Data for 1-phase Auxiliary Current Inputs

The number of 1-phase auxiliary current inputs depends on the device version, see also Table 2-1. Such inputs are used for detection of the starpoint current of an earthed winding of a transformer, generator, or motor, shunt reactor, or neutral reactor, or for different 1-phase measuring purposes. The assignment has already been carried out according Subsection 2.1.2 under margin “Assignment of Auxiliary 1-phase Measuring Locations”, page 32), the assignment of the protection functions will be done in Subsection 2.1.4. These settings here concern exclusively the current transformer data regardless whether or not they belong to the main protected object.

The device requests also the polarity and rated currents of these 1-phase CTs. The clarifications below comprise all possible settings, in the actual case only those addresses will appear which are available in the actual version and defined in the topology.

Enter the primary rated current of each auxiliary 1-phase current transformer which is connected and assigned to an auxiliary 1-phase current input of the device. Consider the correct assignment of the measuring locations (Subsection 2.1.2 under “Assignment of Auxiliary 1-phase Measuring Locations”, page 32).

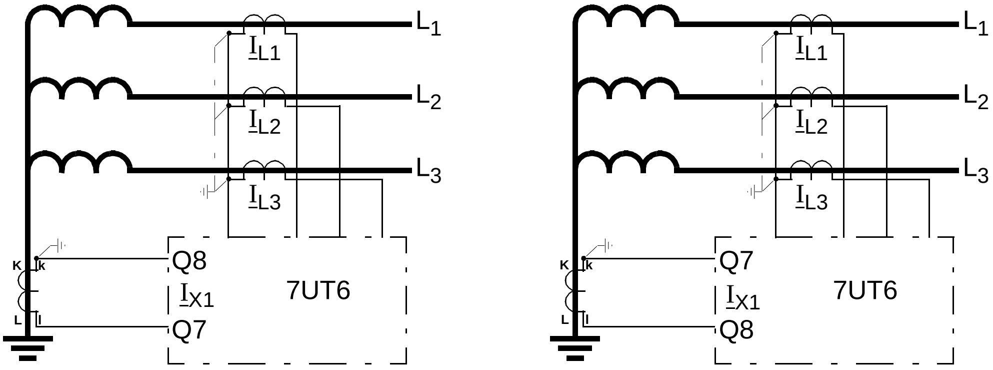
Distinction must be made for the secondary rated currents whether the 1-phase current input is a “normal” input or a “highly sensitive” input of the device:

If a “normal” input is concerned, set the secondary current in the same way as for the 3-phase current inputs. Please make sure that the rated secondary CT current matches with the rated current of the corresponding current input of the device. Rated secondary currents of a device can be matched according to 3.1.3.3 (see margin heading “Input/Output Board C-I/O-2 (7UT613 or 7UT633)”, “Input/Output Board C-I/O-9 (All Versions)”, and “Input/Output Board C-I/O-9 (7UT635 only)”).

If a “high-sensitivity” current input is used, no rated secondary current is defined. In order to calculate primary values in spite of this (e.g. for setting in primary values or for output of primary measured values), the conversion factor I_{Nprim}/I_{Nsec} of the current transformer connected is set.

The polarity of a 1-phase current input is important for correct function of the differential protection and the restricted earth fault protection. If only the magnitude of the current is of interest (e.g. for earth overcurrent protection or single-phase overcurrent protection) the polarity is irrelevant as it is also irrelevant for a high-sensitivity input.

For polarity information, set to which device terminal the side of the current transformer facing the earth electrode is connected, i.e. not the side facing the starpoint itself. The secondary earthing point of the CT is of no interest. Figure 2-14 shows the alternatives using an earthed transformer winding as an example.



711 **EARTH IX1 AT**
= ***Terminal Q7***

711 **EARTH IX1 AT**
= ***Terminal Q8***

Figure 2-14 Polarity setting for the measured current input I_{X1}

The following applies for the (max. 4, dependent on device version on connections) 1-phase current inputs:

For the auxiliary measuring input X1
Address 711 **EARTH IX1 AT** with the options ***Terminal Q7*** or ***Terminal Q8***,
Address 712 **IN-PRI CT IX1** = primary rated CT current,
Address 713 **IN-SEC CT IX1** = secondary rated CT current.

For the auxiliary measuring input X2
Address 721 **EARTH IX2 AT** with the options ***Terminal N7*** or ***Terminal N8***,
Address 722 **IN-PRI CT IX2** = primary rated CT current,
Address 723 **IN-SEC CT IX2** = secondary rated CT current.

For the auxiliary measuring input X3
Address 731 **EARTH IX3 AT** with the options ***Terminal R7*** or ***Terminal R8*** (not for high-sensitivity input),
Address 732 **IN-PRI CT IX3** = primary rated CT current,
Address 733 **IN-SEC CT IX3** = sec. rated CT current (not for high-sensitivity input)
Address 734 **FACTOR CT IX3** = CT transform. ratio (only for high-sensitivity input).

For the auxiliary measuring input X4
Address 741 **EARTH IX4 AT** with the options ***Terminal P7*** or ***Terminal P8*** (not for high-sensitivity input),
Address 742 **IN-PRI CT IX4** = primary rated CT current,

Address 743 **IN-SEC CT IX4** = sec. rated CT current (not for high-sensitivity input)
Address 744 **FACTOR CT IX4** = CT transform. ratio (only for high-sensitivity input).

Note:

For devices in panel surface mounted case, terminal designations apply as to Table 2-2.

Table 2-2 Terminal designation with surface mounted cases

Flush Mounted Case, Terminal	Corresponds to Surface Mounted Case, Terminal			1-phase Current Input
	7UT613	7UT633	7UT635	
Terminal Q7	22	47	47	IX1
Terminal Q8	47	97	97	
Terminal N7	11	36	36	IX2
Terminal N8	36	86	86	
Terminal R7	18	43	43	IX3
Terminal R8	43	93	93	
Terminal P7	—	—	32	IX4
Terminal P8	—	—	82	

Voltage Transformer Data

If the device is equipped with measuring voltage inputs and these inputs are assigned, the voltage transformer data are of relevance.

For the 3-phase voltage input, you set at address 801 **UN-PRI VT SET** the primary rated VT voltage (phase-to-phase), and at address 802 **UN-SEC VT SET** the secondary rated VT voltage.

For the 1-phase voltage input, you set at address 811 **UN-PRI VT U4** the primary rated voltage of the connected 1-phase voltage transformer, and at address 812 **UN-SEC VT U4** the secondary voltage.

2.1.4 Assignment of Protection Functions to Measuring Locations/Sides

Main Protection Function = Differential Protection

The main protected object, i.e. the protected object which has been selected at address 105 **PROT. OBJECT** during the configuration of the protection function, is always defined by its sides, each of which can have one or multiple measuring locations assigned to them (Subsection 2.1.2 under margin header “Assignment of 3-phase Measuring Locations” and subsequent margins). Combined with the object and instrument transformer data according to Subsection 2.1.3, the sides define unambiguously the way to process the currents supplied by the measuring locations (CT sets) for the main protection function, the differential protection (Section 2.2).

In the example shown in Figure 2-1, the side **S1** (upper voltage side of the transformer) has the 3-phase measuring locations **M1** and **M2** assigned to it. This ensures that the summated currents flowing through M1 and M2 towards the protected object are evaluated as currents flowing into the transformer side S1. Likewise, the currents flowing through **M3** and **M4** towards the protected object are evaluated as currents flowing into the transformer side S2. Where an external current flows in through M4 and out again through M3, the sum is $\underline{I}_{M3} + \underline{I}_{M4} = 0$, i.e. no current flows into the protected object at that point. Nevertheless both currents are used for restraint of the differential protection. For more details, please refer to the description of the differential protection function (Subsection 2.1.1).

By the assignment of the auxiliary measuring location X3 to side S1 of the transformer, it is defined that the 1-phase earth fault current measured at **X3** flows into the starpoint of the higher voltage winding S1 (Section 2.1.2 under margin heading “Assignment of Auxiliary 1-phase Measuring Locations”).

As the topology thus provides for the differential protection a full description of the protected object with all its sides and measuring locations, no further information is required for this function. There are, however, various possibilities to enter information for the other protection functions.

Restricted Earth Fault Protection

Normally, the restricted earth fault protection (Section 2.3) is assigned to one side of the main protected object, namely the side with the earthed starpoint. In the example shown in Figure 2-1, this would be the side **S1**; therefore, address 413 **REF PROT. AT** would be set to ***Side 1***. The 3-phase measuring locations **M1** and **M2** have been assigned to this side during the definition of the topology. Therefore, the sum of the currents $\underline{I}_{M1} + \underline{I}_{M2}$ is considered to be flowing into side S1 of the transformer.

By the assignment of the auxiliary measuring location X3 to side S1 of the transformer, it is defined that the 1-phase earth fault current measured at **X3** flows into the starpoint of side **S1** (Subsection 2.1.2 under margin heading “Assignment of Auxiliary 1-phase Measuring Locations“).

But the restricted earth fault protection can also act upon an object other than the main protected object. In Figure 2-2 the main protected object is a three-winding transformer with the sides S1, S2 and S3. The 3-phase measuring location **M5**, on the other hand, belongs to the neutral reactor. You have now the option to use the restricted earth fault protection for this reactor. Since for this further protection object no sides are defined, you can assign here the restricted earth fault protection to the 3-phase measuring location **M5**, which is not assigned to the main protection object: set address 413 **REF PROT. AT** to ***n.assigMeasLoc5***.

By the assignment of the auxiliary measuring location X4 to the 3-phase measuring location M5, it is defined that the 1-phase earth fault current measured at **X4** belongs to the neutral reactor connected to M5 (Subsection 2.1.2 under margin heading “Assignment of Auxiliary 1-phase Measuring Locations”).

Further 3-Phase Protection Functions

Remember that the single-phase power transformer is treated like a three-phase power transformer (without phase L2). Therefore, the three-phase protection functions apply also for this.

The time overcurrent protection for zero-sequence current is also a three-phase protection function as it processes the sum of the three phase currents.

These three-phase protection functions can operate on the main protected object or on a further protected object. The facilities depend on the topology as stated in Subsection 2.1.2.

For the main protection object, you normally choose one side for which the protection function will be effective. If in the example shown in Figure 2-1 you want to use the time overcurrent protection for phase currents (Section 2.4) as a backup protection on the upper voltage side, you set address 420 **DMT/IDMT Ph AT** to ***Side 1***. The phase overcurrent protection then acquires the sum of the currents flowing through the measuring locations M1 and M2 (for each phase) towards the transformer.

You can also set the phase overcurrent protection to be effective for one single measuring location of the main protected object. If in the same example you want to use the overcurrent protection as a protection for the auxiliaries system circuit, you set address 420 **DMT/IDMT Ph AT** to ***Measuring loc.3***.

Finally, you can also set the overcurrent protection to be effective for a further protection object, i.e. a 3-phase measuring location which is not assigned to the main protection object. To do so, you select that measuring location. In the example shown in Figure 2-1, you can use the overcurrent protection as a protection for the cable feeder by setting address 420 **DMT/IDMT Ph AT** to ***Measuring loc.5***.

As the above examples show, this protection function can be assigned as desired. Generally speaking:

- Where a 3-phase protection function is assigned to a measuring location, the currents are acquired at this location, regardless of whether it is assigned to the main protected object or not.
- Where a 3-phase protection function is assigned to a side (of the main protected object), the sum of the currents flowing in at this side from the measuring locations assigned to it is acquired (for each phase).
- Consider also that the time overcurrent protection will receive from the further measuring location assigned here not only its measured values, but also circuit breaker information (current flow and manual-close detection).

The same is true for the assignment of the time overcurrent protection for residual currents (Section 2.4) in address 422 **DMT/IDMT 3I0 AT**. Please keep in mind that this protection function acquires the sum of the phase currents and is therefore considered as a three-phase protection function. The assignment, however, can differ from the assignment used by the overcurrent protection for phase currents. This means that in the example shown in Figure 2-1 you can easily use the overcurrent protection for phase currents (**DMT/IDMT Ph AT**) at the upper voltage side of the transformer (***Side 1***), and the overcurrent protection for residual currents (**DMT/IDMT 3I0 AT**) at the lower voltage side (***Measuring loc.4***).

The same options exist for the unbalanced load protection (Section 2.8) (address 440 **UNBAL. LOAD AT**).

The overload protection (Section 2.9) will always operated on a side of the main protected object. Consequently, address 442 **THERM. O/L AT** allows to select only a side, not a measuring location.

Since the cause for overload comes from outside of the protected object, the overload current is a traversing current. Therefore it does not necessarily have to be detected at the infeeding side.

– For transformers with tap changer the overload protection is assigned to the non-regulated side as it is the only side where we have a defined relation between rated current and rated power.

– For generators the overload protection usually is on the starpoint side.

– For motors and shunt reactors the overload protection is connected to the current transformers of the feeding side.

– For series reactors, lines and busbars there any side can be selected.

– Busbars and sections of overhead lines usually do not require overload protection since it is not reasonable to calculate the temperature rise. Climate and weather conditions (temperature, wind) change to quick. On the other hand, the current alarm stage is able to warn of menacing overload.

The overexcitation protection (Section 2.11) is only possible for devices with voltage connection, and requires a measuring voltage to be connected and declared in the topology (Section 2.1.2 under margin heading “Assignment of Voltage Measuring Inputs”). It is not necessary to assign the protection function, since it always evaluates the three-phase measuring voltages at the voltage inputs, and the frequency derived from it.

When using the circuit breaker failure protection (Section 2.12) (address 470 **BREAKER FAIL.AT**) please make sure that the assignment of this protection function corresponds to *that* side or measuring location whose current actually flows through the circuit breaker to be monitored. In the example shown in Figure 2-1, the assignment must be set in address 470 **BREAKER FAIL.AT** to ***Side 1*** if you want to monitor the circuit breaker of the upper voltage side, since both currents flow through the breaker (via M1 and M2). If on the other hand you want to monitor the circuit breaker of the cable feeder, you set address 470 **BREAKER FAIL.AT** to ***Measuring loc.5***. When assigning the circuit breaker failure protection function, make sure that the breaker auxiliary contacts or feedback information are correctly configured and assigned. Subsection 2.1.5 offers further details.

If you do not wish to assign any measuring location or side to the circuit breaker failure protection because you want only the breaker position to be processed, set **BREAKER FAIL.AT** to ***Ext. switchg. 1***, i.e. external switching device. In this case, the protection handles only the breaker position but not any current flow for its operation. This allows even to monitor a circuit breaker the current of which is not connected to the device. But you have to ensure that the feedback information of this breaker is correctly connected and configured (Subsection 2.1.5).

Further 1-Phase Protection Functions

The 1-phase protection functions evaluate the 1-phase measuring current of a 1-phase auxiliary measuring input. It is irrelevant in this context whether the connected current belongs to the main protected object or not. Only the current connected to the auxiliary measuring input is decisive.

The device must now be informed which current is to be evaluated by the 1-phase protection functions.

Address 424 **DMT/IDMT E AT**. assigns the time overcurrent protection for earth current (Section 2.5) to a 1-phase auxiliary measuring input. In most cases this will be the current flowing in the neutral leads of an earthed winding, measured between the starpoint and the earth electrode. In Figure 2-1 the auxiliary measuring location X3 would be a good choice; so you set here ***AuxiliaryCT IX3***. As this protection function is autonomous, i.e. independent of any other protection function, any 1-phase auxiliary measuring input can be used. This requires, however, that it is not a high-sensitivity measuring input and, of course, that it is connected. Please note also that the earth overcurrent protection will receive from the auxiliary measuring location assigned here not only its measured value, but also circuit breaker information (current flow and manual-close detection).

Address 427 **DMT 1PHASE AT** assigns the single-phase time overcurrent protection (Section 2.7). This protection function is mainly used for high-sensitivity current measurement, e.g. for tank leakage protection or high-impedance unit protection. Therefore a high-sensitivity 1-phase auxiliary measuring input is particularly suited for it. In Figure 2-1 this would be the auxiliary measuring location X4; so you set this address to ***AuxiliaryCT IX4***. However, it is also possible to assign this protection function to any other auxiliary measuring input used, regardless of its sensitivity.

2.1.5 Circuit Breaker Data (Power System Data 1)

Circuit Breaker Status

Various protection and ancillary functions require information of the status of the circuit breaker for faultless operation. Command processing makes also use of the feed-back information from the switching devices.

If, for instance, the circuit breaker failure protection is used to monitor the reaction of a specific circuit breaker, the protection device must know the measuring location at which the current flowing through the breaker is acquired, and the binary inputs which provide information on the breaker status. During the configuration of the binary inputs you merely assigned the (physical) binary inputs to the (logic) functions. The device, however, must also know which measuring location(s) the circuit breaker is assigned to.

The breaker failure protection — and thus the circuit breaker that is monitored by it — is normally assigned to a measuring location or to a side (see above, Subsection 2.1.4 under margin heading “Further 3-Phase Protection Functions”, page 49). You can therefore set addresses 831 to 835 **SwitchgCBaux S**... if a side is concerned, or addresses 836 to 840 **SwitchgCBaux M**... if a measuring location is concerned.

You can, alternatively, monitor any desired circuit breaker, exclusively by means of the CB position indication, i.e. without consideration of current flow. In this case you must have selected ***Ext. switchg. 1*** under address 470 **BREAKER FAIL.AT**. You have then to select the corresponding breaker feedback information under address 841 **SwitchgCBaux E1** (switching device auxiliary contact of external breaker).

Select the address which corresponds to the assignment of the circuit breaker failure protection. There, you choose from the following options:

1. If, during the configuration of the binary inputs, you have defined the circuit breaker as a control object, and allocated the appropriate feedback indications, you choose these feedback indications to determine the circuit breaker position, e.g. ***Q0***. The breaker position is then automatically derived from the circuit breaker Q0.
2. If during the configuration of the binary inputs you have generated a single-point indication which is controlled by the NC or NO auxiliary contacts of the circuit breaker, you select this indication.

3. If during the configuration of the binary inputs you have generated a double-point indication which is controlled by the NC and NO auxiliary contact of the circuit breaker (feedback from the switching device), you select this indication.
4. If you have generated appropriate indications using CFC, you can select these indications.

In any case, you must make sure that the selected option indicates also the position of the monitored circuit breaker. If you have not yet generated an indication for control and feed-back of the breaker to be monitored you should make up for it now. Detailed information is given in the SIPROTEC® System Manual, order-no. E50417–H1176–C151 (Section 5.7).

Example:

> The group “Control Devices” of the configuration matrix contains a double-point indication “`Q0`”. Assuming this should be the breaker to be monitored, you have determined during configuration the physical inputs of the device at which the feedback indication of the breaker Q0 arrive. For example, if the breaker failure protection should monitor the breaker at the high-voltage side (= Side 1) of the transformer in Figure 2-1 you set:
> Address `831` **`SwitchgCBaux S1`** (because breaker at Side S1 is monitored) = ***`Q0`*** (because indication “`Q0`” indicates feed-back of the breaker).

Of course, you can define any desired input indication which indicates the breaker position via an correspondingly assigned physical input.

Manual Close Indication of a Circuit Breaker

If a protection function is to make use of an *external* manual-close command indicated via a binary input, you must have selected *that* logical input indication during the configuration of the binary inputs that corresponds to the side or measuring location to which the protection function is assigned. From the *internal* control, the device uses the same switching objects that were selected at the addresses `831` to `840` (above).

Example:

> If you have assigned the time overcurrent protection for phase currents to measuring location M4 and want it to receive the manual-close command from circuit breaker CB2, you connect the Close command for breaker CB2 to a binary input and allocate that input to “`>ManualClose M4`” (FNo `30354`).

Trip Command Duration

The minimum trip command duration **`TMin TRIP CMD`** is set in address `851`A. This duration is valid for all protection functions which can issue a trip command. This parameter can only be altered with DIGSI® under “**Additional Settings**”.

2.1.6 Setting Overview

Addr.	Setting Title	Setting Options	Default Setting	Comments
211	No Conn.MeasLoc	2 3 4 5	3	Number of connected Measuring Locations
212	No AssigMeasLoc	2 3 4 5	3	Number of assigned Measuring Locations
213	NUMBER OF SIDES	2 3 4 5	3	Number of Sides
216	NUMBER OF ENDS	3 4 5 6 7 8 9 10 11 12	6	Number of Ends for 1 Phase Busbar
220	ASSIGNM. 2M,2S	S1:M1, S2:M2	S1:M1, S2:M2	Assignment at 2 assig.Meas.Loc./ 2 Sides
221	ASSIGNM. 3M,2S	S1:M1+M2, S2:M3 S1:M1, S2:M2+M3	S1:M1+M2, S2:M3	Assignment at 3 assig.Meas.Loc./ 2 Sides
222	ASSIGNM. 3M,3S	S1:M1, S2:M2, S3:M3	S1:M1, S2:M2, S3:M3	Assignment at 3 assig.Meas.Loc./ 3 Sides
223	ASSIGNM. 4M,2S	S1:M1+M2, S2:M3+M4 S1:M1+M2+M3, S2:M4 S1:M1, S2:M2+M3+M4	S1:M1+M2, S2:M3+M4	Assignment at 4 assig.Meas.Loc./ 2 Sides
224	ASSIGNM. 4M,3S	S1:M1+M2, S2:M3, S3:M4 S1:M1, S2:M2+M3, S3:M4 S1:M1, S2:M2, S3:M3+M4	S1:M1+M2, S2:M3, S3:M4	Assignment at 4 assig.Meas.Loc./ 3 Sides
225	ASSIGNM. 4M,4S	S1:M1, S2:M2, S3:M3, S4:M4	S1:M1, S2:M2, S3:M3, S4:M4	Assignment at 4 assig.Meas.Loc./ 4 Sides
226	ASSIGNM. 5M,2S	S1:M1+M2+M3, S2:M4+M5 S1:M1+M2, S2:M3+M4+M5 S1:M1+M2+M3+M4, S2:M5 S1:M1, S2:M2+M3+M4+M5	S1:M1+M2+M3, S2:M4+M5	Assignment at 5 assig.Meas.Loc./ 2 Sides

Addr.	Setting Title	Setting Options	Default Setting	Comments
227	ASSIGNM. 5M,3S	S1:M1+M2, S2:M3+M4, S3:M5 S1:M1+M2, S2:M3, S3:M4+M5 S1:M1, S2:M2+M3, S3:M4+M5 S1:M1+M2+M3, S2:M4, S3:M5 S1:M1, S2:M2+M3+M4, S3:M5 S1:M1, S2:M2, S3:M3+M4+M5	S1:M1+M2, S2:M3+M4, S3:M5	Assignment at 5 assig.Meas.Loc./ 3 Sides
228	ASSIGNM. 5M,4S	S1:M1+M2, S2:M3, S3:M4, S4:M5 S1:M1, S2:M2+M3, S3:M4, S4:M5 S1:M1, S2:M2, S3:M3+M4, S4:M5 S1:M1, S2:M2, S3:M3, S4:M4+M5	S1:M1+M2, S2:M3, S3:M4, S4:M5	Assignment at 5 assig.Meas.Loc./ 4 Sides
229	ASSIGNM. 5M,5S	S1:M1, S2:M2, S3:M3, S4:M4, S5:M5	S1:M1, S2:M2, S3:M3, S4:M4, S5:M5	Assignment at 5 assig.Meas.Loc./ 5 Sides
230	ASSIGNM. ERROR	number of assigned measuring locations number of sides	without	Assignment Error
241	SIDE 1	auto-connected	auto-connected	Side 1 is assigned to
242	SIDE 2	auto-connected	auto-connected	Side 2 is assigned to
243	SIDE 3	auto-connected compensation earthing electrode	auto-connected	Side 3 is assigned to
244	SIDE 4	auto-connected compensation earthing electrode	compensation	Side 4 is assigned to
251	AUX. CT IX1	not connected connected / not assigned Side 1 earth Side 2 earth Side 3 earth Side 4 earth Measurement location 1 earth Measurement location 2 earth Measurement location 3 earth Measurement location 4 earth	not connected	Auxiliary CT IX1 is used as
252	AUX. CT IX2	not connected connected / not assigned Side 1 earth Side 2 earth Side 3 earth Side 4 earth Measurement location 1 earth Measurement location 2 earth Measurement location 3 earth Measurement location 4 earth	not connected	Auxiliary CT IX2 is used as

Addr.	Setting Title	Setting Options	Default Setting	Comments
253	AUX. CT IX3	not connected connected / not assigned Side 1 earth Side 2 earth Side 3 earth Side 4 earth Measurement location 1 earth Measurement location 2 earth Measurement location 3 earth Measurement location 4 earth	not connected	Auxiliary CT IX3 is used as
254	AUX. CT IX4	not connected connected / not assigned Side 1 earth Side 2 earth Side 3 earth Side 4 earth Side 5 earth Measurement location 1 earth Measurement location 2 earth Measurement location 3 earth Measurement location 4 earth Measurement location 5 earth	not connected	Auxiliary CT IX4 is used as
255	AUX CT IX3 TYPE	1A/5A current input sensitiv current input	1A/5A current input	Type of auxiliary CT IX3
256	AUX CT IX4 TYPE	1A/5A current input sensitiv current input	1A/5A current input	Type of auxiliary CT IX4
261	VT SET	not connected Side 1 Side 2 Side 3 Measuring location 1 Measuring location 2 Measuring location 3 Busbar	Measuring location 1	VT set UL1, UL2, UL3 is connected to
262	VT U4	not connected connected / not assigned Side 1 Side 2 Side 3 Measuring location 1 Measuring location 2 Measuring location 3 Busbar	Measuring location 1	VT U4 is connected to
263	VT U4 TYPE	Udelta transformer UL1E transformer UL2E transformer UL3E transformer UL12 transformer UL23 transformer UL31 transformer Ux reference transformer	Udelta transformer	VT U4 is used as

Addr.	Setting Title	Setting Options	Default Setting	Comments
270	Rated Frequency	50 Hz 60 Hz 16,7 Hz	50 Hz	Rated Frequency
271	PHASE SEQ.	L1 L2 L3 L1 L3 L2	L1 L2 L3	Phase Sequence
276	TEMP. UNIT	Degree Celsius Degree Fahrenheit	Degree Celsius	Unit of temperature measurement
311	UN-PRI SIDE 1	0.4..800.0 kV	110.0 kV	Rated Primary Voltage Side 1
312	SN SIDE 1	0.20..5000.00 MVA	38.10 MVA	Rated Apparent Power of Transf. Side 1
313	STARPNT SIDE 1	Solid Earthed Isolated	Solid Earthed	Starpoint of Side 1 is
314	CONNECTION S1	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 1
321	UN-PRI SIDE 2	0.4..800.0 kV	11.0 kV	Rated Primary Voltage Side 2
322	SN SIDE 2	0.20..5000.00 MVA	38.10 MVA	Rated Apparent Power of Transf. Side 2
323	STARPNT SIDE 2	Solid Earthed Isolated	Solid Earthed	Starpoint of Side 2 is
324	CONNECTION S2	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 2
325	VECTOR GRP S2	0 1 2 3 4 5 6 7 8 9 10 11	0	Vector Group Numeral of Side 2
331	UN-PRI SIDE 3	0.4..800.0 kV	11.0 kV	Rated Primary Voltage Side 3
332	SN SIDE 3	0.20..5000.00 MVA	10.00 MVA	Rated Apparent Power of Transf. Side 3
333	STARPNT SIDE 3	Solid Earthed Isolated	Solid Earthed	Starpoint of Side 3 is
334	CONNECTION S3	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 3

Addr.	Setting Title	Setting Options	Default Setting	Comments
335	VECTOR GRP S3	0 1 2 3 4 5 6 7 8 9 10 11	0	Vector Group Numeral of Side 3
341	UN-PRI SIDE 4	0.4..800.0 kV	11.0 kV	Rated Primary Voltage Side 4
342	SN SIDE 4	0.20..5000.00 MVA	10.00 MVA	Rated Apparent Power of Transf. Side 4
343	STARPNT SIDE 4	Solid Earthed Isolated	Solid Earthed	Starpoint of Side 4 is
344	CONNECTION S4	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 4
345	VECTOR GRP S4	0 1 2 3 4 5 6 7 8 9 10 11	0	Vector Group Numeral of Side 4
351	UN-PRI SIDE 5	0.4..800.0 kV	11.0 kV	Rated Primary Voltage Side 5
352	SN SIDE 5	0.20..5000.00 MVA	10.00 MVA	Rated Apparent Power of Transf. Side 5
353	STARPNT SIDE 5	Solid Earthed Isolated	Solid Earthed	Starpoint of Side 5 is
354	CONNECTION S5	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 5

Addr.	Setting Title	Setting Options	Default Setting	Comments
355	VECTOR GRP S5	0 1 2 3 4 5 6 7 8 9 10 11	0	Vector Group Numeral of Side 5
361	UN GEN/MOTOR	0.4..800.0 kV	21.0 kV	Rated Primary Voltage Generator/Motor
362	SN GEN/MOTOR	0.20..5000.00 MVA	70.00 MVA	Rated Apparent Power of the Generator
370	UN BUSBAR	0.4..800.0 kV	110.0 kV	Rated Primary Voltage Busbar
371	I PRIMARY OP.	1..100000 A	200 A	Primary Operating Current of Busbar
372	I PRIMARY OP S1	1..100000 A	200 A	Primary Operating Current Side 1
373	I PRIMARY OP S2	1..100000 A	200 A	Primary Operating Current Side 2
374	I PRIMARY OP S3	1..100000 A	200 A	Primary Operating Current Side 3
375	I PRIMARY OP S4	1..100000 A	200 A	Primary Operating Current Side 4
376	I PRIMARY OP S5	1..100000 A	200 A	Primary Operating Current Side 5
381	I PRIMARY OP 1	1..100000 A	200 A	Primary Operating Current End 1
382	I PRIMARY OP 2	1..100000 A	200 A	Primary Operating Current End 2
383	I PRIMARY OP 3	1..100000 A	200 A	Primary Operating Current End 3
384	I PRIMARY OP 4	1..100000 A	200 A	Primary Operating Current End 4
385	I PRIMARY OP 5	1..100000 A	200 A	Primary Operating Current End 5
386	I PRIMARY OP 6	1..100000 A	200 A	Primary Operating Current End 6
387	I PRIMARY OP 7	1..100000 A	200 A	Primary Operating Current End 7
388	I PRIMARY OP 8	1..100000 A	200 A	Primary Operating Current End 8

Addr.	Setting Title	Setting Options	Default Setting	Comments
389	I PRIMARY OP 9	1..100000 A	200 A	Primary Operating Current End 9
390	I PRIMARY OP 10	1..100000 A	200 A	Primary Operating Current End 10
391	I PRIMARY OP 11	1..100000 A	200 A	Primary Operating Current End 11
392	I PRIMARY OP 12	1..100000 A	200 A	Primary Operating Current End 12
396	PHASE SELECTION	Phase 1 Phase 2 Phase 3	Phase 1	Phase selection
403	I PRIMARY OP M3	1..100000 A	200 A	Primary Operating Current Meas. Loc. 3
404	I PRIMARY OP M4	1..100000 A	200 A	Primary Operating Current Meas. Loc. 4
405	I PRIMARY OP M5	1..100000 A	200 A	Primary Operating Current Meas. Loc. 5
408	UN-PRI M3	0.4..800.0 kV	110.0 kV	Rated Primary Voltage Measuring Loc. 3
409	UN-PRI U4	0.4..800.0 kV	110.0 kV	Rated Primary Voltage U4
413	REF PROT. AT	Side 1 Side 2 Side 3 Side 4 Side 5 auto-connected not assigned measuring location 3 not assigned measuring location 4 not assigned measuring location 5	Side 1	Restricted earth fault prot. assigned to
420	DMT/IDMT Ph AT	Side 1 Side 2 Side 3 Side 4 Side 5 Measuring location 1 Measuring location 2 Measuring location 3 Measuring location 4 Measuring location 5	Side 1	DMT / IDMT Phase assigned to

Addr.	Setting Title	Setting Options	Default Setting	Comments
422	DMT/IDMT 3I0 AT	Side 1 Side 2 Side 3 Side 4 Side 5 Measuring location 1 Measuring location 2 Measuring location 3 Measuring location 4 Measuring location 5	Side 1	DMT / IDMT 3I0 assigned to
424	DMT/IDMT E AT	no assignment possible Auxiliary CT IX1 Auxiliary CT IX2 Auxiliary CT IX3 Auxiliary CT IX4	Auxiliary CT IX1	DMT / IDMT Earth assigned to
427	DMT 1PHASE AT	no assignment possible Auxiliary CT IX1 Auxiliary CT IX2 Auxiliary CT IX3 Auxiliary CT IX4	Auxiliary CT IX1	DMT 1Phase assigned to
440	UNBAL. LOAD AT	Side 1 Side 2 Side 3 Side 4 Side 5 Measuring location 1 Measuring location 2 Measuring location 3 Measuring location 4 Measuring location 5	Side 1	Unbalance Load (Neg. Seq.) assigned to
442	THERM. O/L AT	Side 1 Side 2 Side 3 Side 4 Side 5	Side 1	Thermal Overload Protection assigned to
470	BREAKER FAIL.AT	Side 1 Side 2 Side 3 Side 4 Side 5 Measuring location 1 Measuring location 2 Measuring location 3 Measuring location 4 Measuring location 5 External switchgear 1	Side 1	Breaker Failure Protection assigned to
511	STRPNT->OBJ M1	YES NO	YES	CT-Strpnt. Meas. Loc.1 in Dir. of Object
512	IN-PRI CT M1	1..100000 A	200 A	CT Rated Primary Current Meas. Loc. 1

Addr.	Setting Title	Setting Options	Default Setting	Comments
513	IN-SEC CT M1	1A 5A	1A	CT Rated Secondary Current Meas. Loc. 1
521	STRPNT->OBJ M2	YES NO	YES	CT-Strpnt. Meas. Loc.2 in Dir. of Object
522	IN-PRI CT M2	1..100000 A	2000 A	CT Rated Primary Current Meas. Loc. 2
523	IN-SEC CT M2	1A 5A	1A	CT Rated Secondary Current Meas. Loc. 2
531	STRPNT->OBJ M3	YES NO	YES	CT-Strpnt. Meas. Loc.3 in Dir. of Object
532	IN-PRI CT M3	1..100000 A	2000 A	CT Rated Primary Current Meas. Loc. 3
533	IN-SEC CT M3	1A 5A	1A	CT Rated Secondary Current Meas. Loc. 3
541	STRPNT->OBJ M4	YES NO	YES	CT-Strpnt. Meas. Loc.4 in Dir. of Object
542	IN-PRI CT M4	1..100000 A	2000 A	CT Rated Primary Current Meas. Loc. 4
543	IN-SEC CT M4	1A 5A	1A	CT Rated Secondary Current Meas. Loc. 4
551	STRPNT->OBJ M5	YES NO	YES	CT-Strpnt. Meas. Loc.5 in Dir. of Object
552	IN-PRI CT M5	1..100000 A	2000 A	CT Rated Primary Current Meas. Loc. 5
553	IN-SEC CT M5	1A 5A	1A	CT Rated Secondary Current Meas. Loc. 5
561	STRPNT->BUS I1	YES NO	YES	CT-Starpoint I1 in Direction of Busbar
562	IN-PRI CT I1	1..100000 A	200 A	CT Rated Primary Current I1
563	IN-SEC CT I1	1A 5A 0.1A	1A	CT Rated Secondary Current I1
571	STRPNT->BUS I2	YES NO	YES	CT-Starpoint I2 in Direction of Busbar
572	IN-PRI CT I2	1..100000 A	200 A	CT Rated Primary Current I2
573	IN-SEC CT I2	1A 5A 0.1A	1A	CT Rated Secondary Current I2
581	STRPNT->BUS I3	YES NO	YES	CT-Starpoint I3 in Direction of Busbar
582	IN-PRI CT I3	1..100000 A	200 A	CT Rated Primary Current I3

Addr.	Setting Title	Setting Options	Default Setting	Comments
583	IN-SEC CT I3	1A 5A 0.1A	1A	CT Rated Secondary Current I3
591	STRPNT->BUS I4	YES NO	YES	CT-Starpoint I4 in Direction of Busbar
592	IN-PRI CT I4	1..100000 A	200 A	CT Rated Primary Current I4
593	IN-SEC CT I4	1A 5A 0.1A	1A	CT Rated Secondary Current I4
601	STRPNT->BUS I5	YES NO	YES	CT-Starpoint I5 in Direction of Busbar
602	IN-PRI CT I5	1..100000 A	200 A	CT Rated Primary Current I5
603	IN-SEC CT I5	1A 5A 0.1A	1A	CT Rated Secondary Current I5
611	STRPNT->BUS I6	YES NO	YES	CT-Starpoint I6 in Direction of Busbar
612	IN-PRI CT I6	1..100000 A	200 A	CT Rated Primary Current I6
613	IN-SEC CT I6	1A 5A 0.1A	1A	CT Rated Secondary Current I6
621	STRPNT->BUS I7	YES NO	YES	CT-Starpoint I7 in Direction of Busbar
622	IN-PRI CT I7	1..100000 A	200 A	CT Rated Primary Current I7
623	IN-SEC CT I7	1A 5A 0.1A	1A	CT Rated Secondary Current I7
631	STRPNT->BUS I8	YES NO	YES	CT-Starpoint I8 in Direction of Busbar
632	IN-PRI CT I8	1..100000 A	200 A	CT Rated Primary Current I8
633	IN-SEC CT I8	1A 5A 0.1A	1A	CT Rated Secondary Current I8
641	STRPNT->BUS I9	YES NO	YES	CT-Starpoint I9 in Direction of Busbar
642	IN-PRI CT I9	1..100000 A	200 A	CT Rated Primary Current I9
643	IN-SEC CT I9	1A 5A 0.1A	1A	CT Rated Secondary Current I9
651	STRPNT->BUS I10	YES NO	YES	CT-Starpoint I10 in Direction of Busbar
652	IN-PRI CT I10	1..100000 A	200 A	CT Rated Primary Current I10

Addr.	Setting Title	Setting Options	Default Setting	Comments
653	IN-SEC CT I10	1A 5A 0.1A	1A	CT Rated Secondary Current I10
661	STRPNT->BUS I11	YES NO	YES	CT-Starpoint I11 in Direction of Busbar
662	IN-PRI CT I11	1..100000 A	200 A	CT Rated Primary Current I11
663	IN-SEC CT I11	1A 5A 0.1A	1A	CT Rated Secondary Current I11
671	STRPNT->BUS I12	YES NO	YES	CT-Starpoint I12 in Direction of Busbar
672	IN-PRI CT I12	1..100000 A	200 A	CT Rated Primary Current I12
673	IN-SEC CT I12	1A 5A 0.1A	1A	CT Rated Secondary Current I12
711	EARTH IX1 AT	Terminal Q7 Terminal Q8	Terminal Q7	Earthing electrod IX1 connected to
712	IN-PRI CT IX1	1..100000 A	200 A	CT rated primary current IX1
713	IN-SEC CT IX1	1A 5A	1A	CT rated secondary current IX1
721	EARTH IX2 AT	Terminal N7 Terminal N8	Terminal N7	Earthing electrod IX2 connected to
722	IN-PRI CT IX2	1..100000 A	200 A	CT rated primary current IX2
723	IN-SEC CT IX2	1A 5A	1A	CT rated secondary current IX2
731	EARTH IX3 AT	Terminal R7 Terminal R8	Terminal R7	Earthing electrod IX3 connected to
732	IN-PRI CT IX3	1..100000 A	200 A	CT rated primary current IX3
733	IN-SEC CT IX3	1A 5A	1A	CT rated secondary current IX3
734	FACTOR CT IX3	1.0..300.0	60.0	Factor: prim. over sek. current IX3
741	EARTH IX4 AT	Terminal P7 Terminal P8	Terminal P7	Earthing electrod IX4 connected to
742	IN-PRI CT IX4	1..100000 A	200 A	CT rated primary current IX4
743	IN-SEC CT IX4	1A 5A	1A	CT rated secondary current IX4
744	FACTOR CT IX4	1.0..300.0	60.0	Factor: prim. over sek. current IX4
801	UN-PRI VT SET	1.0..1200.0 kV	110.0 kV	VT Rated Prim. Voltage Set UL1, UL2, UL3

Addr.	Setting Title	Setting Options	Default Setting	Comments
802	UN-SEC VT SET	80..125 V	100 V	VT Rated Sec. Voltage Set UL1, UL2, UL3
811	UN-PRI VT U4	1.0..1200.0 kV	110.0 kV	VT Rated Primary Voltage U4
812	UN-SEC VT U4	80..125 V	100 V	VT Rated Secondary Voltage U4
816	Uph / Udelta	0.10..9.99	1.73	Matching ratio Phase-VT to Open-Delta-VT
817	Uph(U4)/Udelta	0.10..9.99	1.73	Matching ratio Ph-VT(U4) to Open-DeltaVT
831	SwitchgCBaux S1			Switchgear / CBaux at Side 1
832	SwitchgCBaux S2			Switchgear / CBaux at Side 2
833	SwitchgCBaux S3			Switchgear / CBaux at Side 3
834	SwitchgCBaux S4			Switchgear / CBaux at Side 4
835	SwitchgCBaux S5			Switchgear / CBaux at Side 5
836	SwitchgCBaux M1			Switchgear / CBaux at Measuring Loc. M1
837	SwitchgCBaux M2			Switchgear / CBaux at Measuring Loc. M2
838	SwitchgCBaux M3			Switchgear / CBaux at Measuring Loc. M3
839	SwitchgCBaux M4			Switchgear / CBaux at Measuring Loc. M4
840	SwitchgCBaux M5			Switchgear / CBaux at Measuring Loc. M5
841	SwitchgCBaux E1			Switchgear / CBaux at ext. location 1
851A	TMin TRIP CMD	0.01..32.00 sec	0.15 sec	Minimum TRIP Command Duration

2.1.7 Information Overview

F.No.	Alarm	Comments
05145	>Reverse Rot.	>Reverse Phase Rotation
05147	Rotation L1L2L3	Phase Rotation L1L2L3
05148	Rotation L1L3L2	Phase Rotation L1L3L2

2.1.8 Setting Groups

Purpose of Setting Groups

In the 7UT6 relay, four independent setting groups (A to D) are possible. During operation, you may switch between setting groups locally, via binary inputs (if so configured), via the operator or service interface using a personal computer, or via the system interface. For reasons of safety it is not possible to change between setting groups during a power system fault.

A setting group includes the setting values for all functions that have been selected as ***`Enabled`*** during configuration (see Subsection 2.1.1). Whilst setting values may vary among the four setting groups, the scope of functions of each setting group remains the same.

Multiple setting groups allow a specific relay to be used for more than one application, because the function settings for each application are stored and readily retrievable when needed. While all setting groups are stored in the relay, only one setting group may be active at a given time.

If multiple setting groups are not required, Group A is the default selection, and the rest of this subsection is of no importance.

If multiple setting groups are desired, address 103 **`Grp Chge OPTION`** must have been set to ***`Enabled`*** in the relay configuration. Refer to Subsection 2.1.1. Each of these sets (A to D) is adjusted one after the other. You will find more details how to navigate between the setting groups, to copy and reset setting groups, and how to switch over between the setting groups during operation, in the SIPROTEC® System Manual, order number E50417–H1176–C151.

The preconditions to switch from one setting group to another via binary inputs is described in Subsection 3.1.2.

2.1.8.1 Setting Overview

Addr.	Setting Title	Setting Options	Default Setting	Comments
302	CHANGE	Group A Group B Group C Group D Binary Input Protocol	Group A	Change to Another Setting Group

2.1.8.2 Information Overview

F.No.	Alarm	Comments
00007	>Set Group Bit0	>Setting Group Select Bit 0
00008	>Set Group Bit1	>Setting Group Select Bit 1
	Group A	Group A
	Group B	Group B
	Group C	Group C
	Group D	Group D

2.1.9 General Protection Data (Power System Data 2)

General protection data (**P.SYSTEM DATA2**) includes settings associated with all functions rather than a specific protective or monitoring function. In contrast to the **P.SYSTEM DATA1** as discussed before, these settings can be changed over with the setting groups and can be configured via the operator panel of the device.

Sign of Power

When the device is delivered from the factory, its power and energy values are defined so that power in the direction of the protected object is considered as positive: Active components and inductive reactive components in the direction of the protected object are positive. The same applies for the power factor cos φ. It is occasionally desired to define the power draw from the protected object positively. Using parameter address 1107 **P,Q sign** the signs for these components can be inverted.

Circuit Breaker Status

In order to function optimally, several protection and supplementary functions require information regarding the state of the circuit breaker. Furthermore, control functions use feed-back information from the switching devices.

If, for instance, the circuit breaker failure protection is used to monitor the reaction of a specific circuit breaker by means of current flow, the protection device must know the measuring location at which the current flowing through the breaker is acquired.

In addition to such circuit breaker information as may be available from the feedback indications provided by the circuit breaker auxiliary contacts, the device evaluates the electrical criteria which say that a circuit breaker cannot be open if a current is flowing through it. This current criterion is defined by specifying a pole-open current level **PoleOpenCurr.** below which an open breaker is identified.

As the topologies encountered in a system can be quite complex, the circuit breaker can be assigned to a measuring location or to a side.

In 3-phase protected objects you can set such a pole-open current for each of the up to 5 possible sides of the main protected object and for each of the up to 5 possible measuring locations. In the concrete case, the options are of course restricted to the sides and measuring locations which actually exist and have been specified by the topology. The maximum range of possible addresses includes:

Address 1111 **PoleOpenCurr.S1** for side 1 of the main protected object,
Address 1112 **PoleOpenCurr.S2** for side 2 of the main protected object,
Address 1113 **PoleOpenCurr.S3** for side 3 of the main protected object,
Address 1114 **PoleOpenCurr.S4** for side 4 of the main protected object,
Address 1115 **PoleOpenCurr.S5** for side 5 of the main protected object.

Address 1121 **PoleOpenCurr.M1** for measuring location 1,
Address 1122 **PoleOpenCurr.M2** for measuring location 2,
Address 1123 **PoleOpenCurr.M3** for measuring location 3,
Address 1124 **PoleOpenCurr.M4** for measuring location 4,
Address 1125 **PoleOpenCurr.M5** for measuring location 5.

If parasitic currents (e.g. through induction) can be excluded when the circuit breaker is open, these settings may normally be very sensitive. Otherwise the settings must be increased correspondingly. In most cases the setting can be the same for all addresses displayed.

Consider that increased measuring errors may occur if a side is fed from several measuring locations.

In the 1-phase busbar protection, you can set such a pole-open current for each of the up to 6 feeders (7UT613 and 7UT633 for 1-phase connection with summation CT) or 9 feeders (7UT613 and 7UT633 for 1-phase connection without summation CT) or 12 feeders (7UT635 with or without summation CT) of the busbar. The maximum range of possible addresses includes:

Address 1131 **PoleOpenCurr I1** for feeder 1,
Address 1132 **PoleOpenCurr I2** for feeder 2,
Address 1133 **PoleOpenCurr I3** for feeder 3,
Address 1134 **PoleOpenCurr I4** for feeder 4,
Address 1135 **PoleOpenCurr I5** for feeder 5,
Address 1136 **PoleOpenCurr I6** for feeder 6,
Address 1137 **PoleOpenCurr I7** for feeder 7,
Address 1138 **PoleOpenCurr I8** for feeder 8,
Address 1139 **PoleOpenCurr I9** for feeder 9,
Address 1140 **PoleOpenCurrI10** for feeder 10,
Address 1141 **PoleOpenCurrI11** for feeder 11,
Address 1142 **PoleOpenCurrI12** for feeder 12.

Finally, it is also possible to monitor the pole-open currents at the auxiliary measuring locations. The maximum range of possible addresses includes:

Address 1151 **PoleOpenCurrIX1** for auxiliary measuring location 1,
Address 1152 **PoleOpenCurrIX2** for auxiliary measuring location 2,
Address 1153 **PoleOpenCurrIX3** for auxiliary measuring location 3,
Address 1154 **PoleOpenCurrIX4** for auxiliary measuring location 4.

Remember also that all binary inputs must have been allocated which shall generate a manual close signal for the different protection functions (FNos 30351 to 30360).

2.1.9.1 Setting Overview

The referred current values I/I_{NS} are set referred to the nominal current of the assigned side as stated in Subsection 2.1.3. In other cases, current values are set in amps. The setting ranges and the default settings are then stated for a rated secondary current I_N = 1 A. For a rated secondary current of I_N = 5 A these values have to be multiplied by 5.

Addr.	Setting Title	Setting Options	Default Setting	Comments
1107	P,Q sign	not reversed reversed	not reversed	P,Q operational measured values sign
1111	PoleOpenCurr.S1	0.04..1.00 I/InS	0.10 I/InS	Pole Open Current Threshold Side 1
1112	PoleOpenCurr.S2	0.04..1.00 I/InS	0.10 I/InS	Pole Open Current Threshold Side 2
1113	PoleOpenCurr.S3	0.04..1.00 I/InS	0.10 I/InS	Pole Open Current Threshold Side 3
1114	PoleOpenCurr.S4	0.04..1.00 I/InS	0.10 I/InS	Pole Open Current Threshold Side 4
1115	PoleOpenCurr.S5	0.04..1.00 I/InS	0.10 I/InS	Pole Open Current Threshold Side 5
1121	PoleOpenCurr.M1	0.04..1.00 A	0.04 A	Pole Open Current Threshold Meas.Loc. M1
1122	PoleOpenCurr.M2	0.04..1.00 A	0.04 A	Pole Open Current Threshold Meas.Loc. M2
1123	PoleOpenCurr.M3	0.04..1.00 A	0.04 A	Pole Open Current Threshold Meas.Loc. M3
1124	PoleOpenCurr.M4	0.04..1.00 A	0.04 A	Pole Open Current Threshold Meas.Loc. M4
1125	PoleOpenCurr.M5	0.04..1.00 A	0.04 A	Pole Open Current Threshold Meas.Loc. M5
1131	PoleOpenCurr I1	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 1
1132	PoleOpenCurr I2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 2
1133	PoleOpenCurr I3	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 3
1134	PoleOpenCurr I4	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 4
1135	PoleOpenCurr I5	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 5
1136	PoleOpenCurr I6	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 6
1137	PoleOpenCurr I7	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 7
1138	PoleOpenCurr I8	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 8
1139	PoleOpenCurr I9	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 9
1140	PoleOpenCurrI10	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 10
1141	PoleOpenCurrI11	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 11
1142	PoleOpenCurrI12	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 12
1151	PoleOpenCurrIX1	0.04..1.00 A	0.04 A	Pole Open Current Threshold AuxiliaryCT1

Addr.	Setting Title	Setting Options	Default Setting	Comments
1152	PoleOpenCurrIX2	0.04..1.00 A	0.04 A	Pole Open Current Threshold AuxiliaryCT2
1153	PoleOpenCurrIX3	0.04..1.00 A	0.04 A	Pole Open Current Threshold AuxiliaryCT3
1154	PoleOpenCurrIX4	0.04..1.00 A	0.04 A	Pole Open Current Threshold AuxiliaryCT4

2.1.9.2 Information Overview

F.No.	Alarm	Comments
00311	FaultConfig/Set	Fault in configuration / setting
00312	GenErrGroupConn	Gen.err.: Inconsistency group/connection
00313	GenErrEarthCT	Gen.err.: Sev. earth-CTs with equal typ
00314	GenErrSidesMeas	Gen.err.: Number of sides / measurements
30060	Gen CT-M1:	General: Adaption factor CT M1
30061	Gen CT-M2:	General: Adaption factor CT M2
30062	Gen CT-M3:	General: Adaption factor CT M3
30063	Gen CT-M4:	General: Adaption factor CT M4
30064	Gen CT-M5:	General: Adaption factor CT M5
30065	Gen VT-U1:	General: Adaption factor VT UL123
30067	par too low:	parameter too low:
30068	par too high:	parameter too high:
30069	settingFault:	setting fault:
30351	>ManualClose M1	>Manual close signal measurement loc. 1
30070	Man.Clos.Det.M1	Manual close signal meas.loc. 1 detected
30352	>ManualClose M2	>Manual close signal measurement loc. 2
30071	Man.Clos.Det.M2	Manual close signal meas.loc. 2 detected
30353	>ManualClose M3	>Manual close signal measurement loc. 3
30072	Man.Clos.Det.M3	Manual close signal meas.loc. 3 detected
30354	>ManualClose M4	>Manual close signal measurement loc. 4
30073	Man.Clos.Det.M4	Manual close signal meas.loc. 4 detected
30355	>ManualClose M5	>Manual close signal measurement loc. 5
30074	Man.Clos.Det.M5	Manual close signal meas.loc. 5 detected

F.No.	Alarm	Comments
30356	>ManualClose S1	>Manual close signal side 1
30075	Man.Clos.Det.S1	Manual close signal side 1 is detected
30357	>ManualClose S2	>Manual close signal side 2
30076	Man.Clos.Det.S2	Manual close signal side 2 is detected
30358	>ManualClose S3	>Manual close signal side 3
30077	Man.Clos.Det.S3	Manual close signal side 3 is detected
30359	>ManualClose S4	>Manual close signal side 4
30078	Man.Clos.Det.S4	Manual close signal side 4 is detected
30360	>ManualClose S5	>Manual close signal side 5
30079	Man.Clos.Det.S5	Manual close signal side 5 is detected
00501	Relay PICKUP	Relay PICKUP
00511	Relay TRIP	Relay GENERAL TRIP command
	>QuitG-TRP	>Quitt Lock Out: General Trip
	G-TRP Quit	Lock Out: General TRIP
00545	PU Time	Time from Pickup to drop out
00546	TRIP Time	Time from Pickup to TRIP
00126	ProtON/OFF	Protection ON/OFF (via system port)
30251	IL1M1:	Primary fault current IL1 meas. loc. 1
30252	IL2M1:	Primary fault current IL2 meas. loc. 1
30253	IL3M1:	Primary fault current IL3 meas. loc. 1
30254	IL1M2:	Primary fault current IL1 meas. loc. 2
30255	IL2M2:	Primary fault current IL2 meas. loc. 2
30256	IL3M2:	Primary fault current IL3 meas. loc. 2
30257	IL1M3:	Primary fault current IL1 meas. loc. 3
30258	IL2M3:	Primary fault current IL2 meas. loc. 3
30259	IL3M3:	Primary fault current IL3 meas. loc. 3
30260	IL1M4:	Primary fault current IL1 meas. loc. 4
30261	IL2M4:	Primary fault current IL2 meas. loc. 4
30262	IL3M4:	Primary fault current IL3 meas. loc. 4
30263	IL1M5:	Primary fault current IL1 meas. loc. 5
30264	IL2M5:	Primary fault current IL2 meas. loc. 5
30265	IL3M5:	Primary fault current IL3 meas. loc. 5
00576	IL1S1:	Primary fault current IL1 side1
00577	IL2S1:	Primary fault current IL2 side1

F.No.	Alarm	Comments
00578	IL3S1:	Primary fault current IL3 side1
00579	IL1S2:	Primary fault current IL1 side2
00580	IL2S2:	Primary fault current IL2 side2
00581	IL3S2:	Primary fault current IL3 side2
30266	IL1S3:	Primary fault current IL1 side3
30267	IL2S3:	Primary fault current IL2 side3
30268	IL3S3:	Primary fault current IL3 side3
30269	IL1S4:	Primary fault current IL1 side4
30270	IL2S4:	Primary fault current IL2 side4
30271	IL3S4:	Primary fault current IL3 side4
30272	IL1S5:	Primary fault current IL1 side5
30273	IL2S5:	Primary fault current IL2 side5
30274	IL3S5:	Primary fault current IL3 side5
00582	I1:	Primary fault current I1
00583	I2:	Primary fault current I2
00584	I3:	Primary fault current I3
00585	I4:	Primary fault current I4
00586	I5:	Primary fault current I5
00587	I6:	Primary fault current I6
00588	I7:	Primary fault current I7
30275	I8:	Primary fault current I8
30276	I9:	Primary fault current I9
30277	I10:	Primary fault current I10
30278	I11:	Primary fault current I11
30279	I12:	Primary fault current I12

2.2 Differential Protection

The differential protection represents the main protection of the device. It is based on current comparison. 7UT6 is suitable for unit protection of transformers, generators, motors, reactors, short lines (also with branch-points), and (under observance of the available number of analog current inputs) for busbar arrangements. Generator/transformer units may also be protected. 7UT613 and 7UT633 allow up to 3, 7UT635 allows up to 5 three-phase measuring locations.

7UT6 can be used as a single-phase differential protection relay. In this case, 7UT613 and 7UT633 allow up to 9 (with summation CTs 6), 7UT635 allows up to 12 measuring locations, e.g. currents from a busbar with up to 6 or 9 or 12 feeders.

The protected zone is limited selectively by the current transformer sets.

2.2.1 Fundamentals of Differential Protection

The formation of the measured quantities depends on the application of the differential protection. This subsection describes the general method of operation of the differential protection, independent of the type of protected object. The illustrations are based on single-line diagrams. The special features concerning the various types of protected object are covered in the subsequent subsections.

Basic Principle with Two Sides

Differential protection is based on current comparison. It makes use of the fact that a protected object (Figure 2-15) carries always the same current **i** (dashed line) at its two sides in healthy operation. This current flows into one side of the considered zone and leaves it again on the other side. A difference in current marks is a clear indication of a fault within this zone. If the actual current transformation ratios are equal, the secondary windings of the current transformers **CT1** and **CT2** at the sides of the protected object can be connected to form a closed electric circuit with a secondary current $\underline{I}$; a measuring element **M** which is connected to the electrical balance point remains at zero current in healthy operation.

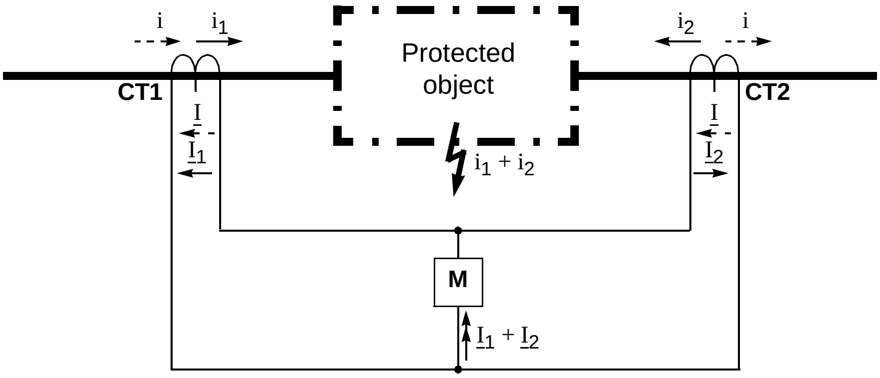


Figure 2-15 Basic principle of differential protection for two sides (single-line illustration)

When a fault occurs in the zone limited by the current transformers, a current $\underline{I}_1 + \underline{I}_2$ which is proportional to the fault currents $i_1 + i_2$ flowing in from both sides is fed to the measuring element. As a result, the simple circuit shown in Figure 2-15 ensures a reliable tripping of the protection if the fault current flowing into the protected zone during a fault is high enough for the measuring element **M** to respond.

All following considerations are based on the convention that all currents flowing into the protected zone are defined as positive unless explicitly stated otherwise.

Basic Principle with more than Two Sides

For protected objects with three or more sides or for busbars, the principle of differential protection is extended in that the total of all currents flowing into the protected object is zero in healthy operation, whereas in case of a fault the total is equal to the fault current.

Figure 2-16 shows the example of a busbar with 4 feeders. The three-winding power transformer of Figure 2-17 is limited by 4 measuring locations (current transformer sets), so it is treated by the differential protection like a 4-winding transformer.

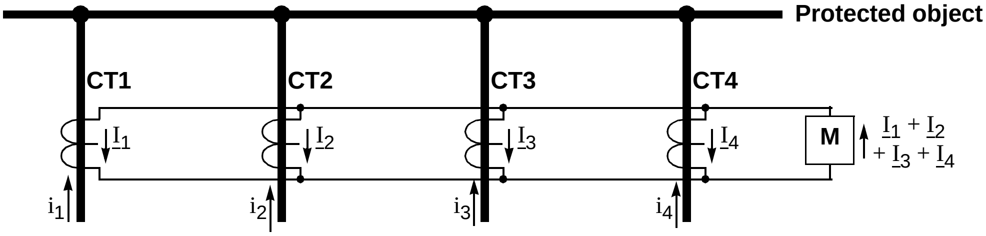


Figure 2-16 Basic principle of differential protection for four feeders (single-line illustration)

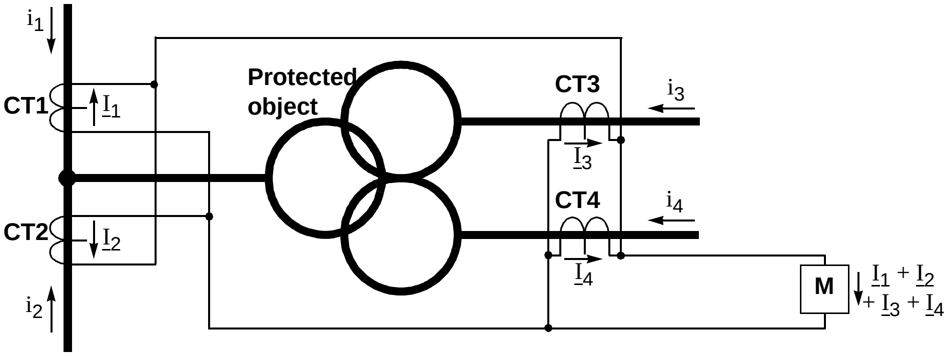


Figure 2-17 Basic principle of differential protection for 4 measuring locations — example of a three-winding power transformer with 4 measuring locations (single-line illustration)

Current Restraint

When an external fault causes a heavy current to flow through the protected zone, differences in the magnetic characteristics of the current transformers **CT1** and **CT2** (Figure 2-15) under conditions of saturation may cause a significant current to flow through the measuring element **M.** If the magnitude of this current lies above the response threshold, the protection would issue a trip signal even though no fault is present within the protected zone. Current restraint prevents such erroneous operation.

In differential protection systems for protected objects with two terminals, a restraining quantity is normally derived from the current difference $|\underline{I}_1 - \underline{I}_2|$ or from the arithmetical sum $|\underline{I}_1| + |\underline{I}_2|$. Both methods are equal in the relevant ranges of the stabilization characteristics. In differential protection systems for protected objects with three or more terminals, e.g multiple-winding transformers or busbars, restraint is only possible with the arithmetic sum. The latter method is used in 7UT6 for all protected objects. The following definitions apply for 2 measuring locations:

a tripping effect or differential current

$I_{Diff} = |\underline{I}_1 + \underline{I}_2|$

and a stabilization or restraining current

$I_{Rest} = |\underline{I}_1| + |\underline{I}_2|$

The current sum definition is extended for more than 2 measurement locations, e.g. for 4 measuring locations (Figure 2-16 or 2-17):

$I_{Diff} = |\underline{I}_1 + \underline{I}_2 + \underline{I}_3 + \underline{I}_4|$

$I_{Rest} = |\underline{I}_1| + |\underline{I}_2| + |\underline{I}_3| + |\underline{I}_4|$

I_{Diff} is calculated from the fundamental wave of the measured currents and produces the tripping effect quantity, I_{Rest} counteracts this effect.

To clarify the situation, three important operating conditions should be examined (refer also to Figure 2-18):

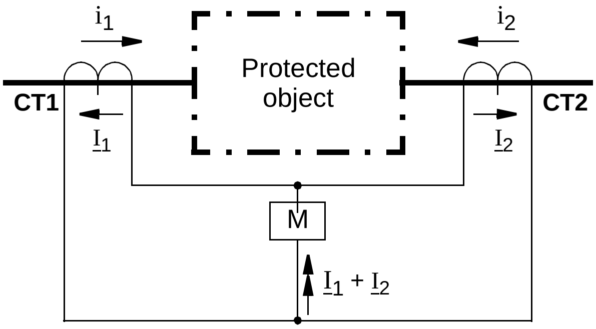


Figure 2-18 Definition of current direction

a) Through-flowing current under healthy conditions or on an external fault:

$\underline{I}_1$ flows into the protected zone, $\underline{I}_2$ leaves the protected zone, i.e. thus has opposite sign, i.e. $\underline{I}_2 = -\underline{I}_1$, and consequently $|\underline{I}_2| = |\underline{I}_1|$

$I_{Diff} = |\underline{I}_1 + \underline{I}_2| = |\underline{I}_1 - \underline{I}_1| = 0$
$I_{Rest} = |\underline{I}_1| + |\underline{I}_2| = |\underline{I}_1| + |\underline{I}_1| = 2 \cdot |\underline{I}_1|$

no tripping effect ($I_{Diff} = 0$); restraint (I_{Rest}) corresponds to twice the through-flowing current.

b) Internal fault, fed from each end e.g. with equal currents:

In this case, $\underline{I}_2 = \underline{I}_1$, and consequently $|\underline{I}_2| = |\underline{I}_1|$

$I_{Diff} = |\underline{I}_1 + \underline{I}_2| = |\underline{I}_1 + \underline{I}_1| = 2 \cdot |\underline{I}_1|$
$I_{Rest} = |\underline{I}_1| + |\underline{I}_2| = |\underline{I}_1| + |\underline{I}_1| = 2 \cdot |\underline{I}_1|$

tripping effect (I_{Diff}) and restraining (I_{Rest}) quantities are equal and correspond to the total fault current.

c) Internal fault, fed from one side only:

In this case, $\underline{I}_2 = 0$

$I_{Diff} = |\underline{I}_1 + \underline{I}_2| = |\underline{I}_1 + 0| = |\underline{I}_1|$
$I_{Rest} = |\underline{I}_1| + |\underline{I}_2| = |\underline{I}_1| + 0 = |\underline{I}_1|$

tripping effect (I_{Diff}) and restraining (I_{Rest}) quantities are equal and correspond to the fault current fed from one side.

This result shows that for internal fault $I_{Diff} = I_{Rest}$. Thus, the characteristic of internal faults is a straight line with the slope 1 (45°) in the operation diagram as illustrated in Figure 2-19 (dash-dotted line).

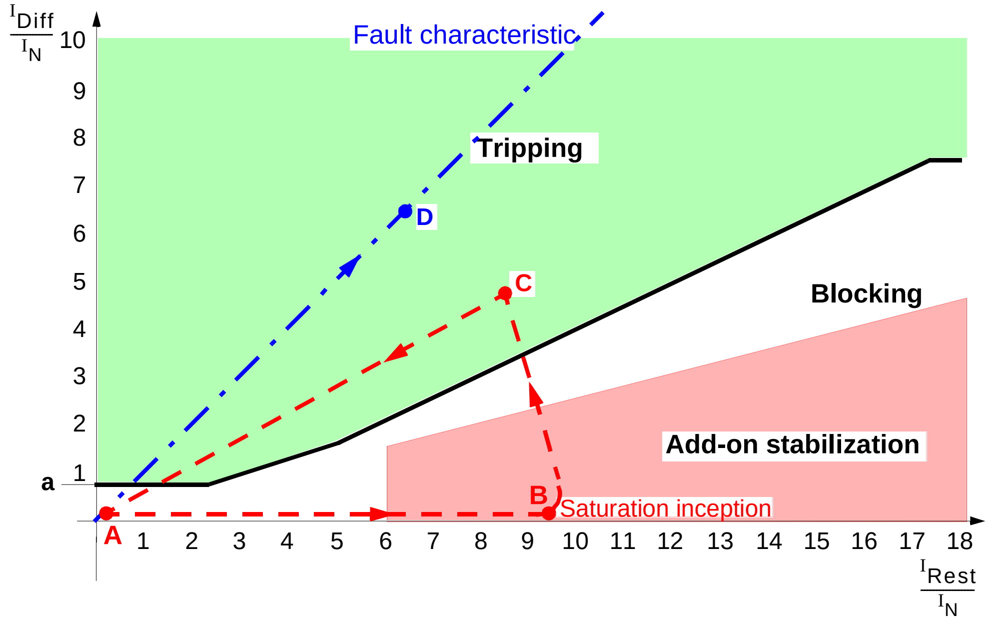


Figure 2-19 Operation characteristic of differential protection and fault characteristic

Add-on Stabilization during External Fault

Saturation of the current transformers caused by high fault currents and/or long system time constants are uncritical for internal faults (fault in the protected zone), since the measured value deformation is found in the differential current as well in the restraint current, to the same extent. The fault characteristic as illustrated in Figure 2-19 is principally valid in this case, too. Of course, the fundamental wave of the current must exceed at least the pickup threshold (branch **a** in Figure 2-19).

During an external fault which produces a high through-flowing fault current causing current transformer saturation, a considerable differential current can be simulated, especially when the degree of saturation is different at the two sides. If the quantities I_{Diff}/I_{Rest} result in an operating point which lies in the trip area of the operating characteristic (Figure 2-19), trip signal would be the consequence if there were no special measures.

7UT6 provides a saturation indicator which detects such phenomena and initiates add-on stabilization measures. The saturation indicator considers the dynamic behaviour of the differential and restraint quantity.

The dashed line in Figure 2-19 shows an example of the shape of the instantaneous quantities during a through-fault current with CT saturation at one side.

Immediately after fault inception (**A**) the fault currents increase severely thus producing a high restraint quantity (twice the through-flowing current). At the instant of CT saturation (**B**) a differential quantity is produced and the restraint quantity is reduced. In consequence, the operating point I_{Diff}/I_{Rest} may move into the tripping area (**C**).

In contrast, the operating point moves immediately along the fault characteristic (**D**) when an internal fault occurs since the restraint current will barely be higher then the differential current.

Current transformer saturation during external faults is detected by the high initial restraint current which moves the operating point briefly into the “add-on stabilization” area (Figure 2-19). The saturation indicator makes its decision within the first quarter cycle after fault inception. When an external fault is detected, the differential stage is blocked for an adjustable time. This blocking is cancelled as soon as the operation point moves steadily (i.e. over at least one cycle) near the fault characteristic (≥90 % of the slope of the fault characteristic). This allows to detect evolving faults in the protected zone reliably even after an external fault with current transformer saturation.

Add-on stabilization operates individually per phase. You can determine by a setting parameter whether only the phase with detected external fault is blocked or also the other phases (so called “crossblock function”).

A further stabilization comes into effect when differential secondary currents are simulated by different transient behaviour of the current transformer sets. This differential current is caused by different DC time constants in the secondary circuits during through-current conditions, i.e. the equal primary DC components are transformed into unequal secondary DC components due to different time constants of the secondary circuits. This produces a DC component in the differential current which increases the pickup values of the differential stage for a short period.

Harmonic Restraint

When switching unloaded transformers or shunt reactors on a live busbar, high magnetizing (inrush) currents may occur. These inrush currents produce differential quantities as they seem like single-end fed fault currents. Also during paralleling of transformers, or an overexcitation of a power transformer, differential quantities may occur due to magnetizing currents cause by increased voltage and/or decreased frequency.

The inrush current can amount to a multiple of the rated current and is characterized by a considerable 2nd harmonic content (double rated frequency) which is practically absent in the case of a short-circuit. If the 2nd harmonic content exceeds a selectable threshold, the differential stage is blocked.

Besides the 2nd harmonic, another harmonic can be selected to cause blocking. A choice can be made between the 3rd and 5th harmonic.

Overexcitation of the transformer iron is characterized by the presence of odd harmonics in the current. Thus, the 3rd and 5th harmonic are suitable to detect such phenomena. But, as the 3rd harmonic is often eliminated in power transformers (e.g. by the delta winding), the use of the 5th is more common.

Furthermore, in case of converter transformers odd harmonics are found which are not present during internal transformer faults.

The differential quantities are examined as to their harmonic content. Numerical filters are used to perform a Fourier analysis of the differential currents. As soon as the harmonic contents exceed the set values, a restraint of the respective phase evaluation is introduced. The filter algorithms are optimized with regard to their transient behaviour such that additional measures for stabilization during dynamic conditions are not necessary.

Since the harmonic restraint operates individually per phase, the protection is fully operative even when e.g. the transformer is switched onto a single-phase fault, whereby inrush currents may possibly be present in one of the healthy phases. However, it is also possible to set the protection such that not only the phase with inrush current exhibiting harmonic content in excess of the permissible value is restrained but also the other phases of the differential stage are blocked (so called “crossblock function”). This crossblock can be limited to a selectable duration.

Fast Unstabilized Trip with High-Current Faults

High-current faults in the protected zone may be cleared instantaneously without regard of the magnitude of the restraining current, when the magnitude of the differential currents can exclude that it is an external fault. In case of protected objects with high direct impedance (transformers, generators, series reactors), a threshold can be found above which a through-fault current never can increase. This threshold (primary) is, e.g. for a power transformer, $\frac{1}{u_{\text{sc transf}}} \cdot I_{\text{Ntransf}}$.

The differential protection 7UT6 provides such unstabilized high-current trip stage. This can operate even when, for example, a considerable 2nd harmonic is present in the differential current caused by current transformer saturation by a DC component in the fault current which could be interpreted by the inrush restraint function as an inrush current.

This high-current stage evaluates the fundamental wave of the currents as well as the instantaneous values. Instantaneous value processing ensures fast tripping even in case the fundamental wave of the current is strongly reduced by current transformer saturation. Because of the possible DC offset after fault inception, the instantaneous value stage operates only above twice the set threshold.

Increase of Pickup Value on Cold Load Startup

The increase of pickup value is especially suited for motors. In contrast to the inrush current of transformers the inrush current of motors is a traversing current. Differential currents, however, can emerge if current transformers still contain different remanent magnetization before energization. Therefore, the current transformers are energized from different operation points of their hysteresis. Although differential currents are usually small, they can be harmful if differential protection is set very sensitive.

An increase of the pickup value on startup provides additional security against overfunctioning when a non-energized protected object is switched in. As soon as the restraining current of one phase has dropped below a settable value **I-REST. STARTUP**, the pickup value increase is activated. The restraint current is twice the traversing current in normal operation. Undershooting of the restraint current is therefore a criterion for the non-energized protected object. The pickup value **I-DIFF>** is now increased by a settable factor (see Figure 2-20). The other branches of the I_{Diff}> stage are shifted proportionally.

The reappearance of the restraint current indicates the startup. After a settable time **T START MAX** the increase of the characteristic is undone. Current conditions $I_{\text{Diff}}/I_{\text{Rest}}$ near the fault characteristic (≥90 % of the slope of the fault characteristic) cause a trip command even before expiry of the time **T START MAX**.

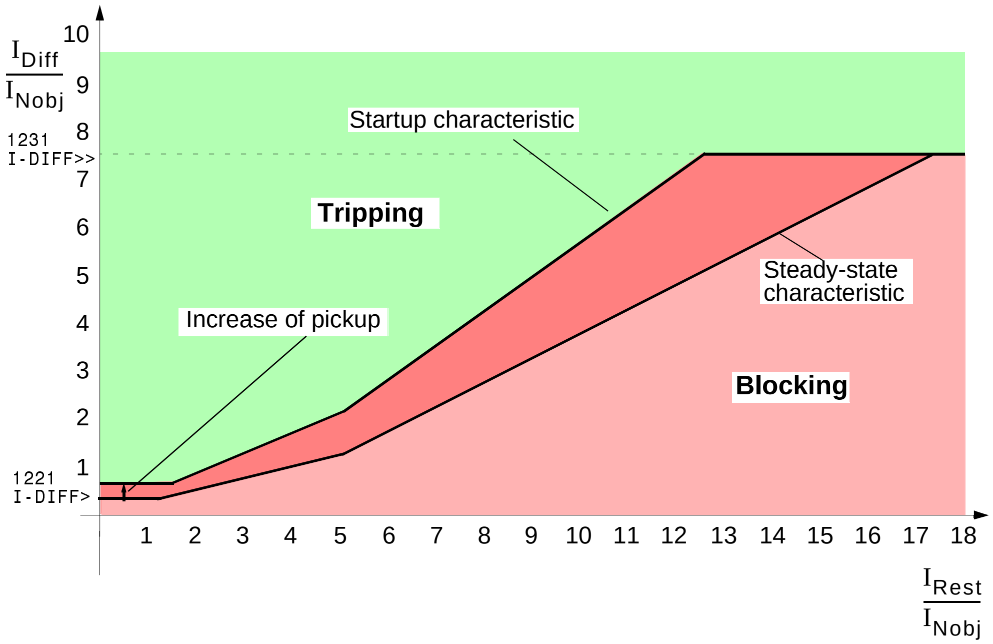


Figure 2-20 Increase of pickup value of the stage on startup

Tripping Characteristic

Figure 2-21 illustrates the complete tripping characteristic of the differential protection. The branch **a** represents the sensitivity threshold of the differential protection (setting **`I-DIFF>`**) and considers constant error current, e.g. magnetizing currents.

Branch **b** takes into consideration current-proportional errors which may result from transformation errors of the main CTs, the input CTs of the relay, or from erroneous current caused by the position of the tap changer of the voltage regulator.

In the range of high currents which may give rise to current transformer saturation, branch **c** causes stronger stabilization.

Differential currents above the branch **d** cause immediate trip regardless of the restraining quantity and harmonic content (setting **`I-DIFF>>`**). This is the area of “Fast Unstabilized Trip with High-Current Faults” (see above).

The area of “Add-on stabilization” is the operation area of the saturation indicator as described above under margin “Add-on Stabilization during External Fault”.

The quantities I_{Diff} and I_{Rest} are compared by the differential protection with the operating characteristic according to Figure 2-21. If the quantities result into a locus in the tripping area, trip signal is given. If the current conditions I_{Diff}/I_{Rest} appear near the fault characteristic (≥90 % of the slope of the fault characteristic) trip occurs even when the trip characteristic has been excessively increased due to add-on stabilization, startup or DC current detection.

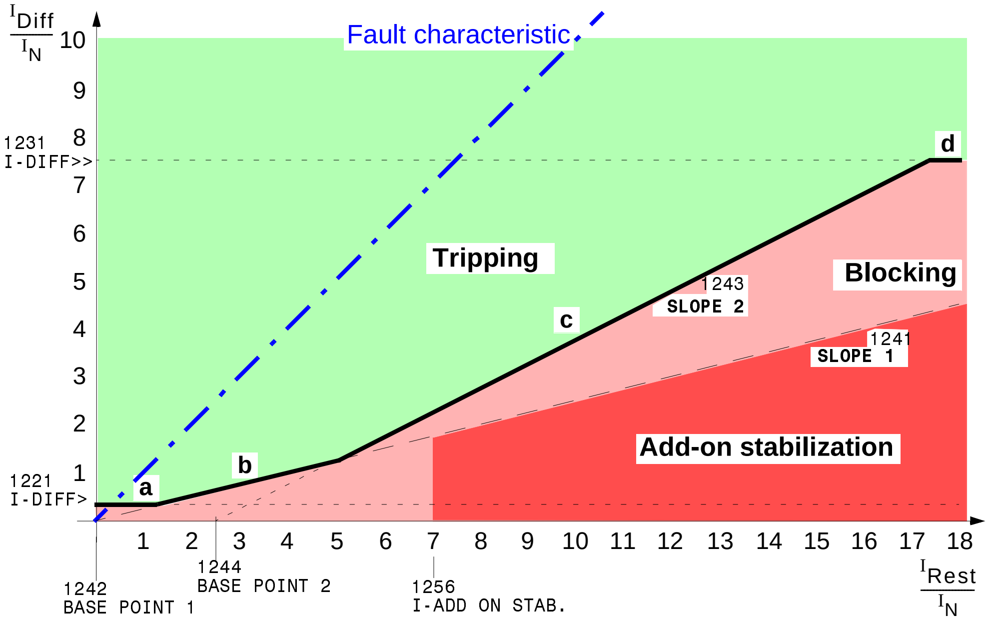


Figure 2-21 Tripping characteristic of differential protection

Fault Detection, Dropout

Normally, a differential protection does not need a “pickup” or “fault detection” function since the condition for a fault detection is identical to the trip condition. But, 7UT6 provides like all SIPROTEC® 4 devices a fault detection function which has the task to define the fault inception instant for a number of further features: Fault detection indicates the beginning of a fault event in the system. This is necessary to open the trip log buffer and the memory for oscillographic fault record data. But, also internal functions need the instant of fault inception even in case of an external fault, e.g. the saturation indicator which has to operate right in case of an external fault.

As soon as the fundamental wave of the differential current exceeds approximately 85 % of the set value or the restraining current reaches 85 % of the add-on stabilization area, the protection picks up (Figure 2-22). Pickup of the fast high-current stage causes a fault detection, too.

If the harmonic restraint is effective, the harmonic analysis is carried out (approx. one AC cycle) in order to examine the restraint conditions. Otherwise, tripping occurs as soon as the tripping conditions are fulfilled (tripping area in Figure 2-21).

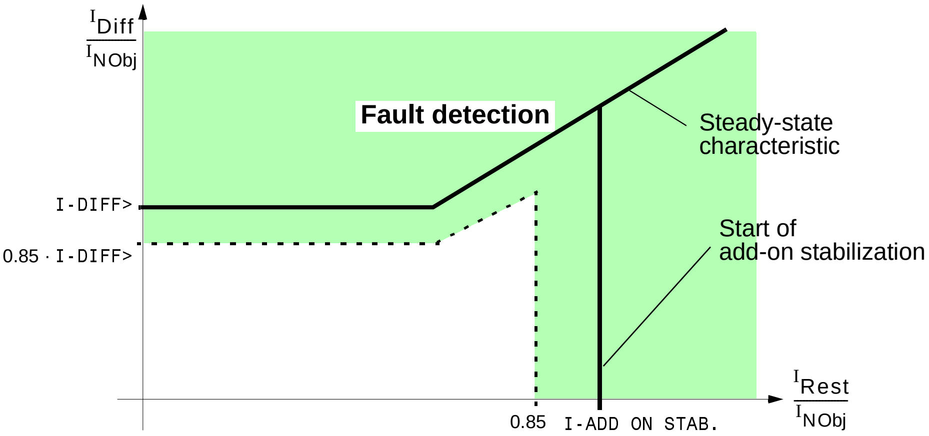


Figure 2-22 Fault detection area of the differential protection

For special cases, the trip command can be delayed.

Figure 2-23 shows a simplified tripping logic.

Reset of pickup is initiated when, during 2 AC cycles, pickup is no longer recognized in the differential values, i.e. the differential current has fallen below 70 % of the set value, and no further fault detection conditions are present.

If a trip command has not been initiated, the fault is considered to be over after reset.

If a trip command has been formed, this is sealed for at least the minimum trip duration which is set under the general protection data, common for all protection function (refer to Subsection 2.1.3 under margin header “Trip Command Duration”, page 53). The trip command is reset when also the reset conditions for pickup (as above) are fulfilled.

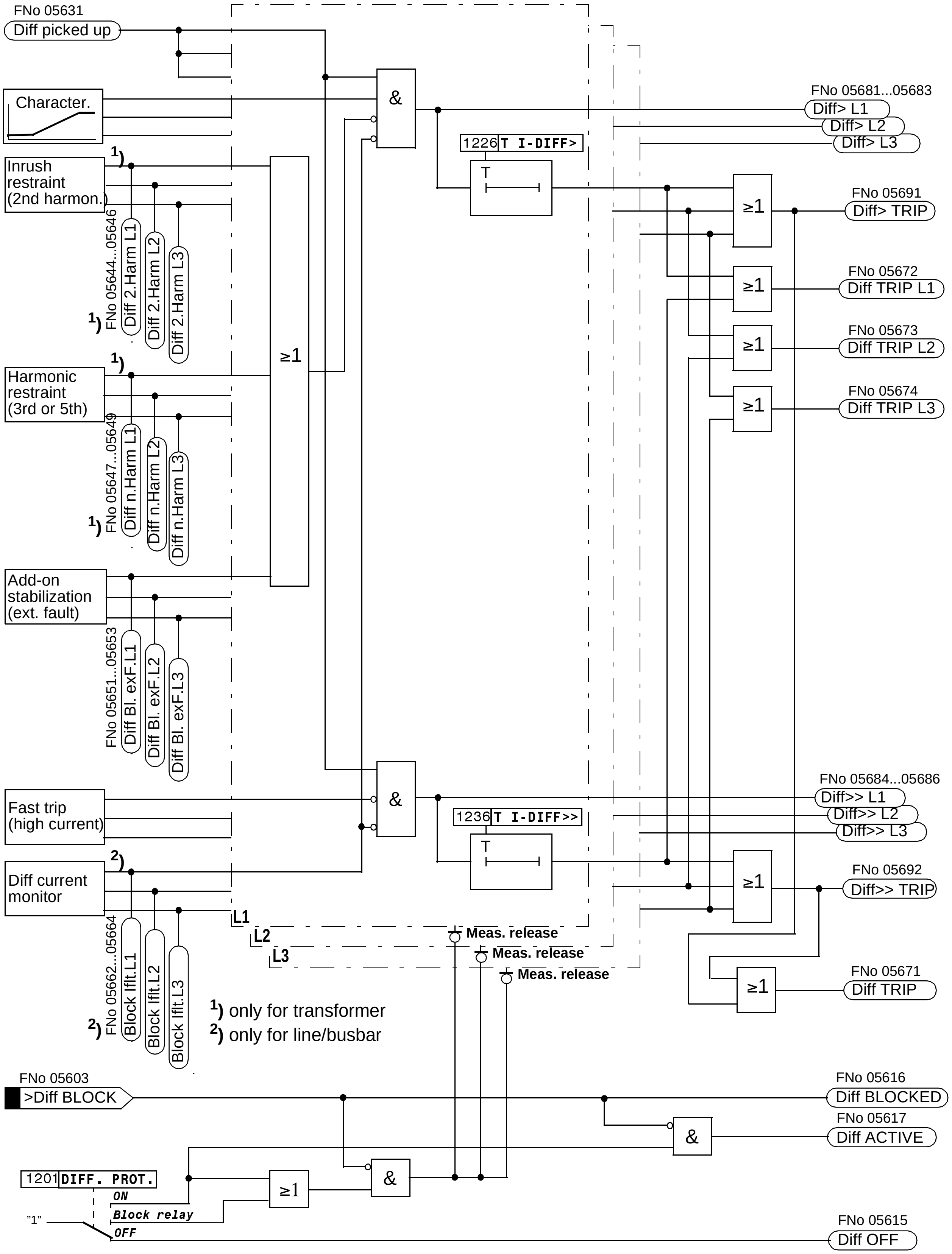


Figure 2-23 Tripping logic of the differential protection (simplified)

2.2.2 Differential Protection for Transformers

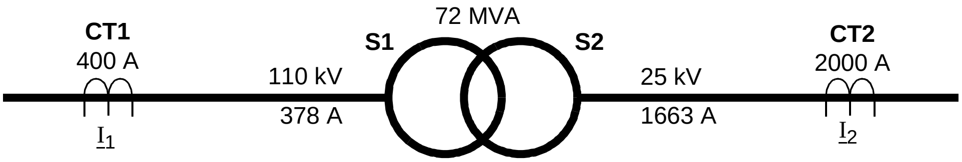
Matching of the Measured Values

In power transformers, generally, the secondary currents of the current transformers are not equal when a current flows through the power transformer, but depend on the transformation ratio and the connection group of the protected power transformer, and the rated currents of the current transformers. The currents must, therefore, be matched in order to become comparable.

Matching to the various power transformer and current transformer ratios and of the phase displacement according to the vector group of the protected transformer is performed purely mathematically. As a rule, external matching transformers are not required.

The input currents are converted in relation to the power transformer rated currents. This is achieved by entering the rated transformer data, such as rated power, rated voltage and rated primary currents of the current transformers, into the protection device (Subsection 2.1.3 under margin header “Object Data with Transformers”, page 36, and “Current Transformer Data for 3-phase Measuring Locations”, page 42).

Figure 2-24 shows an example of magnitude matching. The primary nominal currents of the two sides (windings) S1 and S2 are calculated from the rated apparent power of the transformer (72 MVA) and the nominal voltages of the windings (110 kV and 25 kV). Since the nominal currents of the current transformers deviate from the nominal currents of the power transformer sides, the secondary currents are multiplied with the factors k_1 and k_2. After this matching, equal current magnitudes are achieved at both sides under nominal conditions of the power transformer.



$$I_{NSide1} = \frac{72\ \text{MVA}}{\sqrt{3} \cdot 110\ \text{kV}} = 378\ \text{A} \qquad I_{NSide2} = \frac{72\ \text{MVA}}{\sqrt{3} \cdot 25\ \text{kV}} = 1663\ \text{A}$$

$$I_{N\ Obj} = I_{N\ Side} \qquad I_{N\ Obj} = I_{N\ Side}$$

$$k_1 = \frac{400\ \text{A}}{378\ \text{A}} \qquad k_2 = \frac{2000\ \text{A}}{1663\ \text{A}}$$

Figure 2-24 Magnitude matching — example of a two-winding power transformer (phase relation not considered)

Concerning power transformers with more than two windings, the windings may have different power ratings. In order to achieve comparable currents for the differential protection, all currents are referred to the winding (= side) with the highest power rating. This apparent power is named the *rated power of the protected object*.

Figure 2-25 shows an example of a three-winding power transformer. Winding 1 (S1) and 2 (S2) are rated for 72 MVA; thus, the same considerations apply as in Figure 2-24. But, the third winding (S3) has 16 MVA rating (e.g. for auxiliary supply). The rated current of this *winding* (= side of the protected object) results in 924 A. On the other hand, the differential protection has to process comparable currents. Therefore, the currents of this winding must be referred to the *rated power of the protected object*, i.e. 72 MVA. This results in a nominal current (i.e. the current under nominal conditions of the protected object, 72 MVA) of 4157 A. This is the base value for the third winding: These currents must be multiplied by the factor k_3.

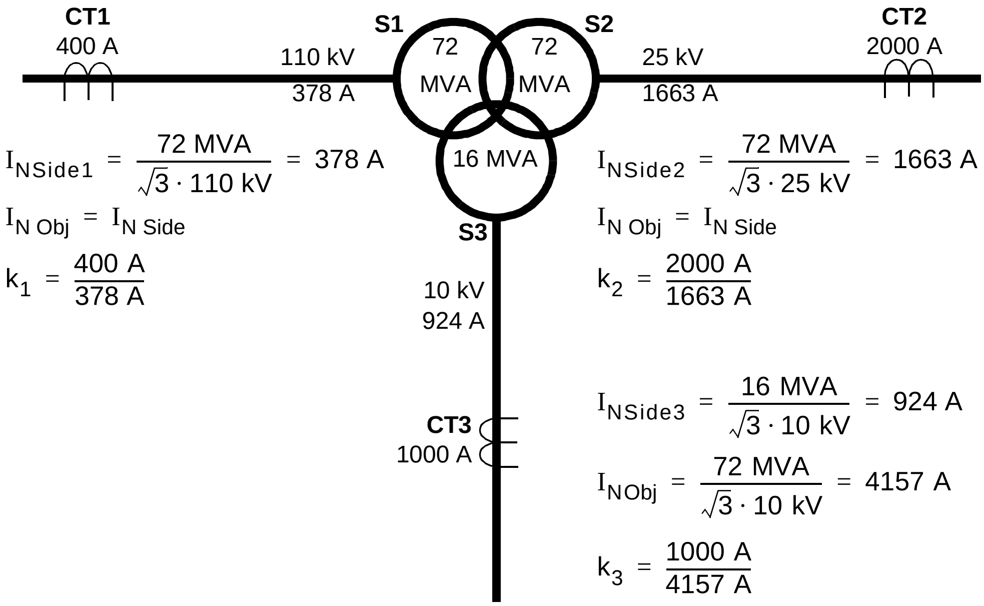


Figure 2-25 Magnitude matching — example of a three-winding power transformer (phase relation not considered)

The device carries out this magnitude matching internally, based on the nominal values set according to Section 2.1.3 under “Object Data with Transformers” (page 36) and “Current Transformer Data for 3-phase Measuring Locations” (page 42). Together with the entered vector group, the protection is capable of performing the current comparison according to fixed formulae.

Conversion of the currents is performed by programmed coefficient matrices which simulate the current conditions in the transformer windings. All conceivable vector groups (including phase exchange) are possible. In this aspect, the conditioning of the starpoint(s) of the power transformer is essential, too.

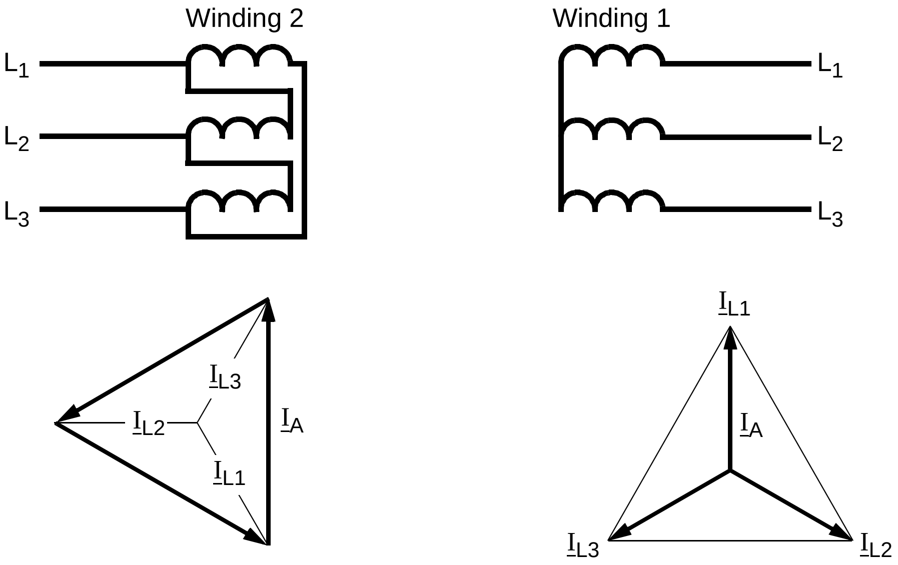
Isolated Starpoint

Figure 2-26 illustrates an example for a power transformer Yd5 (wye-delta with 150 ° phase displacement) without any earthed starpoint. The figure shows the windings and the phasor diagrams of symmetrical currents and, at the bottom, the matrix equation. The general form is

$$(\underline{I}_m) = k \cdot (K) \cdot (\underline{I}_n)$$

where
$(\underline{I}_m)$ – matrix of the matched currents $\underline{I}_A$, $\underline{I}_B$, $\underline{I}_C$,
k – constant factor for magnitude matching,
(K) – coefficient matrix, dependent on the vector group,
$(\underline{I}_n)$ – matrix of the phase currents $\underline{I}_{L1}$, $\underline{I}_{L2}$, $\underline{I}_{L3}$.

On the left (delta) winding, the matched currents $\underline{I}_A$, $\underline{I}_B$, $\underline{I}_C$ are derived from the difference of the phase currents $\underline{I}_{L1}$, $\underline{I}_{L2}$, $\underline{I}_{L3}$. On the right (wye) side, the matched currents are equal to the phase currents (magnitude matching not considered).



$$\begin{pmatrix} \underline{I}_A \\ \underline{I}_B \\ \underline{I}_C \end{pmatrix} = 1 \cdot \begin{pmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{pmatrix} \cdot \begin{pmatrix} \underline{I}_{L1} \\ \underline{I}_{L2} \\ \underline{I}_{L3} \end{pmatrix}$$

Figure 2-26 Matching the transformer vector group, example Yd5 (magnitudes not considered)

Since there is no point earthed within the protected zone, no considerable zero sequence current can be produced within the protected zone in case of an earth fault outside the protected zone, regardless whether or not the system starpoint is earthed anywhere else in the system. In case of an earth fault within the protected zone, a zero sequence current may occur at a measuring location if the system starpoint is earthed anywhere else or another earth fault is present in the system (double earth fault in a non-earthed system). Thus, zero sequence currents are of no concern for the stability of the differential protection as they cannot occur in case of external faults.

However, in case of internal earth faults, the zero sequence currents are nearly fully included in the differential quantity because they pass the measuring points from outside. Even higher earth fault sensitivity during internal earth fault is possible by means of the time overcurrent protection for zero sequence currents (Section 2.4) and/or the single-phase time overcurrent protection (Section 2.7).

Earthed Starpoint

Differential protection makes use of the fact that the total of all currents flowing into the protected object is zero in healthy operation, as explained in Subsection 2.2.1. If the starpoint of a power transformer winding is connected to earth, a current can flow into the protected zone across this earth connection in case of earth faults. Consequently, this current should be included in the current processing in order to obtain a complete image of the in-flowing quantities. For instance, Figure 2-27 shows an external earth fault which produces an out-flowing zero sequence current ($–I_{L3} = –3 \cdot I_0$) which corresponds to the in-flowing starpoint current ($I_{SP} = 3 \cdot I_0$). As a result, these currents cancel each other.

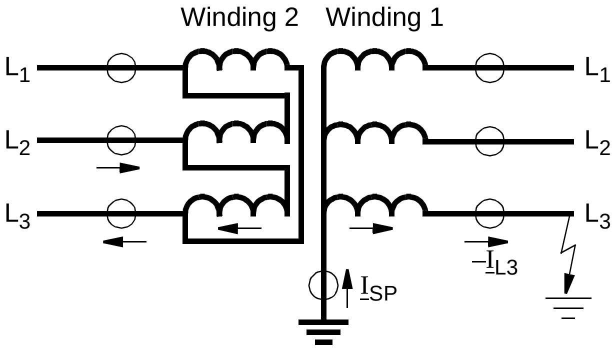


Figure 2-27 Example of a earth fault outside a transformer with earthed starpoint

The complete matrix equation for the earthed side (right) is in this case, including all in-flowing currents:

$$\begin{pmatrix} \underline{I}_A \\ \underline{I}_B \\ \underline{I}_C \end{pmatrix} = 1 \cdot \begin{pmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{pmatrix} \cdot \begin{pmatrix} \underline{I}_{L1} \\ \underline{I}_{L2} \\ \underline{I}_{L3} \end{pmatrix} + \frac{1}{3} \cdot \begin{pmatrix} \underline{I}_{SP} \\ \underline{I}_{SP} \\ \underline{I}_{SP} \end{pmatrix}$$

I_{SP} corresponds to $–3I_0$. The zero sequence current is included in case of an *internal* fault (from $\underline{I}_0 = –{}^1/_3 \underline{I}_{SP}$), whilst the zero sequence component of the line currents is compensated by the starpoint current in case of an *external* earth fault. In this way, nearly full sensitivity is achieved for internal earth faults and full elimination of the zero sequence current in case of external earth faults.

Even higher earth fault sensitivity during internal earth fault is possible by means of the restricted earth fault protection as described in Section 2.3.

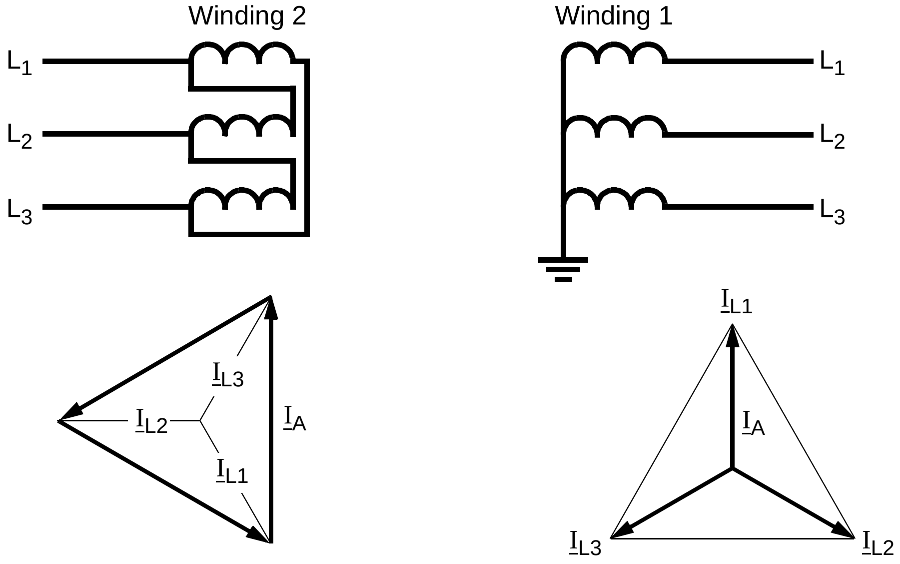
Starpoint Current not Available

In many cases, however, the starpoint current is not available. The total summation of the in-flowing currents is, thus, not possible because I_{SP} is missing. In order to avoid false formation of the differential current, the zero sequence current must be eliminated from the line currents.

Figure 2-28 illustrates an example for a transformer YNd5 with an earthed starpoint on the Y-side.

On the left side, the zero sequence currents cancel each other because of the formation of the current differences. This complies with the fact that zero sequence current is not possible outside of the delta winding. On the right side, the zero sequence current must be eliminated if the starpoint current cannot be included. Thus, the calculation rule of the matrix is, e.g.
${}^1/_3 \cdot (2\ \underline{I}_{L1} – 1\ \underline{I}_{L2} – 1\ \underline{I}_{L3}) = {}^1/_3 \cdot (3\ \underline{I}_{L1} – \underline{I}_{L1} – \underline{I}_{L2} – \underline{I}_{L3}) = {}^1/_3 \cdot (3\ \underline{I}_{L1} – 3\ \underline{I}_0) = (\underline{I}_{L1} – \underline{I}_0)$.

Zero sequence current elimination achieves that fault currents which flow via the transformer during earth faults in the network in case of an earth point in the protected zone (transformer starpoint or starpoint former by neutral earth reactor) are rendered harmless without any special external measures. Refer e.g. to Figure 2-27: Because of the earthed starpoint, a zero sequence current occurs on the right side during a network fault but not on the left side. Comparison of the phase currents, without zero sequence current elimination and without inclusion of the starpoint current, would cause a wrong result (current difference in spite of an external fault).



$$\begin{pmatrix} \underline{I}_A \\ \underline{I}_B \\ \underline{I}_C \end{pmatrix} = \frac{1}{\sqrt{3}} \cdot \begin{pmatrix} -1 & 0 & 1 \\ 1 & -1 & 0 \\ 0 & 1 & -1 \end{pmatrix} \cdot \begin{pmatrix} \underline{I}_{L1} \\ \underline{I}_{L2} \\ \underline{I}_{L3} \end{pmatrix} \qquad \begin{pmatrix} \underline{I}_A \\ \underline{I}_B \\ \underline{I}_C \end{pmatrix} = \frac{1}{3} \cdot \begin{pmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{pmatrix} \cdot \begin{pmatrix} \underline{I}_{L1} \\ \underline{I}_{L2} \\ \underline{I}_{L3} \end{pmatrix}$$

Figure 2-28 Matching the transformer vector group, example YNd5 (magnitudes not considered)

Figure 2-29 shows an example of an earth fault on the delta side *outside* the protected zone if an earthed starpoint former (neutral reactor with zigzag winding) is installed *within* the protected zone. In this arrangement, a zero sequence current occurs on the right side but not on the left, as above. If the starpoint former were *outside* the protected zone (i.e. CTs between power transformer and starpoint former) the zero sequence current would not pass through the measuring point (CTs) and would not have any harmful effect.

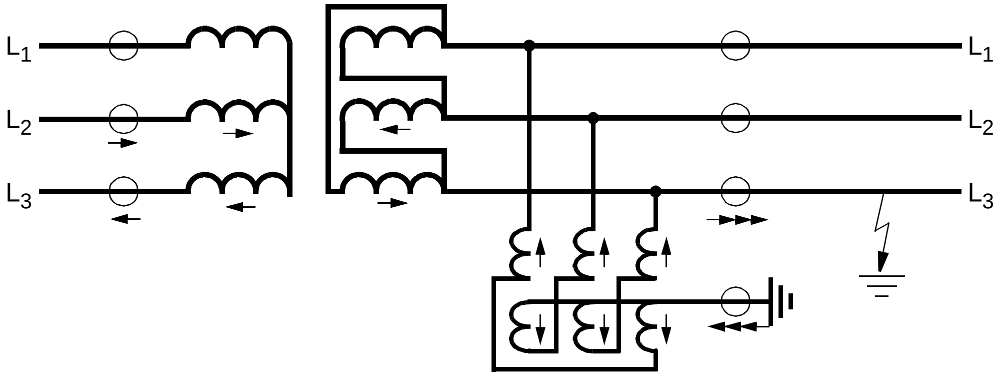


Figure 2-29 Example of an earth fault outside the protected transformer with a neutral earthing reactor within the protected zone

The disadvantage of elimination of the zero sequence current is that the protection becomes less sensitive (factor $^2/_3$ because the zero sequence current amounts to $^1/_3$) in case of an earth fault in the protected area. Therefore, elimination is suppressed in case the starpoint is not earthed (see above, Figure 2-26) or the starpoint current can be included (Figure 2-27).

Use on Auto-Transformers

Auto-transformers can only be connected Y(N)y0. If the starpoint is earthed this is effective for both the system parts (higher and lower voltage system). The zero sequence system of both system parts is coupled because of the common starpoint. In case of an earth fault, the distribution of the fault currents is not unequivocal and cannot be derived from the transformer properties without further ado.

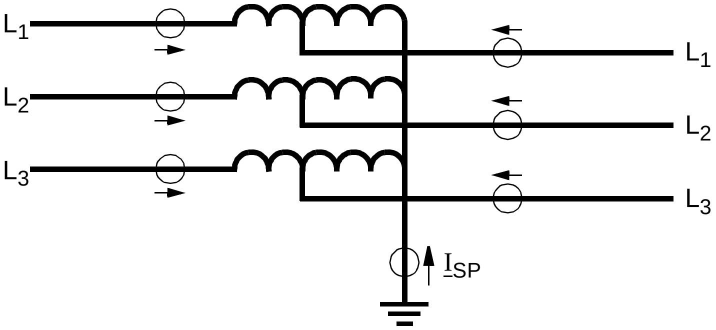


Figure 2-30 Auto-transformer with earthed starpoint

The zero sequence current is eliminated for the differential protection. This is achieved by the application of the matrices with zero sequence current elimination.

The decreased sensitivity due to zero sequence current elimination cannot be compensated by consideration of the starpoint current. This current cannot be assigned to a certain phase nor to a certain side of the transformer.

Higher earth fault sensitivity during internal earth fault can be achieved by using the high-impedance unit protection described in Subsection 2.7.2.

A further possibility to increase the earth fault sensitivity is useful for auto-transformer banks where 3 single-phase auto-transformers are arranged to a transformer bank. In this arrangement, single-phase earth faults are the most probable. A current comparison protection can be built up over each of the auto-connected windings which compares the currents flowing into the total winding. A prerequisite is that the power transformers have no further galvanically isolated accessible (tertiary) winding since this could not be included into the summation of the currents. Further preconditions are discussed with the topology of the protected object (Subsection 2.1.2 under margin “Auto-Transformer Banks”.

Use on Single-Phase Transformers

Single-phase transformers can be designed with one or two windings per side; in the latter case, the winding phases can be wound on one or two iron cores. In order to ensure that optimum matching of the currents would be possible, always two measured current inputs shall be used even if only one current transformer is installed on one phase. The currents are to be connected to the inputs L1 and L3 of the device; they are designated I_{L1} and I_{L3} in the following.

If two winding phases are available, they may be connected either in series (which corresponds to a wye-winding) or in parallel (which corresponds to a delta-winding). The phase displacement between the windings can only be 0° or 180°. Figure 2-31 shows an example of a single-phase power transformer with two phases per side with the definition of the direction of the currents.

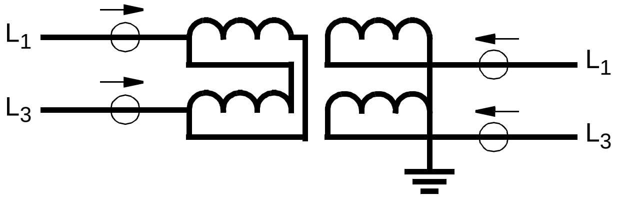


Figure 2-31 Example of a single-phase transformer with current definition

Like with three-phase power transformers, the currents are matched by programmed coefficient matrices which simulate the difference currents in the transformer windings. The common form of these equations is

$$(\underline{I}_m) = k \cdot (K) \cdot (\underline{I}_n)$$

where

$(\underline{I}_m)$ – matrix of the matched currents $\underline{I}_A$, $\underline{I}_C$,
k – constant factor for magnitude matching,
(K) – coefficient matrix,
$(\underline{I}_n)$ – matrix of the phase currents $\underline{I}_{L1}$, $\underline{I}_{L3}$.

Since the phase displacement between the windings can only be 0° or 180°, matching is relevant only with respect to the treatment of the zero sequence current (besides magnitude matching). If the “starpoint” of the protected transformer winding is not earthed (Figure 2-31 left side), the phase currents can directly be used.

If a “starpoint” is earthed (Figure 2-31 right side), the zero sequence current must be eliminated unless it can be compensated by considering the starpoint current. By forming the current differences, fault currents which flow through the transformer during earth faults in the network in case of an earth point in the protected zone (transformer “starpoint”) are rendered harmless without any special external measures.

The matrices are (Figure 2-31):

$$\begin{pmatrix} \underline{I}_A \\ \underline{I}_C \end{pmatrix} = 1 \cdot \begin{pmatrix} 1 & 0 \\ 0 & 1 \end{pmatrix} \cdot \begin{pmatrix} \underline{I}_{L1} \\ \underline{I}_{L3} \end{pmatrix} \qquad \begin{pmatrix} \underline{I}_A \\ \underline{I}_C \end{pmatrix} = \frac{1}{2} \cdot \begin{pmatrix} 1 & -1 \\ -1 & 1 \end{pmatrix} \cdot \begin{pmatrix} \underline{I}_{L1} \\ \underline{I}_{L3} \end{pmatrix}$$

The disadvantage of elimination of the zero sequence current is that the protection becomes less sensitive (factor $^1/_2$ because the zero sequence current amounts to $^1/_2$) in case of an earth fault in the protected area. Higher earth fault sensitivity can be achieved if the “starpoint” current is available, i.e. if a CT is installed in the “starpoint” connection to earth and this current is fed to the device (Figure 2-32).

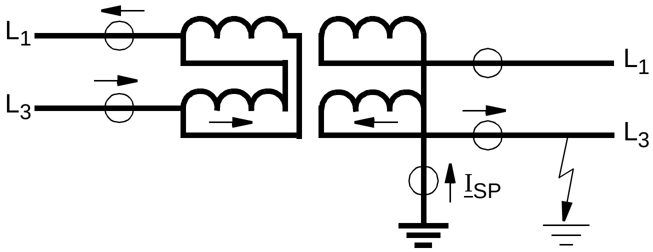


Figure 2-32 Example of an earth fault outside a single-phase transformer with current distribution

The matrices are in this case:

$$\begin{pmatrix} \underline{I}_A \\ \underline{I}_C \end{pmatrix} = 1 \cdot \begin{pmatrix} 1 & 0 \\ 0 & 1 \end{pmatrix} \cdot \begin{pmatrix} \underline{I}_{L1} \\ \underline{I}_{L3} \end{pmatrix} \qquad \begin{pmatrix} \underline{I}_A \\ \underline{I}_C \end{pmatrix} = 1 \cdot \begin{pmatrix} 1 & 0 \\ 0 & 1 \end{pmatrix} \cdot \begin{pmatrix} \underline{I}_{L1} \\ \underline{I}_{L3} \end{pmatrix} + \frac{1}{2} \cdot \begin{pmatrix} \underline{I}_{SP} \\ \underline{I}_{SP} \end{pmatrix}$$

where I_{SP} is the current measured in the “starpoint” connection.

The zero sequence current is not eliminated. Instead of this, for each phase $^1/_2$ of the starpoint current I_{SP} is added. The effect is that the zero sequence current is considered in case of an *internal* fault (from $\underline{I}_0 = -^1/_2\underline{I}_{SP}$), whilst the zero sequence current is eliminated in case of an *external* fault because the zero sequence current on the terminal side $\underline{I}_0 = {^1/_2} \cdot (\underline{I}_{L1} + \underline{I}_{L3})$ compensates for the “starpoint” current. In this way, full sensitivity (with zero sequence current) is achieved for internal earth faults and full elimination of the zero sequence current in case of external earth faults.

Even higher earth fault sensitivity during internal earth fault is possible by means of the restricted earth fault protection as described in Section 2.3.

2.2.3 Differential Protection for Generators, Motors, and Series Reactors

Matching of the Measured Values

Equal conditions apply for generators, motors, and series reactors. The protected zone is limited by the sets of current transformers at each side of the protected object. On generators and motors, the CTs are installed in the starpoint connections and at the terminal side (Figure 2-33). Since the current direction is defined as positive in the direction of the protected object, for differential protection schemes, the definitions of Figure 2-33 apply.

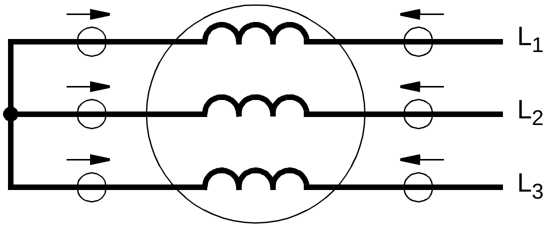


Figure 2-33 Definition of current direction with longitudinal differential protection

In 7UT6, all measured quantities are referred to the rated values of the protected object. The device is informed about the rated machine data during setting: the rated apparent power, the rated voltage, and the rated currents of the current transformers. (Subsection 2.1.3 under margin header “Object Data with Generators, Motors or Reactors”, page 39, and “Current Transformer Data for 3-phase Measuring Locations”, page 42). Measured value matching is reduced to magnitude factors, therefore.

Transverse Differential Protection

A special case is the use as transverse differential protection. The definition of the current direction is shown in Figure 2-34 for this application.

For use as a transverse differential protection, the protected zone is limited by the end of the parallel phases. A differential current always and exclusively occurs when the currents of two parallel windings differ from each other. This indicates a fault current in one of the parallel phases.

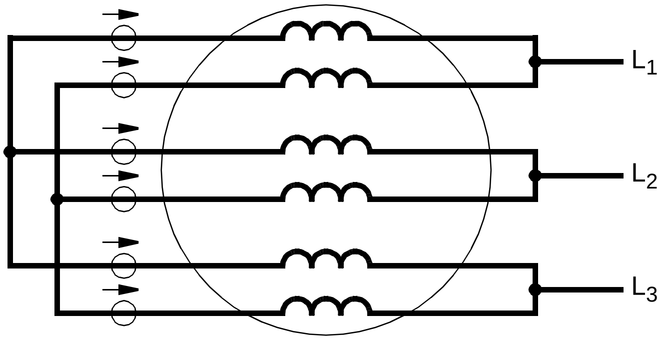


Figure 2-34 Definition of current direction with transverse differential protection

The currents flow into the protected object even in case of healthy operation, in contrast to all other applications. For this reason, the polarity of *one* current transformer set must be reversed, i.e. you must set a “wrong” polarity, as described in Subsection 2.1.3 under “Current Transformer Data for 3-phase Measuring Locations”, page 42.

Starpoint Conditioning

If the differential protection is used as generator or motor protection, the starpoint condition need not be considered even if the starpoint of the machine is earthed (high- or low-resistant). The phase currents are always equal at both measuring locations in case of an external fault. With internal faults, the fault current results always in a differential current.

Nevertheless, increased earth fault sensitivity can be achieved by the restricted earth fault protection as described in Section 2.3 and/or by the high-impedance unit protection described in Subsection 2.7.2.

2.2.4 Differential Protection for Shunt Reactors

If current transformers are available for each phase at both side of a shunt reactor, the same considerations apply as for series reactors (see Subsection 2.2.3).

In most cases, current transformers are installed in the lead phases and in the starpoint connection (Figure 2-35 left graph). In this case, comparison of the zero sequence currents is reasonable. The restricted earth fault protection is most suitable for this application, refer to Section 2.3.

If current transformers are installed in the line at both sides of the connection point of the reactor (Figure 2-35 right graph) the same conditions apply as for auto-transformers.

A neutral earthing reactor (starpoint former) outside the protected zone of a power transformer can be treated as a separate protected object provided it is equipped with current transformers like a shunt reactor. The difference is that the starpoint former has a low impedance for zero sequence currents.

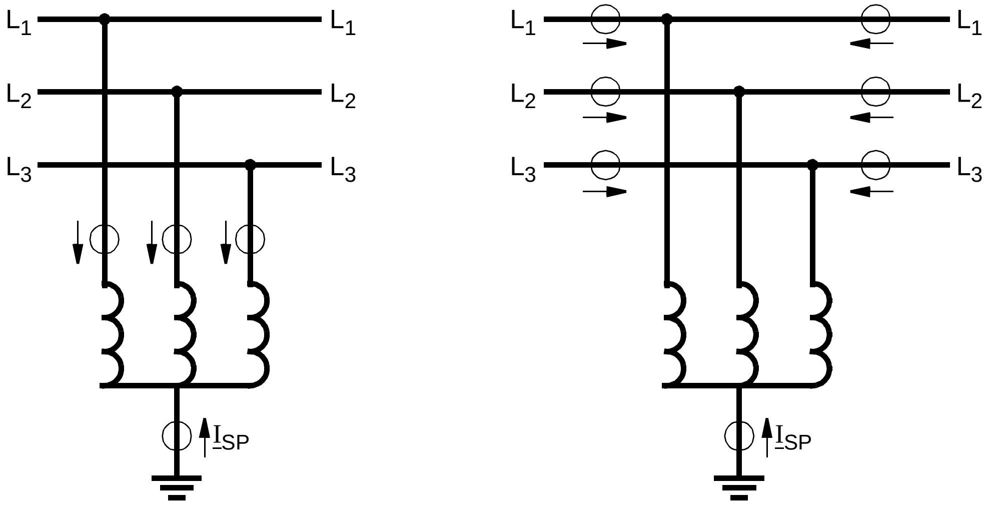


Figure 2-35 Definition of current direction on a shunt reactor

2.2.5 Differential Protection for Mini-Busbars and Short Lines

A mini-busbar or branch-point is defined here as a three-phase, coherent piece of conductor which is limited by sets of current transformers (even this is, strictly speaking, no branch point). Examples are short stubs or mini-busbars (Figure 2-36). The differential protection in this operation mode is not suited to transformers; use the function “Differential Protection for Transformers” for this application (refer to Subsection 2.2.2). Even for other inductors, like series or shunt reactors, the busbar differential protection should not be used because of its lower sensitivity.

This operation mode is also suitable for short lines or cables. “Short” means that the current transformer connections from the CTs to the device cause no impermissible burden for the current transformers. On the other hand, capacitive charging current do not harm this operation because the protection is normally set to less sensitivity with this application.

Since the current direction is normally defined as positive in the direction of the protected object, for differential protection schemes, the definitions of Figures 2-36 and 2-37 apply.

The models 7UT613 and 7UT633 allow mini-busbar with up to 3 feeder or lines with up to 3 terminals (“Teed lines”) to be protected, 5 feeders can be protected using 7UT635. Figure 2-38 shows a busbar with 4 feeders an example.

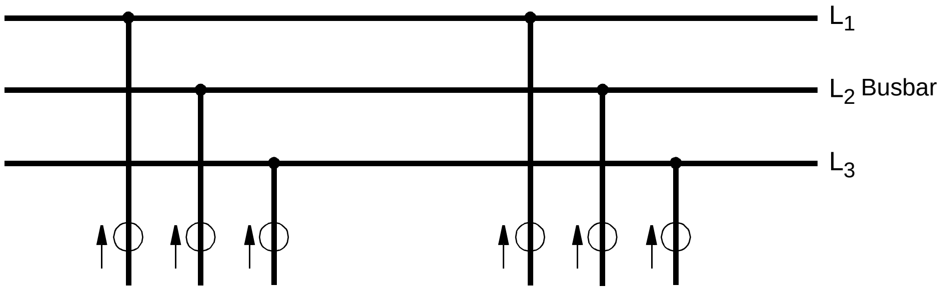


Figure 2-36 Definition of current direction at a branch-point (busbar with 2 feeders)

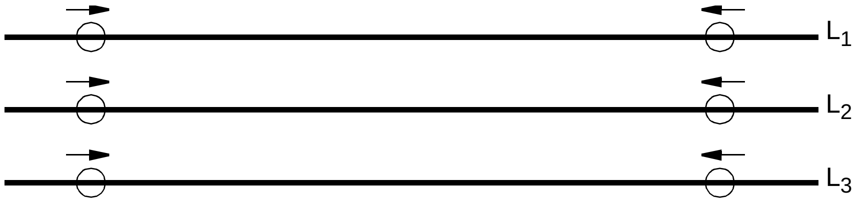


Figure 2-37 Definition of current direction at short lines

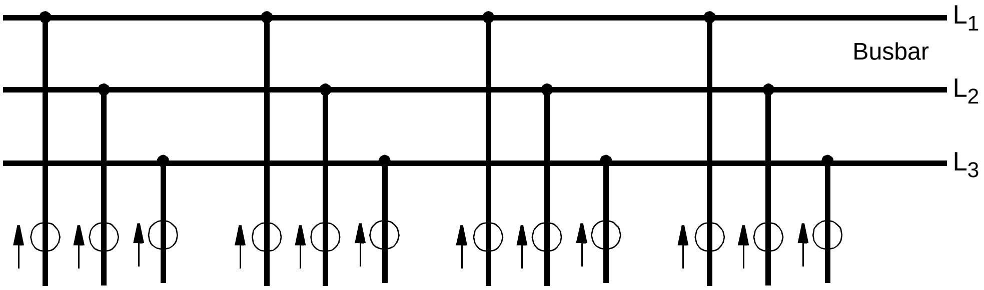


Figure 2-38 Definition of current direction at a busbar with 4 feeders

If 7UT6 is used as differential protection for mini-busbars or short lines, all currents are referred to the nominal current of the protected busbars or line. The device is informed about this during setting (Subsection 2.1.3 under margin header “Object Data with Mini-Busbars or Short Lines (3-phase)”, page 39, and “Current Transformer Data for 3-phase Measuring Locations”, page 42). Measured value matching is reduced to magnitude factors, therefore. No external matching devices are normally necessary if the feeders or current transformer sets at the ends of the protected zone have different primary current.

Differential Current Monitoring

Whereas high sensitivity of the differential protection is normally required for transformers, reactors, and rotating machines in order to detect even small fault currents, high fault currents are expected in case of faults on a busbar or a short line so that a higher pickup threshold (above rated current) is conceded here. This allows for a continuous monitoring of the differential currents on a low level. A small differential current in the range of operational currents indicates a fault in the secondary circuit of the current transformers.

This monitor operates phase segregated. When, during normal load conditions, a differential current is detected in the order of the load current of a feeder, this indicates a missing secondary current, i.e. a fault in the secondary current leads (short-circuit or open-circuit). This condition is annunciated with time delay. The differential protection is blocked in the associated phase at the same time.

Feeder Current Guard

Another feature is provided for protection of mini-busbars or short lines. This feeder current guard monitors the currents of each phase of each measuring location of the protected object. It provides an additional trip condition. Trip command is allowed only when at least one of these currents exceeds a certain (settable) threshold.

2.2.6 Single-Phase Differential Protection for Busbars

Dependent on the ordered model, 7UT6 provides 6, 9, or 12 current inputs of equal design. This allows for a single-phase busbar protection for up to 6 or 9 or 12 feeders.

Two possibilities exist:

1. One 7UT6 is used for each phase (Figure 2-39). Each phase of all busbar feeders is connected to one phase dedicated device.
2. The phase currents of each feeder are summarized into a single-phase summation current (Figure 2-40). These currents are fed to one 7UT6.

Phase Segregated Connection

For each of the phases, a 7UT6 is used in case of single-phase connection. The fault current sensitivity is equal for all types of fault. 7UT613 or 7UT633 is suited for a busbar with up to 9, 7UT635 for up to 12 feeders.

The differential protection refers all measured quantities to the nominal current of the protected object. Therefore, a common nominal current is defined for the entire busbar even if the feeder CTs have different nominal currents. The nominal currents of the busbar and each of the feeders has been set on the relay (Subsection 2.1.3 under margin header “Object Data with Busbars (1-phase Connection) with up to 6 or 9 or 12 Feeders”, page 40, and “Current Transformer Data for 1-phase Busbar Protection”, page 44). Matching of the current magnitudes is performed in the device. No external matching devices are normally necessary even if the current transformer sets at the ends of the protected zone have different primary current.

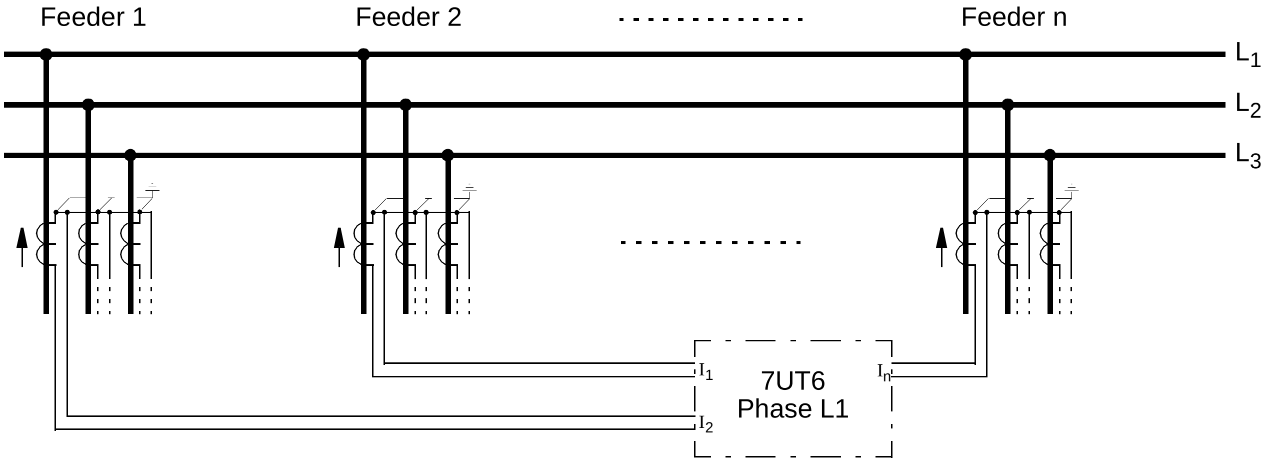


Figure 2-39 Single-phase busbar protection, illustrated for phase L1

Connection via Summation CT’s

One single device 7UT6 is sufficient for a busbar with up to 6 (7UT613/7UT633) or 12 (7UT635) feeders if the device is connected via summation current transformers. The phase currents of each feeder are converted into single-phase current by means of the summation CTs (Figure 2-40). Current summation is unsymmetrical; thus, different sensitivity is valid for different type of fault.

A common nominal current must be defined for the entire busbar. Matching of the currents can be performed in the summation transformer connections if the feeder CTs have different nominal currents. The output of the summation transformers is normally designed for I_M = 100 mA at symmetrical nominal busbar current.

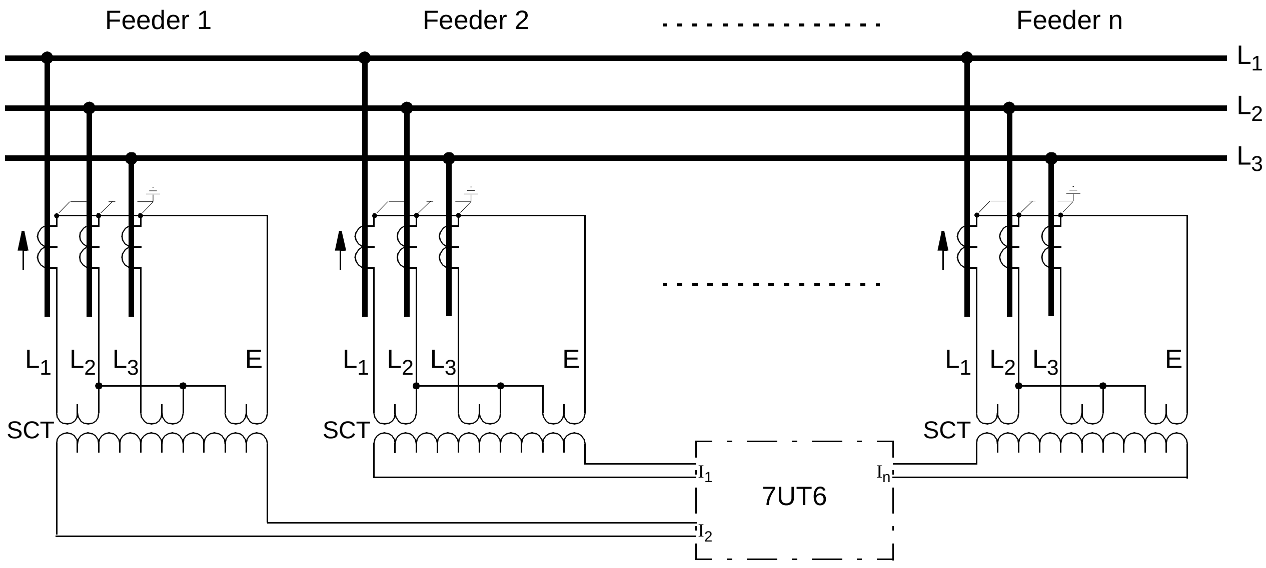


Figure 2-40 Busbar protection with connection via summation current transformers (SCT)

Different schemes are possible for the connection of the current transformers. The same CT connection method must be used for all feeders of a busbar.

The scheme shown in Figure 2-41 is the most common. The input windings of the summation transformer are connected to the CT currents I_{L1}, I_{L3}, and I_E (residual current). This connection is suitable for all kinds of systems regardless of the conditioning of the system neutral. It is characterized by an increased sensitivity for earth faults.

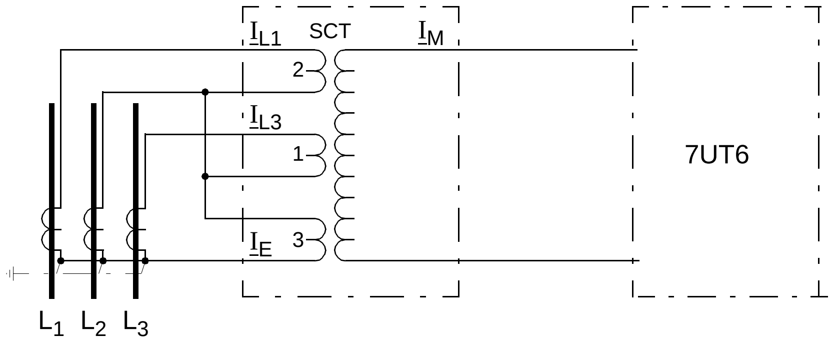


Figure 2-41 CT connection L1−L3−E

For a symmetrical three-phase current (where the residual component, $I_E = 0$) the single-phase summation current is, as illustrated in Figure 2-42, √3 times the winding unit value. That is, the ampere turns are the same as they would be for single-phase current √3 times the value flowing through the winding with the least number of turns (ratio 1). For three-phase symmetrical fault currents equal to rated current I_N, the secondary single-phase current is I_M = 100 mA. All operating values are based on this type of fault and this current.

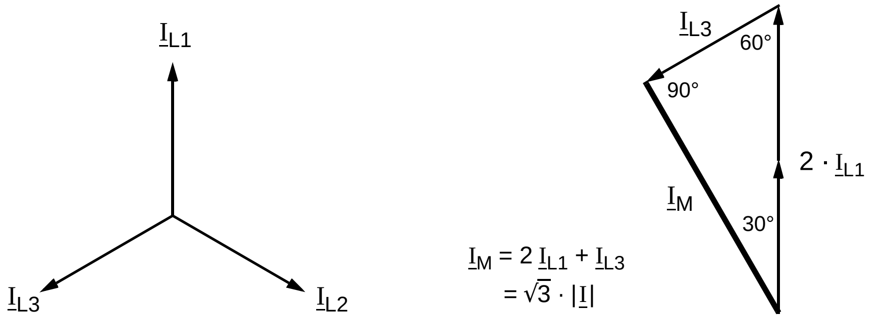


Figure 2-42 Summation of the currents L1−L3−E in the summation transformer

For the connection shown in Figure 2-41, the weighting factors W of the summation currents I_M for the various fault conditions and the ratios to that given by the three-phase symmetrical faults are shown in Table 2-3. On the right hand side is the complementary multiple of rated current which $W/\sqrt{3}$ would have to be, in order to give the summation current I_M = 100 mA in the secondary circuit. If the current setting values are multiplied with this factor, the actual pickup values result.

Table 2-3 Fault types and weighting factor for CT connection L1−L3−E

Fault type	W	$W/\sqrt{3}$	I_1 for I_M = 100 mA
L1–L2–L3 (sym.)	$\sqrt{3}$	1.00	$1.00 \cdot I_N$
L1–L2	2	1.15	$0.87 \cdot I_N$
L2–L3	1	0.58	$1.73 \cdot I_N$
L3–L1	1	0.58	$1.73 \cdot I_N$
L1–E	5	2.89	$0.35 \cdot I_N$
L2–E	3	1.73	$0.58 \cdot I_N$
L3–E	4	2.31	$0.43 \cdot I_N$

The table shows that 7UT6 is more sensitive to earth faults than to those without earth path component. This increased sensitivity is due to the fact that the summation transformer winding in the CT starpoint connection (I_E, residual current, refer to Figure 2-41) has the largest number of turns, and thus, the weighting factor W = 3.

If the higher earth current sensitivity is not necessary, connection according to Figure 2-43 can be used. This is reasonable in earthed systems with particularly low zero sequence impedance where earth fault currents may be larger than those under two-phase fault conditions. With this connection, the values given in Table 2-4 can be recalculated for the seven possible fault conditions in solidly earthed systems.

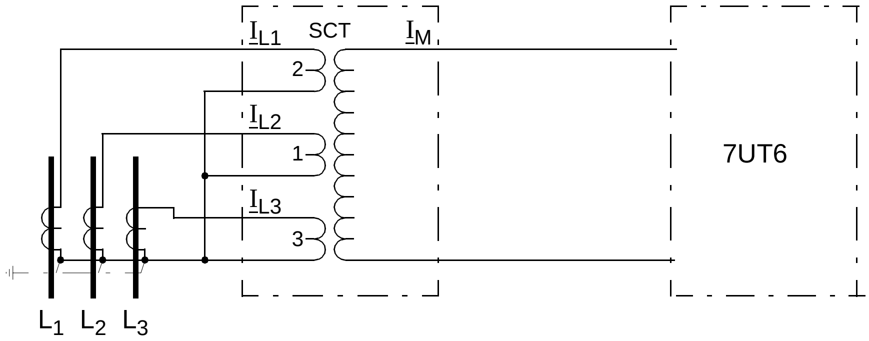


Figure 2-43 CT connection L1−L2−L3 with decreased earth fault sensitivity

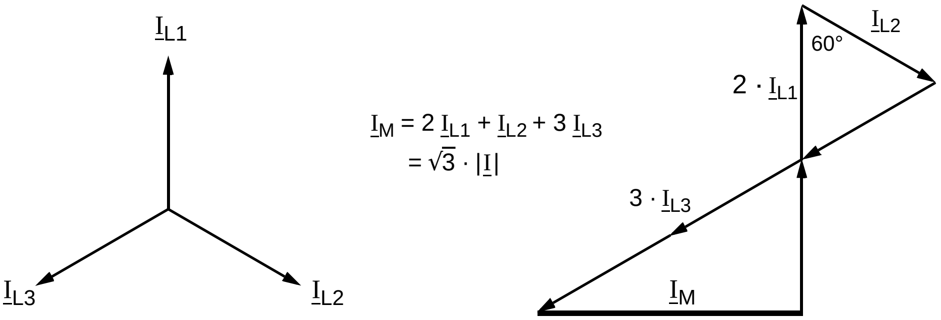


Figure 2-44 Summation of the currents L1−L2−L3 in the summation transformer

Table 2-4 Fault types and weighting factor for CT connection L1−L2−L3

Fault type	W	W/√3	I_1 for I_M = 100 mA
L1–L2–L3 (sym.)	√3	1.00	1.00 · I_N
L1–L2	1	0.58	1.73 · I_N
L2–L3	2	1.15	0.87 · I_N
L3–L1	1	0.58	1.73 · I_N
L1–E	2	1.15	0.87 · I_N
L2–E	1	0.58	1.73 · I_N
L3–E	3	1.73	0.58 · I_N

Comparison with Table 2-3 shows that under earth fault conditions the weighting factor W is less than with the standard connection. Thus the thermal loading is reduced to 36 %, i.e. $(1.73/2.89)^2$.

The described connection possibilities are examples. Certain phase preferences (especially in systems with non-earthed neutral) can be obtained by cyclic or acyclic exchange of the phases. Further increase of the earth current can be performed by introducing an auto-CT in the residual path, as a further possibility.

The type 4AM5120 is recommended for summation current transformer. These transformers have different input windings which allow for summation of the currents with the ratio 2:1:3 as well as matching of different primary currents of the main CTs to an certain extent. Figure 2-45 shows the winding arrangement.

The nominal input current of each summation CT must match the nominal secondary current of the connected main CT set. The output current of the summation CT (= input current of the 7UT6) amounts to I_N = 0.1 A at nominal conditions, with correct matching.

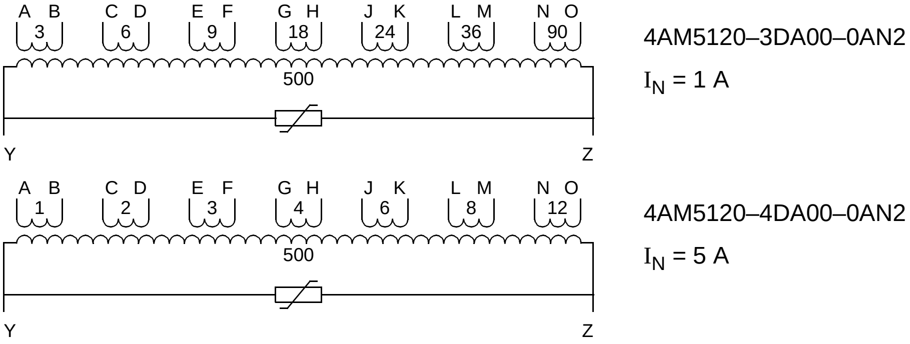


Figure 2-45 Winding arrangement of summation and matching transformers 4AM5120

Differential Current Monitoring

Whereas high sensitivity of the differential protection is normally required for transformers, reactors, and rotating machines in order to detect even small fault currents, high fault currents are expected in case of faults on a busbar so that a higher pickup threshold (above rated current) is conceded here. This allows for a continuous monitoring of the differential currents on a low level.

When, during normal load conditions, a differential current is detected in the order of the load current of a feeder, this indicates a missing secondary current, i.e. a fault in the secondary current leads (short-circuit or open-circuit). This condition is annunciated with time delay. The differential protection is blocked at the same time.

Feeder Current Guard

Another feature is provided for protection of busbars. This feeder current guard monitors the currents of each feeder of the busbar. It provides an additional trip condition. Trip command is allowed only when at least one of these currents exceeds a certain (settable) threshold.

2.2.7 Setting the Function Parameters

General

The differential protection can only operate if this function is set **DIFF. PROT.** = ***Enabled*** during configuration (address 112). If it not used, ***Disabled*** is configured; in this case the associated setting are not accessible.

Additionally, the type of protected object must be decided during configuration (address 105 **PROT. OBJECT**, Subsection 2.1.1). Only those parameters are offered which are reasonable for the selected type of protected object; all remaining are suppressed.

The differential protection can be switched ***ON*** or ***OFF*** in address 1201 **DIFF. PROT.**. The option ***Block relay*** allows to operate the protection but the trip output relay is blocked.

Note:

When delivered from factory, the differential protection is switched ***OFF***. The reason is that the protection must not be in operation unless at least the connection group (of a transformer) and the matching factors have been set before. Without proper settings, the device may show unexpected reactions (incl. tripping)!

Starpoint Conditioning

If there is a current transformer in the starpoint connection of an earthed transformer winding, i.e. between starpoint and earthing electrode, the starpoint current may be taken into consideration for calculations of the differential protection (see also Subsection 2.2.2, margin heading “Earthed Starpoint”, page 85). Thus, full earth fault sensitivity is ensured.

If a starpoint is earthed but the earth current is not available, the zero sequence current is eliminated automatically in order to avoid false operation in case of an external earth fault; the following parameters are then omitted. Equally, the parameters are not available for sides of the protected object which are not earthed. You have informed the device about the earthing conditions during setting of the object properties (Subsection 2.1.3 under margin heading “Object Data with Transformers”, page 36, addresses 313, 323, 333, 343, and/or 353 and Subsection 2.1.2 under header margin “Assignment of Auxiliary 1-phase Measuring Locations”, page 32).

The conclusion is: If the starpoint of a side of the protected power transformer is earthed and the starpoint current is fed to the device (via an auxiliary 1-phase current input) you can, nevertheless, suppress the inclusion of the starpoint current into the formation of the differential quantities, in addresses 1211A **DIFFw.IE1-MEAS** for side 1. This parameter can only be altered with DIGSI® under “**Additional Settings**”. Corresponding for other sides, if applicable:
address 1212A **DIFFw.IE2-MEAS** for side 2 if earthed,
address 1213A **DIFFw.IE3-MEAS** for side 3 if earthed,
address 1214A **DIFFw.IE4-MEAS** for side 4 if earthed,
address 1215A **DIFFw.IE5-MEAS** for side 5 if earthed.

With setting ***YES*** the corresponding earth current will be considered by the differential protection.

Differential Current Monitoring

With busbar protection or short line protection differential current can be monitored (see Subsection 2.2.5 and 2.2.6). This function can be set to ***ON*** and ***OFF*** in address 1208 **I-DIFF> MON.**. Its use only makes sense if one can distinguish clearly between operational error currents caused by missing CT currents and fault currents caused by a fault in the protected object.

The pickup value **I-DIFF> MON.** (address 1281) must be high enough to avoid a pickup caused by a transformation error of the current transformers and by minimum mismatching of different current transformers. On the other hand, the pickup value must lie clearly below the pickup value of the differential protection (**I-DIFF>**, address 1221); otherwise no differentiation between operational errors caused by missing secondary currents and fault currents due to short-circuit in the protected object would be possible. The pickup value is referred to the rated current of the protected object. Time delay **T I-DIFF> MON.** (address 1282) applies to the annunciation and blocking of the differential protection. This setting ensures that blocking with the presence of faults (even of external ones) is avoided. The time delay is usually about some seconds.

Feeder Current Guard

With busbars and short lines a release of the trip command can be set if one of the incoming currents is exceeded. The differential protection only trips if one of the measured currents exceeds the threshold **I> CURR. GUARD** (address 1210). The pickup value is referred to the rated current of the protected object. With setting ***0*** (pre-setting) this release criterion will not be used.

If the feeder current guard is set (i.e. to a value of > 0), the differential protection will not trip before the release criterion is given. This is also the case if, in conjunction with very high differential currents, the extremely fast instantaneous value scheme (see Subsection 2.2.1, margin heading “Fast Unstabilized Trip with High-Current Faults”) has detected the fault already after a few milliseconds.

Trip Characteristic Differential Current

The parameters of the trip characteristic are set in addresses 1221 to 1261A. Figure 2-46 illustrates the meaning of the different settings. The numbers signify the addresses of the setting parameters.

I-DIFF> (address 1221) is the pickup value of the differential current. This is the total fault current into the protected object, regardless of the way this is distributed between the sides. The pickup value is referred to the rated current of the protected object. You may select a high sensitivity (small pickup value) for transformers (presetting $0.2 \cdot I_{NObj}$). For reactors, generators, or motors, a yet smaller pickup value is possible provided the current transformers are of equal design. A higher value (above nominal current) is to be selected for lines and busbars. Higher measuring tolerances must be expected if the nominal currents of the current transformers differ extensively from the nominal current of the protected object or with a higher number of measuring locations.

In addition to the pickup limit **I-DIFF>**, the differential current is subjected to a second pickup threshold. If this threshold **I-DIFF>>** (address 1231) is exceeded then tripping is initiated regardless of the magnitude of the restraint current or the harmonic content or add-on stabilization (unstabilized high-current trip). This stage must be set higher than **I-DIFF>**. If the protected object has a high direct impedance (transformers, generators, series reactors), a threshold can be found above which a through-fault current never can increase. This threshold (primary) is, e.g. for a power transformer, $\frac{1}{u_{sc\ transf}} \cdot I_{Ntransf}$.

The tripping characteristic forms two more branches (Figure 2-46) The slope of the first branch is determined by the address 1241A **SLOPE 1**, its base point by the address 1242A **BASE POINT 1**. This parameter can only be altered with DIGSI® under “**Additional Settings**”. This branch covers current-proportional errors. These are mainly errors of the main current transformers and, in case of power transformers with tap changers, error currents which occur due to the transformer regulating range.

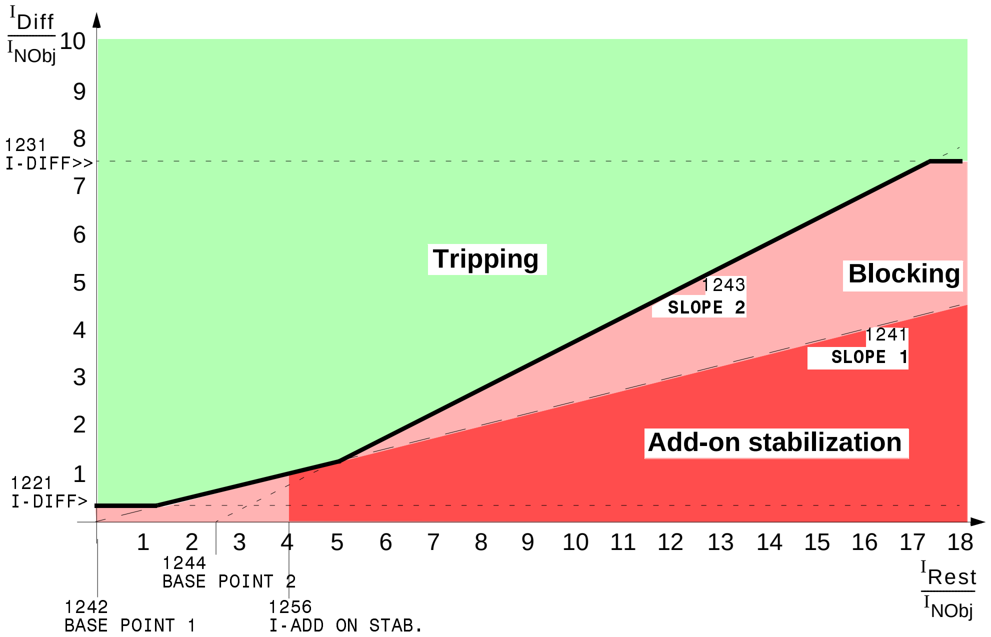


Figure 2-46 Tripping characteristic of the differential protection

The percentage of this latter error current is equal to the percentage of the regulating range provided the rated voltage is corrected according to Subsection 2.1.3 under margin “Object Data with Transformers” (page 36).

The second branch produces a higher restraint in the range of high currents which may lead to current transformer saturation. Its base point is set under address 1244A **BASE POINT 2** and is referred to the rated object current. The slope is set under address 1243A **SLOPE 2**. The stability of the protection can be influenced by these settings. A higher slope results in a higher stability. This parameter can only be altered with DIGSI® under “**Additional Settings**”.

Delay Times

In special cases it may be advantageous to delay the trip signal of the protection. For this, an additional delay can be set. The timer 1226A **T I-DIFF>** is started when an internal fault is detected by the I_{Diff}> stage and the trip characteristic. 1236A **T I-DIFF>>** is the delay for the I_{Diff}>> stage. This parameter can only be altered with DIGSI® under “**Additional Settings**”. The dropout time of all stages is determined by the minimum trip time duration of all protection functions.

These settings are pure delay times which do not include the inherent operating time of the protection.

Increase of Pickup Value on Startup

The increase of the pickup value on startup serves as an additional safety against overfunctioning when a non-energized protection object is switched in. This function can be set to ***ON*** or ***OFF*** in address 1205 **INC.CHAR.START**. Especially for motors or motor/transformer in unit connection it should be set to ***ON***.

The restraint current value **I-REST. STARTUP** (address 1251A) is the value of the restraining current which is likely to be undershot before startup of the protected object takes place (i.e. during standstill). This parameter can only be altered with DIGSI® under “**Additional Settings**”. Note that the restraint current is twice the traversing operational current. The preset value of 0.1 represents 0.05 times the rated current of the protected object.

Address 1252A **START-FACTOR** determines by which factor the pickup value of the I_{Diff}> stage is to be increased on startup. The characteristic of this stage increases by the same factor. The I_{Diff}>> stage is not affected. For motors or motor/transformer in unit connection, a value of 2 is normally adequate. This parameter can only be altered with DIGSI® under "**Additional Settings**".

The increase of the pickup value is set back to its original value after time period **T START MAX** (address 1253) has passed.

Add-on Stabilization

In systems with very high traversing currents a dynamic add-on stabilization is being enabled for external faults (Figure 2-46). The initial value is set in address 1261A **I-ADD ON STAB.**. The value is referred to the rated current of the protected object. The slope is the same as for characteristic branch b (**SLOPE 1**, address 1241A). This parameter can only be altered with DIGSI® under "**Additional Settings**". Note that the restraint current is the arithmetical sum of the currents flowing into the protected object, i. e. it is twice the traversing current. Add-on stabilization has no effect on the **I-DIFF>>** stage.

The maximum duration of the add-on stabilization after detection of an external fault is set in multiples of an AC cycle (address 1262A **T ADD ON-STAB.**). This parameter can only be altered with DIGSI® under "**Additional Settings**". The add-on stabilization is disabled automatically even before the set time period expires as soon as the device has detected that the operation point I_{Diff}/I_{Rest} is located steadily (i.e. for at least one AC-cycle) within the tripping zone.

Add-on stabilization operates individually per phase, but blocking can be extended to all three phases (so called "crossblock" function). By means of address 1262A **T ADD ON-STAB.** you can determine how long time crossblock should take place. This parameter can only be altered with DIGSI® under "**Additional Settings**". Setting is also in multiples of an AC-cycle. If you set ***0 cycles***, crossblock is ineffective, i.e. only the phase with detected external fault will be blocked. Otherwise all phases will be blocked; in this case the same setting as for **T ADD ON-STAB.** is reasonable. If set to ∞ the crossblock function remains active as long as add-on stabilization is effective.

Harmonic Restraint

Stabilization with harmonic content is available only when the device is used as transformer protection, i.e. **PROT. OBJECT** (address 105) is set to ***3 phase transf.*** or ***Autotransf.*** or ***1 phase transf.***. It is used also for shunt reactors if current transformers are installed at both sides of the connection points of the reactor (cf. example in Figure 2-35, right graph).

The inrush restraint function can be switched ***OFF*** or ***ON*** under address 1206 **INRUSH 2.HARM.**. It is based on the evaluation of the 2nd harmonic content of the inrush current. The ratio of the 2nd harmonic to the fundamental frequency **2. HARMONIC** (address 1271) is preset to I_{2fN}/I_{fN} = ***15*** % and can, as a rule, be retained without change. This ratio can be decreased in order to provide for a more stable setting in exceptional cases under especially unfavourable switch-on conditions. Harmonic restraint has no effect on the **I-DIFF>>** stage.

The inrush restraint can be extended by the "Crossblock" function. This means that not only the phase with inrush current exhibiting harmonic content in excess of the permissible value is stabilized but also the other phases of the differential stage I_{Diff}> are blocked. The duration for which the crossblock function is active can be limited under address 1272A **CROSSB. 2. HARM**. Setting is in multiple of the AC-cycle. This parameter can only be altered with DIGSI® under “**Additional Settings**”. If set to ***0*** (presetting) the protection can trip when the transformer is switched on a single-phase fault even while the other phases carry inrush current. If set to ∞ the crossblock function remains active as long as harmonic content is registered in any phase.

Besides the 2nd harmonic, 7UT6 provides stabilization with a further harmonic: the n-th harmonic. Address 1207 **RESTR. n.HARM.** allows to select the ***3. Harmonic*** or the ***5. Harmonic***, or to switch this n-th harmonic restraint ***OFF***.

Steady-state overexcitation of transformers is characterized by odd harmonic content. The 3rd or 5th harmonic is suitable to detect overexcitation. As the 3rd harmonic is often eliminated in the transformer windings (e.g. in a delta connected winding group), the 5th harmonic is usually used.

Converter transformers also produce odd harmonic content, which is absent in the case of an internal short-circuit.

The harmonic content which blocks the differential stage I_{Diff}> is set under address 1276 **n. HARMONIC**. For example, if the 5th harmonic restraint is used to avoid trip during overexcitation, 30 % (presetting) is convenient.

Harmonic restraint with the n-th harmonic operates individual per phase. But possibility exists — as with the inrush restraint — to set the protection such that not only the phase with harmonic content in excess of the permissible value is stabilized but also the other phases of the differential stage I_{Diff}> are blocked (crossblock function). The duration for which the crossblock function is active can be limited under address 1277A **CROSSB. n.HARM**. Setting is in multiple of the AC-cycle. This parameter can only be altered with DIGSI® under “**Additional Settings**”. If set to ***0*** (presetting) the crossblock function is ineffective, if set to ∞ the crossblock function remains active as long as harmonic content is registered in any phase.

If the differential current exceeds the magnitude set in address 1278A **IDIFFmax n.HM** no n-th harmonic restraint takes place. This parameter can only be altered with DIGSI® under “**Additional Settings**”.

2.2.8 Setting Overview

Note: Addresses which have an “A” attached to their end can only be changed in DIGSI®, under “**Additional Settings**”. The referred current values I/I_{NS} are set referred to the nominal current of the assigned side as stated in Subsection 2.1.3. The referred current values I/I_{NO} are referred to the nominal current of the main protected object as stated in Subsection 2.1.3.

Addr.	Setting Title	Setting Options	Default Setting	Comments
1201	DIFF. PROT.	OFF ON Block relay for trip commands	OFF	Differential Protection
1205	INC.CHAR.START	OFF ON	OFF	Increase of Trip Char. During Start

Addr.	Setting Title	Setting Options	Default Setting	Comments
1206	INRUSH 2.HARM.	OFF ON	ON	Inrush with 2. Harmonic Restraint
1207	RESTR. n.HARM.	OFF 3. Harmonic 5. Harmonic	OFF	n-th Harmonic Restraint
1208	I-DIFF> MON.	OFF ON	ON	Differential Current monitoring
1210	I> CURR. GUARD	0.20..2.00 I/InS; 0	0.00 I/InS	I> for Current Guard
1211A	DIFFw.IE1-MEAS	NO YES	NO	Diff-Prot. with meas. Earth Current S1
1212A	DIFFw.IE2-MEAS	NO YES	NO	Diff-Prot. with meas. Earth Current S2
1213A	DIFFw.IE3-MEAS	NO YES	NO	Diff-Prot. with meas. Earth Current S3
1214A	DIFFw.IE4-MEAS	NO YES	NO	Diff-Prot. with meas. Earth Current S4
1215A	DIFFw.IE5-MEAS	NO YES	NO	Diff-Prot. with meas. Earth Current S5
1221	I-DIFF>	0.05..2.00 I/InO	0.20 I/InO	Pickup Value of Differential Curr.
1226A	T I-DIFF>	0.00..60.00 sec; ∞	0.00 sec	T I-DIFF> Time Delay
1231	I-DIFF>>	0.5..35.0 I/InO; ∞	7.5 I/InO	Pickup Value of High Set Trip
1236A	T I-DIFF>>	0.00..60.00 sec; ∞	0.00 sec	T I-DIFF>> Time Delay
1241A	SLOPE 1	0.10..0.50	0.25	Slope 1 of Tripping Characteristic
1242A	BASE POINT 1	0.00..2.00 I/InO	0.00 I/InO	Base Point for Slope 1 of Charac.
1243A	SLOPE 2	0.25..0.95	0.50	Slope 2 of Tripping Characteristic
1244A	BASE POINT 2	0.00..10.00 I/InO	2.50 I/InO	Base Point for Slope 2 of Charac.
1251A	I-REST. STARTUP	0.00..2.00 I/InO	0.10 I/InO	I-RESTRAINT for Start Detection
1252A	START-FACTOR	1.0..2.0	1.0	Factor for Increasing of Char. at Start
1253	T START MAX	0.0..180.0 sec	5.0 sec	Maximum Permissible Starting Time
1261A	I-ADD ON STAB.	2.00..15.00 I/InO	4.00 I/InO	Pickup for Add-on Stabilization
1262A	T ADD ON-STAB.	2..250 Cycle; ∞	15 Cycle	Duration of Add-on Stabilization
1263A	CROSSB. ADD ON	2..1000 Cycle; 0; ∞	15 Cycle	Time for Cross-blocking Add-on Stabiliz.
1271	2. HARMONIC	10..80 %	15 %	2nd Harmonic Content in I-DIFF

Addr.	Setting Title	Setting Options	Default Setting	Comments
1272A	CROSSB. 2. HARM	2..1000 Cycle; 0; ∞	3 Cycle	Time for Cross-blocking 2nd Harm.
1276	n. HARMONIC	10..80 %	30 %	n-th Harmonic Content in I-DIFF
1277A	CROSSB. n.HARM	2..1000 Cycle; 0; ∞	0 Cycle	Time for Cross-blocking n-th Harm.
1278A	IDIFFmax n.HM	0.5..20.0 I/InO	1.5 I/InO	Limit IDIFFmax of n-th Harm.Restraint
1281	I-DIFF> MON.	0.15..0.80 I/InO	0.20 I/InO	Pickup Value of diff. Current Monitoring
1282	T I-DIFF> MON.	1..10 sec	2 sec	T I-DIFF> Monitoring Time Delay

2.2.9 Information Overview

F.No.	Alarm	Comments
05603	>Diff BLOCK	>BLOCK differential protection
05615	Diff OFF	Differential protection is switched OFF
05616	Diff BLOCKED	Differential protection is BLOCKED
05617	Diff ACTIVE	Differential protection is ACTIVE
05620	Diff Adap.fact.	Diff err.: adverse Adaption factor CT
05733	Dif CT-M1:	Diff. prot: Adaption factor CT M1
05734	Dif CT-M2:	Diff. prot: Adaption factor CT M2
05735	Dif CT-M3:	Diff. prot: Adaption factor CT M3
05736	Dif CT-M4:	Diff. prot: Adaption factor CT M4
05737	Dif CT-M5:	Diff. prot: Adaption factor CT M5
05721	Dif CT-I1:	Diff. prot: Adaption factor CT I1
05722	Dif CT-I2:	Diff. prot: Adaption factor CT I2
05723	Dif CT-I3:	Diff. prot: Adaption factor CT I3
05724	Dif CT-I4:	Diff. prot: Adaption factor CT I4
05725	Dif CT-I5:	Diff. prot: Adaption factor CT I5
05726	Dif CT-I6:	Diff. prot: Adaption factor CT I6
05727	Dif CT-I7:	Diff. prot: Adaption factor CT I7
05728	Dif CT-I8:	Diff. prot: Adaption factor CT I8

F.No.	Alarm	Comments
05729	Dif CT-I9:	Diff. prot: Adaption factor CT I9
05730	Dif CT-I10:	Diff. prot: Adaption factor CT I10
05731	Dif CT-I11:	Diff. prot: Adaption factor CT I11
05732	Dif CT-I12:	Diff. prot: Adaption factor CT I12
05738	Dif CT-IX1:	Diff. prot: Adaption factor aux. CT IX1
05739	Dif CT-IX2:	Diff. prot: Adaption factor aux. CT IX2
05740	Dif CT-IX3:	Diff. prot: Adaption factor aux. CT IX3
05741	Dif CT-IX4:	Diff. prot: Adaption factor aux. CT IX4
05631	Diff picked up	Differential protection picked up
05644	Diff 2.Harm L1	Diff: Blocked by 2.Harmon. L1
05645	Diff 2.Harm L2	Diff: Blocked by 2.Harmon. L2
05646	Diff 2.Harm L3	Diff: Blocked by 2.Harmon. L3
05647	Diff n.Harm L1	Diff: Blocked by n.Harmon. L1
05648	Diff n.Harm L2	Diff: Blocked by n.Harmon. L2
05649	Diff n.Harm L3	Diff: Blocked by n.Harmon. L3
05651	Diff Bl. exF.L1	Diff. prot.: Blocked by ext. fault L1
05652	Diff Bl. exF.L2	Diff. prot.: Blocked by ext. fault L2
05653	Diff Bl. exF.L3	Diff. prot.: Blocked by ext. fault.L3
05657	DiffCrosBlk 2HM	Diff: Crossblock by 2.Harmonic
05658	DiffCrosBlk nHM	Diff: Crossblock by n.Harmonic
05660	DiffCrosBlk exF	Diff: Crossblock by ext. fault
05662	Block Iflt.L1	Diff. prot.: Blocked by CT fault L1
05663	Block Iflt.L2	Diff. prot.: Blocked by CT fault L2
05664	Block Iflt.L3	Diff. prot.: Blocked by CT fault L3
05666	DiffStrtInChaL1	Diff: Increase of char. phase (start) L1
05667	DiffStrtInChaL2	Diff: Increase of char. phase (start) L2
05668	DiffStrtInChaL3	Diff: Increase of char. phase (start) L3
05742	Diff DC L1	Diff: DC L1
05743	Diff DC L2	Diff: DC L2
05744	Diff DC L3	Diff: DC L3
05745	Diff DC InCha	Diff: Increase of char. phase (DC)
05670	Diff I-Release	Diff: Curr-Release for Trip
05671	Diff TRIP	Differential protection TRIP
05672	Diff TRIP L1	Differential protection: TRIP L1

F.No.	Alarm	Comments
05673	Diff TRIP L2	Differential protection: TRIP L2
05674	Diff TRIP L3	Differential protection: TRIP L3
05681	Diff> L1	Diff. prot.: IDIFF> L1 (without Tdelay)
05682	Diff> L2	Diff. prot.: IDIFF> L2 (without Tdelay)
05683	Diff> L3	Diff. prot.: IDIFF> L3 (without Tdelay)
05684	Diff>> L1	Diff. prot: IDIFF>> L1 (without Tdelay)
05685	Diff>> L2	Diff. prot: IDIFF>> L2 (without Tdelay)
05686	Diff>> L3	Diff. prot: IDIFF>> L3 (without Tdelay)
05691	Diff> TRIP	Differential prot.: TRIP by IDIFF>
05692	Diff>> TRIP	Differential prot.: TRIP by IDIFF>>
05701	Dif L1 :	Diff. curr. in L1 at trip without Tdelay
05702	Dif L2 :	Diff. curr. in L2 at trip without Tdelay
05703	Dif L3 :	Diff. curr. in L3 at trip without Tdelay
05704	Res L1 :	Restr.curr. in L1 at trip without Tdelay
05705	Res L2 :	Restr.curr. in L2 at trip without Tdelay
05706	Res L3 :	Restr.curr. in L3 at trip without Tdelay

2.3 Restricted Earth Fault Protection

The restricted earth fault protection detects earth faults in power transformers, shunt reactors, neutral earthing transformers/reactors, or rotating machines, the starpoint of which is led to earth. It is also suitable when a starpoint former (neutral reactor) is installed within a protected zone of a non-earthed power transformer. A precondition is that a current transformer is installed in the starpoint connection, i.e. between the starpoint and the earthing electrode. The starpoint CT and the phase CTs define the limits of the protected zone exactly. Restricted earth fault protection is not applicable on auto-transformers and busbars.

Examples are illustrated in the Figures 2-47 to 2-51.

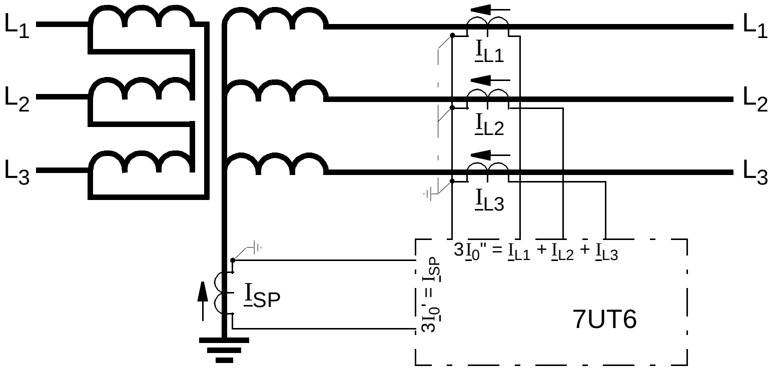


Figure 2-47 Restricted earth fault protection on an earthed winding of a power transformer

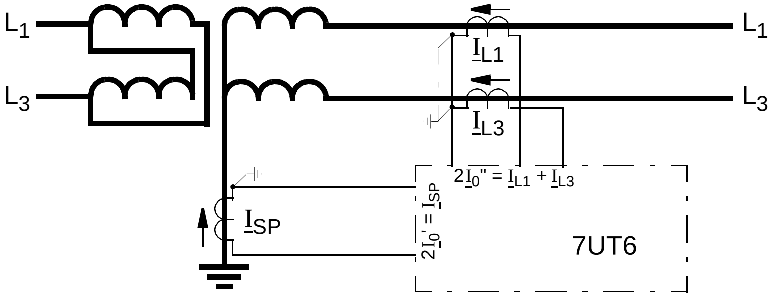


Figure 2-48 Restricted earth fault protection on an earthed winding of a single-phase power transformer

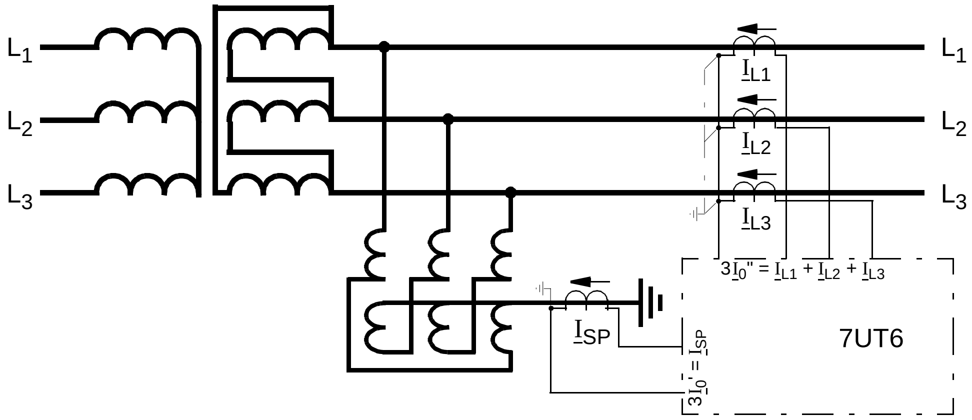


Figure 2-49 Restricted earth fault protection on a non-earthed transformer winding with neutral reactor (starpoint former) within the protected zone

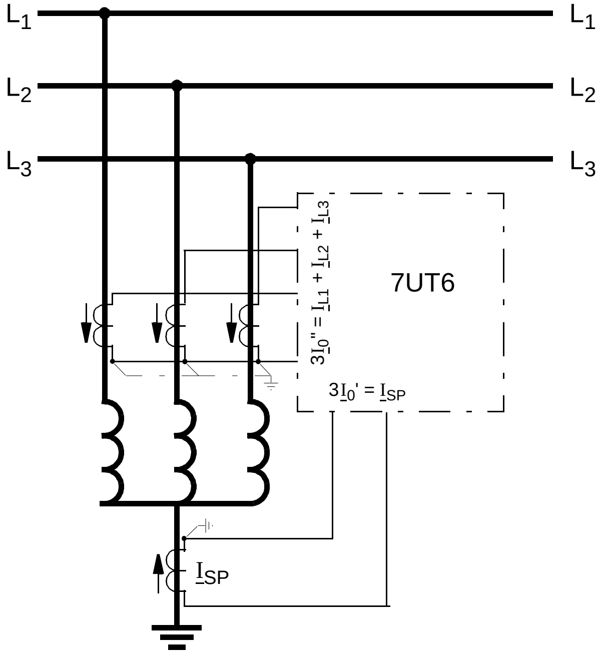


Figure 2-50 Restricted earth fault protection on an earthed shunt reactor with CTs in the reactor leads

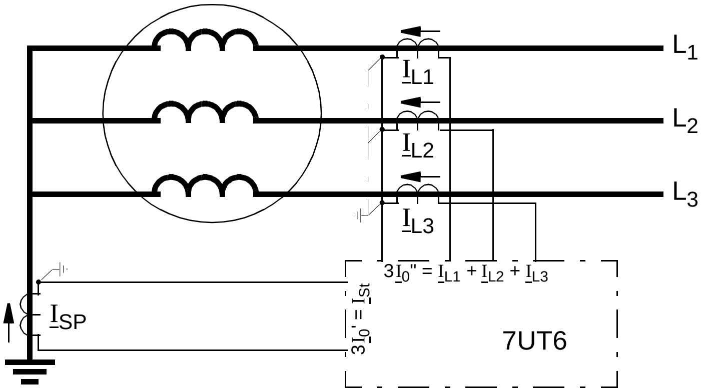


Figure 2-51 Restricted earth fault protection on a generator or motor with earthed starpoint

The restricted earth fault protection can operate on one of the sides of the main protected object (power transformer, generator, motor, reactor) or on a further protected object, according to the topology as stated in Subsection 2.1.2. The assignment of the protection is carried out according Subsection 2.1.4. Furthermore, it is presumed that the assignment of the different measuring locations to the sides of the main protected object or to a further protected object as well as the assignment of the 1-phase current input for the starpoint current has been performed correctly according to Subsection 2.1.2.

2.3.1 Function Description

Basic Principle

During healthy operation, no starpoint current $\underline{I}_{SP}$ flows through the starpoint lead, the sum of the phase currents $3\underline{I}_0 = \underline{I}_{L1} + \underline{I}_{L2} + \underline{I}_{L3}$ is almost zero, too.

When an earth fault occurs in the protected zone (Figure 2-52), a starpoint current $\underline{I}_{SP}$ will flow; depending on the earthing conditions of the power system a further earth current may be recognized in the residual current path of the phase current transformers. Since all currents which flow into the protected zone are defined positive, the residual current from the system will be more or less in phase with the starpoint current.

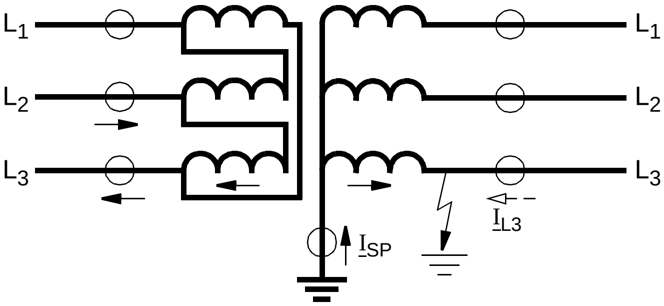


Figure 2-52 Example for an earth fault in a transformer with current distribution

When an earth fault occurs outside the protected zone (Figure 2-53), a starpoint current $\underline{I}_{SP}$ will flow equally; but the residual current of the phase current transformers $3\underline{I}_0$ is now of equal magnitude and in phase opposition with the starpoint current.

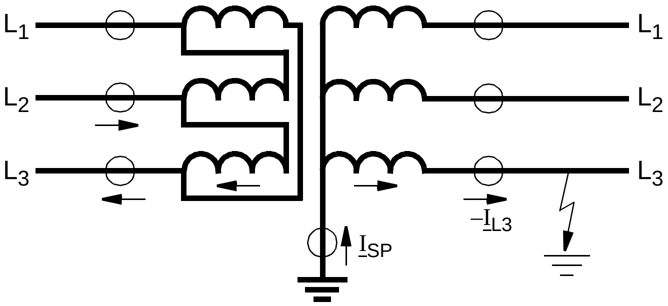


Figure 2-53 Example for an earth fault outside a transformer with current distribution

When a fault without earth connection occurs outside the protected zone, a residual current may occur in the residual current path of the phase current transformers which is caused by different saturation of the phase current transformers under strong through-current conditions. This current could simulate a fault in the protected zone. Wrong tripping must be avoided under such condition. For this, the restricted earth fault protection provides stabilization methods which differ strongly from the usual stabilization methods of differential protection schemes since it uses, besides the magnitude of the measured currents, the phase relationship, too.

Evaluation of the Measured Quantities

The restricted earth fault protection compares the fundamental wave of the current flowing in the starpoint connection, which is designated as $3I_0$’ in the following, with the fundamental wave of the sum of the phase currents, which should be designated in the following as $3I_0$". Thus, the following applies (Figure 2-54):

$$3\underline{I}_0' = \underline{I}_{SP}$$
$$3\underline{I}_0'' = \underline{I}_{L1} + \underline{I}_{L2} + \underline{I}_{L3}$$

Only $3\underline{I}_0$' acts as the tripping effect quantity, during a fault within the protected zone this current is always present.

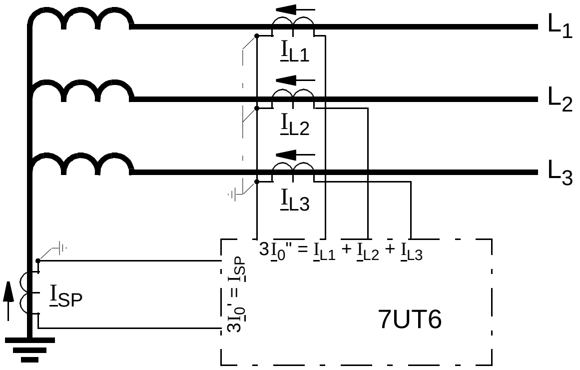


Figure 2-54 Principle of restricted earth fault protection

When an earth fault occurs outside the protected zone, another earth current $3\underline{I}_0''$ flows though the phase current transformers. This is in counter-phase with the starpoint $3\underline{I}_0'$ current and has equal magnitude. The maximum information of the currents is evaluated for stabilization: the magnitude of the currents and their phase position. The following is defined:

A tripping effect current
$I_{REF} = |3\underline{I}_0'|$

and the stabilization or restraining current
$I_{Rest} = k \cdot (|3\underline{I}_0' - 3\underline{I}_0''| - |3\underline{I}_0' + 3\underline{I}_0''|)$

where k is a stabilization factor which will be explained below, at first we assume k = 1. I_{REF} is derived from the fundamental wave and produces the tripping effect quantity, I_{Rest} counteracts this effect.

To clarify the situation, three important operating conditions should be examined:

a) Through-fault current on an external earth fault:

$3\underline{I}_0''$ is in phase opposition with $3\underline{I}_0'$ and of equal magnitude i.e. $3\underline{I}_0'' = -3\underline{I}_0'$

$I_{REF} = |3\underline{I}_0'|$
$I_{Rest} = |3\underline{I}_0' + 3\underline{I}_0''| - |3\underline{I}_0' - 3\underline{I}_0''| = 2 \cdot |3\underline{I}_0'|$

The tripping effect current (I_{REF}) equals the starpoint current; restraint (I_{Rest}) corresponds to twice the tripping effect current.

b) Internal earth fault, fed only from the starpoint:

In this case, $3\underline{I}_0'' = 0$

$I_{REF} = |3\underline{I}_0'|$
$I_{Rest} = |3\underline{I}_0' - 0| - |3\underline{I}_0' + 0| = 0$

The tripping effect current (I_{REF}) equals the starpoint current; restraint (I_{Rest}) is zero, i.e. full sensitivity during internal earth fault.

c) Internal earth fault, fed from the starpoint and from the system, e.g. with equal earth current magnitude:

In this case, $3\underline{I}_0'' = 3\underline{I}_0'$

$I_{REF} = |3\underline{I}_0'|$
$I_{Rest} = |3\underline{I}_0' - 3\underline{I}_0'| - |3\underline{I}_0' + 3\underline{I}_0'| = -2 \cdot |3\underline{I}_0'|$

The tripping effect current (I_{REF}) equals the starpoint current; the restraining quantity (I_{Rest}) is negative and, therefore, set to zero, i.e. full sensitivity during internal earth fault.

This result shows that for internal fault no stabilization is effective since the restraint quantity is either zero or negative. Thus, small earth current can cause tripping. In contrast, strong restraint becomes effective for external earth faults. Figure 2-55 shows that the restraint is the strongest when the residual current from the phase current transformers is high (area with negative $3I_0''/3I_0'$). With ideal current transformers, $3I_0''/3I_0'$ would be –1.

If the starpoint current transformer is designed weaker than the phase current transformers (e.g. by selection of a smaller accuracy limit factor or by higher secondary burden), no trip will be possible under through-fault condition even in case of severe saturation as the magnitude of $3I_0''$ is always higher than that of $3I_0'$.

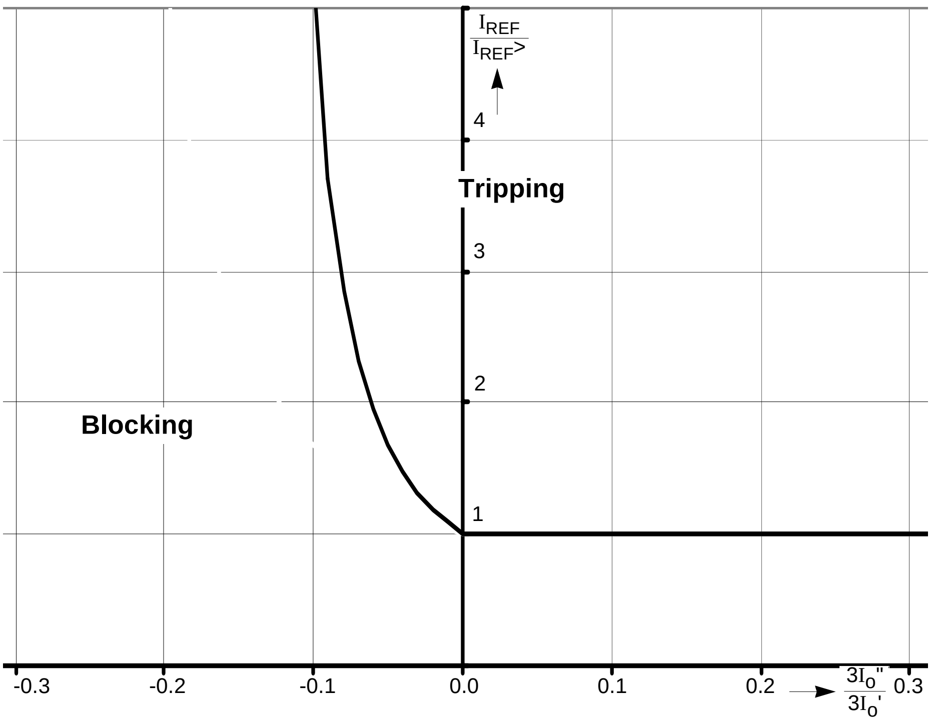


Figure 2-55 Tripping characteristic of the restricted earth fault protection depending on the earth current ratio $3I_0''/3I_0'$ (both currents in phase + or counter-phase –); I_{REF} = tripping effect current; $I_{REF}>$ = setting value

It was assumed in the above examples that the currents $3\underline{I}_0''$ and $3\underline{I}_0'$ are in counter-phase for external earth faults which is only true for the primary measured quantities. Current transformer saturation may cause phase shifting between the fundamental waves of the secondary currents which reduces the restraint quantity. If the phase displacement $\varphi(3\underline{I}_0''; 3\underline{I}_0') = 90°$ then the restraint quantity is zero. This corresponds to the conventional method of direction determination by use of the vectorial sum and difference comparison (Figure 2-56).

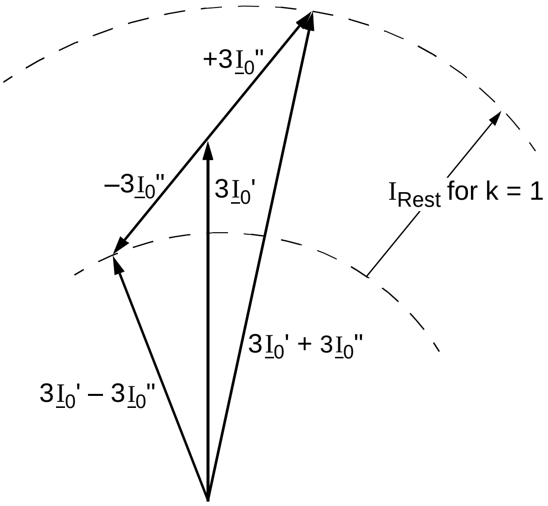


Figure 2-56 Phasor diagram of the restraint quantity during external fault

The restraint quantity can be influenced by means of a factor k. This factor has a certain relationship to the limit angle φ_{limit}. This limit angle determines, for which phase displacement between $3\underline{I}_0''$ and $3\underline{I}_0'$ the pickup value grows to infinity when $3\underline{I}_0'' = 3\underline{I}_0'$, i.e. no pickup occurs. In 7UT6 is k = 4, i.e. the restraint quantity in the above example a) is quadrupled once more: the restraint quantity I_{Rest} is 8 times the tripping effect quantity I_{REF}. The limit angle is $\varphi_{limit} = 100°$. That means no trip is possible for phase displacement $|\varphi(3\underline{I}_0''; 3\underline{I}_0')| \geq 100°$.

Figure 2-57 shows the operating characteristics of the restricted earth fault protection dependent of the phase displacement between $3\underline{I}_0''$ and $3\underline{I}_0'$, for a constant infeed ratio $|3\underline{I}_0''| = |3\underline{I}_0'|$.

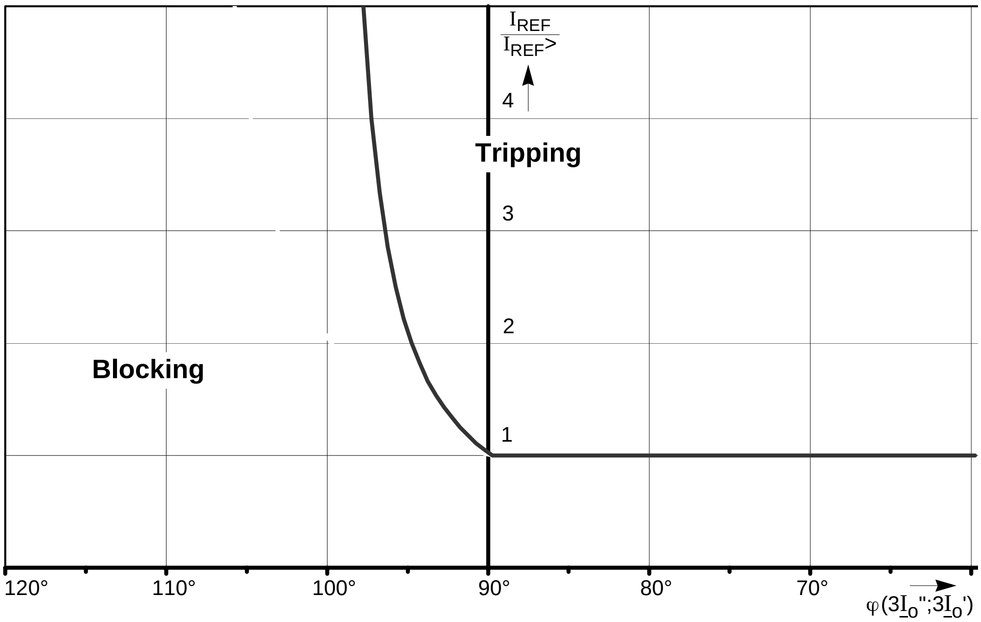


Figure 2-57 Tripping characteristic of the restricted earth fault protection depending on the phase displacement between $3\underline{I}_0''$ and $3\underline{I}_0'$ at $3I_0'' = 3I_0'$ (180° = external fault)

It is possible to increase the tripping value in the tripping area proportional to the arithmetic sum of all currents, i.e. with the sum of the magnitudes $\Sigma|I| = |I_{L1}| + |I_{L2}| + |I_{L3}| + |I_{SP}|$ (Figure 2-58). The slope of this stabilization can be set.

Fault Detection

Normally, a differential protection does not need a “pickup” or “fault detection” function since the condition for a fault detection is identical to the trip condition. But the restricted earth fault protection provides like all protection functions a fault detection signal which forms an additional precondition for tripping and defines the fault inception instant for a number of further activities.

As soon as the fundamental wave of the differential current exceeds 85 % of the pickup value, fault detection is indicated. In this aspect, the differential current is represented by the sum of all in-flowing currents.

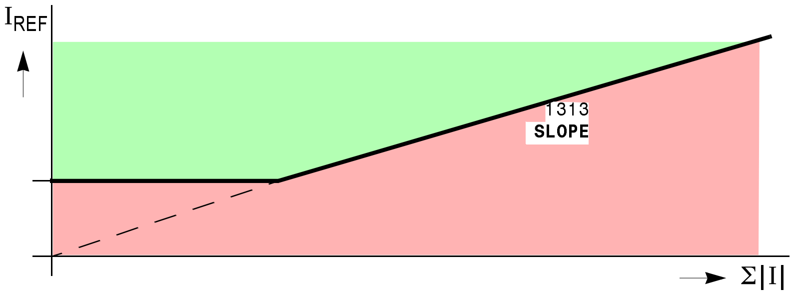


Figure 2-58 Increasing the pickup value

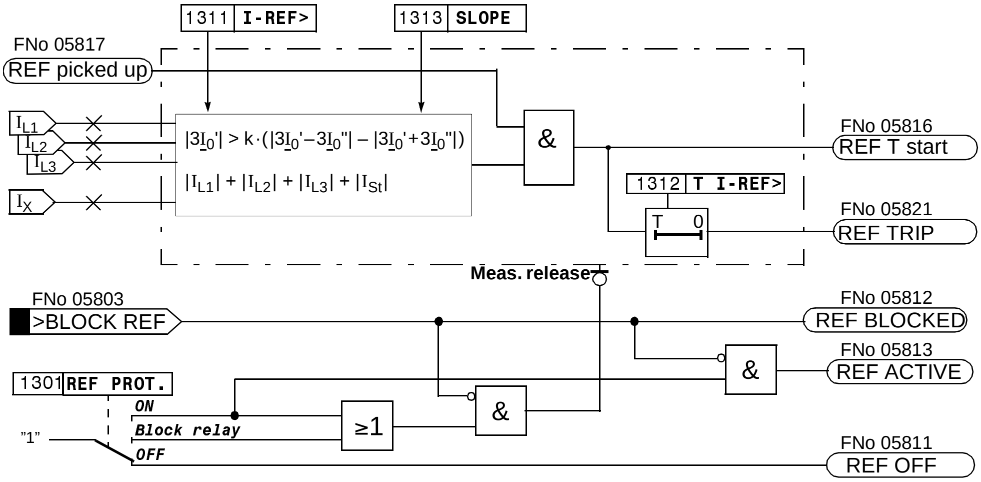


Figure 2-59 Logic diagram of the restricted earth fault protection (simplified)

2.3.2 Setting the Function Parameters

The restricted earth fault protection can only operate if this function has been set during configuration (refer to Subsection 2.1.1, address 113) **REF PROT.** to ***Enabled***. Furthermore, an auxiliary 1-phase measured current input must be assigned to the same side or measuring location where the starpoint current is to be processed. (Subsection 2.1.2. under margin header “Assignment of Auxiliary 1-phase Measuring Locations”). The restricted earth fault protection itself must have been assigned to this side or measuring location (Subsection 2.1.4. under margin header “Restricted Earth Fault Protection”).

The restricted earth fault protection can be set effective (***ON***) or ineffective (***OFF***) in address 1301 **REF PROT.**. The option ***Block relay*** allows to operate the protection but the trip output relay is blocked.

Note:

When delivered from factory, the restricted earth fault protection is switched ***OFF***. The reason is that the protection must not be in operation unless at least the assigned side and the CT polarity have been set before. Without proper settings, the device may show unexpected reactions (incl. tripping)!

The sensitivity of the restricted earth fault protection is determined by the pickup value **I-REF>** (address 1311). The earth fault current which flows through the starpoint lead of the protected object (transformer, generator, motor, shunt reactor) is decisive. A further earth current which may be supplied from the network does not influence the sensitivity. The setting value is referred to the nominal current of the protected side of the main protected object or, in case of a further protected object, to the nominal operation current of the corresponding measuring location.

The set value can be increased in the tripping quadrant depending on the arithmetic sum of the currents (stabilization by the sum of all current magnitudes) which is set under address 1313A **SLOPE**. This parameter can only be altered with DIGSI® under “**Additional Settings**”. The preset value ***0*** is normally adequate.

In special cases it may be advantageous to delay the trip signal of the protection. For. this, an additional delay can be set. The timer 1312A **T I-REF>** is started when an internal fault is detected. This setting is a pure delay time which does not include the inherent operating time of the protection.

2.3.3 Setting Overview

Note: Addresses which have an “A” attached to their end can only be changed in DIGSI®, under “**Additional Settings**”. The referred current values I/I_{NS} are referred to the nominal current of the assigned side of the main protected object as stated in Subsection 2.1.3. If the restricted earth fault protection is not assigned to the main protected object, the nominal current of the assigned 3-phase measuring location as stated in Subsection 2.1.3 is the reference.

Addr.	Setting Title	Setting Options	Default Setting	Comments
1301	REF PROT.	OFF ON Block relay for trip commands	OFF	Restricted Earth Fault Protection
1311	I-REF>	0.05..2.00 I/InS	0.15 I/InS	Pick up value I REF>
1312A	T I-REF>	0.00..60.00 sec; ∞	0.00 sec	T I-REF> Time Delay
1313A	SLOPE	0.00..0.95	0.00	Slope of Charac. I-REF> = f(I-SUM)

2.3.4 Information Overview

F.No.	Alarm	Comments
05803	>BLOCK REF	>BLOCK restricted earth fault prot.
05811	REF OFF	Restricted earth fault is switched OFF
05812	REF BLOCKED	Restricted earth fault is BLOCKED
05813	REF ACTIVE	Restricted earth fault is ACTIVE
05817	REF picked up	Restr. earth flt.: picked up
05816	REF T start	Restr. earth flt.: Time delay started
05821	REF TRIP	Restr. earth flt.: TRIP
05826	REF D:	REF: Value D at trip (without Tdelay)
05827	REF S:	REF: Value S at trip (without Tdelay)
05836	REF Adap.fact.	REF err.: adverse Adaption factor CT
05830	REF Err CTstar	REF err.: No starpoint CT
05835	REF Not avalia.	REF err.: Not avaliable for this objekt

2.4 Time Overcurrent Protection for Phase and Residual Currents

General

Time overcurrent protection is used as backup protection for the short-circuit protection of the main protected object and provides backup protection for external faults which are not promptly disconnected and thus may endanger the protected object. It can also be used as short-circuit protection for a further protected object if it has been assigned to corresponding measuring locations (cf. Subsection 2.1.4 under “Further 3-Phase Protection Functions”, page 49) and these are assigned to the correct current inputs (cf. Subsection 2.1.2 under “Assignment of 3-phase Measuring Locations”, page 28).

Time overcurrent protection for phase currents takes its currents from the side or measuring location to which it is assigned. Time overcurrent protection for residual current always uses the sum of the phase currents of that side or measuring location to which it is assigned. The side or measuring location for the phase currents may be different from that of the residual current.

If the main protected object is **PROT. OBJECT** = ***1ph Busbar*** (address 105, see Subsection 2.1.1), the time overcurrent protection is ineffective.

The time overcurrent protection provides two definite time stages and one inverse time stage for each the phase currents and the residual current. The inverse time stages may operate according an IEC or an ANSI, or an user defined characteristic.

2.4.1 Function Description

2.4.1.1 Definite Time Overcurrent Protection

The definite time stages for phase currents and residual current are always available even if an inverse time characteristic has been configured according to Subsection 2.1.1 (addresses 120 and/or 122).

Pickup, Trip

Two definite time stages are available for each the phase currents and the residual current ($3 \cdot I_0$).

Each phase current and the residual current $3 \cdot I_0$ are compared with the setting value **I>>** (common setting for the three phase currents) and **3I0>>** (independent setting for $3 \cdot I_0$). Currents above the associated pickup value are detected and annunciated. When the respective delay time **T I>>** or **T 3I0>>** is expired, tripping command is issued. The reset value is approximately 5 % below the pickup value for currents above I_N. Lower values require a higher hysteresis in order to avoid intermittent pickup on currents near the pickup value (e.g. 10 % at $0.2 \cdot I_N$).

Figure 2-60 shows the logic diagram for the high-current stages I>> and $3I_0$>>.

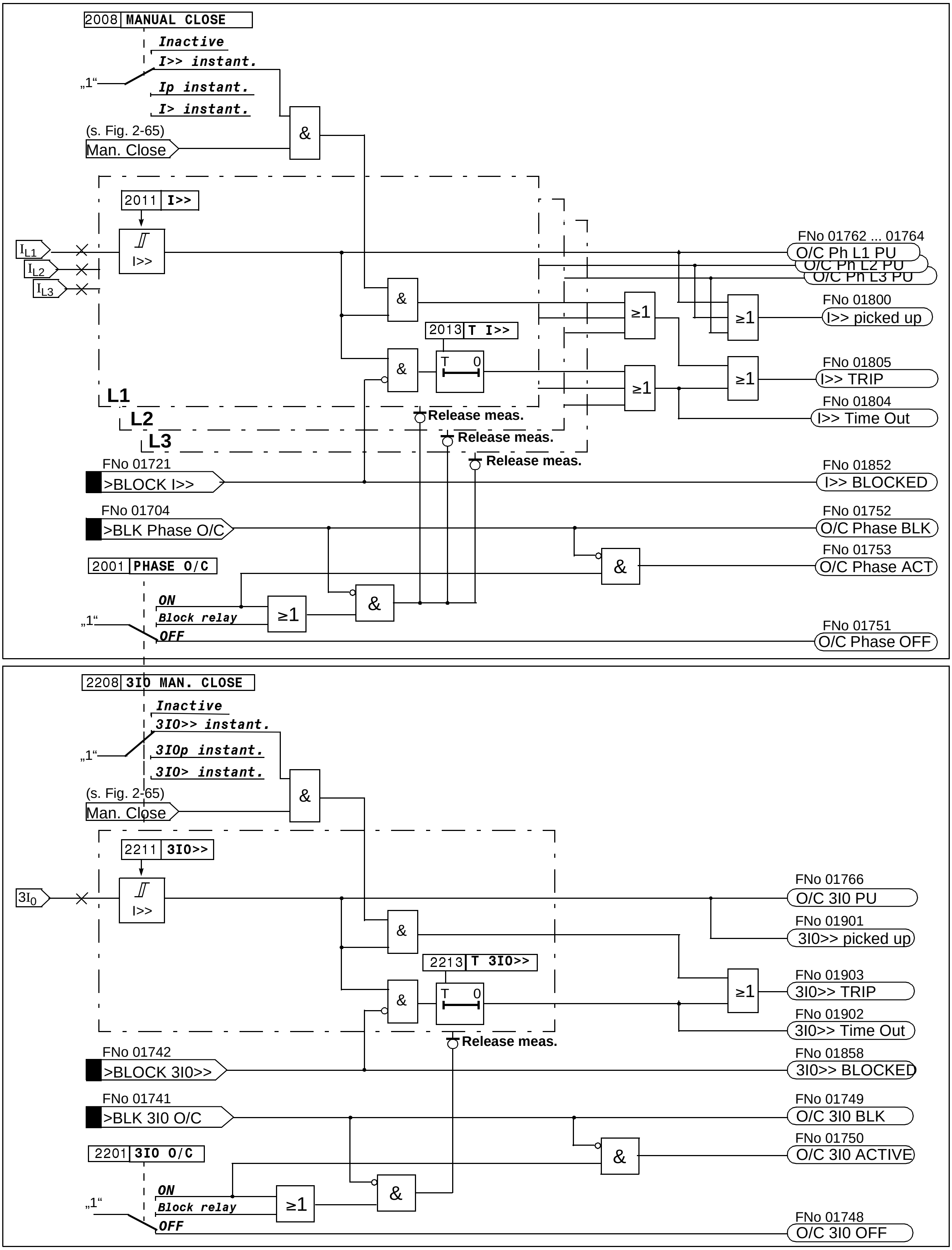


Figure 2-60 Logic diagram of the high-set stages I>> for phase currents and residual current (simplified)

Each phase current and the residual current $3\cdot I_0$ are, additionally, compared with the setting value **I>** (common setting for the three phase currents) and **3I0>** (independent setting for $3\cdot I_0$). When the set thresholds are exceeded, pickup is annunciated. But if inrush restraint is used (cf. Subsection 2.4.1.5), a frequency analysis is performed first (Subsection 2.4.1.5). If an inrush condition is detected, pickup annunciation is suppressed and an inrush message is output instead. When, after pickup without inrush recognition, the relevant delay times **T I>** or **T 3I0>** are expired, tripping command is issued. During inrush condition no trip is possible but expiry of the timer is annunciated. The reset value is approximately 5 % below the pickup value for currents above I_N. Lower values require a higher hysteresis in order to avoid intermittent pickup on currents near the pickup value (e.g. 10 % at $0.2\cdot I_N$).

Figure 2-61 shows the logic diagram of the stages I> for phase currents, Figure 2-62 for residual current.

The pickup values for each of the stages, I> (phase currents), $3I_0$> (residual current), I>> (phase currents), $3I_0$>> (residual current) and the delay times can be set individually.

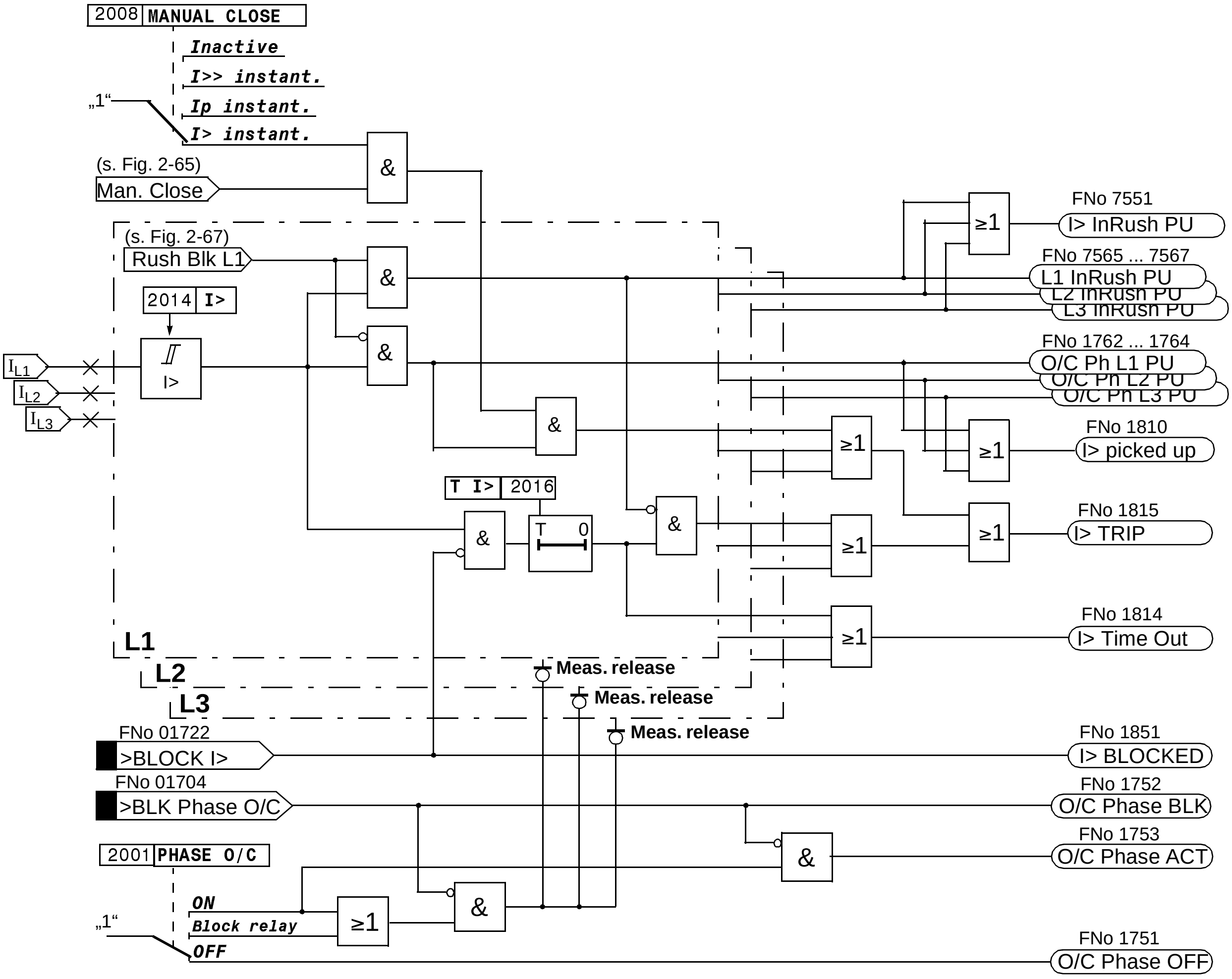


Figure 2-61 Logic diagram of the overcurrent stages I> for phase currents (simplified)

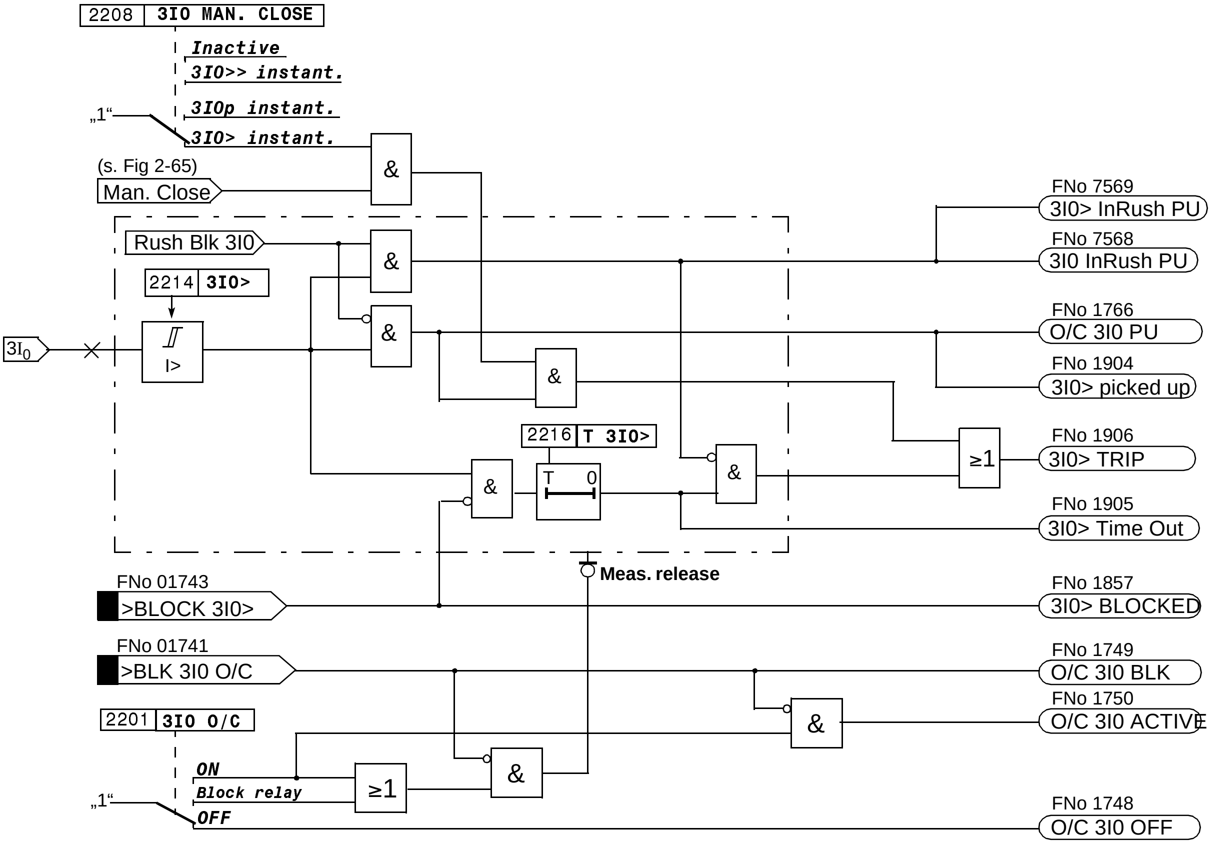


Figure 2-62 Logic diagram of the overcurrent stage $3I_0$> for residual current (simplified)

2.4.1.2 Inverse Time Overcurrent Protection

The inverse time overcurrent stages operate with a characteristic either according to the IEC- or the ANSI-standard or with a user-defined characteristic. The characteristic curves and their equations are represented in Technical Data (Figures 4-7 to 4-9 in Section 4.4). When configuring one of the inverse time characteristics, definite time stages I>> and I> are also available (see Section 2.4.1.1).

Pickup, Trip

Each phase current and the residual current (sum of phase currents) are compared, one by one, to a common setting value **`Ip`** and a separate setting **`3I0p`**. If a current exceeds 1.1 times the setting value, the corresponding stage picks up and is signalled phase-segregated. But if inrush restraint is used (cf. Subsection 2.4.1.5), a frequency analysis is performed first (Subsection 2.4.1.5). If an inrush condition is detected, pickup annunciation is suppressed and an inrush message is output instead. The RMS values of the basic oscillations are used for pickup. During the pickup of an Ip stage, the tripping time is calculated from the flowing fault current by means of an integrating measuring procedure, depending on the selected tripping characteristic. After the expiration of this period, a trip command is transmitted as long as inrush current is detected or inrush restraint is disabled. If inrush restraint is enabled and inrush current is detected, there will be no tripping. Nevertheless, an annunciation is generated indicating that the time has expired.

For the residual current **3I0p** the characteristic can be selected independent from the characteristic used for the phase currents.

The pickup values for the stages I_p (phase currents), $3I_{0p}$ (residual current) and the delay times for each of these stages can be set individually.

Figure 2-63 shows the logic diagram of the inverse time stages for phase currents, Figure 2-64 for residual current.

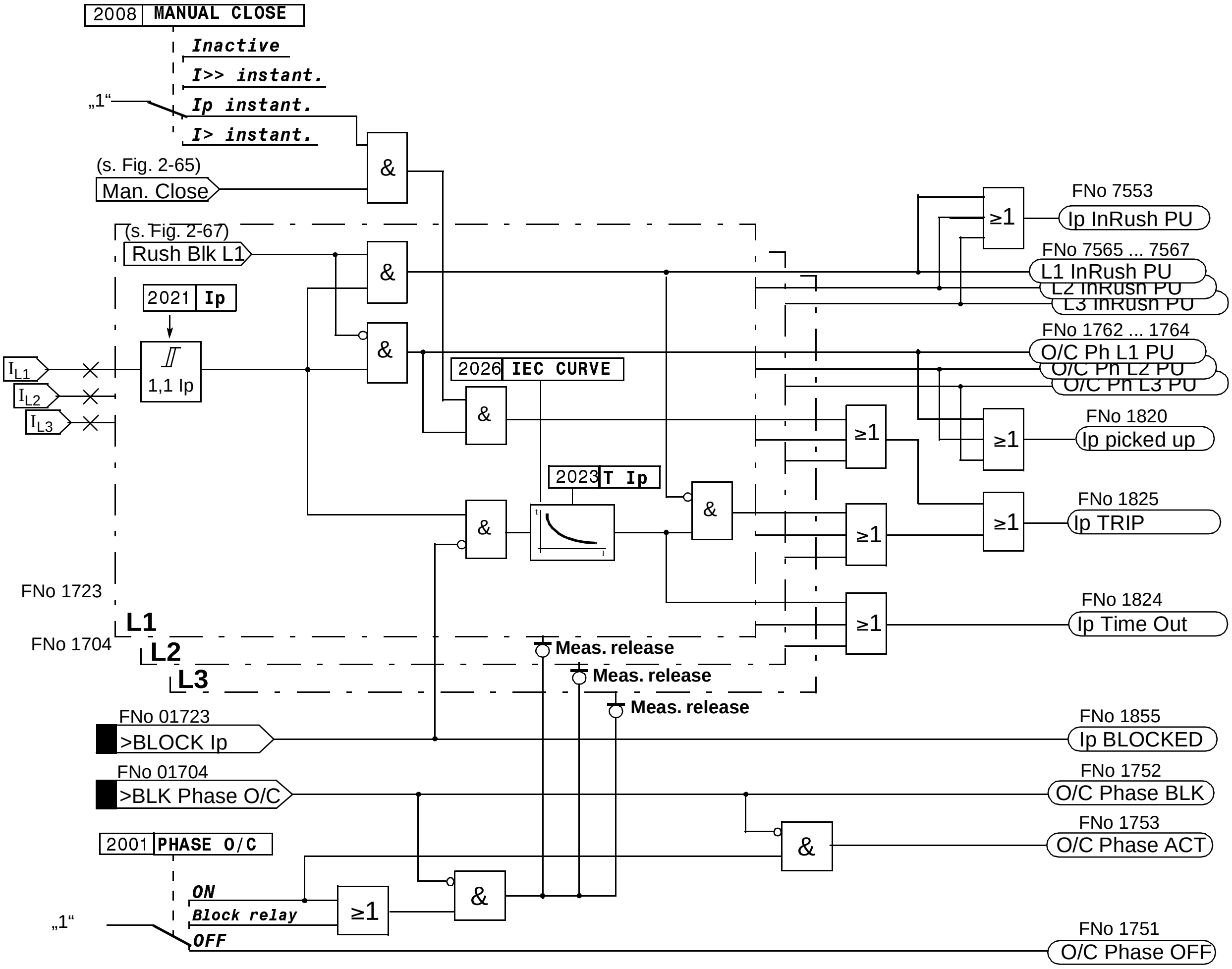


Figure 2-63 Logic diagram of the inverse time overcurrent stages Ip for phase currents — example for IEC curves (simplified)

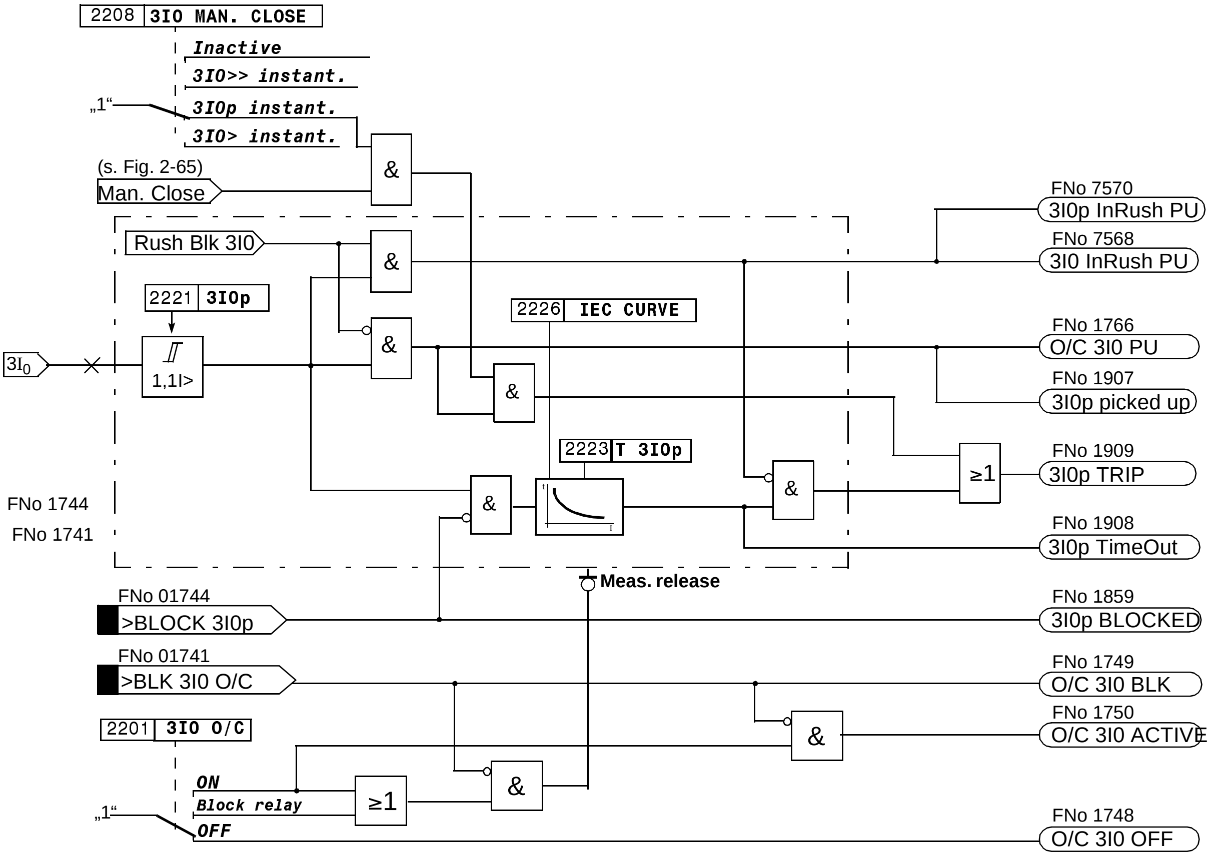


Figure 2-64 Logic diagram of the inverse time overcurrent stage for residual current — example for IEC curves (simplified)

Dropout

You can determine whether the dropout of a stage is to follow right after the threshold undershot or whether it is evoked by disk emulation. “Right after” means that the pickup drops out when the pickup value of approx. 95 % is undershot. For a new pickup the time counter starts at zero.

The disk emulation evokes a dropout process (time counter is decrementing) which begins after de-energization. This process corresponds to the back turn of a Ferraris-disk (explaining its denomination “disk emulation”). In case several faults occur successively, it is ensured that due to the inertia of the Ferraris-disk the “history” is taken into consideration and the time behaviour is adapted. The reset begins as soon as 90 % of the setting value is undershot, in correspondence to the dropout curve of the selected characteristic. Within the range of the dropout value (95 % of the pickup value) and 90 % of the setting value, the incrementing and the decrementing processes are in idle state. If 5 % of the setting value is undershot, the dropout process is being finished, i.e. when a new pickup is evoked, the timer starts again at zero.

The disk emulation offers its advantages when the grading coordination chart of the time overcurrent protection is combined with other devices (on electro-mechanical or induction base) connected to the system.

User-Specified Curves

The tripping characteristic of the user-configurable curves can be defined via several points. Up to 20 pairs of current and time values can be entered. With these values the device approximates a characteristic by linear interpolation.

If required, the dropout characteristic can also be defined. For the functional description see “Dropout” above. If no user-configurable dropout characteristic is desired, dropout is initiated when approximately 95 % of the pickup value is undershot; when a new pickup is evoked, the timer starts again at zero.

2.4.1.3 Manual Close Command

When a circuit breaker is closed onto a faulted protected object, a high speed re-trip by the breaker is often desired. The manual closing feature is designed to remove the delay from one of the time overcurrent stages when the breaker is manually closed onto a fault. The time delay is then bypassed via an impulse from the external control switch. This impulse is prolonged by a period of at least 300 ms (Figure 2-65). Addresses 2008A **`MANUAL CLOSE`** and/or 2208A **`3I0 MAN. CLOSE`** determine for which stages the delay is bypassed under manual close condition.

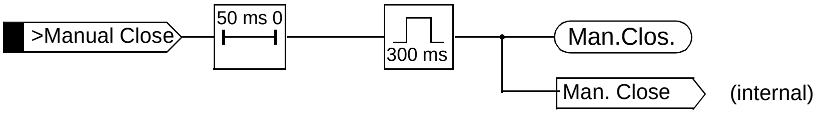


Figure 2-65 Manual close processing

Processing of the manual close command can be executed for each measuring location or side. Manual close signal is also generated when an internal control command is given to a breaker which is assigned to the same protection function as the time overcurrent protection, in the power system data 1 (Subsection 2.1.4).

Strict attention must be paid that the manual close condition is derived from that circuit breaker which feeds the object that is protected by the time overcurrent protection! The breaker concerning the phase overcurrent protection may be different from that for the zero sequence overcurrent protection, dependent of the assignment of these protection functions.

2.4.1.4 Dynamic Cold Load Pickup

With the dynamic cold load pickup feature, it is possible to dynamically increase the pickup values of the time overcurrent protection stages when dynamic cold load overcurrent conditions are anticipated, i.e. when consumers have increased power consumption after a longer period of dead condition, e.g. in air conditioning systems, heating systems, motors, etc. By allowing pickup values and the associated time delays to increase dynamically, it is not necessary to incorporate cold load capability in the normal settings.

Processing of the dynamic cold load pickup conditions is the same for all time overcurrent stages, and is explained in Section 2.6 (page 157). The alternative values themselves are set for each of the stages.

2.4.1.5 Inrush Restraint

When switching unloaded transformers or shunt reactors on a live busbar, high magnetizing (inrush) currents may occur. They can amount to a multiple of the rated current and, dependent on the transformer size and design, may last from several milliseconds to several seconds.

Although overcurrent detection is based only on the fundamental harmonic component of the measured currents, false pickup due to inrush might occur since the inrush current may even comprise a considerable component of fundamental harmonic.

The time overcurrent protection provides an integrated inrush restraint function which blocks the overcurrent stages I> and Ip (not I>>) for phase and residual currents in case of inrush detection. After detection of inrush currents above a pickup value special inrush signals are generated. These signals also initiate fault annunciations and start the assigned trip delay time. If inrush current is still detected after expiration of the delay time, an annunciation is output. Tripping is suppressed.

The inrush current is characterized by a considerable 2nd harmonic content (double rated frequency) which is practically absent in the case of a short-circuit. If the second harmonic content of a phase current exceeds a selectable threshold, trip is blocked for this phase. Similar applies for the residual current stages.

The inrush restraint feature has an upper operation limit. Above this (adjustable) current blocking is suppressed since a high-current fault is assumed in this case. The lower limit is the operating limit of the harmonic filters (0.1 I_N).

Figure 2-66 shows a simplified logic diagram.

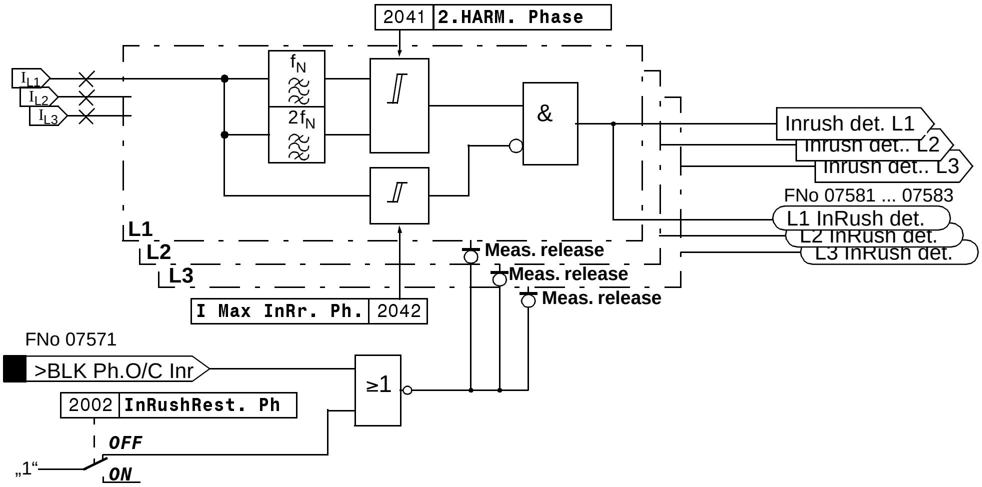


Figure 2-66 Logic diagram of the inrush restraint feature — example for phase currents (simplified)

Since the harmonic restraint operates individually per phase, the protection is fully operative even when e.g. the transformer is switched onto a single-phase fault, whereby inrush currents may possibly be present in one of the healthy phases. However, it is also possible to set the protection such that not only the phase with inrush current exhibiting harmonic content in excess of the permissible value is blocked but also the other phases of the associated stage are blocked (so called “cross-block function”). This cross-block can be limited to a selectable duration. Figure 2-67 shows the logic diagram.

Crossblock refers only to the phase current stages against each other. Phase inrush currents do not block the residual current stages nor vice versa.

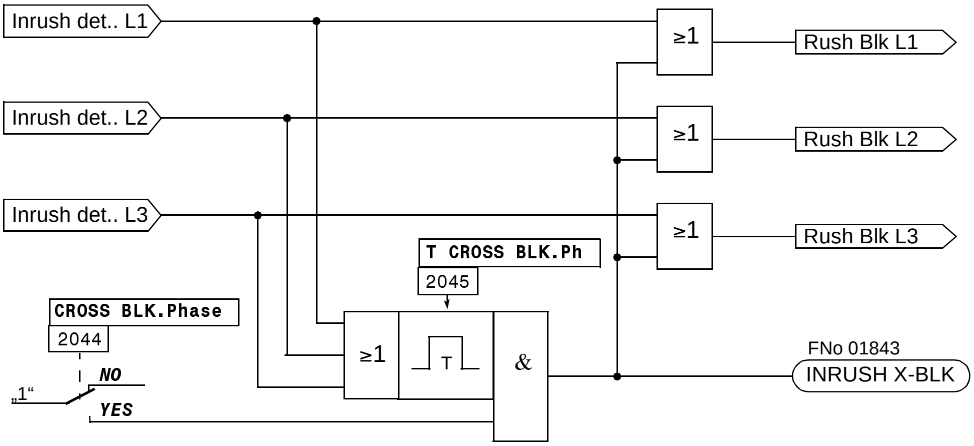


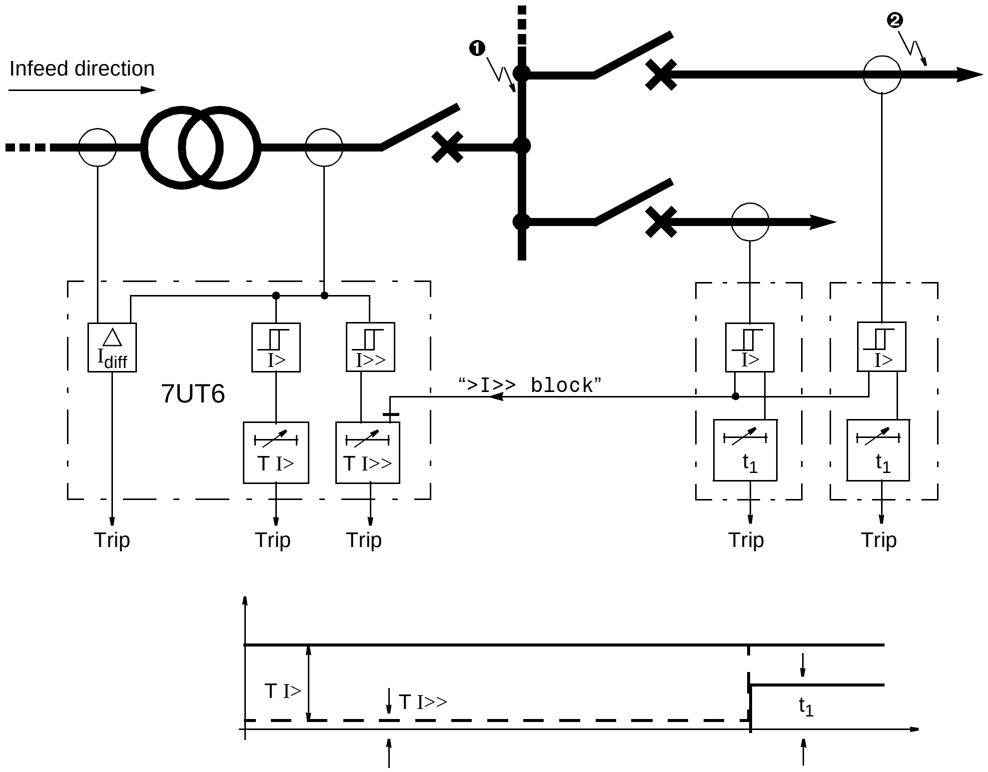
Figure 2-67 Logic diagram of the crossblock function for the phase currents (simplified)

2.4.1.6 Fast Busbar Protection Using Reverse Interlocking

Application Example

Each of the overcurrent stages can be blocked via binary inputs of the relay. A setting parameter determines whether the binary input operates in the “normally open” (i.e. energize input to block) or the “normally closed” (i.e. energize input to release) mode. Thus, the overcurrent time protection can be used as fast busbar protection in star connected networks or in open ring networks (ring open at one location), using the “reverse interlock” principle. This is used in high voltage systems, in power station auxiliary supply networks, etc., in which cases a transformer feeds from the higher voltage system onto a busbar with several outgoing feeders (refer to Figure 2-68).

The time overcurrent protection is applied to the lower voltage side. “Reverse interlocking” means, that the overcurrent time protection can trip within a short time T–I>>, which is independent of the grading time, if it is not blocked by pickup of one of the next downstream time overcurrent relays (Figure 2-68). Therefore, the protection which is closest to the fault will always trip within a short time, as it cannot be blocked by a relay behind the fault location. The time stages I> or Ip operate as delayed backup stages.



Fault location ❶: Tripping time T I>>

Fault location ❷: Tripping time t_1
Backup time T I>

Figure 2-68 Fast busbar protection using reverse interlock — principle

2.4.2 Setting the Function Parameters

During configuration of the functional scope (Subsection 2.1.1, margin heading “Special Cases”) the types of characteristic were determined, separately for the phase current stages (address 120 DMT/IDMT Phase) and the zero sequence current stage (122 DMT/IDMT 3I0). Only the settings for the characteristic selected can be performed here. The definite time stages I>>, 3I0>>, I> and 3I0> are always available.

The protection functions must have been assigned each to a side of the main protected object or another 3-phase current measuring location; this may be different for the phase overcurrent protection and the zero sequence overcurrent protection (Subsection 2.1.4. under margin header “Further 3-Phase Protection Functions”). Consider also the assignment of the measured current inputs of the device against the measuring locations (current transformer sets) of the power plant (Subsection 2.1.2. under margin header “Assignment of 3-phase Measuring Locations”). Remember that the zero sequence overcurrent protection processes a 3-phase measured quantity: the zero sequence system of the three phase currents.

2.4.2.1 Phase Current Stages

Note:

If the time overcurrent protection is assigned to a side of the main protected object, the current values are set referred to the nominal current of that sided (I/I_{NS}) as stated in Subsection 2.1.3. In other cases, current values are set in amps.

General

In address 2001 **PHASE O/C** time overcurrent protection for phase currents can be switched ***ON*** or ***OFF***. The option ***Block relay*** allows to operate the protection but the trip output relay is blocked.

Address 2008A **MANUAL CLOSE** determines the phase current stage which is to be activated instantaneously with a detected manual close. Settings ***I>> instant.*** and ***I> instant.*** can be set independent from the type of characteristic selected. ***Ip instant.*** is only available if one of the inverse time stages is configured. This parameter can only be altered with DIGSI® under “**Additional Settings**”.

If time overcurrent protection is applied on the supply side of a transformer, select the higher stage I>> which does not pick up during inrush conditions or set the manual close feature to ***Inactive***.

In address 2002 **InRushRest. Ph**, inrush restraint (restraint with 2nd harmonic) is enabled or disabled for all phase current stages of time overcurrent protection (excepted the I>> stage). Set ***ON*** if one time overcurrent protection stage is to operate at the supply side of a transformer. Otherwise, use setting ***OFF***. If you intend to set a very small pickup value for any reason, consider that the inrush restraint function cannot operate below 20 % nominal current (lower limit of harmonic filtering).

Definite Time High-Current Stages I>>

If I>>-stage **I>>** (address 2011 or 2011) is combined with I>-stage or I_p-stage, a two-stage characteristic will be the result. If one stage is not required, the pickup value has to be set to ∞. Stage **I>>** always operates with a defined delay time or instantaneous.

If time overcurrent protection is used on the supply side of a transformer, a series reactor, a motor or starpoint of a generator, this stage can also be used for current grading. Setting instructs the device to pick up on faults only inside the protected object but not for traversing fault currents.

Calculation example:

Power transformer feeding a busbar, with the following data:

Power transformer	YNd5 35 MVA 110 kV/20 kV u_{sc} = 15 %
Current transformers	200 A/5 A on the 110 kV side

The time overcurrent protection is assigned to the 110 kV side (= feeding side).

The maximum possible three-phase fault current on the 20 kV side, assuming an impressed voltage source on the 110 kV side, is:

$$I_{3pole\,max} = \frac{1}{u_{sc\,transf}} \cdot I_{N\,transf} = \frac{1}{u_{sc\,transf}} \cdot \frac{S_{N\,transf}}{\sqrt{3} \cdot U_N} = \frac{1}{0.15} \cdot \frac{35\text{ MVA}}{\sqrt{3} \cdot 110\text{ kV}} = 1224.7\text{ A}$$

Assumed a safety margin of 20 %, the primary setting value results:

Setting value I>> = 1.2 · 1224.7 A = 1470 A

For setting in primary values via PC and DIGSI® this value can be set directly. For setting with secondary values the currents will be converted for the secondary side of the current transformer.

Secondary setting value:

$$\text{Setting value I>>} = \frac{1470\text{ A}}{200\text{ A}} \cdot 5\text{ A} = 36.7\text{ A}$$

i.e. for fault currents higher than 1470 A (primary) or 36.7 A (secondary) the fault is in all likelihood located in the transformer zone. This fault can immediately be cleared by the time overcurrent protection.

When setting in per-unit values, the nominal current of the protected object (here equal to the nominal current of the side) is cancelled. Thus the formula gives:

$$\frac{I_{3pole\,max}}{I_{NS}} = \frac{1}{u_{sc\,transf}} = \frac{1}{0.15} = 0.667$$

With the same safety factor results:

Setting value I>> = 0.8 · I_{NS} (nominal current of the side).

Increased inrush currents, if their fundamental oscillation exceeds the setting value, are rendered harmless by delay times (address 2013 **`T I>>`**). The inrush restraint does not apply to stages I>>.

Using reverse interlocking (Subsection 2.4.1.6, see also Figure 2-68) the multi-stage function of the time overcurrent protection offers its advantages: Stage **`T I>>`** e. g. is used as accelerated busbar protection having a short safety delay **`I>>`** (e. g. 50 ms). For faults at the outgoing feeders the stage I>> is blocked. Stages **`Ip`** or **`I>`** serve as backup protection. The pickup values of both stages (**`I>`** or **`Ip`** and **`I>>`**) are set equal. Time delay **`T I>`** or **`T Ip`** (IEC characteristic) or **`D Ip`** (ANSI characteristic) is set such that it overgrades the delay for the outgoing feeders.

If fault protection for motors is applied, you have to make sure that the setting value **`I>>`** is smaller than the smallest (two-pole) fault current and higher than the highest startup current. Since the maximum appearing startup current is usually below 1.6 x the rated startup current (even with unfavourable conditions), the following setting is adequate for fault current stage I>>:

$$1.6 \cdot I_{startup} > \mathbf{I>>} < I_{sc\,2\text{-}pole}$$

The increased startup current possibly caused by increased voltage is already considered with factor 1.6. Stage I>> can trip instantaneously (**`T I>>`** = ***`0.00 s`***) since there is no saturation of shunt reactance for motors, other than for transformers.

The settable time **`T I>>`** is an additional time delay and does not include the operating time (measuring time, dropout time). The delay can be set to infinity ∞. If set to infinity, the pickup of this function will be indicated but the stage will not trip after pickup. If the pickup threshold is set to ∞, neither a pickup annunciation nor a trip is generated.

Definite Time Overcurrent Stages I>

For setting the time overcurrent stage **`I>`** (address 2014 or 2015) the maximum appearing operational current is relevant. A pickup caused by an overload must be excluded, as the device operates in this mode as fault protection with correspondingly short tripping times and not as overload protection. For lines or busbars a rate of approx. 20 % above the maximum expected (over)load is set, for transformers and motors a rate of approx. 40 %.

The settable time delay (address 2016 **`T I>`**) results from the grading coordination chart defined for the network.

The settable time is an additional time delay and does not include the operating time (measuring time, dropout time). The delay can be set to infinity ∞. If set to infinity, the pickup of the corresponding function will be signalled but the stage will not issue a trip command. If the pickup threshold is set to ∞, neither a pickup annunciation nor a trip is generated.

Inverse Time Overcurrent Stages Ip with IEC curves

The inverse time stages, depending on the configuration (Subsection 2.1.1, address 120), enable the user to select different characteristics. With the IEC characteristics (address 120 **`DMT/IDMT Phase`** = ***`TOC IEC`***) the following is made available in address 2026 **`IEC CURVE`**:

`Normal Inverse` (type A according to IEC 60255–3),
`Very Inverse` (type B according to IEC 60255–3),
`Extremely Inv.` (type C according to IEC 60255–3), and
`Long Inverse` (type B according to IEC 60255–3).

The characteristics and equations they are based on are listed in the Technical Data (Section 4.4, Figure 4-7).

If the inverse time trip characteristic is selected, it must be noted that a safety factor of about 1.1 has already been included between the pickup value and the setting value. This means that a pickup will only occur if a current of about 1.1 times of the setting value is present.

The current value is set in address 2021 or 2022 **`Ip`**. The maximum operating current is of primary importance for the setting. A pickup caused by an overload must be excluded, as the device operates in this mode as fault protection with correspondingly short tripping times and not as overload protection.

The corresponding time multiplier is accessible via address 2023 **`T Ip`**. The time multiplier must be coordinated with the grading coordination chart of the network.

The time multiplier can also be set to ∞. If set to infinity, the pickup of this function will be indicated but the stage will not trip after pickup. If the Ip-stage is not required, select address 120 **`DMT/IDMT Phase`** = ***`Definite Time`*** when configuring the protection functions (Subsection 2.1.1).

If ***`Disk Emulation`*** is set in address 2025 **`TOC DROP-OUT`**, dropout is being produced according to the dropout characteristic. For more information see Subsection 2.4.1.2, margin heading “Dropout” (page 124).

Inverse Time Overcurrent Stages Ip with ANSI curves

The inverse time stages, depending on the configuration (Subsection 2.1.1, address 120), enable the user to select different characteristics. With the ANSI characteristics (address 120 **`DMT/IDMT Phase`** = ***`TOC ANSI`***) the following is made available in address 2027 **`ANSI CURVE`**:

`Definite Inv.`,
`Extremely Inv.`,
`Inverse`,
`Long Inverse`,
`Moderately Inv.`,

Short Inverse, and
Very Inverse.

The characteristics and the equations they are based on are listed in the Technical Data (Section 4.4, Figures 4-8 and 4-9).

If the inverse time trip characteristic is selected, it must be noted that a safety factor of about 1.1 has already been included between the pickup value and the setting value. This means that a pickup will only occur if a current of about 1.1 times of the setting value is present.

The current value is set in address 2021 or 2022 **Ip**. The maximum operating current is of primary importance for the setting. A pickup caused by overload must be excluded, since, in this mode, the device operates as fault protection with correspondingly short tripping times and not as overload protection.

The corresponding time multiplier is set in address 2024 **D Ip**. The time multiplier must be coordinated with the grading coordination chart of the network.

The time multiplier can also be set to ∞. If set to infinity, the pickup of this function will be indicated but the stage will not trip after pickup. If the Ip-stage is not required, select address 120 **DMT/IDMT Phase** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

If ***Disk Emulation*** is set in address 2025 **TOC DROP-OUT**, dropout is being produced according to the dropout characteristic. For more information see Subsection 2.4.1.2, margin heading “Dropout” (page 124).

Dynamic Cold Load Pickup

An alternative set of pickup values can be set for each stage. It is selected automatically-dynamically during operation. For more information on this function see Section 2.6 (page 157).

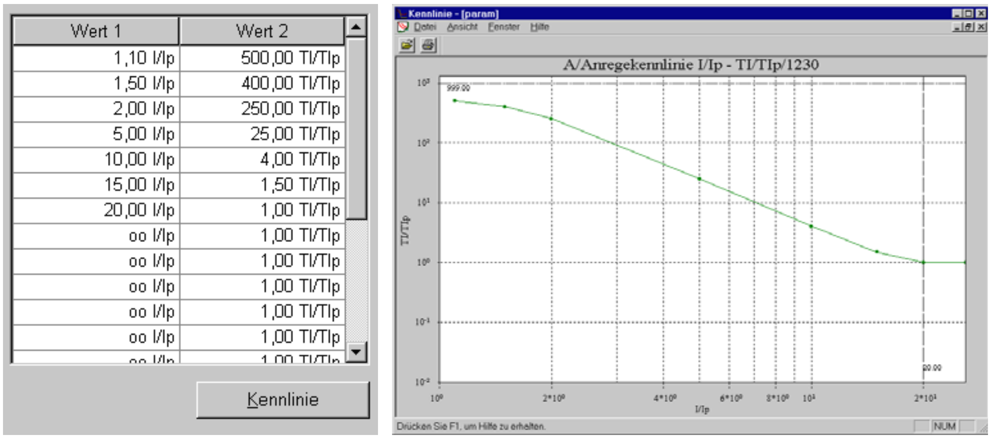
For the stages the following alternative values are set:

- for definite time overcurrent protection (phases):
  address 2111 or 2112 pickup value **I>>**,
  address 2113 delay time **T I>>**,
  address 2114 or 2115 pickup value **I>**,
  address 2116 delay time **T I>**;
- for inverse time overcurrent protection (phases) acc. to IEC curves:
  address 2121 or 2122 pickup value **Ip**,
  address 2123 time multiplier **T Ip**;
- for inverse time overcurrent protection (phases) acc. to ANSI curves:
  address 2121 or 2122 pickup value **Ip**,
  address 2124 time dial **D Ip**.

User Specified Curves

For inverse-time overcurrent protection the user may define his own tripping and dropout characteristic. For configuration in DIGSI® a dialog box will appear. Enter up to 20 pairs of current value and tripping time value (Figure 2-69).

In DIGSI® the characteristic can also be viewed as a graph, see the right part of Figure 2-69.



Wert 1	Wert 2
1,10 I/Ip	500,00 TI/TIp
1,50 I/Ip	400,00 TI/TIp
2,00 I/Ip	250,00 TI/TIp
5,00 I/Ip	25,00 TI/TIp
10,00 I/Ip	4,00 TI/TIp
15,00 I/Ip	1,50 TI/TIp
20,00 I/Ip	1,00 TI/TIp
oo I/Ip	1,00 TI/TIp
oo I/Ip	1,00 TI/TIp
oo I/Ip	1,00 TI/TIp
oo I/Ip	1,00 TI/TIp
oo I/Ip	1,00 TI/TIp

Figure 2-69 Entering a user specified tripping curve using DIGSI® — example

To create a user-defined tripping characteristic, the following must be set for configuration of the functional scope (Subsection 2.1.1): address 120 **`DMT/IDMT Phase`**, option ***`User Defined PU`***. If you also want to specify the dropout characteristic, set ***`User def. Reset`***.

Value pairs are referred to the setting values for current and time.

Since current values are rounded in a specific table before they are processed in the device (see Table 2-5), we recommend to use exactly the same preferred current values you can find in this table.

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Table 2-5 Preferred values of the standard currents for user specified **trip characteristics**

`I/Ip = 1 to 1.94`		**`I/Ip = 2 to 4.75`**		**`I/Ip = 5 to 7.75`**		**`I/Ip = 8 to 20`**	
1.00	1.50	2.00	3.50	5.00	6.50	8.00	15.00
1.06	1.56	2.25	3.75	5.25	6.75	9.00	16.00
1.13	1.63	2.50	4.00	5.50	7.00	10.00	17.00
1.19	1.69	2.75	4.25	5.75	7.25	11.00	18.00
1.25	1.75	3.00	4.50	6.00	7.50	12.00	19.00
1.31	1.81	3.25	4.75	6.25	7.75	13.00	20.00
1.38	1.88					14.00	
1.44	1.94						

The default setting of current values is ∞. Thus they are made invalid. No pickup and no tripping by this protective function takes place.

For specification of a tripping characteristic please observe the following:

– The value pairs are to be indicated in a continuous order. You may also enter less than 20 value pairs. In most cases, 10 value pairs would be sufficient to be able to define an exact characteristic. A value pair which will not be used has to be made invalid entering "∞" for the threshold! Please ensure that a clear and steady characteristic is formed from the value pairs.

- For currents select the values from Table 2-5 and add the corresponding time values. Deviating values I/I_p are rounded. This, however, will not be indicated.
- Currents smaller than the current value of the *smallest* characteristic point do not lead to a prolongation of the tripping time. The pickup characteristic (see Figure 2-70, right side) goes parallel to the current axis, up to the *smallest* characteristic point.

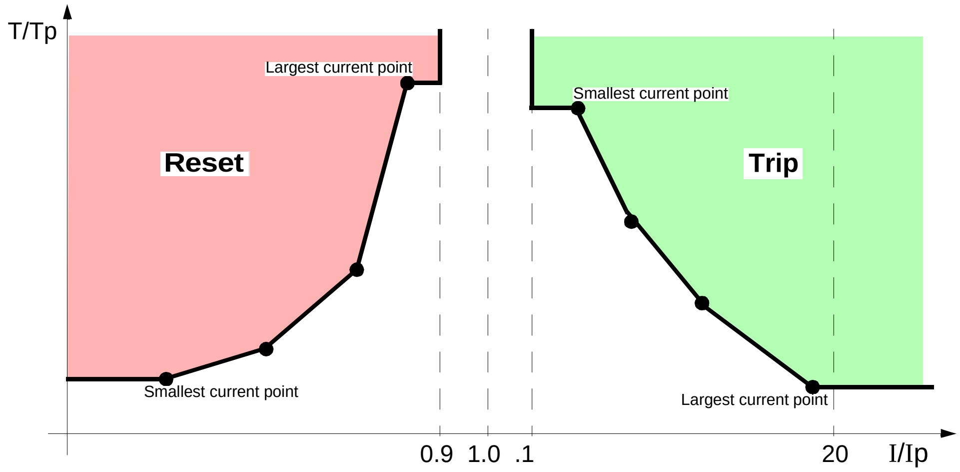

Figure 2-70 User specified characteristic — example

- Currents greater than the current value of the *greatest* characteristic point do not lead to a reduction of the tripping time. The pickup characteristic (see Figure 2-70, right side) goes parallel to the current axis, beginning with the *greatest* characteristic point.

For specification of a dropout characteristic please observe the following:

- For currents select the values from Table 2-6 and add the corresponding time values. Deviating values I/I_p are rounded. This, however, will not be indicated.
- Currents greater than the current value of the *greatest* characteristic point do not lead to a prolongation of the dropout time. The dropout characteristic (see Figure 2-70, left side) goes parallel to the current axis, up to the *greatest* characteristic point.
- Currents smaller than the current value of the *smallest* characteristic point do not lead to a reduction of the dropout time. The dropout characteristic (see Figure 2-70, left side) goes parallel to the current axis, beginning with the *smallest* characteristic point.
- Currents smaller than 0.05 times the setting value of currents lead to an immediate dropout.

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Table 2-6 Preferred values of the standard currents for user specified **reset characteristics**

I/Ip = 1 to 0.86		**I/Ip = 0.84 to 0.67**		**I/Ip = 0.66 to 0.38**		**I/Ip = 0.34 to 0.00**	
1.00	0.93	0.84	0.75	0.66	0.53	0.34	0.16
0.99	0.92	0.83	0.73	0.64	0.50	0.31	0.13
0.98	0.91	0.81	0.72	0.63	0.47	0.28	0.09
0.97	0.90	0.80	0.70	0.61	0.44	0.25	0.06
0.96	0.89	0.78	0.69	0.59	0.41	0.22	0.03
0.95	0.88	0.77	0.67	0.56	0.38	0.19	0.00
0.94	0.86						

Inrush Restraint

In address 2002 **InRushRest. Ph** of the general settings (page 129, margin heading “General”) the inrush restraint can be enabled (***ON***) or disabled (***OFF***). Especially for transformers and if overcurrent time protection is used on the supply side, this inrush restraint is required. Function parameters of the inrush restraint are set in “Inrush”.

It is based on an evaluation of the 2nd harmonic present in the inrush current. The ratio of 2nd harmonics to the fundamental **2.HARM. Phase** (address 2041) is set to I_{2fN}/I_{fN} = ***15*** % as default setting. It can be used without being changed. To provide more restraint in exceptional cases, where energizing conditions are particularly unfavourable, a smaller value can be set in the address before-mentioned.

If the current exceeds the value indicated in address 2042 **I Max InRr. Ph.**, no restraint will be provoked by the 2nd harmonic.

The inrush restraint can be extended by the so-called “cross-block” function. This means that if the harmonic component is only exceeded in *one* phase, all *three* phases of the I>- or Ip-stages are blocked. In address 2044 **CROSS BLK.Phase** the cross-block function is set to ***ON*** or ***OFF***.

The time period for which the crossblock function is active after detection of inrushes is set at address 2045 **T CROSS BLK.Ph**.

2.4.2.2 Residual Current Stages

Note:

If the time overcurrent protection is assigned to a side of the main protected object, the current values are set referred to the nominal current of that sided as stated in Subsection 2.1.3. In other cases, current values are set in amps.

General

In address 2201 **3I0 O/C**, time overcurrent protection for residual current can be set to ***ON*** or ***OFF***. The option ***Block relay*** allows to operate the protection but the trip output relay is blocked.

Address 2208A **3I0 MAN. CLOSE** determines which residual current stage is to be activated instantaneously with a detected manual close. Settings ***3I0>> instant.*** and ***3I0> instant.*** can be set independent from the type of characteristic selected. ***3I0p instant.*** is only available if one of the inverse time stages is configured. This parameter can only be altered with DIGSI® under "**Additional Settings**". For this setting, similar considerations apply as for the phase current stages.

In address 2202 **InRushRest. 3I0** inrush restraint (restraint with 2nd harmonic) is enabled or disabled. Set ***ON*** if the residual current stage of the time overcurrent protection is applied at the supply side of a transformer whose starpoint is earthed. Otherwise, use setting ***OFF***.

Definite Time High-Current Stage 3I0>>

If I_0>>-stage **3I0>>** (address 2211 or 2212) is combined with I>-stage or I_p-stage, a two-stage characteristic will be the result. If one stage is not required, the pickup value has to be set to ∞. Stage **3I0>>** always operates with a defined delay time.

If the protected winding is not earthed, zero sequence current only emerges due to an inner earth fault or double earth fault with one inner base point. Here, no I_0>>-stage is required usually.

Stage I_0>> can be applied e.g. for current grading. Please note that the zero sequence system of currents is decisive. For transformers with separate windings, zero sequence systems are usually separated (exception: bilateral starpoint earthing).

Inrush currents can only be created in zero sequence systems, if the starpoint of the winding regarded is earthed. If its fundamental exceeds the setting value, the inrush currents are rendered harmless by delay (address 2213 **T 3I0>>**).

"Reverse interlocking" (Subsection 2.4.1.6, see Figure 2-68) only makes sense if the winding regarded is earthed. Then, we take advantage of the multi-stage function of time overcurrent protection: Stage **T 3I0>>** e. g. is used as accelerated busbar protection having a short safety delay **3I0>>** (e. g. 50 ms). For faults at the outgoing feeders stage **3I0>>** is blocked. Stages **3I0p** or **3I0>** serve as backup protection. The pickup values of both stages (**3I0>** or **3I0p** and **3I0>>**) are set equal. Time delay **T 3I0>** or **T 3I0p** (IEC characteristic) or **D 3I0p** (ANSI characteristic) is set such that it overgrades the delay for the outgoing feeders. Here, the grading coordination chart for earth faults, which mostly allows shorter setting times, is of primary importance.

The set time **T 3I0>>** is an additional time delay and does not include the operating time (measuring time, dropout time). The delay can be set to infinity ∞. If set to infinity, the pickup of this function will be indicated but the stage will not trip after pickup. If the pickup threshold is set to ∞, neither a pickup annunciation nor a trip is generated.

Definite Time Overcurrent Stage 3I0>

For setting the time overcurrent stage **3I0>** (address 2214 or 2215) the minimum appearing earth fault current is relevant. Consider that increased measuring tolerances may occur if several measuring locations feed on the protected object.

The settable time delay (parameter 2216 **T 3I0>**) derives from the grading coordination chart created for the network. For earth currents with earthed network, you can mostly set up a separate grading coordination chart with shorter delay times. If you set a very small pickup value, consider that the inrush restraint function cannot operate below 10 % nominal current (lower limit of harmonic filtering). An adequate time delay could be reasonable if inrush restraint is used.

The set time is an additional time delay and does not include the operating time (measuring time, dropout time). The delay can be set to infinity ∞. If set to infinity, the pickup of this function will be indicated but the stage will not be able to trip after pickup. If the pickup threshold is set to ∞, neither a pickup annunciation nor a trip is generated.

Inverse Time Overcurrent Stage 3I0p with IEC Curves

The inverse time stage, depending on the configuration (Subsection 2.1.1, address 122), enables the user to select different characteristics. With the IEC characteristics (address 122 **DMT/IDMT 3I0** = ***TOC IEC***) the following is made available in address 2226 **IEC CURVE**:

Normal Inverse (type A according to IEC 60255–3),
Very Inverse (type B according to IEC 60255–3),
Extremely Inv. (type C according to IEC 60255–3), and
Long Inverse (type B according to IEC 60255–3).

The characteristics and equations they are based on are listed in the Technical Data (Section 4.4, Figure 4-7).

If the inverse time trip characteristic is selected, it must be noted that a safety factor of about 1.1 has already been included between the pickup value and the setting value. This means that a pickup will only occur if a current of about 1.1 times of the setting value is present.

The current value is set in address 2221 or 2222 **3I0p**. The most relevant for this setting is the minimum appearing earth fault current. Consider that increased measuring tolerances may occur if several measuring locations feed on the protected object.

The corresponding time multiplier is accessible via address 2223 **T 3I0p**. This has to be coordinated with the grading coordination chart of the network. For earth currents with earthed network, you can mostly set up a separate grading coordination chart with shorter delay times. If you set a very small pickup value, consider that the inrush restraint function cannot operate below 10 % nominal current (lower limit of harmonic filtering). An adequate time delay could be reasonable if inrush restraint is used.

The time multiplier can also be set to ∞. If set to infinity, the pickup of this function will be indicated but the stage will not be able to trip after pickup. If the Ip-stage is not required, select address 122 **DMT/IDMT 3I0** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

If ***Disk Emulation*** is set in address 2225 **TOC DROP-OUT**, dropout is being produced according to the dropout characteristic. For more information see Subsection 2.4.1.2, margin heading “Dropout” (page 124).

Inverse Time Overcurrent Stage 3I0p with ANSI Curves

The inverse time stages, depending on the configuration (Subsection 2.1.1, address 122), enable the user to select different characteristics. With the ANSI characteristics (address 122 **DMT/IDMT 3I0** = ***TOC ANSI***) the following is made available in address 2227 **ANSI CURVE**:

Definite Inv.,
Extremely Inv.,
Inverse,
Long Inverse,
Moderately Inv.,

Short Inverse, and
Very Inverse.

The characteristics and the equations they are based on are listed in the Technical Data (Section 4.4, Figures 4-8 and 4-9).

If the inverse time trip characteristic is selected, it must be noted that a safety factor of about 1.1 has already been included between the pickup value and the setting value. This means that a pickup will only occur if a current of about 1.1 times of the setting value is present.

The current value is set in address 2221 or 2222 **3I0p**. The most relevant for this setting is the minimum appearing earth fault current. Consider that increased measuring tolerances may occur if several measuring locations feed on the protected object.

The corresponding time multiplier is set in address 2224 **D 3I0p**. This has to be coordinated with the grading coordination chart of the network. For earth currents with earthed network, you can mostly set up a separate grading coordination chart with shorter delay times. If you set a very small pickup value, consider that the inrush restraint function cannot operate below 10 % nominal current (lower limit of harmonic filtering). An adequate time delay could be reasonable if inrush restraint is used.

The time multiplier can also be set to ∞. If set to infinity, the pickup of this function will be indicated but the stage will not be able to trip after pickup. If stage $3I_{0p}$ is not required, select address 122 **DMT/IDMT 3I0** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

If ***Disk Emulation*** is set in address 2225 **TOC DROP-OUT**, dropout is being produced according to the dropout characteristic. For more information see Subsection 2.4.1.2, margin heading “Dropout” (page 124).

Dynamic Cold Load Pickup

An alternative set of pickup values can be set for each stage. It is selected automatically-dynamically during operation. For more information on this function see Section 2.6 (page 157).

For the stages the following alternative values are set:

- for definite time overcurrent protection $3I_0$:
  address 2311 or 2312 pickup value **3I0>>**,
  address 2313 delay time **T 3I0>>**,
  address 2314 pickup value **3I0>**,
  address 2316 delay time **T 3I0>**;
- for inverse time overcurrent protection $3I_0$ acc. IEC curves:
  address 2321 or 2322 pickup value **3I0p**,
  address 2323 time multiplier **T 3I0p**;
- for inverse time overcurrent protection $3I_0$ acc. ANSI curves:
  address 2321 or 2322 pickup value **3I0p**,
  address 2324 time dial **D 3I0p**.

User Specified Curves

For inverse time overcurrent protection the user may define his own tripping and dropout characteristic. For configuration in DIGSI® a dialog box is to appear. Enter up to 20 pairs of current and tripping time values (Figure 2-69, page 133).

The procedure is the same as for phase current stages. See Subsection 2.4.2.1, margin heading “User Specified Curves”, page 132.

To create a user defined tripping characteristic, the following must have been set for configuration of the functional scope (Subsection 2.1.1): address 122 **`DMT/IDMT 3I0`**, option ***`User Defined PU`***. If you also want to specify the dropout characteristic, set option ***`User def. Reset`***.

Inrush Restraint

In address 2202 **`InRushRest. 3I0`** of the general settings (page 136, margin heading “General”) the inrush restraint can be enabled (***ON***) or disabled (***OFF***). Especially for transformers and if overcurrent time protection is activated on the earthed supply side, this inrush restraint is required. Function parameters of the inrush restraint are set in “Inrush”.

It is based on an evaluation of the 2nd harmonic present in the inrush current. The ratio of 2nd harmonics to the fundamental **`2.HARM. 3I0`** (address 2241) is preset to I_{2fN}/I_{fN} = ***15*** %. It can be used without being changed. To provide more restraint in exceptional cases, where energizing conditions are particularly unfavourable, a smaller value can be set in the address before-mentioned.

If the current exceeds the value indicated in address 2242 **`I Max InRr. 3I0`**, no restraint will be provoked by the 2nd harmonic.

2.4.3 Setting Overview

Note: Addresses which have an “A” attached to their end can only be changed in DIGSI®, under “**Additional Settings**”. If the time overcurrent protection is assigned to a side of the main protected object, the current values I/I_{NS} are set referred to the nominal current of that sided as stated in Subsection 2.1.3. In other cases, current values are set in amps. The setting ranges and the default settings are then given for a rated secondary current I_N = 1 A. For a rated secondary current of I_N = 5 A these values have to be multiplied by 5.

Phase Currents

Addr.	Setting Title	Setting Options	Default Setting	Comments
2001	PHASE O/C	ON OFF Block relay for trip commands	OFF	Phase Time Overcurrent
2002	InRushRest. Ph	ON OFF	OFF	InRush Restrained O/C Phase
2008A	MANUAL CLOSE	I>> instantaneously I> instantaneously Ip instantaneously Inactive	I>> instantaneously	O/C Manual Close Mode
2011	I>>	0.10..35.00 A; ∞	2.00 A	I>> Pickup
2012	I>>	0.10..35.00 I/InS; ∞	2.00 I/InS	I>> Pickup
2013	T I>>	0.00..60.00 sec; ∞	0.00 sec	T I>> Time Delay

Addr.	Setting Title	Setting Options	Default Setting	Comments
2014	I>	0.10..35.00 A; ∞	1.00 A	I> Pickup
2015	I>	0.10..35.00 I/InS; ∞	1.00 I/InS	I> Pickup
2016	T I>	0.00..60.00 sec; ∞	0.50 sec	T I> Time Delay
2111	I>>	0.10..35.00 A; ∞	10.00 A	I>> Pickup
2112	I>>	0.10..35.00 I/InS; ∞	10.00 I/InS	I>> Pickup
2113	T I>>	0.00..60.00 sec; ∞	0.00 sec	T I>> Time Delay
2114	I>	0.10..35.00 A; ∞	2.00 A	I> Pickup
2115	I>	0.10..35.00 I/InS; ∞	2.00 I/InS	I> Pickup
2116	T I>	0.00..60.00 sec; ∞	0.30 sec	T I> Time Delay
2021	Ip	0.10..4.00 A	1.00 A	Ip Pickup
2022	Ip	0.10..4.00 I/InS	1.00 I/InS	Ip Pickup
2023	T Ip	0.05..3.20 sec; ∞	0.50 sec	T Ip Time Dial
2024	D Ip	0.50..15.00; ∞	5.00	D Ip Time Dial
2025	TOC DROP-OUT	Instantaneous Disk Emulation	Disk Emulation	TOC Drop-out characteristic
2026	IEC CURVE	Normal Inverse Very Inverse Extremely Inverse Long Inverse	Normal Inverse	IEC Curve
2027	ANSI CURVE	Very Inverse Inverse Short Inverse Long Inverse Moderately Inverse Extremely Inverse Definite Inverse	Very Inverse	ANSI Curve
2121	Ip	0.10..4.00 A	1.50 A	Ip Pickup
2122	Ip	0.10..4.00 I/InS	1.50 I/InS	Ip Pickup
2123	T Ip	0.05..3.20 sec; ∞	0.50 sec	T Ip Time Dial
2124	D Ip	0.50..15.00; ∞	5.00	D Ip Time Dial
2031	I/Ip PU T/Tp	1.00..20.00 I / Ip; ∞ 0.01..999.00 Time Dial		Pickup Curve I/Ip - TI/TIp
2032	MofPU Res T/Tp	0.05..0.95 I / Ip; ∞ 0.01..999.00 Time Dial		Multiple of Pickup <-> TI/TIp
2041	2.HARM. Phase	10..45 %	15 %	2nd harmonic O/C Ph. in % of fundamental
2042	I Max InRr. Ph.	0.30..25.00 A	7.50 A	Maximum Current for Inr. Rest. O/C Phase
2043	I Max InRr. Ph.	0.30..25.00 I/InS	7.50 I/InS	Maximum Current for Inr. Rest. O/C Phase

Addr.	Setting Title	Setting Options	Default Setting	Comments
2044	CROSS BLK.Phase	NO YES	NO	CROSS BLOCK O/C Phase
2045	T CROSS BLK.Ph	0.00..180.00 sec	0.00 sec	CROSS BLOCK Time O/C Phase

Residual Current

Addr.	Setting Title	Setting Options	Default Setting	Comments
2201	3I0 O/C	ON OFF Block relay for trip commands	OFF	3I0 Time Overcurrent
2202	InRushRest. 3I0	ON OFF	OFF	InRush Restrained O/C 3I0
2208A	3I0 MAN. CLOSE	3I0>> instantaneously 3I0> instantaneously 3I0p instantaneously Inactive	3I0>> instantaneously	O/C 3I0 Manual Close Mode
2211	3I0>>	0.05..35.00 A; ∞	0.50 A	3I0>> Pickup
2212	3I0>>	0.05..35.00 I/InS; ∞	0.50 I/InS	3I0>> Pickup
2213	T 3I0>>	0.00..60.00 sec; ∞	0.10 sec	T 3I0>> Time Delay
2214	3I0>	0.05..35.00 A; ∞	0.20 A	3I0> Pickup
2215	3I0>	0.05..35.00 I/InS; ∞	0.20 I/InS	3I0> Pickup
2216	T 3I0>	0.00..60.00 sec; ∞	0.50 sec	T 3I0> Time Delay
2311	3I0>>	0.05..35.00 A; ∞	7.00 A	3I0>> Pickup
2312	3I0>>	0.05..35.00 I/InS; ∞	7.00 I/InS	3I0>> Pickup
2313	T 3I0>>	0.00..60.00 sec; ∞	0.00 sec	T 3I0>> Time Delay
2314	3I0>	0.05..35.00 A; ∞	1.50 A	3I0> Pickup
2315	3I0>	0.05..35.00 I/InS; ∞	1.50 I/InS	3I0> Pickup
2316	T 3I0>	0.00..60.00 sec; ∞	0.30 sec	T 3I0> Time Delay
2221	3I0p	0.05..4.00 A	0.20 A	3I0p Pickup
2222	3I0p	0.05..4.00 I/InS	0.20 I/InS	3I0p Pickup
2223	T 3I0p	0.05..3.20 sec; ∞	0.20 sec	T 3I0p Time Dial
2224	D 3I0p	0.50..15.00; ∞	5.00	D 3I0p Time Dial
2225	TOC DROP-OUT	Instantaneous Disk Emulation	Disk Emulation	TOC Drop-out Characteristic
2226	IEC CURVE	Normal Inverse Very Inverse Extremely Inverse Long Inverse	Normal Inverse	IEC Curve

Addr.	Setting Title	Setting Options	Default Setting	Comments
2227	ANSI CURVE	Very Inverse Inverse Short Inverse Long Inverse Moderately Inverse Extremely Inverse Definite Inverse	Very Inverse	ANSI Curve
2321	3I0p	0.05..4.00 A	1.00 A	3I0p Pickup
2322	3I0p	0.05..4.00 I/InS	1.00 I/InS	3I0p Pickup
2323	T 3I0p	0.05..3.20 sec; ∞	0.50 sec	T 3I0p Time Dial
2324	D 3I0p	0.50..15.00; ∞	5.00	D 3I0p Time Dial
2231	I/I0p PU T/TI0p	1.00..20.00 I / Ip; ∞ 0.01..999.00 Time Dial		Pickup Curve 3I0/3I0p - T3I0/ T3I0p
2232	MofPU ResT/TI0p	0.05..0.95 I / Ip; ∞ 0.01..999.00 Time Dial		Multiple of Pickup <-> T3I0/ T3I0p
2241	2.HARM. 3I0	10..45 %	15 %	2nd harmonic O/C 3I0 in % of fundamental
2242	I Max InRr. 3I0	0.30..25.00 A	7.50 A	Maximum Current for Inr. Rest. O/C 3I0
2243	I Max InRr. 3I0	0.30..25.00 I/InS	7.50 I/InS	Maximum Current for Inr. Rest. O/C 3I0

2.4.4 Information Overview

General

F.No.	Alarm	Comments
01761	Overcurrent PU	Time Overcurrent picked up
01791	OvercurrentTRIP	Time Overcurrent TRIP

Phases Currents

F.No.	Alarm	Comments
01704	>BLK Phase O/C	>BLOCK Phase time overcurrent
07571	>BLK Ph.O/C Inr	>BLOCK time overcurrent Phase InRush
01751	O/C Phase OFF	Time Overcurrent Phase is OFF
01752	O/C Phase BLK	Time Overcurrent Phase is BLOCKED
01753	O/C Phase ACT	Time Overcurrent Phase is ACTIVE

F.No.	Alarm	Comments
07581	L1 InRush det.	Phase L1 InRush detected
07582	L2 InRush det.	Phase L2 InRush detected
07583	L3 InRush det.	Phase L3 InRush detected
01843	INRUSH X-BLK	Cross blk: PhX blocked PhY
01762	O/C Ph L1 PU	Time Overcurrent Phase L1 picked up
01763	O/C Ph L2 PU	Time Overcurrent Phase L2 picked up
01764	O/C Ph L3 PU	Time Overcurrent Phase L3 picked up
07565	L1 InRush PU	Phase L1 InRush picked up
07566	L2 InRush PU	Phase L2 InRush picked up
07567	L3 InRush PU	Phase L3 InRush picked up
01721	>BLOCK I>>	>BLOCK I>>
01852	I>> BLOCKED	I>> BLOCKED
01800	I>> picked up	I>> picked up
01804	I>> Time Out	I>> Time Out
01805	I>> TRIP	I>> TRIP
01722	>BLOCK I>	>BLOCK I>
01851	I> BLOCKED	I> BLOCKED
01810	I> picked up	I> picked up
07551	I> InRush PU	I> InRush picked up
01814	I> Time Out	I> Time Out
01815	I> TRIP	I> TRIP
01723	>BLOCK Ip	>BLOCK Ip
01855	Ip BLOCKED	Ip BLOCKED
01820	Ip picked up	Ip picked up
07553	Ip InRush PU	Ip InRush picked up
01824	Ip Time Out	Ip Time Out
01825	Ip TRIP	Ip TRIP
01860	O/C Ph. Not av.	O/C Phase Not avali. for this objekt

Residual Current

F.No.	Alarm	Comments
01741	>BLK 3I0 O/C	>BLOCK 3I0 time overcurrent
07572	>BLK 3I0O/C Inr	>BLOCK time overcurrent 3I0 InRush
01748	O/C 3I0 OFF	Time Overcurrent 3I0 is OFF

F.No.	Alarm	Comments
01749	O/C 3I0 BLK	Time Overcurrent 3I0 is BLOCKED
01750	O/C 3I0 ACTIVE	Time Overcurrent 3I0 is ACTIVE
01766	O/C 3I0 PU	Time Overcurrent 3I0 picked up
07568	3I0 InRush PU	3I0 InRush picked up
01742	>BLOCK 3I0>>	>BLOCK 3I0>> time overcurrent
01858	3I0>> BLOCKED	3I0>> BLOCKED
01901	3I0>> picked up	3I0>> picked up
01902	3I0>> Time Out	3I0>> Time Out
01903	3I0>> TRIP	3I0>> TRIP
01743	>BLOCK 3I0>	>BLOCK 3I0> time overcurrent
01857	3I0> BLOCKED	3I0> BLOCKED
01904	3I0> picked up	3I0> picked up
07569	3I0> InRush PU	3I0> InRush picked up
01905	3I0> Time Out	3I0> Time Out
01906	3I0> TRIP	3I0> TRIP
01744	>BLOCK 3I0p	>BLOCK 3I0p time overcurrent
01859	3I0p BLOCKED	3I0p BLOCKED
01907	3I0p picked up	3I0p picked up
07570	3I0p InRush PU	3I0p InRush picked up
01908	3I0p TimeOut	3I0p Time Out
01909	3I0p TRIP	3I0p TRIP
01861	O/C 3I0 Not av.	O/C 3I0 Not avali. for this objekt

2.5 Time Overcurrent Protection for Earth Current

The time overcurrent protection for earth current is assigned to a 1-phase measured current input of the device (cf. Subsection 2.1.4 under “Further 1-Phase Protection Functions”, page 51). Principally, it can be used for any desired application of single-phase overcurrent detection. Its preferred application is the detection of an earth current between the starpoint of a protected three-phase object and the earthing electrode. The correct assignment of the related 1-phase current input and the 1-phase current transformer of the power plant must be ensured (cf. Subsection 2.1.2 under “Assignment of Auxiliary 1-phase Measuring Locations”, page 32).

This protection can be used in addition to the restricted earth fault protection (Section 2.3). Then it forms the backup protection for earth faults outside the protected zone which are not cleared there. Figure 2-71 shows an example.

The time overcurrent protection for earth current provides two definite time stages and one inverse time stage. The latter may operate according an IEC or an ANSI, or an user defined characteristic.

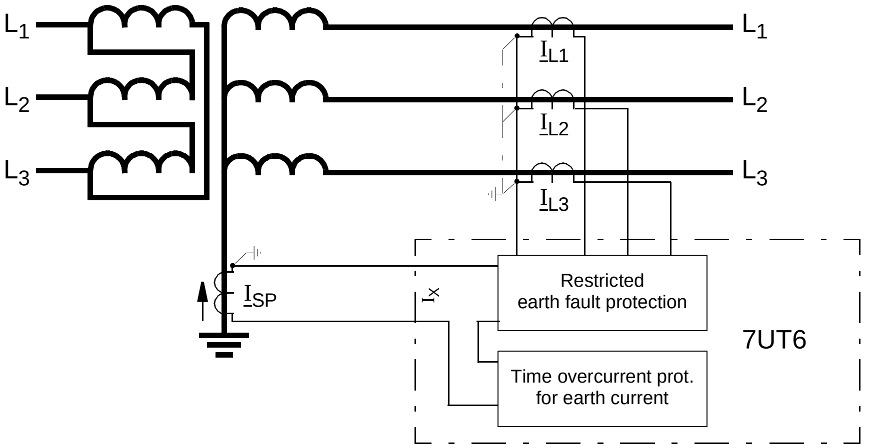


Figure 2-71 Time overcurrent protection as backup protection for restricted earth fault protection

2.5.1 Function Description

2.5.1.1 Definite Time Overcurrent Protection

The definite time stages for earth current are always available even if an inverse time characteristic has been configured according to Subsection 2.1.1 (address 124).

Pickup, Trip

Two definite time stages are available for the earth current I_E.

The current measured at the assigned 1-phase current input is compared with the setting value **IE>>**. Current above the pickup value is detected and annunciated. When the delay time **T IE>>** is expired, tripping command is issued. The reset value is approximately 5 % below the pickup value for currents above I_N. Lower values require a higher hysteresis in order to avoid intermittent pickup on currents near the pickup value (e.g. 10 % at $0.2 \cdot I_N$).

Figure 2-72 shows the logic diagram for the high-current stage I_E>>.

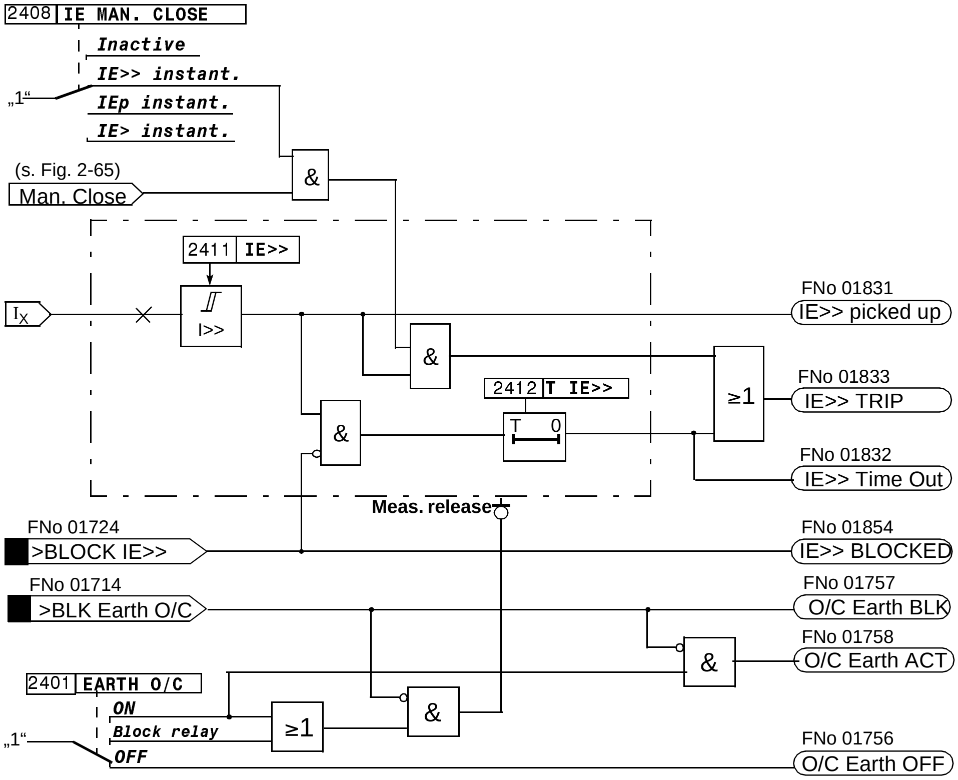


Figure 2-72 Logic diagram of the high-current stage I_E>> for earth current (simplified)

The current detected at the assigned 1-phase current measuring input is additionally compared with setting value **IE>**. An annunciation is generated if the value is exceeded. But if inrush restraint is used (cf. Subsection 2.5.1.5), a frequency analysis is performed first (Subsection 2.5.1.5). If an inrush condition is detected, pickup annunciation is suppressed and an inrush message is output instead. If there is no inrush or if inrush restraint is disabled, a tripping command will be output after expiration of delay time **T IE>**. If inrush restraint is enabled and inrush current is detected, there will be no tripping. Nevertheless, an annunciation is generated indicating that the time expired. The reset value is approximately 5 % below the pickup value for currents above I_N. Lower values require a higher hysteresis in order to avoid intermittent pickup on currents near the pickup value (e.g. 20 % at $0.1 \cdot I_N$).

Figure 2-73 shows the logic diagram of the earth overcurrent stage I_E>.

The pickup values for each of the stages I_E> and I_E>> and the delay times can be set individually.

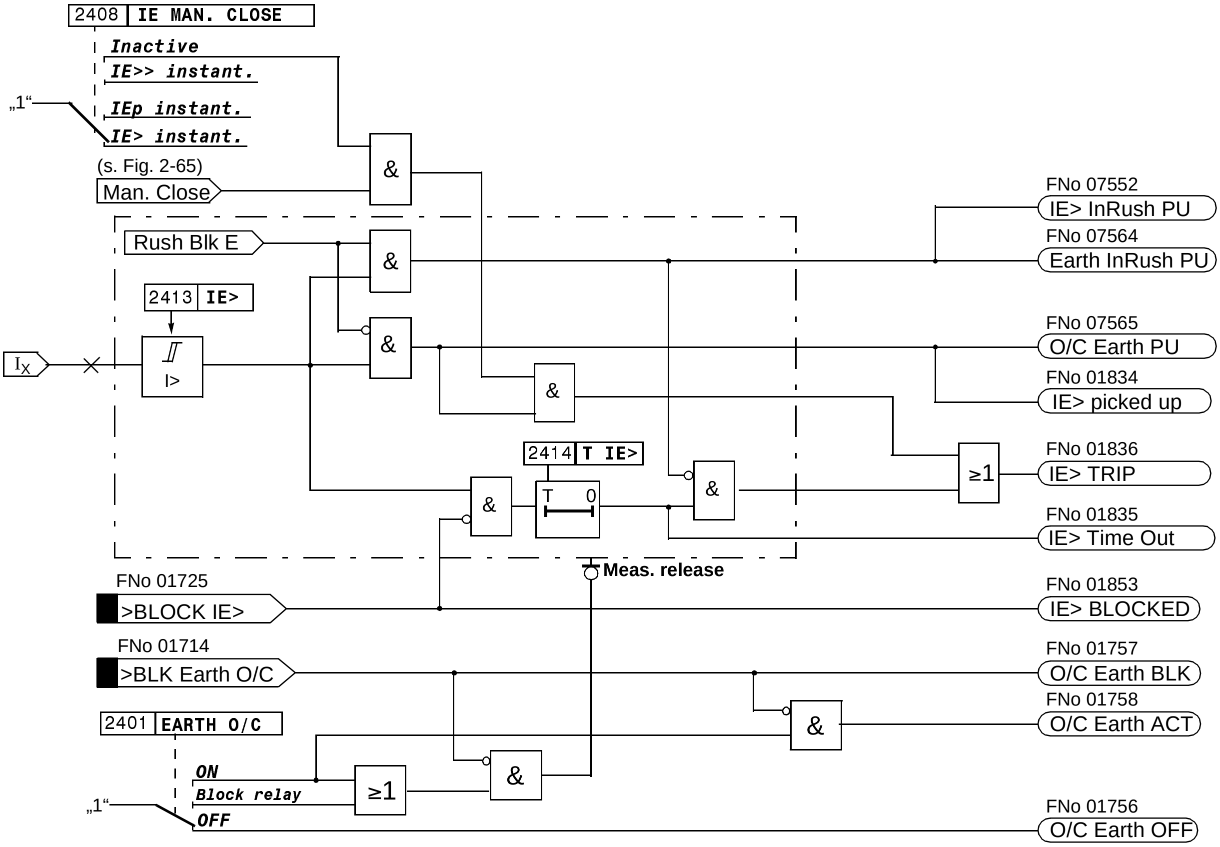


Figure 2-73 Logic diagram of the overcurrent stage I_E> for earth current (simplified)

2.5.1.2 Inverse Time Overcurrent Protection

The inverse-time overcurrent stage operates with a characteristic either according to the IEC- or the ANSI-standard or with a user-defined characteristic. The characteristic curves and their equations are represented in Technical Data (Figures 4-7 to 4-9 in Section 4.4). If one of the inverse time characteristics is configured, the definite time stages I_E>> and I_E> are also enabled (see Subsection 2.5.1.1).

Pickup, Trip

The current measured at the assigned 1-phase current input is compared with setting value **IEp**. If the current exceeds 1.1 times the set value, the stage picks up and an annunciation is made. But if inrush restraint is used (cf. Subsection 2.5.1.5), a frequency analysis is performed first (Subsection 2.5.1.5). If an inrush condition is detected, pickup annunciation is suppressed and an inrush message is output instead. The RMS value of the fundamental is used for the pickup. During the pickup of an I_{Ep} stage, tripping time is calculated from the flowing fault current by means of an integrating measuring procedure, depending on the selected tripping characteristic. After expiration of this time period, a trip command is output as long as no inrush current is detected or inrush restraint is disabled. If inrush restraint is enabled and inrush current is detected, there will be no tripping. Nevertheless, an annunciation is generated indicating that the time expired.

Figure 2-74 shows the logic diagram of the inverse time overcurrent protection.

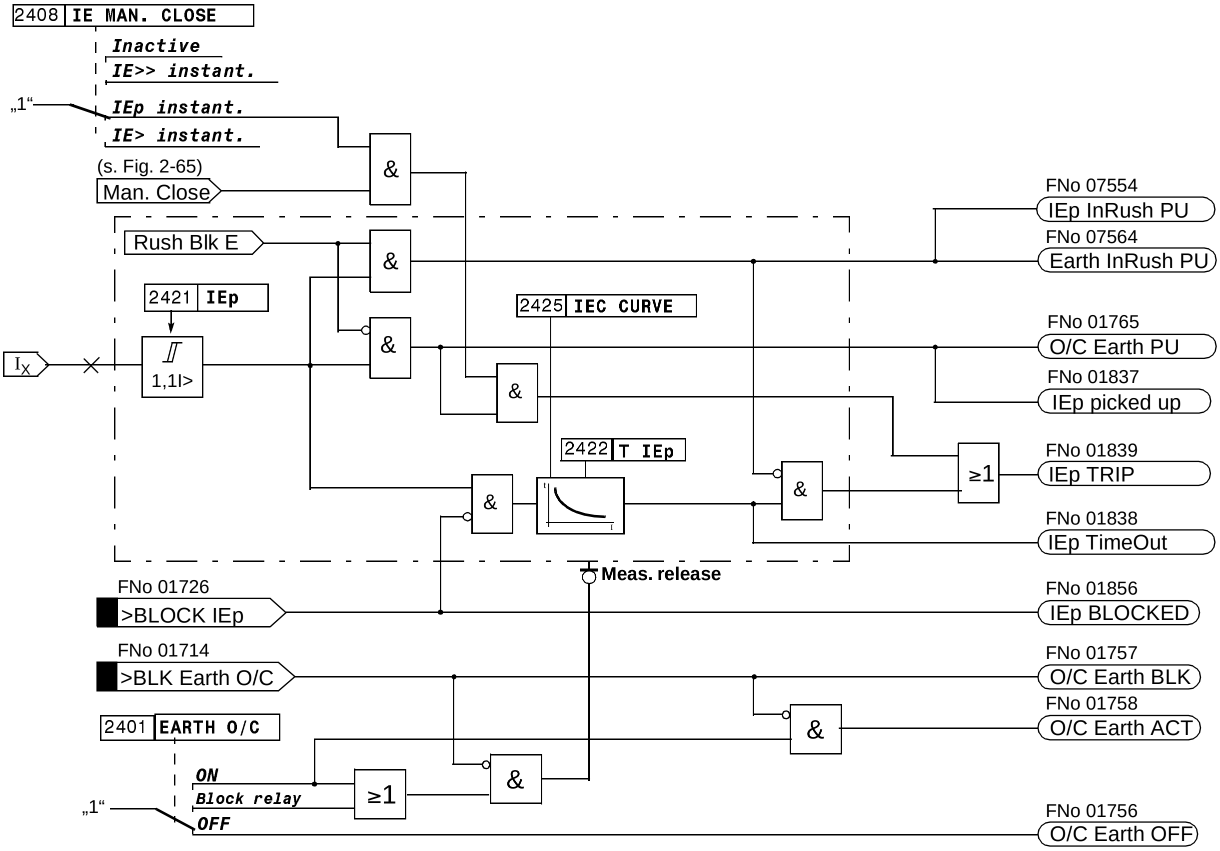


Figure 2-74 Logic diagram of the inverse time overcurrent protection stage I_{Ep} — example for IEC curves (simplified)

Dropout

You can determine whether the dropout of the stage is to follow right after the threshold undershot or whether it is evoked by disk emulation. “Right after” means that the pickup drops out when the pickup value of approx. 95 % is undershot. For a new pickup the time counter starts at zero.

The disk emulation evokes a dropout process (time counter is decrementing) which begins after de-energization. This process corresponds to the back turn of a Ferraris-disk (explaining its denomination “disk emulation”). In case several faults occur successively, it is ensured that due to the inertia of the Ferraris-disk the “History” is taken into consideration and the time behaviour is adapted. The reset begins as soon as approximately 90 % of the setting value is undershot, in correspondence to the dropout curve of the selected characteristic. Within the range of the dropout value (95 % of the pickup value) and 90 % of the setting value, the incrementing and the decrementing processes are in idle state. If 5 % of the setting value is undershot, the dropout process is being finished, i.e. when a new pickup is evoked, the timer starts again at zero.

The disk emulation offers its advantages when the grading coordination chart of the time overcurrent protection is combined with other devices (on electro-mechanical or induction base) connected to the system.

Use Specified Curves

The tripping characteristic of the user-configurable characteristic can be defined via several points. Up to 20 pairs of current and time values can be entered. With these values the device approximates a characteristic by linear interpolation.

If required, the dropout characteristic can also be defined. For the functional description see “Dropout”. If no user-configurable dropout characteristic is desired and if approx. a 95 % of the pickup value is undershot, dropout is initiated. When a new pickup is evoked, the timer starts again at zero.

2.5.1.3 Manual Close Command

When a circuit breaker is closed onto a faulted protected object, a high speed re-trip by the breaker is often desired. The manual closing feature is designed to remove the delay from one of the time overcurrent stages when the breaker is manually closed onto a fault. The time delay is then bypassed via an impulse from the external control switch. This impulse is prolonged by a period of at least 300 ms (Figure 2-65, page 125). Address 2408A **IE MAN. CLOSE** determines for which stages the delay is bypassed under manual close condition.

Processing of the manual close command can be executed for each measuring location or side. Manual close signal is also generated when an internal control command is given to a breaker which is assigned to the same protection function as the earth overcurrent protection, in the power system data 1 (Subsection 2.1.4).

Strict attention must be paid that the manual close condition is derived from that circuit breaker which feeds the object that is protected by the earth overcurrent protection!

2.5.1.4 Dynamic Cold Load Pickup

Dynamic changeover of pickup values is available also for time overcurrent protection for earth current as it is for the time overcurrent protection for phase currents and residual current (Section 2.4). Processing of the dynamic cold load pickup conditions is the same for all time overcurrent stages, and is explained in Section 2.6 (page 157). The alternative values themselves are set for each of the stages.

2.5.1.5 Inrush Restraint

Earth current time overcurrent protection provides an integrated inrush restraint function which blocks the overcurrent stages I_E> and I_{Ep} (not I_E>>) in case of detection of an inrush on a transformer.

If the second harmonic content of the earth current exceeds a selectable threshold, trip is blocked.

The inrush restraint feature has an upper operation limit. Above this (adjustable) current blocking is suppressed since a high-current fault is assumed in this case. The lower limit is the operating limit of the harmonic filter (0.1 I_N).

Figure 2-75 shows a simplified logic diagram.

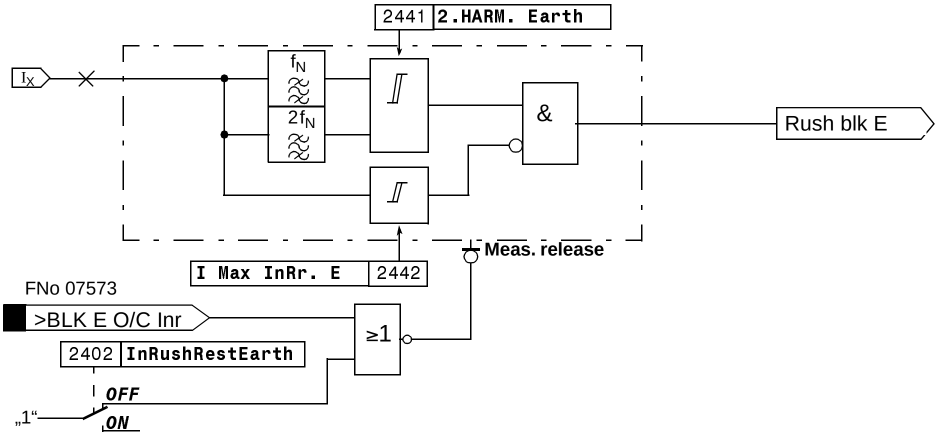


Figure 2-75 Logic diagram of the inrush restraint feature (simplified)

2.5.2 Setting the Function Parameters

General

When configuring the protection functions (see Subsection 2.1.1, margin heading “Special Cases”, page 15) the type of characteristic was set (address 124). Only settings for the characteristic selected can be performed. Definite time stages I_E>> and I_E> are always available.

The earth overcurrent protection must have been assigned to an auxiliary 1-phase current input of the device (Subsection 2.1.4. under margin header “Further 1-Phase Protection Functions”). Consider also the assignment of the measured current input of the device against the current transformer of the power plant (Subsection 2.1.2. under margin header “Assignment of Auxiliary 1-phase Measuring Locations”).

In address 2401 **EARTH O/C**, time overcurrent protection for earth current can be set to ***ON*** or ***OFF***. The option ***Block relay*** allows to operate the protection but the trip output relay is blocked.

Address 2408A **IE MAN. CLOSE** determines which earth current stage is to be activated instantaneously with a detected manual close. Settings ***IE>> instant.*** and ***IE> instant.*** can be set independent from the type of characteristic selected. ***IEp instant.*** is only available if one of the inverse time stages is configured. This parameter can only be altered with DIGSI® under "**Additional Settings**".

If time overcurrent protection is applied on the feeding side of a transformer, select the higher stage I_E>> which does not pick up by the inrush current, or select the Manual Close ***Inactive***.

In address 2402 **InRushRestEarth** inrush restraint (inrush restraint with 2nd harmonic) is enabled or disabled. Set ***ON*** if the protection is applied at the feeding side of an earthed transformer. Otherwise, use setting ***OFF***.

Definite Time High-Current Stage I_E>>

If **IE>>** stage (address 2411) is combined with the I_E> stage or the I_{Ep} stage, a two-stage characteristic will be the result. If this stage is not required, the pickup value shall be set to ∞. Stage **IE>>** always operates with a defined delay time.

Current and time setting shall exclude pickup during switching operations. This stage is applied if you want to create a multi-stage characteristic together with stage I_E> or I_{Ep} (below described). With a certain degree, current grading can also be achieved, similar to the corresponding stages of the time overcurrent protection for phase and residual currents (Subsection 2.4.2). However, zero sequence system quantities must be taken into consideration.

In most cases, this stage operates instantaneously. A time delay, however, can be achieved by setting address 2412 **T IE>>**.

The set time is an additional time delay and does not include the operating time (measuring time, dropout time). The delay can be set to infinity ∞. If set to infinity, the pickup of this function will be indicated but the stage will not trip after pickup. If the pickup threshold is set to ∞, neither a pickup annunciation nor a trip is generated.

Definite Time Overcurrent Stage I_E>

Using the time overcurrent stage **IE>** (address 2413) earth faults can also be detected with smaller fault currents. Since the starpoint current originates from one single current transformer, it is not affected by summation effects evoked by different current transformer errors like, for example, the zero sequence current derived from phase currents. Therefore, this address can be set to very sensitive. But consider that the inrush restraint function cannot operate below 10 % nominal current (lower limit of harmonic filter). An adequate time delay could be reasonable for very sensitive setting if inrush restraint is used.

Since this stage also picks up with earth faults in the network, the time delay (address 2414 **T IE>**) has to be coordinated with the grading coordination chart of the network for earth faults. Mostly, you may set shorter tripping times than for phase currents since a galvanic separation of the zero sequence systems of the connected power system sections is ensured by a transformer with separate windings.

The set time is an additional time delay and does not include the operating time (measuring time, dropout time). The delay can be set to infinity ∞. If set to infinity, the pickup of this function will be indicated but the stage will not trip after pickup. If the pickup threshold is set to ∞, neither a pickup annunciation nor a trip is generated.

Inverse Time Overcurrent Stages IEp with IEC Curves

The inverse time stage, depending on the configuration (Subsection 2.1.1, address 124), enables the user to select different characteristics. With the IEC characteristics (address 124 **DMT/IDMT Earth** = ***TOC IEC***) the following is made available in address 2425 **IEC CURVE**:

Normal Inverse (type A according to IEC 60255–3),
Very Inverse (type B according to IEC 60255–3),
Extremely Inv. (type C according to IEC 60255–3), and
Long Inverse (type B according to IEC 60255–3).

The characteristics and equations they are based on are listed in the Technical Data (Section 4.4, Figure 4-7).

If the inverse time trip characteristic is selected, it must be noted that a safety factor of about 1.1 has already been included between the pickup value and the setting value. This means that a pickup will only occur if a current of about 1.1 times of the setting value is present.

Using the time overcurrent stage **IEp** (address 2421) earth faults can also be detected with weak fault currents. Since the starpoint current originates from one single current transformer, it is not affected by summation effects evoked by different current transformer errors like, for example, the zero sequence current derived from phase currents. Therefore, this address can be set to very sensitive. Consider that the inrush restraint function cannot operate below 10 % nominal current (lower limit of harmonic filtering). An adequate time delay could be reasonable for very sensitive setting if inrush restraint is used.

Since this stage also picks up with earth faults in the network, the time multiplier (address 2422 **T IEp**) has to be coordinated with the grading coordination chart of the network for earth faults. Mostly, you may set shorter tripping times than for phase currents since a galvanic separation of the zero sequence systems of the connected power system sections is ensured by a transformer with separate windings.

The time multiplier can also be set to ∞. If set to infinity, the pickup of this function will be indicated but the stage will not trip after pickup. If the I_{Ep}-stage is not required, select address 124 **DMT/IDMT Earth** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

If ***Disk Emulation*** is set in address 2424 **TOC DROP-OUT**, dropout is being produced according to the dropout characteristic. For more information see Subsection 2.5.1.2, margin heading “Dropout” (page 148).

Inverse Time Overcurrent Stages Ip with ANSI Curves

The inverse time stages, depending on the configuration (Subsection 2.1.1, address 124), enable the user to select different characteristics. With the ANSI characteristics (address 124 **DMT/IDMT Earth** = ***TOC ANSI***) the following is made available in address 2426 **ANSI CURVE**:

Definite Inv.,
Extremely Inv.,
Inverse,
Long Inverse,
Moderately Inv.,
Short Inverse, and
Very Inverse.

The characteristics and the equations they are based on are listed in the Technical Data (Section 4.4, Figures 4-8 and 4-9).

If the inverse time trip characteristic is selected, it must be noted that a safety factor of about 1.1 has already been included between the pickup value and the setting value. This means that a pickup will only occur if a current of about 1.1 times of the setting value is present.

Using the time overcurrent stage **IEp** (address 2421) earth faults can also be detected with weak fault currents. Since the starpoint current originates from one single current transformer, it is not affected by summation effects evoked by different current transformer errors like, for example, the zero sequence current derived from phase currents. Therefore, this address can be set to very sensitive. But consider that the inrush restraint function cannot operate below 10 % nominal current (lower limit of harmonic filter). An adequate time delay could be reasonable for very sensitive setting if inrush restraint is used.

Since this stage also picks up with earth faults in the network, the time multiplier (address 2423 **D IEp**) has to be coordinated with the grading coordination chart of the network for earth faults. Mostly, you may set shorter tripping times than for phase currents since a galvanic separation of the zero sequence systems of the connected power system sections is ensured by a transformer with separate windings.

The time multiplier can also be set to ∞. If set to infinity, the pickup of this function will be indicated but the stage will not trip after pickup. If the I_{Ep}-stage is not required, select address 124 **DMT/IDMT Earth** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

If ***Disk Emulation*** is set in address 2424 **TOC DROP-OUT**, dropout is being produced according to the dropout characteristic. For more information see Subsection 2.5.1.2, margin heading “Dropout” (page 148).

Dynamic Cold Load Pickup

An alternative set of pickup values can be set for each stage. It is selected automatically-dynamically during operation. For more information on this function see Section 2.6 (page 157).

For the stages the following alternative values are set:

- for definite time overcurrent protection:
  address 2511 pickup value **IE>>**,
  address 2512 delay time **T IE>>**,
  address 2513 pickup value **IE>**,
  address 2514 delay time **T IE>**;
- for inverse time overcurrent protection acc. IEC curves:
  address 2521 pickup value **IEp**,
  address 2522 time multiplier **T IEp**;
- for inverse time overcurrent protection acc. ANSI curves:
  address 2521 pickup value **IEp**,
  address 2523 time dial **D IEp**.

User Specified Curves

For inverse time overcurrent protection the user may define his own tripping and dropout characteristic. For configuration in DIGSI® a dialog box is to appear. Enter up to 20 pairs of current and tripping time values (Figure 2-69, page 133).

The procedure is the same as for phase current stages. See Subsection 2.4.2.1, margin heading “User Specified Curves”, page 132.

To create a user-defined tripping characteristic for earth current, the following has to be set for configuration of the functional scope: address 124 (Subsection 2.1.1) **DMT/ IDMT Earth**, option ***User Defined PU***. If you also want to specify the dropout characteristic, set option ***User def. Reset***.

Inrush Restraint

In address 2402 **InRushRestEarth** of the general settings (page 150, margin heading “General”) the inrush restraint can be enabled (***ON***) or disabled (***OFF***). This inrush restraint only makes sense for transformers and if overcurrent time protection is activated on the earthed feeding side. Function parameters of the inrush restraint are set in “Inrush”.

It is based on an evaluation of the 2nd harmonic present in the inrush current. The ratio of 2nd harmonics to the fundamental **2.HARM. Earth** (address 2441) is set to I_{2fN}/I_{fN} = ***15*** % as default setting. It can be used without being changed. To provide more restraint in exceptional cases, where energizing conditions are particularly unfavourable, a smaller value can be set in the address before-mentioned.

If the current exceeds the value indicated in address 2442 **I Max InRr. E**, no restraint will be provoked by the 2nd harmonic.

2.5.3 Setting Overview

Note: Addresses which have an “A” attached to their end can only be changed in DIGSI$^{®}$, Section „**Additional Settings**“. The following list indicates the setting ranges and the default settings of a rated secondary current I_N = 1 A. For a rated secondary current of I_N = 5 A these values have to be multiplied by 5.

Addr.	Setting Title	Setting Options	Default Setting	Comments
2401	EARTH O/C	ON OFF Block relay for trip commands	OFF	Earth Time Overcurrent
2402	InRushRestEarth	ON OFF	OFF	InRush Restrained O/C Earth
2408A	IE MAN. CLOSE	IE>> instantaneously IE> instantaneously IEp instantaneously Inactive	IE>> instantaneously	O/C IE Manual Close Mode
2411	IE>>	0.05..35.00 A; ∞	0.50 A	IE>> Pickup
2412	T IE>>	0.00..60.00 sec; ∞	0.10 sec	T IE>> Time Delay
2413	IE>	0.05..35.00 A; ∞	0.20 A	IE> Pickup
2414	T IE>	0.00..60.00 sec; ∞	0.50 sec	T IE> Time Delay
2511	IE>>	0.05..35.00 A; ∞	7.00 A	IE>> Pickup
2512	T IE>>	0.00..60.00 sec; ∞	0.00 sec	T IE>> Time Delay

Addr.	Setting Title	Setting Options	Default Setting	Comments
2513	IE>	0.05..35.00 A; ∞	1.50 A	IE> Pickup
2514	T IE>	0.00..60.00 sec; ∞	0.30 sec	T IE> Time Delay
2421	IEp	0.05..4.00 A	0.20 A	IEp Pickup
2422	T IEp	0.05..3.20 sec; ∞	0.20 sec	T IEp Time Dial
2423	D IEp	0.50..15.00; ∞	5.00	D IEp Time Dial
2424	TOC DROP-OUT	Instantaneous Disk Emulation	Disk Emulation	TOC Drop-out Characteristic
2425	IEC CURVE	Normal Inverse Very Inverse Extremely Inverse Long Inverse	Normal Inverse	IEC Curve
2426	ANSI CURVE	Very Inverse Inverse Short Inverse Long Inverse Moderately Inverse Extremely Inverse Definite Inverse	Very Inverse	ANSI Curve
2521	IEp	0.05..4.00 A	1.00 A	IEp Pickup
2522	T IEp	0.05..3.20 sec; ∞	0.50 sec	T IEp Time Dial
2523	D IEp	0.50..15.00; ∞	5.00	D IEp Time Dial
2431	I/IEp PU T/TEp	1.00..20.00 I / Ip; ∞ 0.01..999.00 Time Dial		Pickup Curve IE/IEp - TIE/TIEp
2432	MofPU Res T/TEp	0.05..0.95 I / Ip; ∞ 0.01..999.00 Time Dial		Multiple of Pickup <-> TI/TIEp
2441	2.HARM. Earth	10..45 %	15 %	2nd harmonic O/C E in % of fundamental
2442	I Max InRr. E	0.30..25.00 A	7.50 A	Maximum Current for Inr. Rest. O/C Earth

2.5.4 Information Overview

F.No.	Alarm	Comments
01714	>BLK Earth O/C	>BLOCK Earth time overcurrent
07573	>BLK E O/C Inr	>BLOCK time overcurrent Earth InRush
01756	O/C Earth OFF	Time Overcurrent Earth is OFF
01757	O/C Earth BLK	Time Overcurrent Earth is BLOCKED

F.No.	Alarm	Comments
01758	O/C Earth ACT	Time Overcurrent Earth is ACTIVE
01765	O/C Earth PU	Time Overcurrent Earth picked up
07564	Earth InRush PU	Earth InRush picked up
01724	>BLOCK IE>>	>BLOCK IE>>
01854	IE>> BLOCKED	IE>> BLOCKED
01831	IE>> picked up	IE>> picked up
01832	IE>> Time Out	IE>> Time Out
01833	IE>> TRIP	IE>> TRIP
01725	>BLOCK IE>	>BLOCK IE>
01853	IE> BLOCKED	IE> BLOCKED
01834	IE> picked up	IE> picked up
07552	IE> InRush PU	IE> InRush picked up
01835	IE> Time Out	IE> Time Out
01836	IE> TRIP	IE> TRIP
01726	>BLOCK IEp	>BLOCK IEp
01856	IEp BLOCKED	IEp BLOCKED
01837	IEp picked up	IEp picked up
07554	IEp InRush PU	IEp InRush picked up
01838	IEp TimeOut	IEp Time Out
01839	IEp TRIP	IEp TRIP
01862	O/C 3I0 Err CT	O/C 3I0 err.: No further CT assigned

2.6 Dynamic Cold Load Pickup for Time Overcurrent Protection

With the dynamic cold load pickup feature, it is possible to dynamically increase the pickup values of the time overcurrent protection stages when dynamic cold load overcurrent conditions are anticipated, i.e. when consumers have increased power consumption after a longer period of dead condition, e.g. in air conditioning systems, heating systems, motors, etc. By allowing pickup values and the associated time delays to increase dynamically, it is not necessary to incorporate cold load capability in the normal settings.

Note:

Dynamic cold load pickup is in addition to the four setting groups (A to D) which are configured separately.

The dynamic cold load pickup feature operates with the time overcurrent protection functions described in the sections 2.4 and 2.5. A set of alternative values can be set for each stage.

2.6.1 Function Description

There are two criteria to determine if the protected equipment is de-energized:

- Via a binary input, an auxiliary contact in the circuit breaker can be used to determine if the circuit breaker is open or closed.
- The current flow monitoring threshold may be used to determine if the equipment is de-energized.

You may select one of these criteria for the time overcurrent protection for phase currents (Section 2.4) and for that for residual current (Section 2.4). The device assigns automatically the correct side or measuring location for current detection or the breaker auxiliary contact in accordance with the assignment of the associated protection functions. The time overcurrent protection for earth current (Section 2.5) allows the breaker criterion only if it is assigned to a certain side of the protected object (see also Subsection 2.1.2 under margin header “Assignment of Auxiliary 1-phase Measuring Locations”, page 32); otherwise exclusively the current criterion can be used.

If the device recognizes the protected equipment be de-energized via one of the criteria above, then the alternative pickup values will become effective for the overcurrent stages once a specified time delay has elapsed. Figure 2-77 shows the logic diagram for dynamic cold load pickup function. The time **`CB Open Time`** controls how long the equipment can be de-energized before the dynamic cold load pickup function is activated. When the protected equipment is re-energized (i.e. the device receives input via a binary input that the assigned circuit breaker is closed or the assigned current flowing through the breaker increases above the current flow monitoring threshold), the active time **`Active Time`** is initiated. Once the active time has elapsed, the pickup values of the overcurrent stages return to their normal settings. The active time controls how long dynamic cold load pickup settings remain in place once the protected object is re-energized. Upon re-energizing of the equipment, if the measured current values are below the normal pickup settings, an alternative time delay referred to as the **`Stop Time`** is also initiated. As in the case with the active time, once this time has elapsed, the pickup values of overcurrent stages change from the dynamic cold load pickup values to their normal settings. The **`Stop Time`** controls how long dynamic cold load pickup settings remain in place given that measured currents are below the normal pickup settings. To defeat this time from switching the overcurrent stages pickup settings back to normal, it may be set to ∞ or blocked via the binary input “`>BLK CLP stpTim`”.

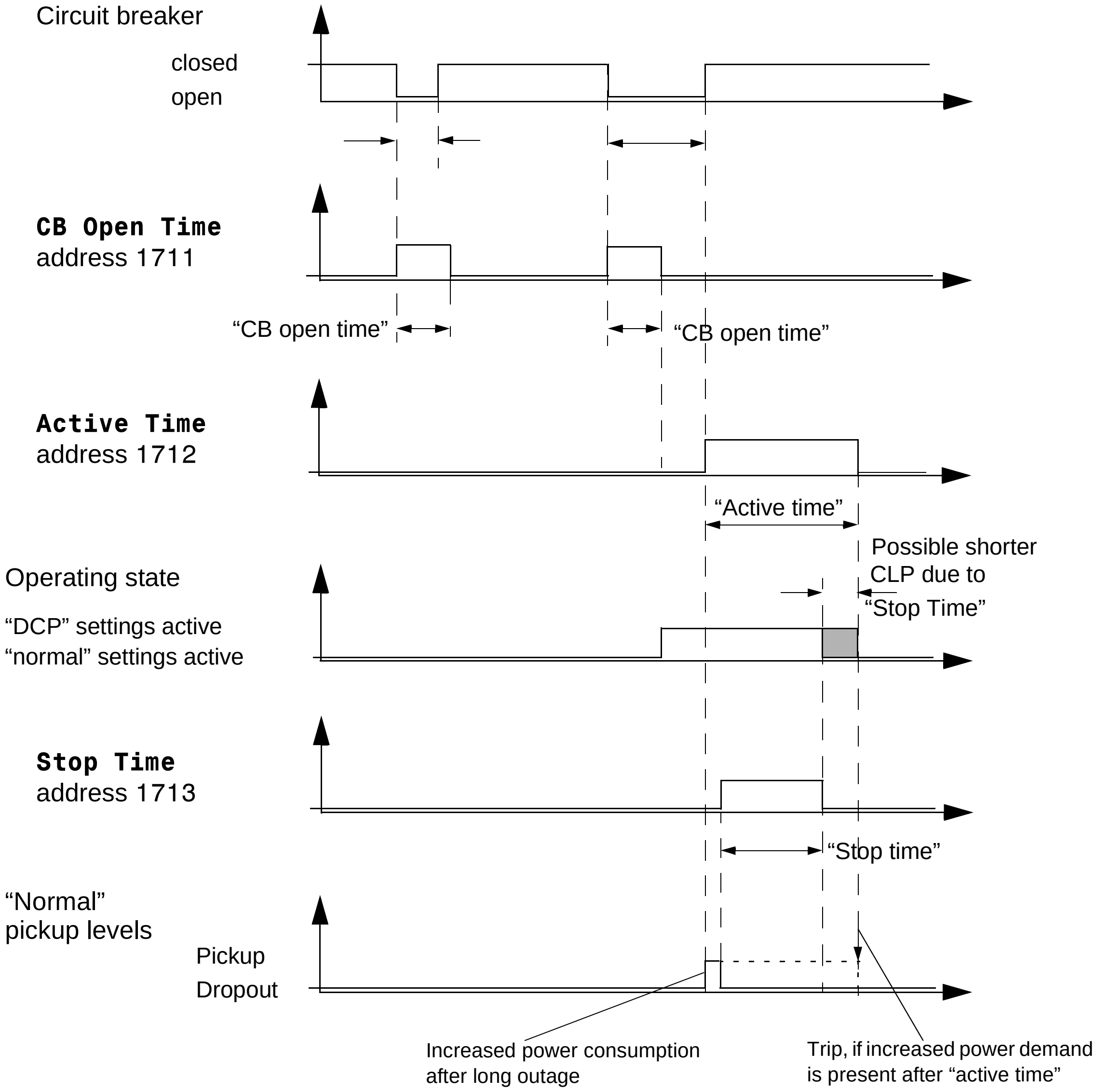


Figure 2-76 Cold load pickup timing sequence

If an overcurrent stage picks up while the dynamic settings are enabled, elapse of the active time **`Active Time`** will not restore the normal pickup settings until dropout of the overcurrent stage occurs based on the dynamic settings.

If the dynamic cold load pickup function is blocked via the binary input “`>BLOCK CLP`”, all triggered timers will be immediately reset and all “normal” settings will be restored. If blocking occurs during an on-going fault with dynamic cold load pickup functions enabled, the timers of all overcurrent stages will be stopped, and then restarted based on their “normal” duration.

During power up of the protective relay with an open circuit breaker, the time delay **`CB Open Time`** is started, and is processed using the normal settings. Therefore, when the circuit breaker is closed, the normal settings are effective.

Figure 2-76 shows a timing diagram, Figure 2-77 describes the logic for cold load pickup function as an example for time overcurrent protection for phase currents.

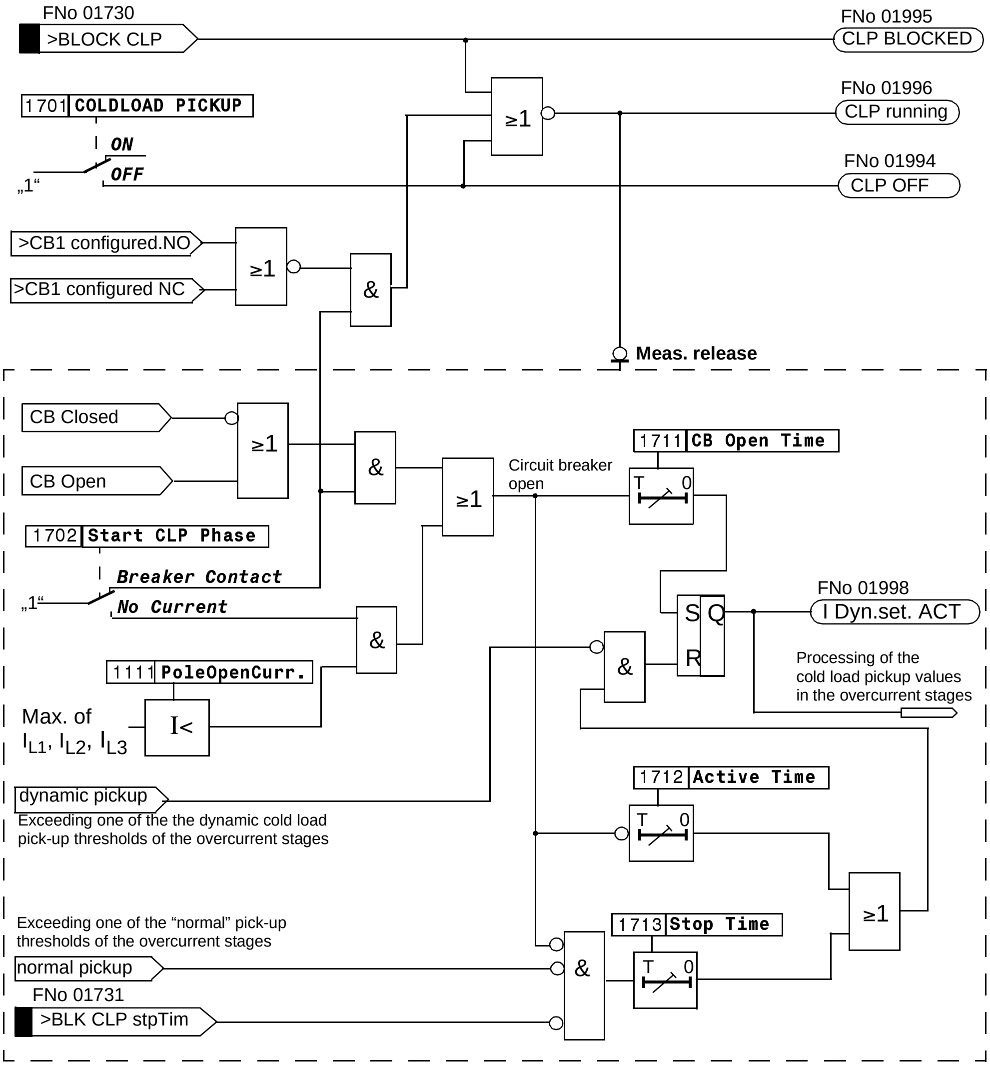


Figure 2-77 Logic diagram for dynamic cold load pickup feature — illustrated for phase overcurrent protection stage on side 1 (simplified)

2.6.2 Setting the Function Parameters

General

Dynamic cold load pickup can only be enabled if address 117 **COLDLOAD PICKUP** was set to ***Enabled***. If this feature is not required, address 117 is set to ***Disabled***. Under address 1701 **COLDLOAD PICKUP** the function can be switched ***ON*** or ***OFF***.

Cold Load Criteria

You can determine the criteria for dynamic switchover to the cold load pickup values for all protective functions which allow this switchover. Select the current criterion ***No Current*** or the breaker position criterion ***Breaker Contact***:

address 1702 **Start CLP Phase** for the phase current stages,
address 1703 **Start CLP 3I0** for the residual current stages,
address 1704 **Start CLP Earth** for the earth current stages.

The current criterion takes the currents of that side or measuring location where the corresponding protective function is assigned to. When using the breaker position criterion, the feedback information of the assigned breaker must inform the device about the breaker position.

The time overcurrent protection for earth current allows the breaker criterion only if an unequivocal relationship exists between its assigned side and the feedback information of the breaker.

Timers

There are no specific procedures on how to set the time delays at addresses 1711 **CB Open Time**, 1712 **Active Time** and 1713 **Stop Time**. These time delays must be based on the specific loading characteristics of the equipment being protected, and should be selected to allow the brief overloads associated with dynamic cold load conditions.

Cold Load Pickup Values

The dynamic pickup values and time delays associated with the time overcurrent stages are set in the related addresses of these stages themselves.

2.6.3 Setting Overview

Addr.	Setting Title	Setting Options	Default Setting	Comments
1701	COLDLOAD PICKUP	OFF ON	OFF	Cold-Load-Pickup Function
1702	Start CLP Phase	No Current Breaker Contact	No Current	Start Condition CLP for O/C Phase
1703	Start CLP 3I0	No Current Breaker Contact	No Current	Start Condition CLP for O/C 3I0
1704	Start CLP Earth	No Current Breaker Contact	No Current	Start Condition CLP for O/C Earth
1711	CB Open Time	0..21600 sec	3600 sec	Circuit Breaker OPEN Time
1712	Active Time	1..21600 sec	3600 sec	Active Time

Addr.	Setting Title	Setting Options	Default Setting	Comments
1713	Stop Time	1..600 sec; ∞	600 sec	Stop Time

2.6.4 Information Overview

F.No.	Alarm	Comments
01730	>BLOCK CLP	>BLOCK Cold-Load-Pickup
01731	>BLK CLP stpTim	>BLOCK Cold-Load-Pickup stop timer
01994	CLP OFF	Cold-Load-Pickup switched OFF
01995	CLP BLOCKED	Cold-Load-Pickup is BLOCKED
01996	CLP running	Cold-Load-Pickup is RUNNING
01998	I Dyn.set. ACT	Dynamic settings O/C Phase are ACTIVE
01999	3I0 Dyn.set.ACT	Dynamic settings O/C 3I0 are ACTIVE
02000	IE Dyn.set. ACT	Dynamic settings O/C Earth are ACTIVE

2.7 Single-Phase Time Overcurrent Protection

The single-phase time overcurrent protection can be assigned to either of the 1-phase measured current input of the device (Section 2.1.4 under margin header "Further 1-Phase Protection Functions"). This may be a "normal" or "high-sensitivity" input (Section 2.1.2 under margin header "High-Sensitivity Auxiliary 1-phase Measuring Locations"). In the latter case, a very sensitive pickup threshold is possible (smallest setting 3 mA at the current input).

It can be used for any desired single-phase application. Examples are high-impedance unit protection or highly sensitive tank leakage protection. These applications are covered in the following subsections: Subsection 2.7.2 for high-impedance protection, and Subsection 2.7.3 for high-sensitivity tank leakage protection.

The single-phase time overcurrent protection comprises two definite time delayed stages which can be combined as desired. If you need only one stage, the other can be set to infinity.

2.7.1 Function Description

The measured current is filtered by numerical algorithms. Because of the high sensitivity a particular narrow band filter is used.

For the single-phase I>> stage, the current measured at the assigned current input is compared with the setting value **1Phase I>>**. Current above the pickup value is detected and annunciated. When the delay time **T 1Phase I>>** has expired, tripping command is issued. The reset value is approximately 5 % below the pickup value for currents above I_N. Lower values require a higher hysteresis in order to avoid intermittent pickup on currents near the pickup value (e.g. 10 % at $0.2 \cdot I_N$).

When high fault current occurs, the current filter can be bypassed in order to achieve a very short tripping time. This is automatically done when the instantaneous value of the current exceeds the set value I>> by the factor $2 \cdot \sqrt{2}$.

For the single-phase I> stage, the current measured at the assigned current input is compared with the setting value **1Phase I>**. Current above the pickup value is detected and annunciated. When the delay time **T 1Phase I>** has expired, tripping command is issued. The reset value is approximately 5 % below the pickup value for currents above I_N. Lower values require a higher hysteresis in order to avoid intermittent pickup on currents near the pickup value (e.g. 20 % at $0.1 \cdot I_N$).

Both stages form a two-stage definite time overcurrent protection whose tripping characteristic is illustrated in Figure 2-78.

The logic diagram of the single-phase time overcurrent protection is shown in Figure 2-79.

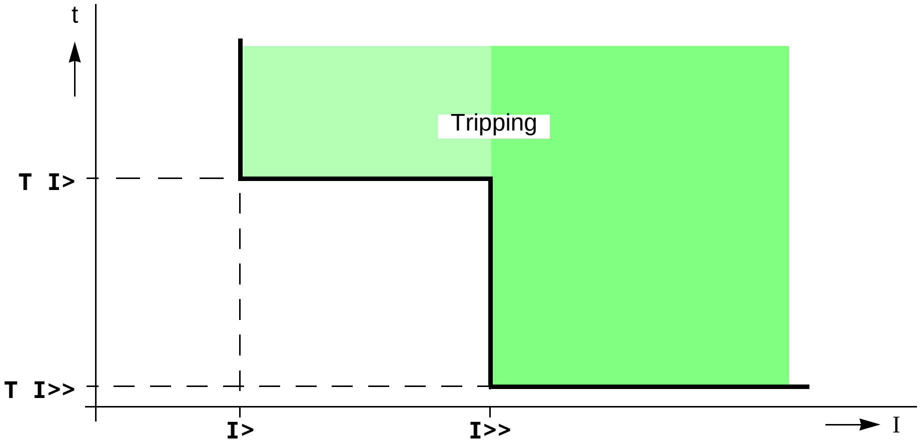


Figure 2-78 Two-stage tripping characteristic of the single-phase time overcurrent protection

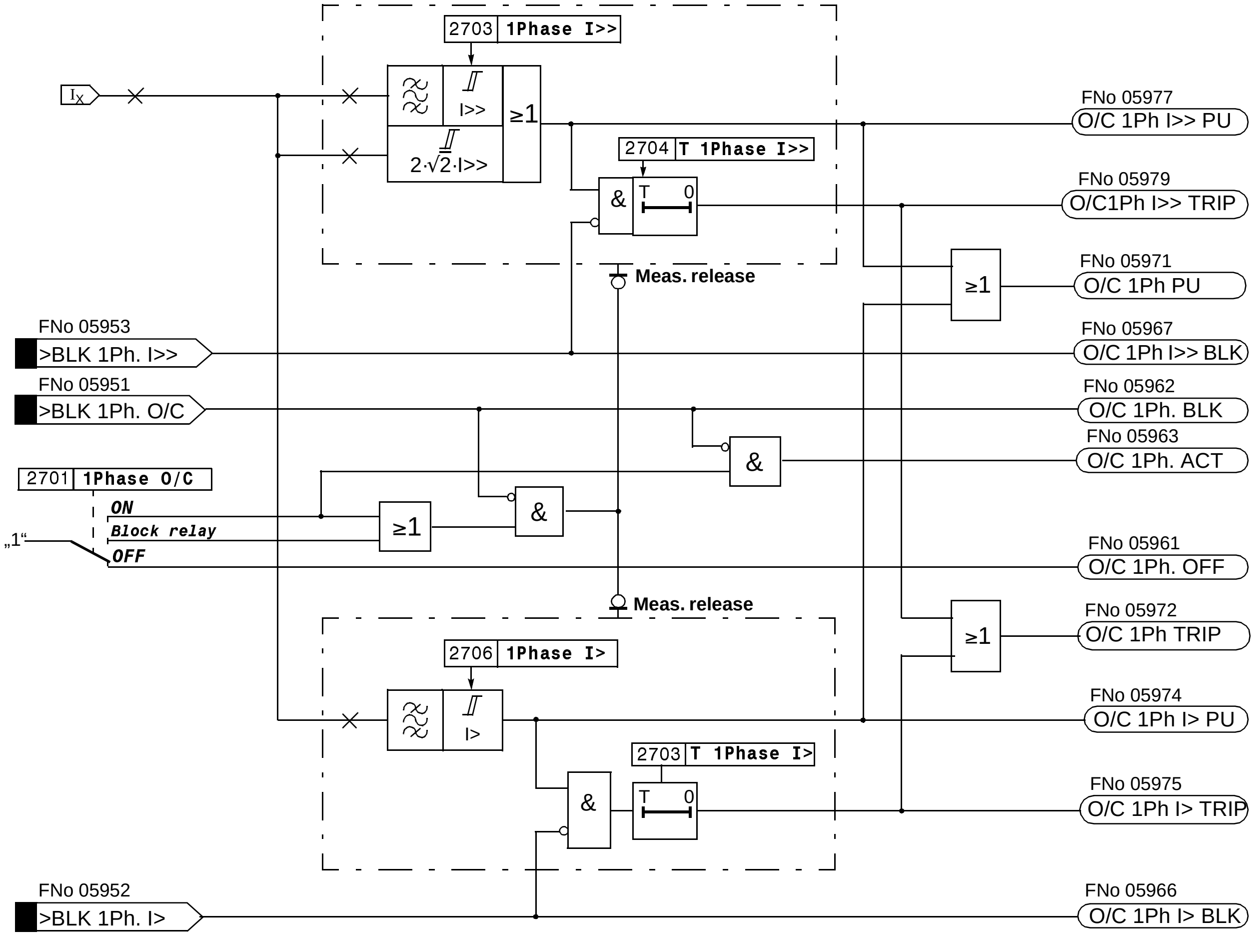


Figure 2-79 Logic diagram of the single-phase time overcurrent protection (simplified)

2.7.2 High-Impedance Unit Protection

Application Example

With the high-impedance scheme all current transformers at the limits of the protection zone operate parallel to a common relatively high-ohmic resistance R whose voltage is measured. With 7UT6 the voltage is registered by measuring the current through the external resistor R at a sensitive 1-phase current measuring input.

The current transformers have to be of equal design and provide at least a separate core for high-impedance protection. They also must have the same transformation ratio and approximately the same knee-point voltage.

With 7UT6 the high-impedance principle is very suited for detection of earth faults in transformers, generators, motors and shunt reactors in earthed systems. High-impedance protection can be used instead of or in addition to the restricted earth fault protection (see Section 2.3).

Figure 2-80 (left side) illustrates an application example for an earthed transformer winding or an earthed motor/generator. The example on the right side shows a non-earthed transformer winding or an non-earthed motor/generator where the earthing of the system is assumed somewhere else.

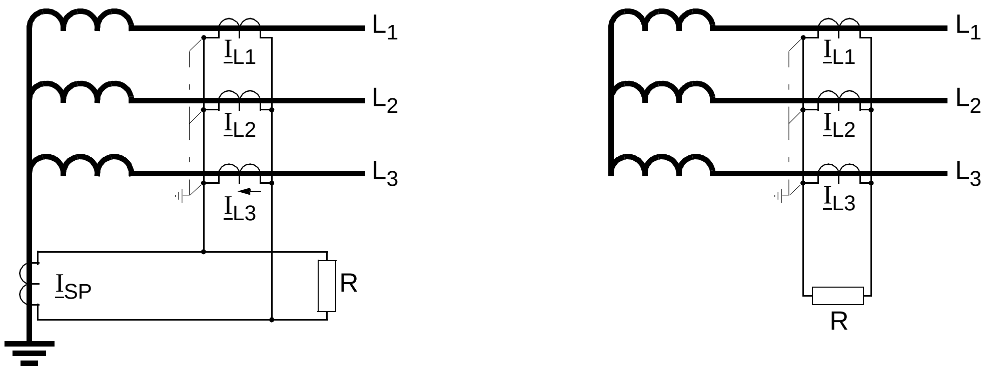


Figure 2-80 Earth fault protection according to the high-impedance scheme

High-Impedance Principle

The high-impedance principle is explained on the basis of an earthed transformer winding (Figure 2-81).

No zero sequence current will flow during normal operation, i.e. the starpoint current is $\underline{I}_{SP} = 0$ and the line currents are $3\underline{I}_0 = \underline{I}_{L1} + \underline{I}_{L2} + \underline{I}_{L3} = 0$.

With an external earth fault (Figure 2-81, left side), whose fault current is supplied via the earthed starpoint, the same current flows through the transformer starpoint and the phases. The corresponding secondary currents (all current transformers having the same transformation ratio) compensate each other, they are connected in series. Across resistance R only a small voltage is generated. It originates from the inner resistance of the transformers and the connecting cables of the transformers. Even if any current transformer experiences a partial saturation, it will become low-ohmic for the period of saturation and creates a low-ohmic shunt resistance to the high-ohmic resistor R. Thus, the high resistance of the resistor also has an stabilizing effect (the so-called resistance stabilization).

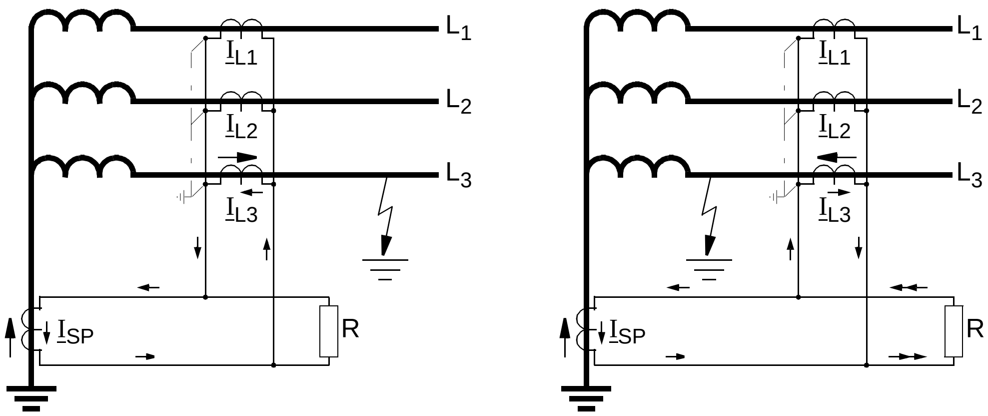


Figure 2-81 Earth fault protection using the high-impedance principle

In case there is an earth fault in the protection zone (Figure 2-81, right side), a starpoint current $\underline{I}_{SP}$ will be present for sure. The earthing conditions in the rest of the network determine how strong a zero sequence current from the system is. A secondary current which is equal to the total fault current tries to pass through the resistor R. Since the latter is high-ohmic, a high voltage emerges immediately. Therefore, the current transformers get saturated. The RMS voltage across the resistor approximately corresponds to the knee-point voltage of the current transformers.

Resistance R is dimensioned such that, even with the very lowest earth fault current to be detected, it generates a secondary voltage which is equal to the half knee-point voltage of current transformers (see also notes on dimensioning in Subsection 2.7.4).

High-Impedance Protection with 7UT6

With 7UT6 a highly sensitive measuring 1-phase input is used for high-impedance protection. As this is a current input, the protection detects current through the resistor instead of the voltage across the resistor R.

Figure 2-82 shows the connection example. The 7UT6 is connected in series to resistor R and measures its current.

Varistor V limits the voltage when inner faults occur. High voltage peaks emerging with transformer saturation are cut by the varistor. At the same time, voltage is smoothed without reduction of the mean value.

For protection against hazardous voltages it is also important that the device is directly connected to the earthed side of the current transformers so that the high voltage at the resistor is kept away from the device.

For generators, motors and shunt reactors high-impedance protection can be used analogously. All current transformers at the overvoltage side, the undervoltage side and the current transformer at the starpoint have to be connected in parallel when using auto-transformers.

In principle, this scheme can be applied to every protected object. When applied as busbar protection, for example, the device is connected to the parallel connection of all feeder current transformers via the resistor.

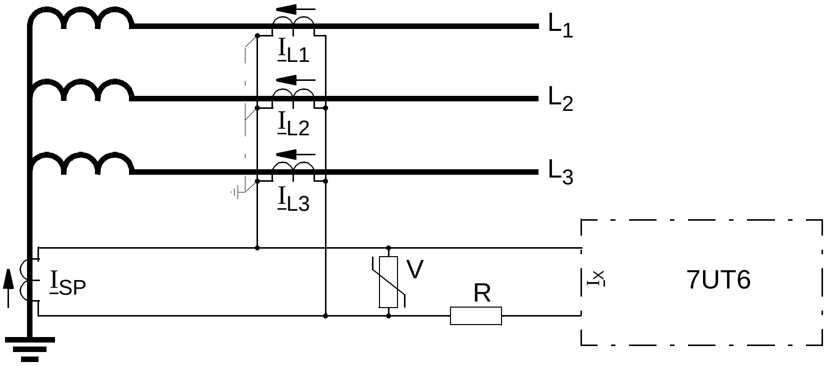


Figure 2-82 Connection scheme for earth fault protection according to the high-impedance principle

2.7.3 Tank Leakage Protection

Application Example

The tank leakage protection has the task to detect earth leakage — even high-ohmic — between a phase and the frame of a power transformer. The tank must be isolated from earth (refer to Figure 2-83). A conductor links the tank to earth, and the current through this conductor is fed to a current input of the relay. When a tank leakage occurs, a fault current (tank leakage current) will flow through the earthing conductor to earth. This tank leakage current is detected by the single-phase overcurrent protection as an overcurrent; an instantaneous or delayed trip command is issued in order to disconnect all sides of the transformer.

A high-sensitivity single-phase current input is used for tank leakage protection.

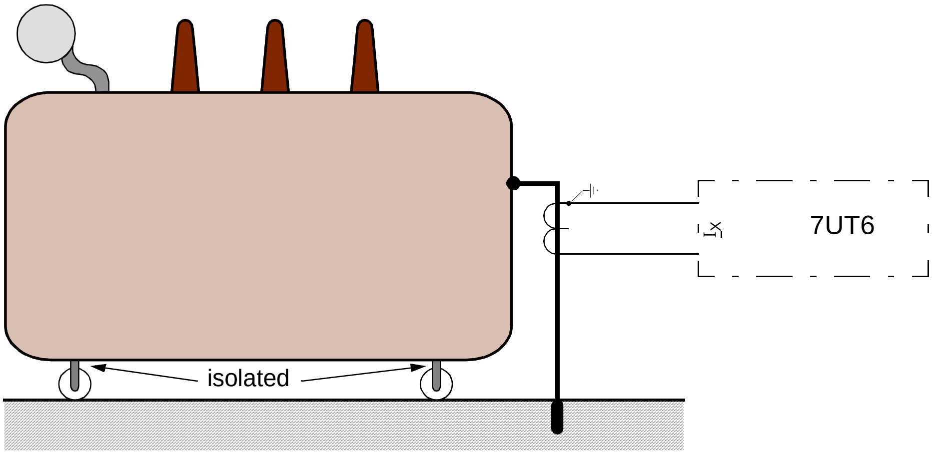


Figure 2-83 Principle of tank leakage protection

2.7.4 Setting the Function Parameters

General

In address 2701 **`1Phase O/C`**, the single-phase time overcurrent protection can switched ***`ON`*** or ***`OFF`***. The option ***`Block relay`*** allows to operate the protection but the trip output relay is blocked.

The settings depend on the application. The setting ranges depend on whether a “normal” or a “high-sensitivity” current input is used. This was determined during assignment of the protection functions (Subsection 2.1.4 under “Further 1-Phase Protection Functions”, page 51) and the properties of the 1-phase input (Subsection 2.1.2 under “High-Sensitivity Auxiliary 1-phase Measuring Locations”, page 33).

- If you have declared the type of the associated 1-phase current input as ***`1A/5A input`*** in address 255 and/or 256, you set the pickup value **`1Phase I>>`** in address 2702, the pickup value **`1Phase I>`** in address 2705. If you need only one stage, set the other to ∞.
- If you have declared the type of the associated 1-phase current input as ***`sensitiv input`*** in address 255 and/or 256, you set the pickup value **`1Phase I>>`** in address 2703, the pickup value **`1Phase I>`** in address 2706. If you need only one stage, set the other to ∞.

If you need a trip time delay, set it in address 2704 **`T 1Phase I>>`** for the I>> stage, and/or in address 2707 **`T 1Phase I>`** for the I> stage. With setting ***`0`*** s no delay takes place.

The set times are pure delay times which do not include the inherent operating times of the protection stages. If you set a time to ∞ the associated stage does not trip but pickup annunciation will occur.

Special notes are given in the following for the use as high-impedance unit protection and tank leakage protection.

Use as High-Impedance Protection

When used as high-impedance protection, only the pickup value of the single-phase overcurrent protection is set on the 7UT6 to detect overcurrent at the assigned highly sensitive 1-phase current input.

But, the entire function of the high-impedance unit protection is dependent on the coordination of the current transformer characteristics, the external resistor R and the voltage across R. The following three header margins give information about these considerations.

Current Transformer Data for High-Impedance Protection

All current transformers must have identical transformation ratio and nearly equal knee-point voltage. This is usually the case if they are of equal design and identical rated data. If the knee-point voltage is not stated, it can be approximately calculated from the rated data of a CT as follows:

$$U_{KPV} = \left(R_i + \frac{P_N}{I_N^2}\right) \cdot ALF \cdot I_N$$

where U_{KPV} = knee-point voltage of the CT
R_i = Internal burden of the CT
P_N = rated power of the CT
I_N = rated secondary current of the CT
ALF = rated accuracy limit factor of the CT

The rated current, rated power and accuracy limit factor are normally stated on the rating plate of the current transformer, e.g.

Current transformer 800/5; 5P10; 30 VA
That means
I_N = 5 A (from 800/**5**)
ALF = 10 (from 5P**10**)
P_N = **30** VA

The internal burden is often stated in the test report of the current transformer. If not it can be derived from a DC measurement on the secondary winding.

Calculation example:

Current transformer 800/5; 5P10; 30 VA with $R_i = 0.3\ \Omega$

$$U_{KPV} = \left(R_i + \frac{P_N}{I_N^2}\right) \cdot ALF \cdot I_N = \left(0.3\ \Omega + \frac{30\ VA}{(5\ A)^2}\right) \cdot 10 \cdot 5\ A = 75\ V$$

or

Current transformer 800/1; 5P10; 30 VA with $R_i = 5\ \Omega$

$$U_{KPV} = \left(R_i + \frac{P_N}{I_N^2}\right) \cdot ALF \cdot I_N = \left(5\ \Omega + \frac{30\ VA}{(1\ A)^2}\right) \cdot 10 \cdot 1\ A = 350\ V$$

Besides the CT data, the resistance of the longest connection lead between the CTs and the 7UT6 device must be known.

Stability with High-Impedance Protection

The stability condition is based on the following simplified assumption: If there is an external fault, *one* of the current transformers gets totally saturated. The other ones will continue transmitting their (partial) currents. In theory, this is the most unfavourable case. Since, in practice, it is also the saturated transformer which supplies current, an automatic safety margin is guaranteed.

Figure 2-84 shows a simplified equivalent circuit. CT1 and CT2 are assumed as ideal transformers with their inner resistances R_{i1} and R_{i2}. R_a are the resistances of the connecting cables between current transformers and resistor R. They are multiplied by 2 as they have a go- and a return line. R_{a2} is the resistance of the longest connecting cable.

CT1 transmits current I_1. CT2 shall be saturated. Because of saturation the transformer represents a low-resistance shunt which is illustrated by a dashed short-circuit line.

$R >> (2R_{a2} + R_{i2})$ is a further prerequisite.

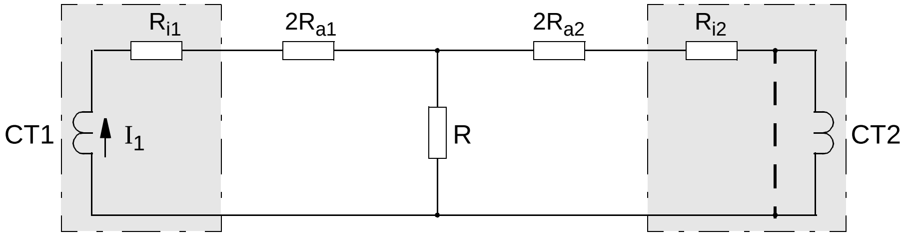


Figure 2-84 Simplified equivalent circuit of a circulating current system for high-impedance unit protection

The voltage across R is then

$$U_R \approx I_1 \cdot (2R_{a2} + R_{i2})$$

It is assumed that the pickup value of the 7UT6 corresponds to half the knee-point voltage of the current transformers. In the balanced case results

$$U_R = U_{KPV}/2$$

This results in a stability limit I_{SL}, i.e. the maximum through-fault current below which the scheme remains stable:

$$I_{SL} = \frac{U_{KPV}/2}{2 \cdot R_{a2} + R_{i2}}$$

Calculation example:

For the 5 A CT like above with $U_{KPV} = 75$ V and $R_i = 0.3\ \Omega$
longest CT connection lead 22 m with 4 mm^2 cross-section, results in $R_a \approx 0{,}1\ \Omega$

$$I_{SL} = \frac{U_{KPV}/2}{2 \cdot R_{a2} + R_{i2}} = \frac{37.5\ \text{V}}{2 \cdot 0.1\ \Omega + 0.3\ \Omega} = 75\ \text{A}$$

that is 15 × rated current or 12 kA primary.

For the 1 A CT like above with $U_{KPV} = 350$ V and $R_i = 5\ \Omega$
longest CT connection lead 107 m with 2.5 mm^2 cross-section, results in $R_a \approx 0.75\ \Omega$

$$I_{SL} = \frac{U_{KPV}/2}{2 \cdot R_{a2} + R_{i2}} = \frac{175\ \text{V}}{2 \cdot 0.75\ \Omega + 5\ \Omega} = 27\ \text{A}$$

that is 27 × rated current or 21,6 kA primary.

Sensitivity with High Impedance Protection

As before mentioned, high-impedance protection is to pick up with approximately half the knee-point voltage of the current transformers. Resistance R can be calculated from it.

Since the device measures the current flowing through the resistor, resistor and measuring input of the device are to be connected in series (see also Figure 2-82). Since, furthermore, the resistance shall be high-ohmic (condition: $R >> 2R_{a2} + R_{i2}$, as above mentioned), the inherent resistance of the measuring input can be neglected. The resistance is then calculated from the pickup current I_{pu} and the half knee-point voltage:

$$R = \frac{U_{KPV}/2}{I_{pu}}$$

Calculation example:

For the 5 A CT like above with
required pickup value $I_{pu} = 0.1$ A (corresponding to 16 A primary)

$$R = \frac{U_{KPV}/2}{I_{pu}} = \frac{75\ \text{V}/2}{0.1\ \text{A}} = 375\ \Omega$$

For the 1 A CT like above
required pickup value $I_{pu} = 0.05$ A (corresponding to 40 A primary)

$$R = \frac{U_{KPV}/2}{I_{pu}} = \frac{350\ \text{V}/2}{0.05\ \text{A}} = 3500\ \Omega$$

The required short-term power of the resistor is derived from the knee-point voltage and the resistance:

$$P_R = \frac{U_{KPV}^2}{R} = \frac{(75\ \text{V})^2}{375\ \Omega} = 15\ \text{W} \qquad \text{for the 5 A CT example}$$

$$P_R = \frac{U_{KPV}^2}{R} = \frac{(350\ \text{V})^2}{3500\ \Omega} = 35\ \text{W} \qquad \text{for the 1 A CT example}$$

As this power only appears during earth faults for a short period of time, the rated power can be smaller by approx. factor 5.

The varistor (see also Figure 2-82) must be dimensioned such that it remains high-ohmic up to the knee-point voltage, e.g.

approx. 100 V for the 5 A CT example,
approx. 500 V for the 1 A CT example.

For 7UT6, the pickup value (0.1 A or 0.05 A in the example) is set in address 2706 **1Phase I>**. Stage I>> is not required (Address 2703 **1Phase I>>** = ∞).

The trip command of the protection can be delayed in address 2707 **T 1Phase I>**. This time delay is usually set to ***0***.

If a higher number of current transformers is connected in parallel, e.g. when using as busbar protection with several feeders, the magnetizing currents of the transformers connected in parallel cannot be neglected any more. In this case, the magnetizing currents at the half knee-point voltage (corresponds to the setting value) have to be summed. These magnetizing currents reduce the current through the resistor R. Therefore the actual pickup value will be correspondingly higher.

Use as Tank Leakage Protection

If the single-phase time overcurrent protection is used as tank leakage protection, merely the pickup value for the assigned 1-phase current input is set on 7UT6.

The tank leakage protection is a highly sensitive overcurrent protection which detects the leakage current between the isolated transformer tank and earth. Its sensitivity is set in address 2706 **1Phase I>**. The I>> stage is not used (address 2703 **1Phase I>>** = ∞).

The trip command can be delayed under address 2707 **T 1Phase I>**. Normally, this delay time is set to ***0***.

2.7.5 Setting Overview

The following list indicates the setting ranges and the default settings of a rated secondary current I_N = 1 A. For a rated secondary current of I_N = 5 A these values have to be multiplied by 5. The addresses 2703 and 2706 (for high-sensitivity input) are independent of the rated current.

Addr.	Setting Title	Setting Options	Default Setting	Comments
2701	1Phase O/C	OFF ON Block relay for trip commands	OFF	1Phase Time Overcurrent
2702	1Phase I>>	0.05..35.00 A; ∞	0.50 A	1Phase O/C I>> Pickup
2703	1Phase I>>	0.003..1.500 A; ∞	0.300 A	1Phase O/C I>> Pickup
2704	T 1Phase I>>	0.00..60.00 sec; ∞	0.10 sec	T 1Phase O/C I>> Time Delay
2705	1Phase I>	0.05..35.00 A; ∞	0.20 A	1Phase O/C I> Pickup
2706	1Phase I>	0.003..1.500 A; ∞	0.100 A	1Phase O/C I> Pickup
2707	T 1Phase I>	0.00..60.00 sec; ∞	0.50 sec	T 1Phase O/C I> Time Delay

2.7.6 Information Overview

F.No.	Alarm	Comments
05951	>BLK 1Ph. O/C	>BLOCK Time Overcurrent 1Phase
05952	>BLK 1Ph. I>	>BLOCK Time Overcurrent 1Ph. I>
05953	>BLK 1Ph. I>>	>BLOCK Time Overcurrent 1Ph. I>>
05961	O/C 1Ph. OFF	Time Overcurrent 1Phase is OFF
05962	O/C 1Ph. BLK	Time Overcurrent 1Phase is BLOCKED
05963	O/C 1Ph. ACT	Time Overcurrent 1Phase is ACTIVE
05966	O/C 1Ph I> BLK	Time Overcurrent 1Phase I> BLOCKED
05967	O/C 1Ph I>> BLK	Time Overcurrent 1Phase I>> BLOCKED
05971	O/C 1Ph PU	Time Overcurrent 1Phase picked up
05972	O/C 1Ph TRIP	Time Overcurrent 1Phase TRIP
05974	O/C 1Ph I> PU	Time Overcurrent 1Phase I> picked up
05975	O/C 1Ph I> TRIP	Time Overcurrent 1Phase I> TRIP
05977	O/C 1Ph I>> PU	Time Overcurrent 1Phase I>> picked up
05979	O/C1Ph I>> TRIP	Time Overcurrent 1Phase I>> TRIP
05980	O/C 1Ph I:	Time Overcurrent 1Phase: I at pick up
05981	O/C 1Ph Err CT	O/C 1Phase err.: No further CT assigned

2.8 Unbalanced Load Protection

General

Negative sequence protection detects unbalanced loads on the system. In addition, it may be used to detect interruptions, faults, and polarity problems with current transformers. Furthermore, it is useful in detecting phase-to-ground, phase-to-phase, and double phase-to-ground faults with magnitudes lower than the maximum load current.

Negative sequence protection is reasonable only for three-phase equipment. It is, therefore, not available in case of **PROT. OBJECT** = ***1ph Busbar*** or ***1 phase transf.*** (address 105, see Subsection 2.1.1).

The application of unbalanced load protection to generators and motors has a special significance. The negative sequence currents associated with unbalanced loads create counter-rotating fields in three-phase induction machines, which act on the rotor at double frequency. Eddy currents are induced at the rotor surface, and local overheating at the transition between the slot wedges and the winding bundles takes place.

In addition, the threat of thermal overload exists when motors are supplied by unbalanced system voltages. Because the motor represents a small negative sequence impedance, small voltage imbalances can lead to large negative sequence currents.

The unbalanced load protection operates always on the side of the protected object or to the measuring location which it is assigned to (see Subsection 2.1.4 under “Further 3-Phase Protection Functions”, page 49, address 440).

The unbalanced load protection consists of two definite time stages and one inverse time stage which latter may operate according to an IEC or ANSI characteristic.

2.8.1 Function Description

Determination of Unbalanced Load

The unbalanced load protection of 7UT6 uses numerical filters to dissect the phase currents into their symmetrical components. If the negative sequence component of the phase currents exceeds the pole open current **PoleOpenCurr.** of the concerned side or measuring location, and all phase currents are less than four times the rated current of the concerned side or measuring location, then the negative sequence current is fed into the current detector elements.

2.8.1.1 Definite Time Stages

The definite time characteristic is of two-stage design. When the negative sequence current exceeds the set threshold **I2>** the timer **T I2>** is started and a corresponding pickup message is output. When the negative sequence current exceeds the set threshold **I2>>** of the high-set stage the timer **T I2>>** is started and a corresponding pickup message is output.

When a delay time is expired trip command is issued (see Figure 2-85).

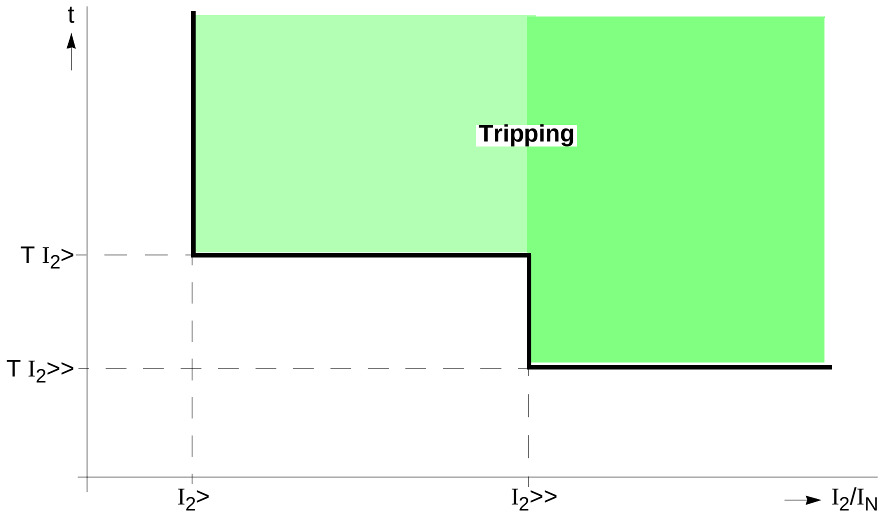


Figure 2-85 Trip characteristic of the definite time unbalanced load protection

2.8.1.2 Inverse Time Stage

The inverse time overcurrent stage operates with a tripping characteristic either according to the IEC- or the ANSI-standard. The characteristic curves and the corresponding equations are represented in the Technical Data (Figures 4-7 and 4-8 in Section 4.4). The inverse time characteristic superposes the definite time stages I_2>> and I_2> (see Subsection 2.8.1.1).

Pickup, Trip

The negative sequence current I_2 is compared with setting value **`I2p`**. When negative sequence current exceeds 1.1 times the setting value, a pickup annunciation is generated. The tripping time is calculated from the negative sequence current according to the characteristic selected. After expiration of the time period a tripping command is output. Figure 2-86 shows the qualitative course of the characteristic. In this figure the overlapping stage I_2>> is represented as a dashed line.

Dropout

You can determine whether the dropout of the stage is to follow right after the threshold undershot or whether it is evoked by disk emulation. “Right after” means that the pickup drops out when the pickup value of approx. 95 % is undershot. For a new pickup the time counter starts at zero.

The disk emulation evokes a dropout process (time counter is decrementing) which begins after de-energization. This process corresponds to the back turn of a Ferraris-disk (explaining its denomination “disk emulation”). In case several faults occur successively, it is ensured that due to the inertia of the Ferraris-disk the “history” is taken into consideration and the time behaviour is adapted. This ensures a proper simulation of the temperature rise of the protected object even for extremely fluctuating unbalanced load values. The reset begins as soon as 90 % of the setting value is undershot, in correspondence to the dropout curve of the selected characteristic. Within the range of the dropout value (approx. 95 % of the pickup value) and 90 % of the setting value, the incrementing and the decrementing processes are in idle state. If 5 % of the setting value is undershot, the dropout process is finished, i.e. when a new pickup is evoked, the timer starts again at zero.

Logic

Figure 2-87 shows the logic diagram of the unbalanced load protection. The protection may be blocked via a binary input. That way, pickups and time stages are reset.

When the tripping criterion leaves the operating range of the unbalanced load protection (all phase currents below the minimum current **`PoleOpenCurr.`** of the concerned measuring location or side or at least one phase current is greater than 4 · I_N), the pickups of all unbalanced load stages drop off.

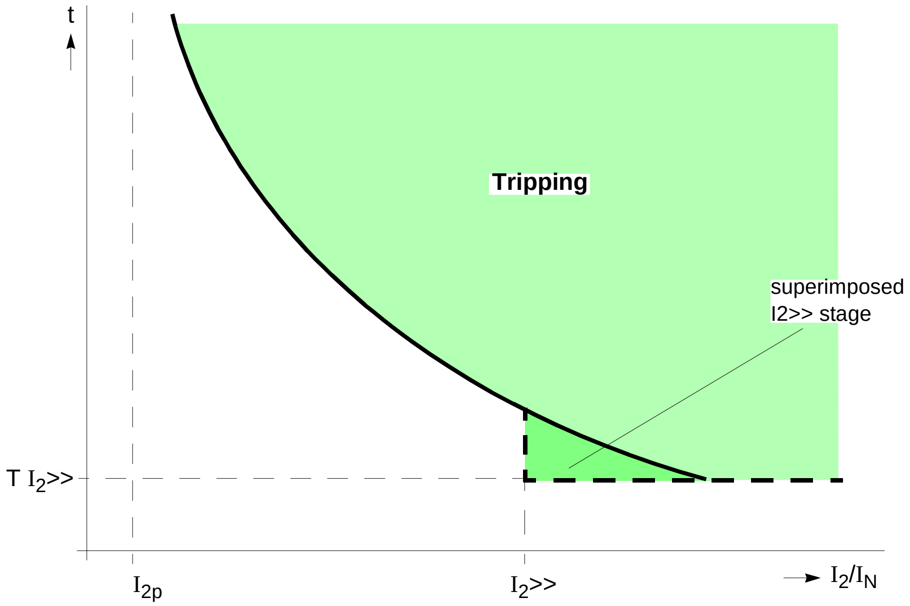


Figure 2-86 Trip characteristic of the inverse time unbalanced load protection (with superimposed definite time stage)

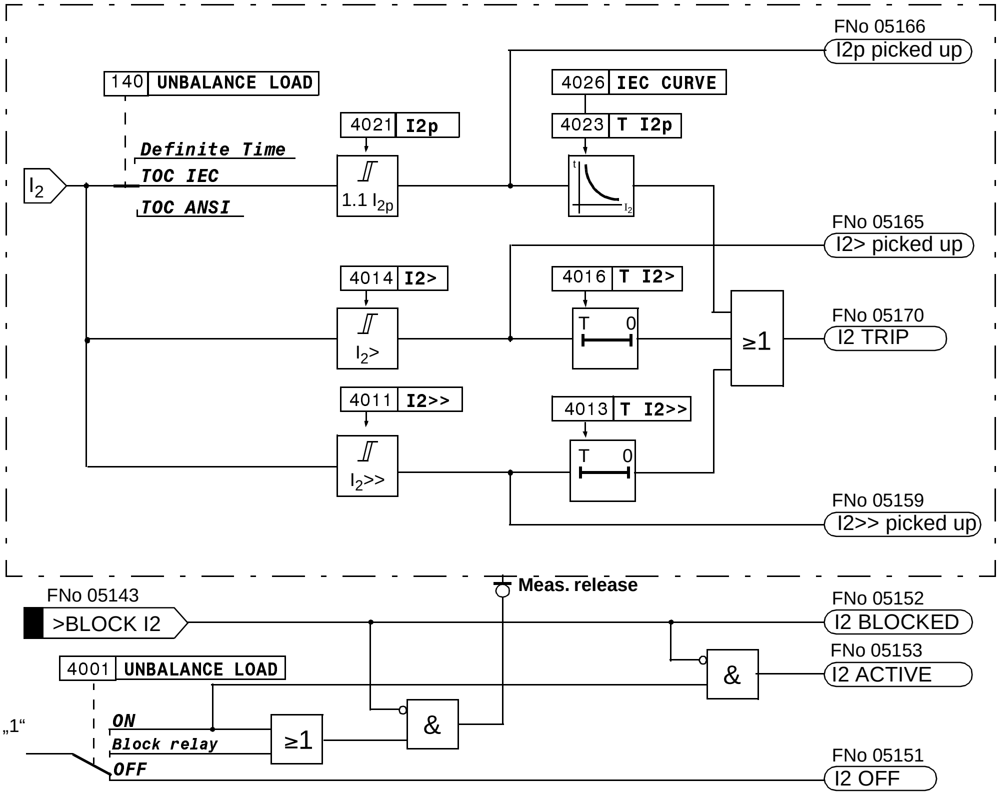


Figure 2-87 Logic diagram of the unbalanced load protection — illustrated for IEC characteristic (simplified)

2.8.2 Setting the Function Parameters

General

Unbalanced load protection only makes sense with three-phase protected objects. For **PROT. OBJECT** = ***1ph Busbar*** or ***1 phase transf.*** (address 105, see Subsection 2.1.1) the following settings are not available.

During configuration of the functional scope (Subsection 2.1.1, margin heading “Special Cases”, page 17) the type of characteristic was determined (address 140 **UNBALANCE LOAD**). In the following only settings for the characteristic selected can be performed. The definite time stages I_2>> and I_2> are always available.

The unbalanced load protection must have been assigned to a side of the main protected object or another 3-phase current measuring location (Subsection 2.1.4. under margin header “Further 3-Phase Protection Functions”). Consider also the assignment of the measured current inputs of the device against the measuring locations (current transformer sets) of the power plant (Subsection 2.1.2. under margin header “Assignment of 3-phase Measuring Locations”).

In address 4001 **UNBALANCE LOAD** the function can be set to ***ON*** or ***OFF***. The option ***Block relay*** allows to operate the protection but the trip output relay is blocked.

Note:

If the unbalanced protection is assigned to a side of the main protected object, the current values are set referred to the nominal current of that sided (I/I_{NS}) as stated in Subsection 2.1.3. In other cases, current values are set in amps.

Definite Time Stages I_2>>, I_2>

A two-stage characteristic enables the user to set a short time delay (address 4013 **`T I2>>`**) for the upper stage (address 4011 or 4012 **`I2>>`**) and longer time delay (address 4016 **`T I2>`**) for the lower stage (address 4014 or 4015 **`I2>`**). Stage I_2>, for example, can be used as alarm stage, stage I_2>> as tripping stage. Setting **`I2>>`** to a percentage higher than 60 % makes sure that no tripping is performed with stage I_2>> in case of phase failure.

The magnitude of the negative sequence current when one phase is lost, is

$$I_2 = \frac{1}{\sqrt{3}} \cdot I = 0.58 \cdot I$$

On the other hand, with more than 60 % negative sequence current, a two-phase fault in the system may be assumed. Therefore, the delay time **`T I2>>`** must be coordinated with the time grading of the system.

On line feeders, negative sequence protection may serve to identify low-current unsymmetrical faults below the pickup values of the time overcurrent protection. In this case:

- a two-phase fault with fault current I produces a negative sequence current

  $$I_2 = \frac{1}{\sqrt{3}} \cdot I = 0.58 \cdot I$$

- a single-phase fault with fault current I produces a negative sequence current

  $$I_2 = \frac{1}{3} \cdot I = 0.33 \cdot I$$

With more than 60 % negative sequence current, a two-phase fault can be assumed. The delay time **`T I2>>`** must be coordinated with the time grading of the system.

For a power transformer, negative sequence protection may be used as sensitive protection for low magnitude phase-to-ground and phase-to-phase faults. In particular, this application is well suited for delta-wye transformers where low side phase-to-ground faults do not generate a high side zero sequence current.

The relationship between negative sequence currents and total fault current for phase-to-phase faults and phase-to-ground faults are valid for the transformer as long as the turns ratio is taken into consideration.

Considering a power transformer with the following data:

Rated apparent power	S_{NT} = 16 MVA
Nominal high side voltage	U_{HS} = 110 kV
Nominal low side voltage	U_{LS} = 20 kV
Transformer connection	Dyn5
CTs high side	100 A/1 A

the following faults may be detected at the lower-voltage side:

If the pickup setting (PU) of the device on the high side is set to **I2>** = 0.1 A, then a single-phase fault current of $I_{F1} = 3 \cdot \frac{110\text{ kV}}{20\text{ kV}} \cdot \frac{100\text{ A}}{1\text{ A}} \cdot 0.1\text{ A} = 165\text{ A}$ and a two-phase fault of $I_{F2} = \sqrt{3} \cdot \frac{100\text{ kV}}{20\text{ kV}} \cdot \frac{100\text{ A}}{1\text{ A}} = 95\text{ A}$ can be detected on the low-voltage side. This corresponds to 36 % and 20 % of the power transformer rating.

To prevent false operation for faults in other zones of protection, the delay time **T I2>** must be coordinated with the time grading of other relays in the system.

For generators and motors, the setting depends on the permissible unbalanced load of the protected object. It is reasonable to set the I_2> stage to the continuously permissible negative sequence current and a long time delay in order to obtain an alarm stage. The I_2>> stage is then set to a short-term negative sequence current with the delay time permitted here.

Example:

Motor	$I_{N\,motor}$	= 545 A
	$I_{2prim} / I_{N\,motor}$	= 0,11 continuous
	$I_{2prim} / I_{N\,motor}$	= 0,55 for T_{max} = 1 s
Current transf.	$I_{N\,prim} / I_{N\,sec}$	= 600 A/1 A
Setting	$I_2>$	= 0.11 · 545 A = 60 A primary or 0.11 · 545 A · (1/600) = 0.10 A secondary
Setting	$I_2>>$	= 0.55 · 545 A = 300 A primary or 0,55 · 545 A · (1/600) = 0.50 A secondary
Delay	$T_{I2>>}$	= 1 s

To achieve a better adaptation to the protected object, use the additional inverse-time stage.

Inverse Time Stage I2p with IEC curves

Having selected an inverse time tripping characteristic the thermal load of a machine caused by unbalanced load can be simulated easily. Use the characteristic which is most similar to the thermal unbalanced load curve of the machine manufacturer.

With the IEC-characteristics (address 140 **UNBALANCE LOAD** = ***TOC IEC***, see also Subsection 2.1.1) the following characteristics are made available in address 4026 **IEC CURVE**:

Normal Inverse (type A according to IEC 60255–3),
Very Inverse (type B according to IEC 60255–3),
Extremely Inv. (type C according to IEC 60255–3).

The characteristics and equations they are based on are listed in the Technical Data (Section 4.4, Figure 4-7).

If an inverse-time characteristic is selected, it must be noted that a safety factor of about 1.1 has already been included between the pickup value and the setting value. This means that a pickup will only occur if an unbalanced load of about 1.1 times the setting value of **I2p** (Address 4021 or 4022) is present.

The corresponding time multiplier is accessible via address 4023 **T I2p**.

The time multiplier can also be set to ∞. If set to infinity, the pickup of this function will be indicated but the stage will not be able to trip after pickup. If the inverse time stage is not required, select address 140 **UNBALANCE LOAD** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

If ***Disk Emulation*** is set in address 4025 **I2p DROP-OUT**, dropout is being produced according to the dropout characteristic. For more information see Subsection 2.8.1.2, margin heading “Dropout” (page 173).

The above mentioned definite time stages can be used in addition to the inverse-time stage as alarm and tripping stages (see margin heading “Definite Time Stages I2>>, I2>”).

Inverse Time Stage I2p with ANSI curves

Having selected an inverse-time tripping characteristic the thermal load of a machine caused by unbalanced load can be simulated easily. Use the characteristic which is most similar to the thermal unbalanced load curve of the machine manufacturer.

With the ANSI characteristics (address 140 **UNBALANCE LOAD** = ***TOC ANSI***) the following is made available in address 4027 **ANSI CURVE**:

Extremely Inv.,
Inverse,
Moderately Inv., and
Very Inverse.

The characteristics and equations they are based on are listed in the Technical Data (Section 4.4, Figure 4-8).

If an inverse-time characteristic is selected, it must be noted that a safety factor of about 1.1 has already been included between the pickup value and the setting value. This means that a pickup will only occur if an unbalanced load of about 1.1 times the setting value of **I2p** (Address 4021 or 4022) is present.

The corresponding time multiplier is accessible via address 4024 **D I2p**.

The time multiplier can also be set to ∞. If set to infinity, the pickup of this function will be indicated but the stage will not be able to trip after pickup. If the inverse-time stage is not required, select address 140 **UNBALANCE LOAD** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

If ***Disk Emulation*** is set in address 4025 **I2p DROP-OUT**, dropout is being produced according to the dropout characteristic. For more information see Subsection 2.8.1.2, margin heading “Dropout” (page 173).

The above mentioned definite time stages can be used in addition to the inverse-time stage as alarm and tripping stages (see margin heading “Definite Time Stages I2>>, I2>”).

2.8.3 Setting Overview

If the unbalanced load protection is assigned to a side of the main protected object, the current values are set referred to the nominal current of that sided I/I_{NS} as stated in Subsection 2.1.3. In other cases, current values are set in amps. The setting ranges and the default settings are then stated for a rated secondary current I_N = 1 A. For a rated secondary current of I_N = 5 A these values have to be multiplied by 5.

Addr.	Setting Title	Setting Options	Default Setting	Comments
4001	UNBALANCE LOAD	OFF ON Block relay for trip commands	OFF	Unbalance Load (Negative Sequence)
4011	I2>>	0.10..3.00 A	0.50 A	I2>> Pickup
4012	I2>>	0.10..3.00 I/InS	0.50 I/InS	I2>> Pickup
4013	T I2>>	0.00..60.00 sec; ∞	1.50 sec	T I2>> Time Delay
4014	I2>	0.10..3.00 A	0.10 A	I2> Pickup
4015	I2>	0.10..3.00 I/InS	0.10 I/InS	I2> Pickup
4016	T I2>	0.00..60.00 sec; ∞	1.50 sec	T I2> Time Delay
4021	I2p	0.10..2.00 A	0.90 A	I2p Pickup
4022	I2p	0.10..2.00 I/InS	0.90 I/InS	I2p Pickup
4023	T I2p	0.05..3.20 sec; ∞	0.50 sec	T I2p Time Dial
4024	D I2p	0.50..15.00; ∞	5.00	D I2p Time Dial
4025	I2p DROP-OUT	Instantaneous Disk Emulation	Instantaneous	I2p Drop-out Characteristic
4026	IEC CURVE	Normal Inverse Very Inverse Extremely Inverse	Extremely Inverse	IEC Curve
4027	ANSI CURVE	Extremely Inverse Inverse Moderately Inverse Very Inverse	Extremely Inverse	ANSI Curve

2.8.4 Information Overview

F.No.	Alarm	Comments
05143	>BLOCK I2	>BLOCK I2 (Unbalance Load)
05151	I2 OFF	I2 switched OFF
05152	I2 BLOCKED	I2 is BLOCKED
05153	I2 ACTIVE	I2 is ACTIVE
05159	I2>> picked up	I2>> picked up
05165	I2> picked up	I2> picked up
05166	I2p picked up	I2p picked up
05170	I2 TRIP	I2 TRIP
05168	I2 Adap.fact.	I2 err.: adverse Adaption factor CT
05172	I2 Not avalia.	I2 err.: Not avaliable for this objekt

2.9 Thermal Overload Protection

The thermal overload protection prevents damage to the protected object caused by thermal overloading, particularly in case of power transformers, rotating machines, power reactors and cables. Two methods of overload detection are available in 7UT6:

- Overload calculation using a thermal replica according to IEC 60255-8,
- Calculation of the hot-spot temperature and determination of the ageing rate according to IEC 60354.

You may select one of these two methods. The first one is characterized by easy handling and setting, the second needs some knowledge about the protected object and its thermal characteristics and the input of the cooling medium temperature.

2.9.1 Overload Protection Using a Thermal Replica

Principle

The thermal overload protection of 7UT6 can be assigned to one of the sides of the main protected object (selectable), i.e. it evaluates the currents flowing at this side. Since the cause of overload is normally outside the protected object, the overload current is a through-flowing current.

The unit computes the temperature rise according to a thermal single-body model as per the following thermal differential equation

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

with Θ – actual valid temperature rise referred to the final temperature rise at maximum permissible current of the assigned side of the protected object $k \cdot I_{Nobj}$,

τ_{th} – thermal time constant for heating up of the protected object,

k – k-factor which states the maximum permissible continuous current, referred to the rated current of the assigned side of the protected object,

I – currently valid RMS current of the assigned side of the protected object,

I_{Nobj} – rated current of the assigned side of the protected object.

The solution of this equation under steady-state conditions is an e-function whose asymptote shows the final temperature rise Θ_{end}. When the temperature rise reaches the first settable temperature threshold Θ_{alarm}, which is below the final temperature rise, a warning alarm is given in order to allow an early load reduction. When the second temperature threshold, i.e. the final temperature rise or tripping temperature, is reached, the protected object is disconnected from the network. The overload protection can, however, also be set on ***Alarm Only***. In this case only an alarm is output when the final temperature rise is reached.

The temperature rises are calculated separately for each phase in a thermal replica from the square of the associated phase current. This guarantees a true RMS value measurement and also includes the effect of harmonic content. The maximum calculated temperature rise of the three phases is decisive for evaluation of the thresholds.

The maximum permissible continuous thermal overload current I_{max} is described as a multiple of the rated current I_{Nobj}:

$I_{max} = k \cdot I_{N obj}$

$I_{N obj}$ is the rated current of the assigned side of the protected object:

- For power transformers, the rated power of the assigned *winding* is decisive. The device calculates this rated current from the rated apparent power of the transformer and the rated voltage of the assigned winding. For transformers with tap changer, the non-regulated side must be used.
- For generators, motors, or reactors, the rated object current is calculated by the device from the set rated apparent power and the rated voltage.
- For short lines or busbars, the rated current was directly set.

In addition to the k-factor, the thermal time constant τ_{th} as well as the alarm temperature rise Θ_{alarm} must be entered into the protection.

Apart from the thermal alarm stage, the overload protection also includes a current overload alarm stage I_{alarm}, which can output an early warning that an overload current is imminent, even when the temperature rise has not yet reached the alarm or trip temperature rise values.

The overload protection can be blocked via a binary input. In doing so, the thermal replica are also reset to zero.

Extension of the Time Constant for Machines

The differential equation mentioned above assumes a constant cooling represented by the thermal time constant $\tau_{th} = R_{th} \cdot C_{th}$ (thermal resistance times thermal capacitance). But, the thermal time constant of a self-ventilated machine during stand-still differs substantially from that during operation because of the missing ventilation.

Thus, in this case, two time constants exist. This must be considered in the thermal replica.

Stand-still of the machine is assumed when the current drops below the threshold **`PoleOpenCurr.S1`** etc. (the minimum current of the feeding side below which the protected object is assumed to be switched off, refer also to “Circuit Breaker Status” in Subsection 2.1.9).

Motor Startup Recognition

On startup of electrical machines the temperature rise calculated by the thermal replica may exceed the alarm temperature rise or even the trip temperature rise. To avoid an alarm or trip, the starting current is acquired and the increase of temperature rise deriving from it is suppressed. This means that the calculated temperature rise is kept constant as long as the starting current is detected.

Emergency Starting of Machines

When machines must be started for emergency reasons, operating temperatures above the maximum permissible operating temperatures are allowed (emergency start). Then exclusively the tripping signal can be blocked via a binary input (”`>Emer.Start O/L`”). After startup and dropout of the binary input, the thermal replica may still be greater than the trip temperature rise. Therefore the thermal replica features a settable run-on time (**`T EMERGENCY`**) which is started when the binary input drops out. It also suppresses the trip command. Tripping by the overload protection will be defeated until this time interval elapses. This binary input only affects the trip command. There is no effect on fault recording, nor does the thermal replica reset.

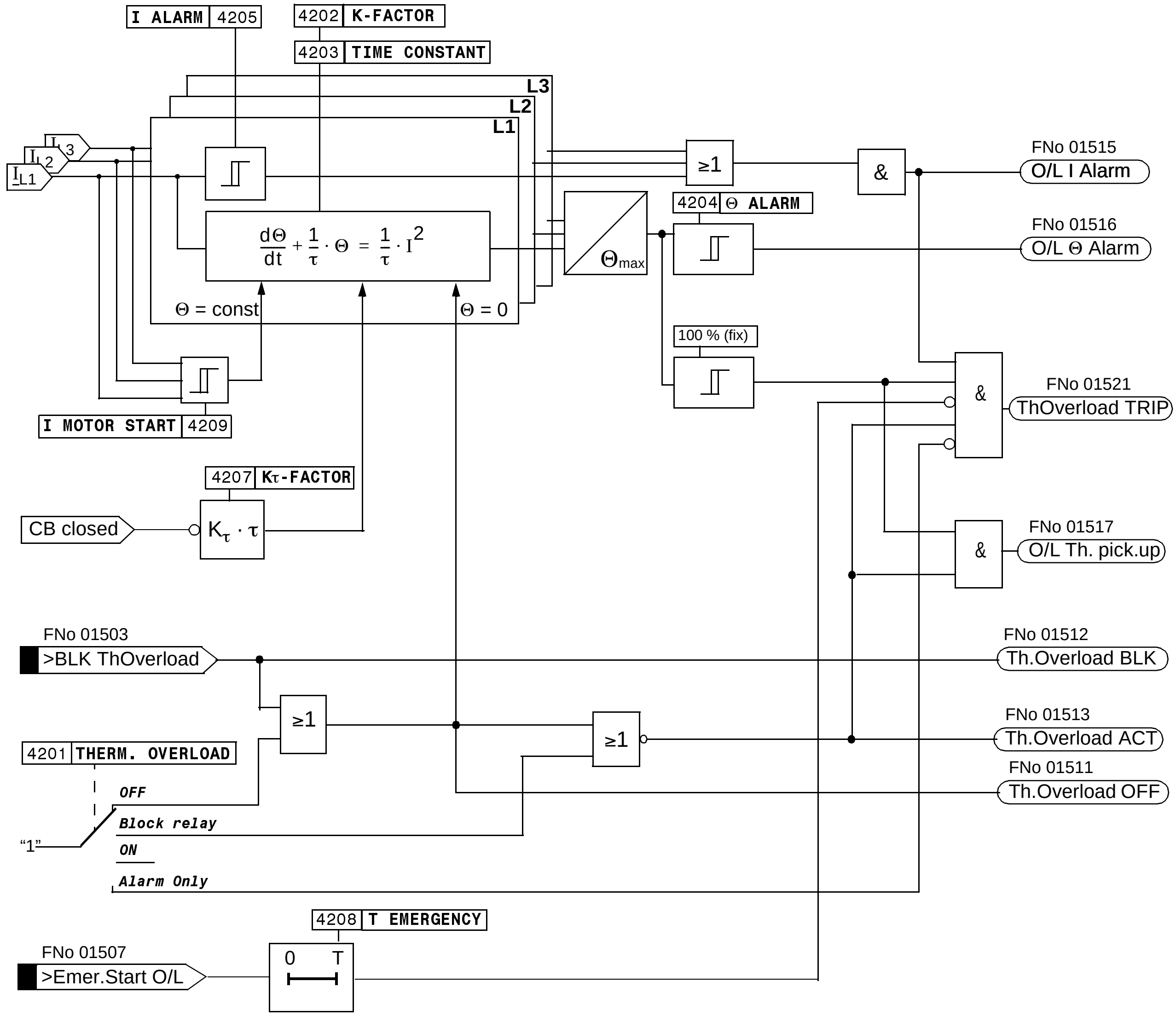


Figure 2-88 Logic diagram of the thermal overload protection (simplified)

2.9.2 Hot-Spot Calculation and Determination of the Ageing Rate

The overload calculation according to IEC 60354 calculates two quantities relevant for the protection function: the relative ageing and the hot-spot temperature in the protected object. The user can install up to 12 temperature measuring points (RTD = Resistance Temperature Detector) in the protected object. Via one or two RTD-boxes and a serial data connection the measuring points inform the overload protection of the 7UT6 about the local coolant temperature. *One* of these points is selected to form the relevant point for hot-spot calculation. This point shall be situated at the insulation of the upper inner turn of the winding since this is the location of the hottest temperature.

The relative ageing is acquired cyclically and summed up to a total ageing sum.

Cooling Methods

The hot-spot calculation is dependent on the cooling method. Air cooling is always available. Two different methods are distinguished:

- **AN** (**A**ir **N**atural): natural air circulation and
- **AF** (**A**ir **F**orced): forced air circulation (ventilation).

If liquid coolants are used in combination with the two cooling methods above-described, the following types of coolants exist:

- **ON** (**O**il **N**atural = naturally circulating oil): Because of emerging differences in temperature the coolant (oil) circulates within the tank. The cooling effect is not very intense due to its natural convection. This cooling variant, however, is almost noiseless.
- **OF** (**O**il **F**orced = forced oil circulation): An oil pump makes the coolant (oil) move within the tank. The cooling effect of this method is therefore more intense than with the ON method.
- **OD** (**O**il **D**irected = forced-directed oil circulation): The coolant (oil) is directed through the tank. Therefore the oil flow is intensified for sections which are extremely temperature-intensive. Therefore, the cooling effect is very good. This method has the lowest temperature rise.

Figures 2-89 to 2-91 show examples of the cooling methods.

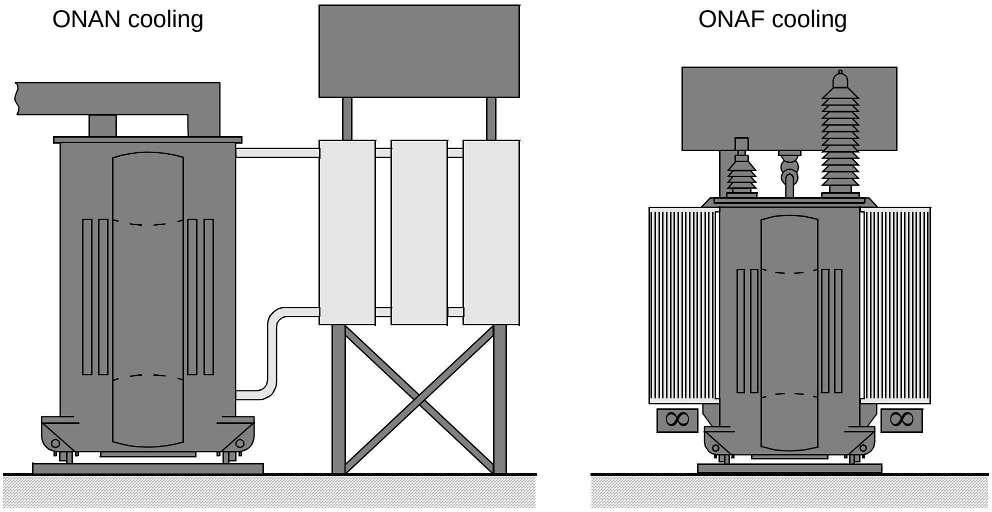


Figure 2-89 ON cooling (Oil Natural)

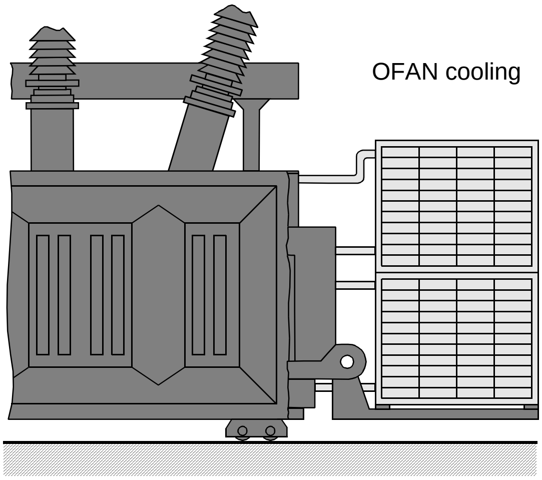


Figure 2-90 OF cooling (Oil Forced)

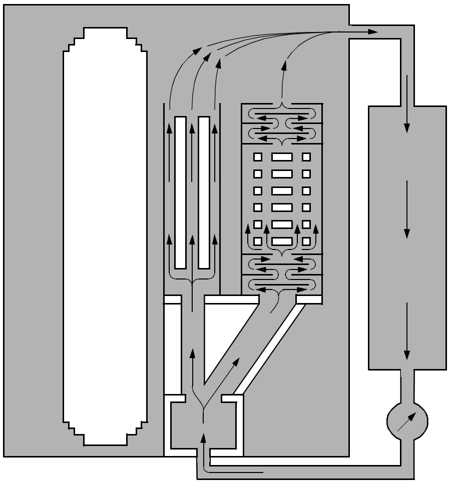


Figure 2-91 OD cooling (Oil Directed)

Hot-Spot Calculation

The hot-spot temperature of the protected object is an important value of status. The hottest spot relevant for the life-time of the transformer is usually situated at the insulation of the upper inner turn. Generally the temperature of the coolant increases from the bottom up. The cooling method, however, affects the temperature gradient.

The hot-spot temperature is composed of two parts:
the temperature at the hottest spot of the coolant (included via RTD-box),
the temperature rise of the winding turn caused by the transformer load.

RTD-box 7XV566 can be used to acquire the temperature of the hottest spot. It converts the temperature value into numerical signals and sends them to the corresponding interface of device 7UT6. The RTD-box is able to acquire the temperature at up to 6 points of the transformer tank. Up to two RTD-boxes of this types can be connected to a 7UT6.

The device calculates the hot-spot temperature from these data and the settings of the characteristical properties. When a settable threshold (temperature alarm) is exceeded, an annunciation and/or a trip is generated.

Hot-spot calculation is done with different equations depending on the cooling method.

For **ON**-cooling and **OF**-cooling:

$$\Theta_h = \Theta_o + H_{gr} \cdot k^Y$$

with

Θ_h	hot-spot temperature
Θ_o	top oil temperature
H_{gr}	hot-spot to top-oil gradient
k	load factor I/I_N (measured)
Y	winding exponent

For **OD**-cooling:

$$\Theta_h = \Theta_o + H_{gr} \cdot k^Y \qquad \text{for } k \le 1$$

$$\Theta_h = \Theta_o + H_{gr} \cdot k^Y + 0{,}15 \cdot [(\Theta_o + H_{gr} \cdot k^Y) - 98\ ^\circ\mathrm{C}] \qquad \text{for } k > 1$$

In this aspect, the load factor I/I_N is determined from the currents of that side to which the overload protection is assigned. The phase information is taken from the concerned phase in case of generators, motors, etc., or wye- or zigzag-connected transformer windings; in case of delta-connected transformer windings the difference current is taken. The nominal current I_N is that of the corresponding side.

Ageing Rate Calculation

The life-time of a cellulose insulation refers to a temperature of 98 °C or 208.4 °F in the direct environment of the insulation. Experience shows that an increase of 6 K results in half of the life-time. For a temperature which defers from the basic value of 98 °C (208.4 °F), the relative ageing rate V is given by

$$V = \frac{\text{Ageing at } \Theta_h}{\text{Ageing at } 98^\circ\ \mathrm{C}} = 2^{(\Theta_h - 98)/6}$$

The mean value of the relative ageing rate L is given by the calculation of the mean value of a certain period of time, i.e. from T_1 to T_2:

$$L = \frac{1}{T_2 - T_1} \cdot \int_{T_1}^{T_2} V\, dt$$

With constant rated load, the relative ageing rate L is equal to 1. For values greater than 1, accelerated ageing applies, e.g. if L = 2 only half of the life-time is expected compared to the life-time under nominal load conditions.

According to IEC, the ageing range is defined from 80 °C to 140 °C (176 °F to 284 °F). This is the operating range of the ageing calculation in 7UT6: Temperatures below 80 °C (176 °F) do not extent the calculated ageing rate; values greater than 140 °C (284 °F) do not reduce the calculated ageing rate.

The above-described relative ageing calculation only applies to the insulation of the winding and cannot be used for other failure causes.

Output of Results

The hot-spot temperature is calculated for the winding which corresponds to the side of the main protected object assigned to the overload protection (Subsection 2.1.4 under margin header “Further 3-Phase Protection Functions”, page 49). The calculation includes the current of that side and the cooling temperature measured at a certain measuring point. The phase information is taken from the concerned phase in case of generators, motors, etc., or wye- or zigzag-connected transformer windings; in case of delta-connected transformer windings the phase-difference currents are decisive which correspond to the current flowing in the winding.

There are two thresholds which can be set: The output a warning (Stage 1) and an alarm (Stage 2) signal. When the alarm signal is assigned to a trip output, it can also be used for tripping the circuit breaker(s).

For the middle ageing rate, there is also a threshold for each of the warning and the alarm signal.

The status can be read out from the operational measured values at any time. The information includes:

- hot-spot temperature for each winding in °C or °F (as configured),
- relative ageing rate expressed in per unit,
- load reserve up to warning signal (Stage 1) expressed in per cent,
- load reserve up to alarm signal (Stage 2) expressed in per cent.

2.9.3 Setting the Function Parameters

General

The overload protection can be assigned to any desired side of the main protected object. Since the cause of the overload current is outside the protected object, the overload current is a through-flowing current, the overload protection may be assigned to a feeding or a non-feeding side. When setting the assignment of the protection functions to the sides of the protected object according to Subsection 2.1.4 (margin header “Further 3-Phase Protection Functions”, page 49) you have performed this assignment under address `442`. Respective notes are given there.

There are two methods for evaluation of overload conditions in 7UT6, as explained above. During configuration of the protection function (Subsection 2.1.1), you had already decided under address `142` **`THERM. OVERLOAD`**, whether the protection shall operate according to the method of a thermal replica (**`THERM. OVERLOAD`** = ***`thermal replica`***) or whether the calculation of the hot-spot temperature according to IEC 60354 (**`THERM. OVERLOAD`** = ***`IEC354`***) shall be carried out. In the latter case, at least one RTD-box 7XV566 must be connected to the device in order to inform the device about the cooling medium temperature. The data concerning the RTD-box were entered to the device under address `191` **`RTD CONNECTION`** (Subsection 2.1.1).

The thermal overload protection can be switched ***`ON`*** or ***`OFF`*** under address `4201` **`THERM. OVERLOAD`**. The option ***`Block relay`*** allows to operate the protection but the trip output relay is blocked. Furthermore ***`Alarm Only`*** can be set. With that latter setting the protection function is active but only outputs an alarm when the tripping temperature rise is reached, i.e. the output function “`ThOverload TRIP`” is not active.

k-Factor

The rated current of the side of the main protected object which is assigned to the overload protection is taken as the base current for detecting an overload. The factor k is set under address 4202 **K-FACTOR**. It is determined by the relation between the permissible thermal continuous current and this rated current:

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

When using the method with a thermal replica, it is not necessary to evaluate any absolute temperature nor the trip temperature since the trip temperature rise is equal to the final temperature rise at $k \cdot I_{Nobj}$. Manufacturers of electrical machines usually state the permissible continuous current. If no data are available, k is set to 1.1 times the rated current of the assigned side of the protected object. For cables, the permissible continuous current depends on the cross-section, the insulation material, the design and the method of installation, and can be derived from the relevant tables.

When using the method with hot-spot evaluation according to IEC 60354, set k = 1 since all remaining parameters are referred to the rated current of the assigned side of the protected object.

Time Constant τ for Thermal Replica

The thermal time constant τ_{th} is set under the address 4203 **TIME CONSTANT**. This is also to be stated by the manufacturer. Please note that the time constant is set in minutes. Quite often other values are stated which can be converted into the time constant as follows:

- 1-s current
  $$\frac{\tau_{th}}{min} = \frac{1}{60} \cdot \left(\frac{\text{permissible 1-s current}}{\text{permissible continuous current}}\right)^2$$
- permissible current for application time other than 1 s, e.g. for 0.5 s
  $$\frac{\tau_{th}}{min} = \frac{0.5}{60} \cdot \left(\frac{\text{permissible 0.5-s current}}{\text{permissible continuous current}}\right)^2$$
- t_6-time; this is the time in seconds for which a current of 6 times the rated current of the protected object may flow
  $$\frac{\tau_{th}}{min} = 0.6 \cdot t_6$$

<u>Calculation examples:</u>

Cable with

permissible continuous current	322 A
permissible 1-s current	13.5 kA

$$\frac{\tau_{th}}{min} = \frac{1}{60} \cdot \left(\frac{13500\ A}{322\ A}\right)^2 = \frac{1}{60} \cdot 42^2 = 29.4$$

Setting value **TIME CONSTANT** = ***29.4*** min.

Motor with t_6-time = 12 s

$$\frac{\tau_{th}}{min} = 0.6 \cdot 12\ s = 7.2$$

Setting value **TIME CONSTANT** = ***7.2*** min.

For rotating machines, the time constant as set under address 4203 **TIME CONSTANT** is valid as long as the machine is running. The machine will cool down extensively slower during stand-still or running down if it is self-ventilated. This phenomenon is considered by a higher stand-still time constant **Kτ-FACTOR** (address 4207A) which is set as a factor of the normal time constant. This parameter can only be altered with DIGSI® under "**Additional Settings**".

If it not necessary to distinguish between different time constants, leave the factor **Kτ-FACTOR** at ***1*** (default setting).

Alarm Stages with Thermal Replica

By setting a thermal alarm stage Θ **ALARM** (address 4204) an alarm can be output before the tripping temperature is reached, so that a trip can be avoided by early load reduction or by switching over. The percentage is referred to the tripping temperature rise. Note that the final temperature rise is proportional to the square of the current.

Example:

k-factor = 1.1
Alarm shall be given when the temperature rise reaches the final (steady-state) temperature rise at nominal current.

$$\Theta_{\text{alarm}} = \frac{1}{1.1^2} = 0.826$$

Setting value Θ **ALARM** = ***82*** %.

The current overload alarm setpoint **I ALARM** (address 4205) is stated referred to the rated current of the applicable side and should be set equal to or slightly below the permissible continuous current $k \cdot I_{\text{Nobj}}$. It can also be used *instead* of the thermal alarm stage. In this case the thermal alarm stage is set to 100 % and thus practically ineffective.

Emergency Start for Motors

The run-on time value to be entered at address 4208A **T EMERGENCY** must ensure that after an emergency start and dropout of the binary input ">Emer.Start O/L" the trip command is blocked until the thermal replica has fallen below the dropout threshold. This parameter can only be altered with DIGSI® under "**Additional Settings**".

The startup itself is only recognized if the startup current **I MOTOR START** set in address 4209A is exceeded. Under each load and voltage condition during motor start, the value must be overshot by the actual startup current. With short-time permissible overload the value must not be reached. For other protected objects the setting ∞ will not be changed. Thus the emergency start is disabled.

Temperature Detectors

For the hot-spot calculation according to IEC 60354 the device must be informed on the type of resistance temperature detectors (RTD) that will be used for measuring the oil temperature, the one relevant for the hot-spot calculation and ageing determination. Up to 6 sensors can be used with one RTD-box 7XV566, with 2 boxes up to 12 sensors. In address 4221 **OIL-DET. RTD** the identification number of the resistance temperature detector decisive for hot-spot calculation is set.

The characteristic values of the temperature detectors are set separately, see Section 2.10.

Hot-Spot Stages

There are two annunciation stages for the hot-spot temperature. To set a specific hot-spot temperature value (expressed in °C) which is meant to generate the warning signal (Stage 1), use address 4222 **HOT SPOT ST. 1**. Use address 4224 **HOT SPOT ST. 2** to indicate the corresponding alarm temperature (Stage 2). Optionally, it can be used for tripping of circuit breakers if the outgoing message “O/L h.spot TRIP” (FNo 01542) is allocated to a trip relay.

If address 276 **TEMP. UNIT** = ***Fahrenheit*** is set (Subsection 2.1.3, margin heading “Temperature Unit”), thresholds for warning and alarm temperatures are expressed in Fahrenheit degrees (addresses 4223 and 4225).

If the temperature unit is changed in address 276 after having set the thresholds for temperature, these thresholds for the temperature unit changed must be set again in the corresponding addresses.

Ageing Rate

For ageing rate L thresholds can also be set, i.e. for the warning signal (Stage 1) in address 4226 **AG. RATE ST. 1** and for alarm signal (Stage 2) in address 4227 **AG. RATE ST. 2**. This information is referred to the relative ageing, i.e. L = 1 is reached at 98 °C or 208 °F at the hot spot. L > 1 means an accelerated ageing, L < 1 a delayed ageing.

Cooling Method and Insulation Data

Set in address 4231 **METH. COOLING** which cooling method is used: ***ON*** = Oil Natural for natural cooling, ***OF*** = Oil Forced for oil forced cooling or ***OD*** = Oil Directed for oil directed cooling. For definitions see also Subsection 2.9.2, margin heading “Cooling Methods”.

For hot-spot calculation the device requires the winding exponent Y and the hot-spot to top-oil gradient H_{gr} which is set in addresses 4232 **Y-WIND.EXPONENT** and 4233 **HOT-SPOT GR**. If the corresponding information is not available, it can be taken from the IEC 60354. An extract from the applicable table of the standard with the technical data relevant for this project can be found hereinafter (Table 2-7).

Table 2-7 Thermal characteristics of power transformers

		Distribution transformers	Medium and large power transformers		
Cooling method:		ONAN	ON..	OF..	OD..
Winding exponent	Y	1.6	1.8	1.8	2.0
Hot-spot to top-oil gradient	H_{gr}	23	26	22	29

2.9.4 Setting Overview

Note: Addresses which have an “A” attached to their end can only be changed in DIGSI®, under “**Additional Settings**”. The referred current values I/I_{NS} are set referred to the nominal current of the assigned side of the protected object as stated in Subsection 2.1.3.

Addr.	Setting Title	Setting Options	Default Setting	Comments
4201	THERM. OVERLOAD	OFF ON Block relay for trip commands Alarm Only	OFF	Thermal Overload Protection
4202	K-FACTOR	0.10..4.00	1.10	K-Factor
4203	TIME CONSTANT	1.0..999.9 min	100.0 min	Thermal Time Constant
4204	Θ ALARM	50..100 %	90 %	Thermal Alarm Stage
4205	I ALARM	0.10..4.00 I/InS	1.00 I/InS	Current Overload Alarm Setpoint
4207A	Kτ-FACTOR	1.0..10.0	1.0	Kt-FACTOR when motor stops
4208A	T EMERGENCY	10..15000 sec	100 sec	Emergency Time
4209A	I MOTOR START	0.60..10.00 I/InS; ∞	∞ I/InS	Current Pickup Value of Motor Starting
4221	OIL-DET. RTD	1..6	1	Oil-Detector conected at RTD
4222	HOT SPOT ST. 1	98..140 °C	98 °C	Hot Spot Temperature Stage 1 Pickup
4223	HOT SPOT ST. 1	208..284 °F	208 °F	Hot Spot Temperature Stage 1 Pickup
4224	HOT SPOT ST. 2	98..140 °C	108 °C	Hot Spot Temperature Stage 2 Pickup
4225	HOT SPOT ST. 2	208..284 °F	226 °F	Hot Spot Temperature Stage 2 Pickup
4226	AG. RATE ST. 1	0.125..128.000	1.000	Aging Rate STAGE 1 Pickup
4227	AG. RATE ST. 2	0.125..128.000	2.000	Aging Rate STAGE 2 Pickup
4231	METH. COOLING	ON (Oil-Natural) OF (Oil-Forced) OD (Oil-Directed)	ON (Oil-Natural)	Method of Cooling
4232	Y-WIND.EXPONENT	1.6..2.0	1.6	Y-Winding Exponent
4233	HOT-SPOT GR	22..29	22	Hot-spot to top-oil gradient

2.9.5 Information Overview

F.No.	Alarm	Comments
01503	>BLK ThOverload	>BLOCK Thermal Overload Protection
01507	>Emer.Start O/L	>Emergency start Th. Overload Protection
01511	Th.Overload OFF	Thermal Overload Protection OFF
01512	Th.Overload BLK	Thermal Overload Protection BLOCKED
01513	Th.Overload ACT	Thermal Overload Protection ACTIVE
01515	O/L I Alarm	Th. Overload Current Alarm (I alarm)
01516	O/L Θ Alarm	Thermal Overload Alarm
01517	O/L Th. pick.up	Thermal Overload picked up
01521	ThOverload TRIP	Thermal Overload TRIP
01541	O/L ht.spot Al.	Thermal Overload hot spot Th. Alarm
01542	O/L h.spot TRIP	Thermal Overload hot spot Th. TRIP
01543	O/L ag.rate Al.	Thermal Overload aging rate Alarm
01544	O/L ag.rt. TRIP	Thermal Overload aging rate TRIP
01546	O/L Adap.fact.	Th. Overload err.:adverse Adap.factor CT
01545	O/L No Th.meas.	Th. Overload No temperature mesured
01549	O/L Not avail.	Th. Overload Not available for this obj.

2.10 RTD-Boxes for Overload Detection

For overload protection with hot-spot calculation and relative ageing rate determination, the temperature of the hottest spot of the coolant is required. At least one resistance temperature detector (RTD) must be installed at the hot-spot location which informs the device about this temperature via a RTD-box 7XV566. One RTD-box is able to process up to 6 RTDs. One or two RTD-boxes can be connected to the 7UT6.

2.10.1 Function Description

An RTD-box 7XV566 is suited for up to 6 measuring points (RTDs) in the protected object, e.g. in the transformer tank. The RTD-box takes the coolant temperature of each measuring point from the resistance value of the temperature detectors connected with a two- or three-wire line (Pt100, Ni100 or Ni120) and converts it to a digital value. The digital values are output at the serial interface RS485.

One or two RTD-boxes can be connected to the service or additional interface of the 7UT6. Thus, up to 6 or 12 measuring points (RTDs) can be processed. For each temperature detector, characteristic data as well as alarm (stage 1) and trip (stage 2) temperature can be set.

The RTD-box also acquires thresholds of each single measuring point. The information is then passed on via an output relay. For further information refer to the instruction manual of the RTD-box.

2.10.2 Setting the Function Parameters

For RTD1 (temperature detector for measuring point 1) the type of temperature detector is set in address 9011A **RTD 1 TYPE**. ***Pt 100*** Ω, ***Ni 120*** Ω and ***Ni 100*** Ω are available. If there is no measuring point for RTD1, set **RTD 1 TYPE** = ***Not connected***. This parameter can only be altered with DIGSI® under “**Additional Settings**”.

Address 9012A **RTD 1 LOCATION** informs the device on the mounting location of RTD1. ***Oil***, ***Ambient***, ***Winding***, ***Bearing*** and ***Other*** are available. This parameter can only be altered with DIGSI® under “**Additional Settings**”.

Furthermore, alarm and trip temperature can be set. Depending on the temperature unit selected in the Power System Data (Subsection 2.1.3 in address 276 **TEMP. UNIT**, page 36), the alarm temperature can be expressed in Celsius (°C) (address 9013 **RTD 1 STAGE 1**) or Fahrenheit (°F) (address 9014 **RTD 1 STAGE 1**). The trip temperature expressed in Celsius (°C) is set in address 9015 **RTD 1 STAGE 2**. To express it in Fahrenheit (°F) use address 9016 **RTD 1 STAGE 2**.

For other temperature detectors connected to the first RTD-box make settings correspondingly:

for RTD2 address 9021A **RTD 2 TYPE**,
address 9022A **RTD 2 LOCATION**,
address 9023 **RTD 2 STAGE 1** (in °C) or 9024 **RTD 2 STAGE 1** (°F),
address 9025 **RTD 2 STAGE 2** (in °C) or 9026 **RTD 2 STAGE 2** (°F);

for RTD3 address 9031A **RTD 3 TYPE**,
address 9032A **RTD 3 LOCATION**,
address 9033 **RTD 3 STAGE 1** (in °C) or 9034 **RTD 3 STAGE 1** (°F),
address 9035 **RTD 3 STAGE 2** (in °C) or 9036 **RTD 3 STAGE 2** (°F);

for RTD4 address 9041A **RTD 4 TYPE**,
address 9042A **RTD 4 LOCATION**,
address 9043 **RTD 4 STAGE 1** (in °C) or 9044 **RTD 4 STAGE 1** (°F),
address 9045 **RTD 4 STAGE 2** (in °C) or 9046 **RTD 4 STAGE 2** (°F);

for RTD5 address 9051A **RTD 5 TYPE**,
address 9052A **RTD 5 LOCATION**,
address 9053 **RTD 5 STAGE 1** (in °C) or 9054 **RTD 5 STAGE 1** (°F),
address 9055 **RTD 5 STAGE 2** (in °C) or 9056 **RTD 5 STAGE 2** (°F);

for RTD6 address 9061A **RTD 6 TYPE**,
address 9062A **RTD 6 LOCATION**,
address 9063 **RTD 6 STAGE 1** (in °C) or 9064 **RTD 6 STAGE 1** (°F),
address 9065 **RTD 6 STAGE 2** (in °C) or 9066 **RTD 6 STAGE 2** (°F);

If two RTD-boxes are connected, information for further temperature detectors can be set:

for RTD7 address 9071A **RTD 7 TYPE**,
address 9072A **RTD 7 LOCATION**,
address 9073 **RTD 7 STAGE 1** (in °C) or 9074 **RTD 7 STAGE 1** (°F),
address 9075 **RTD 7 STAGE 2** (in °C) or 9076 **RTD 7 STAGE 2** (°F);

for RTD8 address 9081A **RTD 8 TYPE**,
address 9082A **RTD 8 LOCATION**,
address 9083 **RTD 8 STAGE 1** (in °C) or 9084 **RTD 8 STAGE 1** (°F),
address 9085 **RTD 8 STAGE 2** (in °C) or 9086 **RTD 8 STAGE 2** (°F);

for RTD9 address 9091A **RTD 9 TYPE**,
address 9092A **RTD 9 LOCATION**,
address 9093 **RTD 9 STAGE 1** (in °C) or 9094 **RTD 9 STAGE 1** (°F),
address 9095 **RTD 9 STAGE 2** (in °C) or 9096 **RTD 9 STAGE 2** (°F);

for RTD10 address 9101A **RTD10 TYPE**,
address 9102A **RTD10 LOCATION**,
address 9103 **RTD10 STAGE 1** (in °C) or 9104 **RTD10 STAGE 1** (°F),
address 9105 **RTD10 STAGE 2** (in °C) or 9106 **RTD10 STAGE 2** (°F);

for RTD11 address 9111A **RTD11 TYPE**,
address 9112A **RTD11 LOCATION**,
address 9113 **RTD11 STAGE 1** (in °C) or 9114 **RTD11 STAGE 1** (°F),
address 9115 **RTD11 STAGE 2** (in °C) or 9116 **RTD11 STAGE 2** (°F);

for RTD12 address 9121A **RTD12 TYPE**,
address 9122A **RTD12 LOCATION**,
address 9123 **RTD12 STAGE 1** (in °C) or 9124 **RTD12 STAGE 1** (°F),
address 9125 **RTD12 STAGE 2** (in °C) or 9126 **RTD12 STAGE 2** (°F).

2.10.3 Setting Overview

Note: Addresses which have an “A” attached to their end can only be changed in DIGSI®, under “**Additional Settings**”.

Addr.	Setting Title	Setting Options	Default Setting	Comments
9011A	RTD 1 TYPE	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	Pt 100 Ohm	RTD 1: Type
9012A	RTD 1 LOCATION	Oil Ambient Winding Bearing Other	Oil	RTD 1: Location
9013	RTD 1 STAGE 1	-50..250 °C; ∞	100 °C	RTD 1: Temperature Stage 1 Pickup
9014	RTD 1 STAGE 1	-58..482 °F; ∞	212 °F	RTD 1: Temperature Stage 1 Pickup
9015	RTD 1 STAGE 2	-50..250 °C; ∞	120 °C	RTD 1: Temperature Stage 2 Pickup
9016	RTD 1 STAGE 2	-58..482 °F; ∞	248 °F	RTD 1: Temperature Stage 2 Pickup
9021A	RTD 2 TYPE	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 2: Type
9022A	RTD 2 LOCATION	Oil Ambient Winding Bearing Other	Other	RTD 2: Location
9023	RTD 2 STAGE 1	-50..250 °C; ∞	100 °C	RTD 2: Temperature Stage 1 Pickup
9024	RTD 2 STAGE 1	-58..482 °F; ∞	212 °F	RTD 2: Temperature Stage 1 Pickup
9025	RTD 2 STAGE 2	-50..250 °C; ∞	120 °C	RTD 2: Temperature Stage 2 Pickup
9026	RTD 2 STAGE 2	-58..482 °F; ∞	248 °F	RTD 2: Temperature Stage 2 Pickup
9031A	RTD 3 TYPE	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 3: Type

Addr.	Setting Title	Setting Options	Default Setting	Comments
9032A	RTD 3 LOCATION	Oil Ambient Winding Bearing Other	Other	RTD 3: Location
9033	RTD 3 STAGE 1	-50..250 °C; ∞	100 °C	RTD 3: Temperature Stage 1 Pickup
9034	RTD 3 STAGE 1	-58..482 °F; ∞	212 °F	RTD 3: Temperature Stage 1 Pickup
9035	RTD 3 STAGE 2	-50..250 °C; ∞	120 °C	RTD 3: Temperature Stage 2 Pickup
9036	RTD 3 STAGE 2	-58..482 °F; ∞	248 °F	RTD 3: Temperature Stage 2 Pickup
9041A	RTD 4 TYPE	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 4: Type
9042A	RTD 4 LOCATION	Oil Ambient Winding Bearing Other	Other	RTD 4: Location
9043	RTD 4 STAGE 1	-50..250 °C; ∞	100 °C	RTD 4: Temperature Stage 1 Pickup
9044	RTD 4 STAGE 1	-58..482 °F; ∞	212 °F	RTD 4: Temperature Stage 1 Pickup
9045	RTD 4 STAGE 2	-50..250 °C; ∞	120 °C	RTD 4: Temperature Stage 2 Pickup
9046	RTD 4 STAGE 2	-58..482 °F; ∞	248 °F	RTD 4: Temperature Stage 2 Pickup
9051A	RTD 5 TYPE	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 5: Type
9052A	RTD 5 LOCATION	Oil Ambient Winding Bearing Other	Other	RTD 5: Location
9053	RTD 5 STAGE 1	-50..250 °C; ∞	100 °C	RTD 5: Temperature Stage 1 Pickup
9054	RTD 5 STAGE 1	-58..482 °F; ∞	212 °F	RTD 5: Temperature Stage 1 Pickup
9055	RTD 5 STAGE 2	-50..250 °C; ∞	120 °C	RTD 5: Temperature Stage 2 Pickup

Addr.	Setting Title	Setting Options	Default Setting	Comments
9056	RTD 5 STAGE 2	-58..482 °F; ∞	248 °F	RTD 5: Temperature Stage 2 Pickup
9061A	RTD 6 TYPE	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 6: Type
9062A	RTD 6 LOCATION	Oil Ambient Winding Bearing Other	Other	RTD 6: Location
9063	RTD 6 STAGE 1	-50..250 °C; ∞	100 °C	RTD 6: Temperature Stage 1 Pickup
9064	RTD 6 STAGE 1	-58..482 °F; ∞	212 °F	RTD 6: Temperature Stage 1 Pickup
9065	RTD 6 STAGE 2	-50..250 °C; ∞	120 °C	RTD 6: Temperature Stage 2 Pickup
9066	RTD 6 STAGE 2	-58..482 °F; ∞	248 °F	RTD 6: Temperature Stage 2 Pickup
9071A	RTD 7 TYPE	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 7: Type
9072A	RTD 7 LOCATION	Oil Ambient Winding Bearing Other	Other	RTD 7: Location
9073	RTD 7 STAGE 1	-50..250 °C; ∞	100 °C	RTD 7: Temperature Stage 1 Pickup
9074	RTD 7 STAGE 1	-58..482 °F; ∞	212 °F	RTD 7: Temperature Stage 1 Pickup
9075	RTD 7 STAGE 2	-50..250 °C; ∞	120 °C	RTD 7: Temperature Stage 2 Pickup
9076	RTD 7 STAGE 2	-58..482 °F; ∞	248 °F	RTD 7: Temperature Stage 2 Pickup
9081A	RTD 8 TYPE	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 8: Type
9082A	RTD 8 LOCATION	Oil Ambient Winding Bearing Other	Other	RTD 8: Location
9083	RTD 8 STAGE 1	-50..250 °C; ∞	100 °C	RTD 8: Temperature Stage 1 Pickup

Addr.	Setting Title	Setting Options	Default Setting	Comments
9084	RTD 8 STAGE 1	-58..482 °F; ∞	212 °F	RTD 8: Temperature Stage 1 Pickup
9085	RTD 8 STAGE 2	-50..250 °C; ∞	120 °C	RTD 8: Temperature Stage 2 Pickup
9086	RTD 8 STAGE 2	-58..482 °F; ∞	248 °F	RTD 8: Temperature Stage 2 Pickup
9091A	RTD 9 TYPE	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 9: Type
9092A	RTD 9 LOCATION	Oil Ambient Winding Bearing Other	Other	RTD 9: Location
9093	RTD 9 STAGE 1	-50..250 °C; ∞	100 °C	RTD 9: Temperature Stage 1 Pickup
9094	RTD 9 STAGE 1	-58..482 °F; ∞	212 °F	RTD 9: Temperature Stage 1 Pickup
9095	RTD 9 STAGE 2	-50..250 °C; ∞	120 °C	RTD 9: Temperature Stage 2 Pickup
9096	RTD 9 STAGE 2	-58..482 °F; ∞	248 °F	RTD 9: Temperature Stage 2 Pickup
9101A	RTD10 TYPE	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD10: Type
9102A	RTD10 LOCATION	Oil Ambient Winding Bearing Other	Other	RTD10: Location
9103	RTD10 STAGE 1	-50..250 °C; ∞	100 °C	RTD10: Temperature Stage 1 Pickup
9104	RTD10 STAGE 1	-58..482 °F; ∞	212 °F	RTD10: Temperature Stage 1 Pickup
9105	RTD10 STAGE 2	-50..250 °C; ∞	120 °C	RTD10: Temperature Stage 2 Pickup
9106	RTD10 STAGE 2	-58..482 °F; ∞	248 °F	RTD10: Temperature Stage 2 Pickup
9111A	RTD11 TYPE	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD11: Type

Addr.	Setting Title	Setting Options	Default Setting	Comments
9112A	RTD11 LOCATION	Oil Ambient Winding Bearing Other	Other	RTD11: Location
9113	RTD11 STAGE 1	-50..250 °C; ∞	100 °C	RTD11: Temperature Stage 1 Pickup
9114	RTD11 STAGE 1	-58..482 °F; ∞	212 °F	RTD11: Temperature Stage 1 Pickup
9115	RTD11 STAGE 2	-50..250 °C; ∞	120 °C	RTD11: Temperature Stage 2 Pickup
9116	RTD11 STAGE 2	-58..482 °F; ∞	248 °F	RTD11: Temperature Stage 2 Pickup
9121A	RTD12 TYPE	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD12: Type
9122A	RTD12 LOCATION	Oil Ambient Winding Bearing Other	Other	RTD12: Location
9123	RTD12 STAGE 1	-50..250 °C; ∞	100 °C	RTD12: Temperature Stage 1 Pickup
9124	RTD12 STAGE 1	-58..482 °F; ∞	212 °F	RTD12: Temperature Stage 1 Pickup
9125	RTD12 STAGE 2	-50..250 °C; ∞	120 °C	RTD12: Temperature Stage 2 Pickup
9126	RTD12 STAGE 2	-58..482 °F; ∞	248 °F	RTD12: Temperature Stage 2 Pickup

2.10.4 Information Overview

Note: Further annunciations on setpoints of each measuring point are available at the RTD-box itself for output at the relay contacts.

F.No.	Alarm	Comments
14101	Fail: RTD	Fail: RTD (broken wire/shorted)
14111	Fail: RTD 1	Fail: RTD 1 (broken wire/shorted)
14112	RTD 1 St.1 p.up	RTD 1 Temperature stage 1 picked up
14113	RTD 1 St.2 p.up	RTD 1 Temperature stage 2 picked up

F.No.	Alarm	Comments
14121	Fail: RTD 2	Fail: RTD 2 (broken wire/shorted)
14122	RTD 2 St.1 p.up	RTD 2 Temperature stage 1 picked up
14123	RTD 2 St.2 p.up	RTD 2 Temperature stage 2 picked up
14131	Fail: RTD 3	Fail: RTD 3 (broken wire/shorted)
14132	RTD 3 St.1 p.up	RTD 3 Temperature stage 1 picked up
14133	RTD 3 St.2 p.up	RTD 3 Temperature stage 2 picked up
14141	Fail: RTD 4	Fail: RTD 4 (broken wire/shorted)
14142	RTD 4 St.1 p.up	RTD 4 Temperature stage 1 picked up
14143	RTD 4 St.2 p.up	RTD 4 Temperature stage 2 picked up
14151	Fail: RTD 5	Fail: RTD 5 (broken wire/shorted)
14152	RTD 5 St.1 p.up	RTD 5 Temperature stage 1 picked up
14153	RTD 5 St.2 p.up	RTD 5 Temperature stage 2 picked up
14161	Fail: RTD 6	Fail: RTD 6 (broken wire/shorted)
14162	RTD 6 St.1 p.up	RTD 6 Temperature stage 1 picked up
14163	RTD 6 St.2 p.up	RTD 6 Temperature stage 2 picked up
14171	Fail: RTD 7	Fail: RTD 7 (broken wire/shorted)
14172	RTD 7 St.1 p.up	RTD 7 Temperature stage 1 picked up
14173	RTD 7 St.2 p.up	RTD 7 Temperature stage 2 picked up
14181	Fail: RTD 8	Fail: RTD 8 (broken wire/shorted)
14182	RTD 8 St.1 p.up	RTD 8 Temperature stage 1 picked up
14183	RTD 8 St.2 p.up	RTD 8 Temperature stage 2 picked up
14191	Fail: RTD 9	Fail: RTD 9 (broken wire/shorted)
14192	RTD 9 St.1 p.up	RTD 9 Temperature stage 1 picked up
14193	RTD 9 St.2 p.up	RTD 9 Temperature stage 2 picked up
14201	Fail: RTD10	Fail: RTD10 (broken wire/shorted)
14202	RTD10 St.1 p.up	RTD10 Temperature stage 1 picked up
14203	RTD10 St.2 p.up	RTD10 Temperature stage 2 picked up
14211	Fail: RTD11	Fail: RTD11 (broken wire/shorted)
14212	RTD11 St.1 p.up	RTD11 Temperature stage 1 picked up
14213	RTD11 St.2 p.up	RTD11 Temperature stage 2 picked up
14221	Fail: RTD12	Fail: RTD12 (broken wire/shorted)
14222	RTD12 St.1 p.up	RTD12 Temperature stage 1 picked up
14223	RTD12 St.2 p.up	RTD12 Temperature stage 2 picked up

2.11 Overexcitation Protection

General

The overexcitation protection is used to detect increased overflux or overinduction conditions in generators and transformers. An increase in induction above the rated value leads very quickly to saturation of the iron core and to large eddy current losses which cause impermissible temperature rise in the iron.

The overexcitation protection picks up when the permissible limit of induction is exceeded in the core of the protected object (e.g. power station unit transformer). Increased induction occurs, for example, when the power station block is disconnected from the system from full-load, and the voltage regulator either does not operate or does not operate sufficiently fast to control the associated voltage rise. Similarly, decrease in frequency (speed), e.g. in island systems, can cause increased induction in the transformer.

2.11.1 Function Description

Measured Values

The use of the overexcitation protection presumes that measured voltages are connected to the device; this is not possible in model 7UT635. Overexcitation protection makes no sense on 1-phase busbar protection and is, therefore, not available for this application.

The overexcitation protection measures the ratio voltage/frequency (U/f) which is proportional to the induction B of the iron core (with invariable dimensions).

If the quotient U/f is set in relation to the voltage and frequency under nominal conditions of the protected object U_{Nobj}/f_N, a direct measure of the induction B, referred to the induction B_{Nobj} under nominal conditions, is achieved. All constant quantities cancel each other:

$$\frac{B}{B_{Nobj}} = \frac{\frac{U}{U_{Nobj}}}{\frac{f}{f_N}} = \frac{U/f}{U_{Nobj}/f_N}$$

The benefit of these referred values is that no explicit calculations are necessary. You can enter all values directly referred to the induction under nominal conditions of the protected object. The device has been informed about the nominal values of the protected object and the voltage transformers according to Subsection 2.1.3.

The maximum of the three phase-to-phase voltages is decisive for the calculation. The voltages are filtered by numerical algorithms. The specified frequency range is f_N ± 10 %.

Characteristics

The overexcitation protection includes two definite time stages and a further thermal characteristic which latter forms an approximate replica of the temperature rise caused by overflux in the protected object.

As soon as a threshold (warning stage **U/f >**) has been exceeded, pickup indication is output and a timer **T U/f >** starts. A warning message is transmitted subsequent to the expiration of this timer. A further high-set stage **U/f >>** serves as short-delay tripping stage after **T U/f >>**. The dropout values are approximately 5 % below the pickup values.

Figure 2-92 shows a logic diagram of the overexcitation protection.

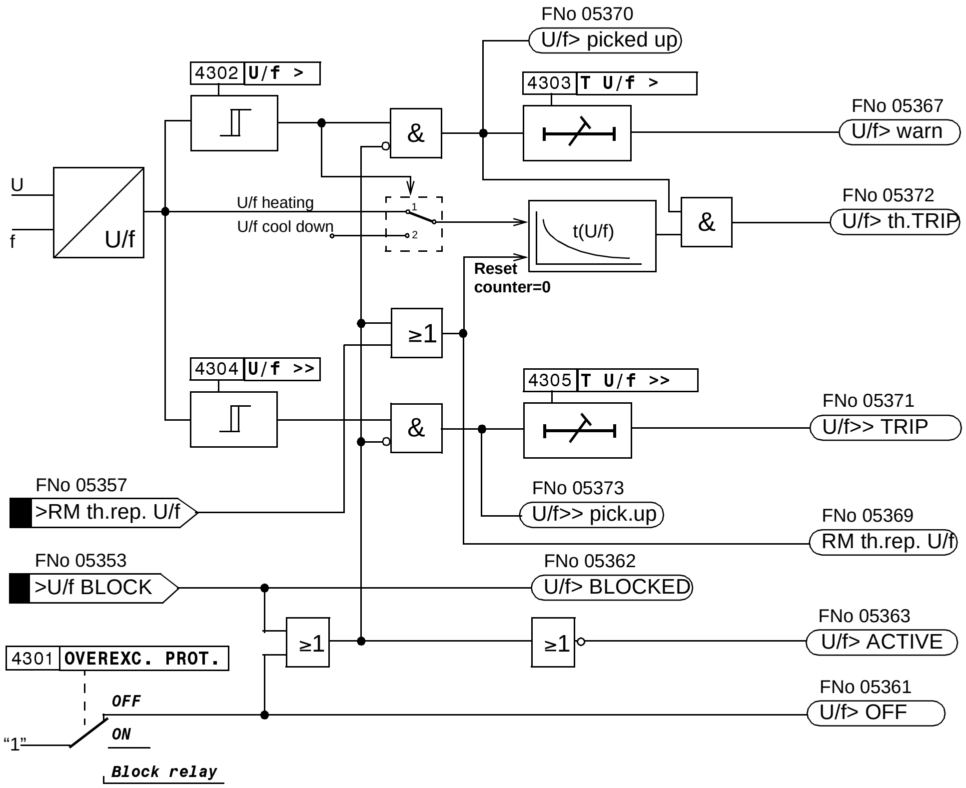


Figure 2-92 Logic diagram of the overexcitation protection (simplified)

The thermal replica is realized by a counter which is incremented in accordance with the value U/f calculated from the measure voltages. A prerequisite is that the U/f value has exceeded the pickup value **U/f >** of the warning stage. If the counter reaches a level corresponding with the set trip characteristic, trip command is given.

The trip signal is cancelled as soon as the value falls below the pickup threshold and the counter is decremented according to the set cool-down rate.

The thermal characteristic is specified by 8 value pairs concerning the U/f value (referred to nominal value) and the associated trip time. In most cases, the prespecified characteristic related to standard transformers provides for sufficient protection. If this characteristic does not correspond to the actual thermal behaviour of the object to be protected, each desired characteristic can be implemented by entering user-specific trip times for the specified U/f overexcitation values. Intermediate values are determined by a linear interpolation within the device.

The counter can be reset to zero by means of a blocking input or a reset input. The internal upper limit of the thermal replica is 150 % of trip temperature rise.

2.11.2 Setting the Function Parameters

General

Precondition for use of the overexcitation protection is that measured voltages are connected to the device and that a 3-phase object has been selected during configuration of the protection functions. Additionally, the overexcitation protection can only operate if it has been configured under address 143 **OVEREXC. PROT.** = ***Enabled***.

The overexcitation protection can be switched ***ON*** or ***OFF*** under address 4301 **OVEREXC. PROT.**. The option ***Block relay*** allows to operate the protection but the trip output relay is blocked.

Definite Time Stages

The limit-value setting at address 4302 **U/f >** is based on the continuously permissible induction value related to the nominal induction (B/B_N) specified by the manufacturer of the object to be protected. This setting determines the pickup of the warning stage as well as the minimum value for the thermal stage (see below).

After the time **T U/f >** (address 4303) has expired (approx 10 s) alarm is output.

Strong overexcitation endangers the protected object after short time. The high-set stage **U/f >>** (address 4304) should, therefore be only shortly delayed (approx. 1 s) by the time **T U/f >>** (address 4305).

The set times are additional time delays which do not include the inherent operating time (measuring time, dropout time) of the protection. If you set a time delay to ∞ the associated stage does not trip; nevertheless, a pickup indication is output.

Thermal Characteristic

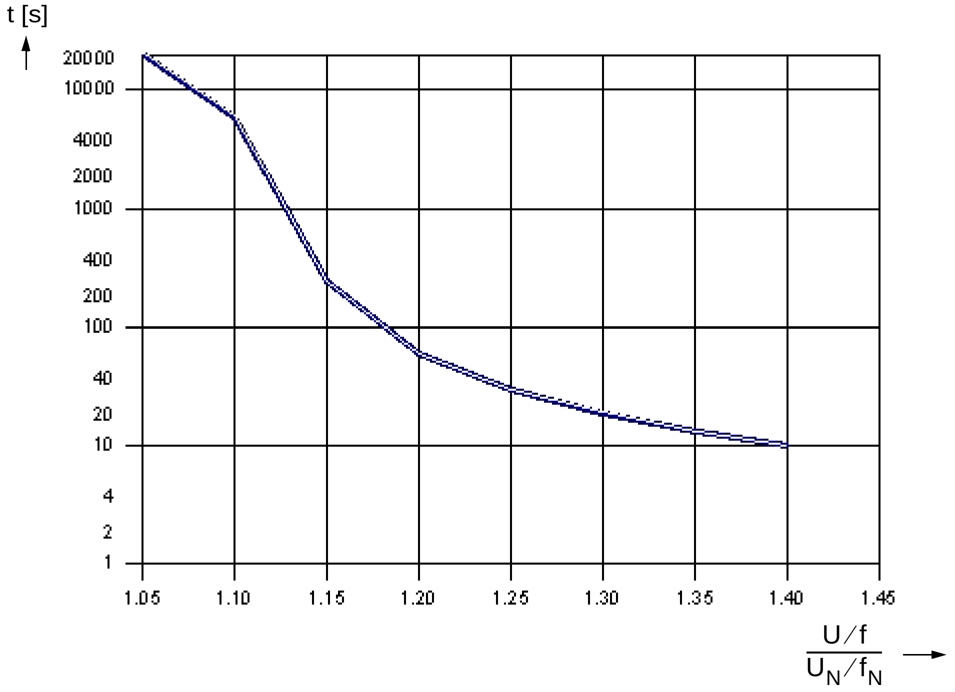
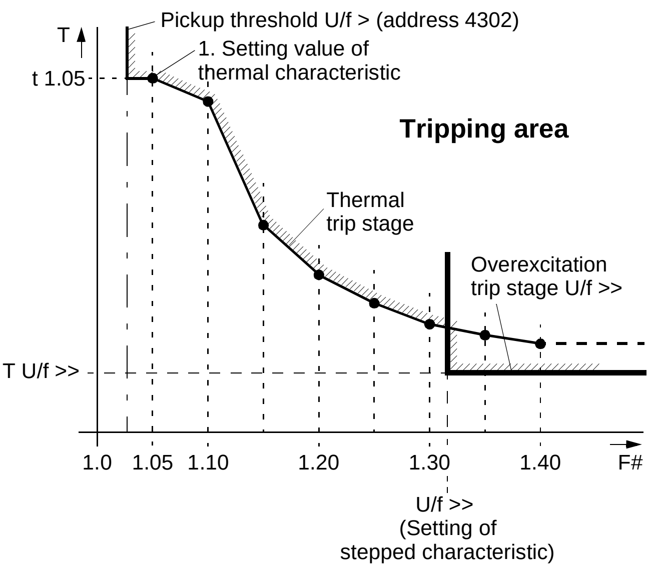


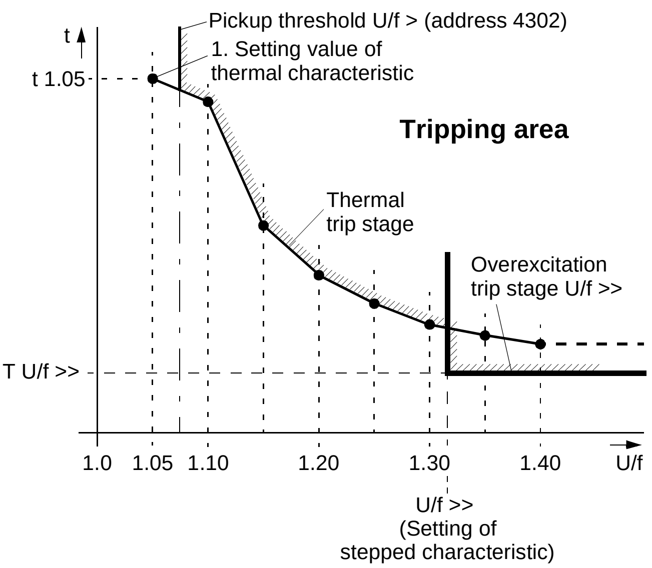
Figure 2-93 Tripping time characteristic of the overexcitation protection — presettings

The thermal characteristic is intended to simulate the temperature rise of the iron core due to overflux. The heating-up characteristic is approximated by 8 time values for the 8 predefined induction values B/B_{Nobj} (reduced U/f). Intermediate values are gained in the device by linear interpolation.

If no instructions of the manufacturer are available, the preset standard characteristic should be used; this corresponds to a standard Siemens transformer (Figure 2-93).



a) Pickup threshold U/f > is less than the 1st setting value of the thermal characteristic



b) Pickup threshold U/f > is greater than the 1st setting value of the thermal characteristic

Figure 2-94 Tripping time characteristic of the overexcitation protection

Otherwise, any trip characteristic can be specified by point-wise entering the delay times for the 8 predefined U/f-values:

Address 4306 **`t(U/f=1.05)`**
Address 4307 **`t(U/f=1.10)`**
Address 4308 **`t(U/f=1.15)`**
Address 4309 **`t(U/f=1.20)`**
Address 4310 **`t(U/f=1.25)`**
Address 4311 **`t(U/f=1.30)`**
Address 4312 **`t(U/f=1.35)`**
Address 4313 **`t(U/f=1.40)`**

As mentioned above, the thermal characteristic is effective only if the pickup threshold **`U/f >`** is exceeded. For your information, Figure 2-94 illustrates the behaviour of the protection on the assumption that the setting for the pickup threshold (parameter 4302 **`U/f >`**) was chosen higher or lower than the first setting value of the thermal characteristic.

Cooling-Down Time

The tripping by the thermal replica drops out by the time of the pickup threshold dropout. However, the counter content is reset to zero with the cooling-down time at address 4314 **`T COOL DOWN`**. In this context, this parameter is defined as the time required by the thermal replica to cool down from 100 % to 0 %.

2.11.3 Setting Overview

Note: The U/f-values are referred to the nominal conditions, i.e. to U_N/f_N.

Addr.	Setting Title	Setting Options	Default Setting	Comments
4301	OVEREXC. PROT.	OFF ON Block relay for trip commands	OFF	Overexcitation Protection (U/f)
4302	U/f >	1.00..1.20	1.10	U/f > Pickup
4303	T U/f >	0.00..60.00 sec; ∞	10.00 sec	T U/f > Time Delay
4304	U/f >>	1.00..1.40	1.40	U/f >> Pickup
4305	T U/f >>	0.00..60.00 sec; ∞	1.00 sec	T U/f >> Time Delay
4306	t(U/f=1.05)	0..20000 sec	20000 sec	U/f = 1.05 Time Delay
4307	t(U/f=1.10)	0..20000 sec	6000 sec	U/f = 1.10 Time Delay
4308	t(U/f=1.15)	0..20000 sec	240 sec	U/f = 1.15 Time Delay
4309	t(U/f=1.20)	0..20000 sec	60 sec	U/f = 1.20 Time Delay
4310	t(U/f=1.25)	0..20000 sec	30 sec	U/f = 1.25 Time Delay
4311	t(U/f=1.30)	0..20000 sec	19 sec	U/f = 1.30 Time Delay

Addr.	Setting Title	Setting Options	Default Setting	Comments
4312	t(U/f=1.35)	0..20000 sec	13 sec	U/f = 1.35 Time Delay
4313	t(U/f=1.40)	0..20000 sec	10 sec	U/f = 1.40 Time Delay
4314	T COOL DOWN	0..20000 sec	3600 sec	Time for Cooling Down

2.11.4 Information Overview

F.No.	Alarm	Comments
05353	>U/f BLOCK	>BLOCK overexcitation protection
05357	>RM th.rep. U/f	>Reset memory of thermal replica U/f
05361	U/f> OFF	Overexcitation protection is swiched OFF
05362	U/f> BLOCKED	Overexcitation protection is BLOCKED
05363	U/f> ACTIVE	Overexcitation protection is ACTIVE
05369	RM th.rep. U/f	Reset memory of thermal replica U/f
05367	U/f> warn	Overexc. prot.: U/f warning stage
05370	U/f> picked up	Overexc. prot.: U/f> picked up
05373	U/f>> pick.up	Overexc. prot.: U/f>> picked up
05371	U/f>> TRIP	Overexc. prot.: TRIP of U/f>> stage
05372	U/f> th.TRIP	Overexc. prot.: TRIP of th. stage
05376	U/f Err No VT	Overexc. err: No VT assigned
05377	U/f Not avalia.	Overexc. err: Not avali. for this object

2.12 Circuit Breaker Failure Protection

2.12.1 Function Description

General

The circuit breaker failure protection provides rapid backup fault clearance, in the event that the circuit breaker fails to respond to a trip command from a feeder protection.

Whenever e.g. the differential protection or any internal or external short-circuit protection function of a feeder issues a trip command to the circuit breaker, this is repeated to the breaker failure protection (Figure 2-95). A timer T–BF in the breaker failure protection is started. The timer runs as long as a trip command is present and current continues to flow through the breaker poles.

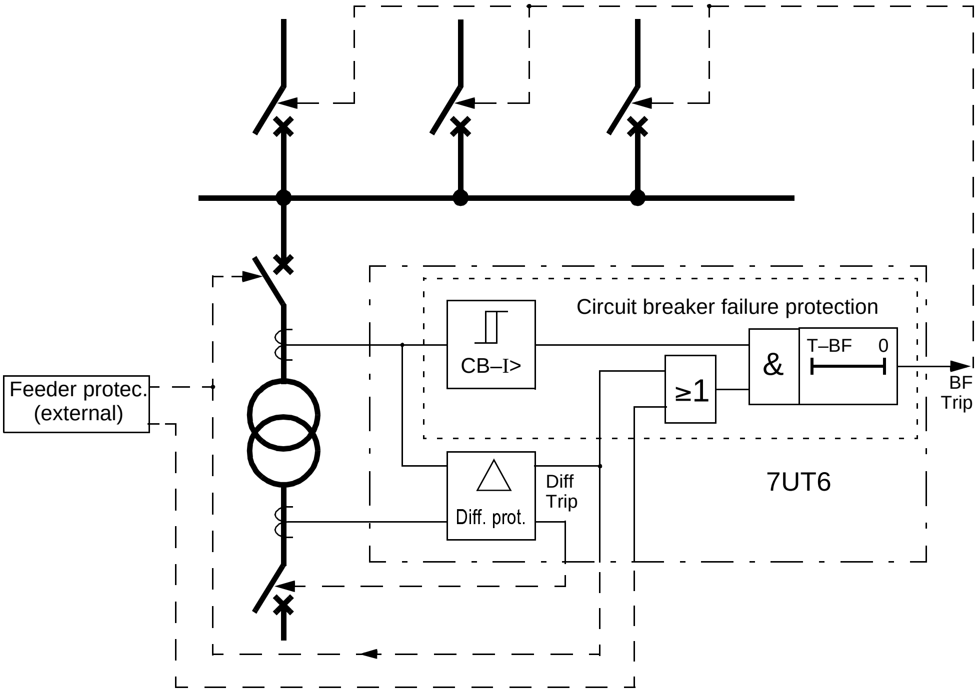


Figure 2-95 Simplified function diagram of circuit breaker failure protection with current flow monitoring

Normally, the breaker will open and interrupt the fault current. The current monitoring stage CB–I> quickly resets (typically $^1/_2$ AC cycle) and stops the timer T–BF.

If the trip command is not carried out (breaker failure case), current continues to flow and the timer runs to its set limit. The breaker failure protection then issues a command to trip the adjacent breakers and interrupt the fault current.

The reset time of the feeder protection is not relevant because the breaker failure protection itself recognizes the interruption of the current.

For protection functions where the tripping criterion is not dependent on current (e.g. overexcitation protection or Buchholz protection), current flow is not a reliable criterion to determine the correct response of the breaker. In such cases, the circuit breaker position can be derived from the auxiliary contacts of the breaker or from the feed-back information of the integrated control function. Therefore, instead of monitoring the current, the condition of the breaker position is monitored (see Figure 2-96).

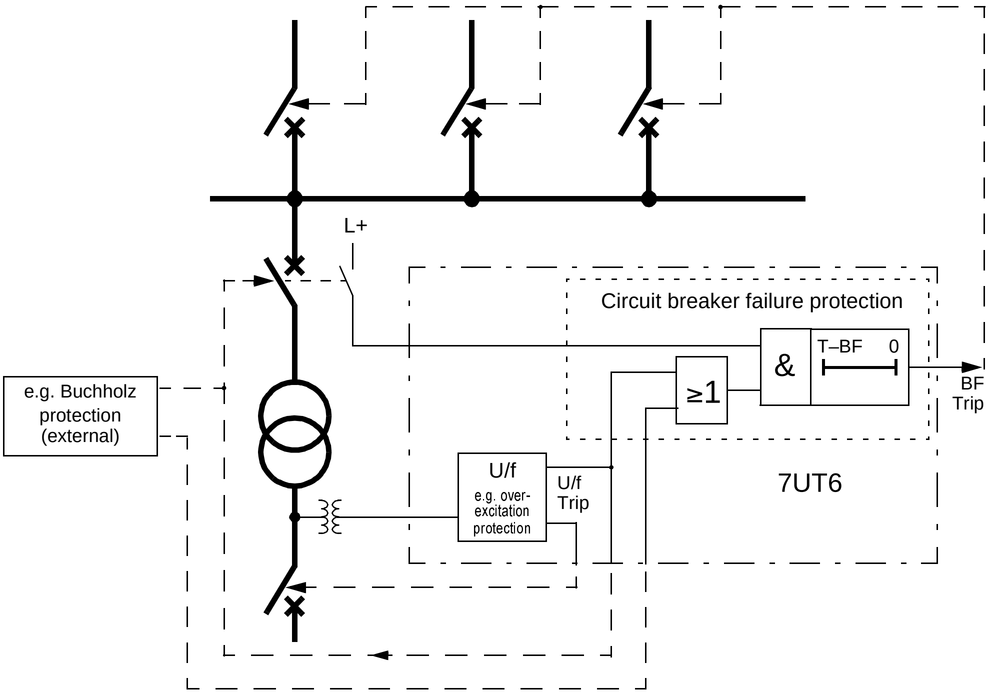


Figure 2-96 Simplified function diagram of circuit breaker failure protection controlled by the circuit breaker auxiliary contact(s)

Normally, both criteria, i.e. current flow as well as breaker position indication, are processed in 7UT6. If only one of the criteria is intended to be considered, this can be achieved by corresponding configuration (Subsections 2.1.4 and 2.1.5).

It is imperative that the measuring point of the currents and the monitored circuit breaker belong together! Both must be located at the supply side of a protected object. In Figure 2-95 the current is measured at the busbar side of the transformer (= supply side), therefore the circuit breaker at the busbar side is monitored. The adjacent circuit breakers are those of the busbar illustrated.

With generators the breaker failure protection usually affects the network breaker. In cases other than that, the supply side must be the relevant one.

Initiation

Figure 2-97 shows a logic diagram of the circuit breaker failure protection.

The breaker failure protection can be initiated by internal protective function of the 7UT6, i.e. trip commands of protective functions or via CFC (internal logic functions), or by external trip signals via a binary input. Both sources are processed in the same way but separately annunciated.

The breaker failure protection checks now the continuation of current flow through the breaker to be monitored. Additionally, the breaker position (read from the feedback of the auxiliary contacts) is checked provided associated feedback information is available.

The current criterion is fulfilled if at least one of the three phase currents exceeds a set threshold value, e.g. **PoleOpenCurr.S1** if the breaker failure protection is assigned to side 1, see also Subsection 2.1.9 under margin “Circuit Breaker Status” (page 67). Special features detect the instant of current interruption. With sinusoidal currents, current interruption is detected after approx. $^1/_2$ AC cycle. With aperiodic DC current components in the fault current and/or in the current transformer secondary circuit after interruption (e.g. current transformers with linearized core), or saturation of the current transformers caused by the DC component in the fault current, it may take one AC cycle until the interruption of the primary current is reliably detected.

Evaluation of the breaker auxiliary contacts is carried out only when no current flow is detected at the instant of initiation, i.e. the trip command of a protection function (internal or external) which is to start the breaker failure protection. In this case the breaker is assumed to be open as soon as the auxiliary contact criterion indicates open breaker.

Once the current flow criterion has picked up before the trip signal from the initiating protection, the circuit breaker is assumed to be open as soon as the current disappears, even if the associated auxiliary contact does not (yet) indicate that the circuit breaker has opened. This gives preference to the more reliable current criterion and avoids false operation due to a defect e.g. in the auxiliary contact mechanism or circuit. If the auxiliary contacts indicate open breaker even though current is flowing, an alarm is given (FNos 30135 to 30144).

If both positions of the breaker are indicated (NO contact and NC contact via double-point indication) the auxiliary contact criterion is not evaluated if, at the instant of initiation, an intermediate position is indicated, but only the current criterion. On the other hand, if the breaker failure protection is already started, the breaker is assumed to have opened as soon as it is no longer indicated as closed, either in intermediate position.

Initiation can be blocked via the binary input “`>BLOCK BkrFail`” (FNo 01403) (e.g. during testing of the feeder protection relay).

Delay Times and Breaker Failure Trip

The breaker failure protection in 7UT6 can be operated single-stage or two-stage.

With single-stage breaker failure protection, the trip command is routed to the adjacent circuit breakers should the local feeder breaker fail (refer to Figure 2-95 or 2-96). The adjacent circuit breakers are all those which must trip in order to interrupt the fault current, i.e. the breakers which feed the busbar or the busbar section to which the feeder under consideration is connected.

After initiation the timer **T2** is started. When this time has elapsed, the indication “`BF T2-TRIP(bus)`” (FNo 01494) appears which is also intended for trip of the adjacent breakers.

With two-stage breaker failure protection, the trip command of the initiating protection is usually repeated, after a first time stage **T1**, to the feeder circuit breaker, often via a second trip coil, that is if the breaker has not responded to the original trip command. This is achieved via the output indication “`BF T1-TRIP(loc)`” (FNo 01492). A second time stage **T2** monitors the response to this repeated trip command and is used to trip the adjacent breakers of the busbar or busbar section, if the fault has not yet been cleared after the repeated trip command. The output indication “`BF T2-TRIP(bus)`” (FNo `01494`) is again used for tripping the adjacent breakers.

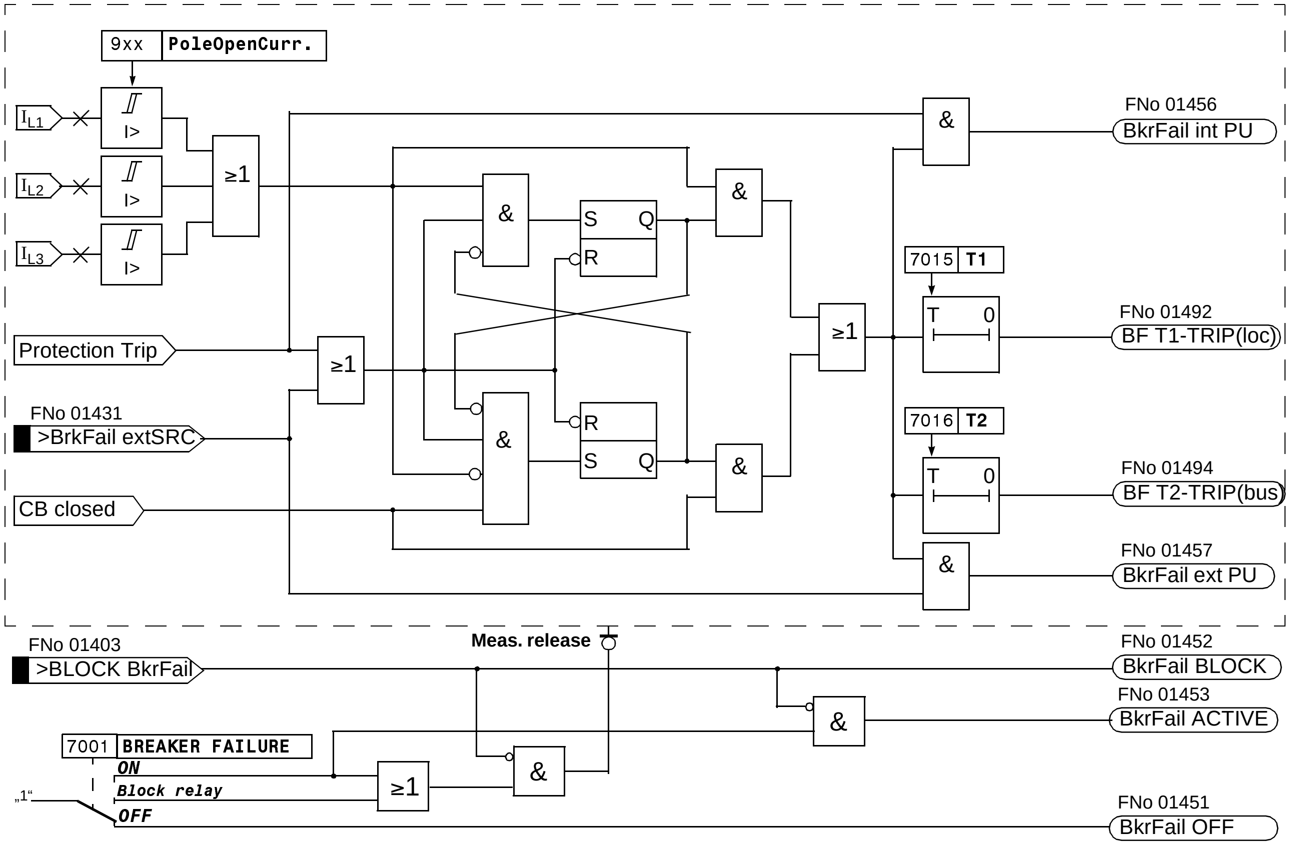


Figure 2-97 Logic diagram of the breaker failure protection (simplified)

2.12.2 Setting the Function Parameters

General

The circuit breaker failure protection can only operate if it has been configured as ***Enabled*** during configuration of the functional scope (Subsection 2.1.1) in address 170 **BREAKER FAILURE**. Breaker failure protection is not possible for single-phase busbar protection.

With the assignment of the protection functions (Subsection 2.1.4) under header margin “Further 3-Phase Protection Functions” you have defined in address 470 **BREAKER FAIL.AT** to which side of the protected object the circuit breaker failure protection shall operate. Please make sure that the side or measuring location of the current and the monitored circuit breaker belong together! Both must be located at the supply side of the protected object.

The breaker failure protection is switched ***OFF*** or ***ON*** under address 7001 **BREAKER FAILURE**. The option ***Block relay*** allows to operate the protection but the trip output relay is blocked.

Initiation

Three statements are essential for the correct initiation of the circuit beaker failure protection:

Current flow monitoring verifies that current flow stops after the trip command has been issued to the breaker to be monitored. It uses the values set in the General Protection Data (Power System Data 2) (Subsection 2.1.9 under margin “Circuit Breaker Status”, page 67). The decisive value is the setting assigned to the side or measuring location that indicates the current of the monitored circuit breaker (addresses `1111` to `1125`). With the circuit breaker open, the current will certainly be below this value.

Assignment of the breaker auxiliary contacts or feed-back information has been assigned as described in Subsection 2.1.5. The corresponding binary inputs must have been configured as well.

The trip command for the monitored breaker is determined by address `7011` or `7012` **`START WITH REL.`** (depending on the version of the device). Chose the number of the output relay which shall trip the breaker to be monitored. Since 7UT6 will normally trip several circuit breakers by the various protection functions, the device must be informed about which trip command is decisive for the initiation of the breaker failure protection. If the breaker failure protection is intended to be initiated also by external trip commands (for the same breaker) the device has to be informed about this trip via the binary input “`>BrkFail extSRC`” (FNo `01431`).

Two-Stage Breaker Failure Protection

In two-stage operation, the trip command is sent after a delay time **`T1`** (address `7015`) to the locally monitored feeder circuit breaker, normally to a separate trip coil of the breaker.

If the circuit breaker does not respond to the repeated trip command, the protection trips after a second waiting time **`T2`** (address `7016`) the adjacent circuit breakers, i.e. those of the busbar or the affected busbar section and, if applicable, also the circuit breaker at the die remote end, if the fault has not yet been eliminated.

The delay times are determined from the maximum operating time of the monitored circuit breaker, the reset time of the current detectors of the breaker failure protection, plus a safety margin which allows for any tolerance of the delay timers. The time sequences are illustrated in Figure 2-98 by an example. For sinusoidal currents one can assume that the reset time of the current detectors is about $^1/_2$ cycle but if current transformer saturation is expected then $1^1/_2$ cycles should be assumed as worst case.

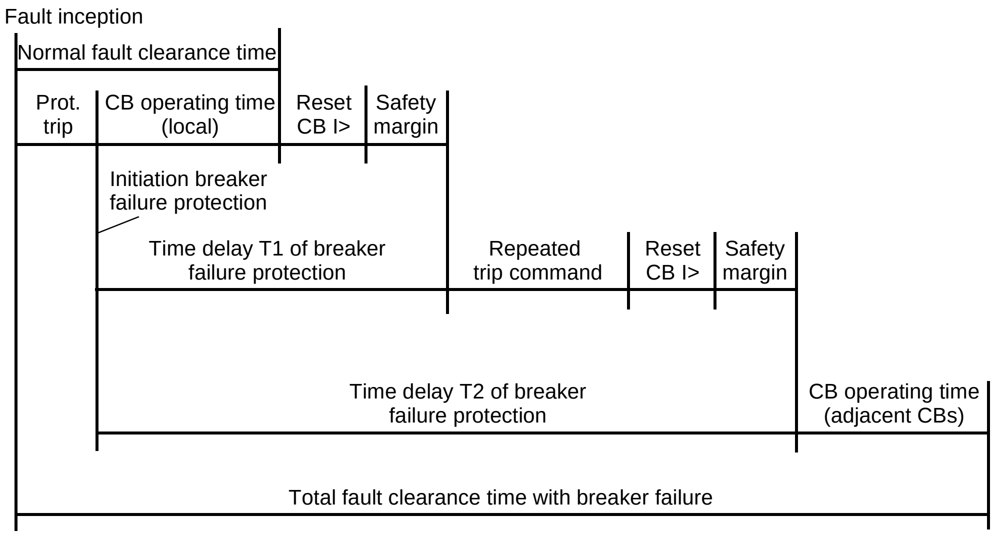


Figure 2-98 Time sequence for normal clearance of a fault, and with circuit breaker failure — example for two-stage breaker failure protection

Single-Stage Breaker Failure Protection

With single-stage operation, the adjacent circuit breakers (i.e. the breakers of the busbar zone and, if applicable, the breaker at the remote end) are tripped after a delay time **T2** (address `7016`) following initiation, should the fault not have been cleared within this time.

The timer **T1** (address `7015`) is then set to ∞ since it is not needed.

The delay time is determined from the maximum operating time of the feeder circuit breaker, the reset time of the current detectors of the breaker failure protection, plus a safety margin which allows for any tolerance of the delay timers. The time sequence is illustrated in Figure 2-99. For sinusoidal currents one can assume that the reset time of the current detectors is about $^1/_2$ cycle but if current transformer saturation is expected then $1^1/_2$ cycles should be assumed.

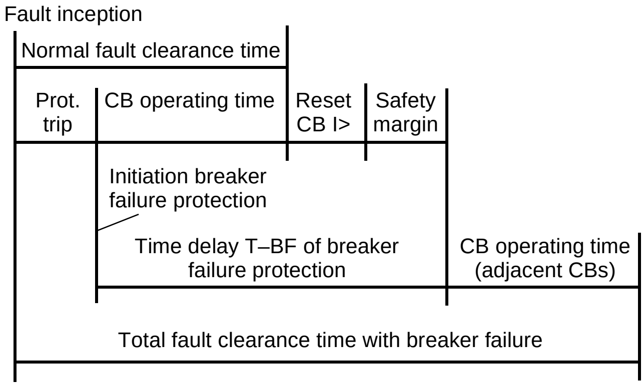


Figure 2-99 Time sequence example for normal clearance of a fault, and with circuit breaker failure

2.12.3 Setting Overview

Addr.	Setting Title	Setting Options	Default Setting	Comments
7001	BREAKER FAILURE	OFF ON Block relay for trip commands	OFF	Breaker Failure Protection
7011	START WITH REL.	0..8	0	Start with Relay (intern)
7012	START WITH REL.	0..24	0	Start with Relay (intern)
7015	T1	0.00..60.00 sec; ∞	0.15 sec	T1, Delay of 1st stage (local trip)
7016	T2	0.00..60.00 sec; ∞	0.30 sec	T2, Delay of 2nd stage (busbar trip)

2.12.4 Information Overview

F.No.	Alarm	Comments
01403	>BLOCK BkrFail	>BLOCK Breaker failure
01431	>BrkFail extSRC	>Breaker failure initiated externally
01451	BkrFail OFF	Breaker failure is switched OFF
01452	BkrFail BLOCK	Breaker failure is BLOCKED
01453	BkrFail ACTIVE	Breaker failure is ACTIVE
01456	BkrFail int PU	Breaker failure (internal) PICKUP
01457	BkrFail ext PU	Breaker failure (external) PICKUP
01492	BF T1-TRIP(loc)	BF TRIP T1 (local trip)
01494	BF T2-TRIP(bus)	BF TRIP T2 (busbar trip)
01488	BkrFail Not av.	Breaker failure Not avail. for this obj.

2.13 Processing of External Signals

2.13.1 Function Description

External Trip Commands

Two desired trip signals from external protection or supervision units can be incorporated into the processing of the differential protection 7UT6. The signals are coupled into the device via binary inputs. Like the internal protection and supervision signals, the can be annunciated, delayed, transmitted to the output trip relays, and blocked. This allows to include mechanical protective devices (e.g. pressure switch, Buchholz protection) in the processing of 7UT6.

The minimum trip command duration set for all protective functions are also valid for these external trip commands. (Subsection 2.1.3 under “Trip Command Duration”, page 53, address `851A`).

Figure 2-100 shows the logic diagram of one of these external trip commands. Two of these functions are available. The function numbers FNo are illustrated for the external trip command 1.

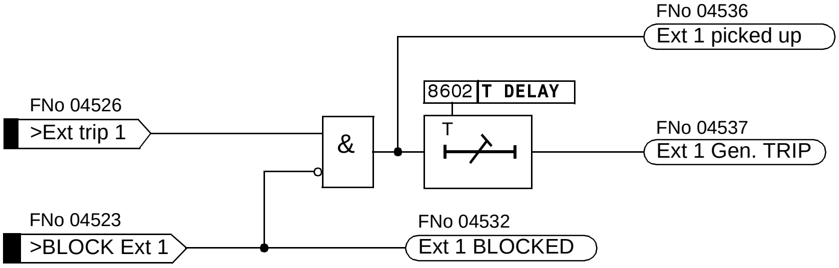


Figure 2-100 Logic diagram of external trip feature — illustrated for External Trip 1 (simplified)

Transformer Messages

In addition to the external trip commands as described above, some typical messages from power transformers can be incorporated into the processing of the 7UT6 via binary inputs. This prevents the user from creating user specified annunciations.

These messages are the Buchholz alarm, Buchholz trip and Buchholz tank alarm as well as gassing alarm of the oil.

Blocking Signal for External Faults

Sometimes for transformers so-called sudden pressure relays (SPR) are installed in the tank which are meant to switch off the transformer in case of a sudden pressure increase. Not only transformer failures but also high traversing fault currents originating from external faults can lead to a pressure increase.

External faults are quickly recognized by 7UT6 (refer also to Subsection 2.2.1, margin heading “Add-on Stabilization during External Fault”, page 76). A blocking signal can be created by means of a CFC logic in order to prevent from erroneous trip of the SPR. Such a logic can be created according to Figure 2-101, for example.

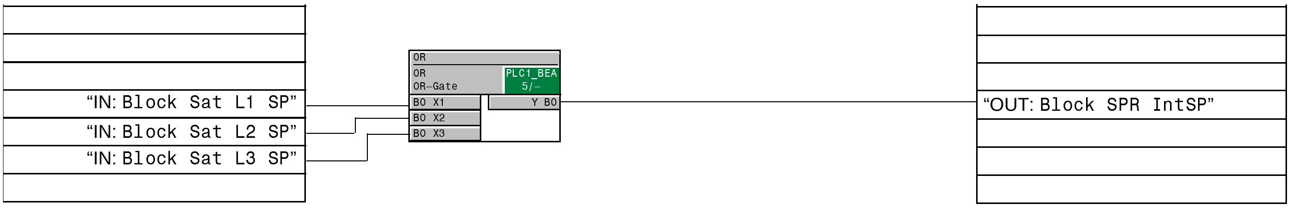


Figure 2-101 CFC chart for blocking of a pressure sensor during external fault

2.13.2 Setting the Function Parameters

General

The direct external trip functions are only enabled if addresses 186 **EXT. TRIP 1** and/or 187 **EXT. TRIP 2** are set to ***Enabled*** in the relay configuration (Subsection 2.1.1).

In addresses 8601 **EXTERN TRIP 1** and 8701 **EXTERN TRIP 2** functions can be set to ***ON*** or ***OFF*** apart from each other. And, if required, only the trip command can be blocked (***Block relay***).

Signals included from outside can be stabilized by means of a delay time and thus increase the dynamic margin against interference signals. For external trip function 1 settings are done in address 8602 **T DELAY**, for external trip function 2 in address 8702 **T DELAY**.

2.13.3 Setting Overview

Addr.	Setting Title	Setting Options	Default Setting	Comments
8601	EXTERN TRIP 1	OFF ON Block relay for trip commands	OFF	External Trip Function 1
8602	T DELAY	0.00..60.00 sec; ∞	1.00 sec	Ext. Trip 1 Time Delay
8701	EXTERN TRIP 2	OFF ON Block relay for trip commands	OFF	External Trip Function 2
8702	T DELAY	0.00..60.00 sec; ∞	1.00 sec	Ext. Trip 2 Time Delay

2.13.4 Information Overview

F.No.	Alarm	Comments
04523	>BLOCK Ext 1	>Block external trip 1
04526	>Ext trip 1	>Trigger external trip 1
04531	Ext 1 OFF	External trip 1 is switched OFF
04532	Ext 1 BLOCKED	External trip 1 is BLOCKED
04533	Ext 1 ACTIVE	External trip 1 is ACTIVE
04536	Ext 1 picked up	External trip 1: General picked up
04537	Ext 1 Gen. TRIP	External trip 1: General TRIP
04543	>BLOCK Ext 2	>BLOCK external trip 2
04546	>Ext trip 2	>Trigger external trip 2
04551	Ext 2 OFF	External trip 2 is switched OFF
04552	Ext 2 BLOCKED	External trip 2 is BLOCKED
04553	Ext 2 ACTIVE	External trip 2 is ACTIVE
04556	Ext 2 picked up	External trip 2: General picked up
04557	Ext 2 Gen. TRIP	External trip 2: General TRIP

F.No.	Alarm	Comments
00390	>Gas in oil	>Warning stage from gas in oil detector
00391	>Buchh. Warn	>Warning stage from Buchholz protection
00392	>Buchh. Trip	>Tripp. stage from Buchholz protection
00393	>Buchh. Tank	>Tank supervision from Buchh. protect.

2.14 Monitoring Functions

The device incorporates comprehensive monitoring functions which cover both hardware and software; the measured values are continuously checked for plausibility, so that the CT circuits are also included in the monitoring system to a large extent. Furthermore, binary inputs are available for supervision of the trip circuit.

2.14.1 Function Description

2.14.1.1 Hardware Monitoring

The complete hardware including the measurement inputs and the output relays is monitored for faults and inadmissible states by monitoring circuits and by the processor.

Auxiliary and Reference Voltages

The processor voltage is monitored by the hardware as the processor cannot operate if the voltage drops below the minimum value. In that case, the device is not operational. When the correct voltage has re-established the processor system is restarted.

Failure or switch-off of the supply voltage sets the system out of operation; this status is signalled by a fail-safe contact. Transient dips in supply voltage will not disturb the function of the relay (see also Subsection 4.1.2 in the Technical Data).

The processor monitors the offset and the reference voltage of the ADC (analog-to-digital converter). In case of inadmissible deviations the protection is blocked; persistent faults are signalled.

Back-up Battery

The back-up battery guarantees that the internal clock continues to work and that metered values and alarms are stored if the auxiliary voltage fails. The charge level of the battery is checked regularly. If the voltage drops below the permissible minimum the alarm “`Fail Battery`” (FNo `00177`) is output.

Memory Modules

All working memories (RAMs) are checked during start-up. If a fault occurs, the start is aborted and an LED starts flashing. During operation the memories are checked with the help of their checksum.

For the program memory, the cross-check sum is cyclically generated and compared to a stored reference program cross-check sum.

For the parameter memory, the cross-check sum is cyclically generated and compared to the cross-check sum that is refreshed after each parameter change.

If a fault occurs the processor system is restarted.

Sampling Frequency

The sampling frequency and the synchronism between the ADC (analog-to-digital converters) is continuously monitored. If deviations cannot be corrected by another synchronization, the device sets itself out of operation and the red LED “Blocked” lights up; the “Device OK” relay drops off and signals the malfunction by its life contact.

2.14.1.2 Software Monitoring

Watchdog

For continuous monitoring of the program sequences, a watchdog timer is provided in the hardware (hardware watchdog) which will reset and completely restart the processor system in the event of processor failure or if a program falls out of step.

A further software watchdog ensures that any error in the processing of the programs will be recognized. Such errors also lead to a reset of the processor.

If such an error is not eliminated by restarting, another restart attempt is initiated. If the fault is still present after three restart attempts within 30 s, the protection system will take itself out of service, and the red LED “Blocked” lights up. The “Device OK” relay drops off and signals the malfunction by its healthy status contact.

2.14.1.3 Monitoring of Measured Quantities

The device detects and signals most of the interruptions, short-circuits, or wrong connections in the secondary circuits of current or voltage transformers (an important commissioning aid). For this the measured values are checked in background routines at cyclic intervals, as long as no pickup condition exists.

Current Balance

In healthy network operation it can be expected that the currents will be approximately balanced. The monitoring of the measured values in the device checks this balance for each 3-phase measuring location. For this the lowest phase current is set in relation to the highest. An imbalance is detected, e.g. for measuring location 1, when

$|I_{min}| / |I_{max}| <$ **BAL. FACT. I M1** provided that

$I_{max} / I_N >$ **BAL. I LIMIT M1** $/ I_N$

I_{max} is the highest, I_{min} the lowest of the three phase currents. The balance factor **BAL. FACT. I M1** represents the degree of imbalance of the phase currents, the limiting value **BAL. I LIMIT M1** is the lower threshold of the operating range of this monitoring function (see Figure 2-102). Both parameters can be set. The resetting ratio is approx. 97 %.

Current balance monitoring is available separate for each 3-phase measuring location. It has no meaning with single-phase busbar protection and does not operate in this case. Unsymmetrical condition is indicated for the corresponding measuring location with the alarm, e.g. “`Fail balan. IM1`” (FNo 30110). The common message “`Fail I balance`” (FNo 00163) appears for all measuring locations.

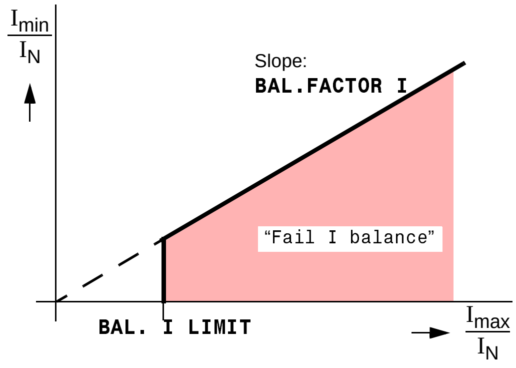


Figure 2-102 Current balance monitoring

Voltage Balance

In healthy network operation it can be expected that the voltages are nearly balanced. If measured voltages are connected to the device, this symmetry is checked by the device. The lowest phase-to-phase voltage is set in relation to the highest. An imbalance is detected when

$|U_{min}| / |U_{max}|$ < **`BAL. FACTOR U`** provided that |Umax| > **`BALANCE U-LIMIT`**

U_{max} is the highest, U_{min} the lowest of the three phase-to-earth voltages. The symmetry factor **`BAL. FACTOR U`** is the measure for the asymmetry of the phase voltages, the limiting value **`BALANCE U-LIMIT`** is the lower threshold of the operating range of this monitoring function (see Figure 2-103). Both parameters can be set. The resetting ratio is approx. 97 %.

This fault is indicated with the alarm “`Fail U balance`“.

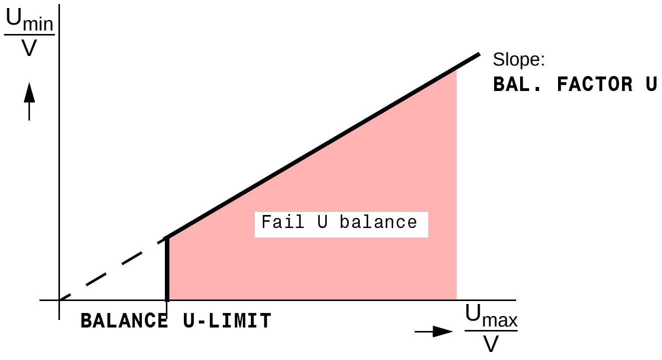


Figure 2-103 Voltage balance monitoring

Voltages Sum

If measured voltages are connected to the device and these are used, voltage sum supervision is possible. A further prerequisite is that the displacement voltage (e-n voltage of an open delta connection) at the same voltage measuring point is connected to the 4th voltage input U_4 of the device. Then the sum of the three digitized phase voltages must equal three times the zero sequence voltage. Errors in the voltage transformer circuits are detected when

$U_F = |\underline{U}_{L1} + \underline{U}_{L2} + \underline{U}_{L3} - k_U \cdot \underline{U}_{EN}| \quad > \quad 25\ V.$

The factor k_U allows for a difference of the transformation ratio between the displacement voltage input and the phase voltage inputs. Due to the settings of the nominal voltages and ratios (Subsection 2.1.3 under margin heading “Voltage Transformer Data”, page 48) the device is informed about these data. The reset ratio is approx. 97 %.

This fault is reported by “`Fail Σ U Ph-E`“.

Current Phase Sequence

To detect swapped connections in the current input circuits, the direction of rotation of the phase currents for three-phase application is checked. Therefore the sequence of the zero crossings of the currents (having the same sign) is checked for each 3-phase measuring location. For single-phase busbar differential protection and single-phase transformers this function would not be of any use and is thus disabled.

Especially the unbalanced load protection requires clockwise rotation. If rotation in the protected object is reverse, this must be considered during the configuration of the general power system data (Subsection 2.1.3, margin heading “Phase Sequence”).

Phase rotation is checked by supervising the phase sequence of the currents, i.e. for clockwise rotation.

$\underline{I}_{L1}$ before $\underline{I}_{L2}$ before $\underline{I}_{L3}$

Supervision of current rotation requires a minimum current of

$|\underline{I}_{L1}|, |\underline{I}_{L2}|, |\underline{I}_{L3}| > 0.5\ I_N$.

If the measured rotation differs from the set rotation, the annunciation for the corresponding measuring location is output, e.g. “`FailPh.Seq IM1`” (FNo 30115). At the same time, the common annunciation appears: “`Fail Ph. Seq. I`” (FNo 00175).

Voltage Phase Sequence

If measured voltages are connected to the device and these are used, the voltage phase rotation is supervised. On clockwise phase rotation, the sequence of the zero crossings of the 3-phase voltages (having the same sign) is

$\underline{U}_{L1}$ before $\underline{U}_{L2}$ before $\underline{U}_{L3}$.

This check is made as long as the voltages have a magnitude of at least

$|\underline{U}_{L1}|, |\underline{U}_{L2}|, |\underline{U}_{L3}| > 40\ V/\sqrt{3}$

Wrong phase sequence is alarmed with “`Fail Ph. Seq. U`” (FNo 00176)

Broken-Wire

During steady-state operation the broken wire monitoring registers interruptions in the secondary circuit of the current transformers. In addition to the hazardous potential caused by high voltages in the secondary circuit, this kind of interruptions simulates differential currents to the differential protection, such as those evoked by faults in the protected object.

The broken-wire monitor scans the transient behaviour of the currents of each phase of each 3-phase measuring location. The instantaneous currents are checked for plausibility and continuity. If an instantaneous value does not correspond with the expected value, a broken wire is considered. If the current decays strongly or drops abruptly to 0 (from $> 0.1 \cdot I_N$), or no zero crossing is registered, broken wire is assumed. The currents flowing in other phases must not exceed $2 \cdot I_N$ at the same time.

The differential protection and the restricted earth fault protection are blocked immediately. The protection functions which react on unsymmetrical currents are blocked as well provided they are assigned to the defective measuring location: the time overcurrent protection for residual current and the unbalanced load protection. The device issues the message “`Broken Iwire`” indicating also the affected phase and measuring location.

The blocking is cancelled as soon as the device is again supplied with current in the relevant phase.

Detection of a broken wire is restricted by technical limits: A broken wire in the secondary circuit can, of course, only be detected when a steady state current has been flowing through the respective phase. Furthermore, a wire break at the instant of zero crossing in current cannot always be detected reliably. No expected value can be calculated when the frequency is out of the operation frequency (f_N ± 10 %).

Note that electronic test devices do not simulate the correct behaviour of broken wire so that pickup may occur during such tests.

2.14.1.4 Trip Circuit Supervision

The differential protection relay 7UT6 is equipped with an integrated trip circuit supervision. Depending on the number of available binary inputs that are not connected to a common potential, supervision modes with one or two binary inputs can be selected. If the allocation of the necessary binary inputs does not comply with the selected monitoring mode, an alarm is given (“`TripC ProgFail`”).

Supervision Using Two Binary Inputs

If two binary inputs are used, they are connected according to Figure 2-104, one in parallel to the assigned command relay contact of the protection and the other parallel to the circuit breaker auxiliary contact.

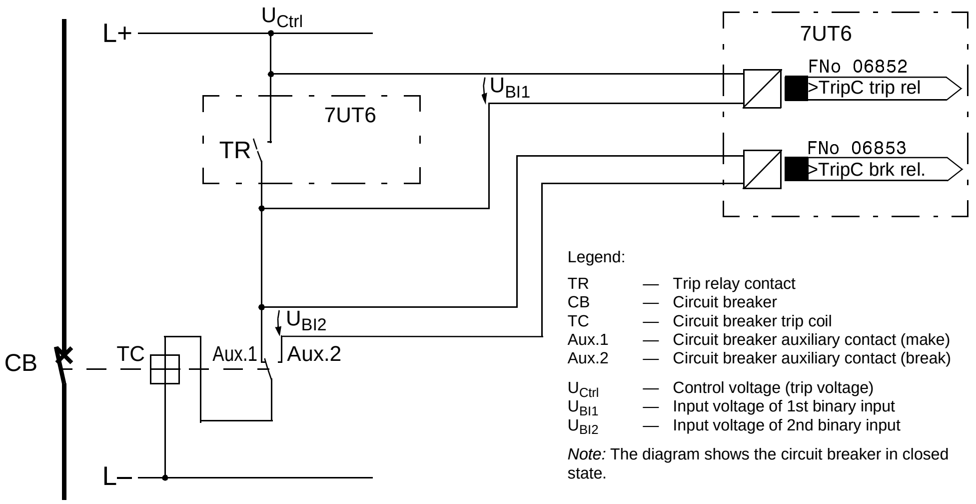


Figure 2-104 Principle of the trip circuit supervision with two binary inputs

A precondition for the use of the trip circuit supervision is that the control voltage for the circuit breaker is higher than the total of the minimum voltages drops at the two binary inputs ($U_{Ctrl} > 2 \cdot U_{BImin}$). As at least 19 V are needed at each binary input, supervision can be used with a control voltage higher than 38 V.

Depending on the state of the trip relay and the circuit breaker’s auxiliary contact, the binary inputs are triggered (logic state “H” in Table 2-8) or short-circuited (logic state “L”).

A state in which both binary inputs are not activated (“L”) is only possible in intact trip circuits for a short transition period (trip relay contact closed but circuit breaker not yet open).

This state is only permanent in the event of interruptions or short-circuits in the trip circuit or a battery voltage failure. Therefore, this state is the supervision criterion.

Table 2-8 Status table of the binary inputs depending on TR and CB

No	Trip relay	Circuit breaker	Aux.1	Aux.2	BI 1	BI 2
1	open	CLOSED	closed	open	H	L
2	open	OPEN	open	closed	H	H
3	closed	CLOSED	closed	open	L	L
4	closed	OPEN	open	closed	L	H

The states of the two binary inputs are interrogated periodically, approximately every 500 ms. Only after n = 3 of these consecutive state queries have detected a fault an alarm is given (see Figure 2-105). These repeated measurements result in a delay of this alarm and thus avoid that an alarm is given during short-time transient periods. After the fault is removed in the trip circuit, the fault message is reset automatically after the same time delay.

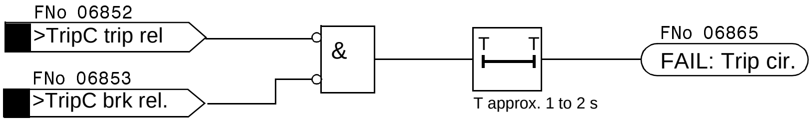


Figure 2-105 Logic diagram of the trip circuit supervision with two binary inputs (simplified)

Supervision Using One Binary Input

The binary input is connected in parallel to the respective command relay contact of the protection device according to Figure 2-106. The circuit breaker auxiliary contact is bridged with the help of a high-ohmic substitute resistor R.

The control voltage for the circuit breaker should be at least twice as high as the minimum voltage drop at the binary input ($U_{Ctrl} > 2 \cdot U_{BImin}$). Since at least 19 V are necessary for the binary input, this supervision can be used with a control voltage higher than 38 V.

An calculation example for the substitute resistance of R is shown in Subsection 3.1.2, margin “Trip Circuit Supervision”.

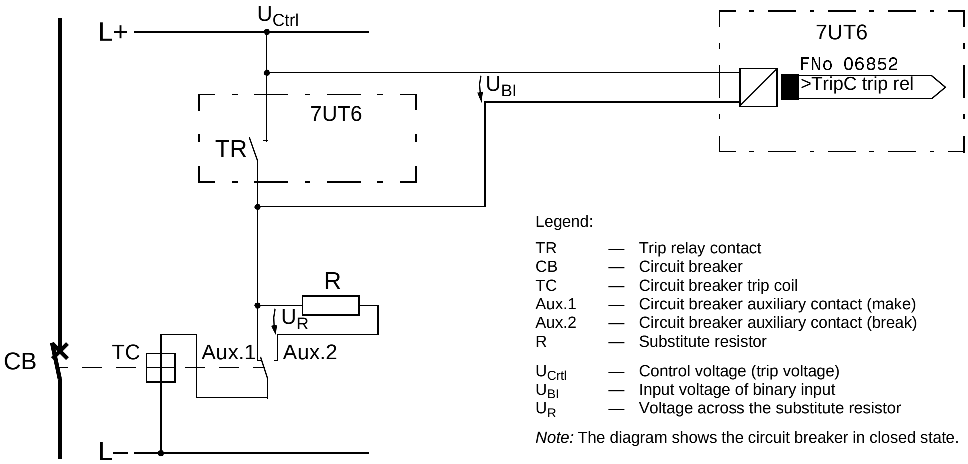


Figure 2-106 Principle of the trip circuit supervision with one binary input

In normal operation the binary input is energized when the trip relay contact is open and the trip circuit is healthy (logic state “H”), as the monitoring circuit is closed via the auxiliary contact (if the circuit breaker is closed) or via the substitute resistor R. The binary input is short-circuited and thus deactivated only as long as the tripping relay is closed (logic state “L”).

If the binary input is permanently deactivated during operation, an interruption in the trip circuit or a failure of the (trip) control voltage can be assumed.

As the trip circuit supervision is not operative during a system fault condition (picked-up status of the device), the closed trip contact does not lead to an alarm. If, however, the trip contacts of other devices are connected in parallel, the alarm must be delayed (see also Figure 2-107). After the fault in the trip circuit is removed, the alarm is reset automatically after the same time.

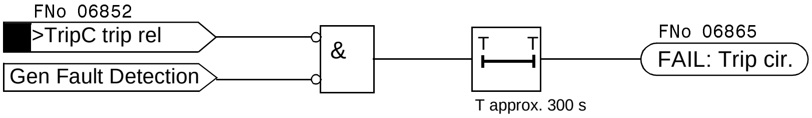


Figure 2-107 Logic diagram of the trip circuit supervision with one binary input (simplified)

2.14.1.5 Fault Reactions

Depending on the kind of fault detected, an alarm is given, the processor is restarted or the device is taken out of operation. If the fault is still present after three restart attempts the protection system will take itself out of service and indicate this condition by drop-off of the life contact, thus indicating the device failure. The red LED “Blocked” on the device front lights up, provided that there is an internal auxiliary voltage, and the green LED “RUN” goes off. If the internal auxiliary voltage supply fails, all LEDs are dark. Table 2-9 shows a summary of the most important monitoring functions and the fault reactions of the device.

Table 2-9 Summary of the fault reactions of the device

Supervision	Possible causes	Fault reaction	Alarm	Output
Auxiliary voltage failure	External (aux. voltage) Internal (converter)	Device out of operation alarm, if possible	All LEDs dark	DOK2) drops off
Measured value acquisition	Internal (converter or sampling)	Protection out of operation, alarm	LED “ERROR” “Error MeasurSys”	DOK2) drops off
	internal (offset)	Protection out of operation, alarm	LED “ERROR” “Error Offset”	DOK2) drops off
Hardware watchdog	Internal (processor failure)	Device out of operation	LED “ERROR”	DOK2) drops off
Software watchdog	Internal (program flow)	Restart attempt 1)	LED “ERROR”	DOK2) drops off
Working memory	Internal (RAM)	Restart attempt 1), Restart abort device out of operation	LED flashes	DOK2) drops off
Program memory	Internal (EPROM)	Restart attempt 1)	LED “ERROR”	DOK2) drops off
Parameter memory	Internal (EEPROM or RAM)	Restart attempt 1)	LED “ERROR”	DOK2) drops off
1 A/5 A/0.1 A settings	1/5/0.1 A jumper wrong	Alarms Protection out of operation	“Error1A/5Awrong” (with input indication) LED “ERROR“	DOK2) drops off
Calibration data	Internal (device not calibrated)	Alarm Using default values	“Alarm adjustm.”	as allocated
Backup battery	Internal (backup battery)	Alarm	“Fail Battery”	as allocated
Time clock	Time synchronization	Alarm	“Clock SyncError”	as allocated
P.C.B. Modules	Module does not comply with ordering number	Alarms Protection out of operation	“Error Board 0...7” and if applicable “Error MeasurSys”	DOK2) drops off
Interface modules	Defective interface	Alarm	“Err. Module B” (C,D)”	as allocated
RTD-box connection	RTD-box not connected or number does not match	Alarm No overload protection with RTD	“Fail: RTD-Box 1” or “Fail: RTD-Box 2”	as allocated
Current balance	External (system or current transformers)	Alarm with identification of the measuring location	“Fail balan. IM1... M5” (meas.location), “Fail I balance”	as allocated
Voltage sum	Internal (measured value acquisition)	Alarm	“Fail Σ U Ph-E”	as allocated

1) After three unsuccessful attempts the device is put out of operation

2) DOK = “Device OK” relay = life contact

Table 2-9 Summary of the fault reactions of the device

Supervision	Possible causes	Fault reaction	Alarm	Output
Voltage balance	External (system or connections)	Alarm	“`Fail U balance`”	as allocated
Phase sequence	External (system or connections)	Alarm with identification of the measuring location	“`FailPh.Seq IM1`... M5” (meas.location), “`Fail Ph. Seq. I`” “`Fail Ph. Seq. U`”	as allocated
Trip circuit supervision	External (trip circuit or control voltage)	Alarm	“`FAIL: Trip cir.`”	as allocated

[1]) After three unsuccessful attempts the device is put out of operation

[2]) DOK = “Device OK” relay = life contact

2.14.1.6 Group Alarms

Certain messages of the monitoring functions are already combined to group alarms. Table 2-10 shows an overview of these group alarms an their composition. Table 2-10 shows these group alarms and what they are composed of. Alarms may be nested; for instance, the alarm “`FailPh.Seq IM1`” (for the individual measuring location) is included in the group alarm for current phase sequence monitoring, which is included as the alarm “`Fail Ph. Seq. I`” in the global phase sequence monitoring, which is in turn part of the Alarm Sum Event as “`Fail Ph. Seq.`”.

Note that the group alarms can only comprise those individual alarms which are possible in the actual version and configuration of the device.

Table 2-10 Group alarms

Group alarm		Composed of	
FN0	**Designation**	**FNo**	**Designation**
00163	Failure Current Balance	30110 30111 30112 30113 30114	Fail balan. IM1 Fail balan. IM2 Fail balan. IM3 Fail balan. IM4 Fail balan. IM5
00161	Failure Current Supervision (Measured value supervision without consequences on protection functions)	00163	Fail I balance
00164	Failure Voltage Supervision (Measured value supervision without consequences on protection functions)	00165 00167	Fail Σ U Ph-E Fail U balance
00175	Failure Phase Sequence I	30115 30116 30117 30118 30119	FailPh.Seq IM1 FailPh.Seq IM2 FailPh.Seq IM3 FailPh.Seq IM4 FailPh.Seq IM5

Table 2-10 Group alarms

Group alarm		Composed of	
FN0	**Designation**	**FNo**	**Designation**
00176	Failure Phase Sequence U	00176	Fail Ph. Seq. U
00171	Failure Phase Sequence (Failures or configuration errors without consequences on protection functions)	00175	Fail Ph. Seq. I
		00176	Fail Ph. Seq. U
00160	Alarm Sum Event (Failures or configuration errors without consequences on protection functions)	00161	Fail I Superv.
		00164	Fail U Superv.
		00171	Fail Ph. Seq.
		00193	Alarm adjustm.
		00177	Fail Battery
		00198	Err. Module B
		00199	Err. Module C
		00200	Err. Module D
		00068	Clock SyncError
		30135	Incons.CBaux M1
		30136	Incons.CBaux M2
		30137	Incons.CBaux M3
		30138	Incons.CBaux M4
		30139	Incons.CBaux M5
		30140	Incons.CBaux S1
		30141	Incons.CBaux S2
		30142	Incons.CBaux S3
		30143	Incons.CBaux S4
		30144	Incons.CBaux S5
00192	I_N Jumpers differ from I_N Setting	30097	Err. IN CT M1
		30098	Err. IN CT M2
		30099	Err. IN CT M3
		30100	Err. IN CT M4
		30101	Err. IN CT M5
		30102	Err.IN CT1..3
		30103	Err.IN CT4..6
		30104	Err.IN CT7..9
		30105	Err.IN CT10..12
		30106	Err. IN CT IX1
		30107	Err. IN CT IX2
		30108	Err. IN CT IX3
		30109	Err. IN CT IX4
00181	Failure Measured Values (Fatal configuration or measured value errors with blocking of all protection functions)	00190	Error Board 0
		00183	Error Board 1
		00184	Error Board 2
		00185	Error Board 3
		00186	Error Board 4
		00187	Error Board 5
		00188	Error Board 6
		00189	Error Board 7
		00192	Error1A/5Awrong
		00191	Error Offset
00140	Error Sum Alarm (Problems which can lead to partial or total blocking of protection functions)	00181	Error MeasurSys
		00264	Fail: RTD-Box 1
		00267	Fail: RTD-Box 2
		00251	Broken wire
		30145	Fail.Disconnect

2.14.1.7 Setting Errors

If setting of the configuration and function parameters is carried out according to the order they appear in this chapter, conflicting settings may be avoided. Nevertheless, changes made in settings, during allocation of binary inputs and outputs or during assignment of measuring inputs may lead to inconsistencies endangering proper operation of protective and supplementary functions.

The device 7UT6 checks settings for inconsistencies and reports them. For instance, the restricted earth fault protection cannot be applied if there is no measuring input assigned for the starpoint current between the starpoint of the protected object and the earth electrode.

These inconsistencies are output with the operational and spontaneous annunciations. Table 3-23 (Subsection 3.3.5, page 314) gives an overview.

2.14.2 Setting the Function Parameters

Measured Value Supervision

The sensitivity of the measurement supervision can be altered. Experienced values set ex works are sufficient in most cases. If an extremely high operational imbalance of the currents and/or voltages is to be expected in the specific application, or if during operation monitoring functions are operated sporadically, the relevant parameters should be set less sensitive.

The current balance supervision can be switched ***ON*** or ***OFF*** in address 8101 **BALANCE I**, the voltage balance supervision (if possible) in address 8102 **BALANCE U**.

In address 8105 **PHASE ROTAT. I** phase rotation supervision of the currents can be set to ***ON*** or ***OFF***, in address 8106 **PHASE ROTAT. U** that of the voltages (if possible).

In address 8104 **SUMMATION U** the voltage sum supervision (if possible) can be switched ***ON*** or ***OFF***.

Address 8111 **BAL. I LIMIT M1** determines the threshold current for measuring location 1 above which the current balance supervision is effective (see also Figure 2-102). Address 8112 **BAL. FACT. I M1** is the associated balance factor, i.e. the gradient of the balance characteristic (Figure 2-102).

For the further measuring locations the setting are carried out in
address 8121 **BAL. I LIMIT M2** and 8122 **BAL. FACT. I M2** for meas. location 2,
address 8131 **BAL. I LIMIT M3** and 8132 **BAL. FACT. I M3** for meas. location 3,
address 8141 **BAL. I LIMIT M4** and 8142 **BAL. FACT. I M4** for meas. location 4,
address 8151 **BAL. I LIMIT M5** and 8152 **BAL. FACT. I M5** for meas. location 5.

Address 8161 **BALANCE U-LIMIT** determines the threshold voltage above which the voltage balance supervision is effective (see also Figure 2-103). Address 8162 **BAL. FACTOR U** is the associated balance factor, i.e. the gradient of the balance characteristic (Figure 2-103).

In address 8401 **BROKEN WIRE** the broken wire monitoring can be switched ***ON*** or ***OFF***.

Trip Circuit Supervision

When address 182 **`Trip Cir. Sup.`** was configured (Subsection 2.1.1), the number of binary inputs per trip circuit was set. If the trip circuit supervision function is not used at all, ***`Disabled`*** is set there. If the routing of the binary inputs required for this does not comply with the selected supervision mode, an alarm is output (“`TripC ProgFail`”).

The trip circuit supervision can be switched ***`ON`*** or ***`OFF`*** in address 8201 **`TRIP Cir. SUP.`**.

2.14.3 Setting Overview

The following list indicates the setting ranges and the default settings of a rated secondary current I_N = 1 A. For a rated secondary current of I_N = 5 A, these values must be multiplied by 5.

Addr.	Setting Title	Setting Options	Default Setting	Comments
8101	BALANCE I	ON OFF	OFF	Current Balance Supervision
8102	BALANCE U	ON OFF	OFF	Voltage Balance Supervision
8104	SUMMATION U	ON OFF	OFF	Voltage Summation Supervision
8105	PHASE ROTAT. I	ON OFF	OFF	Current Phase Rotation Supervision
8106	PHASE ROTAT. U	ON OFF	OFF	Voltage Phase Rotation Supervision
8111	BAL. I LIMIT M1	0.10..1.00 A	0.50 A	Current Balance Monitor Meas. Loc. 1
8112	BAL. FACT. I M1	0.10..0.90	0.50	Bal. Factor for Curr. Monitor Meas.Loc.1
8121	BAL. I LIMIT M2	0.10..1.00 A	0.50 A	Current Balance Monitor Meas. Loc. 2
8122	BAL. FACT. I M2	0.10..0.90	0.50	Bal. Factor for Curr. Monitor Meas.Loc.2
8131	BAL. I LIMIT M3	0.10..1.00 A	0.50 A	Current Balance Monitor Meas. Loc. 3
8132	BAL. FACT. I M3	0.10..0.90	0.50	Bal. Factor for Curr. Monitor Meas.Loc.3
8141	BAL. I LIMIT M4	0.10..1.00 A	0.50 A	Current Balance Monitor Meas. Loc. 4
8142	BAL. FACT. I M4	0.10..0.90	0.50	Bal. Factor for Curr. Monitor Meas.Loc.4

Addr.	Setting Title	Setting Options	Default Setting	Comments
8151	BAL. I LIMIT M5	0.10..1.00 A	0.50 A	Current Balance Monitor Meas. Loc. 5
8152	BAL. FACT. I M5	0.10..0.90	0.50	Bal. Factor for Curr. Monitor Meas.Loc.5
8161	BALANCE U-LIMIT	10..100 V	50 V	Voltage Threshold for Balance Monitoring
8162	BAL. FACTOR U	0.58..0.90	0.75	Balance Factor for Voltage Monitor

Addr.	Setting Title	Setting Options	Default Setting	Comments
8401	BROKEN WIRE	OFF ON	OFF	Fast broken current-wire supervision

Addr.	Setting Title	Setting Options	Default Setting	Comments
8201	TRIP Cir. SUP.	ON OFF	OFF	TRIP Circuit Supervision

2.14.4 Information Overview

F.No.	Alarm	Comments
00161	Fail I Superv.	Failure: General Current Supervision
00163	Fail I balance	Failure: Current Balance
30110	Failure Isym M1	Fail.: Curr. sym. supervision meas.loc.1
30111	Failure Isym M2	Fail.: Curr. sym. supervision meas.loc.2
30112	Failure Isym M3	Fail.: Curr. sym. supervision meas.loc.3
30113	Failure Isym M4	Fail.: Curr. sym. supervision meas.loc.4
30114	Failure Isym M5	Fail.: Curr. sym. supervision meas.loc.5
00164	Fail U Superv.	Failure: General Voltage Supervision
00165	Fail Σ U Ph-E	Failure: Voltage Summation Phase-Earth
00167	Fail U balance	Failure: Voltage Balance
00171	Fail Ph. Seq.	Failure: Phase Sequence
00175	Fail Ph. Seq. I	Failure: Phase Sequence Current
30115	FailPh.Seq I M1	Failure: Phase Sequence I meas. loc. 1
30116	FailPh.Seq I M2	Failure: Phase Sequence I meas. loc. 2
30117	FailPh.Seq I M3	Failure: Phase Sequence I meas. loc. 3
30118	FailPh.Seq I M4	Failure: Phase Sequence I meas. loc. 4

F.No.	Alarm	Comments
30119	FailPh.Seq I M5	Failure: Phase Sequence I meas. loc. 5
00176	Fail Ph. Seq. U	Failure: Phase Sequence Voltage

F.No.	Alarm	Comments
	SysIntErr.	Error Systeminterface
	Error FMS1	Error FMS FO 1
	Error FMS2	Error FMS FO 2
00110	Event Lost	Event lost
00113	Flag Lost	Flag Lost
00140	Error Sum Alarm	Error with a summary alarm
00181	Error MeasurSys	Error: Measurement system
00190	Error Board 0	Error Board 0
00183	Error Board 1	Error Board 1
00184	Error Board 2	Error Board 2
00185	Error Board 3	Error Board 3
00186	Error Board 4	Error Board 4
00187	Error Board 5	Error Board 5
00188	Error Board 6	Error Board 6
00189	Error Board 7	Error Board 7
00192	Error1A/5Awrong	Error:1A/5Ajumper different from setting
30097	Err. IN CT M1	Err: inconsist. jumper/setting CT M1
30098	Err. IN CT M2	Err: inconsist. jumper/setting CT M2
30099	Err. IN CT M3	Err: inconsist. jumper/setting CT M3
30100	Err. IN CT M4	Err: inconsist. jumper/setting CT M4
30101	Err. IN CT M5	Err: inconsist. jumper/setting CT M5
30102	Err.IN CT1..3	Err: inconsist. jumper/setting CT I1..3
30103	Err.IN CT4..6	Err: inconsist. jumper/setting CT I4..6
30104	Err.IN CT7..9	Err: inconsist. jumper/setting CT I7..9
30105	Err.IN CT10..12	Err:inconsist. jumper/setting CT I10..12
30106	Err. IN CT IX1	Err: inconsist. jumper/setting CT IX1
30107	Err. IN CT IX2	Err: inconsist. jumper/setting CT IX2
30108	Err. IN CT IX3	Err: inconsist. jumper/setting CT IX3
30109	Err. IN CT IX4	Err: inconsist. jumper/setting CT IX4
00191	Error Offset	Error: Offset

F.No.	Alarm	Comments
00264	Fail: RTD-Box 1	Failure: RTD-Box 1
00267	Fail: RTD-Box 2	Failure: RTD-Box 2
30145	Fail.Disconnect	Failure: disconnect measurment location
30054	Broken wire OFF	Broken wire is switched OFF
00251	Broken wire	Broken wire detected
30120	brk. wire IL1M1	Broken wire IL1 measurement location 1
30121	brk. wire IL2M1	Broken wire IL2 measurement location 1
30122	brk. wire IL3M1	Broken wire IL3 measurement location 1
30123	brk. wire IL1M2	Broken wire IL1 measurement location 2
30124	brk. wire IL2M2	Broken wire IL2 measurement location 2
30125	brk. wire IL3M2	Broken wire IL3 measurement location 2
30126	brk. wire IL1M3	Broken wire IL1 measurement location 3
30127	brk. wire IL2M3	Broken wire IL2 measurement location 3
30128	brk. wire IL3M3	Broken wire IL3 measurement location 3
30129	brk. wire IL1M4	Broken wire IL1 measurement location 4
30130	brk. wire IL2M4	Broken wire IL2 measurement location 4
30131	brk. wire IL3M4	Broken wire IL3 measurement location 4
30132	brk. wire IL1M5	Broken wire IL1 measurement location 5
30133	brk. wire IL2M5	Broken wire IL2 measurement location 5
30134	brk. wire IL3M5	Broken wire IL3 measurement location 5
00160	Alarm Sum Event	Alarm Summary Event
00193	Alarm adjustm.	Alarm: Analog input adjustment invalid
00177	Fail Battery	Failure: Battery empty
00068	Clock SyncError	Clock Synchronization Error
00198	Err. Module B	Error: Communication Module B
00199	Err. Module C	Error: Communication Module C
00200	Err. Module D	Error: Communication Module D
30135	Incons.CBaux M1	Incons. M1: CBaux open/ curr. persistent
30136	Incons.CBaux M2	Incons. M2: CBaux open/ curr. persistent
30137	Incons.CBaux M3	Incons. M3: CBaux open/ curr. persistent
30138	Incons.CBaux M4	Incons. M4: CBaux open/ curr. persistent
30139	Incons.CBaux M5	Incons. M5: CBaux open/ curr. persistent
30140	Incons.CBaux S1	Incons. S1: CBaux open/ curr. persistent
30141	Incons.CBaux S2	Incons. S2: CBaux open/ curr. persistent

F.No.	Alarm	Comments
30142	Incons.CBaux S3	Incons. S3: CBaux open/ curr. persistent
30143	Incons.CBaux S4	Incons. S4: CBaux open/ curr. persistent
30144	Incons.CBaux S5	Incons. S5: CBaux open/ curr. persistent

F.No.	Alarm	Comments
06851	>BLOCK TripC	>BLOCK Trip circuit supervision
06852	>TripC trip rel	>Trip circuit supervision: trip relay
06853	>TripC brk rel.	>Trip circuit supervision: breaker relay
06861	TripC OFF	Trip circuit supervision OFF
06862	TripC BLOCKED	Trip circuit supervision is BLOCKED
06863	TripC ACTIVE	Trip circuit supervision is ACTIVE
06864	TripC ProgFail	Trip Circuit blk. Bin. input is not set
06865	FAIL: Trip cir.	Failure Trip Circuit

2.15 Protection Function Control

The function control is the control centre of the device. It coordinates the sequence of the protection and ancillary functions, processes their decisions and the information coming from the power system. Among these are

- processing of the circuit breaker position,
- fault detection/pickup logic,
- tripping logic.

2.15.1 Fault Detection Logic of the Entire Device

General Pickup

The fault detection logic combines the pickup signals of all protection functions. The pickup signals are combined with *OR* and lead to a general pickup of the device. It is signalled with the alarm “`Relay PICKUP`”. If no protection function of the device has picked up any longer, “`Relay PICKUP`” disappears (message: “`Going`”).

The general pickup is the precondition for a number of internal and external consequential functions. Among these functions, which are controlled by the general pickup, are:

- Start of a fault log: All fault messages are entered into the trip log from the beginning of the general pickup to the dropout.
- Initialization of the fault recording: The recording and storage of fault wave forms can additionally be made subject to the presence of a trip command.
- Creation of spontaneous displays: Certain fault messages can be displayed as so called spontaneous displays (see “Spontaneous Displays” below). This display can additionally be made subject to the presence of a trip command.

External functions can be controlled via an output contact. Examples are:

- Further additional devices or similar.

Spontaneous Displays

Spontaneous displays are alarms that are displayed automatically after a general pickup of the device or after the trip command of the device. In the case of 7UT6 they are the following:

- “(Prot.) `PICKUP`”: pickup of any protection function with phase indication;
- “(Prot.) `TRIP`”: trip of any protection function;
- “`PU Time`”: the operating time from the general pickup to the dropout of the device, the time is given in ms;
- “`TRIP Time`”: the operating time from the general pickup to the first trip command of the device, the time is given in ms.

Note, that the overload protection does not have a pickup comparable to the other protective functions. The general device pickup time is started with the trip signal, which starts the trip log.

2.15.2 Tripping Logic of the Entire Device

General Tripping

All tripping signals of the protection functions are combined with logical *OR* and lead to the alarm “`Relay TRIP`”. This can be allocated to an LED or output relay as can be each of the individual trip commands. It is suitable as general trip information as well as used for the output of trip commands to the circuit breaker.

Terminating the Trip Command

Once a trip command is activated, it is stored separately for each protection function (Figure 2-108). At the same time a minimum trip command duration **`TMin TRIP CMD`** is started to ensure that the command is sent to the circuit breaker long enough if the tripping protection function should drop off too quickly or if the breaker of the feeding end operates faster. The trip commands cannot be terminated until the last protection function has dropped off (no function picked up) *AND* the minimum trip command duration is over.

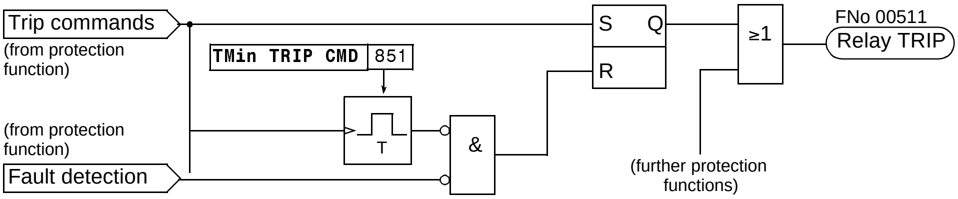


Figure 2-108 Storage and termination of the trip command (simplified)

Reclosure Interlocking

After tripping the circuit breaker by a protection function the manual reclosure must often be blocked until the cause for the protection operation is found.

Using the user-configurable logic functions (CFC) an automatic reclosure interlocking function can be created. The default setting of 7UT6 offers a pre-defined CFC logic which stores the trip command of the device until the command is acknowledged manually. The CFC-block is illustrated in Appendix A.5, margin heading “Preset CFC-Charts” (page 423). The internal output “`G-TRP Quit`” must be additionally assigned to the tripping output relays which are to be sealed.

Acknowledgement is done via binary input “`>QuitG-TRP`”. With default configuration, press function key F4 at the device front to acknowledge the stored trip command.

If the reclosure interlocking function is not required, delete the allocation between the internal single-point indication “`G-TRP Quit`” and the source “CFC” in the configuration matrix.

Note:

The internal single-point indication “`G-TRP Quit`” is not affected by the setting option ***`Block relay`*** of the protection functions. If this indication is allocated to a trip relay, this relay will be actuated in case of a trip of the protection functions, even if ***`Block relay`*** is set for that function.

“No Trip no Flag”

The storage of fault messages allocated to local LEDs and the availability of spontaneous displays can be made dependent on the device sending a trip command. Fault event information is then *not* output when one or more protection functions have picked up due to a fault but no tripping occurred because the fault was cleared by another device (e.g. on a different feeder). The information is thus limited to faults on the protected line (so-called “no trip – no flag” feature).

Figure 2-109 shows the logic diagram of this function.

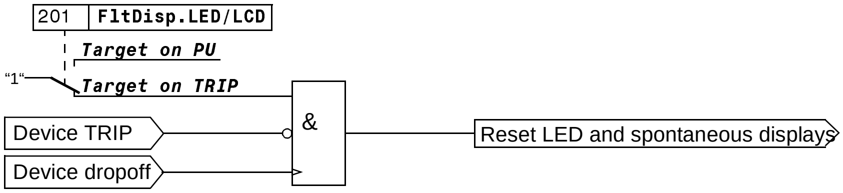


Figure 2-109 Logic diagram of the “no trip – no flag” feature (command-dependent alarms) (simplified)

CB Operation Statistics

The number of trips caused by the device 7UT6 is counted.

Furthermore, the current interrupted for each pole and each measuring location is acquired, provided as an information and accumulated in a memory. The criterion for the acquisition and accumulation of the current levels is that a trip command has been output by any protection function.

The levels of these counted values are buffered against auxiliary voltage failure. They can be set to zero or to any other initial value. For further information refer to the SIPROTEC® 4 System Manual, order no. E50417–H1176–C151.

2.15.3 Setting the Function Parameters

The parameters for the tripping logic of the entire device have already been set in Subsection 2.1.3.

Address 201 **FltDisp.LED/LCD** still decides whether the alarms that are allocated to local LEDs and the spontaneous displays that appear on the local display after a fault should be displayed on every pickup of a protection function (***Target on PU***) or whether they should be stored only when a tripping command is given (***Target on TRIP***).

2.15.4 Setting Overview

Addr.	Setting Title	Setting Options	Default Setting	Comments
201	FltDisp.LED/LCD	Display Targets on every Pickup Display Targets on TRIP only	Display Targets on every Pickup	Fault Display on LED / LCD
202	Spont. FltDisp.	NO YES	NO	Spontaneous display of flt.annunciations
204	Start image DD	image 1 image 2 image 3 image 4 image 5 image 6 image 7	image 1	Start image Default Display

2.15.5 Information Overview

F.No.	Alarm	Comments
00003	>Time Synch	>Synchronize Internal Real Time Clock
00005	>Reset LED	>Reset LED
00060	Reset LED	Reset LED
00015	>Test mode	>Test mode
	Test mode	Test mode
00016	>DataStop	>Stop data transmission
	DataStop	Stop data transmission
	UnlockDT	Unlock data transmission via BI
	>Light on	>Back Light on
00051	Device OK	Device is Operational and Protecting
00052	ProtActive	At Least 1 Protection Funct. is Active
00055	Reset Device	Reset Device
00056	Initial Start	Initial Start of Device
00067	Resume	Resume
00069	DayLightSavTime	Daylight Saving Time
	SynchClock	Clock Synchronization
00070	Settings Calc.	Setting calculation is running

F.No.	Alarm	Comments
00071	Settings Check	Settings Check
00072	Level-2 change	Level-2 change
00109	Frequ. o.o.r.	Frequency out of range
00125	Chatter ON	Chatter ON
	HWTestMod	Hardware Test Mode

2.16 Disconnection, Visualization Tools

Disconnection of Measuring Locations

During maintenance work, or when parts of the system are shut down during operation, it is sometimes necessary to suspend the processing of individual measuring locations by the differential protection system. For maintenance work on the circuit breaker **CBC** in Figure 2-110, for instance, the breaker would be isolated by opening the adjacent isolators.

The main protected object, a transformer, is in this example fed on side **S1** through the measuring locations **M1** and **M2**; the measuring location **M3** is on side **S2**. Assuming the measuring location **M2** should now be suspended due to the maintenance work on the circuit breaker. If this information is sent to the device through a binary input — in this case “`>disconnect M2`” —, the measuring location will no longer be included in the formation of the differential protection values. The measuring location is disconnected, i.e. any kind of work can be performed there without affecting the differential protection.

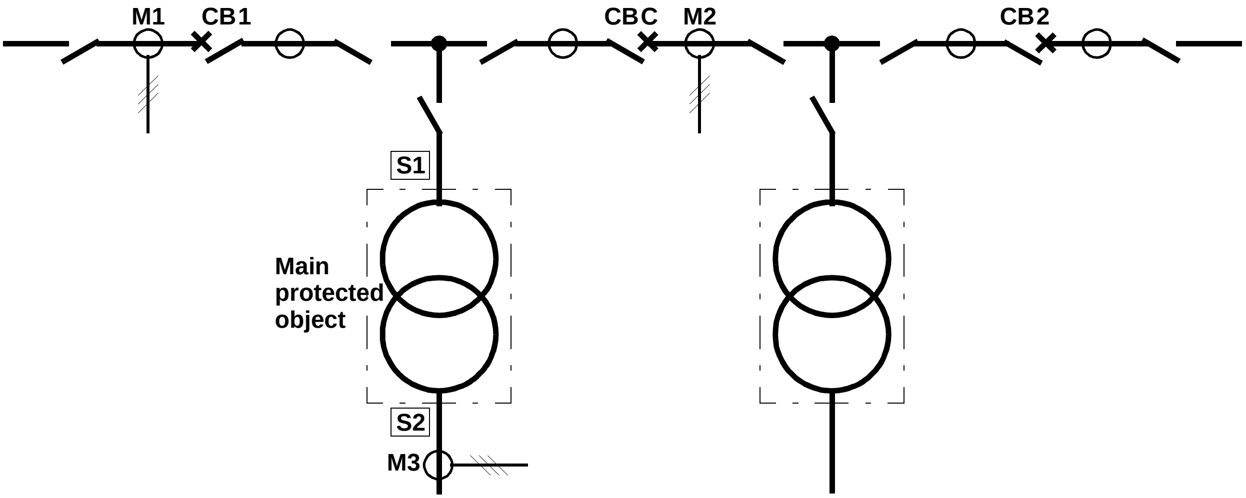


Figure 2-110 Arrangement with $1^1/_2$ circuit breakers (3 breakers for 2 transformer feeders)

Any measuring location can be disconnected by means of an appropriate binary input. In 1-phase busbar protection, such a binary input can be used for each feeder.

The disconnection works only in the specified frequency range of the protection, i.e. f_N ± 10 %. It is thus not suited for blocking the protection during startup of a machine. Instead, the blocking features provided in the protection functions must be used for this purpose.

The disconnection becomes effective only if no current is flowing through the measuring location to be disconnected. This is done by checking whether the current arriving from the measuring location has dropped below the threshold **`PoleOpenCurr.`** of the measuring location. Once the disconnection has become effective, this fact is reported by an output indication, e.g. with the indication “`M2 disconnected`”. The current threshold is no longer being checked from then on.

The disconnection ends when the binary input is deactivated. This requires, once again, that no current is flowing at the moment the disconnection is ended.

You can evade the condition that the disconnection mode can only be started or ended when no current is flowing via the measuring location. If you wish to start and end the disconnection mode even in case of current flow, you have to activate — together with the corresponding binary input “`>disconnect Mx`” — the input “`>disconn. I>=0`” (FNo `30361`). This can be done by means of a logical CFC-combination which combines all necessary disconnection inputs by *OR* so that the input “`>disconn. I>=0`” is activated always at the same instant.

The effectiveness of the disconnection is stored in the device and saved against auxiliary voltage failure, i.e. the last information about the disconnection state is maintained when the power supply of the device fails. When the power supply reverts, the state of the binary input(s) for disconnection is checked against the stored information. Only when they match, the protection functions will become active again. Inconsistencies are indicated as an alarm “`Fail.Disconnect`” (FNo `30145`) and the life-contact of the relay remains open. Only when the state of the binary input(s) will have been adapted to the stored information the device can operate again.

The effect of the disconnection is that the currents from the disconnected measuring location — as far as they are assigned to a side of the main protected object — are set to zero for those protection functions that are assigned to this side. Currents arriving from the system after disconnecting the measuring location are not effective here. The currents from 1-phase auxiliary measuring inputs allocated to the disconnected measuring location, on the other hand, are still valid. Currents remain valid, too, for those protection function which are not assigned to a side.

No protection functions are blocked. The differential protection continues to work with the remaining available measured values. In the above example, the transformer can still operate through measuring location M1, with the differential protection remaining fully effective.

Overcurrent protection functions assigned to a side continue to work without the current from the disconnected measuring location.

Overcurrent protection functions which are assigned *exclusively* to the disconnected measuring location (i.e. not via a side definition) are supplied with the currents of the disconnected measuring location, i.e. continue to operate with these currents. If necessary, they must be blocked by the information about disconnection (either by corresponding assignment in the matrix of binary inputs or by user defined logical combination by means of CFC).

The restricted earth fault protection, too, does not receive any more currents from the disconnected measuring location. If it is assigned to a side with two or more measuring locations, it can continue to work with the currents from the remaining measuring location(s). If the disconnected measuring location is the only 3-phase source for the restricted earth fault protection, the starpoint current stays effective. This means that the restricted earth fault protection will trip immediately if the starpoint current exceeds the pickup threshold. Such a current must be a fault current in the protected object: it cannot come from the power system, which is in fact isolated from the protected object.

“IBS-Tool”

The device is provided with a comprehensive commissioning and monitoring tool that is suitable for retrieving and checking the measured values and the whole differential protection system. Using a personal computer in conjunction with a web browser, this tool enables the user to clearly chart the state of the system and the differential protection values, measured values and indications. The necessary operator software is integrated in the device; online help can be found on the DIGSI® CD and is also available in the Internet.

To ensure a proper communication between the device and the PC browser the transmission speed must be equal for both. Furthermore, an IP-address is necessary so that the browser can identify the device. For 7UT6, the following is valid:

Transmission speed: **115** kBaud;

IP-address for connection at the front interface: **141.141.255.160**,
IP-address for connection at the rear interface port C: **141.143.255.160**.

The “IBS-Tool” shows the device front with its keypad and LCD display on the screen, thus allowing to operate the device from the PC. The actual operation of the device can be simulated with the mouse pointer.

Measured values and the values derived from them are graphically displayed as phasor diagrams. You can also view tripping diagrams. Scalar values are shown in numerical form. Most of the measured values discussed in Subsection 2.17.2, Tables 2-11 to 2-15, can also be displayed in the “IBS-Tool”. Figure 2-112 (page 249) shows an example of phasor diagrams for measured values.

For more details on working with the “IBS-Tool”, refer to the Online Help attached.

2.17 Ancillary Functions

The ancillary functions of the 7UT6 relay include:

- processing of messages,
- processing of operational measured values,
- storage of fault record data.

2.17.1 Processing of Messages

2.17.1.1 General

For the detailed fault analysis, the information regarding the reaction of the protection device and the measured values following a system fault are of interest. For this purpose, the device provides information processing which operates in a threefold manner:

Indicators (LEDs) and Binary Outputs (Output Relays)

Important events and states are indicated with optical indicators (LED) on the front plate. The device furthermore has output relays for remote indication. Most of the signals and indications can be marshalled, i.e. routing can be changed from the presetting with delivery. The procedure is described in detail in the SIPROTEC® 4 system manual, order no. E50417–H1176–C151. The state of the delivered relay (presetting) is listed in Section A.5 of the Appendix

The output relays and the LEDs may be operated in a latched or unlatched mode (each may be individually set).

The latched state is saved against loss of auxiliary supply. It is reset:

- locally by operation of the key LED reset on the front of the device,
- from remote via a binary input,
- via one of the serial interfaces,
- automatically on detection of a new fault.

Condition messages should not be latched. Also, they cannot be reset until the condition to be reported has reset. This applies to e.g. messages from monitoring functions, or similar.

A green LED indicates that the device is in service (“RUN”); it can not be reset. It extinguishes if the self-monitoring of the microprocessor recognizes a fault or if the auxiliary supply fails.

In the event that the auxiliary supply is available while there is an internal device failure, the red LED (“ERROR”) is illuminated and the device is blocked.

The binary inputs, outputs, and LEDs of a SIPROTEC®4 device can be individually and precisely checked using DIGSI®. This feature is used to verify wiring from the device to plant equipment during commissioning (refer also to Subsection 3.3.4).

Information on the Integrated Display (LCD) or to a Personal Computer

Events and states can be obtained from the LCD on the front plate of the device. A personal computer can be connected to the front interface or the service interface for retrieval of information.

In the quiescent state, i.e. as long as no system fault is present, the LCD can display selectable operational information (overview of the operational measured values). An overview is given in the Appendix A.5 under margin heading “Default Indications with 4-Line Display” or “Default Indications with Graphic Display” (page 421). In the event of a system fault, information regarding the fault, the so-called spontaneous displays, are displayed instead. The quiescent state information is displayed again once the fault messages have been acknowledged. The acknowledgement is identical to the resetting of the LEDs (see above).

The device in addition provides several event buffers for operational messages, switching statistics, etc., which are saved against loss of auxiliary supply by means of a battery buffer. These messages can be displayed on the LCD at any time by selection via the keypad or transferred to a personal computer via the serial service or PC interface. The retrieval of events/alarms during operation is extensively described in the SIPROTEC® 4 System Manual, order no. E50417–H1176–C151.

With a PC and the protection data processing program DIGSI® it is also possible to retrieve and display the events with the convenience of visualisation on a monitor and a menu-guided dialogue. The data may be printed or stored for later evaluation.

Information to a Control Centre

If the device has a serial system interface, the information may additionally be transferred via this interface to a centralized control and monitoring system. Several communication protocols are available for the transfer of this information.

You may test whether the information is transmitted correctly with DIGSI®.

Also the information transmitted to the control centre can be influenced during operation or tests. For on-site monitoring, the IEC protocol 60870–5–103 offers the option to add a comment saying “test mode” to all annunciations and measured values transmitted to the control centre. It is then understood as the cause of annunciation and there is no doubt on the fact that messages do not derive from real disturbances. Alternatively, you may disable the transmission of annunciations to the system interface during tests (“transmission block”).

To influence information at the system interface during test mode (“test mode” and “transmission block”) a CFC logic is required. Default settings already include this logic (see Appendix A.5, margin heading “Preset CFC-Charts”, page 423).

For information on how to enable and disable the test mode and the transmission block see for the SIPROTEC® 4 System Manual E50417–H1176–C151.

Structure of Messages

The messages are categorized as follows:

- Event Log: These are operating messages that can occur during the operation of the device. They include information about the status of device functions, measurement data, system data, and similar information.
- Trip Log: These are fault messages from the last eight network faults that were processed by the device.
- Switching statistics: These messages count the breaker control commands initiated by the device, values of accumulated circuit currents and interrupted currents.

A complete list of all message and output functions that can be generated by the device, with the associated information number (FNo), can be found in the Appendix. The lists also indicate where each message can be sent. The lists are based on a SIPROTEC® 4 device with the maximum complement of functions. If functions are not present in the specific version of the device, or if they are set as “***`Disabled`***” in device configuration, then the associated messages cannot appear.

2.17.1.2 Event Log (Operating Messages)

Operating messages contain information that the device generates during operation and about the operation. Up to 200 operating messages are stored in chronological order in the device. New messages are added at the end of the list. If the memory has been exceeded, then the oldest message is overwritten for each new message.

Operational annunciations come in automatically and can be read out from the device display or a personal computer. Faults in the power system are indicated with “`Network Fault`” and the present fault number. The fault messages (Trip Log) contain details about the history of faults. This topic is discussed in Subsection 2.17.1.3.

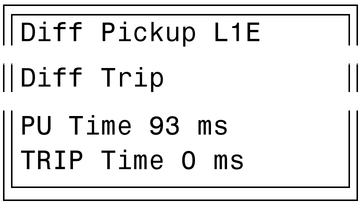
2.17.1.3 Trip Log (Fault Messages)

Following a system fault, it is possible to for example retrieve important information regarding its progress, such as pickup and trip. The start of the fault is time stamped with the absolute time of the internal system clock. The progress of the disturbance is output with a relative time referred to the instant of fault detection (first pickup of a protection function), so that the duration of the fault until tripping and up to reset of the trip command can be ascertained. The resolution of the time information is 1 ms.

A system fault starts with the recognition of the fault by the fault detection, i.e. first pickup of any protection function, and ends with the reset of the fault detection, i.e. dropout of the last protection function.

Spontaneous Displays

Spontaneous messages appear automatically in the display, after a general pickup of the device. The most important data about a fault can be viewed on the device front in the sequence shown in Figure 2-111.



```
Diff Pickup L1E
Diff Trip
PU Time 93 ms
TRIP Time 0 ms
```

Protection function that had picked up, e.g. differential protection, with phase information;

Protection function that had tripped, e.g. differential protection;

Elapsed time from pickup until dropoff;

Elapsed time from pickup until the first trip command of a protection function.

Figure 2-111 Display of spontaneous messages in the display

Retrieved Messages

The messages for the last eight network faults can be retrieved. Altogether up to 600 indications can be stored. Oldest data are erased for newest data when the buffer is full.

2.17.1.4 Spontaneous Annunciations

Spontaneous annunciations contain information on new incoming annunciations. Each new incoming annunciation appears immediately, i.e. the user does no have to wait for an update or initiate one. This can be a useful help during operation, testing and commissioning.

Spontaneous annunciations can be read out via DIGSI®. For further information see the SIPROTEC® 4 System Manual (order-no. E50417–H1176–C151).

2.17.1.5 General Interrogation

The present condition of a SIPROTEC® device can be examined by using DIGSI® by viewing the contents of the “General Interrogation” annunciation. All of the messages that are needed for a general interrogation are shown along with the actual values or states.

2.17.1.6 Switching Statistics

The messages in switching statistics are counters for the accumulation of interrupted currents by each of the breaker poles, the number of control commands issued by the device to the breakers. The interrupted currents are in primary terms.

Switching statistics can be viewed on the LCD of the device, or on a PC running DIGSI® and connected to the operating or service interface.

The counters and memories of the statistics are saved by the device. Therefore the information will not get lost in case the auxiliary voltage supply fails. The counters, however, can be reset back to zero or to any value within the setting range.

A password is not required to read switching statistics; however, a password is required to change or delete the statistics. For further information see the SIPROTEC® 4 System Manual (order-no. E50417–H1176–C151).

2.17.2 Measurement during Operation

Display and Transmission of Measured Values

Operating measured values and metered values are determined in the background by the processor system. They can be called up at the front of the device, read out via the operating interface using a PC with DIGSI®, or transferred to a central master station via the system interface (if available).

The computation of the operational measured values is also executed during an existent system fault in intervals of approx. 0,6 s.

The processing of operational measured values is much more than just the output of the measured values that can be acquired directly at the device's measuring inputs. A multitude of measured values is calculated from the measured values and referred to the application in hand. The options provided to flexibly adapt the device to a wide range of protected objects with various topologies require an equally flexible adaptation of the output of operational measured values. Only those operational values are displayed that result from the connected measured values and that make sense for the cases configured.

A correct display of primary and percentage values requires the complete and correct entry of the topology of the protected object (Subsection 2.1.2) and its nominal values (Subsection 2.1.3), as well as of the nominal instrument transformer values (Subsection 2.1.3).

For the measuring locations the primary and secondary measured values as per Table 2-11 are output. Depending on the device's order number, connection type, topology and protection functions configured, only a part of the magnitudes listed there is available. In single-phase transformers, all magnitudes of phase L2 are absent.

The powers S,P,Q are calculated from the measuring location to which the voltage transformers are assigned. If the voltage transformers are assigned to a *side* of the main protected object, the current sum applies, if the side has two or more measuring locations. With single-phase busbar protection, power calculation is not possible.

The definition of the signs is normally that the power flowing into the protected object is considered as positive: Active components and inductive reactive components in the direction of the protected object are positive. The same applies for the power factor cos φ. It is occasionally desired to define the power draw from the protected object (e.g. as seen from the busbar) positively. Using parameter address 1107 **P,Q sign** (Subsection 2.1.9 under margin heading "Sign of Power", page 67) the signs for these components can be inverted.

In devices without voltage measuring inputs, it is nevertheless possible to output a voltage and an apparent power if a voltage is connected via an external series resistor to a 1-phase current measuring input. Via a user-configurable CFC logic (CFC block "Life_Zero") the current proportional to the voltage can be measured and indicated as voltage "Umeas". The procedure is described in the CFC manual.

The apparent power "S" is (without voltage connections) not a measured value, but a value calculated from the rated voltage of the protected object which is set and the actually flowing currents of side 1: $S = \frac{U_N}{\sqrt{3}} \cdot (I_{L1S1} + I_{L2S1} + I_{L3S1})$ for three-phase applications or $S = \frac{U_N}{2} \cdot (I_{L1S1} + I_{L3S1})$ for single-phase transformers. If, however, the voltage measurement described in the previous paragraph is applied, this voltage measurement is used to calculate the apparent power. The apparent power is output here as a magnitude; it does not contain any directional information.

Table 2-11 Operational measured values (magnitudes) of the measuring locations

Measured values		**Primary**	**Secondary**	**% referred to**
IL1M1; IL2M1; IL3M1; IL1M2; IL2M2; IL3M2; IL1M3; IL2M3; IL3M3 1)	Phase currents at the measuring locations M1 to M3 1)	A; kA	A	—
I1M1; I2M1; 3I0M1; I1M2; I2M2; 3I0M2; I1M3; I2M3; 3I0M3 2)	Positive, negative and zero sequence component of the currents at the measuring locations M1 to M3 2)	A; kA	A	—
IL1M4; IL2M4; IL3M4; IL1M5; IL2M5; IL3M5 1) 6)	Phase currents at the measuring locations M4 and M5 1) 6)	A; kA	A	—
I1M4; I2M4; 3I0M4; I1M5; I2M5; 3I0M5 2) 6)	Positive, negative and zero sequence component of the currents at the measuring locations M4 and M5 2) 6)	A; kA	A	—
IX1; IX2; IX3	Currents at the 1-phase auxiliary measuring locations X1 to X3	A; kA	A	—
IX4 6)	Current at the auxiliary measuring location X4 6)	A; kA	A	—
I1 to I9 3)	Currents at the measuring inputs 3)	A; kA	A	—
I10 to I12 3) 6)	Currents at the measuring inputs 3) 6)	A; kA	A	—
UL1E; UL2E; UL3E 1) 5)	Phase-to-earth voltages at the 3-phase voltage meas. location 1) 5)	V; kV; MV	V	Operating nom. voltage/√3
UL12; UL23; UL31 1) 5)	Phase-to-phase voltages at the 3-phase voltage meas. location 1) 5)	V; kV; MV	V	Operating nominal voltage
U1; U2; U0 2) 5)	Positive, negative and zero sequence component of the voltages at the measuring locations M1 to M3 2) 5)	V; kV; MV	V	Operating nom. voltage/√3
Uen 5)	Displacement voltage if connected to the 1-phase voltage measuring input 5)	—	V	Operating nominal voltage
U4 5)	Voltage at the 1-phase voltage measuring input 5)	V; kV; MV	V	Operating nominal voltage
S; P; Q 1) 5)	Apparent, active and reactive power 1) 5)	kVA; MVA; kW; MW	—	Operating nominal apparent power
cos φ 1) 5)	Power factor 1) 5)	(absolute)	—	(absolute)
Umeas 7)	Voltage from the current measured at the 1-phase measuring input 7)	V; kV; MV	—	—
U/f	Overexcitation factor	U_N/f_N	—	U_N/f_N
S 8)	Apparent power from Umeas 8)	kVA; MVA	—	—
f	Frequency	Hz	Hz	Rated frequency

1) only for 3-phase objects, also for single-phase transformers
2) only for 3-phase objects, not for single-phase transformers
3) only for single-phase busbar protection
5) only for 7UT613 and 7UT633 with voltage measuring inputs
6) only for 7UT635
7) if configured and prepared in CFC
8) calculated from phase currents and nominal voltage or measured voltage Umeas

In addition to the measured and calculated values at the measuring locations, measured values are output at the sides of the main protected object. This makes it possible to obtain the data relevant for the protected object even if they are fed to the protected object from several measuring locations, as in the arrangement shown in Figure 2-1 (page 22) for the higher voltage side (S1) of the transformer. Also, relative values are always referred to a specific side of the protected object. A current which does not flow into the object from 2 measuring locations (such as in Figure 2-1 a current flowing from one busbar through M1 and M2 to the other busbar) is theoretically zero because no current flows into the protected object.

Table 2-12 summarizes the operational measured values that are assigned to the sides. Depending on the device's order number, connection type, topology and protection functions configured, only a part of the magnitudes listed there is available. The table does not apply to the single-phase busbar protection, since no sides are defined there.

Table 2-12 Operational measured values (magnitudes) of the sides

Measured values		Primary	Secondary	Referred to
IL1S1; IL2S1; IL3S1; IL1S2; IL2S2; IL3S2; IL1S3; IL2S3; IL3S3 ^{1})	Phase currents (total) flowing in from the sides S1 to S3 ^{1})	A; kA	—	Operating nominal current of the respective side
I1S1; I2S1; 3I0S1; I1S2; I2S2; 3I0S2; I1S3; I2S3; 3I0S3 ^{2})	Positive, negative and zero sequence component of the currents at the sides S1 to S3 ^{2})	A; kA	—	Operating nominal current of the respective side
IL1S4; IL2S4; IL3S4; IL1S5; IL2S5; IL3S5 ^{1}) ^{6})	Phase currents (total) flowing in from the sides S4 and S5 ^{1}) ^{6})	A; kA	—	Operating nominal current of the respective side
I1S4; I2S4; 3I0S4; I1S5; I2S5; 3I0S5 ^{2}) ^{6})	Positive, negative and zero sequence component of the currents at the sides S4 and S5 ^{2}) ^{6})	A; kA	—	Operating nominal current of the respective side

^{1}) only for 3-phase objects, also for single-phase transformers
^{2}) only for 3-phase objects, not for single-phase transformers
^{6}) only for 7UT635

The phase angles are listed separately in Table 2-13. The reference value for 3-phase objects is the current I_{L1M1} (current in phase L1 at measuring location M1), which has thus a phase angle = 0°. With 1-phase busbar protection, the current I_1 has the phase angle 0°, i.e. it is the reference value.

Depending on the device's order number, connection type, topology and protection functions configured, only a part of the phase angles listed there is available.

The phase angles are indicated in degrees. Since further processing of such values (in CFC or when transmitted through serial interfaces) requires values without dimension, arbitrary references have been chosen, which are contained in the column "% conversion".

Table 2-13 Operational measured values (phase relationship)

Measured values		Dimension	% Conversion 7)
φIL1M1; φIL2M1; φIL3M1; φIL1M2; φIL2M2; φIL3M2; φIL1M3; φIL2M3; φIL3M3 1)	Phase angle of the currents at the measuring locations M1 to M3, referred to I_{L1M1} 1)	°	0° = 0 % 360° = 100 %
φIL1M4; φIL2M4; φIL3M4; φIL1M5; φIL2M5; φIL3M5 1) 6)	Phase angle of the currents at the measuring locations M4 and M5, referred to I_{L1M1} 1) 6)	°	0° = 0 % 360° = 100 %
φIX1; φIX2; φIX3	Phase angle of the currents at the 1-phase aux. measuring locations X1 to X3, referred to I_{L1M1}	°	0° = 0 % 360° = 100 %
φIX4 6)	Phase angle of the currents at the 1-phase aux. measuring location X4, referred to I_{L1M1} 6)	°	0° = 0 % 360° = 100 %
φI1 to φI9 3)	Phase angle of the currents at the measuring inputs, referred to I_1 3)	°	0° = 0 % 360° = 100 %
φI10 to φI12 3) 6)	Phase angle of the currents at the measuring inputs, referred to I_1 3) 6)	°	0° = 0 % 360° = 100 %
φUL1E; φUL2E; φUL3E 1) 5)	Phase angle of the voltages at the 3-phase voltage meas. location, referred to I_{L1M1} or I_1 1) 5)	°	0° = 0 % 360° = 100 %
φUen 2) 5)	Phase angle of the displacement voltage, if connected to the 1-phase voltage measuring input, referred to I_{L1M1} or I_1 5)	°	0° = 0 % 360° = 100 %
φU4 5)	Phase angle of the voltage at the 1-phase voltage measuring input, referred to I_{L1M1} or I_1 5)	°	0° = 0 % 360° = 100 %
1) only for 3-phase objects, also for single-phase transformers 2) only for 3-phase objects, not for single-phase transformers 3) only for single-phase busbar protection 5) only for 7UT613 and 7UT633 with voltage measuring inputs 6) only for 7UT635			7) only for CFC and serial interfaces

The thermal values are listed in Table 2-14. They can only be displayed of the overload protection has been configured as ***`Enabled`***. Which measured values are possible is also dependent of the overload detection method chosen and, if applicable, of the number of temperature detectors connected through the RTD-box.

The hot-spot temperatures are calculated in transformers for each leg. Therefore, temperatures are indicated with a phase (in the case of Y windings), or with a phase-to-phase concatenation (D windings). For standard vector groups, this information correspond to the ends of the windings. In more unusual vector groups (which are created by phase swapping), the phase assignment in the vector group is not always clear.

The thermal values are referred to the tripping temperature rise. For degrees of temperature there are no referred values. However, since further processing of such values (in CFC or when transmitted through serial interfaces) requires values without dimension, arbitrary references have been chosen, which are contained in Table 2-14 in the column "% conversion".

Table 2-14 Thermal values

Measured values		Dimension	% Conversion 7)
$\Theta_{L1}/\Theta_{trip}$; $\Theta_{L2}/\Theta_{trip}$; $\Theta_{L3}/\Theta_{trip}$ 1)	Thermal value of each phase, referred to the tripping value	%	
Θ/Θ_{trip} 1)	Thermal resultant value, referred to the tripping value	%	
Ag.Rate 2) 3)	Relative ageing rate L	p.u.	
ResWARN2) 3)	Load reserve to hot-spot warning (stage 1)	%	
ResALARM 2) 3)	Load reserve to hot-spot alarm (stage 2)	%	
Θ leg L1; Θ leg L2; Θ leg L3 2) 3)	Hot-spot temperature for each phase (Y winding)	°C or °F	0 °C = 0 % 500 °C = 100 % 0 °F = 0 % 1000 °F = 100 %
Θ leg L21; Θ leg L23; Θ leg L31 2) 3)	Hot-spot temperature for each phase (D winding)	°C or °F	
Θ RTD 1... Θ RTD12 3)	Temperature of the temperature detectors 1 to 12	°C or °F	

1) only for overload protection with thermal replica (IEC 60255–8): address 142 **THERM. OVERLOAD** = ***thermal replica*** (Subsection 2.1.1)

2) only for overload protection with hot-spot calculation (IEC 60354): address 142 **THERM. OVERLOAD** = ***IEC354*** (Subsection 2.1.1)

3) only if RTD-box(es) available (Subsection 2.10)

7) only for CFC and serial interfaces

Differential Protection Values

The differential and restraining values of the differential protection and the restricted earth fault protection are listed in Table 2-15. They are always referred to the nominal current of the main protected object, which results from the parameterized nominal data of the main protected object (Subsection 2.1.3). For multi-winding transformers with different winding ratings, the most powerful winding is decisive, for busbars and lines the nominal operation current as set for the protected object. With 1-phase busbar protection, only the values of the connected and declared phase are displayed.

For restricted earth fault protection, the nominal of the phase related currents provide the reference value.

Table 2-15 Values of the differential protection

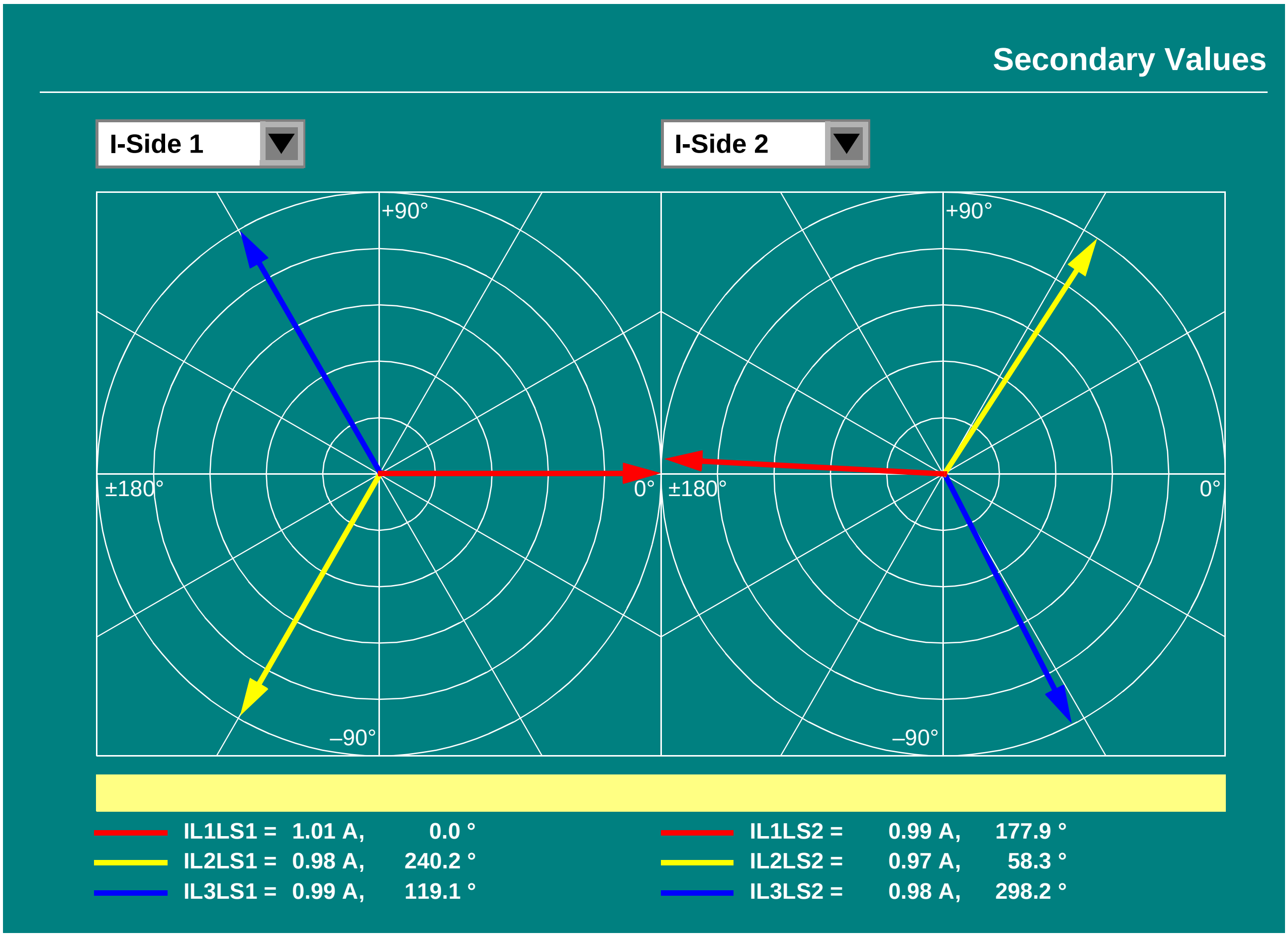
Measured values		% referred to
$I_{Diff L1}$, $I_{Diff L2}$, $I_{Diff L3}$	Calculated differential currents of the three phases	Operating nominal current of the protected object
$I_{Rest L1}$, $I_{Rest L2}$, $I_{Rest L3}$	Calculated restraining currents of the three phases	Operating nominal current of the protected object
$I_{Diff REF}$	Calculated differential current of the restricted earth fault protection	Operating nom. current of the side or 3-phase meas. loc.
$I_{Rest REF}$	Calculated restraining current of the restricted earth fault protection	Operating nom. current of the side or 3-phase meas. loc.

The IBS-Tool

The commissioning help “IBS-tool” offers a wide range of commissioning, visualization, and monitoring functions that allow a detailed illustration of the most important measured values via a personal computer equipped with a web-browser. For more details refer to the “Online Help” for the IBS-tool.

This tool allows to illustrate the measured values of all measuring locations or sides of the protected object during commissioning and during operation. The currents appear as phasor diagrams and are indicated as numerical values. Figure 2-112 shows an example.

Additionally the position of the differential and restraint values can be viewed in the pickup characteristic.



IL1LS1 = 1.01 A, 0.0 °
IL2LS1 = 0.98 A, 240.2 °
IL3LS1 = 0.99 A, 119.1 °

IL1LS2 = 0.99 A, 177.9 °
IL2LS2 = 0.97 A, 58.3 °
IL3LS2 = 0.98 A, 298.2 °

Figure 2-112 Measured values of the sides of the protected object — example for through-flowing currents

User Defined Set-Points

In SIPROTEC® 7UT6, set-points can be configured for measured and metered values. If, during operation, a value reaches one of these set-points, the device generates an alarm which is indicated as an operational message. As for all operational messages, it is possible to output the information to LED and/or output relay and via the serial interfaces. Unlike real protection functions such as time overcurrent protection or overload protection, this monitoring routine runs in the background, so that in the case of a fault and rapidly changing measured values it may not respond when protection functions pick up. Also, these set-points do not respond immediately before a trip because an alarm is only output if the setpoint are repeatedly violated.

Set-points can only be set if their measured and metered values have been configured correspondingly in CFC (see SIPROTEC®4 System Manual, ordering number E50417–H1176–C151).

Energy Metering

7UT6 integrates the calculated power which is then made available with the Measured Values. The components as listed in Table 2-16 can be read out. Note that “input” and “output” are always as seen from the protected object. The signs of the operating values depend (as for the powers) on the setting at address 1107 **P,Q sign** (see above under margin heading “Display and Transmission of Measured Values“, page 244). With single-phase busbar protection no calculation of the real power is possible.

Of course, the energy counter can only be used in situations where a calculation of the power is possible.

The values are always incremented upwards, never downwards. This means, for instance, that W_p+ goes up if the real power is positive and that in the presence of a negative real power W_p– goes up, but Wp+ does not go down, etc.

Please keep in mind that the 7UT6 is mainly designed for protection. The accuracy of the measured values depends on the current transformers (normally protection cores) and the tolerances of the device. The metering is therefore not suited for tariff purposes. Furthermore, currents below the minimum current **PoleOpenCurr.** for the respective side are not processed.

The counters can be reset to zero or any initial value (cf. SIPROTEC®System Description, Order No. E50417–H1176–C151).

Table 2-16 Operational metered values

Measured values		primary
W_p+	Real power, input	kWh, MWh, GWh
W_p–	Real power, output	kWh, MWh, GWh
W_q+	Reactive power, input	kVARh, MVARh, GVARh
W_q–	Reactive power, output	kVARh, MVARh, GVARh

Operating Hours Meter

The main protected object is considered to be in operation if a current flows at least on one side, i.e. if the minimum threshold for detection of a current flow is exceeded, e.g. for side 1 the threshold **PoleOpenCurr.S1** (address 1111). A current which does not flow into the object from 2 measuring locations (such as in Figure 2-1 a current flowing from one busbar through M1 and M2 to the other busbar) is not metered because no current flows into the protected object.

In busbar protection, the busbar is considered to be in operation if a current flows through at least one measuring location (i.e. one feeder).

The 7UT6 meters the operating hours and outputs them in the measured values. The upper limit is 999,999 hours (approx. 114 years).

You can define for the operating hours a setpoint for the output of an operational indication.

2.17.3 Fault Recording

The differential protection 7UT6 is equipped with a fault recording function. The instantaneous values of the measured quantities

i_{L1}, i_{L2}, i_{L3}, $3i_0$ of all available 3-phase measuring locations,
i_{L1}, i_{L2}, i_{L3}, $3i_0$ of all available sides of the main protected object,
i_{X1}, i_{X2}, i_{X3}, i_{X4} of all available 1-phase auxiliary measuring locations,
u_{L1}, u_{L2}, u_{L3}, u_{en}, u_4 of all available voltages,
I_{DiffL1}, I_{DiffL2}, I_{DiffL3}, I_{RestL1}, I_{RestL2}, I_{RestL3}, referred to the nominal object current.

are sampled at $1^2/_3$ ms intervals (for a frequency of 50 Hz) and stored in a cyclic buffer (12 samples per period). The centre phase (L2) is omitted in case of a single-phase power transformer. When used as single-phase busbar protection, the feeder currents are stored instead of the phase currents, the zero sequence currents are nor applicable.

During a system fault these data are stored over a time span that can be set (5 s at the longest for each fault record). Up to 8 faults can be stored. The total capacity of the fault record memory is approx. 5 s. The fault recording buffer is updated when a new fault occurs, so that acknowledging is not necessary. Fault recording can be initiated, additionally to the protection pickup, via the integrated operator panel, the serial operator interface and the serial service interface.

The data can be retrieved via the serial interfaces by means of a personal computer and evaluated with the protection data processing program DIGSI® and the graphic analysis software SIGRA. The latter graphically represents the data recorded during the system fault and calculates additional information from the measured values. A selection may be made as to whether the measured quantities are represented as primary or secondary values. Binary signal traces (marks) of particular events e.g. “fault detection”, “tripping” are also represented.

If the device has a serial system interface, the fault recording data can be passed on to a central device via this interface. The evaluation of the data is done by the respective programs in the central device. The measured quantities are referred to their maximum values, scaled to their rated values and prepared for graphic representation. In addition, internal events are recorded as binary traces (marks), e.g. “fault detection”, “tripping”.

Where transfer to a central device is possible, the request for data transfer can be executed automatically. It can be selected to take place after each fault detection by the protection, or only after a trip.

2.17.4 Setting the Function Parameters

Measured Values

In addition to the values measured directly and the measured values calculated from currents and maybe from voltages and temperatures, 7UT6 can also output a voltage and apparent power even if no voltage inputs are available.

To get the voltage value in this case, a voltage must be connected to one of the 1-phase current measuring inputs via an external series resistor. Additionally, a user-defined logic must be created in CFC (see Subsection 2.17.2, margin heading “Display and Transmission of Measured Values”).

The apparent power is either calculated from this voltage proportional current or from the rated voltage of side 1 of the protected object and the currents of the same side. For the first case, set address 7601 **POWER CALCUL.** to = ***with V measur.***, for the latter case ***with V setting***.

Waveform Capture

The settings pertaining to waveform capture are found under the **OSC.FAULT REC.** sub-menu of the **SETTINGS** menu.

Distinction is made between the starting instant (i.e. the instant where time tagging is T = 0) and the criterion to save the record (address 901 **WAVEFORMTRIGGER**). With the setting ***Save w. Pickup***, the starting instant and the criterion for saving are the same: the pickup of any protective element. The option ***Save w. TRIP*** means that also the pickup of a protective function starts fault recording but the record is saved only if the device issues a trip command. The final option for address 901 is ***Start w. TRIP***: A trip command issued by the device is both the starting instant and the criterion to save the record.

An oscillographic record includes data recorded prior to the time of trigger, and data after the dropout of the recording criterion. You determine the length of pre-trigger time and post-dropout time to be included in the fault record with the settings in Address 904 **PRE. TRIG. TIME** and address 905 **POST REC. TIME.**

The maximum length of time of a record is entered in address 903 **MAX. LENGTH**. The largest value here is 5 seconds. A total of 8 records can be saved. However the total length of time of all fault records in the buffer may not exceed 5 seconds. Once the capacity of the buffer is exceeded the oldest fault is deleted, whereas the new fault is saved in the buffer.

An oscillographic record can be triggered and saved via a binary input or via the operating interface connected to a PC. The trigger is dynamic. The length of a record for these special triggers is set in address 906 **BinIn CAPT.TIME** (upper bound is address 903). Pre-trigger and post-dropout settings in Addresses 904 and 905 are included. If address 906 is set for “∞”, then the length of the record equals the time that the binary input is activated (static), or the **MAX. LENGTH** setting in address 903, whichever is shorter.

2.17.5 Setting Overview

Measured Values

Addr.	Setting Title	Setting Options	Default Setting	Comments
7601	POWER CALCUL.	with V setting with V measuring	with V setting	Calculation of Power

Fault Recording

Addr.	Setting Title	Setting Options	Default Setting	Comments
401	WAVEFORMTRIGGER	Save with Pickup Save with TRIP Start with TRIP	Save with Pickup	Waveform Capture
403	MAX. LENGTH	0.30..4.00 sec	1.00 sec	Max. length of a Waveform Capture Record
404	PRE. TRIG. TIME	0.05..0.50 sec	0.10 sec	Captured Waveform Prior to Trigger
405	POST REC. TIME	0.05..0.50 sec	0.10 sec	Captured Waveform after Event
406	BinIn CAPT.TIME	0.10..5.00 sec; ∞	0.50 sec	Capture Time via Binary Input

2.17.6 Information Overview

Statistics

F.No.	Alarm	Comments
00409	>BLOCK Op Count	>BLOCK Op Counter
01020	Op.Hours=	Counter of operating hours
01000	# TRIPs=	Number of breaker TRIP commands
30763	ΣIL1M1:	Accumulation of interrupted curr. L1 M1
30764	ΣIL2M1:	Accumulation of interrupted curr. L2 M1
30765	ΣIL3M1:	Accumulation of interrupted curr. L3 M1
30766	ΣIL1M2:	Accumulation of interrupted curr. L1 M2
30767	ΣIL2M2:	Accumulation of interrupted curr. L2 M2
30768	ΣIL3M2:	Accumulation of interrupted curr. L3 M2
30769	ΣIL1M3:	Accumulation of interrupted curr. L1 M3
30770	ΣIL2M3:	Accumulation of interrupted curr. L2 M3
30771	ΣIL3M3:	Accumulation of interrupted curr. L3 M3

F.No.	Alarm	Comments
30772	ΣIL1M4:	Accumulation of interrupted curr. L1 M4
30773	ΣIL2M4:	Accumulation of interrupted curr. L2 M4
30774	ΣIL3M4:	Accumulation of interrupted curr. L3 M4
30775	ΣIL1M5:	Accumulation of interrupted curr. L1 M5
30776	ΣIL2M5:	Accumulation of interrupted curr. L2 M5
30777	ΣIL3M5:	Accumulation of interrupted curr. L3 M5
30607	ΣIL1S1:	Accumulation of interrupted curr. L1 S1
30608	ΣIL2S1:	Accumulation of interrupted curr. L2 S1
30609	ΣIL3S1:	Accumulation of interrupted curr. L3 S1
30610	ΣIL1S2:	Accumulation of interrupted curr. L1 S2
30611	ΣIL2S2:	Accumulation of interrupted curr. L2 S2
30612	ΣIL3S2:	Accumulation of interrupted curr. L3 S2
30778	ΣIL1S3:	Accumulation of interrupted curr. L1 S3
30779	ΣIL2S3:	Accumulation of interrupted curr. L2 S3
30780	ΣIL3S3:	Accumulation of interrupted curr. L3 S3
30781	ΣIL1S4:	Accumulation of interrupted curr. L1 S4
30782	ΣIL2S4:	Accumulation of interrupted curr. L2 S4
30783	ΣIL3S4:	Accumulation of interrupted curr. L3 S4
30784	ΣIL1S5:	Accumulation of interrupted curr. L1 S5
30785	ΣIL2S5:	Accumulation of interrupted curr. L2 S5
30786	ΣIL3S5:	Accumulation of interrupted curr. L3 S5
30620	ΣI1:	Accumulation of interrupted curr. I1
30621	ΣI2:	Accumulation of interrupted curr. I2
30622	ΣI3:	Accumulation of interrupted curr. I3
30623	ΣI4:	Accumulation of interrupted curr. I4
30624	ΣI5:	Accumulation of interrupted curr. I5
30625	ΣI6:	Accumulation of interrupted curr. I6
30626	ΣI7:	Accumulation of interrupted curr. I7
30787	ΣI8:	Accumulation of interrupted curr. I8
30788	ΣI9:	Accumulation of interrupted curr. I9
30789	ΣI10:	Accumulation of interrupted curr. I10
30790	ΣI11:	Accumulation of interrupted curr. I11
30791	ΣI12:	Accumulation of interrupted curr. I12

Measured Values

F.No.	Alarm	Comments
30661	IL1M1=	Operat. meas. current IL1 meas. loc. 1
30662	IL2M1=	Operat. meas. current IL2 meas. loc. 1
30663	IL3M1=	Operat. meas. current IL3 meas. loc. 1
30664	3I0M1=	3I0 (zero sequence) of meas. loc. 1
30665	I1M1=	I1 (positive sequence) of meas. loc. 1
30666	I2M1=	I2 (negative sequence) of meas. loc. 1
30667	IL1M2=	Operat. meas. current IL1 meas. loc. 2
30668	IL2M2=	Operat. meas. current IL2 meas. loc. 2
30669	IL3M2=	Operat. meas. current IL3 meas. loc. 2
30670	3I0M2=	3I0 (zero sequence) of meas. loc. 2
30671	I1M2=	I1 (positive sequence) of meas. loc. 2
30672	I2M2=	I2 (negative sequence) of meas. loc. 2
30673	IL1M3=	Operat. meas. current IL1 meas. loc. 3
30674	IL2M3=	Operat. meas. current IL2 meas. loc. 3
30675	IL3M3=	Operat. meas. current IL3 meas. loc. 3
30676	3I0M3=	3I0 (zero sequence) of meas. loc. 3
30677	I1M3=	I1 (positive sequence) of meas. loc. 3
30678	I2M3=	I2 (negative sequence) of meas. loc. 3
30679	IL1M4=	Operat. meas. current IL1 meas. loc. 4
30680	IL2M4=	Operat. meas. current IL2 meas. loc. 4
30681	IL3M4=	Operat. meas. current IL3 meas. loc. 4
30682	3I0M4=	3I0 (zero sequence) of meas. loc. 4
30683	I1M4=	I1 (positive sequence) of meas. loc. 4
30684	I2M4=	I2 (negative sequence) of meas. loc. 4
30685	IL1M5=	Operat. meas. current IL1 meas. loc. 5
30686	IL2M5=	Operat. meas. current IL2 meas. loc. 5
30687	IL3M5=	Operat. meas. current IL3 meas. loc. 5
30688	3I0M5=	3I0 (zero sequence) of meas. loc. 5
30689	I1M5=	I1 (positive sequence) of meas. loc. 5
30690	I2M5=	I2 (negative sequence) of meas. loc. 5
00721	IL1S1=	Operat. meas. current IL1 side 1
00722	IL2S1=	Operat. meas. current IL2 side 1
00723	IL3S1=	Operat. meas. current IL3 side 1

F.No.	Alarm	Comments
30640	3I0S1=	3I0 (zero sequence) of side 1
30641	I1S1=	I1 (positive sequence) of side 1
30642	I2S1=	I2 (negative sequence) of side 1
00724	IL1S2=	Operat. meas. current IL1 side 2
00725	IL2S2=	Operat. meas. current IL2 side 2
00726	IL3S2=	Operat. meas. current IL3 side 2
30643	3I0S2=	3I0 (zero sequence) of side 2
30644	I1S2=	I1 (positive sequence) of side 2
30645	I2S2=	I2 (negative sequence) of side 2
00727	IL1S3=	Operat. meas. current IL1 side 3
00728	IL2S3=	Operat. meas. current IL2 side 3
00729	IL3S3=	Operat. meas. current IL3 side 3
30713	3I0S3=	3I0 (zero sequence) of side 3
30714	I1S3=	I1 (positive sequence) of side 3
30715	I2S3=	I2 (negative sequence) of side 3
30716	IL1S4=	Operat. meas. current IL1 side 4
30717	IL2S4=	Operat. meas. current IL2 side 4
30718	IL3S4=	Operat. meas. current IL3 side 4
30719	3I0S4=	3I0 (zero sequence) of side 4
30720	I1S4=	I1 (positive sequence) of side 4
30721	I2S4=	I2 (negative sequence) of side 4
30722	IL1S5=	Operat. meas. current IL1 side 5
30723	IL2S5=	Operat. meas. current IL2 side 5
30724	IL3S5=	Operat. meas. current IL3 side 5
30725	3I0S5=	3I0 (zero sequence) of side 5
30726	I1S5=	I1 (positive sequence) of side 5
30727	I2S5=	I2 (negative sequence) of side 5
30646	I1=	Operat. meas. current I1
30647	I2=	Operat. meas. current I2
30648	I3=	Operat. meas. current I3
30649	I4=	Operat. meas. current I4
30650	I5=	Operat. meas. current I5
30651	I6=	Operat. meas. current I6
30652	I7=	Operat. meas. current I7

F.No.	Alarm	Comments
30653	I8=	Operat. meas. current I8
30732	I9=	Operat. meas. current I9
30733	I10=	Operat. meas. current I10
30734	I11=	Operat. meas. current I11
30735	I12=	Operat. meas. current I12
30728	IX1=	Operat. meas. auxiliary current IX1
30729	IX2=	Operat. meas. auxiliary current IX2
30730	IX3=	Operat. meas. auxiliary current IX3
30731	IX4=	Operat. meas. auxiliary current IX4
30736	φIL1M1=	Phase angle in phase IL1 meas. loc. 1
30737	φIL2M1=	Phase angle in phase IL2 meas. loc. 1
30738	φIL3M1=	Phase angle in phase IL3 meas. loc. 1
30739	φIL1M2=	Phase angle in phase IL1 meas. loc. 2
30740	φIL2M2=	Phase angle in phase IL2 meas. loc. 2
30741	φIL3M2=	Phase angle in phase IL3 meas. loc. 2
30742	φIL1M3=	Phase angle in phase IL1 meas. loc. 3
30743	φIL2M3=	Phase angle in phase IL2 meas. loc. 3
30744	φIL3M3=	Phase angle in phase IL3 meas. loc. 3
30745	φIL1M4=	Phase angle in phase IL1 meas. loc. 4
30746	φIL2M4=	Phase angle in phase IL2 meas. loc. 4
30747	φIL3M4=	Phase angle in phase IL3 meas. loc. 4
30748	φIL1M5=	Phase angle in phase IL1 meas. loc. 5
30749	φIL2M5=	Phase angle in phase IL2 meas. loc. 5
30750	φIL3M5=	Phase angle in phase IL3 meas. loc. 5
30633	φI1=	Phase angle of current I1
30634	φI2=	Phase angle of current I2
30635	φI3=	Phase angle of current I3
30636	φI4=	Phase angle of current I4
30637	φI5=	Phase angle of current I5
30638	φI6=	Phase angle of current I6
30639	φI7=	Phase angle of current I7
30755	φI8=	Phase angle of current I8
30756	φI9=	Phase angle of current I9
30757	φI10=	Phase angle of current I10

F.No.	Alarm	Comments
30758	φI11=	Phase angle of current I11
30759	φI12=	Phase angle of current I12
30751	φIX1=	Phase angle in auxiliary current IX1
30752	φIX2=	Phase angle in auxiliary current IX2
30753	φIX3=	Phase angle in auxiliary current IX3
30754	φIX4=	Phase angle in auxiliary current IX4
00621	UL1E=	U L1-E
00622	UL2E=	U L2-E
00623	UL3E=	U L3-E
00624	UL12=	U L12
00625	UL23=	U L23
00626	UL31=	U L31
30760	U4 =	Operat. meas. voltage U4
00627	UE =	Displacement voltage UE
30761	U0meas.=	Operat. meas. voltage U0 measured
30762	U0calc.=	Operat. meas. voltage U0 calculated
00629	U1 =	U1 (positive sequence)
00630	U2 =	U2 (negative sequence)
30656	Umeas.=	Operat. meas. voltage Umeas.
30792	φUL1E=	Phase angle of voltage UL1E
30793	φUL2E=	Phase angle of voltage UL2E
30794	φUL3E=	Phase angle of voltage UL3E
30795	φU4=	Phase angle of voltage U4
30796	φUE=	Phase angle of voltage UE
00641	P =	P (active power)
00642	Q =	Q (reactive power)
00645	S =	S (apparent power)
00644	Freq=	Frequency
00901	PF =	Power Factor
00765	U/f =	(U/Un) / (f/fn)

Thermal Values

F.No.	Alarm	Comments
00801	Θ /Θtrip =	Temperat. rise for warning and trip
00802	Θ /ΘtripL1=	Temperature rise for phase L1
00803	Θ /ΘtripL2=	Temperature rise for phase L2
00804	Θ /ΘtripL3=	Temperature rise for phase L3
30691	Θ leg L1=	Hot spot temperature of leg L1
30692	Θ leg L2=	Hot spot temperature of leg L2
30693	Θ leg L3=	Hot spot temperature of leg L3
30694	Θ leg L12=	Hot spot temperature of leg L12
30695	Θ leg L23=	Hot spot temperature of leg L23
30696	Θ leg L31=	Hot spot temperature of leg L31
01063	Ag.Rate=	Aging Rate
01066	ResWARN=	Load Reserve to warning level
01067	ResALARM=	Load Reserve to alarm level
01068	Θ RTD 1 =	Temperature of RTD 1
01069	Θ RTD 2 =	Temperature of RTD 2
01070	Θ RTD 3 =	Temperature of RTD 3
01071	Θ RTD 4 =	Temperature of RTD 4
01072	Θ RTD 5 =	Temperature of RTD 5
01073	Θ RTD 6 =	Temperature of RTD 6
01074	Θ RTD 7 =	Temperature of RTD 7
01075	Θ RTD 8 =	Temperature of RTD 8
01076	Θ RTD 9 =	Temperature of RTD 9
01077	Θ RTD10 =	Temperature of RTD10
01078	Θ RTD11 =	Temperature of RTD11
01079	Θ RTD12 =	Temperature of RTD12
00766	U/f th. =	Calculated temperature (U/f)

Diff-Values

F.No.	Alarm	Comments
07742	IDiffL1=	IDiffL1(I/Inominal object [%])
07743	IDiffL2=	IDiffL2(I/Inominal object [%])
07744	IDiffL3=	IDiffL3(I/Inominal object [%])
07745	IRestL1=	IRestL1(I/Inominal object [%])
07746	IRestL2=	IRestL2(I/Inominal object [%])
07747	IRestL3=	IRestL3(I/Inominal object [%])
30654	IdiffREF=	Idiff REF (I/Inominal object [%])
30655	IrestREF=	Irest REF (I/Inominal object [%])

Set-Points

F.No.	Alarm	Comments
	ThreshVal1	Threshold Value 1

F.No.	Alarm	Comments
00272	SP. Op Hours>	Set Point Operating Hours

Fault Recording

F.No.	Alarm	Comments
00004	>Trig.Wave.Cap.	>Trigger Waveform Capture
00203	Wave. deleted	Waveform data deleted
	FltRecSta	Fault Recording Start

Metering

if configured (CFC)

F.No.	Alarm	Comments
00924	Wp+=	Wp Forward
00925	Wq+=	Wq Forward
00928	Wp-=	Wp Reverse
00929	Wq-=	Wq Reverse
00888	Wp(puls)=	Pulsed Energy Wp (active)
00889	Wq(puls)=	Pulsed Energy Wq (reactive)

2.18 Processing of Commands

General

In addition to the protective functions described so far, control command processing is integrated in the SIPROTEC® 7UT6 to coordinate the operation of circuit breakers and other equipment in the power system. Control commands can originate from four command sources:

- Local operation using the keypad on the local user interface of the device,
- Local or remote operation using DIGSI®,
- Remote operation via system (SCADA) interface (e.g. SICAM),
- Automatic functions (e.g. using a binary inputs, CFC).

The number of switchgear devices that can be controlled is basically limited by the number of available and required binary inputs and outputs. For the output of control commands it has be ensured that all the required binary inputs and outputs are configured and provided with the correct properties.

If specific interlocking conditions are needed for the execution of commands, the user can program the device with bay interlocking by means of the user-defined logic functions (CFC).

The configuration of the binary inputs and outputs, the preparation of user defined logic functions, and the procedure during switching operations are described in the SIPROTEC® 4 System Manual, order no. E50417–H1176–C151.

2.18.1 Types of Commands

The following types of commands are distinguished.

Control Commands

These commands operate binary outputs and change the power system status:

- Commands for the operation of circuit breakers (without synchro-check) as well as commands for the control of isolators and earth switches,
- Step commands, e.g. for raising and lowering transformer taps,
- Commands with configurable time settings (e.g. Petersen coils).

Internal / Pseudo Commands

These commands do not directly operate binary outputs. They serve to initiate internal functions, simulate or acknowledge changes of state.

- Manual entries to change the feedback indication of plant such as the status condition, for example in the case when the physical connection to the auxiliary contacts is not available or is defective. The process of manual entries is recorded and can be displayed accordingly.
- Additionally, tagging commands can be issued to establish internal settings, such as switching authority (remote / local), parameter set changeover, data transmission inhibit and metering counter reset or initialization.

- Acknowledgment and resetting commands for setting and resetting internal buffers.
- Status information commands for setting / deactivating the “information status” for the information value of an object:
  - Controlling activation of binary input status,
  - Blocking binary outputs.

2.18.2 Steps in the Command Sequence

Safety mechanisms in the command sequence ensure that a command can only be released after a thorough check of preset criteria has been successfully concluded. Additionally, user-defined interlocking conditions can be configured separately for each device. The actual execution of the command is also monitored after its release. The entire sequence of a command is described briefly in the following:

Check Sequence

- Command entry (e.g. using the keypad on the local user interface of the device)
  - Check password → access rights;
  - Check switching mode (interlocking activated/deactivated) → selection of deactivated interlocking status.
- User configurable interlocking checks that can be selected for each command
  - Switching authority (local, remote),
  - Switching direction control (target state = present state),
  - Zone controlled/bay interlocking (logic using CFC),
  - System interlocking (centrally via SICAM),
  - Double operation (interlocking against parallel switching operation),
  - Protection blocking (blocking of switching operations by protective functions).
- Fixed command checks
  - Timeout monitoring (time between command initiation and execution can be monitored),
  - Configuration in process (if setting modification is in process, commands are rejected or delayed),
  - Equipment not present at output (if controllable equipment is not assigned to a binary output, then the command is denied),
  - Output block (if an output block has been programmed for the circuit breaker, and is active at the moment the command is processed, then the command is denied),
  - Component hardware malfunction,
  - Command in progress (only one command can be processed at a time for each circuit breaker or switch),

- 1-out-of-n check (for schemes with multiple assignments and common potential contact, it is checked whether a command has already been initiated for the common output contact).

Monitoring the Command Execution

- Interruption of a command because of a cancel command,
- Running time monitor (feedback message monitoring time).

2.18.3 Interlocking

Interlocking is executed by the user-defined logic (CFC). The interlocking checks of a SICAM/SIPROTEC®-system are classified into:

- System interlocking checked by a central control system (for interbay interlocking)
- Zone controlled/bay interlocking checked in the bay device (for the feeder-related interlocking)

System interlocking relies on the system data base in the central control system. Zone controlled/bay interlocking relies on the status of the circuit breaker and other switches that are connected to the relay.

The extent of the interlocking checks is determined by the configuration and interlocking logic of the relay.

Switchgear which is subject to system interlocking in the central control system is identified with a specific setting in the command properties (in the routing matrix).

For all commands the user can select the operation mode with interlocking (normal mode) or without interlocking (test mode):

- for local commands by reprogramming the settings with password check,
- for automatic commands via command processing with CFC,
- for local / remote commands by an additional interlocking command via Profibus.

2.18.3.1 Interlocked/Non-Interlocked Switching

The command checks that can be selected for the SIPROTEC®-relays are also referred to as “standard interlocking”. These checks can be activated (interlocked) or deactivated (non interlocked) via DIGSI®.

Deactivated interlock switching means the configured interlocking conditions are bypassed in the relay.

Interlocked switching means that all configured interlocking conditions are checked in the command check routines. If a condition could not be fulfilled, the command will be rejected by a message with a minus added to it (e.g. “**CO-**”), followed by an operation response information. Table 2-17 shows some types of commands and messages. For the device the messages designated with *) are displayed in the event logs, for DIGSI® they appear in spontaneous messages.

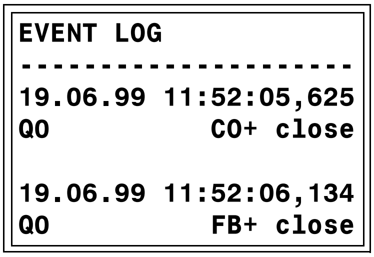
Table 2-17 Types of command and messages

Type of command	Command	Abbrev.	Message
Control **i**ssued	Switching	CO	BF+/–
Manual **t**agging (positive / negative)	Manual tagging	MT	NF+/–
Information status command, **i**nput **b**locking	Input blocking	IB	ST+/– *)
Information status command, **o**utput **b**locking	Output blocking	OB	ST+/– *)
Control **a**bortion	Abortion	CA	AB+/–

*) These messages are displayed in this form in the operational messages on the device display, and in the spontaneous messages under DIGSI®

The “plus” sign indicated in the message is a confirmation of the command execution: the command execution was as expected, in other words positive. The “minus” is a negative confirmation, the command was rejected. Figure 2-113 shows the messages relating to command execution and operation response information for a successful operation of the circuit breaker.

The check of interlocking can be programmed separately for all switching devices and tags that were set with a tagging command. Other internal commands such as manual entry or abort are not checked, i.e. carried out independent of the interlocking.



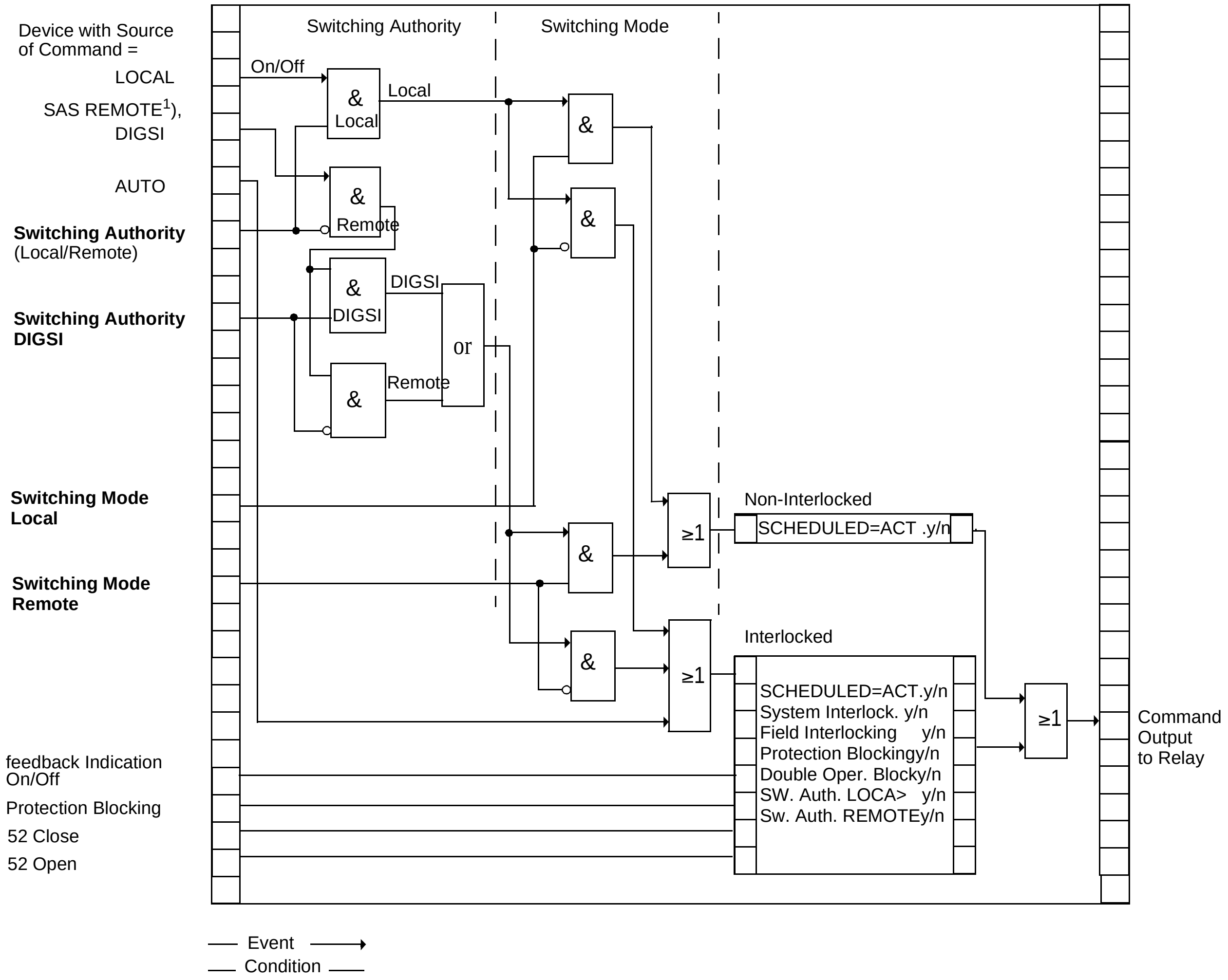
```
EVENT LOG
--------------------
19.06.99 11:52:05,625
QO          CO+ close

19.06.99 11:52:06,134
QO          FB+ close
```

Figure 2-113 Example of a message when closing the circuit breaker Q0

Standard Interlocking

The standard interlocking includes the checks for each device which were set during the configuration of inputs and outputs.

An overview for processing the interlocking conditions in the relay is shown by Figure 2-114.



[1]) Source REMOTE also includes SAS.

LOCAL Command via substation controller.

REMOTE Command via telecontrol system to substation controller and from substation controller to device.

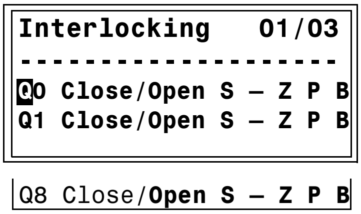
Figure 2-114 Standard Interlocking Arrangements

The display shows the configured interlocking reasons. The are marked by letters explained in the following Table 2-18.

Table 2-18 Interlocking commands

Interlocking commands	Abbrev.	Message
Control authorization	L	L
System interlock	S	S
Zone controlled	Z	Z
Target state = present state (check switch position)	P	P
Block by protection	B	B

Figure 2-115 shows all interlocking conditions (which usually appear in the display of the device) for three switchgear items with the relevant abbreviations explained in Table 2-18. All parameterized interlocking conditions are indicated (see Figure 2-115).



```
Interlocking   01/03
--------------------
Q0 Close/Open S – Z P B
Q1 Close/Open S – Z P B

Q8 Close/Open S – Z P B
```

Figure 2-115 Example of configured interlocking conditions

Control Logic using CFC

For zone controlled/field interlocking, control logic can be programmed, using the CFC. Via specific release conditions the information “released” or “bay interlocked” are available.

2.18.4 Recording and Acknowledgement of Commands

During the processing of the commands, independent of the further processing of information, command and process feedback information are sent to the message processing centre. These messages contain information on the cause. The messages are entered in the event list.

Acknowledgement of Commands to the Device Front

All information which relates to commands that were issued from the device front “Command Issued = Local” is transformed into a corresponding message and shown in the display of the device.

Acknowledgement of Commands to Local/Remote/Digsi

The acknowledgement of messages which relate to commands with the origin “Command Issued = Local/Remote/DIGSI” are sent back to the initiating point independent of the routing (configuration on the serial digital interface).

The acknowledgement of commands is therefore not provided with a response indication as it is done with the local command but with ordinary recorded command and feedback information.

Monitoring of Feedback Information

The processing of commands monitors the command execution and timing of feedback information for all commands. At the same time the command is sent, the monitoring time is started (monitoring of the command execution). This time controls whether the device operation is executed with the required final result within the monitoring time. The monitoring time is stopped as soon as the feedback information is detected. If no feedback information arrives, a response “Timeout command monitoring time” is indicated and the command sequence is terminated.

Commands and information feedback are also recorded in the event list. Normally the execution of a command is terminated as soon as the feedback information (FB+) of the relevant switchgear arrives or, in case of commands without process feedback information, the command output resets.

The “plus” appearing in a feedback information confirms that the command was successful, the command was as expected, in other words positive. The “minus” is a negative confirmation and means that the command was not executed as expected.

Command Output and Switching Relays

The command types needed for tripping and closing of the switchgear or for raising and lowering of transformer taps are described in the SIPROTEC® 4 System Manual, order no. E50417–H1176–C151.

2.18.5 Information Overview

F.No.	Alarm	Comments
	Cntrl Auth	Control Authority
	ModeREMOTE	Controlmode REMOTE
	ModeLOCAL	Controlmode LOCAL

F.No.	Alarm	Comments
	Q0	circuit breaker Q0
	Q0	circuit breaker Q0

■

Installation and Commissioning

3

This chapter is primarily for personnel who are experienced in installing, testing, and commissioning protective and control systems, and are familiar with applicable safety rules, safety regulations, and the operation of the power system.

Installation of the 7UT6 is described in this chapter. Hardware modifications that might be needed in certain cases are explained. Connection verifications required before the device is put in service are also given. Commissioning tests are provided. Some of the tests require the protected object (line, transformer, etc.) to carry load.

3.1 Mounting and Connections

Warning!

The successful and safe operation of the device is dependent on proper handling, installation, and application by qualified personnel under observance of all warnings and hints contained in this manual.

In particular the general erection and safety regulations (e.g. IEC, DIN, VDE, EN or other national and international standards) regarding the correct use of hoisting gear must be observed. Non-observance can result in death, personal injury, or substantial property damage.

Preconditions

Verify that the 7UT6 has the expected features by checking the complete ordering number with the ordering number codes given in Section A.1 of the Appendix. Also check that the required and expected accessories are included with the device. The ordering number of the device is on the nameplate sticker on the housing. The nameplate also indicates the measured value and power supply ratings of the device. A verification that these ratings are the expected values is especially important.

3.1.1 Installation

Panel Flush Mounting

Depending on the version of the device, the housing width may be $^1/_2$ or $^1/_1$ of a 19 inch rack. For housing size $^1/_2$ (7UT613, Figure 3-1) there are 4 covers and 4 holes for securing the device, for size $^1/_1$ (7UT633 or 7UT635, Figure 3-2) there are 6 covers and 6 securing holes.

☐ Remove the 4 or 6 covering caps located on the front cover, reveal the 4 or 6 slots in the mounting flange.

☐ Insert the device into the panel cut-out and fasten it with four screws. Refer to Figure 4-14 (7UT613, size $^1/_2$) or 4-15 (7UT633 or 7UT635, size $^1/_1$) in Section 4.16 for dimensions.

☐ Replace the covers.

☐ Connect the ground on the rear plate of the device to the protective earth of the panel. Use at least one M4 screw for the device ground. The cross-section of the ground wire must be greater than or equal to the cross-section of any other control conductor connected to the device. Furthermore, the cross-section of the ground wire must be at least 2.5 mm^2.

☐ Connect the plug terminals and/or the screwed terminals on the rear side of the device according to the wiring diagram for the panel.
When using forked lugs or directly connecting wires to screwed terminals, the screws must be tightened so that the heads are even with the terminal block before the lugs or wires are inserted.

A ring lug must be centred in the connection chamber so that the screw thread fits in the hole of the lug.

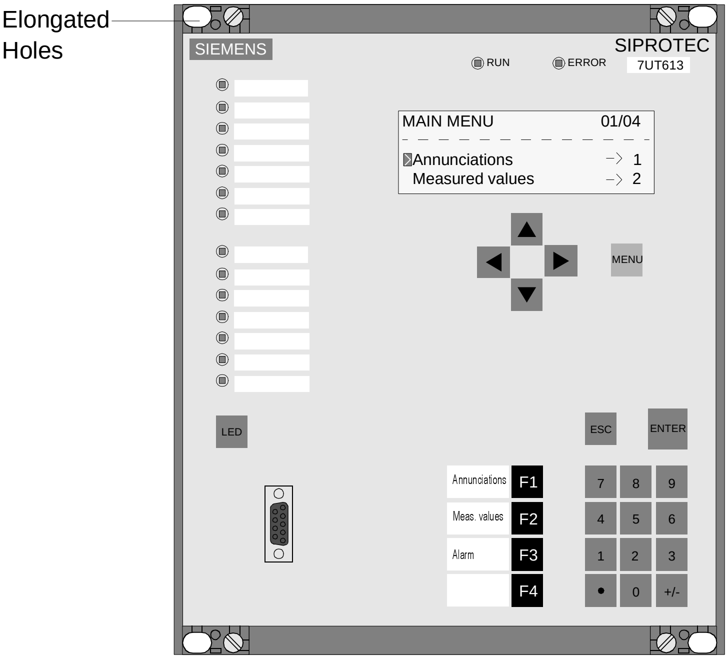


Figure 3-1 Panel mounting of a 7UT613 with 4-line display (housing size $^1/_2$) — example

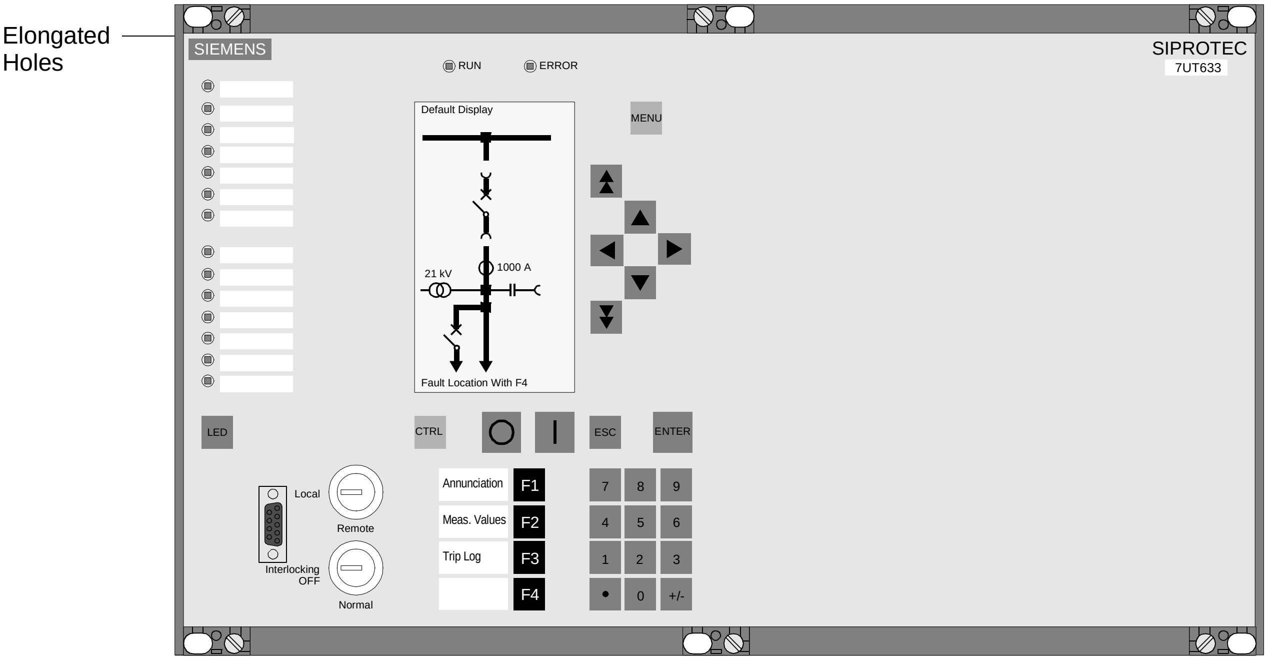


Figure 3-2 Panel mounting of a 7UT633 or 7UT635 with graphic display (housing size $^1/_1$) — example

The System Manual (order no. E50417–H1176–C151) has pertinent information regarding wire size, lugs, bending radii, etc. Installation notes are also given in the brief reference booklet attached to the device.

Rack Mounting and Cubicle Mounting

In housing sizes $^1/_2$ (7UT613, Figure 3-3) there are 4 covers and 4 securing holes, with the housing size $^1/_1$ (7UT633 or 7UT635, Figure 3-4) there are 6 covers and 6 securing holes available.

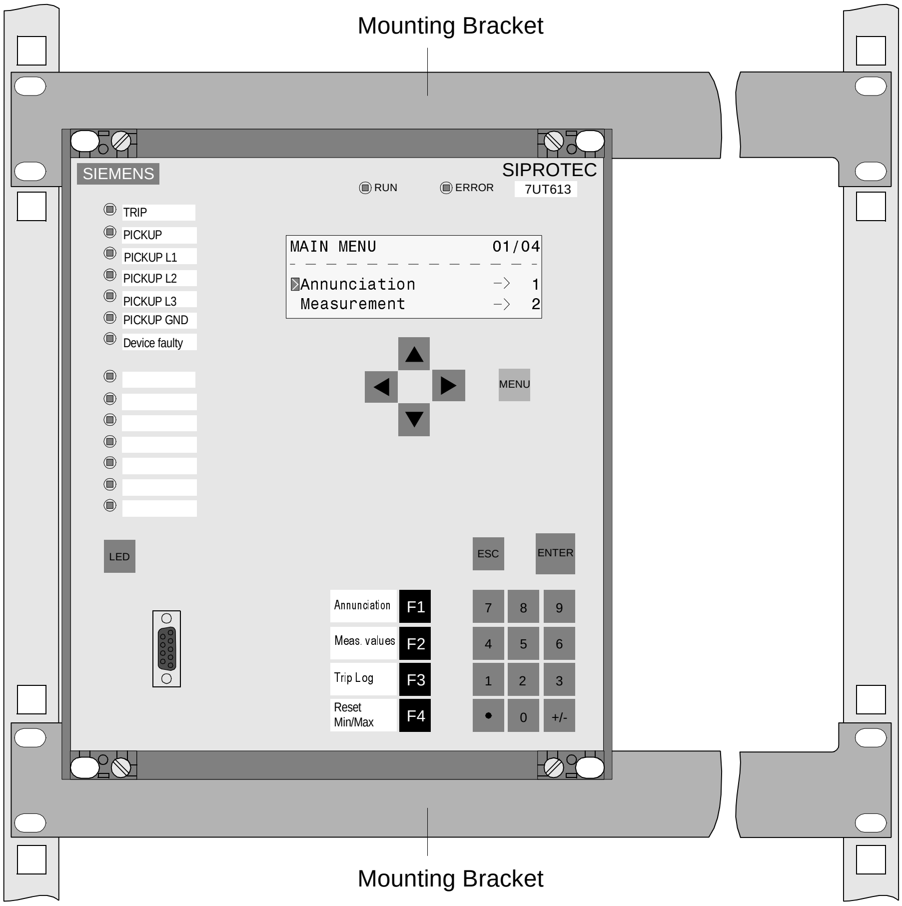


Figure 3-3 Installing a 7UT613 ($^1/_2$ size housing) in a rack or cubicle — example

To install the device in a frame or cubicle, two mounting brackets are required. The ordering codes are stated in the Appendix A in Subsection A.1.3.

- ☐ Loosely screw the two mounting brackets in the rack with 4 screws.
- ☐ Remove the 4 or 6 covers located on the front cover. The slots in the mounting flange are revealed and can be accessed.
- ☐ Fasten the device to the mounting brackets with 4 or 6 screws. Refer to Figure 4-14 (size $^1/_2$) or 4-15 (size $^1/_1$) in Section 4.16 for dimensions.
- ☐ Replace the covers.
- ☐ Tighten the mounting brackets to the rack using 8 screws.

☐ Connect the ground on the rear plate of the device to the protective ground of the rack. Use at least one M4 screw for the device ground. The cross-section of the ground wire must be greater than or equal to the cross-section of any other control conductor connected to the device. Furthermore, the cross-section of the ground wire must be at least 2.5 mm^2.

☐ Connect the plug terminals and/or the screwed terminals on the rear side of the device according to the wiring diagram for the rack.
When using forked lugs or directly connecting wires to screwed terminals, the screws must be tightened so that the heads are even with the terminal block before the lugs or wires are inserted.
A ring lug must be centred in the connection chamber so that the screw thread fits in the hole of the lug.

The System Manual (order no. E50417–H1176–C151) has pertinent information regarding wire size, lugs, bending radii, etc. Installation notes are also given in the brief reference booklet attached to the device.

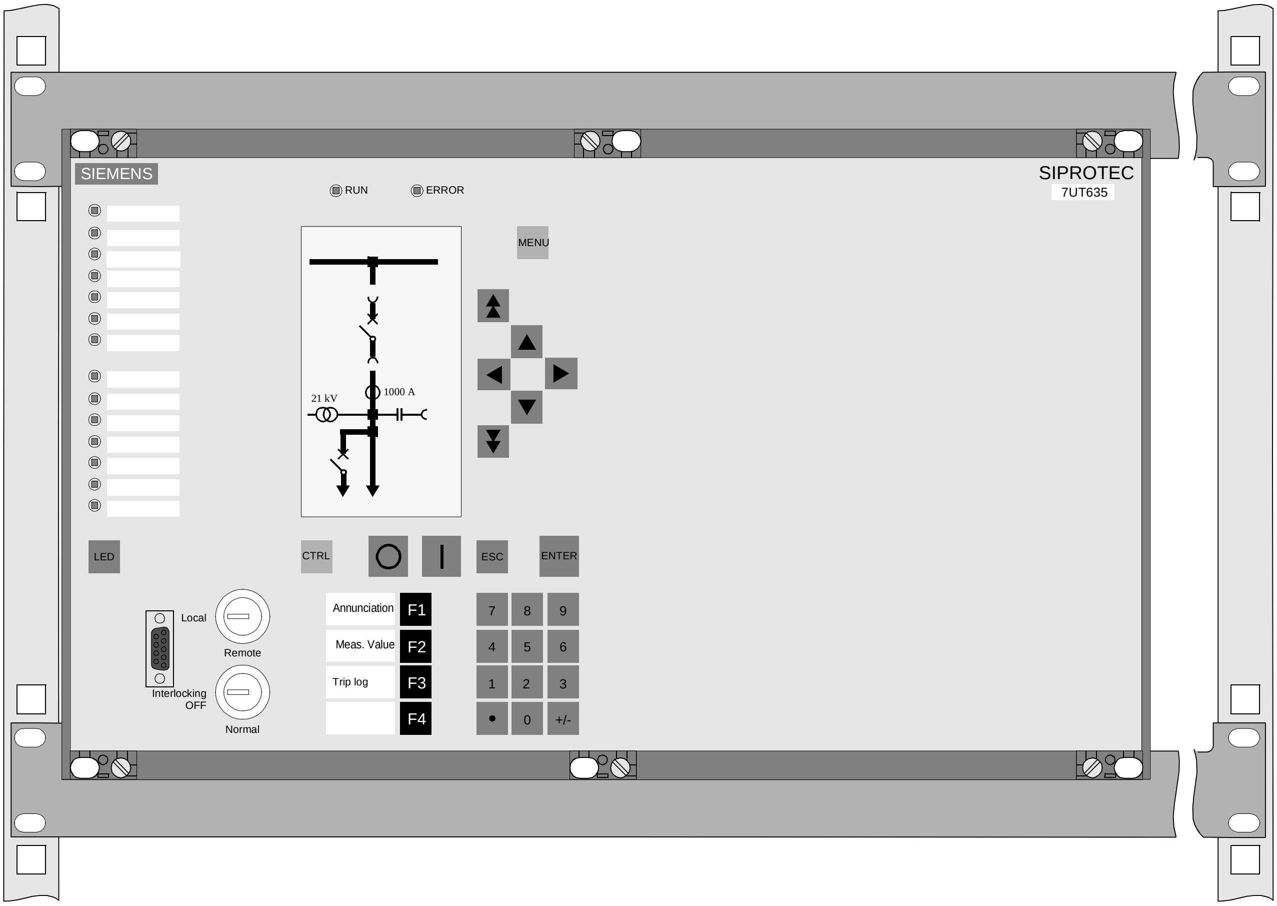


Figure 3-4 Installing a 7UT633 or 7UT635 (housing size $^1/_1$) in a rack or cubicle (housing size $^1/_1$) — example

Panel Surface Mounting

Attention! The transport protection elements of housing size $^1/_1$ have to be removed only at the point of final installation. If a device is prepared (e.g. on a panel) for further transport it must be mounted including the transport protection. To do this, fasten the device using the 4 bolts with female screws and washers of the transport protection.

In other cases of housing size $^1/_1$ remove the transport protection elements (see below “Removal of transport protection”).

- ☐ Secure the device to the panel with four screws. Refer to Figure 4-16 (7UT613, size $^1/_2$) or 4-17 (7UT633 or 7UT635, size $^1/_1$) in Section 4.16 for dimensions.
- ☐ Connect the ground of the device to the protective ground of the panel. The cross-sectional area of the ground wire must be greater than or equal to the cross-sectional area of any other control conductor connected to the device. Furthermore, the cross-section of the ground wire must be at least 2.5 mm^2.
- ☐ Solid, low-impedance operational grounding (cross-sectional area ≥2.5 mm^2) must be connected to the grounding surface on the side. Use at least one M4 screw for the device ground.
- ☐ Connect the screwed terminals on the top and bottom of the device according to the wiring diagram for the panel. Optical connections are made on the inclined housings on the top and/or bottom of the case. The System Manual (order no. E50417–H1176–C151) has pertinent information regarding wire size, lugs, bending radii, etc. Installation notes are also given in the brief reference booklet attached to the device.

Removal of transport protection

Devices in housing size $^1/_1$ for panel surface mounting are provided with a transport protection (Figure 3-5). This has to be removed only at the point of final installation.

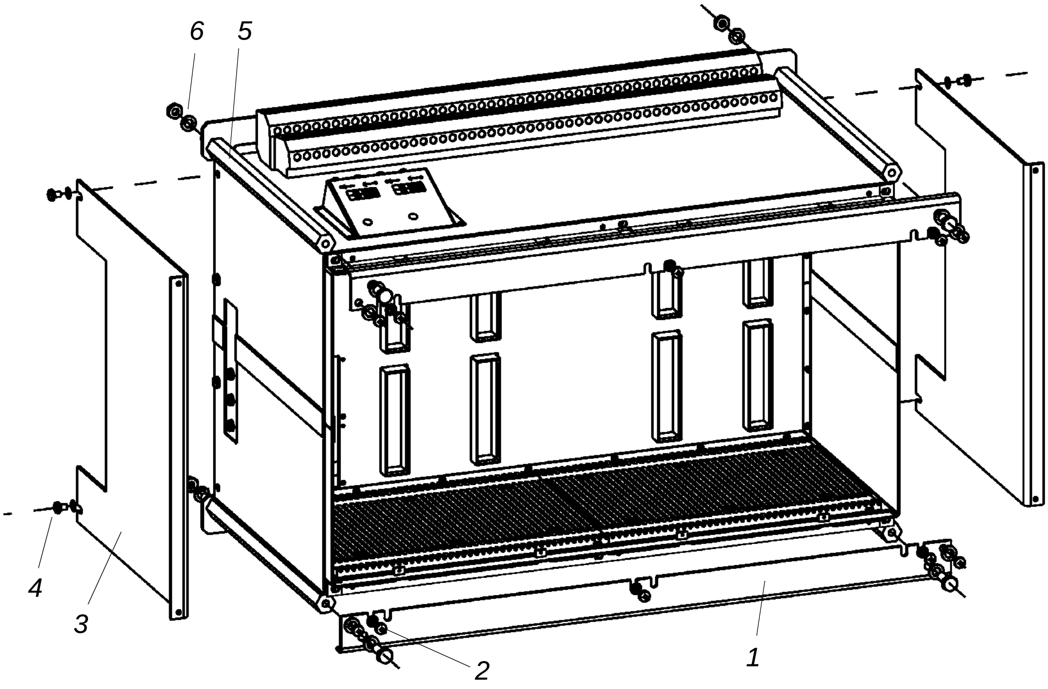


Figure 3-5 View of a housing size $^1/_1$ with transport protection (without front and modules)

☐ Remove the 4 covers on the corners of the front plate and the 2 covers above and below at the centre. 6 elongated holes in the mounting angle strips become accessible.

☐ Unfasten the 6 screws (*2*).

☐ Unscrew all further screws in the rails (*1*); then remove the rails above and below.

☐ Unfasten the 2 screws (*4*) of each of the elongated holes on the right and left side plate; then remove the side plates.

☐ Re-fasten all the 10 loosened screws.

☐ **Attention!** If the devices has been pre-installed with the transport protection included (e.g. on a switch board) do not remove all bolts at the same time. Instead, remove only one bolt at a time and re-fasten this point with a screw at the same place, one after another.

☐ Unscrew the female screws and washers (*6*) from the bolts (*5*) and remove the bolts.

☐ Secure the device using 4 screws.

3.1.2 Termination Variants

General diagrams are shown in Appendix A.2. Connection examples for current and voltage transformer circuits are provided in Appendix A.3. It must be checked that the settings for configuration (Subsection 2.1.1) and the power system data (Subsection 2.1.2 to 2.1.5) match the connections to the device.

Protected Object

The setting **PROT. OBJECT** (address 105) must correspond to the object to be protected. Wrong setting may cause unexpected reaction of the device.

Please note that auto-transformers are identified as **PROT. OBJECT** = ***Autotransf.*** (auto-transformer), not ***3 phase transf.*** (three-phase transformer). For ***1 phase transf.***, the centre phase L2 remains unconnected.

Currents

Connection of the CT currents depends on the mode of application.

With three-phase connection the three phase currents are allocated to each measuring location. For connection examples see Appendix A.3, Figures A-10 to A-15 and A-19 to A-21 and A-23 depending on the protected object types. Observe also the General Diagrams of the actual device model in Appendix A.2. Pay attention to the assignment of the different measuring locations to the sides of the protected object and to the current inputs of the device. Refer to Subsection 2.1.2 and 2.1.3 for more details.

With two-phase connection of a single-phase transformer the centre phase will not be used (I_{L2}). Figures A-17 and A-18 in Appendix A.3 show connection examples. Even if there is only one current transformer, both phases will be used (I_{L1} and I_{L3}), see the right part of Figure A-18. Observe also the General Diagrams of the actual device model in Appendix A.2.

For single-phase busbar protection the measuring inputs are allocated each to a busbar feeder. Figure A-24 in Appendix A.3 illustrates an example for one phase. The other phases are to be connected correspondingly. Observe also the General Diagrams of the actual device model in Appendix A.2.

If the device is connected via summation transformers, see Figure A-25. In this case you have to take into consideration that the rated output current of the summation transformers is usually 100 mA. The measuring inputs of the device have to be matched accordingly (refer also to Subsection 3.1.3). Consider also that in 7UT613 and 7UT633 only 6 of the current inputs can be changed to 0.1 A rated input. Pay attention to the assignment of the different feeder currents to the current inputs of the device. Refer to Subsection 2.1.2 and 2.1.3 for more details.

The allocation of the 1-phase current inputs is to be checked. Connections also differ according to the application the device is used for. The Appendix offers some connection examples (e.g. Figures A-11 and A-12, A-14 to A-17 and A-21 to A-23) which refer to different applications. Observe also the General Diagrams of the actual device model in Appendix A.2. Pay attention to the assignment of the different 1-phase measuring locations to the 1-phase current inputs of the device. Refer to Subsection 2.1.2 and 2.1.3 for more details.

Also check the rated data and the matching factors for the current transformers.

The allocation of the protection functions to the sides must be consistent. This particularly applies for the circuit breaker failure protection whose measuring location or side must correspond with the side of the circuit breaker to be monitored.

Voltages

Voltages are only applicable with 7UT613 or 7UT633 if the device is accordingly ordered and voltage transformers are connected to the device and this has been stated in the configuration according to Subsection 2.1.2 under margin header “Assignment of Voltage Measuring Inputs”.

The Figures A-26 and A-27 show examples of the voltage transformer connection options.

The voltage transformer connections must comply with the settings in Section 2.1.2 under margin header “Assignment of Voltage Measuring Inputs”. Pay attention to the application and mode of connection of the 4th voltage input U_4 if it is used.

Binary Inputs and Outputs

The connections to the power plant depend on the possible allocation of the binary inputs and outputs, i.e. how they are assigned to the power equipment. The preset allocation can be found in Tables A-2 and A-3 in Section A.5 of Appendix A. Also check that the labels on the front panel correspond to the configured message functions.

It is also very important that the feedback components (auxiliary contacts) of the circuit breaker monitored are connected to the correct binary inputs which correspond to the assigned side of the circuit breaker failure protection and the cold load pickup function. Similar applies for the manual close recognition of the time overcurrent protection functions.

Changing Setting Groups with Binary Inputs

If binary inputs are used to switch setting groups, note:

- Two binary inputs must be dedicated to the purpose of changing setting groups when four groups are to be switched. One binary input must be set for “`>Set Group Bit 0`”, the other input for “`>Set Group Bit 1`”. If either of these input functions is not assigned, then it is considered as not controlled.

- To control two setting groups, one binary input set for “`>Set Group Bit 0`” is sufficient since the binary input “`>Set Group Bit 1`”, which is not assigned, is considered to be not controlled.
- The status of the signals controlling the binary inputs to activate a particular setting group must remain constant as long as that particular group is to remain active.

Table 3-1 shows the relationship between “`>Set Group Bit 0`”, “`>Set Group Bit 1`”, and the setting groups A to D. Principal connection diagrams for the two binary inputs are illustrated in Figure 3-6. The figure illustrates an example in which both Set Group Bits 0 and 1 are configured to be controlled (actuated) when the associated binary input is energized (high).

Table 3-1 Setting group selection with binary inputs — example

Binary Input Events		Active Group
`>Set Group Bit 0`	`>Set Group Bit 1`	
no	no	Group A
yes	no	Group B
no	yes	Group C
yes	yes	Group D

no = not energized
yes = energized

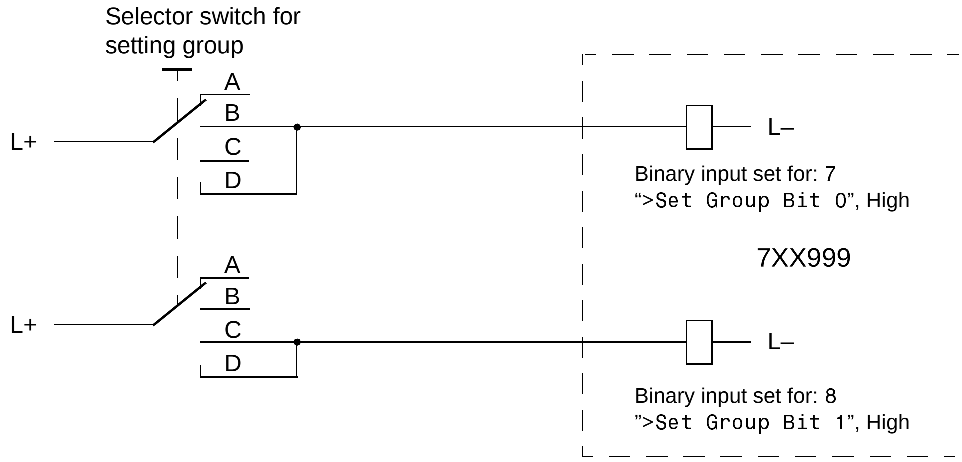


Figure 3-6 Connection diagram (example) for setting group switching with binary inputs

Trip Circuit Supervision

It must be noted that two binary inputs or one binary input and one bypass resistor R must be connected in series. The pick-up threshold of the binary inputs must therefore be substantially below half the rated control DC voltage.

If *two* binary inputs are used for the trip circuit supervision, these binary inputs must be volt-free i.o.w. not be commoned with each other or with another binary input.

If *one* binary input is used, a bypass resistor R must be employed (refer to Figure 3-7). This resistor R is connected in series with the second circuit breaker auxiliary contact (Aux2). The value of this resistor must be such that in the circuit breaker open condition (therefore Aux1 is open and Aux2 is closed) the circuit breaker trip coil (TC) is no longer picked up and binary input (BI1) is still picked up if the command relay contact is open.

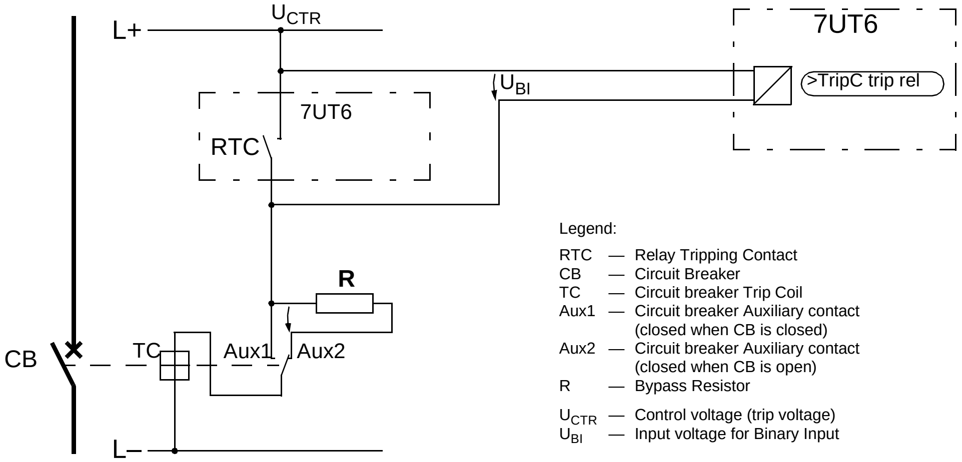


Figure 3-7 Trip circuit supervision with one binary input

This results in an upper limit for the resistance dimension, R_{max}, and a lower limit R_{min}, from which the optimal value of the arithmetic mean should be selected.

$$R = \frac{R_{max} + R_{min}}{2}$$

In order that the minimum voltage for controlling the binary input is ensured, R_{max} is derived as:

$$R_{max} = \left(\frac{U_{CRT} - U_{BI\ min}}{I_{BI\ (High)}}\right) - R_{CBTC}$$

So the circuit breaker trip coil does not remain energized in the above case, R_{min} is derived as:

$$R_{min} = R_{TC} \cdot \left(\frac{U_{CTR} - U_{TC\ (LOW)}}{U_{TC\ (LOW)}}\right)$$

$I_{BI\ (HIGH)}$	Constant current with BI on (=1.7 mA)
$U_{BI\ min}$	Minimum control voltage for BI =19 V for delivery setting for nominal voltage of 24/48/60 V = 73 V for delivery setting for nominal voltage of 110/125/220/250 V
U_{CTR}	Control voltage for trip circuit
R_{CBTC}	DC resistance of circuit breaker trip coil
$U_{CBTC\ (LOW)}$	Maximum voltage on the circuit breaker trip coil that does not lead to tripping

- If the calculation results that $R_{max} < R_{min}$, then the calculation must be repeated, with the next lowest switching threshold $U_{BI\ min}$, and this threshold must be implemented in the relay using plug-in bridges (see Subsection 3.1.3).

For the power consumption of the resistor:

$$P_R = I^2 \cdot R = \left(\frac{U_{CTR}}{R + R_{CBTC}}\right)^2 \cdot R$$

Example:

$I_{BI\ (HIGH)}$	1.7 mA (from SIPROTEC® 7UT6)
$U_{BI\ min}$	19 V for delivery setting for nominal voltage 24/48/60 V 73 V for delivery setting for nominal voltage 110/125/220/250 V
U_{CTR}	110 V from trip circuit (control voltage)
R_{CBTC}	500 Ω from trip circuit (resistance of CB trip coil)
$U_{CBTC\ (LOW)}$	2 V from trip circuit (max. voltage not to trip breaker)

$$R_{max} = \left(\frac{110\ V - 19\ V}{1.7\ mA}\right) - 500\ \Omega$$

$$R_{max} = 53\ k\Omega$$

$$R_{min} = 500\ \Omega \left(\frac{110\ V - 2\ V}{2\ V}\right) - 500\ \Omega$$

$$R_{min} = 27\ k\Omega$$

$$R = \frac{R_{max} + R_{min}}{2} = 40\ k\Omega$$

The closed standard value of 39 kΩ is selected; the power is:

$$P_R = \left(\frac{110\ V}{39\ k\Omega + 0.5\ k\Omega}\right)^2 \cdot 39\ k\Omega$$

$$P_R \geq 0.3\ W$$

RTD-Boxes

If the overload protection operates with processing of the coolant temperature (overload protection with hot-spot calculation), one or two RTD-boxes 7XV5662 can be connected to the serial service interface at port C or the additional interface port D.

3.1.3 Hardware Modifications

3.1.3.1 General

Hardware modifications might be necessary or desired. For example, a change of rated input currents or the pickup threshold for some of the binary inputs might be advantageous in certain applications. Terminating resistors might be required for the communication bus. In either case, hardware modifications are needed. If modifications are done or interface modules are replaced, please observe the details in Subsections 3.1.3.2 to 3.1.3.5.

Power Supply Voltage

There are different input ranges for the power supply voltage. Refer to the data for the 7UT6 ordering numbers in Section A.1 of Appendix A. The power supplies with the ratings 60/110/125 VDC and 110/125/220/250 VDC / 115/230 VAC are interconvertible. Jumper settings determine the rating. The assignment of these jumpers to the supply voltages are illustrated below in Section 3.1.3.3 under margin “Processor Board C-CPU-2”. When the relay is delivered, these jumpers are set according to the name-plate sticker. Generally, they need not be altered.

Nominal Currents

Jumper settings determine the rating of the current inputs of the device. When the relay is delivered, these jumpers are set according to the name-plate to 1 A or 5 A.

If the current transformer sets at the measuring locations and/or the 1-phase current inputs have different rated secondary currents, the device’s inputs must be adapted to it. The same applies for the current transformers of the busbar feeders when single-phase busbar protection is applied. Using single-phase busbar protection with interposed summation transformers, rated current for current inputs are usually 100 mA.

The physical arrangements of these jumpers that correspond to the different current ratings are described below in Subsection 3.1.3.3 under margin heading “Input/Output Board C-I/O-2 (7UT613 or 7UT633)”, “Input/Output Board C-I/O-9 (All Versions)”, and “Input/Output Board C-I/O-9 (7UT635 only)”.

When performing changes, please make sure that the device is always informed about them:

- Using three-phase applications and single-phase transformers, changes for the different measuring locations must correspond to the associated current transformer data (refer to Subsection 2.1.3, margin heading “Current Transformer Data for 3-phase Measuring Locations”, page 42).
- Changes for a 1-phase auxiliary input must correspond to the associated current transformer data (refer to Subsection 2.1.3, margin heading “Current Transformer Data for 1-phase Auxiliary Current Inputs”, page 46).
- For changes of high-sensitivity auxiliary current input the CT transformation ratio must correspond to associated factor (refer to Subsection 2.1.3, margin heading “Current Transformer Data for 1-phase Auxiliary Current Inputs”, page 46).
- Using single-phase busbar protection, changes for the different measuring locations must correspond to the associated current transformer data (refer to Subsection 2.1.3, margin heading (refer to Subsection 2.1.3, margin heading “Current Transformer Data for 1-phase Busbar Protection”, page 44).

Control Voltages for Binary Inputs

When the device is delivered from the factory, the binary inputs are set to operate with a voltage that corresponds to the rated voltage of the power supply. In general, to optimize the operation of the inputs, the pickup voltage of the inputs should be set to most closely match the actual control voltage being used. Each binary input has a pickup voltage that can be independently adjusted; therefore, each input can be set according to the function performed.

A jumper position is changed to adjust the pickup voltage of a binary input. The physical arrangement of the binary input jumpers in relation to the pickup voltages is explained below in Section 3.1.3.3, margin heading “Processor Board C-CPU-2” and “Input/Output Board C-I/O-1”.

Note:

If the 7UT6 performs trip circuit monitoring, two binary inputs, or one binary input and a resistor, are connected in series. The pickup voltage of these inputs must be less than half of the nominal DC voltage of the trip circuit.

Type of Contact for Binary Outputs

Depending on the version, some output relays can be set to have normally closed or normally open contact. Therefore it might be necessary to rearrange a jumper. Subsection 3.1.3.3, margin headings “Processor Board C-CPU-2” and “Input/Output Board C-I/O-1” describe to which type of relays in which boards this applies.

Interface Modules

The serial interface modules can be replaced. Which kind of interfaces and how the interfaces can be replaced is described in “Replacing Interface Modules”, Section 3.1.3.4.

Termination of Serial Interfaces

If the device is equipped with a serial RS 485 port, the RS 485 bus must be terminated with resistors at the last device on the bus to ensure reliable data transmission. For this purpose, terminating resistors are provided for the integrated interface and on the interface modules. The physical arrangement and jumper positions on the interface modules see Subsection 3.1.3.3, margin heading “Processor Board C-CPU-2” and Subsection 3.1.3.4, margin heading “RS485 Interface”.

Spare Parts

Spare parts may be the backup battery that maintains the data in the battery-buffered RAM when the voltage supply fails, and the miniature fuse of the internal power supply. Their physical location is shown in Figure 3-10. The ratings of the fuse are printed on the module next to the fuse itself and in Table 3-2. When exchanging the fuse, please observe the hints given in the System Manual (order no. E50417–H1176–C151) in Chapter “Maintenance”.

3.1.3.2 Disassembling the Device

WARNING!

For the following steps it is assumed that the device is not in operating state. Since dangerous voltages and laser radiation may develop, do not connect the device to auxiliary voltage, measured values or optical fibres!

If changes to jumper settings are required to modify the rating of the power supply, the nominal rating of the current inputs, the pickup voltage of binary inputs, or the state of the terminating resistors, proceed as follows:

Caution!

Jumper-setting changes that affect nominal values of the device render the ordering number and the corresponding nominal values on the name-plate sticker invalid. If such changes are necessary, the changes should be clearly and fully noted on the device. Self adhesive stickers are available that can be used as replacement name-plates.

☐ Prepare area of work. Provide a grounded mat for protecting components subject to damage from electrostatic discharges (ESD). The following equipment is needed:

- screwdriver with a 5 to 6 mm wide tip,
- 1 Philips screwdriver size Pz1,
- 5 mm socket or nut driver.

☐ Unfasten the screw-posts of the D-subminiature connector on the back panel at location “A” and “C”.
This activity does not apply if the device is for surface mounting.

☐ If the device has more communication interfaces on the rear, the screws located diagonally to the interfaces must be removed.
This activity is not necessary if the device is for surface mounting.

☐ Remove the caps on the front cover and loosen the screws that become accessible.

Caution!

Electrostatic discharges through the connections of the components, wiring, plugs, and jumpers must be avoided. Wearing a grounded wrist strap is preferred. Otherwise, first touch a grounded metal part.

The physical arrangement of the boards is shown in Figure 3-8 for housing size $^1/_2$ and 3-9 for housing size $^1/_1$.

☐ Disconnect the ribbon-cable between the front cover and the C-CPU-2 board (❶) at the cover end. To disconnect the cable, push up the top latch of the plug connector and push down the bottom latch of the plug connector. Carefully set aside the front cover.

☐ Disconnect the ribbon-cables between the CPU board (❶) and the I/O boards (❷ to ❹, depending on version).

☐ Remove the boards and set them on the grounded mat to protect them from electrostatic damage.
A greater effort is required to withdraw the CPU board, especially in versions of the device for surface mounting, because of the plug connectors.

☐ Check the jumpers according to Figures 3-10 to 3-18 and the following notes. Change or remove the jumpers as necessary.

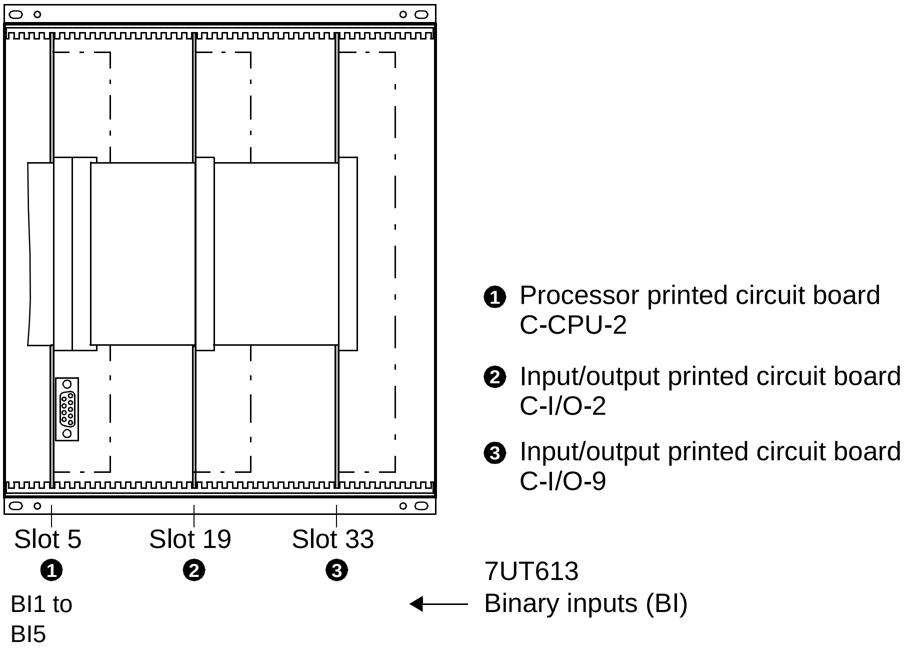
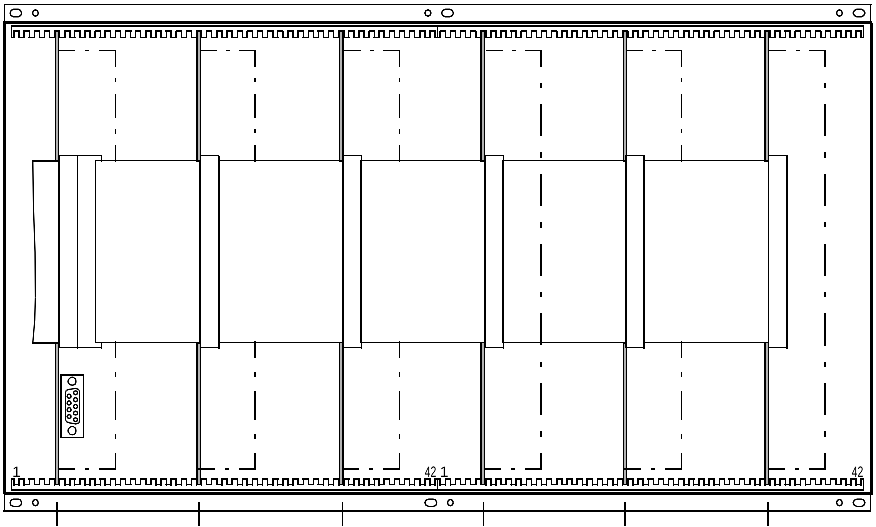


Figure 3-8 Front view of 7UT613 (housing size $^1/_2$) after removal of the front cover (simplified and scaled down)



❶ Processor printed circuit board C-CPU-2

❷ Input/output printed circuit board C-I/O-2

❸ Input/output printed circuit board C-I/O-9

❹ Input/output printed circuit board C-I/O-1

Slot 5	Slot 19	Slot 33	Slot 5	Slot 19	Slot 33	
❶ BI1 to BI5	❹ BI14 to BI21	❹ BI6 to BI13	not fitted	❷	❸	← 7UT633 Binary inputs (BI)
❶ BI1 to BI5	❹ BI14 to BI21	❹ BI6 to BI13	❹ BI22 to BI29	❸	❸	← 7UT635 Binary inputs (BI)

Figure 3-9 Front view of 7UT633 and 7UT635 (housing size $^1/_1$) after removal of the front cover (simplified and scaled down)

3.1.3.3 Jumper Settings on Printed Circuit Boards

Processor Board C-CPU-2

The layout of the jumper settings for the processor board C-CPU-2 is shown in Figure 3-10.

The preset rated voltage of the integrated power supply is checked according to Table 3-2, the pickup voltages of the binary inputs BI1 through BI5 are checked according to Table 3-3, the quiescent state of the life contact according to Table 3-4, and the type of integrated interface according to Tables 3-5 to 3-7.

Some of the jumpers may be situated under the plugged interface modules which must then be removed for alteration.

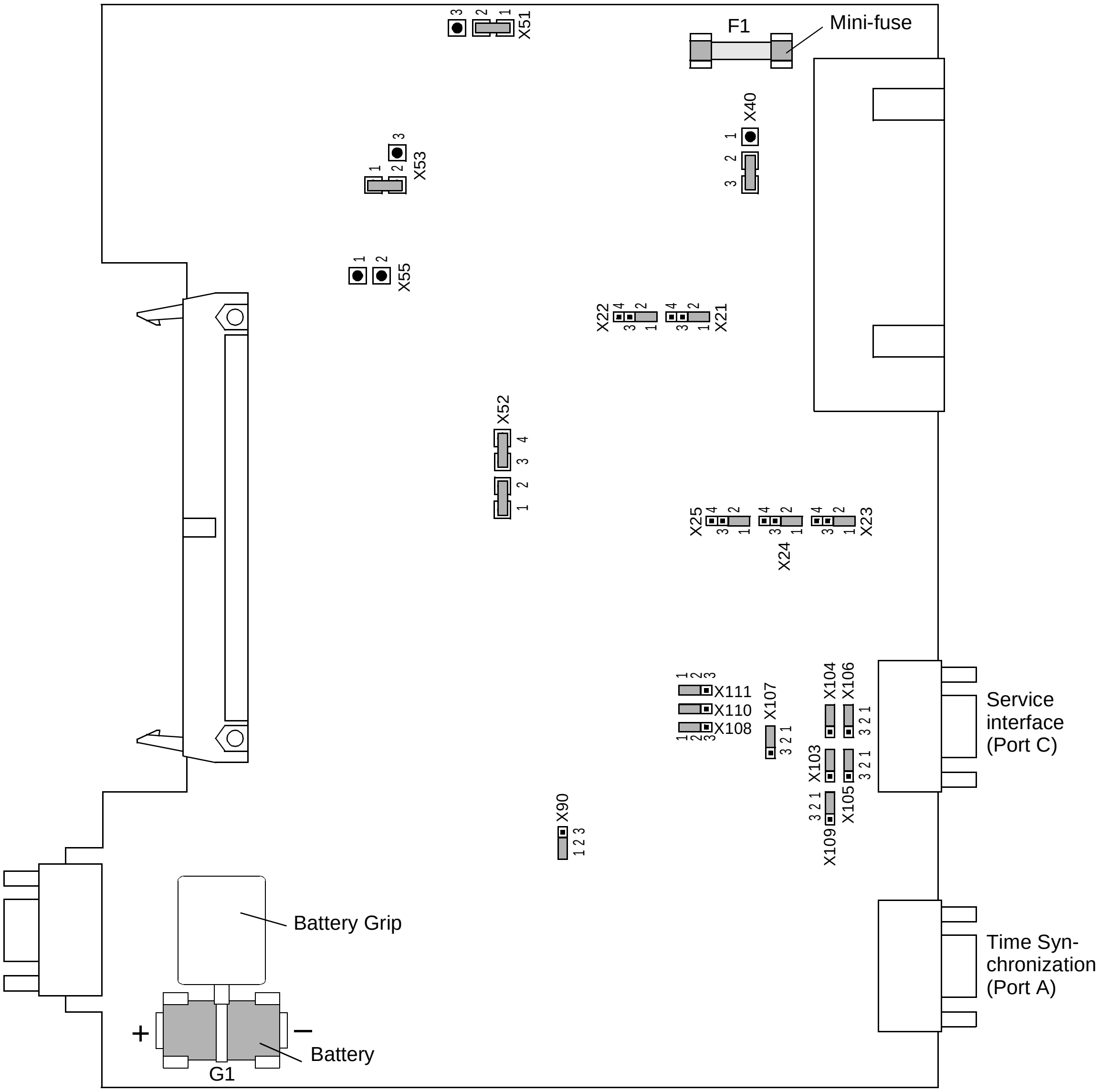


Figure 3-10 Processor board C-CPU-2 (illustrated without interface modules) with representation of the jumper settings required for the module configuration (Observe Tables 3-2 to 3-7)

Table 3-2 Jumper settings for the nominal voltage of the integrated **power supply** on the processor board C-CPU-2

Jumper	Nominal voltage		
	DC 24 to 48 V	DC 60 to 125 V	DC 110 to 250 V, AC 115 to 230 V
X51	not fitted	1–2	2–3
X52	not fitted	1–2 and 3–4	2–3
X53	not fitted	1–2	2–3
X55	not fitted	not fitted	1–2
Mini-fuse	T4H250V	T2H250V	

Table 3-3 Jumper settings for the **pickup voltages** of the binary inputs BI1 through BI5 on the processor board C-CPU-2

Binary Input	Jumper	17 VDC pickup 1)	73 VDC pickup 2)
BI1	X21	1–2	2–3
BI2	X22	1–2	2–3
BI3	X23	1–2	2–3
BI4	X24	1–2	2–3
BI5	X25	1–2	2–3

1) Factory settings for devices with power supply voltages of 24 VDC to 125 VDC

2) Factory settings for devices with power supply voltages of 110 V to 250 VDC and 115 to 230 VAC

Table 3-4 Jumper settings for the quiescent state of the **Life contact** on the processor board C-CPU-2

Jumper	Open in the quiescent state (NO contact)	Closed in the quiescent state (NC contact)	Presetting
X40	1–2	2–3	2–3

It is possible to transform the RS485 interface into a RS232 interface and vice versa. Jumpers X105 to X110 must have equal position!

Table 3-5 Jumper position for the **integrated RS232/RS485 interface** on the processor board C-CPU-2

Jumper	RS232	RS485
X103 and X104	1–2	1–2
X105 to X110	1–2	2–3

When the device is delivered the jumper positions correspond to the ordered variant.

With jumper X111 the flow control which is important for modem communication is enabled. Jumper settings are explained in the following:

Jumper setting 2–3: The modem control signals CTS (Clear-To-Send) according to RS 232 are not available. This is a standard connection via star coupler or optical fibre converter. They are not required since the connection to the SIPROTEC® devices is always operated in the half-duplex mode. Please use connection cable with order number 7XV5100–4.

Jumper setting 1–2: Modem signals are made available. For a direct RS 232 connection between the device and the modem this setting can be selected optionally. We recommend to use a standard RS 232 modem connection cable (converter 9-pole on 25-pole).

Note: If the DIGSI® PC is directly connected to the RS 232 interface jumper X111 must be in position 2–3.

Table 3-6 Jumper setting for **CTS (Clear-To-Send)** on the integrated interface

Jumper	/CTS from RS232 interface	/CTS controlled by /RTS
X111	1–2	2–3 *)

*) state as delivered

Using the RS 485 interfaces with bus capability requires a termination for the last device at the bus, i.e. terminating resistors must be switched to the line unless external termination is used. See Table 3-7.

Both jumpers must have equal position!

Table 3-7 Jumper settings of the **termination resistors** for the RS 485 interface on the processor board C-CPU-2

Jumper	Terminating resistors connected	Terminating resistors disconnected
X103	2–3	1–2 *)
X104	2–3	1–2 *)

*) state as delivered

When delivered, the jumpers are plugged so that the resistors are disconnected (position 1–2).

Terminating resistors can also be implemented outside the device (e.g. in the plug connectors, see also Figure 3-19). In that case the terminating resistors provided on the RS 485 interface module must be disconnected.

Jumper X90 has no function in this device. Leave it in position 1–2.

Input/Output Board C-I/O-1

The input/output board C-I/O-1 is available only in 7UT633 and 7UT635. The layout with the jumper settings is shown in Figure 3-11.

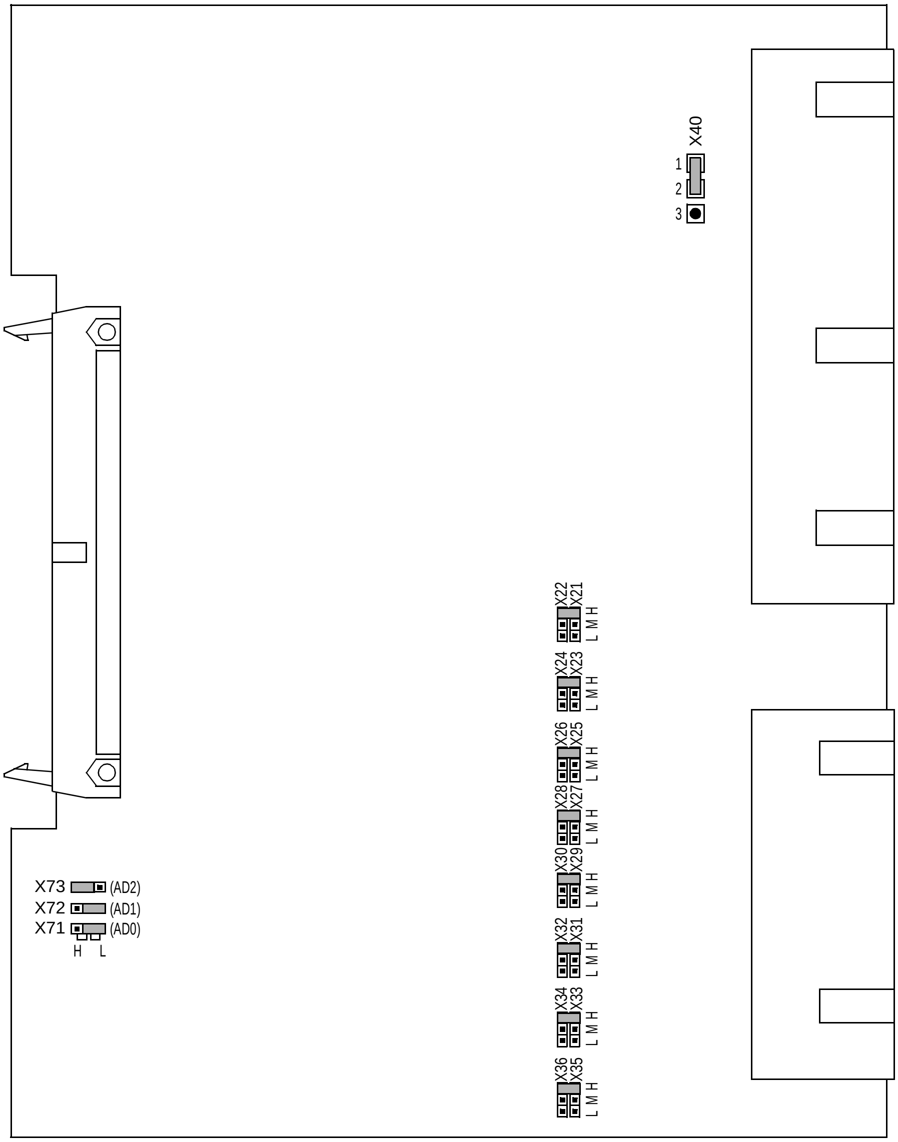


Figure 3-11 Input/output board C-I/O-1 with representation of the jumper settings required for the module configuration (Observe Tables 3-8 to 3-10)

Some of the output contacts can be changed from NO (normally open) operation to NC (normally closed) operation (refer also to the General Diagrams in Appendix A.2).

In 7UT633, this applies for the binary outputs BO9 and BO17 (Figure 3-9, slot 33 left and 19 left.

In 7UT635, this applies for the binary outputs BO1, BO9, and BO17 (Figure 3-9, slot 5 right, 33 left, and 19 left.

Refer to Table 3-8 for the jumper options.

Table 3-8 Jumper settings for **quiescent state** of binary outputs BO1, BO9 and BO17 on the input/output boards C-I/O-1

Device version	p.c.b. on slot	for output	Jumper	Open in the quiescent state (NO contact)	Closed in the quiescent state (NC contact)	Presetting
7UT633	33 left	BO9	X40	1–2	2–3	1–2
	19 left	BO17	X40	1–2	2–3	1–2
7UT635	5 right	BO1	X40	1–2	2–3	1–2
	33 left	BO9	X40	1–2	2–3	1–2
	19 left	BO17	X40	1–2	2–3	1–2

The pickup voltages of the binary inputs BI6 through BI29 are checked according to Table 3-9.

Table 3-9 Jumper settings for the **pickup voltages** of the binary inputs BI6 through BI29 on the input/output board C-I/O-1

Binary inputs			Jumper	17 VDC pickup 1)	73 VDC pickup 2)	154 VDC pickup 3)
Slot 33 left	Slot 19 left	Slot 5 right				
BI6	BI14	BI22	X21/X22	L	M	H
BI7	BI15	BI23	X23/X24	L	M	H
BI8	BI16	BI24	X25/X26	L	M	H
BI9	BI17	BI25	X27/X28	L	M	H
BI10	BI18	BI26	X29/X30	L	M	H
BI11	BI19	BI27	X31/X32	L	M	H
BI12	BI20	BI28	X33/X34	L	M	H
BI13	BI21	BI29	X35/X36	L	M	H

1) Factory settings for devices with power supply voltages of DC 24 to 125 V
2) Factory settings for devices with power supply voltages of DC 110 to 250 V and AC 115 V
3) only for devices with control voltage DC 220 to 250 V and AC 115 V

Jumpers X71 through X73 serve for module identification and must not be changed:

Table 3-10 Jumper position of **module addresses** of input/output boards C-I/O-1

Jumper	Slot 19 left	Slot 33 left	Slot 5 right
X71	H	L	H
X72	H	H	L
X73	H	H	H

Input/Output Board C-I/O-2 (7UT613 or 7UT633)

Mounting locations:
at 7UT613 board ❷ in Figure 3-8, slot 19,
at 7UT633 board ❷ in Figure 3-9, slot 19 right.

The input/output board C-I/O-2 is available only in 7UT613 and 7UT633. The layout with jumper settings is shown in Figure 3-12.

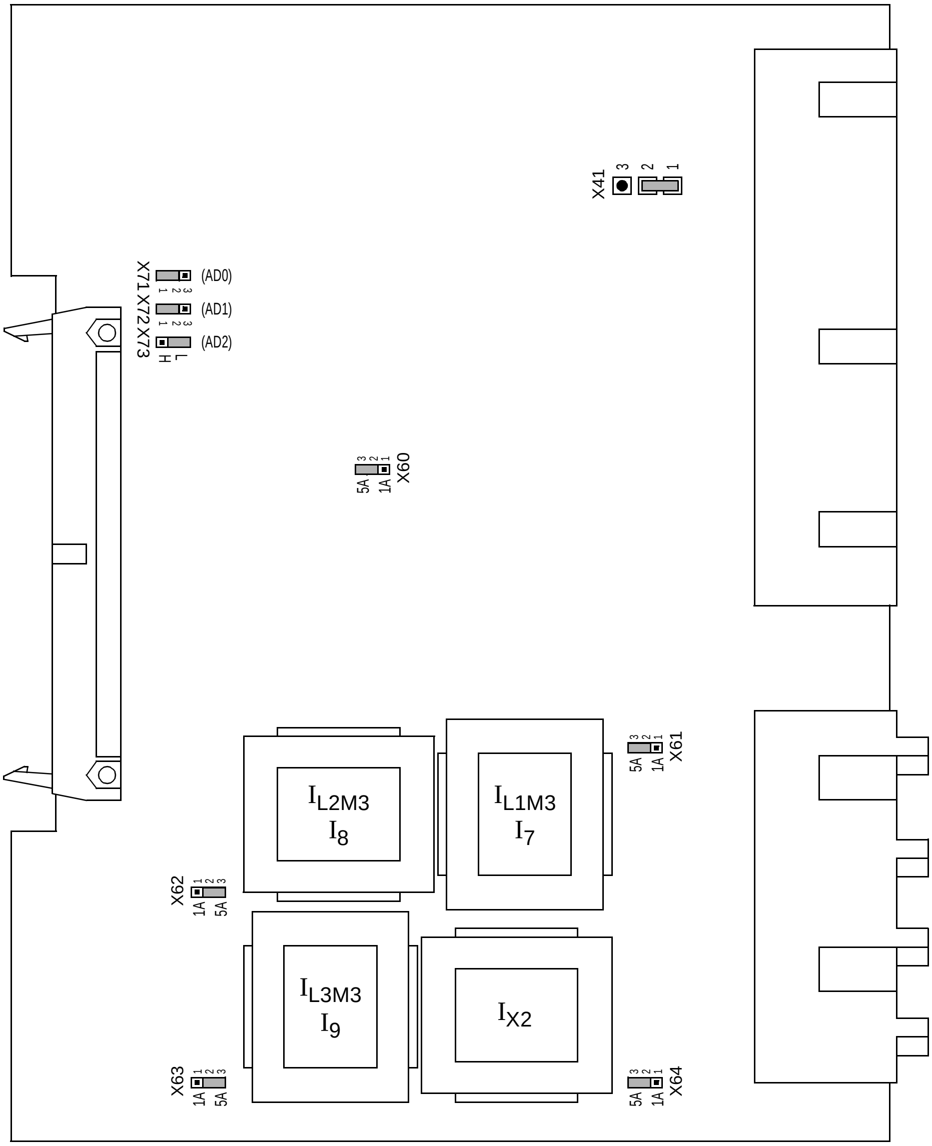


Figure 3-12 Input/output board C-I/O-2 with representation of the jumper settings required for the module configuration (Observe Tables 3-11 to 3-13)

The output contact of binary output BO6 can be changed from NO (normally open) operation to NC (normally closed) operation (refer also to the General Diagrams in Appendix A.2). See also Table 3-11.

Table 3-11 Jumper setting for the **quiescent state** of the output contact BO6 on the input/output board C-I/O-2

Jumper	Open in the quiescent state (NO contact)	Closed in the quiescent state (NC contact)	Presetting
X41	1–2	2–3	1–2

Jumpers X71 through X73 serve for module identification and must not be changed. Table 3-12 shows the preset jumper positions.

Table 3-12 Jumper position of **module addresses** of input/output boards C-I/O-2

Jumper	Presetting
X71	1–2 (H)
X72	1–2 (H)
X73	2–3 (L)

The **rated currents** of the measured current inputs can be determined for each analog input. With default settings all jumpers are set to the same rated current (according to the order number of the device).

The input/output board C-I/O-2 carries the following measured current inputs:

- For three-phase applications (also single-phase transformers):
  There are 3 measuring inputs for the 3-phase measuring location M3: I_{L1M3}, I_{L2M3}, I_{L3M3}.
  The jumpers belonging to this measuring location (X61, X62, X63) must be plugged all to the rated secondary current of the connected current transformers: “5A” or “1A”. Furthermore, the corresponding common jumper (X60) has to be plugged to the same rated current.
- For single-phase busbar protection:
  There are 3 measuring inputs for 3 different measuring locations, i.e. the feeders 7 to 9: I_7, I_8, I_9. Each input can be set individually (X61, X62, X63): “5A” or “1A”.
  Only if the measuring inputs I_7 to I_9 have equal rated current, X60 is plugged to this rated current.
  If different rated currents are reigning within this input group, the position of the common jumper (X60) is irrelevant.
- For the auxiliary 1-phase input I_{X2}:
  Jumper X64 is set to the required rated current for this 1-phase current input: “5A” or “1A”.
- These current inputs on C-I/O-2 are not suitable for interposed summation transformers with 100 mA rated output.

Table 3-13 gives a summary of the jumpers for the rated secondary currents.

Table 3-13 Assignment of the jumpers to the measured **current inputs** on the input/output board C-I/O-2

Application		Jumper	
3-phase	1-phase	Individual	Common
I_{L1M3}	I_7	X61	X60
I_{L2M3}	I_8	X62	
I_{L3M3}	I_9	X63	
I_{X2}	I_{X2}	X64	—

Input/Output Board C-I/O-9 (All Versions)

Mounting locations:
at 7UT613, board ❸ in Figure 3-8, slot 33,
at 7UT633 and 7UT635, board ❸ in Figure 3-9, slot 33 right.

The layout of the input/output boards C-I/O-9 with jumper settings is shown in Figure 3-13.

Jumpers X71 through X73 serve for module identification and must not be changed. Table 3-14 shows the preset jumper positions.

Table 3-14 Jumper position of **module addresses** of input/output boards C-I/O-9; slot 33 in 7UT613 or slot 33 right in 7UT633 and 7UT635

Jumper	7UT613	7UT633 and 7UT635
	Slot 33	Slot 33 right
X71	2–3 (L)	2–3 (L)
X72	1–2 (H)	1–2 (H)
X73	2–3 (L)	2–3 (L)

The **rated currents** of the measured current inputs can be determined for each analog input. With default settings all jumpers are set to the same rated current (according to the order number of the device).

The measured current inputs depend on the application and the ordered model of 7UT6:

- For three-phase applications (also single-phase transformers):
  There are 3 measuring inputs for each of the two 3-phase measuring locations M1 and M2: I_{L1M1}, I_{L2M1}, I_{L3M1}, I_{L1M2}, I_{L2M2}, I_{L3M2}.
  The jumpers belonging to the measuring location M1 (X61, X62, X63) must all be plugged to rated secondary current of the connected current transformers: “5A”, “1A” or “0.1A”. Furthermore, the corresponding common jumper (X82) has to be plugged to the same rated current.
  The jumpers belonging to the measuring location M2 (X65, X66, X67) must all be plugged to the rated secondary current of the connected current transformers: “5A”,

“1A” or “0.1A”. Furthermore, the corresponding common jumper (X81) has to be plugged to the same rated current.

- For three-phase applications in 7UT635:
  The auxiliary current inputs I_{X1} and I_{X3} can be used for the 5th 3-phase measuring location M5. In this case set the jumpers X64, X68, X83, and X84 all to the required rated secondary current for M5: “5A”, “1A” or “0.1A”. Set X85 and X86 to position 1–2.
- For single-phase busbar protection:
  There are 6 measuring inputs for 6 different measuring locations, i.e. the feeders 1 to 6: I_1, I_2, I_3, I_4, I_5, I_6. Each input can be set individually (X61, X62, X63, X65, X66, X67): “5A”, “1A” or “0.1A”.
  Only if the measuring inputs I_1 to I_3 have equal rated current, X82 is plugged to this rated current.
  Only if the measuring inputs I_4 to I_6 have equal rated current, X81 is plugged to this rated current.
  If different rated currents are reigning within the input groups, the corresponding common jumper (X82, X81) is plugged to “undef”.
- For the auxiliary 1-phase input I_{X1}:
  Jumpers X64 and X83 are both set to the required rated secondary current for this 1-phase current input: “5A”, “1A”.
  But: If, in 7UT635, this input is used for a 5th 3-phase measuring location M5 then set the jumpers to this rated secondary current (see above).
- For the auxiliary 1-phase input I_{X3}:
  If this input is used as a “normal” 1-phase current input, set Jumpers X68 and X84 both to the required rated secondary current: “5A” or “1A”; set X85 and X86 both into position 1–2.
  If this input is used as a “high-sensitivity” current input, Jumper X68 is irrelevant; set Jumper X84 to “1.6A”; set X85 and X86 both into position 2–3.
  But: If, in 7UT635, this input is used for a 5th 3-phase measuring location M5 then set the jumpers to this rated secondary current (see above). X85 and X86 must the be set to position 1–2.

Table 3-15 gives a summary of the jumpers for the rated currents.

Table 3-15 Assignment of the jumpers to the measured **current inputs** on the input/output board C-I/O-9; slot 33 in 7UT613 or slot 33 right in 7UT633 and 7UT635

Application		Jumper	
3-phase	1-phase	individual	common
I_{L1M1}	I_1	X61	X82
I_{L2M1}	I_2	X62	
I_{L3M1}	I_3	X63	
I_{L1M2}	I_4	X65	X81
I_{L2M2}	I_5	X66	
I_{L3M2}	I_6	X67	

[1]) at 7UT635 applicable for measuring location M5; see text

Table 3-15 Assignment of the jumpers to the measured **current inputs** on the input/output board C-I/O-9; slot 33 in 7UT613 or slot 33 right in 7UT633 and 7UT635

Application		Jumper	
3-phase	1-phase	individual	common
I_{X1} (I_{L1M5}[1])	—	X64	X83
I_{X3} (I_{L2M5}[1])	—	X68	X84/X85/X86
I_{X3} (sensitive)	—	—	

[1]) at 7UT635 applicable for measuring location M5; see text

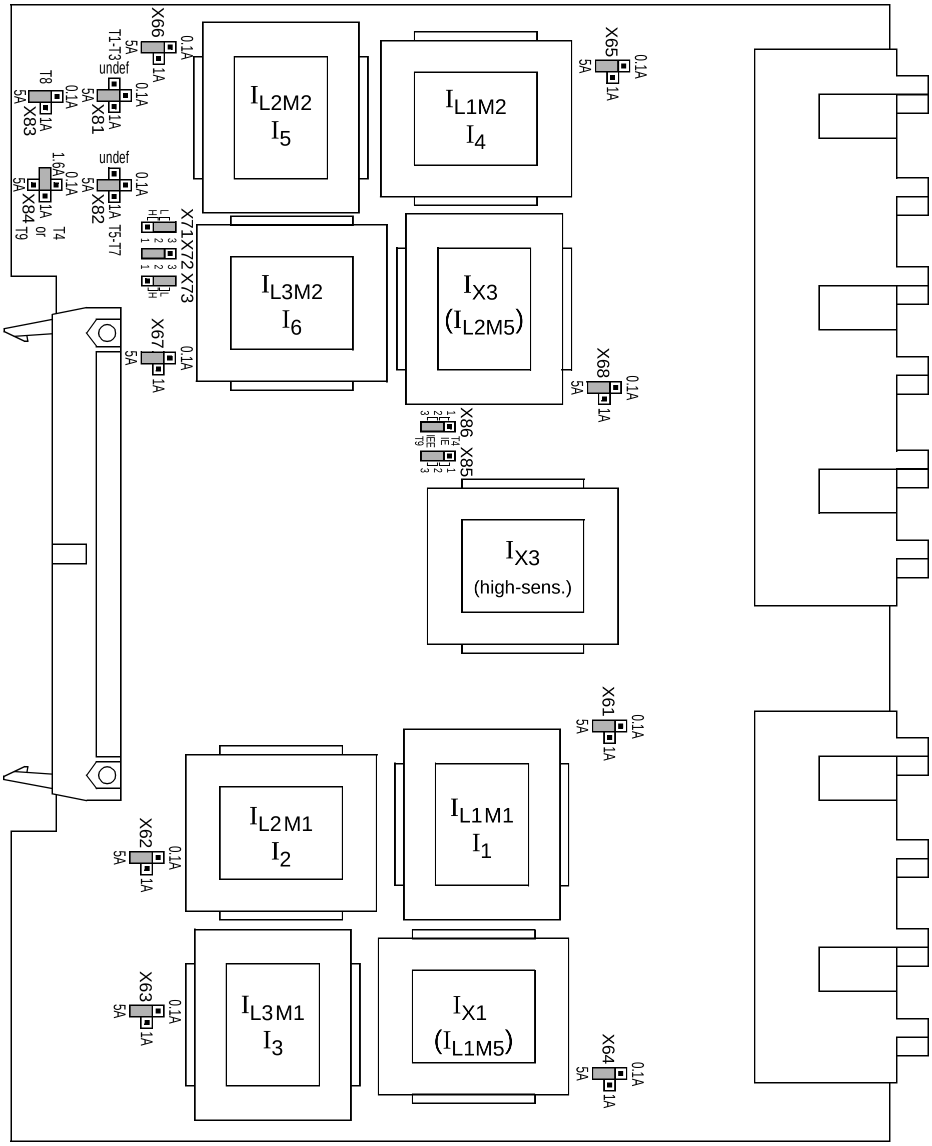


Figure 3-13 Input/output board C-I/O-9 with representation of the jumper settings required for the module configuration; slot 33 in 7UT613 or slot 33 right in 7UT633 and 7UT635 (Observe Tables 3-14 to 3-15)

Input/Output Board C-I/O-9 (7UT635 only)

Mounting location:
at 7UT635 board ❸ in Figure 3-9, slot 19 right.

7UT635 provides a second input/output board C-I/O-9 which is shown in Figure 3-14.

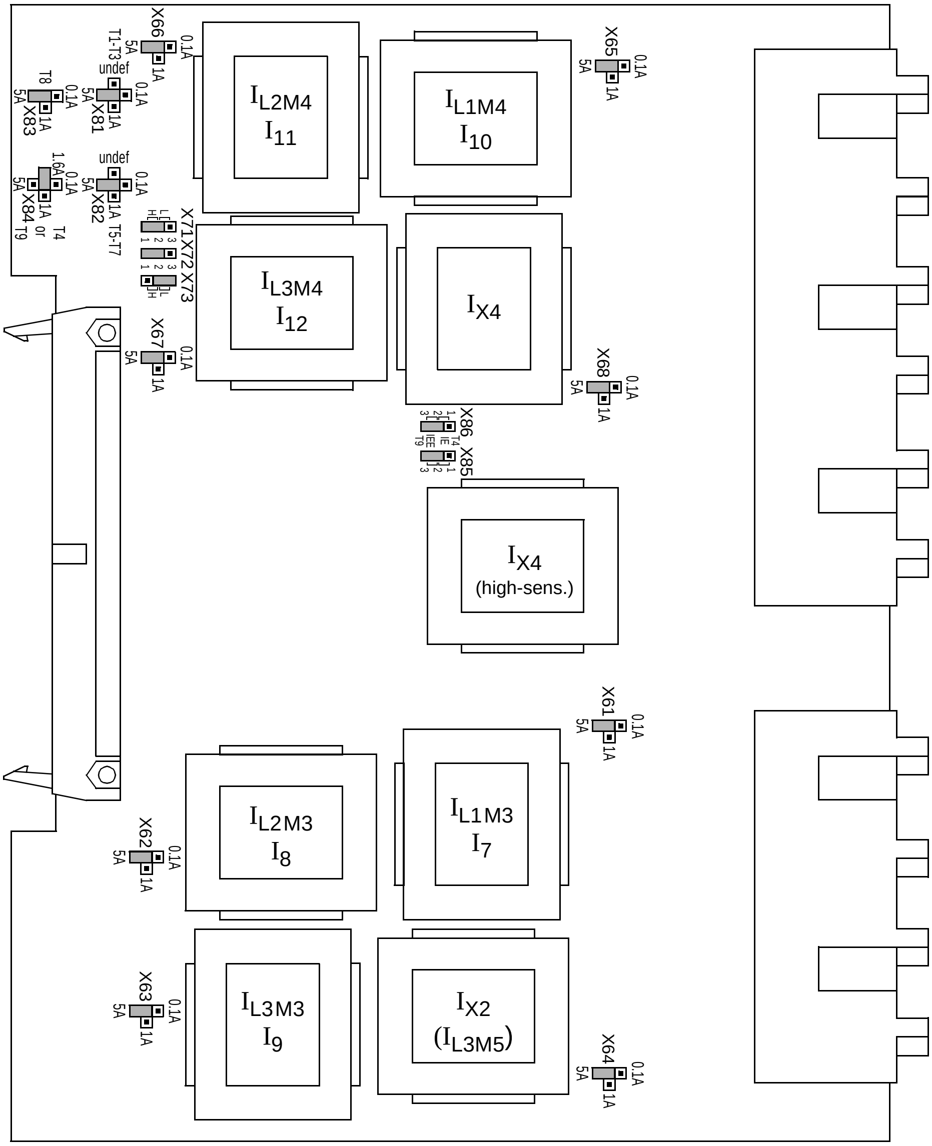


Figure 3-14 Input/output board C-I/O-9 with representation of the jumper settings required for the module configuration; slot 19 right in 7UT635 (Observe Tables 3-16 to 3-17)

Jumpers X71 through X73 serve for module identification and must not be changed. Table 3-16 shows the preset jumper positions.

Table 3-16 Jumper position of **module addresses** of input/output boards C-I/O-9; slot 19 right in 7UT635

Jumper	7UT635
	Slot 19 right
X71	1–2 (H)
X72	1–2 (H)
X73	2–3 (L)

The **rated currents** of the measured current inputs can be determined for each analog input. With default settings all jumpers are set to the same rated current (according to the order number of the device).

- For three-phase applications (also single-phase transformers):
  There are 3 measuring inputs for each of the 3-phase measuring locations M3 and M4: I_{L1M3}, I_{L2M3}, I_{L3M3}, I_{L1M4}, I_{L2M4}, I_{L3M4}.
  The jumpers belonging to the measuring location M3 (X61, X62, X63) must all be plugged to the rated secondary current of the connected current transformers: “5A”, “1A” or “0.1A”. Furthermore, the corresponding common jumper (X82) has to be plugged to the same rated current.
  The jumpers belonging to the measuring location M4 (X65, X66, X67) must all be plugged to the rated secondary current of the connected current transformers: “5A”, “1A” or “0.1A”. Furthermore, the corresponding common jumper (X81) has to be plugged to the same rated current: the rated secondary current of the connected current transformers.

- For three-phase applications in 7UT635:
  The auxiliary current inputs I_{X2} can be used for the 5th measuring location M5. In this case set the jumpers X64 and X83 both to the required rated secondary current for M5: “5A”, “1A” or “0.1A”.

- For single-phase busbar protection:
  There are 6 measuring inputs for 6 different measuring locations, i.e. the feeders 7 to 12: I_7, I_8, I_9, I_{10}, I_{11}, I_{12}. Each input can be set individually (X61, X62, X63, X65, X66, X67): “5A”, “1A” or “0.1A”.
  Only if the measuring inputs I_7 to I_9 have equal rated current, X82 is plugged to this rated current.
  Only if the measuring inputs I_{10} to I_{12} have equal rated current, X81 is plugged to this rated current.
  If different rated currents are reigning within the input groups, the corresponding common jumper (X82, X81) is plugged to “undef”.

- For the auxiliary 1-phase input I_{X2}:
  Jumper X64 is set to the required rated secondary current for this 1-phase current input: “5A”, “1A”; set X83 to the same rated current.
  But: If this input is used for the 5th measuring location M5 then set the jumpers to this rated current (see above).

- For the auxiliary 1-phase input I_{X4}:
  If this input is used as a "normal" current input, set Jumpers X68 and X84 both to the required rated secondary current: "5A", "1A". Set X85 and X86 both into position 1–2.
  If this input is used as a "high-sensitivity" current input, Jumper X68 is irrelevant; set Jumper X84 to "1.6A"; set X85 and X86 both into position 2–3.

Table 3-15 gives a summary of the jumpers for the rated currents.

Table 3-17 Assignment of the jumpers to the measured **current inputs** on the input/output board C-I/O-9; slot 19 right in 7UT635

Application		Jumper	
3-phase	1-phase	individual	common
I_{L1M3}	I_7	X61	X82
I_{L2M3}	I_8	X62	
I_{L3M3}	I_9	X63	
I_{L1M4}	I_{10}	X65	X81
I_{L2M4}	I_{11}	X66	
I_{L3M4}	I_{12}	X67	
I_{X2} (I_{L3M5}[1])	—	X64	X83
I_{X4}	—	X68	X84/X85/X86
I_{X4} (sensitive)	—	—	

[1]) at 7UT635 applicable for measuring location M5; see text

3.1.3.4 Interface Modules

Note:

Devices in surface mounted housing with optical fibre connection have the fibre-optic module installed in the inclined console housing. On the CPU board, however, an RS232 interface module is placed which communicates electrically with the fibre-optic module.

Replacing Interface Modules

The interface modules are dependent on the ordered version. They are located on the processor board C-CPU-2 (❶ in Figure 3-8 or 3-9). Figure 3-15 shows the CPU board with the location of the interface modules.

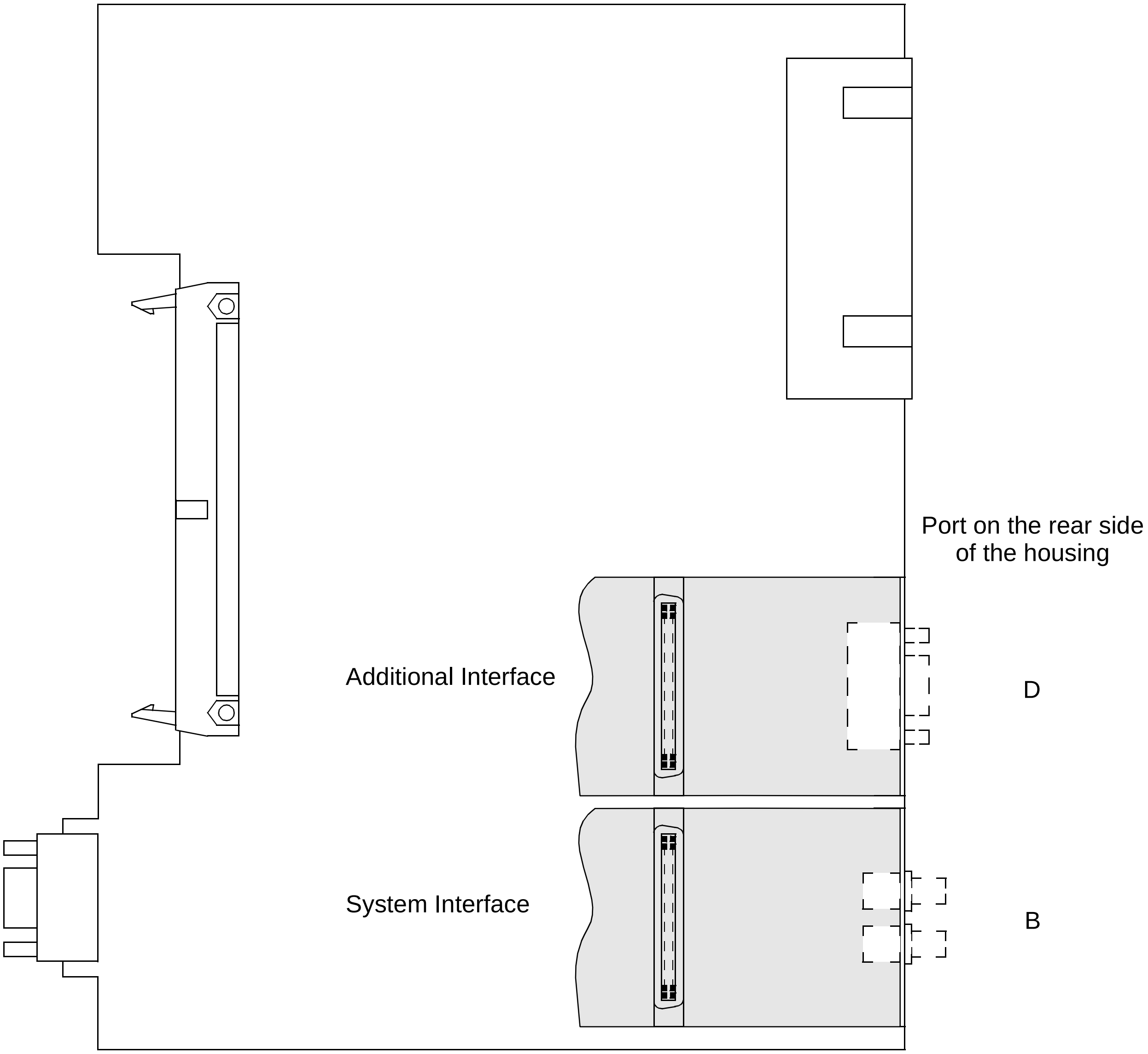


Figure 3-15 Processor board C-CPU-2 with interface modules

Please note the following:

- Interface modules can only be exchanged for devices with flush mounting housing. Interface modules for devices with surface mounting housing must be exchanged in our manufacturing centre.
- Use only interface modules that can be ordered as an option of the device (see also Appendix A.1).
- Termination of the serial interfaces in case of RS485 must be ensured according to header margin “RS485 Interface”.

Table 3-18 Exchange interface modules for devices with flush mounting housing

Interface	Mounting Port	Replacing Module
System Interface	B	RS232
		RS485
		Optical 820 nm
		Profibus FMS RS485
		Profibus FMS single ring
		Profibus FMS double ring
		Profibus DP RS485
		Profibus DP double ring
		Modbus RS485
		Modbus 820 nm
		DNP 3.0 RS485
		DNP 3.0 820 nm
Additional Interface	D	RS485
		Optical 820 nm

The ordering numbers of the exchange modules are listed in Appendix A.1.3 (Accessories and Spare Parts).

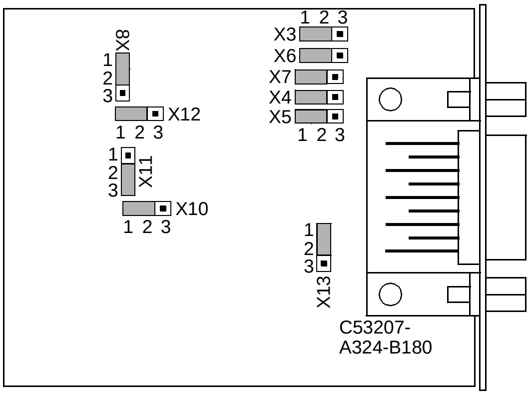
RS232 Interface

The RS232 interface can be transformed into a RS485 interface according to Figure 3-17.

Figure 3-15 shows the PCB of the C-CPU-2 with the location of the modules. Figure 3-16 shows how jumpers of interface RS232 are located on the interface module.

Here, terminating resistors are not required. They are always disabled.

Note that devices in surface mounted housing with optical fibre connection have an electrical RS232 module on the CPU board (see *Note* above). For this application type, the jumpers X12 and X13 on the RS232 module are plugged in position 2–3, in contrast to the illustration in Figure 3-16.



Jumpers illustrated in factory position

Figure 3-16 Location of the jumpers on interface module for RS232

With jumper X11 the flow control which is important for modem communication is enabled. Jumper settings are explained in the following:

Jumper setting 2–3: The modem control signals CTS (Clear-To-Send) according to RS232 are not available. This is a standard connection via star coupler or optical fibre converter. They are not required since the connection to the SIPROTEC® devices is always operated in the half-duplex mode. Please use connection cable with order number 7XV5100–4.

Jumper setting 1–2: Modem signals are made available. For a direct RS232 connection between the device and the modem this setting can be selected optionally. We recommend to use a standard RS232 modem connection cable (converter 9-pole on 25-pole).

Table 3-19 Jumper setting for **CTS (Clear-To-Send)** on the interface module

Jumper	/CTS from RS232 interface	/CTS controlled by /RTS
X11	1–2	2–3

RS485 Interface

The interface RS485 can be transformed into interface RS232 according to Figure 3-16.

Using interfaces with bus capability requires a termination for the last device at the bus, i.e. terminating resistors must be switched to the line.

The terminating resistors are connected to the corresponding interface module that is mounted to the processor input/output board C-CPU. Figure 3-15 shows the printed circuit board of the C-CPU and the allocation of the modules.

The module for the RS485 interface is illustrated in Figure 3-17, for the profibus interface in Figure 3-18. The two jumpers of a module must always be plugged in the same position.

When the module is delivered, the jumpers are plugged so that the resistors are disconnected.

Jumper	Terminating Resistors	
	Connected	Disconnected
X3	2–3	1–2 *)
X4	2–3	1–2 *)

*) Factory setting

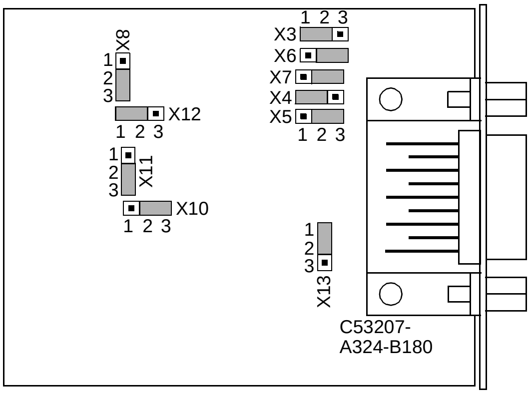


Figure 3-17 Location of the jumpers of the RS485 interface module

Jumper	Terminating Resistors	
	Connected	Disconnected
X3	1–2	2–3 *)
X4	1–2	2–3 *)

*) Factory Setting

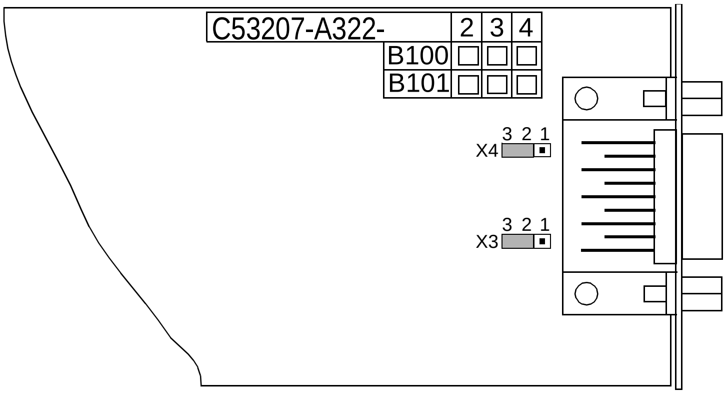


Figure 3-18 Location of the jumpers of the Profibus interface module

Terminating resistors can also be implemented outside the device (e.g. in the plug connectors). In that case the terminating resistors provided on the RS485 or Profibus interface module must be switched out.

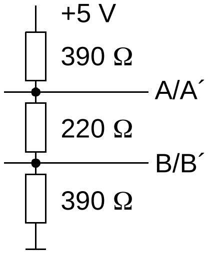


Figure 3-19 External terminating resistors

3.1.3.5 Reassembling the Device

To reassemble the device, proceed as follows:

☐ Carefully insert the boards into the housing. The installation locations of the boards are shown in Figures 3-8 and 3-9.
For the model of the device designed for surface mounting, use the metal lever to insert the C-CPU-2 board. The installation is easier with the lever.

☐ First insert the plug connectors of the ribbon cable on the input/output boards C-I/O and then on the processor board C-CPU-2. Be careful not to bend any of the connecting pins! Do not use force!

☐ Insert the plug connector of the ribbon cable between the processor board C-CPU-2 and the front cover in the socket on the front cover.

☐ Press the latches of the plug connectors together.

☐ Replace the front cover and secure to the housing with the screws.

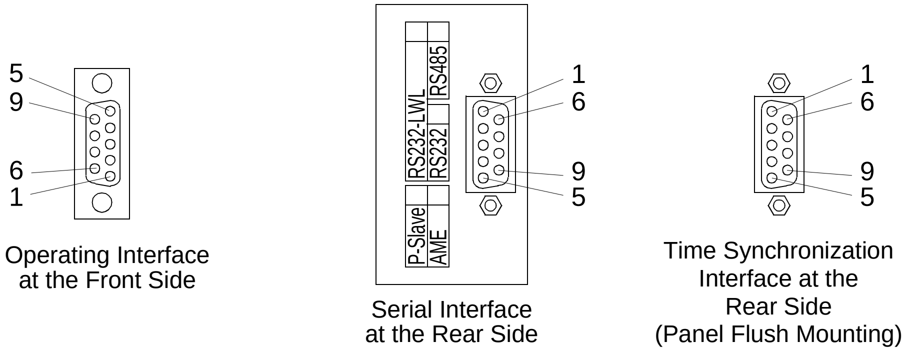
☐ Replace the covers.

☐ Re-fasten the interfaces on the rear of the device housing.
This activity is not necessary if the device is for surface mounting.

3.2 Checking the Connections

3.2.1 Data Connections of the Serial Interfaces

The tables of the following margin headers list the pin-assignments for the different serial interfaces of the device and the time synchronization interface. The physical arrangement of the connectors is illustrated in Figure 3-20.



Operating Interface at the Front Side

Serial Interface at the Rear Side

Time Synchronization Interface at the Rear Side (Panel Flush Mounting)

Figure 3-20 9-pin D-subminiature sockets

Operating Interface at Front

When the recommended communication cable is used, correct connection between the SIPROTEC® device and the PC is automatically ensured. See the Appendix A, Subsection A.1.3 for an ordering description of the cable.

System (SCADA) Interface

When a serial interface of the device is connected to a central substation control system, the data connection must be checked. A visual check of the transmit channel and the receive channel is important. Each connection is dedicated to one transmission direction. The data output of one device must be connected to the data input of the other device, and vice versa.

The data cable connections are designated in sympathy with DIN 66020 and ISO 2110 (see also Table 3-20):

– TxD	Data Transmit
– RxD	Data Receive
– $\overline{\text{RTS}}$	Request to Send
– $\overline{\text{CTS}}$	Clear to Send
– DGND	Signal/Chassis Ground

The cable shield is to be grounded at only **both ends**. For extremely EMC-loaded environments the GND may be integrated into a separate individually shielded wire pair to improve the immunity to interference.

Table 3-20 Pin-assignments of the D-subminiature ports

Pin-No.	**Operating Interface**	**RS232**	**RS485**	**Profibus FMS Slave, RS485** **Profibus DP Slave, RS485**	**Modbus RS485** **DNP3.0 RS485**
1	Screen (with screen ends electrically connected)				
2	RxD	RxD	—	—	—
3	TxD	TxD	A/A' (RxD/TxD–N)	B/B' (RxD/TxD–P)	A
4	—	—	—	CNTR–A (TTL)	RTS (TTL level)
5	GND	GND	C/C' (GND)	C/C' (GND)	GND1
6	—	—	—	+5 V (max. load 100 mA)	VCC1
7	$\overline{\text{RTS}}$	$\overline{\text{RTS}}$	—*)	—	—
8	$\overline{\text{CTS}}$	$\overline{\text{CTS}}$	B/B' (RxD/TxD–P)	A/A' (RxD/TxD–N)	B
9	—	—	—	—	—

*) Pin 7 also may carry the RS232 $\overline{\text{RTS}}$ signal on an RS485 interface. Pin 7 must therefore not be connected!

Termination

The RS485 interfaces are capable of half-duplex service with the signals A/A' and B/B' with a common reference potential C/C' (DGND). Verify that only the last device on the bus has the terminating resistors connected, and that the other devices on the bus do not.

Jumpers for the terminating resistors for an integrated RS485 interface are on the processor board C-CPU-2, refer to Figure 3-10 and Table 3-7.

On interface modules see Figure 3-17 (RS485) or Figure 3-18 (Profibus RS485).

It is also possible that the terminating resistors are arranged externally (Figure 3-19).

If the bus is extended, make sure again that only the last device on the bus has the terminating resistors switched in, and that all other devices on the bus do not.

Time Synchronization

Either 5 VDC, 12 VDC or 24 VDC time synchronization signals can be processed if the connections are made as indicated in Table 3-21.

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Table 3-21 Pin-assignments of the D-subminiature port of the time synchronization interface

Pin-No.	Designation	Signal Meaning
1	P24_TSIG	Input 24 V
2	P5_TSIG	Input 5 V
3	M_TSIG	Return Line
4	M_TSYNC*)	Return Line *)
5	Screen	Screen potential
6	—	—
7	P12_TSIG	Input 12 V
8	P_TSYNC*)	Input 24 V *)
9	Screen	Screen potential

*) assigned, but not available

Optical Fibres

Signals transmitted over optical fibres are unaffected by interference. The fibres guarantee electrical isolation between the connections. Transmit and receive connections are identified with the symbols •⟶ for transmit and ⟶• for receive.

The character idle state for the optical fibre interface is “Light off”. If this setting is to be changed, use the operating program DIGSI®, as described in the SIPROTEC® System Manual, order-no. E50417–H1176–C151.

Warning!

Laser injection! Do not look directly into the fibre-optic elements!

RTD-Boxes

If one or two RTD-boxes 7XV566 are connected for considering the coolant temperature when using overload protection with hot-spot calculation, check this connection at the service interface (Port C) or the additional interface (Port D).

Check also for the termination: The terminating resistors must be connected to the device 7UT6 (see Subsection 3.1.3.4, margin heading “RS485 Interface”).

For notes concerning the 7XV566 see for the instruction manual attached to the device. Check the transmission parameters at the temperature measuring device. Besides Baud-rate and parity also the bus number is of primary importance.

- For the connection of **1** RTD-box 7XV566:
  bus number = ***0*** with Simplex-transmission (to be set at 7XV566),
  bus number = ***1*** with Duplex-transmission (to be set at 7XV566),
- For the connection of **2** RTD-boxes 7XV566:
  bus number = ***1*** for the 1st RTD-box (to be set at 7XV566 for RTD1 to 6),
  bus number = ***2*** for the 2nd RTD-box (to be set at 7XV566 for RTD7 to 12).

3.2.2 Checking Power Plant Connections

Warning!

Some of the following test steps will be carried out in presence of hazardous voltages. They shall be performed only by qualified personnel which is thoroughly familiar with all safety regulations and precautionary measures and pay due attention to them.

Caution!

Operating the device on a battery charger without a connected battery can lead to impermissibly high voltages and consequently, the destruction of the device. For limit values see Subsection 4.1.2 in the Technical Data.

Before the device is energized for the first time, the device should be in the final operating environment for at least 2 hours to equalize the temperature and to minimize humidity and avoid condensation. Connection are checked with the device at its final location. The plant must first be switched off and grounded.

Connection examples for the current and voltage transformer circuits are given in the Appendix Section A.3. Please observe the general diagrams (Appendix A.2) and the plant diagrams, too.

☐ Protective switches (e.g. test switches, fuses, or miniature circuit breakers) for the power supply and the measured voltages must be opened.

☐ Check the continuity of all current and voltage (if available) transformer connections against the switch-gear and connection diagrams:

- ☐ Is the connection of all 3-phase current transformer sets to the device inputs correct (refer to the set topology according to Subsection 2.1.2 and 2.1.3 for more details)?
- ☐ Is the connection of all 1-phase current transformers to the device inputs correct (refer to the set topology according to Subsection 2.1.2 and 2.1.3 for more details)?
- ☐ Are all current transformers grounded properly?
- ☐ Are the polarities of all current transformers the same for each CT set?
- ☐ Is the phase relationship of all 3-phase current transformer sets correct?
- ☐ Are the polarities for all 1-phase current inputs correct (as far as used)?
- ☐ Are the voltage transformers grounded properly (if used)?
- ☐ Are the polarities of the voltage transformers correct (if used)?
- ☐ Is the phase relationship of the voltage transformers correct (if used)?
- ☐ Is the polarity for voltage input U_4 correct (if used, e.g. with open delta winding)?

☐ Check the functions of all test switches that may be installed for the purposes of secondary testing and isolation of the device. Of particular importance are test switches in current transformer circuits. Be sure these switches short-circuit the current transformers when they are in the test mode (open).

☐ The short-circuit feature of the current circuits of the device are to be checked. An ohmmeter or other test equipment for checking continuity is needed. Be sure that continuity is not simulated by the reverse connected current transformers themselves or their short-circuit links.

- ☐ Remove the front panel of the device (see Figure 3-8 or 3-9).
- ☐ Remove the ribbon cable connected to the C-I/O-9 board
  7UT613: C-I/O-9 Slot 33;
  7UT633: C-I/O-9 Slot 33 right;
  7UT635: C-I/O-9 Slot 33 right;
  and pull the board out until there is no contact between the board and the rear connections of the device.
- ☐ At the terminals of the device, check continuity for each pair of terminals that receives current from the CTs.
- ☐ Firmly re-insert the board.
- ☐ Check continuity for each of the current terminal-pairs again.

☐ Carry out the complete previous continuity tests with the further boards with current connections (see Figure 3-8 or 3-9):
7UT613: C-I/O-2 Slot 19;
7UT633: C-I/O-2 Slot 19 right;
7UT635: C-I/O-9 Slot 19 right.

☐ Carefully re-connect the ribbon cable. Do not bend any connector pins! Do not use force!

☐ Attach the front panel and tighten the screws.

☐ Connect an ammeter in the supply circuit of the power supply. A range of about 2.5 A to 5 A for the meter is appropriate.

☐ Close the protective switches to apply voltage to the power supply of the device. Check the polarity and magnitude of the voltage at the device terminals.

☐ The measured steady-state current should correspond to the quiescent power consumption of the device. Transient movement of the ammeter merely indicates the charging current of capacitors.

☐ Remove the voltage from the power supply by opening the protective switches.

☐ Disconnect the measuring equipment; restore the normal power supply connections.

☐ Close the protective switches for the voltage transformers (if used).

☐ Verify that the voltage phase rotation at the device terminals is correct.

☐ Open the protective switches for the voltage transformers (if used) and the power supply.

☐ Check the trip circuits to the power system circuit breakers.

☐ Verify that the control wiring to and from other devices is correct.

☐ Check the signalling connections.

☐ Close the protective switches to apply voltage to the power supply.

3.3 Commissioning

Warning!

Hazardous voltages are present in this electrical equipment during operation. Non-observance of the safety rules can result in severe personal injury or property damage.

Only qualified personnel shall work on and around this equipment after becoming thoroughly familiar with all warnings and safety notices of this manual as well as with the applicable safety regulations.

Particular attention must be drawn to the following:

- The earthing screw of the device must be connected solidly to the protective earth conductor before any other electrical connection is made.
- Hazardous voltages can be present on all circuits and components connected to the supply voltage or to the measuring and test quantities.
- Hazardous voltages can be present in the device even after disconnection of the supply voltage (storage capacitors!).
- Wait for at least 10 s after having disconnected the supply voltage before you re-apply the voltage in order to achieve defined initial conditions.
- The limit values stated in the Technical Data must not be exceeded at all, not even during testing and commissioning.

When testing the device with secondary test equipment, make sure that no other measurement quantities are connected. Take also into consideration that the trip and close commands to the circuit breakers and other primary switches are disconnected from the device unless expressly stated.

DANGER!

Current transformer secondary circuits must have been short-circuited before the current leads to the device are disconnected!

If test switches are installed that automatically short-circuit the current transformer secondary circuits, it is sufficient to place them into the “Test” position provided the short-circuit functions has been previously tested.

For the commissioning switching operations have to be carried out. A prerequisite for the prescribed tests is that these switching operations can be executed without danger. They are accordingly not meant for operational checks.

Warning!

Primary tests must only be carried out by qualified personnel, who are familiar with the commissioning of protection systems, the operation of the plant and the safety rules and regulations (switching, earthing, etc.).

3.3.1 Testing Mode and Transmission Blocking

If the device is connected to a substation control system or a server, the user is able to modify, in some protocols, information that is transmitted to the substation (see Section A.6 “Protocol Dependent Functions” in Appendix A).

In the **`testing mode`** all messages sent from a SIPROTEC®4 device to the substation are marked with an extra test bit so that the substation is able to identify them as messages announcing no real faults. Furthermore the **`transmission blocking`** function leads to a total blocking of the message transmission process via the system interface in the testing mode.

Refer to System Manual (Order-no. E50417–H1176–C151) to know how the testing mode and the transmission blocking can be enabled and disabled. Please note that it is necessary to be **`Online`** to be able to use the testing mode.

3.3.2 Checking Time Synchronization

If external time synchronization sources are used (IRIG B, DCF77) the data of the time source (antenna system, time generator) are checked (see Subsection 4.1.4 under “Time Synchronization”). Using time signal IRIG B or DCF77 the correct time must appear at last 3 minutes after startup of the processor system, i.e. the clock alarm must go off (message “`Clock SyncError OFF`” in the operating messages or spontaneous messages.

Table 3-22 Time Status

No.	Status Bits	
1	**`-- -- -- --`**	synchronized
2	**`-- -- -- ST`**	
3	**`-- -- ER --`**	not synchronized
4	**`-- -- ER ST`**	
5	**`-- NS ER --`**	
6	**`-- NS -- --`**	
	Legend: NS ER ST	 Not synchronized Time error savings time

3.3.3 Checking the System (SCADA) Interface

Preliminary Notes

Provided that the device is equipped with a system (SCADA) interface that is used for the communication with a central computer station, it is possible to test via the DIGSI® operational function whether the messages are being transmitted correctly. Do **not** apply this test feature while the device is in service on a live system!

DANGER!

The initiation or extraction of messages via the system (SCADA) interface using the test function constitutes an actual exchange of information between the device and the control system. Connected equipment such as e.g. circuit breakers or isolators may be switched as a result of this!

Note:

After termination of this test, the device will reboot. All annunciation buffers are erased. If required, these buffers should be extracted with DIGSI® prior to the test.

The interface test can be done using DIGSI® in the online operating mode:

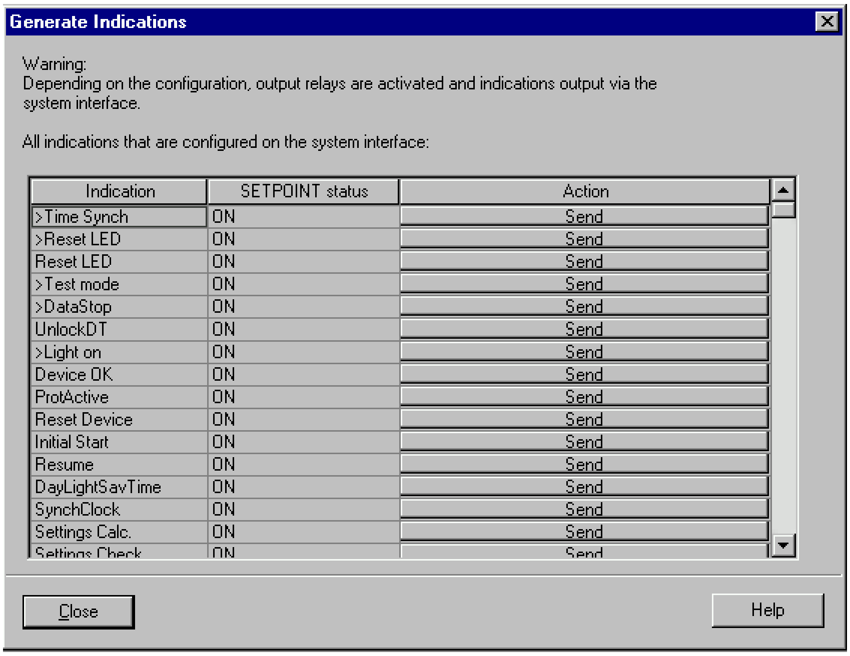
❑ Double-click on the **`Online`** directory to open the required dialog box.

❑ Click on **`Test`** and the functional options appear on the right side of the window.

❑ Double-click on **`Testing Messages for System Interface`** shown in the list view. The dialogue box **`Generate Indications`** opens (refer to Figure 3-21).

Structure of the Test Dialogue Box

In the column **`Indication`**, all message texts that were configured for the system interface in the matrix will then appear. In the column **`SETPOINT status`** you to define the value for the messages to be tested. Depending on the type of message different entering fields are available (e.g. message **`ON`** / message **`OFF`**). By clicking onto one of the fields the required value can be selected from the list.



Generate Indications

Warning:
Depending on the configuration, output relays are activated and indications output via the system interface.

All indications that are configured on the system interface:

Indication	SETPOINT status	Action
>Time Synch	ON	Send
>Reset LED	ON	Send
Reset LED	ON	Send
>Test mode	ON	Send
>DataStop	ON	Send
UnlockDT	ON	Send
>Light on	ON	Send
Device OK	ON	Send
ProtActive	ON	Send
Reset Device	ON	Send
Initial Start	ON	Send
Resume	ON	Send
DayLightSavTime	ON	Send
SynchClock	ON	Send
Settings Calc.	ON	Send
Settings Check	ON	Send

Figure 3-21 Dialog box: Generate indications — example

Changing the Operating State

Following the first operation of one of the keys in the column **Action** you will be asked for password no. 6 (for hardware test menus). Having entered the correct password messages can be issued. To do so, click on **Send**. The corresponding message is issued and can be read out either from the event log of the SIPROTEC$^{®}$ 4 device as well as from the central master computer.

As long as the windows is open, further tests can be performed.

Test in the Transmission Direction

For all information that is transmitted to the central station the following is to be checked under **SETPOINT status**:

- Ensure that any switching operations that may result from these tests can be executed without danger (see above under **DANGER**!).
- Click on **Send** and check whether the transmitted information reaches the central station and shows the desired reaction.

Exiting the Procedure

To end the interface test, click on **Close**. The dialog box closes. The device becomes unavailable for a brief start-up period immediately after this.

Test in the Control Direction

The information elements starting with a „>“-character are transmitted to the device. Such information must be initiated by the control centre. The correct response in the device must be checked.

3.3.4 Checking the Binary Inputs and Outputs

Preliminary Notes

The binary inputs, outputs, and LEDs of a SIPROTEC® 4 device can be individually and precisely controlled using DIGSI®. This feature is used to verify control wiring from the device to plant equipment during commissioning. This test feature shall **not** be used while the device is in service on a live system.

DANGER!

Changing the status of a binary input or output using the test feature of DIGSI® results in an actual and immediate corresponding change in the SIPROTEC® device. Connected equipment such as circuit breakers or disconnectors will be operated as a result of these actions!

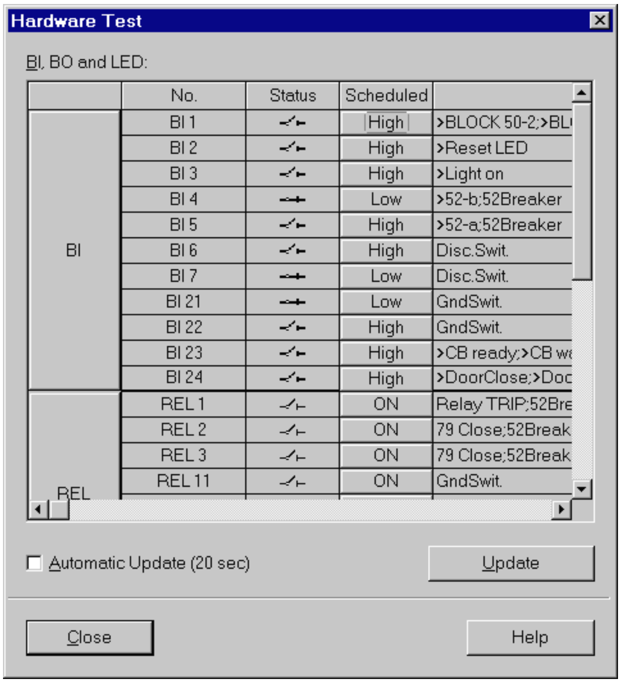
Note: After termination of the hardware test, the device will reboot. Thereby, all annunciation buffers are erased. If required, these buffers should be extracted with DIGSI® prior to the test.

The hardware test can be done using DIGSI® in the online operating mode:

❑ Open the **`Online`** directory by double-clicking; the operating functions for the device appear.

❑ Click on **`Test`**; the function selection appears in the right half of the screen.

❑ Double-click in the list view on **`Hardware Test`**. The dialogue box of the same name opens (see Figure 3-22).



Hardware Test

BI, BO and LED:

	No.	Status	Scheduled	
BI	BI 1	-/-	High	>BLOCK 50-2;>BL
	BI 2	-/-	High	>Reset LED
	BI 3	-/-	High	>Light on
	BI 4	---	Low	>52-b;52Breaker
	BI 5	-/-	High	>52-a;52Breaker
	BI 6	-/-	High	Disc.Swit.
	BI 7	---	Low	Disc.Swit.
	BI 21	---	Low	GndSwit.
	BI 22	-/-	High	GndSwit.
	BI 23	-/-	High	>CB ready;>CB w
	BI 24	-/-	High	>DoorClose;>Doc
REL	REL 1	-/-	ON	Relay TRIP;52Bre
	REL 2	-/-	ON	79 Close;52Break
	REL 3	-/-	ON	79 Close;52Break
	REL 11	-/-	ON	GndSwit.

☐ Automatic Update (20 sec)

Figure 3-22 Dialogue box for hardware test — example

Structure of the Test Dialogue Box

The dialogue box is divided into three groups: **BI** for binary inputs, **REL** for output relays, and **LED** for light-emitting diodes. Each of these groups is associated with an appropriately marked switching area. By double-clicking in an area, components within the associated group can be turned on or off.

In the **Status** column, the present (physical) state of the hardware component is displayed. The binary inputs and outputs are indicated by an open or closed switch symbol, the LEDs by a dark or illuminated LED symbol.

The possible intended condition of a hardware component is indicated with clear text under the **Scheduled** column, which is next to the **Status** column. The intended condition offered for a component is always the opposite of the present state.

The right-most column indicates the commands or messages that are configured (masked) to the hardware components.

Changing the Hardware Conditions

To change the condition of a hardware component, click on the associated switching field in the **Scheduled** column.

Password No. 6 (if activated during configuration) will be requested before the first hardware modification is allowed. After entry of the correct password a condition change will be executed.

Further condition changes remain possible while the dialog box is open.

Test of the Binary Outputs

Each individual output relay can be energized allowing a check of the wiring between the output relay of the 7UT6 and the plant, without having to generate the message that is assigned to the relay. As soon as the first change of state for any one of the output relays is initiated, *all* output relays are separated from the internal device functions, and can only be operated by the hardware test function. This implies that a switching signal to an output relay from e.g. a protection function or control command cannot be executed.

- ❑ Ensured that the switching of the output relay can be executed without danger (see above under **DANGER**!).
- ❑ Each output relay must be tested via the corresponding **Scheduled**-cell in the dialog box.
- ❑ The test sequence must be terminated (refer to margin heading “Exiting the Procedure”), to avoid the initiation of inadvertent switching operations by further tests.

Test of the Binary Inputs

To test the wiring between the plant and the binary inputs of the 7UT6 the condition in the plant which initiates the binary input must be generated and the response of the device checked.

To do this, the dialogue box **Hardware Test** must again be opened to view the physical state of the binary inputs. The password is not yet required.

- ❑ Each state in the plant which causes a binary input to pick up must be generated.
- ❑ The response of the device must be checked in the **Status**-column of the dialogue box. To do this, the dialogue box must be updated. The options may be found below under the margin heading “Updating the Display”.

If however the effect of a binary input must be checked without carrying out any switching in the plant, it is possible to trigger individual binary inputs with the hardware test function. As soon as the first state change of any binary input is triggered and the password nr. 6 has been entered, *all* binary inputs are separated from the plant and can only be activated via the hardware test function.

- ❑ Terminate the test sequence (see above under the margin heading „Exiting the Procedure“).

Test of the LED's

The LED's may be tested in a similar manner to the other input/output components. As soon as the first state change of any LED has been triggered, *all* LEDs are separated from the internal device functionality and can only be controlled via the hardware test frunction. This implies that no LED can be switched on anymore by e.g. a protection function or operation of the LED reset key.

Updating the Display

When the dialog box **`Hardware Test`** is opened, the present conditions of the hardware components at that moment are read in and displayed. An update occurs:

- for each harware component, if a command to change the condition is successfully performed,
- for all hardware components if the **`Update`** button is clicked,
- for all hardware components with cyclical updating if the **`Automatic Update (20sec)`** field is marked.

Exiting the Procedure

To end the hardware test, click on **`Close`**. The dialog box closes. The device becomes unavailable for a brief start-up period immediately after this. Then all hardware components are returned to the operating conditions determined by the plant settings.

3.3.5 Checking the Setting Consistency

The device 7UT6 checks settings of the protection functions against the corresponding configuration parameters. Any inconsistencies will be reported. For instance, earth fault differential protection cannot be applied if there is no measuring input for the starpoint current between starpoint of the protected object and the earthing electrode.

The device also checks the matching factors between the rated currents of the CT's and the operational currents of the protected object(s) as processed by the protection functions. If very high deviations combined with sensitive protection settings are discovered an alarm is output which also indicates the suspicious setting address(es).

In the operational or spontaneous annunciations check if there is any information on inconsistencies. Table 3-23 shows such inconsistency annunciations.

Table 3-23 Indications on inconsistencies

Message	FNo	Description	See Section
Error1A/5Awrong	00192	Setting of the rated secondary currents on input/output module inconsistent, general	2.1.3 3.1.3.3

Table 3-23 Indications on inconsistencies

Message	FNo	Description	See Section
Err. IN CT M1 to Err. IN CT M5	30097 to 30101	Setting of the rated secondary currents inconsistent for the indicated measured current input (3-phase inputs)	2.1.3 3.1.3.3
Err.IN CT1..3 to Err.IN CT10..12	30102 to 30105	Setting of the rated secondary currents inconsistent for the indicated measured current input (inputs for 1-phase busbar protection)	2.1.3 3.1.3.3
Err. IN CT IX1 to Err. IN CT IX4	30106 to 30109	Setting of the rated secondary currents inconsistent for the indicated measured current input (1-phase inputs)	2.1.3 3.1.3.3
FaultConfig/Set	00311	Group indication of configuration errors	
GenErrGroupConn	00312	General: Error in transformer connection group	2.1.3
GenErrEarthCT	00313	General: Error in 1-phase inputs for earth current	2.1.2
GenErrSidesMeas	00314	General: Error in assignment of sides/measuring locations	2.1.2
par too low:	30067	Parameter setting value too small for the indicated address number	
par too high:	30068	Parameter setting value too high for the indicated address number	
settingFault:	30069	Parameter setting implausible for the indicated address number	
Diff Adap.fact.	05620	The matching factor of the current transformers for differential protection is too great or too small	2.1.3 2.2
REF Not avail.	05835	Restricted earth fault protection is not available for the configured protected object	2.1.2 2.1.4
REF Adap.fact.	05836	The matching factor of the current transformers for restricted earth fault protection is too great or too small	2.1.3 2.3
REF Err CTstar	05830	There is no 1-phase measuring input assigned for the starpoint current for restricted earth fault protection	2.1.2 2.1.4 2.3
O/C Ph. Not av.	01860	Time overcurrent protection for phase currents is not available for the configured protected object	2.1.2 2.1.4
O/C 3I0 Not av.	01861	Time overcurrent protection for residual current is not available for the configured protected object	2.1.2 2.1.4
O/C Earth ErrCT	01862	No assignment possible for time overcurrent protection for earth current	2.1.2 2.1.4
O/C 1Ph Err CT	05981	No assignment possible for single-phase time overcurrent protection	2.1.2 2.1.4
I2 Not avail.	05172	Unbalanced load protection is not available for the configured protected object	2.1.2 2.1.4
I2 Adap.fact.	05168	The matching factor of the current transformers for unbalanced load protection is too great or too small	2.1.3 2.8
O/L No Th.meas.	01545	Temperature reception for overload protection is missing (from RTD-box)	2.1.1 2.9.3
O/L Not avail.	01549	Overload protection is not available for the configured protected object	2.1.2 2.1.4
O/L Adap.fact.	01546	The matching factor of the current transformers for overload protection is too great or too small	2.1.3 2.9

Table 3-23 Indications on inconsistencies

Message	FNo	Description	See Section
U/f Not avail.	05377	Overexcitation protection is not available for the configured protected object	2.1.2 2.1.4
U/f Err No VT	05376	Overexcitation protection is not available without voltage connection	2.1.2
BkrFail Not av.	01488	Breaker failure protection is not available for the configured protected object	2.1.2 2.1.4
TripC ProgFail	06864	For trip circuit supervision the number of binary inputs was set incorrectly	2.14.1.4 3.1.2

In the operational or spontaneous annunciations also check whether there are any suspect annunciations from the device.

The matching factors of all measured value inputs are indicated in the operational annunciations. It is recommended to check these factors even if none of the above mentioned alarms is present. The indicated factors are:

– general the ratio of the nominal current/voltage of the side referred to the rated current/voltage of the instrument transformers at the measuring locations;

– for differential protection the ratio of the nominal current of the protected object referred to the rated current of the current transformers at the measuring locations;

– for restricted earth fault protection the ratio of the nominal current of the assigned side of the protected object referred to the rated current of the starpoint current transformer.

None of the factors should be greater than 5 or smaller than 0.2. Otherwise the risk of higher measuring errors could arise. If a factor is greater than 50 or smaller than 0.02, unexpected reactions of protection functions may occur.

Table 3-24 Indications on matching factors

Message	FNo	Description	See Section
Gen CT-M1: to Gen CT-M5:	30060 to 30064	General: Magnitude matching factor at the indicated measuring location	2.1.3
Gen VT-U1:	30065	General: Magnitude matching factor of 3-phase voltage input	2.1.3
Dif CT-M1: to Dif CT-M5:	05733 to 05737	Differential protection: Magnitude matching factor of the indicated measuring location (3-phase protected objects)	2.1.3
Dif CT-I1: to Dif CT-I12:	05721 to 05732	Differential protection: Magnitude matching factor of the indicated measuring location (1-phase busbar protection)	2.1.3
Dif CT-IX1: to Dif CT-IX4:	05738 to 05741	Differential protection: Magnitude matching factor of the indicated auxiliary 1-phase measuring location	2.1.3
REF CTstar:	05833	Restricted earth fault protection: Magnitude matching factor of the starpoint current	2.1.3

3.3.6 Checking for Breaker Failure Protection

If the device is equipped with the breaker failure protection and this function is used, the interaction with the breakers of the power plant must be tested.

Because of the manifold application facilities and various configuration possibilities of the power plant it is not possible to give detailed description of the test steps necessary to verify the correct interaction between the breaker failure protection and the breakers. It is important to consider the local conditions and the protection and plant drawings.

It is advised to isolate the circuit breaker of the tested feeder at both sides, i.e. to keep the busbar disconnector and the line disconnector open, in order to ensure operation of the breaker without risk.

Caution!

Tripping of the complete busbar or busbar section may occur even during tests at the local feeder breaker. Therefore, it is recommended to interrupt the tripping commands to the adjacent (busbar) breakers e.g. by switch-off of the associated control voltage. Nevertheless ensure that trip remains possible in case of a real primary fault if parts of the power plant are in service.

The trip command of the tested differential protection is made ineffective so that the local breaker can be tripped only by the breaker failure protection function.

The following lists do not claim to cover all possibilities. On the other hand, they may contain items that can be bypassed in the actual application.

Circuit Breaker Auxiliary Contacts

The circuit breaker auxiliary contact(s) form an essential part of the breaker failure protection system in case they have been connected to the device. Make sure that the correct assignment has been checked (Subsection 3.3.4). Make sure that the measured currents for breaker failure protection (CTs), the tested circuit breaker, and its auxiliary contact(s) relate to the same measuring location or side of the protected object.

External Initiation Conditions

If the breaker failure protection is intended to be initiated by external protection devices, each of the external initiation conditions must be checked.

At least the tested phase of the device must be subjected to a test current to enable initiation of the breaker failure protection. This may be a secondary injected current.

- ☐ Start by trip command of the external protection:
  Binary input “`>BrkFail extSRC`” (FNo `01431`); look up in the trip log or spontaneous messages.
- ☐ Following initiation the message “`BkrFail ext PU`” (FNo `01457`) must appear in the fault annunciations (trip log) or in the spontaneous messages.
- ☐ With two-stage breaker failure protection, trip command to the local circuit breaker after the delay time **`T1`** (address `7015`).
- ☐ With single- or two-stage failure protection, trip command to the adjacent circuit breakers after the delay time **`T2`** (address `7016`).

Switch off test current.

The following applies if initiation without current flow is possible:

- ☐ Close tested circuit breaker while the disconnectors at both sides open.
- ☐ Start by trip command of the external protection:
  Binary input “`>BrkFail extSRC`” (FNo `01431`); look up in the trip log or spontaneous messages.
- ☐ Following initiation the indication “`BkrFail ext PU`” (FNo `01457`) must appear in the fault annunciations (trip log) or in the spontaneous messages.
- ☐ With two-stage breaker failure protection, indication “`BF T1-TRIP(loc)`” (FNo `01492`) and trip command to the local circuit breaker after the delay time **T1** (address `7015`).
- ☐ With single- or two-stage failure protection, indication “`BF T2-TRIP(bus)`” (FNo `01494`) and trip command to the adjacent circuit breakers after the delay time **T2** (address `7016`).

Reopen the circuit breakers.

Busbar Trip

The most important thing is the check of the correct distribution of the trip commands to the adjacent circuit breakers in case the local breaker fails.

The adjacent circuit breakers are those of all feeders which must be tripped in order to ensure interruption of the fault current should the local breaker fail. In other words, the adjacent breaker are those of all feeders which may feed the same busbar or busbar section as the faulty feeder. In case of a power transformer, the adjacent breakers may include the breaker of the other side of the transformer.

The identification of the adjacent feeders depends widely on the topology of the busbar and its possible arrangement or switching states. That is why a generally detailed test description cannot be specified.

In particular if multiple busbars are concerned the trip distribution logic to the other breakers must be checked. It must be verified for each busbar section that all breakers connected to the same section are tripped in case the concerned feeder breaker fails, and no other breakers.

Termination of the Checks

After completion of the tests, re-establish all provisory measures which might have been taken for the above tests. Ensure that the states of all switching devices of the plant are correct, that interrupted trip commands are reconnected and control voltages are switched on, that setting values which might have been altered are reverted to correct values, and that protective function are switched to the intended state (on or off).

3.3.7 Symmetrical Current Tests on the Protected Object

Should secondary test equipment be connected to the device, it is to be removed or, if applying, test switches should be in normal operation position.

Note:

It must be taken into consideration that tripping may occur if connections were made wrong.

The measured quantities of the following tests can be read out from the PC using DIGSI® or a web browser via the “IBS-Tool”. This provides comfortable read-out possibilities for all measured values with visualisation using phasor diagrams.

If you choose to work with the IBS-Tool, please note the Help files referring to the “IBS-Tool”. The IP-address needed for the browser depends on the port where the PC is connected:

- Connection to the front **operation** interface: IP-address **141.141.255.160**
- Connection to the rear **service** interface: IP-address **141.143.255.160**

Transmission speed is 115 kBit/s.

The following descriptions refer to read-out using DIGSI®. All measured values can be retrieved in the device display, too.

Preparation of Symmetrical Current Tests

At first commissioning, current checks must be performed before the protected object is energized for the first time. This ensures that the differential protection is operative as a short-circuit protection during the first excitation of the protected object with voltage. If current checks are only possible with the protected object under voltage (e.g. power transformers in networks when no low-voltage test equipment is available), it is imperative that a backup protection, e.g. time overcurrent protection, be commissioned before, which operates at least at the feeding side. The trip circuit of other protection devices (e.g. Buchholz protection) must either remain operative.

If more than 2 measuring locations are present for the main protected object, the test must be repeated such that each possible current path through the protected object will have been part of a test. It is not necessary to test each possible current path but each measuring location must be included in a test current path at least once. Thus, it is advised to begin with the side S1 of the main protected object. If a side has more than one measuring location each must be included in a test. The other measuring locations remain current-free.

If further protected object are present these are tested individually according to their topology.

The test arrangement varies dependent on the application.

DANGER!

Operations in the primary area must be performed only with plant sections voltage-free and earthed! Perilous voltages may occur even on voltage-free plant sections due to capacitive influence caused by other live sections.

On network power transformers and asynchronous machines, a low-voltage test equipment is preferably used. A low-voltage source is used to energize the protected object, which is completely disconnected from the network (see Figure 3-23). On transformers, the test source is normally connect at the primary side. A short-circuit bridge which is capable to carry the test current, is installed outside of the protected zone and allows the symmetrical current to flow. On a motor, its star point enables current flow.

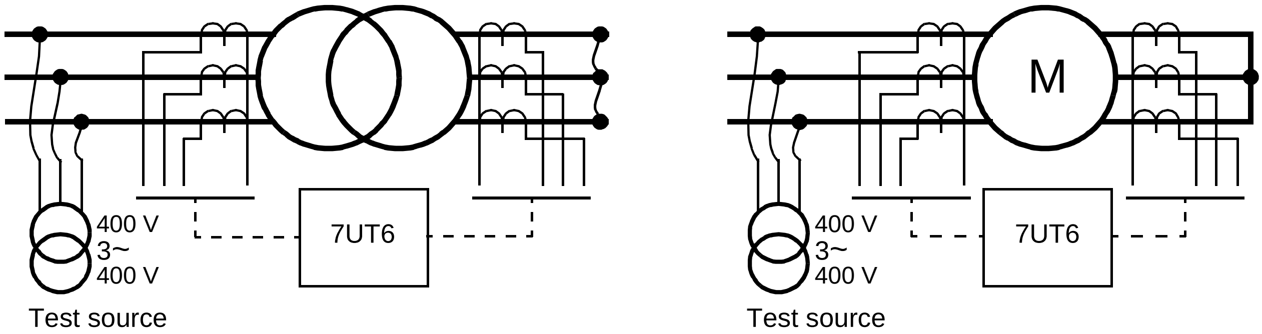


Figure 3-23 Current test with low-voltage test source — examples for a transformer and a motor

On power station unit transformers and synchronous machines, the checks are performed during the current tests. The generator itself forms the test current source (see Figure 3-24). The current is produced by a three-pole short-circuit bridge which is installed outside of the protected zone and is capable to carry the test current.

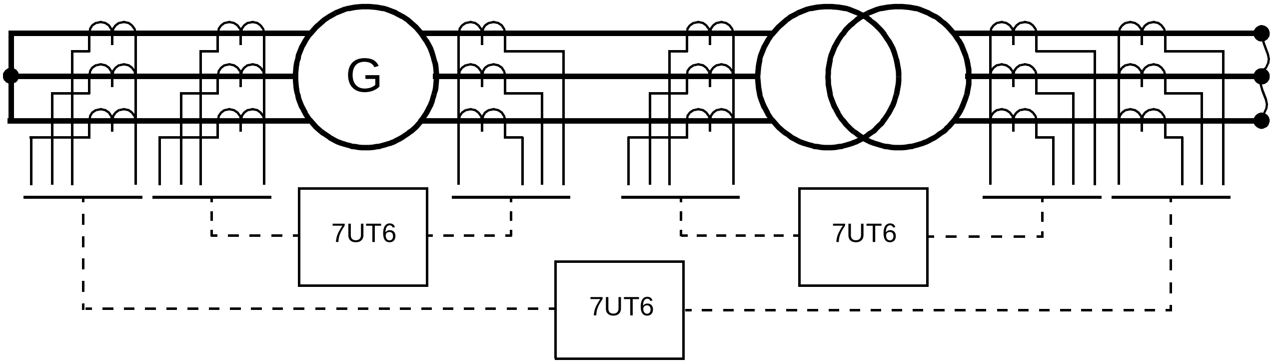


Figure 3-24 Current test in a power station with generator as test source — example

On busbars and short lines, a low-voltage test source can be used. Alternatively, load current test is possible. In the latter case the above hint about backup protection must be observed!

With the single-phase differential protection for busbars with more than 2 feeders, symmetrical current test is not necessary (but permissible, of course). The test can be carried out using a single-phase current source. Current tests must be performed for each possible current path, e.g. feeder 1 against feeder 2, feeder 1 against feeder 3, etc. Please read at first the notes about “Checking for Busbar Protection”, Subsection 3.3.9 (page 332).

Realization of Symmetrical Current Tests

Before beginning with the first current test check the correct polarity setting for measuring location 1 on the basis of address 511 **`STRPNT->OBJ M1`** and compare with the actual current connections. Refer to Section 2.1.3 under “Current Transformer Data for 3-phase Measuring Locations” (page 42) for more details. This check is also important for devices with measured voltage inputs as all further wrong polarities will not be recognized because the protection functions may operate even correctly if *all* polarities are wrong. Only during power check (Subsection 3.3.11) the errors would be recognized.

For this commissioning tests, the test current must be at least 2 % of the rated relay current for each phase.

These tests cannot replace visual inspection of the correct current transformer connections. Therefore, the inspection according to Section 3.2.2 is a prerequisite.

Since 7UT6 offers comprehensive commissioning aids commissioning can be performed quickly and without external instrumentation. The following indices are used for the display of measured values:

The equation symbol for current (I, φ) is followed by the phase identifier L and by a number that identifies the side (e.g. the transformer winding) or the measuring location. Example:
$I_{\mathbf{L1S1}}$ current in phase **L1** on side **S1**,
$I_{\mathbf{L1M1}}$ current in phase **L1** on measuring location **M1**.

The following procedure applies to a three-phase protected object for measuring location M1 against measuring location M2. For transformers it is assumed that measuring location 1 is assigned to side 1, and this is the high voltage side of the transformer. The other possible current paths are tested in an analogous way.

☐ Switch on the test current, or start up the generator and bring it to nominal speed and excite it to the required test current. None of the measurement monitoring functions in the device must respond. If there was a fault message, however, the Event Log or spontaneous messages could be checked to investigate the reason for it. Refer also to the SIPROTEC® 4 System Manual, order-no. E50417–H1176–C151.

- ☐ At the indication of imbalance there might actually be asymmetries of the primary system. If they are part of normal operation, the corresponding monitoring function is set less sensitive (see Subsection 2.14.2 under “Measured Value Supervision”, page 226).
- ☐ Phase rotation is clockwise in most cases. If the system has an counter-clockwise phase rotation, this must have been considered when the power system data was set (address 271 **`PHASE SEQ.`**, refer to Sub-section 2.1.3 under margin header “Phase Sequence”, page 36). If the phase rotation is incorrect, the alarm “`Fail Ph. Seq. I`” (FNo 00175) is generated. The measuring location with wrong phase rotation is also stated. The phase allocation of the measured value inputs must be checked and corrected, if required. The phase rotation check must then be repeated.

☐ Magnitude measurement with applied test current:

Compare the measured values under **`Measurement`** → **`Secondary Values`** → **`Operational values, secondary`** with the real values. This applies for all measuring locations included in the test.

Note: The “IBS Tool” provides comfortable read-out possibilities for all measured values with visualisation using phasor diagrams (Figure 3-25).

If deviations occur which cannot be explained by measuring tolerances, an error can be assumed in the device connections or in the test arrangement.

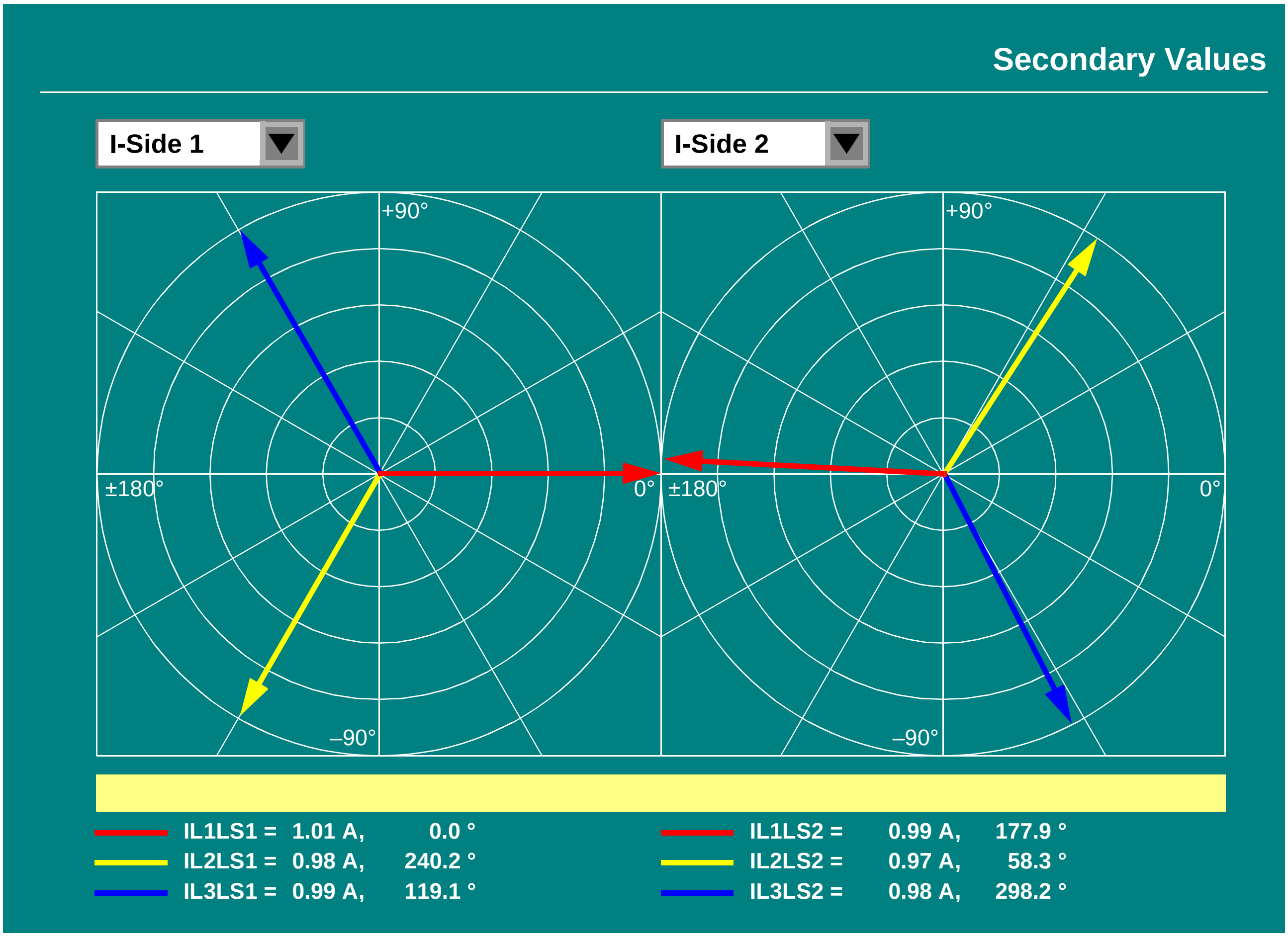
- ☐ Switch off the test source and the protected object (shut down the generator) and earth it.
- ☐ Re-check the assignment or the tested measuring location (Section 2.1.2 under header margin “Assignment of 3-phase Measuring Locations”).
- ☐ Re-check the settings for the magnitude matching (Section 2.1.3 under header margin “Current Transformer Data for 3-phase Measuring Locations”).
- ☐ Re-check the plant connections to the device and the test arrangement and correct them if necessary.
  If a substantial zero sequence current $3I_0$ occurs one of the currents of the corresponding measuring location must be missing or have a wrong polarity.
  - $3I_0 \approx$ phase current ⇒ one or two phase currents are missing,
  - $3I_0 \approx$ doubled phase current ⇒ one or two phase currents have a reversed polarity.
- ☐ Repeat test and re-check the current magnitudes.

☐ Phase angle measurement for measuring location 1 with test current:

Read out the phase angles under **`Measurement`** → **`Secondary Values`** → **`Angles`** of measuring location 1. All angles are referred to I_{L1M1}. The following values must result approximately for a clockwise phase rotation:
$\varphi_{L1M1} \approx 0°$
$\varphi_{L2M1} \approx 240°$
$\varphi_{L3M1} \approx 120°$

If the angles are wrong, reverse polarity or swapped phase connections on measuring location 1 may be the cause.

- ☐ Switch off the test source and the protected object (shut down the generator) and earth it.
- ☐ Re-check the plant connections to the device and the test arrangement and correct them. Check also phase sequence setting in address 271 **`PHASE SEQ.`**.
- ☐ Repeat test and re-check the current angles.



🟥 IL1LS1 = 1.01 A, 0.0 °
🟨 IL2LS1 = 0.98 A, 240.2 °
🟦 IL3LS1 = 0.99 A, 119.1 °

🟥 IL1LS2 = 0.99 A, 177.9 °
🟨 IL2LS2 = 0.97 A, 58.3 °
🟦 IL3LS2 = 0.98 A, 298.2 °

Figure 3-25 Measured values of the sides of the protected object — example for through-flowing currents

☐ Phase angle measurement for measuring location 2 with test current:

Read out the phase angles under **Measurement** → **Secondary Values** → **Angles** of measuring location 2. All angles are referred to I_{L1M1}.

Consider that always the currents flowing into the protected object are defined as positive. That means that, with through-flowing in-phase currents, the currents leaving the protected object at measuring location 2, have reversed polarity (180° phase displacement) against the corresponding in-flowing currents at measuring location 1. *Exception:* With transverse differential protection, the currents of the corresponding phase have equal phase!

For clockwise phase rotation and without phase displacement, the angles should be approximately:
$\varphi_{L1M2} \approx 180°$
$\varphi_{L1M2} \approx 60°$
$\varphi_{L1M2} \approx 300°$.

When measuring across a power transformer, approximately the values according to Table 3-25 result for clockwise phase rotation.

Table 3-25 Phase indication dependent on the protected object (three-phase)

Prot. object →	Generator/Motor/	Transformer with connection group numeral [1]											
↓ Phase angle	Busbar/Line	**0**	**1**	2	3	4	**5**	**6**	**7**	8	9	10	**11**
φ_{L1M2} ≈	180°	180°	150°	120°	90°	60°	30°	0°	330°	300°	270°	240°	210°
φ_{L2M2} ≈	60°	60°	30°	0°	330°	300°	270°	240°	210°	180°	150°	120°	90°
φ_{L3M2} ≈	300°	300°	270°	240°	210°	180°	150°	120°	90°	60°	30°	0°	330°

[1] The stated angles are valid if the high-voltage winding is side 1. Otherwise read 360° minus the stated angle

If considerable deviations occur, reversed polarity or swapped phases are expected on measuring location M2 or the actually tested measuring location.

- Deviation in individual phases indicates reversed polarity in the related phase current connection or acyclically swapped phases.
- If all phase angles differ by the same value, phase current connections of measuring location M2 are cyclically swapped or the connection group of the transformer differs from the set group. In the latter case, re-check the matching parameters (Subsection 2.1.3 under margin “Object Data with Transformers”, page 36) under addresses 314 for side 1, 324 and 325 for side 2, or the corresponding parameters for the tested measuring location. Consider also the assignment of the measuring location to the side and the side to the protected object.
- If all phase angles differ by 180°, the polarity of the complete CT set for measuring location M2 is wrong. Check and correct the applicable power system data (cf. Subsection 2.1.3 under “Current Transformer Data for 3-phase Measuring Locations”, page 42):
  address 511 **STRPNT->OBJ M1** for measuring location M1,
  address 521 **STRPNT->OBJ M2** for measuring location M2,
  or the corresponding parameters for the tested measuring location.

  For single-phase busbar protection refer to Subsection 2.1.3 under header margin “Current Transformer Data for 1-phase Busbar Protection”.

If connection errors are assumed:

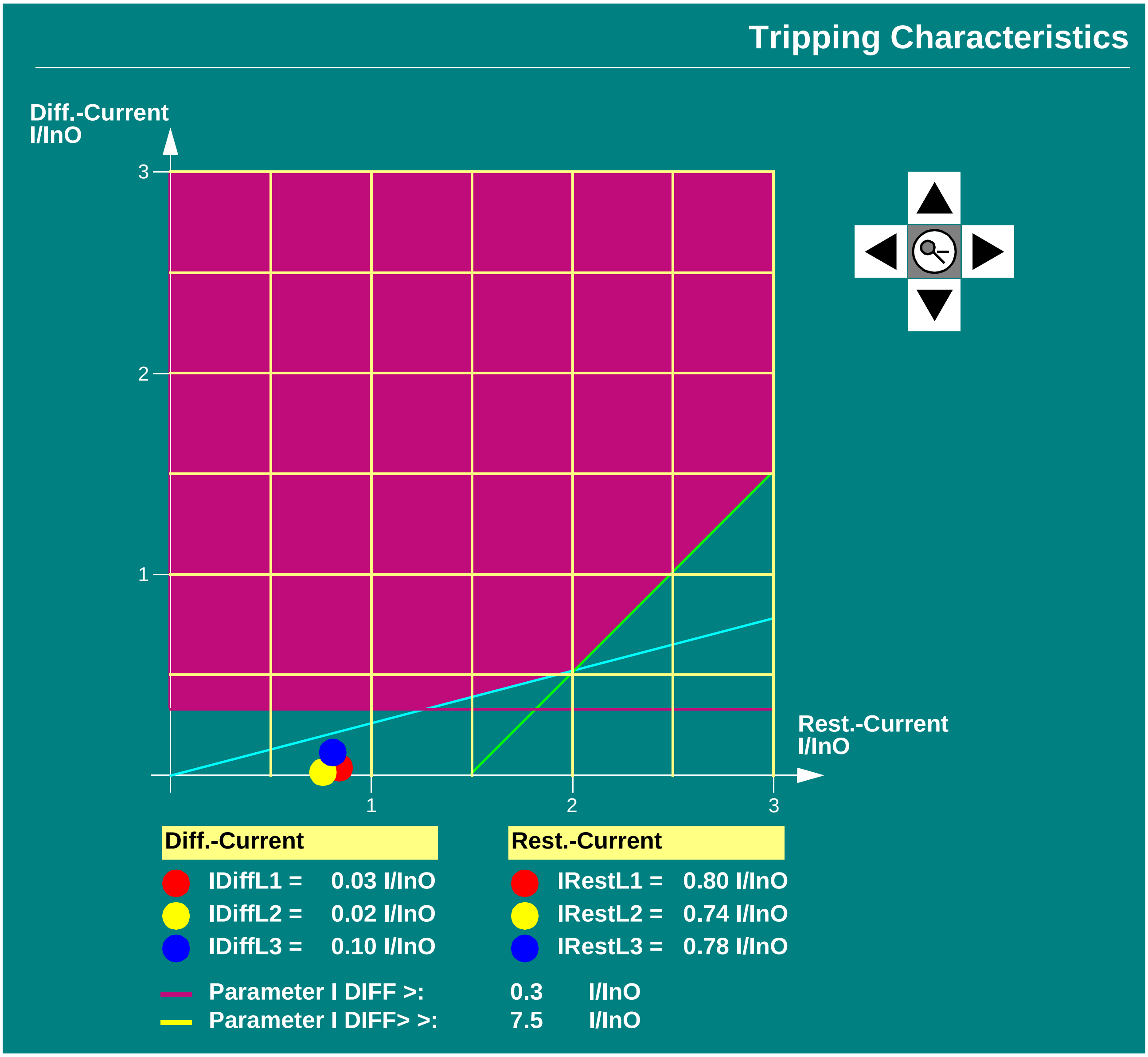
- Switch off the test source and the protected object (shut down the generator) and earth it.
- Re-check the plant connections to the device and the test arrangement and correct them. Check also the corresponding setting for the CT data.
- Repeat test and re-check the current angles.

All pre-described test must be repeated until every measuring location of the main protected object has been included in at least one test.

Measuring of the Differential and Restraint Currents

Before the tests with symmetrical currents for a current path are terminated, the differential and restraint currents are examined. Even though the above tests with symmetrical current should have widely detected connection errors, nevertheless, errors are possible concerning current matching and the assignment of the connection group cannot be completely excluded.

The differential and restraint currents are referred to the nominal currents of the protected object. This must be considered when they are compared with the test currents. With more than 2 sides, the highest nominal current of any side of the protected object is the nominal object current.



Tripping Characteristics

Diff.-Current

● IDiffL1 = 0.03 I/InO
● IDiffL2 = 0.02 I/InO
● IDiffL3 = 0.10 I/InO

Rest.-Current

● IRestL1 = 0.80 I/InO
● IRestL2 = 0.74 I/InO
● IRestL3 = 0.78 I/InO

▬ Parameter I DIFF >: 0.3 I/InO
▬ Parameter I DIFF> >: 7.5 I/InO

Figure 3-26 Differential and restraint currents — example for plausible currents

☐ Read out the differential and restraint currents under **Measurement** → **Percent Values** → **Differential and Restraint Currents**.

In the “IBS-Tool”, the differential and restraint currents are displayed as a graph in a characteristics diagram. An example is illustrated in Figure 3-26.

- ☐ The differential currents must be low, at least one scale less than the currents flowing through.

- ☐ The restraint currents correspond to twice the through-flowing test currents.
- ☐ If there are differential currents in the size of the restraint currents (approximately twice the through-flowing test current), you may assume a polarity reversal of the current transformer(s) at one side. Check the polarity again and set it right after short-circuiting all the six current transformers. If you have modified these current transformers, also perform an angle test.
- ☐ If there are differential currents which are nearly equal in all three phases, matching of the measured values may be erroneous. Wrong connection group of a power transformer can be excluded because they should have been detected during the phase angle test. Re-check the settings for current matching. These are mainly the data of the protected object:
  - For all kind of power transformers, addresses 311 and 312 for side 1 under “Object Data with Transformers”, (page 36) and accordingly the parameters for the other side under test. Further, the addresses 512, 513 for measuring location 1 under “Current Transformer Data for 3-phase Measuring Locations” (page 42) and accordingly the parameters for the other measuring location under test.
  - For generators, motors, reactors, addresses 361 and 362 under “Object Data with Generators, Motors or Reactors” (page 39) and addresses 512, 513 for measuring location 1 under “Current Transformer Data for 3-phase Measuring Locations” (page 42) and accordingly the parameters for the other measuring location under test.
  - For mini-busbars (3-phase), address 372 under “Object Data with Mini-Busbars or Short Lines (3-phase)” (page 39) for feeder 1 and accordingly the parameters for the other feeder under test, and addresses 512, 513 for measuring location 1 under “Current Transformer Data for 3-phase Measuring Locations” (page 42) and accordingly the parameters for the other measuring location under test.
  - For single-phase busbar protection, address 381 under “Object Data with Busbars (1-phase Connection) with up to 6 or 9 or 12 Feeders” (page 40) and addresses 562 and 563 under “Current Transformer Data for 1-phase Busbar Protection” (page 44) for feeder 1 and accordingly the parameters for the other feeder under test. If interposed summation transformers are used, matching errors can be caused by wrong connections at the summation CTs.

☐ Finally, switch off the test source and the protected object (shut down the generator).

☐ If parameter settings have been changed for the tests, reset them to the values necessary for operation.

Please keep in mind that the previous tests must be repeated for each current path.

3.3.8 Zero Sequence Current Tests on the Protected Object

The zero sequence current tests are only necessary if the starpoint of a three-phase object or a single-phase transformer is earthed on a side or winding. If more than one starpoint is earthed then the zero sequence current test has to be performed for each earthed winding.

If the current between starpoint and earth is available and fed to one of the 1-phase current inputs of the device the polarity of the earth current (starpoint current) at a 1-phase current input is essential for zero sequence current inclusion of the differential protection and the restricted earth fault protection. If the starpoint current is not available then the zero sequence current tests serve for verification of the correct processing of the zero sequence currents in the differential protection.

Note:

It must be taken into consideration that tripping may occur if connections were made wrong.

Preparation of Zero Sequence Current Tests

Zero sequence current measurements are always performed from that side or measuring location of the protected object where the starpoint is earthed, on auto-transformers from the high-voltage side. Power transformers shall be equipped with a delta winding (delta-winding or compensating winding). The sides which are not included in the tests remain open as the delta winding ensures low-ohmic termination of the current path.

The test arrangement varies with the application. Figure 3-27 shows a schematic examples of the test arrangement on a star-delta power transformer. In the Figures 3-28 to 3-34, the starpoint current is included into the tests. If it is not available the relevant connection is omitted.

DANGER!

Operations in the primary area must be performed only with plant sections voltage-free and earthed! Perilous voltages may occur even on voltage-free plant sections due to capacitive influence caused by other live sections.

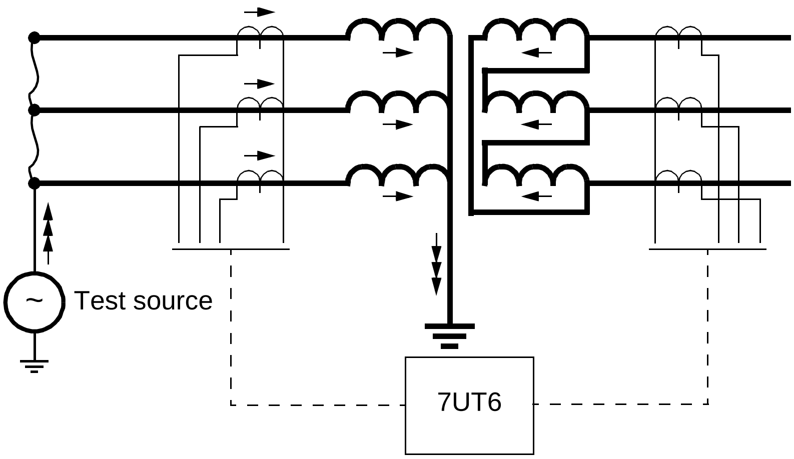


Figure 3-27 Zero sequence current measurement on a star-delta transformer — without inclusion of the starpoint current

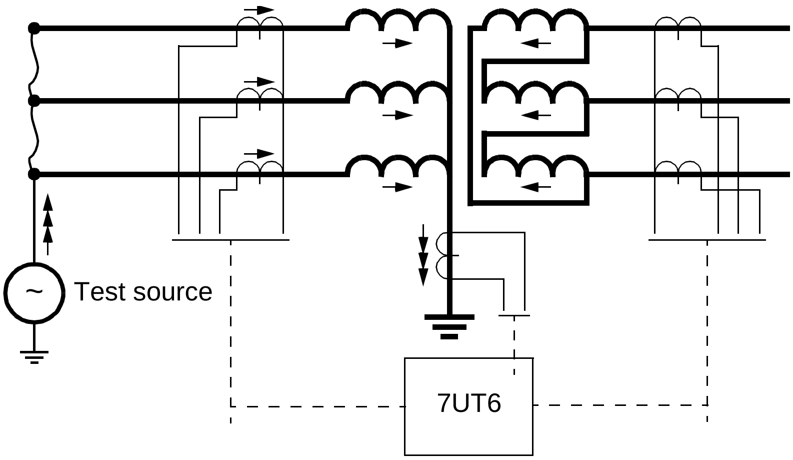


Figure 3-28 Zero sequence current measurement on a star-delta transformer

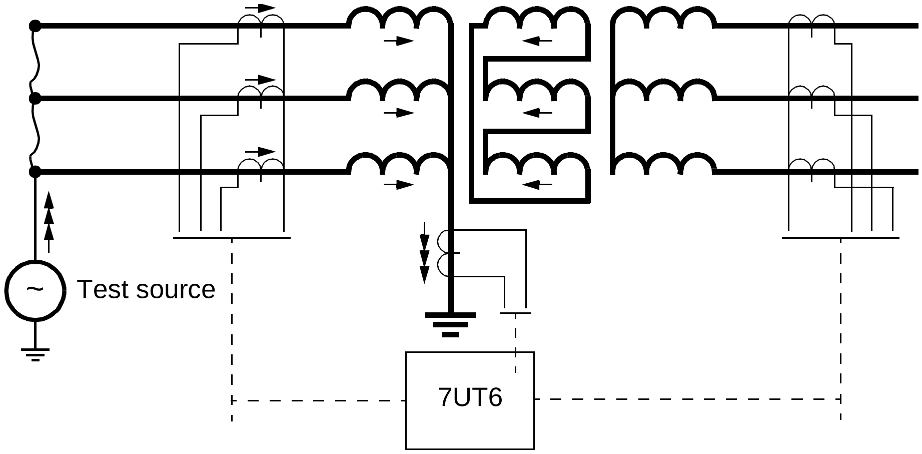


Figure 3-29 Zero sequence current measurement on a star-star transformer with compensation winding

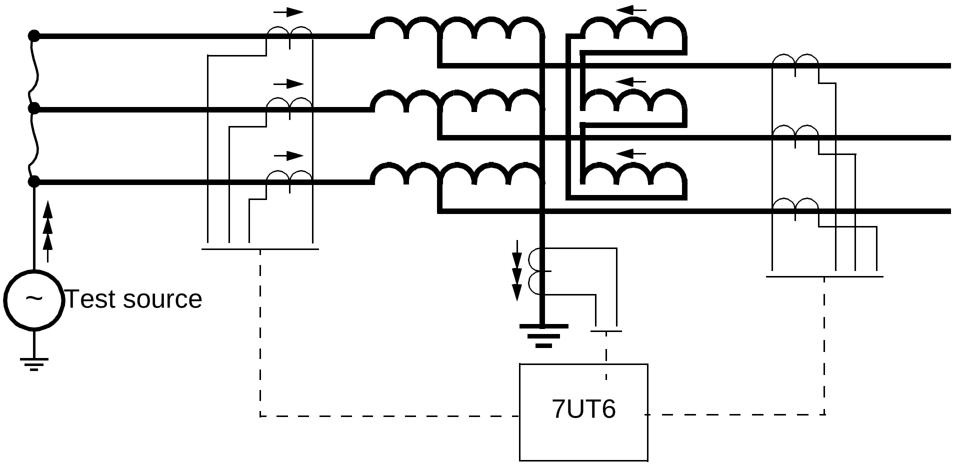


Figure 3-30 Zero sequence current measurement on an auto-transformer with compensation winding

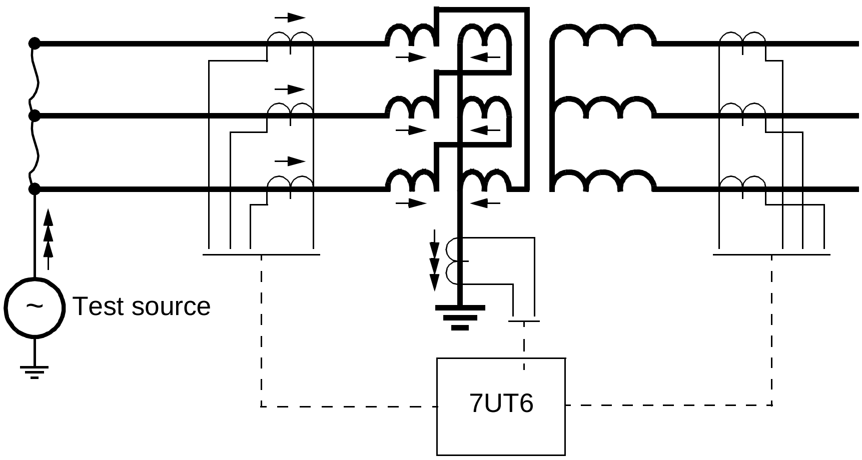


Figure 3-31 Zero sequence current measurement on a zig-zag-winding

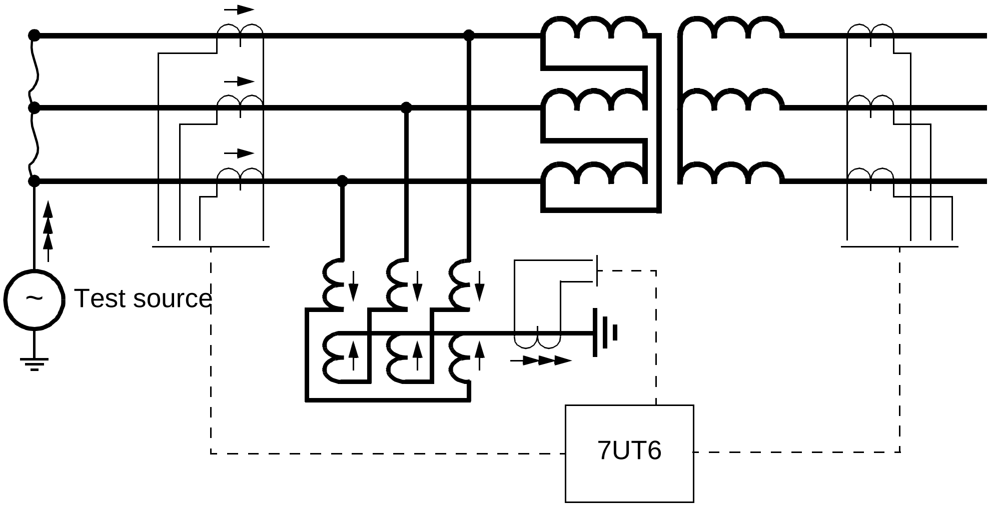


Figure 3-32 Zero sequence current measurement on a delta winding with neutral earthing reactor within the protected zone

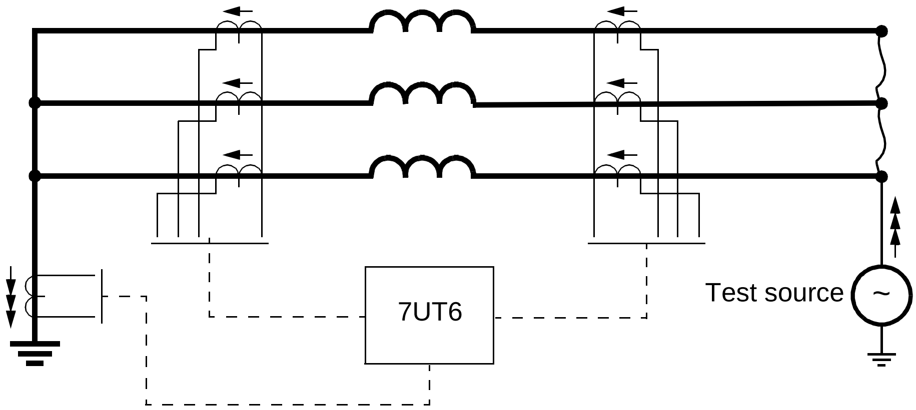


Figure 3-33 Zero sequence current measurement on an earthed series reactor

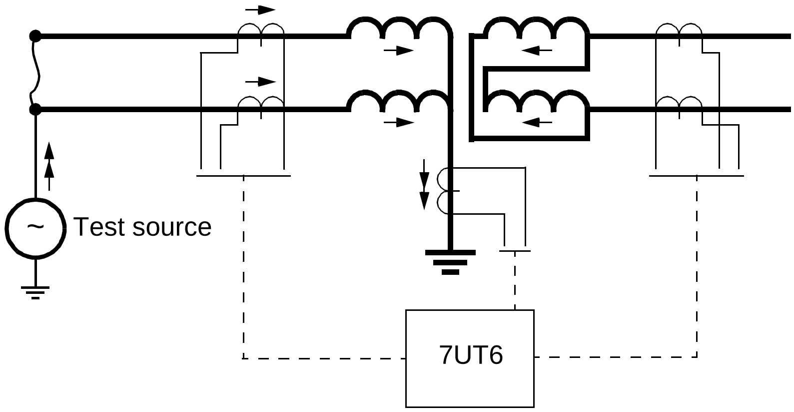


Figure 3-34 Zero sequence current measurement on an earthed single-phase transformer

Realization of Zero Sequence Current Tests

For this commissioning tests, the zero sequence current must be at least 2 % of the rated relay current for each phase, i.e. the test current at least 6 %.

This test cannot replace visual inspection of the correct current transformer connections. Therefore, the inspection according to Section 3.2.2 is a prerequisite.

☐ Switch on test current.

☐ Magnitude measurement with applied test current:

Compare the measured values under **`Measurement`** → **`Secondary Values`** → **`Operational values, secondary`** with the real values:

- All phase currents of the tested measuring location correspond to approximately $^1/_3$ of the test current ($^1/_2$ with single-phase transformers).
- $3I_0$ of the tested measuring location corresponds to the test current.
- Phase currents and zero sequence current of the other measuring location are, on transformers, nearly 0.
- The current at the 1-phase current input correspond to the test current — provided this current is available and included.

Deviation can practically occur only for the 1-phase current (if included) because the connection of the phase currents had been verified already during the symmetrical tests. When deviations on the 1-phase current occur:

☐ Switch off the test source and the protected object (shut down the generator) and earth it.

☐ Re-check the assignment or the tested 1-phase input (Section 2.1.2 under header margin “Assignment of Auxiliary 1-phase Measuring Locations”).

☐ Re-check the settings for the magnitude matching (Section 2.1.3 under header margin “Current Transformer Data for 1-phase Auxiliary Current Inputs”).

☐ Re-check the connections for the 1-phase input, the assignment according to the topology, and the test arrangement and correct them.

☐ Repeat test and re-check the current magnitudes.

Measuring Differential and Restraint Currents

The differential and restraint currents are referred to the nominal currents of the tested side of the main protected object. If a zero sequence current test does not concern the main protected object but a different earthed object (e.g. a shunt reactor outside the main object) then the base of the referred currents is the nominal current of that 3-phase measuring location to which the 1-phase current input is assigned, i.e. the measuring location under test. This must be considered when they are compared with the test currents.

☐ Switch on test current.

☐ If the starpoint current is available:

Read out the differential and restraint currents under **Measurement** → **Percent Values** → **Differential and Restraint Currents**.

- ☐ The differential current of the restricted earth fault protection $I_{DiffREF}$ must be low, at least one scale less than the test current.
- ☐ The restraint current $I_{RestREF}$ corresponds to twice the test current.
- ☐ If the differential current is in the size of the restraint current (approximately twice the test current), you may assume a polarity reversal of the 1-phase current transformer. Check the polarity again and compare it with the setting in address 711 **EARTH IX1 AT** if the additional 1-phase input IX1 is under test (cf. also Subsection 2.1.3 under margin “Current Transformer Data for 1-phase Auxiliary Current Inputs” (page 46), or accordingly the parameters for the actual input under test.
- ☐ If there is a differential current which does not correspond to twice the test current, the matching factor for the 1-phase input may be incorrect. Check the settings relevant for current matching. These are mainly the data of the protected object and its current transformers (Subsection 2.1.3):
  - for power transformers addresses 313, 323 etc. (dependent on the tested side) under “Object Data with Transformers”, (page 36) and
  - in all cases addresses 712 and 713, or 732 733, etc. (depending on the used 1-phase input) and under “Current Transformer Data for 1-phase Auxiliary Current Inputs” (page 46).

☐ In all cases (whether or not the starpoint current is available):

Check the differential currents I_{DiffL1}, I_{DiffL2}, I_{DiffL3}.

- ☐ The differential currents of the differential protection must be low, at least one scale less than the test current. If considerable differential currents occur, re-check the settings for the starpoints:
  - Starpoint conditioning of a transformer: addresses 313 **STARPNT SIDE 1**, 323 **STARPNT SIDE 2**, etc. (depending on the tested winding), see Subsection 2.1.3 under margin “Object Data with Transformers”, (page 36), as well as
  - the assignment of the starpoint current transformer to the 1-phase current input under test (if available): address 251, 252, etc., see Subsection 2.1.2 under “Assignment of Auxiliary 1-phase Measuring Locations” (page 32).
- ☐ Countercheck: The restraint currents of the differential protection I_{RestL1}, I_{RestL2}, I_{RestL3} are equally small. If all tests have been successful until now, this should be ensured.

☐ Finally, switch off the test source and the protected object (shut down the generator).

☐ If parameter settings have been changed for the tests, reset them to the values necessary for operation.

Please keep in mind that the previous tests must be repeated for each earthed side.

3.3.9 Checking for Busbar Protection

General

For single-phase busbar protection with one device per phase or with summation transformers, the same checks have to be performed as described in Subsection 3.3.7 “Symmetrical Current Tests on the Protected Object”. Please observe the following 4 notes:

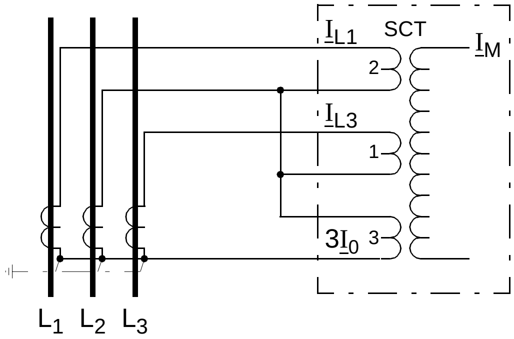
1. Checks are often done with operational currents or primary testing devices. Please take note of all warnings you can find in the sections and be aware of the fact that you will require a backup protection at the supplying point.
2. Checks have to be performed for every current path, beginning with the supplying feeder.
3. When using one device per phase, checks are to be performed for each phase. In the following you can find some more information on summation transformers.
4. However, each check is restricted on *one* current pair, i.e. on the *one* traversing testing current. Information on vector group matching and vectors (except the phase angle comparison of the traversing current = 180° at the sides tested) or similar is not relevant.

Connection via Summation CTs

If summation transformers are used, different connection possibilities exist. The following clarification are based on the normal connection mode L1−L3−E according to Figure 3-35. Figure 3-36 applies for connection L1−L2−L3.

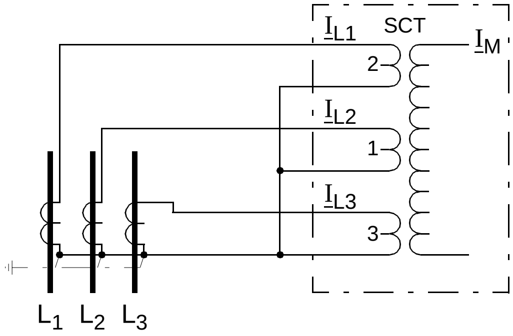
Single-phase primary tests are to be preferred, since they evoke clearer differences in the measured currents. They also detect connecting errors in the earth current path.

The measured current to be read out in the operational measured values only corresponds to the testing current if three-phase symmetrical check is performed. In other cases there are deviations which are listed in the figures as factor of the testing current.



Test Current	Measured Current
L1–L2–L3 (sym.)	1.00
L1–L2	1.15
L2–L3	0.58
L3–L1	0.58
L1–E	2.89
L2–E	1.73
L3–E	2.31

Figure 3-35 CT connection L1–L3–E



Test Current	Measured Current
L1–L2–L3 (sym.)	1.00
L1–L2	0.58
L2–L3	1.15
L3–L1	0.58
L1–E	1.15
L2–E	0.58
L3–E	1.73

Figure 3-36 CT connection L1–L2–L3

Deviations which cannot be explained by measuring tolerances may be caused by connection errors or matching errors of the summation transformers:

❑ Switch off the test source and the protected object and earth it.

❑ Re-check the connections and the test arrangement and correct them.

❑ Repeat test and re-check the current magnitudes.

The phase angles must be 180° in all cases.

Check the differential and restraint currents.

If single-phase primary checks cannot be carried out but only symmetrical operational currents are available, polarity or connecting errors in the earth current path with summation transformer connection L1–L3–E according to Figure 3-35 will not be detected with the before-mentioned checks. In this case, asymmetry is to be achieved by secondary manipulation.

Therefore the current transformer of phase L2 is short-circuited. See Figure 3-37.

DANGER!

All precautionary measures must be observed when working on the instrument transformers! Secondary connections of the current transformers must have been short-circuited before any current lead to the relay is interrupted!

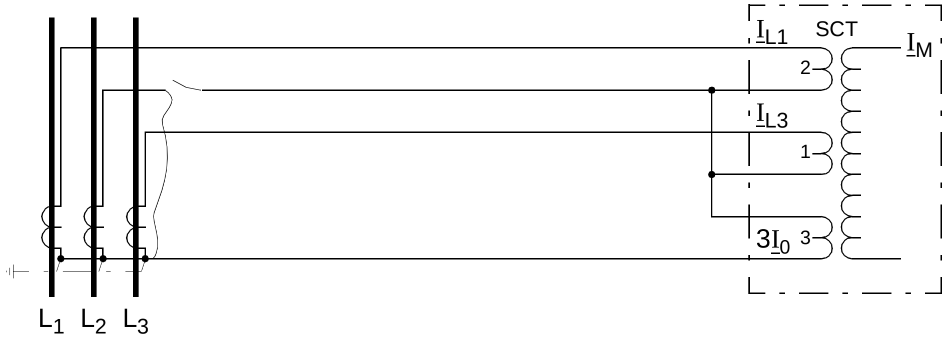


Figure 3-37 Unsymmetrical test with summation CT connection L1−L3−E

The measured current is now 2.65 times the current of the symmetrical test.

This test must be carried out for each summation CT.

3.3.10 Checking for the Non-Assigned 1-Phase Current Inputs

As far as 1-phase current inputs belong to the main protected object, i.e. they are assigned to a side of the main protected object, they were already checked with the zero sequence current tests as described in Subsection 3.3.8.

Even if they are not assigned to the main protected object but to a 3-phase measuring location of a further protected object (e.g. restricted earth fault protection for a separate neutral earthing reactor), the procedure according to Subsection 3.3.8 applies. Perform the zero sequence current tests unless it has yet been done.

Single-phase measured current inputs of the device can also be used for any desired 1-phase protection function. If this is an actual case and the same input has not yet been checked as a starpoint current input of the main protected object, an additional check of this 1-phase input must be carried out.

The test methods depend widely on the application of the 1-phase input.

By any means, the nominal currents and matching factors for the magnitude have to be checked. Consider whether or not the input under test is a high-sensitivity input (address 255 **AUX CT IX3 TYPE** or 256 **AUX CT IX4 TYPE**, refer to Subsection 2.1.2 under “High-Sensitivity Auxiliary 1-phase Measuring Locations” page 33). The data are set according to Subsection 2.1.3, margin heading “Current Transformer Data for 1-phase Auxiliary Current Inputs” (page 46). For “normal” inputs, the nominal primary and secondary CT currents are decisive (addresses 712, 713, 722, 723, 732, 733, 742, 743); for “high-sensitivity inputs the ratios (address 734 **FACTOR CT IX3** and/ or 744 **FACTOR CT IX4**).

Polarity check is not required since only the current magnitude is processed.

With high-impedance protection the assigned 1-phase current corresponds to the fault current in the protected object. Polarity of all current transformers supplying the resistor, whose current is measured, must be uniform. Here, traversing currents are used as for differential protection checks. Each current transformer must be included into a measurement. The measured current must not exceed, for each through-current test, the half of the pickup value of the single-phase time overcurrent protection.

3.3.11 Checking the Voltage Connections

Voltage and Phase Rotation Check

If the device is connected to voltage transformers, these connections are checked using primary values. For devices without voltage transformer connection this Section can be bypassed.

The voltage transformer connections are tested for that measuring location or side to which they are assigned. Refer to Subsection 2.1.2 under margin header "Assignment of Voltage Measuring Inputs" (page 34), address `261`.

☐ Having energized the voltage transformer set, none of the measurement monitoring functions in the device may respond.

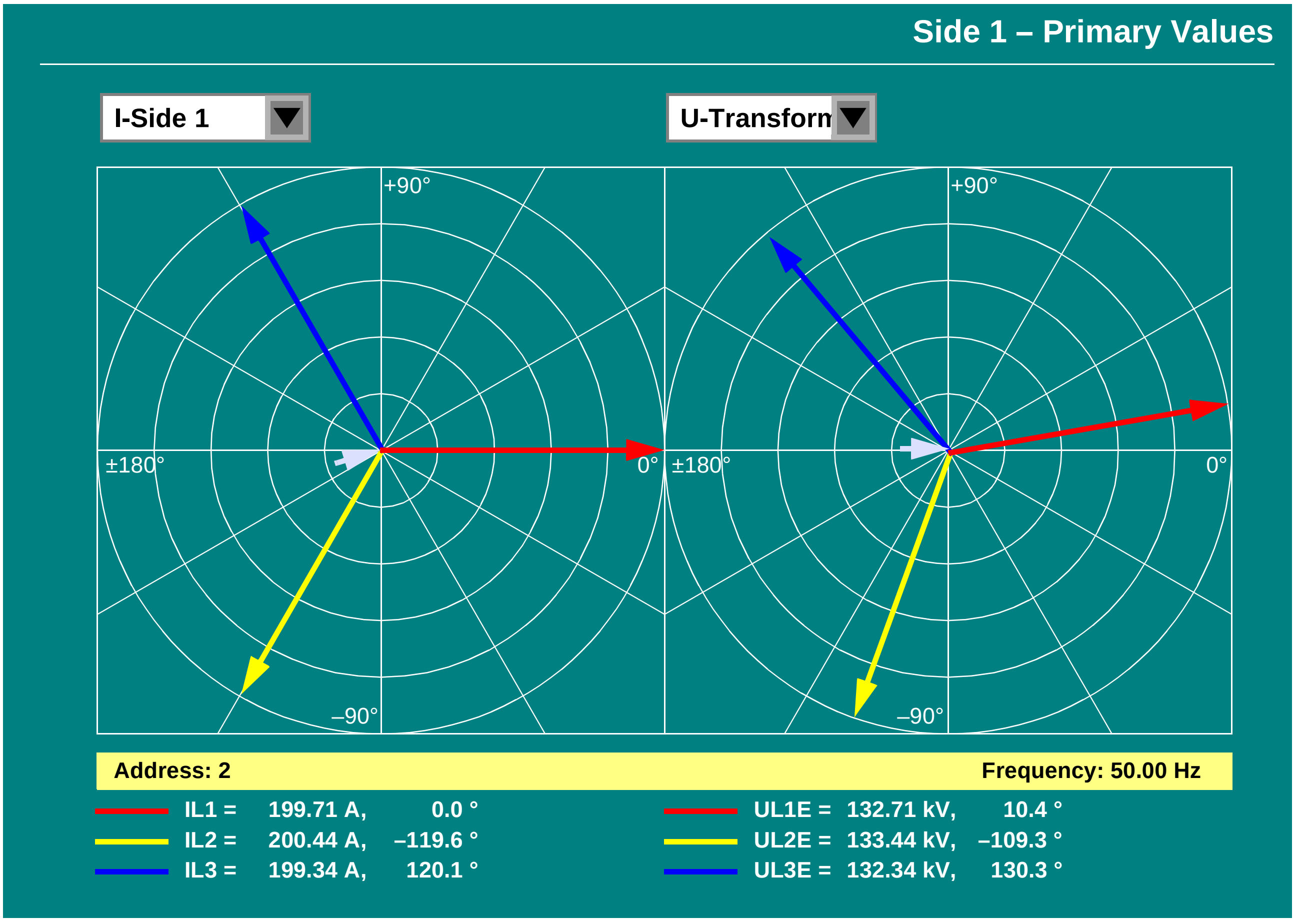
- ❑ If there was a fault message, however, the Event Log or spontaneous messages could be checked to investigate the reason for it.
- ❑ At the indication of voltage summation error check also the assignment of the 1-phase voltage input and the matching factors. For further details see Subsection 2.1.2 under margin header "Assignment of Voltage Measuring Inputs" (page 34).
- ❑ At the indication of balance monitoring there might actually be asymmetries of the primary system. If they are part of normal operation, the corresponding monitoring function is set less sensitive (see Subsection 2.14.2 under "Voltage Balance", page 218).

The voltages can be read on the display at the front, or called up in the PC via the operator or service interface, and compared with the actual measured quantities as primary or secondary values. Besides the magnitudes of the phase-to-phase and the phase-to-earth voltages, the phase angles can be read out thus enabling to verify the correct phase sequence and polarity of individual voltage transformers. The voltages can also be read with the "IBS-Tool" (see example in Figure 3-38).

☐ The voltage magnitudes should be almost equal. All the three angles must be approximately 120° to each other.

- ❑ If the measured quantities are not plausible, the connections must be checked and revised after switching off the measuring location. If the phase difference angle between two voltages is 60° instead of 120°, one voltage must be polarity-reversed. The same applies if there are phase-to-phase voltages which almost equal the phase-to-ground voltages instead of having a value that is $\sqrt{3}$ greater. The measurements are to be repeated after setting the connections right.
- ❑ In general, the phase rotation is a clockwise phase rotation. If the system has an counter-clockwise phase rotation, this must be considered in address `271` **`PHASE SEQ.`** (see Subsection 2.1.3 under "Phase Sequence", page 36). Wrong phase rotation is indicated with the annunciation "`Fail Ph. Seq. U`" (FNo `00176`). The measured value allocation must be checked and corrected, if required, after the measuring location has been isolated. The phase rotation check must then be repeated.

☐ Finally, the measuring location is switched off.



Address: 2

Frequency: 50.00 Hz

🟥 IL1 = 199.71 A, 0.0 °
🟨 IL2 = 200.44 A, –119.6 °
🟦 IL3 = 199.34 A, 120.1 °

🟥 UL1E = 132.71 kV, 10.4 °
🟨 UL2E = 133.44 kV, –109.3 °
🟦 UL3E = 132.34 kV, 130.3 °

Figure 3-38 Currents and voltages in the “IBS-Tool” — example

Assignment and Polarity Check

Voltages are also used for calculation of powers and metering of energy. Therefore, it must be checked whether the connected voltages have correct relationship with respect to the currents which are to be used for power calculation.

Primary tests are preferred as secondary tests cannot proof the correct polarity.

A load current of at least 5 % of the operational nominal current is required. Any direction is possible but must be known.

☐ At first, check whether power measurement is carried out at the desired measuring location, i.e. that the assignment of the 3-phase voltage transformer set is made correct. The powers are always calculated from the connected voltages and the currents of that measuring location to which the voltages are assigned. If the voltage inputs are assigned to a *side* of the protected object with more than one measuring location, the sum of the currents flowing into the protected object is decisive.

Check address 261 **VT SET**. Refer to Subsection 2.1.2 under margin heading “Assignment of Voltage Measuring Inputs” (page 34) for more details.

☐ With closed circuit breaker, the power values can be viewed as primary and secondary measured values in the front display panel or via the operator or service interface with a personal computer.

Here, again, the IBS Tool is a comfortable help as the vector diagrams also show the correlation between the currents and voltages (Figure 3-38). Cyclically and acyclically swapped phases can easily be detected.

☐ With the aid of the measured power values you are able to verify that they correlate to the load direction, reading either at the device itself or in DIGSI® (Figure 3-39):

P positive, if active power flows into the protected object,

P negative, if active power leaves the protected object,

Q positive, if (inductive) reactive power flows into the protected object,

Q negative, if (inductive) reactive power leaves the protected object.

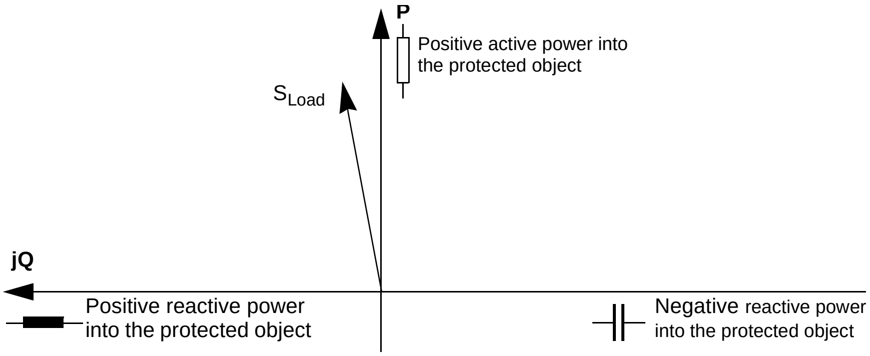


Figure 3-39 Complex (apparent) power

If all signs are inverted this may be intentional. Check the setting of address 1107 **`P,Q sign`** in the power system data 2 (see also Subsection 2.1.9 under “Sign of Power” (page 67).

If the test results do not match the power sign setting, polarity reversal in the voltage transformer connections is probable. If wrong sign is indicated in spite of correct VT connections, **all** CT polarities must be wrong!

If the voltage inputs are assigned to a side with more than one current measuring location, currents may flow through the measuring locations without entering the protected object. Power measurement is not possible in this case. Make sure that the currents for power measurement flow really through the protected object. Preferably use only one measuring location for the power test.

Finally, disconnect the power plant.

3.3.12 Testing User Specified Functions

7UT6 has a vast capability for allowing functions to be defined by the user, especially with the CFC logic. Any special function or logic added to the device must be checked.

Naturally, general test procedures cannot be given. Rather, the configuration of these user defined functions and the necessary associated conditions must be known and verified. Of particular importance are possible interlocking conditions of the switchgear (circuit breakers, isolators, etc.). They must be considered and tested.

3.3.13 Stability Check and Triggering Oscillographic Recordings

At the end of commissioning, an investigation of switching operations of the circuit breaker(s), under load conditions, should be done to assure the stability of the protection system during the dynamic processes. Oscillographic recordings obtain the maximum information about the behaviour of the 7UT6.

Requirements

Along with the capability of recording waveform data during system faults, the 7UT6 also has the capability of capturing the same data when commands are given to the device via the service program DIGSI®, the serial interfaces, or a binary input. For the latter, the binary input must be assigned to the function “`>Trig.Wave.Cap.`” (FNo `00004`). Triggering for the oscillographic recording then occurs when the input is energized.

An oscillographic recording that is externally triggered (that is, without a protective element pickup or device trip) is processed by the device as a normal fault recording with the exception that data are not given in the fault messages (trip log). The externally triggered record has a number for establishing a sequence.

Triggering with DIGSI®

To trigger oscillographic recording with DIGSI®, click on **`Test`** in the left part of the window. Double click the entry **`Test Wave Form`** in the list in the right part of the window to trigger the recording. See Figure 3-40.

A report is given in the bottom left region of the screen. In addition, message segments concerning the progress of the procedure are displayed.

The SIGRA program or the Comtrade Viewer program is required to view and analyse the oscillographic data.

Such test records are especially informative on power transformers when they are triggered by the switch-on command of the transformer. Since the inrush current may have the same effect as a single-ended infeed but must not initiate tripping, the effectiveness of the inrush restraint is checked by energizing the power transformer several times.

The trip circuit should be interrupted or the differential protection should be switched to **`DIFF. PROT.`** = ***`Block relay`*** (address `1201`) during this tests in order to avoid tripping.

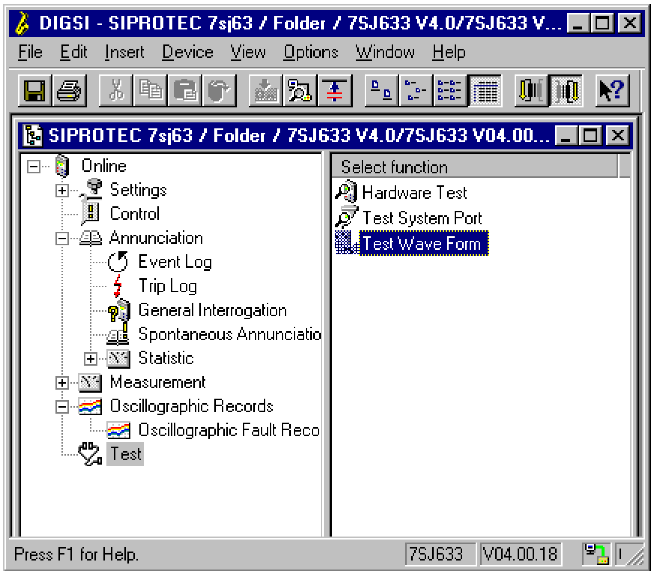


Figure 3-40 Triggering oscillographic recording with DIGSI® — example

As the pickup signal of the protection is not stabilized, the inrush current will start fault recording automatically provided the pickup threshold is reached.

Conclusions as to the effectiveness of the inrush restraint can be drawn from the recording of the differential currents and the harmonic contents. If necessary the inrush current restraint effect can be increased (smaller value of **2. HARMONIC**, address 1271) when trip occurs or when the recorded data show that the second harmonic content does not safely exceed the restraining threshold (address 1271). A further method to increase inrush stability is to set the crossblock function effective or to increase the duration of the crossblock function (address 1272A **CROSSB. 2. HARM**). For further detail refer to Subsection 2.2.7 under “Harmonic Restraint”, page 103).

Note:

Do not forget to switch the differential protection ***ON*** (address 1201) after completion of the test.

3.4 Final Preparation of the Device

Tighten the used screws at the terminals; those ones not being used should be slightly fastened. Ensure all pin connectors are properly inserted.

⚠

Caution!

Do not use force! The permissible tightening torques must not be exceeded as the threads and terminal chambers may otherwise be damaged!

Verify that all service settings are correct. This is a crucial step because some setting changes might have been made during commissioning. The protective settings under device configuration, input/output configuration are especially important as well as the power system data, and activated Groups A through D (if applicable). All desired elements and functions must be set ***ON***. See (Chapter 2). Keep a copy of all of the in-service settings on a PC.

Check the internal clock of the device. If necessary, set the clock or synchronize the clock if it is not automatically synchronized. For assistance, refer to the system manual.

The annunciation memory buffers should be cleared, particularly the operational messages (event log) and fault messages (trip log). Future information will then only apply for actual system events and faults. To clear the buffers, press **MAIN MENU** → **Annunciation** → **Set/Reset**. Refer to the system manual if further assistance is needed. The numbers in the switching statistics should be reset to the values that were existing prior to the testing, or to values in accordance with the user's practices. Set the statistics by pressing **MAIN MENU** → **Annunciation** → **Statistic**.

Press the **ESC** key, several times if necessary, to return to the default display.

Clear the LEDs on the front panel by pressing the **LED** key. Any output relays that were picked up prior to clearing the LEDs are reset when the clearing action is performed. Future indications of the LEDs will then apply only for actual events or faults. Pressing the **LED** key also serves as a test for the LEDs because they should all light when the button is pushed. Any LEDs that are lit after the clearing attempt are displaying actual conditions.

The green “RUN” LED must be on. The red “ERROR” LED must not be lit.

Close the protective switches. If test switches are available, then these must be in the operating position.

The device is now ready for operation.

■

Technical Data

4

This chapter provides the technical data of the SIPROTEC® 4 7UT6 device and its individual functions, including the limiting values that must not be exceeded under any circumstances. The electrical and functional data of fully equipped 7UT6 devices are followed by the mechanical data, with dimensional drawings.

4.1 General Device Data

4.1.1 Analog Inputs

	Nominal frequency	f_N	50 Hz / 60 Hz / 16,7 Hz (adjustable)
Current Inputs	Nominal current	I_N	1 A or 5 A or 0.1 A (changeable)
	Power consumption per input		
	– at IN = 1 A		approx. 0.05 VA
	– at IN = 5 A		approx. 0.3 VA
	– at IN = 0.1 A		approx. 1 mVA
	– for high-sensitivity input at 1 A		approx. 0.05 VA
	Current overload capability per input		
	– thermal (RMS)		100 $\cdot I_N$ for 1 s
			30 $\cdot I_N$ for 10 s
			4 $\cdot I_N$ continuous
	– dynamic (pulse)		1250 A (half cycle)
	Current overload capability for high-sensitivity input		
	– thermal (RMS)		300 A for 1 s
			100 A for 10 s
			15 A continuous
	– dynamic (pulse)		750 A (half cycle)
Current Transformer Requirements	Underburden factor $n' = n \cdot \frac{P_N + P_i}{P' + P_i}$		$n' \geq 4 \cdot \frac{I_{cc\ max}}{I_{N\ prim}}$ for $\tau \leq 100$ ms $n' \geq 5 \cdot \frac{I_{cc\ max}}{I_{N\ prim}}$ for $\tau > 100$ ms
	max. ratio of nominal primary current of the current transformers to nominal object current		$\frac{I_{N\,prim\ CT}}{I_{N\,prim\ obj}} \leq \begin{cases} 4 \text{ for phase currents} \\ 8 \text{ for earth current} \end{cases}$

4.1.2 Power Supply

Direct Voltage

Voltage supply via integrated DC/DC converter:

Nominal power supply direct voltage U_{NDC}	24/48 VDC	60/110/125 VDC
Permissible voltage ranges	19 to 58 VDC	48 to 150 VDC

Nominal power supply direct voltage U_{NDC}	110/125/220/250 VDC
Permissible voltage ranges	88 to 300 VDC

Permissible AC ripple voltage, peak to peak	≤15 % of the nominal power supply voltage

Power consumption		
– quiescent		approx. 6 W
– energized	7UT613	approx. 12 W
	7UT633/7UT635	approx. 20 W
Bridging time for failure/short-circuit of the power supply		≥50 ms at U_H = 48 V and U_{NDC} ≥ 110 V ≥20 ms at U_H = 24 V and U_{NDC} = 60 V

Alternating Voltage

Voltage supply via integrated AC/DC converter

Nominal power supply alternating voltage U_{NAC}	115/230 VAC
Permissible voltage ranges	92 to 265 VAC

Power consumption		
– quiescent		approx. 12 VA
– energized	7UT613	approx. 19 VA
	7UT633/7UT635	approx. 28 VA
Bridging time for failure/short-circuit of the power supply		≥ 50 ms

4.1.3 Binary Inputs and Outputs

Binary Inputs

Number (see also General Diagrams in Section A.2 of Appendix A)

7UT613		5 (allocatable)
7UT633		21 (allocatable)
7UT635		29 (allocatable)
Nominal voltage		24 VDC to 250 VDC in 2 ranges, bipolar
Switching thresholds		adjustable with jumpers
– for nominal voltages 24/48 VDC		U_{pickup} ≥ 19 VDC
	60/110/125 VDC	$U_{dropoff}$ ≤ 14 VDC
– for nominal voltages 110/125/		U_{pickup} ≥ 88 VDC
	220/250 VDC	$U_{dropoff}$ ≤ 66 VDC
Current consumption, energized		approx. 1.8 mA independent of the control voltage
Maximum permissible voltage		300 VDC
Input interference suppression		220 nF coupling capacitance at 220 V with recovery time >60 ms

Binary Outputs

Signalling/command relays (see also General Diagrams in Section A.2 of Appendix A)

Number:		
7UT613		8 (allocatable)
7UT633		24 (allocatable)
7UT635		24 (allocatable)
Switching capability	MAKE	1000 W/VA
	BREAK	30 VA 40 W ohmic 25 W for L/R ≤ 50 ms

Alarm relay		1, with 1 NC or NO contact (reconnectable)
Switching capability	MAKE	1000 W/VA
	BREAK	30 VA 40 W ohmic 25 W for L/R ≤ 50 ms
Switching voltage		250 V
Permissible current per contact		5 A continuous
make and carry		30 A for 0.5 s (NO contacts)
Permissible total current on common paths make and carry		5 A continuous 30 A for 0.5 s (NO contacts)

4.1.4 Communications Interfaces

Operation Interface	– Connection	front panel, non-isolated, RS 232 9-pin DSUB socket for connecting a personal computer
	– Operation	with DIGSI®
	– Transmission speed	min. 4 800 Baud; max. 115200 Baud factory setting: 115200 Baud; parity: 8E1
	– Maximum transmission distance	approx. 15 m (50 ft)
Service/Modem Interface (optional)	RS232/RS485/Optical acc. ordered version	isolated interface for data transfer for operation with DIGSI® or connection of a RTD-box
	RS232	
	– Connection for flush mounted case	rear panel, mounting location “C” 9-pin DSUB socket
	for surface mounted case	at the inclined housing on the case bottom
		shielded data cable
	– Test voltage	500 V; 50 Hz
	– Transmission speed	min. 4 800 Baud; max. 115200 Baud factory setting: 38400 Baud
	– Maximum transmission distance	approx. 15 m (50 ft)
	RS485	
	– Connection for flush mounted case	rear panel, mounting location “C” 9-pin DSUB socket
	for surface mounted case	at the inclined housing on the case bottom
		shielded data cable
	– Test voltage	500 V; 50 Hz

	– Transmission speed	min. 4800 Baud; max. 115200 Baud factory setting: 38400 Baud
	– Maximum transmission distance	approx. 1000 m (3300 ft)
	Optical fibre	
	– Connector Type	ST-connector
	for flush mounted case	rear panel, mounting location “C”
	for surface mounted case	at the inclined housing on the case bottom
	– Optical wavelength	λ = 820 nm
	– Laser class 1 acc. EN 60825–1/ –2	using glass fibre 50/125 µm or using glass fibre 62.5/125 µm
	– Permissible optical signal attenuation	max. 8 dB using glass fibre 62.5/125 µm
	– Maximum transmission distance	approx. 1.5 km (1 mile)
	– Character idle state	selectable; factory setting: “Light off”
System (SCADA) Interface (optional)	RS232/RS485/Optical Profibus RS485/Profibus Optical acc. to ordered version	isolated interface for data transfer to a master terminal
	RS232	
	– Connection for flush mounted case	rear panel, mounting location “B” 9-pin DSUB socket
	for surface mounted case	at the inclined housing on the case bottom
	– Test voltage	500 V; 50 Hz
	– Transmission speed	min. 300 Baud, max. 57600 Baud factory setting: 9600 Baud
	– Maximum transmission distance	approx. 15 m (50 ft)
	RS485	
	– Connection for flush mounted case	rear panel, mounting location “B” 9-pin DSUB socket
	for surface mounted case	at the inclined housing on the case bottom
	– Test voltage	500 V, 50 Hz
	– Transmission speed	min. 300 Baud, max. 57600 Baud factory setting: 9600 Baud
	– Maximum transmission distance	approx. 1000 m (3300 ft)
	Optical fibre	
	– Connector Type	ST-connector
	for flush mounted case	rear panel, mounting location “B”
	for surface mounted case	at the inclined housing on the case bottom
	– Optical wavelength	λ = 820 nm

– Laser class 1 acc. EN 60825–1/ –2	using glass fibre 50/125 µm or using glass fibre 62.5/125 µm
– Permissible optical signal attenuation	max. 8 dB using glass fibre 62.5/125 µm
– Maximum transmission distance	approx. 1.5 km (1 mile)
– Character idle state	selectable; factory setting: “Light off”

Profibus RS485 (FMS and DP)

– Connectionfor flush mounted case	rear panel, mounting location “B” 9-pin DSUB socket
for surface mounted case	at the inclined housing on the case bottom
– Test voltage	500 V; 50 Hz
– Transmission speed	up to 1.5 MBd
– Maximum transmission distance	1000 m (3300 ft) at ≤ 93.75 kBd 500 m (1640 ft) at ≤ 187.5 kBd 200 m (660 ft) at ≤ 1.5 MBd

Profibus Optical (FMS and DP)

– Connector Type	ST-plug FMS: single ring or twin ring depending on ordered version DP: twin ring only
– Connection for flush mounted case	rear panel, mounting location “B”
for surface mounted case	only with external OLM
– Transmission speed	to 1.5 MBd
recommended:	> 500 kBd
– Optical wavelength	λ = 820 nm
– Laser class 1 acc. EN 60825–1/ –2	using glass fibre 50/125 µm or using glass fibre 62.5/125 µm
– Optical budget	max. 8 dB using glass fibre 62.5/125 µm
– Maximum transmission distance between 2 modules at redundant optical ring topology and glass fiber 62.5/125 µm	1.6 km (1 mile) at 500 kB/s 530 m ($^1/_3$ mile) at 1500 kB/s
– Character idle state	“Light off”
– Number of modules in optical rings	max. 41 at 500 kB/s or 1500 kB/s

DNP3.0 RS485

– Connectionfor flush mounted case	rear panel, mounting location “B” 9-pin DSUB socket
for surface mounted case	at the inclined housing on the case bottom
– Test voltage	500 V; 50 Hz
– Transmission speed	up to 19200 Bd

	– Maximum transmission distance	approx. 1000 m (3300 ft)
	DNP 3.0 Optical	
	– Connector Type	ST-plug transmitter/receiver
	– Connection for flush mounted case	rear panel, mounting location “B”
	for surface mounted case	only with external converter
	– Transmission speed	up to 19200 Baud
	– Optical wavelength	λ = 820 nm
	– Laser class 1 acc. EN 60825–1/ –2	using glass fibre 50/125 μm or using glass fibre 62.5/125 μm
	– Permissible optical signal attenuation	max. 8 dB using glass fibre 62.5/125 μm
	– Maximum transmission distance	1.5 km (1 mile)
	MODBUS RS485	
	– Connection for flush mounted case	rear panel, mounting location “B” 9-pin DSUB socket
	for surface mounted case	at the inclined housing on the case bottom
	– Test voltage	500 V; 50 Hz
	– Transmission speed	up to 19200 Baud
	– Maximum transmission distance	approx. 1000 m (3300 ft)
	MODBUS LWL	
	– Connector Type	ST-plug transmitter/receiver
	– Connection for flush mounted case	rear panel, mounting location “B”
	for surface mounted case	only with external converter
	– Transmission speed	up to 19200 Baud
	– Optical wavelength	λ = 820 nm
	– Laser class 1 acc. EN 60825–1/ –2	using glass fibre 50/125 μm or using glass fibre 62.5/125 μm
	– Permissible optical signal attenuation	max. 8 dB using glass fibre 62,5/125 μm
	– Maximum transmission distance	approx. 1.5 km (1 mile)
Additional Interface (optional)	RS485/Optical acc. to ordered version	isolated interface for connection of a RTD-box
	RS485	
	– Connection for flush mounted case	rear panel, mounting location “D” 9-pin DSUB socket
	for surface mounted case	at the inclined housing on the case top
	– Test voltage	500 V, 50 Hz
	– Transmission speed	9600 Baud
	– Maximum transmission distance	1000 m (3300 ft)

Optical fibre

– Connector Type for flush mounted case for surface mounted case	ST-connector rear panel, mounting location “D” at the inclined housing on the case top
– Optical wavelength	λ = 820 nm
– Laser class 1 acc. EN 60825–1/ –2	using glass fibre 50/125 µm or using glass fibre 62.5/125 µm
– Permissible optical signal attenuation	max. 8 dB using glass fibre 62.5/125 µm
– Maximum transmission distance	approx. 1.5 km (1 mile)
– Character idle state	selectable; factory setting: “Light off”

Time Synchronization	– Signal type	DCF77/IRIG B-Signal
	– Connection for flush mounted case	rear panel, mounting location “A” 9-pin DSUB socket
	for surface mounted case	at the terminal on the case bottom
	– Nominal signal voltages	optional 5 V, 12 V or 24 V
	– Signal properties for DCF77/IRIG B:	

	Nominal signal input voltage		
	5 V	12 V	24 V
U_{IHigh}	6.0 V	15.8 V	31 V
U_{ILow}	1.0 V at I_{ILow} = 0.25 mA	1.4 V at I_{ILow} = 0.25 mA	1.9 V at I_{ILow} = 0.25 mA
I_{IHigh}	4.5 mA to 9.4 mA	4.5 mA to 9.3 mA	4.5 mA to 8.7 mA
R_I	890 Ω at U_I = 4 V 640 Ω at U_I = 6 V	1930 Ω at U_I = 8.7 V 1700 Ω at U_I = 15.8 V	3780 Ω at U_I = 17 V 3560 Ω at U_I = 31 V

4.1.5 Electrical Tests

Specifications	Standards:	IEC 60255 (Product standards) IEEE Std C37.90.0; C37.90.0.1; C37.90.0.2 VDE 0435 See also standards for individual tests
Insulation Tests	Standards:	IEC 60255–5 and 60870–2–1
	– High voltage test (routine test) all circuits except power supply, binary inputs, and communication/time sync. interfaces	2.5 kV (RMS); 50 Hz
	– High voltage test (routine test) only power supply and binary inputs	3.5 kVDC

	– High Voltage Test (routine test) only isolated communication /time sync. interfaces	500 V (RMS); 50 Hz
	– Impulse voltage test (type test) all circuits except communication /time sync. interfaces, class III	5 kV (peak); 1.2/50 µs; 0.5 Ws; 3 positive and 3 negative impulses in intervals of 5 s
EMC Tests; Interference Immunity (Type Tests)	Standards:	IEC 60255–6 and –22 (Product standards) EN 61000–6–2 (Generic standard) VDE 0435 Part 303
	– High frequency test IEC 60255–22–1; VDE 0435 part 301 class III	2.5 kV (Peak); 1 MHz; τ = 15 µs; 400 surges per s; test duration 2 s R_i = 200 Ω
	– Electrostatic discharge IEC 60255–22–2; IEC 61000–4–2 class IV	8 kV contact discharge; 15 kV air discharge, both polarities; 150 pF; R_i = 330 Ω
	– Irradiation with HF field, frequency sweep IEC 60255–22–3, IEC 61000–4–3 class III	10 V/m; 80 MHz to 1000 MHz; 80 % AM; 1 kHz
	– Irradiation with HF field, individual frequencies IEC 60255–22–3, IEC 61000–4–3 class III	10 V/m
	amplitude modulated	80 MHz; 160 MHz; 450 MHz; 900 MHz; 80 % AM; duty >10 s
	pulse modulated	900 Hz; 50 % PM; repetition frequency 200 Hz
	– Fast transient disturbance/burst IEC 60255–22–4, IEC 61000–4–4 class IV	4 kV; 5/50 ns; 5 kHz; burst length = 15 ms; repetition rate 300 ms; both polarities; R_i = 50 Ω; test duration 1 min
	– High energy surge voltages (SURGE) IEC 61000–4–5, installation class 3	impulse: 1.2/50 µs
	power supply	common mode: 2 kV; 12 Ω; 9 µF diff. mode: 1 kV; 2 Ω; 18 µF
	analogue inputs, binary inputs and outputs	common mode: 2 kV; 42 Ω; 0.5 µF diff. mode: 1 kV; 42 Ω; 0.5 µF
	– Line conducted HF, amplitude modulated IEC 61000–4–6; class III	10 V; 150 kHz to 80 MHz; 80 % AM; 1 kHz
	– Power system frequency magnetic field IEC 61000–4–8, IEC 60255–6 class IV	30 A/m continuous; 300 A/m for 3 s; 50 Hz 0.5 mT; 50 Hz
	– Oscillatory surge withstand capability IEEE Std C37.90.1	2.5 kV (peak value); 1 MHz; τ = 15 µs; 400 surges per s; R_i = 200 Ω; test duration 2 s

	– Fast transient surge withstand capability IEEE Std C37.90.1	4 kV (peak value); 5/50 ns; 5 kHz; burst length 15 ms; repetition rate 300 ms; both polarities; R_i = 80 Ω; duration 2 s 50 surges per s;
	– Damped oscillations IEC 60694, IEC 61000–4–12	2.5 kV (peak value), polarity alternating; 100 kHz, 1 MHz, 10 MHz and 50 MHz; R_i = 200 Ω
EMC Tests; Interference Emission (Type Tests)	Standard:	EN 50081–* (Generic standard)
	– Conducted interference, only power supply voltage IEC–CISPR 22	150 kHz to 30 MHz limit class B
	– Radio interference field strength IEC–CISPR 22	30 MHz to 1000 MHz limit class B
	– Harmonic currents on the mains conductors at 230 VAC IEC 61000–3–2	class A limits are fulfilled
	Voltage fluctuations and flicker on the mains conductors at 230 VAC IEC 61000–3–3	limits are fulfilled

4.1.6 Mechanical Stress Tests

Vibration and Shock During Operation	Standards:	IEC 60255–21 and IEC 60068
	– Vibration IEC 60255–21–1, class 2 IEC 60068–2–6	sinusoidal 10 Hz to 60 Hz: ±0.075 mm amplitude 60 Hz to 150 Hz: 1 g acceleration frequency sweep rate 1 octave/min 20 cycles in 3 orthogonal axes.
	– Shock IEC 60255–21–2, class 1 IEC 60068–2–27	half-sine shaped acceleration 5 g, duration 11 ms, 3 shocks in each direction of 3 orthogonal axes
	– Seismic vibration IEC 60255–21–3, class 1 IEC 60068–3–3	sinusoidal 1 Hz to 8 Hz: ± 3.5 mm amplitude (horizontal axis) 1 Hz to 8 Hz: ± 1.5 mm amplitude (vertical axis) 8 Hz to 35 Hz: 1 g acceleration (horizontal axis) 8 Hz to 35 Hz: 0.5 g acceleration (vertical axis) Frequency sweep rate1 octave/min 1 cycle in 3 orthogonal axes

Vibration and Shock During Transport	Standards:	IEC 60255–21 and IEC 60068
	– Vibration IEC 60255–21–1, class 2 IEC 60068–2–6	sinusoidal 5 Hz to 8 Hz: ±7.5 mm amplitude 8 Hz to 150 Hz: 2 g acceleration Frequency sweep rate1 octave/min 20 cycles in 3 orthogonal axes
	– Shock IEC 60255–21–2, class 1 IEC 60068–2–27	half-sine shaped acceleration 15 g; duration 11 ms; 3 shocks in each direction of 3 orthogonal axes
	– Continuous shock IEC 60255–21–2, class 1 IEC 60068–2–29	half-sine shaped acceleration 10 g; duration 16 ms; 1000 shocks in each direction of 3 orthogonal axes

Note:

All mechanical stress specifications are valid for standard works packaging!

4.1.7 Climatic Stress Tests

Temperatures	– type tested (acc. IEC 60068–2–1 and –2)	–25 °C to +85 °C	or –13 °F to +185 °F
	– temporalily allowed operating temperature (tested for 96 h)	–20 °C to +70 °C	or –4 °F to +158 °F
	– recommended permanent operating temperature (acc. IEC 60255–6)	–5 °C to +55 °C	or +23 °F to 131 °F
	– limiting temperature during permanent storage	–25 °C to +55 °C	or –13 °F to +131 °F
	– limiting temperature during transport	–25 °C to +70 °C	or –13 °F to +158 °F
	Storage and transport with standard works packaging!		
Humidity	Permissible humidity	mean value p. year ≤75 % relative humidity on 56 days per year up to 93 % relative humidity; condensation not permissible!	
	All devices shall be installed such that they are not exposed to direct sunlight, nor subject to large fluctuations in temperature that may cause condensation to occur.		

4.1.8 Service Conditions

The device is designed for use in an industrial environment or an electrical utility environment, for installation in standard relay rooms and compartments so that proper installation and electromagnetic compatibility (EMC) is ensured. In addition, the following are recommended:

- All contactors and relays that operate in the same cubicle, cabinet, or relay panel as the numerical protective device should, as a rule, be equipped with suitable surge suppression components.
- For substations with operating voltages of 100 kV and above, all external cables should be shielded with a conductive shield grounded at both ends. The shield must be capable of carrying the fault currents that could occur. For substations with lower operating voltages, no special measures are normally required.
- Do not withdraw or insert individual modules or boards while the protective device is energized. When handling the modules or the boards outside of the case, standards for components sensitive to electrostatic discharge (ESD) must be observed. The modules, boards, and device are not endangered when the device is completely assembled.

4.1.9 Construction

Housing		7XP20
Dimensions		see drawings, Section 4.16
Weight (mass), approx.		
– 7UT613	in flush mounted case $^{1}/_{2}$	13.5 kg
	in surface mounted case $^{1}/_{2}$	8.7 kg
– 7UT633	in flush mounted case $^{1}/_{1}$	22.0 kg
	in surface mounted case $^{1}/_{1}$	13.8 kg *)
– 7UT635	in flush mounted case $^{1}/_{1}$	22.7 kg
	in surface mounted case $^{1}/_{1}$	14.5 kg *)
*) with transport protection element plus		3.3 kg
Degree of protection acc. IEC 60529		
– for the device		
in surface mounted case		IP 51
in flush mounted case		
front		IP 51
rear		IP 50
– for human safety		IP 2x with closed protection cover

4.2 Differential Protection

4.2.1 General

Pickup Values	Differential current	$I_{DIFF}>/I_{N obj}$	0.05 to 2.00	(steps 0.01)
	High-current stage	$I_{DIFF}>>/I_{N obj}$	0.5 to 35.0 or ∞ (stage ineffective)	(steps 0.1)
	Pickup on switch-on (factor of $I_{DIFF}>$)		1.0 to 2.0	(steps 0.1)
	Add-on stabilization on external fault (I_{Rest} > set value) action time	$I_{add-on}/I_{N obj}$	2.00 to 15.00 2 to 250 cycles or ∞ (effective until dropoff)	(steps 0.01) (steps 1 cycle)
	Trip characteristic		see Figure 4-1	
	Tolerances (at preset parameters with 2 sides and 1 measuring location per side)			
	– $I_{DIFF}>$ stage and characteristic		5 % of set value	
	– $I_{DIFF}>>$ stage		5 % of set value	
Time Delays	Delay of $I_{DIFF}>$ stage	$T_{I-DIFF>}$	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
	Delay of $I_{DIFF}>>$ stage	$T_{I-DIFF>>}$	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
	Time tolerance		1 % of set value or 10 ms	
	The set times are pure delay times			

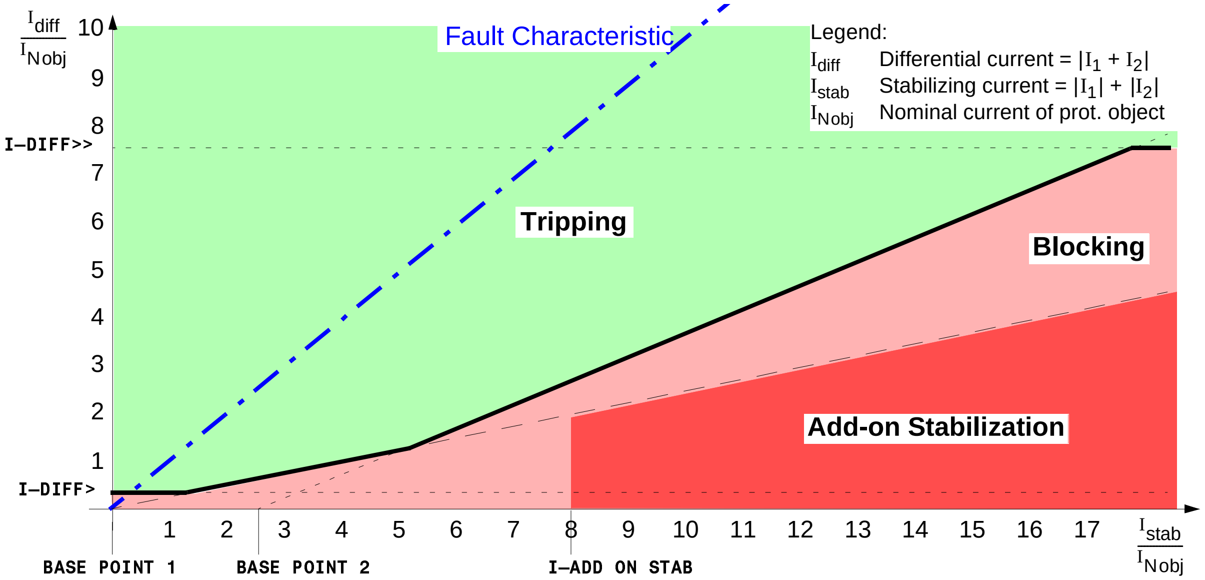


Figure 4-1 Tripping characteristic of the differential protection

4.2.2 Transformers

Harmonic Restraint	Inrush restraint ratio (2nd harmonic) I_{2fN}/I_{fN}	10 % to 80 % see also Figure 4-2	(steps 1 %)
	Stabilization ratio further (n-th) harmonic (optional 3. or 5.) I_{nfN}/I_{fN}	10 % to 80 % see also Figure 4-3	(steps 1 %)
	Crossblock function	can be activated / deactivated	
	max. action time for Crossblock	2 to 1000 AC cycles or 0 (crossblock deactivated) or ∞ (active until dropout)	(steps 1 cycle)
Operating Times	Pickup time/dropout time with single-side infeed		

Pickup time at frequency, approx.	50 Hz	60 Hz	16,7 Hz
Stage I_{DIFF}>, min.	30 ms	27 ms	78 ms
Stage I_{DIFF}>>, min.	11 ms	11 ms	20 ms
Dropout time, approx.	54 ms	46 ms	150 ms

	Dropout ratio, approx.	0.7	
Current Matching for Transformers	Matching of vector group	0 to 11 (× 30°)	(steps 1)
	Star point conditioning	earthed or non-earthed (for each winding)	
Frequency	Frequency correction in the range	$0.9 \le f/f_N \le 1.1$	
	Frequency influence	see Figure 4-4	

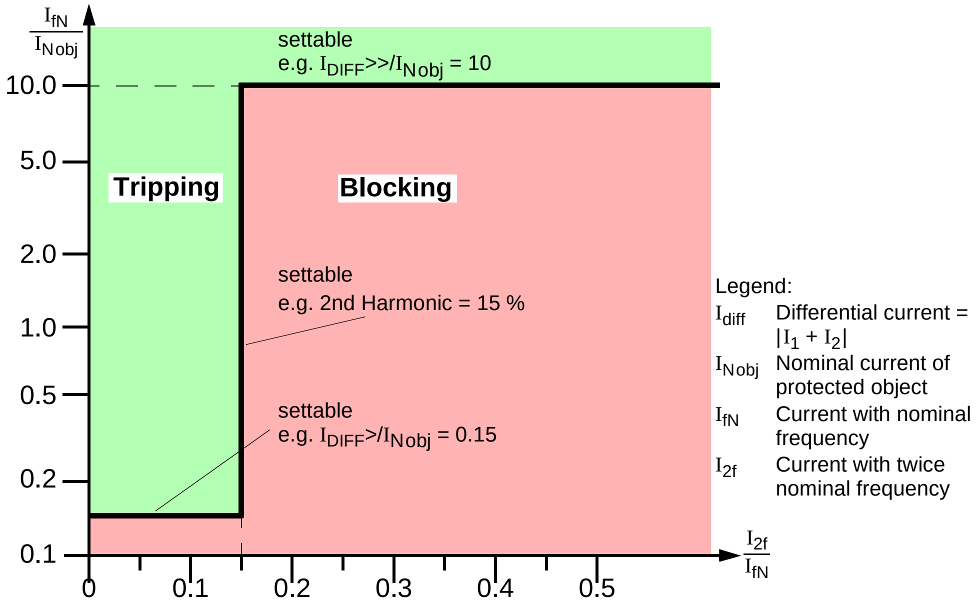


Figure 4-2 Stabilizing influence of 2nd harmonic (transformer protection)

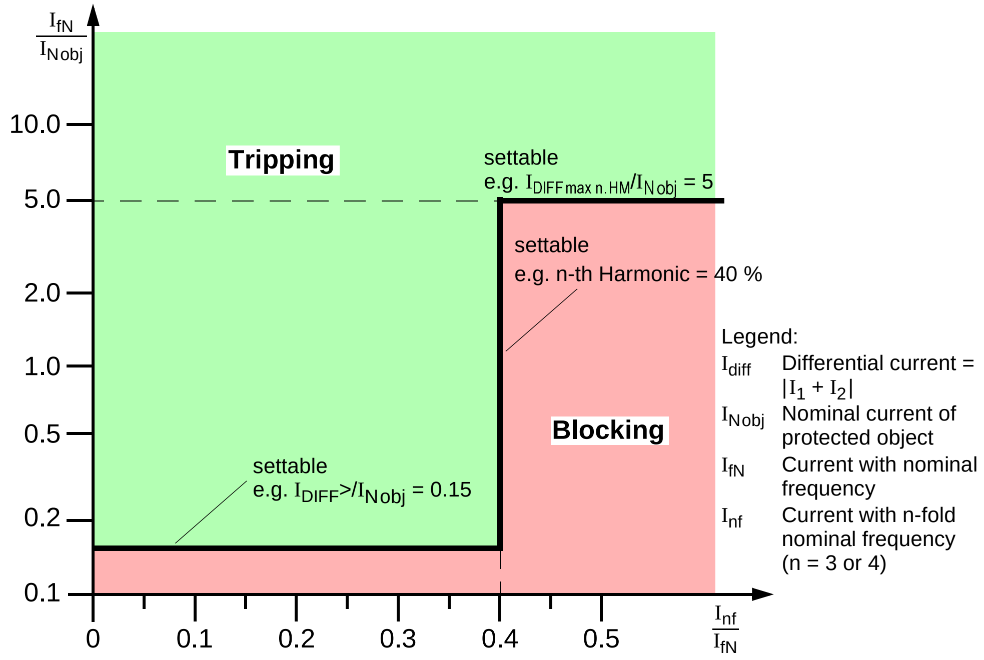


Figure 4-3 Stabilizing influence of n-th harmonic (transformer protection)

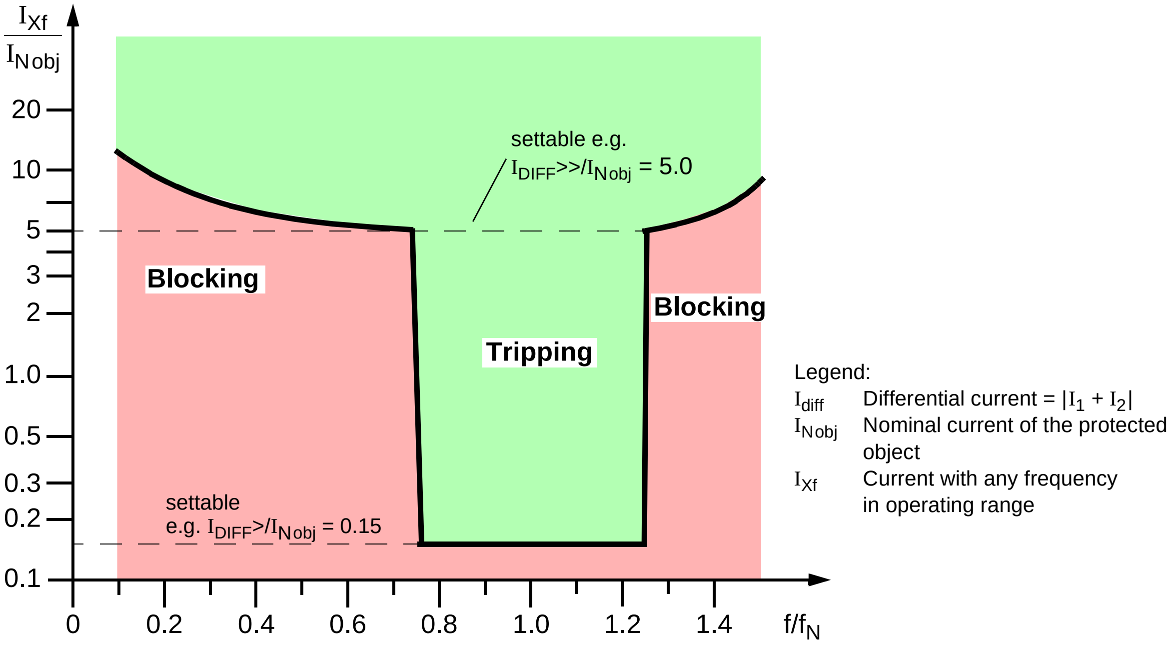


Figure 4-4 Frequency influence (transformer protection)

4.2.3 Generators, Motors, Reactors

Operating Times	Pickup time/dropout time with single-side infeed			
	Pickup time at frequency, approx.	50 Hz	60 Hz	16,7 Hz
	Stage I_{DIFF}>, min.	30 ms	27 ms	78 ms
	Stage I_{DIFF}>>, min.	11 ms	11 ms	20 ms
	Dropout time, approx.	54 ms	46 ms	150 ms
	Dropout ratio, approx.	0.7		
Frequency	Frequency correction in the range	$0.9 \le f/f_N \le 1.1$		
	Frequency influence	see Figure 4-5		

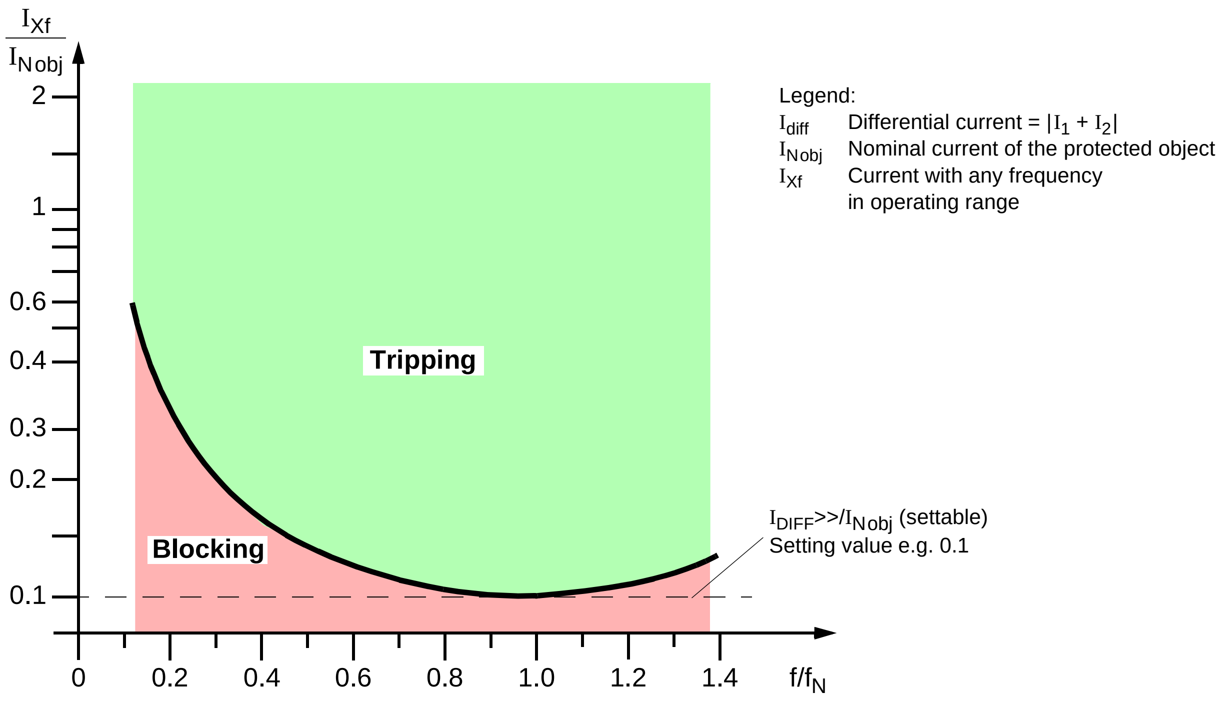


Figure 4-5 Frequency influence (generator / motor protection)

4.2.4 Busbars, Short Lines

Note:
In case of connection via interposing CTs and rated current = 0.1 A, higher tolerances are to be expected. The errors of the interposing CTs themselves and the influence of the magnetizing currents are not included in the device tolerances.

Differential Current Monitor	Steady-state differential current monitoring	$I_{\text{diff mon}}/I_{\text{N obj}}$	0.15 to 0.80	(steps 0.01)
	Delay of blocking of differential current monitoring	$T_{\text{diff mon}}$	1 s to 10 s	(steps 1 s)
Feeder Current Guard	Trip release by feeder current guard	$I_{\text{guard}}/I_{\text{N Obj}}$	0.20 to 2.00 or 0 (always released)	(steps 0.01)
Operating Times	Pickup time/dropout time with single-side infeed			

Pickup time at frequency	50 Hz	60 Hz	16,7 Hz
Stage I_{DIFF}>, min.	11 ms	11 ms	18 ms
Stage I_{DIFF}>>, min.	11 ms	11 ms	18 ms
Dropout time, approx.	54 ms	46 ms	150 ms

	Dropout ratio, approx.	0.7
Frequency	Frequency correction in the range	$0.9 \leq f/f_N \leq 1.1$
	Frequency influence	see Figure 4-5

4.3 Restricted Earth Fault Protection

Settings	Differential current	$I_{REF}>/I_{N\,obj}$	0.05 to 2.00	(steps 0.01)
	Limit angle	φ_{REF}	100° (fix)	
	Trip characteristic		see Figure 4-6	
	Pickup tolerance (at preset parameters with one 3-phase measuring location)		5 % at $I < 5 \cdot I_N$	
	Time delay	T_{REF}	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
	Time tolerance		1 % of set value or 10 ms	
	The set times are pure delay times			

Operating Times

Pickup time at frequency	50 Hz	60 Hz	16,7 Hz
at 1.5 · setting value $I_{EDS}>$, approx. at 2.5 · setting value $I_{EDS}>$, approx.	35 ms 33 ms	30 ms 29 ms	110 ms 87 ms
Dropout time, approx.	26 ms	23 ms	51 ms

Dropout ratio, approx. 0.7

Frequency Frequency influence 1 % in the range $0.9 \leq f/f_N \leq 1.1$

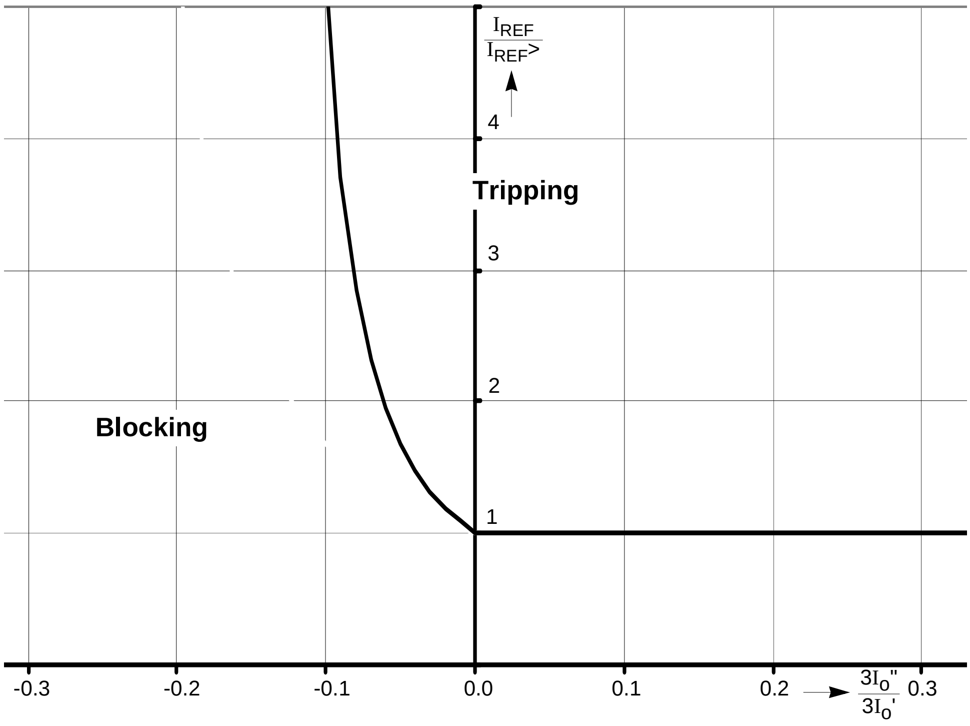


Figure 4-6 Tripping characteristic of the restricted earth fault protection dependent on zero sequence current ratio $3I_0''/3I_0'$ (both current in phase or counter-phase)

4.4 Time Overcurrent Protection for Phase and Residual Currents

Characteristics	Definite time stages	(DT)	I_{Ph}>>, $3I_0$>>, I_{Ph}>, $3I_0$>	
	Inverse time stages (acc. IEC or ANSI)	(IT)	I_P, $3I_{0P}$ one of the curves according to Figures 4-7 to 4-9 can be selected alternatively user specified trip and reset characteristic	
	Reset characteristics (acc. ANSI with disk emulation)	(IT)	see Figures 4-10 and 4-11	
Current Stages	High-current stages	I_{Ph}>>	0.10 A to 35.00 A 1) or ∞ (stage ineffective)	(steps 0.01 A)
		$T_{IPh>>}$	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
		$3I_0$>>	0.05 A to 35.00 A 1) or ∞ (stage ineffective)	(steps 0.01 A)
		$T_{3I0>>}$	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
	Definite time stages	I_{Ph}>	0.10 A to 35.00 A 1) or ∞ (stage ineffective)	(steps 0.01 A)
		$T_{IPh>}$	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
		$3I_0$>	0.05 A to 35.00 A 1) or ∞ (stage ineffective)	(steps 0.01 A)
		$T_{3I0>}$	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
	Inverse time stages	I_P	0.10 A to 4.00 A 1)	(steps 0.01 A)
	(acc. IEC)	T_{IP}	0.05 s to 3.20 s or ∞ (no trip)	(steps 0.01 s)
		$3I_{0P}$	0.05 A to 4.00 A 1)	(steps 0.01 A)
		T_{3I0P}	0.05 s to 3.20 s or ∞ (no trip)	(steps 0.01 s)
	Inverse time stages	I_P	0.10 A to 4.00 A 1)	(steps 0.01 A)
	(acc. ANSI)	D_{IP}	0.50 s to 15.00 s or ∞ (no trip)	(steps 0.01 s)
		$3I_{0P}$	0.05 A to 4.00 A 1)	(steps 0.01 A)
		D_{3I0P}	0.50 s to 15.00 s or ∞ (no trip)	(steps 0.01 s)
	Tolerances 2) with definite time	currents times	3 % of set value or 1 % of nominal current 1 % of set value or 10 ms	

Tolerances 2) with inverse time	currents	Pickup at $1.05 \le I/I_P \le 1.15$; or $1.05 \le I/3I_{0P} \le 1.15$
(acc. IEC	times	5 % ± 15 ms at f_N = 50/60 Hz 5 % ± 45 ms at f_N = 16,7 Hz for $2 \le I/I_P \le 20$ and T_{IP}/s ≥ 1; or $2 \le I/3I_{0P} \le 20$ and T_{3I0P}/s ≥ 1
(acc. ANSI)	times	5 % ± 15 ms at f_N = 50/60 Hz 5 % ± 45 ms at f_N = 16,7 Hz for $2 \le I/I_P \le 20$ and D_{IP}/s ≥ 1; or $2 \le I/3I_{0P} \le 20$ and D_{3I0P}/s ≥ 1

The set definite times are pure delay times.

1) Secondary values based on I_N = 1 A; for I_N = 5 A they must be multiplied by 5.
2) with one 3-phase measuring location and I_N = 1 A/5 A.

Operating Times of the Definite Time Stages

Pickup time/dropout time phase current stages

Pickup time at frequency	50 Hz	60 Hz	16,7 Hz
without inrush restraint, min.	11 ms	11 ms	16 ms
with inrush restraint, min.	33 ms	29 ms	76 ms
Dropout time, approx.	35 ms	35 ms	60 ms

Pickup time/dropout time residual current stages

Pickup time at frequency	50 Hz	60 Hz	16,7 Hz
without inrush restraint, min.	21 ms	19 ms	46 ms
with inrush restraint, min.	31 ms	29 ms	56 ms
Dropout time, approx.	45 ms	43 ms	90 ms

Drop-out Ratios

Current stages — approx. 0.95 for $I/I_N \ge 0.5$

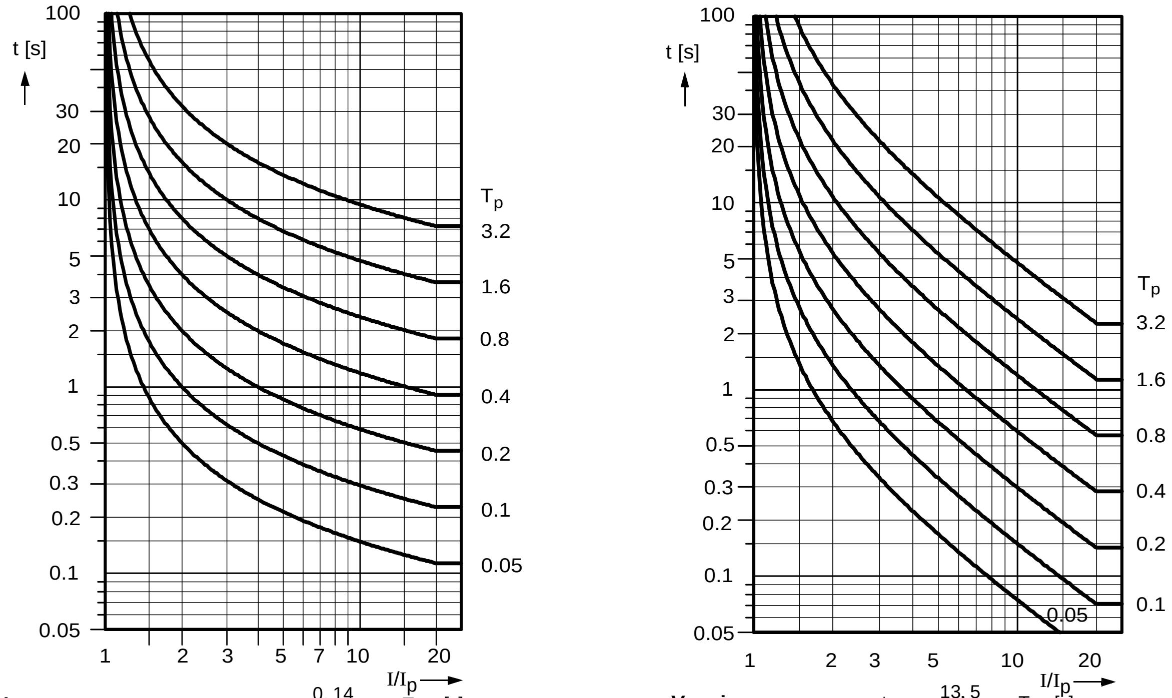
Inrush Blocking

Inrush blocking ratio (2nd harmonic)	I_{2fN}/I_{fN}	10 % to 45 %	(steps 1 %)
Lower operation limit		$I > 0.2$ A 1)	
Max. current for blocking		0.03 A to 25.00 A 1)	(steps 0.10 A)
Crossblock function between phases		can be activated/deactivated	
max. action time for crossblock		0.00 s to 180 s	(steps 0.01 s)

1) Secondary values based on I_N = 1 A; for I_N = 5 A they must be multiplied by 5.

Frequency

Frequency influence — 1 % in the range $0.9 \le f/f_N \le 1.1$

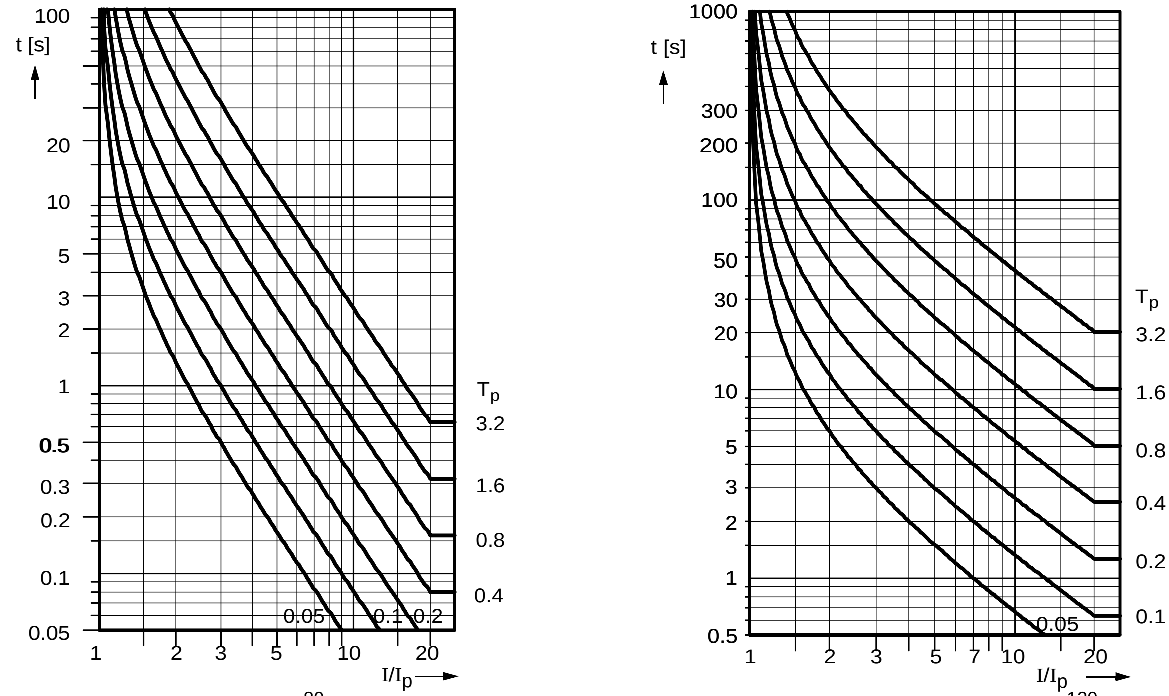


Inverse:
(type A)

$$t = \frac{0,14}{(I/I_p)^{0.02}-1}\cdot T_p \quad [s]$$

Very inverse:
(type B)

$$t = \frac{13,5}{(I/I_p)^{1}-1}\cdot T_p \quad [s]$$



Extremely inverse:
(type C)

$$t = \frac{80}{(I/I_p)^{2}-1}\cdot T_p \quad [s]$$

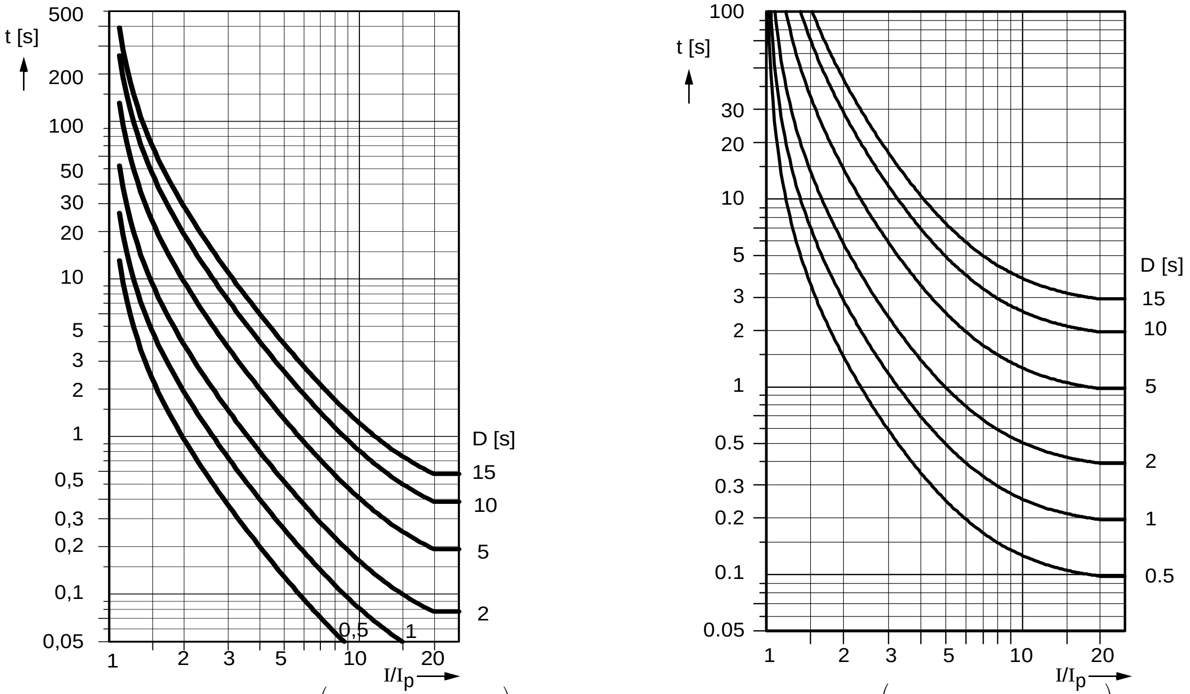
Longtime inverse:
not for unbalanced load protection

$$t = \frac{120}{(I/I_p)^{1}-1}\cdot T_p \quad [s]$$

t	tripping time
T_p	set time multiplier
I	fault current
I_p	set pickup value

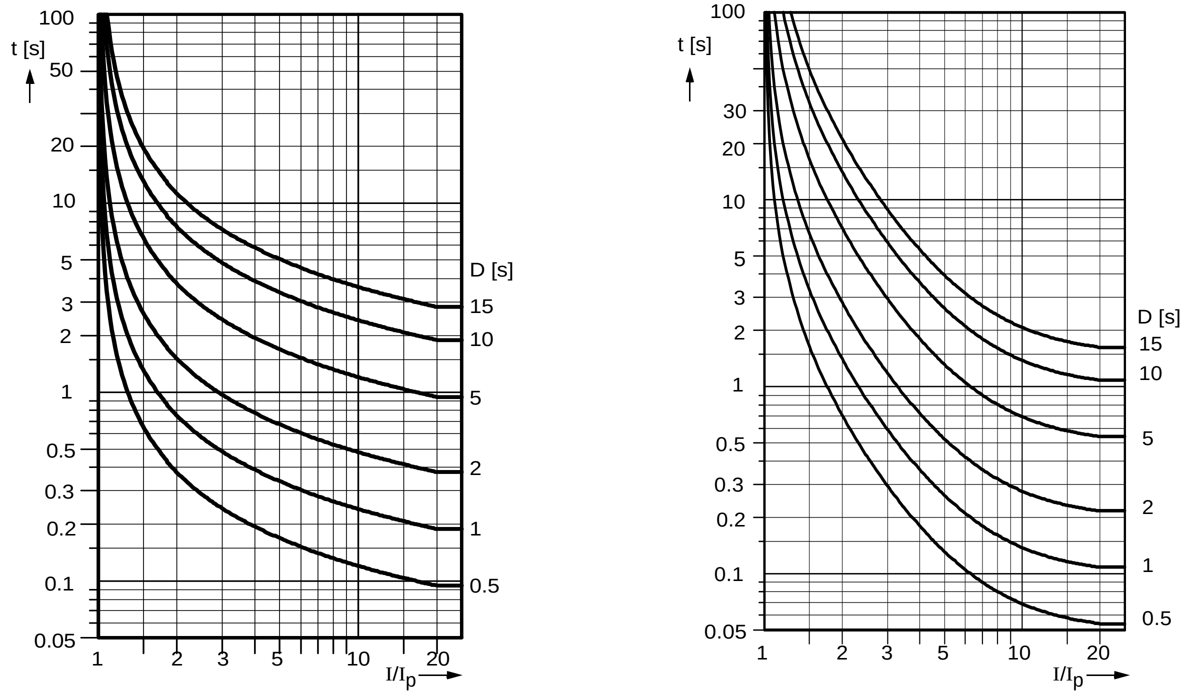
Notes: Shortest trip time for 16,7 Hz is 100 ms.
For residual current read $3I_{0p}$ instead of I_p and T_{3I0p} instead of T_p
for earth current read I_{Ep} instead of I_p and T_{IEp} instead of T_p
for unbalanced load read I_{2p} instead of I_p and T_{I2p} instead of T_p

Figure 4-7 Trip time characteristics of inverse time overcurrent protection and unbalanced load protection, according IEC



Extremely inverse $t = \left(\frac{5.64}{(I/I_p)^2 - 1} + 0.02434\right) \cdot D$ [s]

Inverse $t = \left(\frac{8.9341}{(I/I_p)^{2.0938} - 1} + 0.17966\right) \cdot D$ [s]



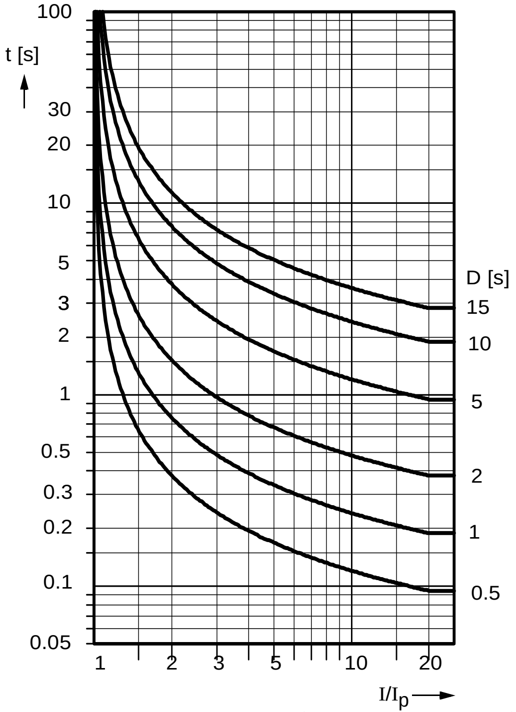
Moderately inverse $t = \left(\frac{0.0103}{(I/I_p)^{0.02} - 1} + 0.0228\right) \cdot D$ [s]

Very inverse $t = \left(\frac{3.992}{(I/I_p)^2 - 1} + 0.0982\right) \cdot D$ [s]

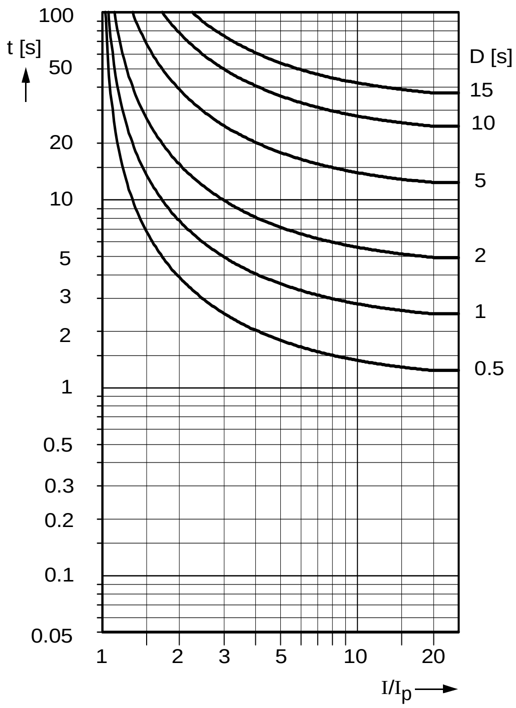
t	tripping time
D	set time dial
I	fault current
I_p	set pickup value

Notes: Shortest trip time for 16,7 Hz is 100 ms.
For residual current read $3I_{0p}$ instead of I_p
for earth current read I_{Ep} instead of I_p
for unbalanced load read I_{2p} instead of I_p

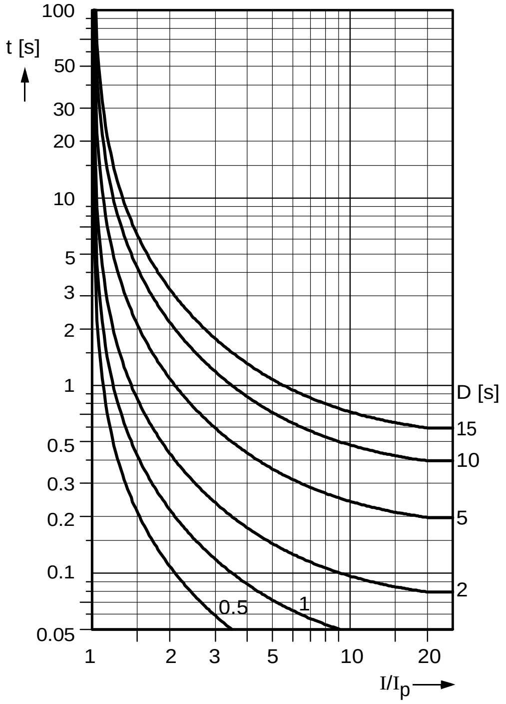
Figure 4-8 Trip time characteristics of inverse time overcurrent protection and unbalanced load protection, according ANSI/IEEE



Definite inverse
$$t = \left(\frac{0.4797}{(I/I_p)^{1.5625} - 1} + 2.1359 \right) \cdot D \quad [s]$$



Long inverse
$$t = \left(\frac{5.6143}{(I/I_p) - 1} + 2.18592 \right) \cdot D \quad [s]$$

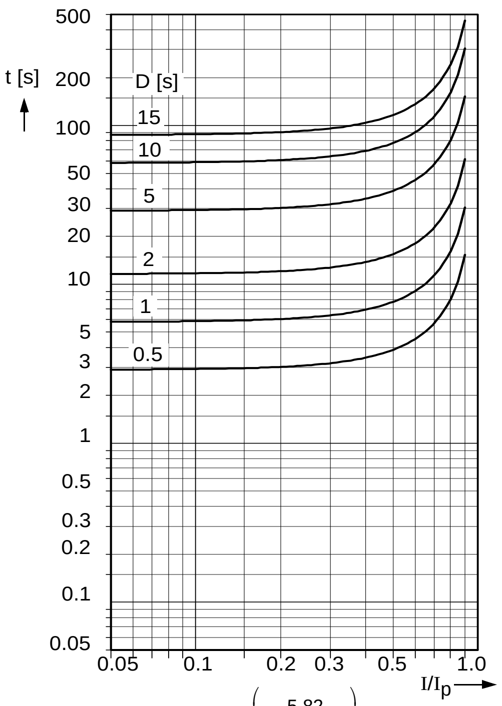


Short inverse
$$t = \left(\frac{0.2663}{(I/I_p)^{1.2969} - 1} + 0.03393 \right) \cdot D \quad [s]$$

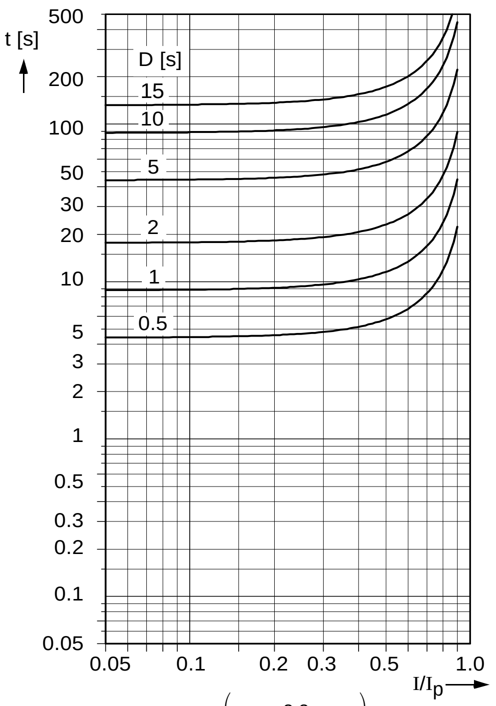
t	tripping time
D	set time dial
I	fault current
I_p	set pickup value

Notes: Shortest trip time for 16,7 Hz is 100 ms.
For residual current read $3I_{0p}$ instead of I_p
for earth current read I_{Ep} instead of I_p a

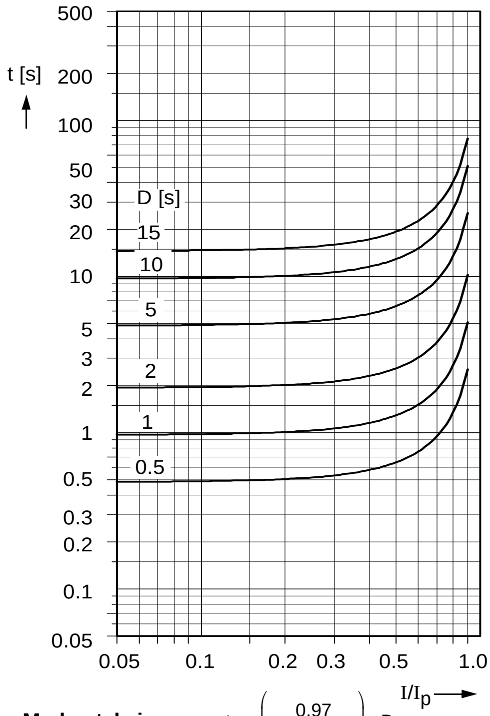
Figure 4-9 Trip time characteristics of inverse time overcurrent protection, according ANSI/IEEE



Extremely inverse $t = \left(\frac{5.82}{(I/I_p)^2 - 1}\right) \cdot D$ [s]

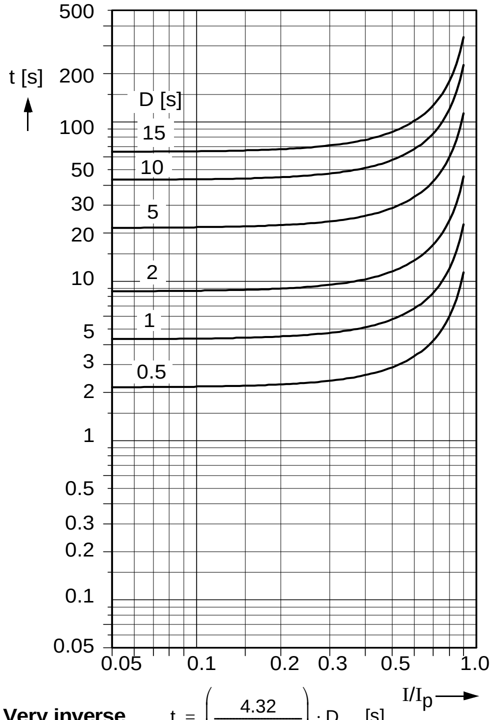


Inverse $t = \left(\frac{8.8}{(I/I_p)^{2.0938} - 1}\right) \cdot D$ [s]



Moderately inverse $t = \left(\frac{0.97}{(I/I_p)^2 - 1}\right) \cdot D$ [s]

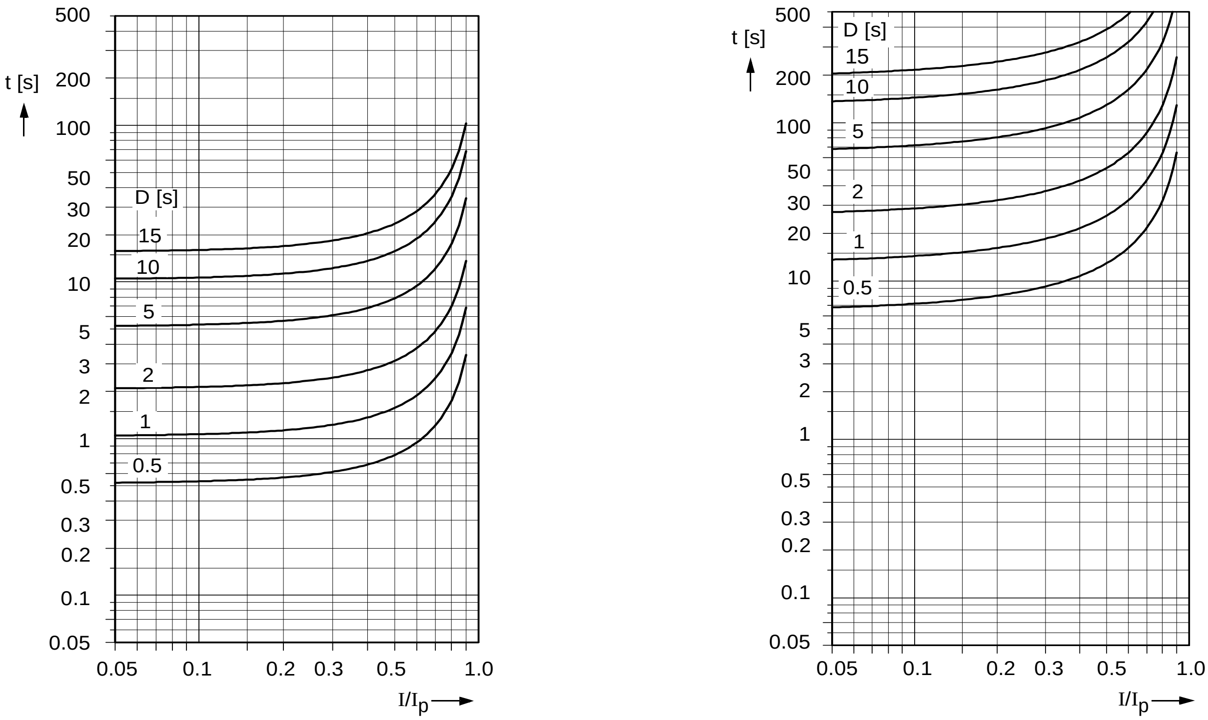
t	reset time
D	set time dial
I	interrupted current
I_p	set pickup value



Very inverse $t = \left(\frac{4.32}{(I/I_p)^2 - 1}\right) \cdot D$ [s]

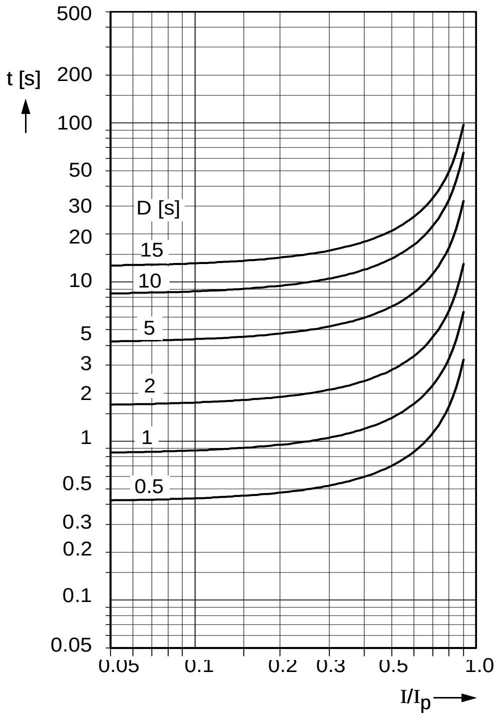
Notes: For residual current read $3I_{0p}$ instead of I_p
for earth current read I_{Ep} instead of I_p
for unbalanced load read I_{2p} instead of I_p

Figure 4-10 Reset time characteristics of inverse time overcurrent protection and unbalanced load protection with disk emulation, according ANSI/IEEE



Definite inverse $t = \left(\dfrac{1.0394}{(I/I_p)^{1.5625} - 1}\right) \cdot D \quad [s]$

Long inverse $t = \left(\dfrac{12.9}{(I/I_p)^{1} - 1}\right) \cdot D \quad [s]$



Short inverse $t = \left(\dfrac{0.831}{(I/I_p)^{1.2969} - 1}\right) \cdot D \quad [s]$

t	reset time
D	set time dial
I	interrupted current
I_p	set pickup value

Notes: For residual current read $3I_{0p}$ instead of I_p
for earth current read I_{Ep} instead of I_p

Figure 4-11 Reset time characteristics of inverse time overcurrent protection with disk emulation, according ANSI/IEEE

4.5 Time Overcurrent Protection for Earth Current

Characteristics	Definite time stages	(DT)	$I_E>>$, $I_E>$	
	Inverse time stages (acc. IEC or ANSI)	(IT)	I_{EP} one of the curves according to Figures 4-7 to 4-9 can be selected alternatively user specified trip and reset characteristic	
	Reset characteristics (acc. ANSI with disk emulation)	(IT)	see Figures 4-10 and 4-11	
Current Stages	High-current stage	$I_E>>$	0.05 A to 35.00 A 1) or ∞ (stage ineffective)	(steps 0.01 A)
		$T_{IE>>}$	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
	Definite time stage	$I_E>$	0.05 A to 35.00 A 1) or ∞ (stage ineffective)	(steps 0.01 A)
		$T_{IE>}$	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
	Inverse time stages	I_{EP}	0.05 A to 4.00 A 1)	(steps 0.01 A)
	(acc. IEC)	T_{IEP}	0.05 s to 3.20 s or ∞ (no trip)	(steps 0.01 s)
	Inverse time stages	I_{EP}	0.05 A to 4.00 A 1)	(steps 0.01 A)
	(acc. ANSI)	D_{IEP}	0.50 s to 15.00 s or ∞ (no trip)	(steps 0.01 s)
	Tolerances definite time	currents times	3 % of set value or 1 % of nominal current 1 % of set value or 10 ms	
	Tolerances inverse time (acc. IEC	currents times	Pickup at $1.05 \le I/I_{EP} \le 1.15$ 5 % ± 15 ms at f_N = 50/60 Hz 5 % ± 45 ms at f_N = 16,7 Hz for $2 \le I/I_{EP} \le 20$ and $T_{IEP}/s \ge 1$	
	(acc. ANSI)	times	5 % ± 15 ms at f_N = 50/60 Hz 5 % ± 45 ms at f_N = 16,7 Hz for $2 \le I/I_{EP} \le 20$ and $D_{IEP}/s \ge 1$	

The set definite times are pure delay times.

1) Secondary values based on I_N = 1 A; for I_N = 5 A they must be multiplied by 5.

Operating Times of the Definite Time Stages

Pickup time/dropout time

Pickup time at frequency	50 Hz	60 Hz	16,7 Hz
without inrush restraint, min.	11 ms	11 ms	16 ms
with inrush restraint, min.	33 ms	29 ms	76 ms
Dropout time, approx.	35 ms	35 ms	60 ms

Drop-out ratios	Current stages		approx. 0.95 for $I/I_N \geq 0.5$	
Inrush Blocking	Inrush blocking ratio (2nd harmonic)	I_{2fN}/I_{fN}	10 % to 45 %	(steps 1 %)
	Lower operation limit		$I > 0.2$ A [1])	
	Max. current for blocking		0.30 A to 25.00 A [1])	(steps 0.01 A)
	[1]) Secondary values based on I_N = 1 A; for I_N = 5 A they must be multiplied by 5.			
Frequency	Frequency influence		1 % in the range $0.9 \leq f/f_N \leq 1.1$	

4.6 Dynamic Cold Load Pickup for Time Overcurrent Protection

Time Control	Start criterion		Binary input from circuit breaker auxiliary contact or current criterion (of the assigned side)	
	CB open time	$T_{CB\ open}$	0 s to 21600 s (= 6 h)	(steps 1 s)
	Active time	$T_{Active\ time}$	1 s to 21600 s (= 6 h)	(steps 1 s)
	Accelerated dropout time	$T_{Stop\ Time}$	1 s to 600 s (= 10 min) or ∞ (no accelerated dropout)	(steps 1 s)
Setting Ranges and Changeover Values	Dynamic parameters of current pickups and delay times or time multipliers		Setting ranges and steps are the same as for the functions to be influenced	

4.7 Single-Phase Time Overcurrent Protection

Current Stages	High-current stage	$I>>$	0.05 A to 35.00 A 1) 0.003 A to 1.500 A 2) or ∞ (stage ineffective)	(steps 0.01 A) (steps 0.001 A)
		$T_{I>>}$	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
	Definite time stage	$I>$	0.05 A to 35.00 A 1) 0.003 A to 1.500 A 2) or ∞ (stage ineffective)	(steps 0.01 A) (steps 0.001 A)
		$T_{I>}$	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
	Tolerances	currents	3 % of set value or 1 % of nominal current at I_N = 1 A or 5 A; 5 % of set value or 3 % of nominal current at I_N = 0.1 A	
		times	1 % of set value or 10 ms	

The set definite times are pure delay times.

1) Secondary values based on I_N = 1 A; for I_N = 5 A they must be multiplied by 5.

2) Secondary values for high-sensitivity current input I_7, independent of nominal current.

Operating Times

Pickup time/dropout time

Pickup time at frequency	50 Hz	60 Hz	16,7 Hz
minimum (at 10 × setting value)	14 ms	13 ms	23 ms
Dropout time, approx.	25 ms	22 ms	66 ms

Drop-out Ratios	Current stages	approx. 0.95 for $I/I_N \geq 0.5$
Frequency	Frequency influence	1 % in the range $0.9 \leq f/f_N \leq 1.1$

4.8 Unbalanced Load Protection

Characteristics	Definite time stages	(DT)	I_2>>, I_2>
	Inverse time stages (acc. IEC or ANSI)	(IT)	I_{2P} one of the curves according to Figures 4-7 or 4-8 can be selected
	Reset characteristics (acc. ANSI with disk emulation)	(IT)	see Figure 4-10
	Operating range		0.1 A to 4 A 1)

1) Secondary values based on I_N = 1 A; for I_N = 5 A they must be multiplied by 5.

Current Stages	High-current stage	I_2>>	0.10 A to 3.00 A 1)	(steps 0.01 A)
		$T_{I2>>}$	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
	Definite time stage	I_2>	0.10 A to 3.00 A 1)	(steps 0.01 A)
		$T_{I2>}$	0.00 s to 60.00 s or ∞ (no trip)	(steps 0.01 s)
	Inverse time stages	I_{2P}	0.10 A to 2.00 A 1)	(steps 0.01 A)
	(acc. IEC)	T_{I2P}	0.05 s to 3.20 s or ∞ (no trip)	(steps 0.01 s)
	Inverse time stages	I_{2P}	0.10 A to 2.00 A 1)	(steps 0.01 A)
	(acc. ANSI)	D_{I2P}	0.50 s to 15.00 s or ∞ (no trip)	(steps 0.01 s)
	Tolerances 2) definite time	currents	3 % of set value or 1 % of nominal current	
		times	1 % of set value or 10 ms	
	Tolerances 2) inverse time	currents	Pickup at $1.05 \le I_2/I_{2P} \le 1.15$;	
	(acc. IEC	times	5 % ± 15 ms at f_N = 50/60 Hz 5 % ± 45 ms at f_N = 16,7 Hz for $2 \le I_2/{}_2I_P \le 20$ and $T_{I2P}/s \ge 1$	
	(acc. ANSI)	times	5 % ± 15 ms at f_N = 50/60 Hz 5 % ± 45 ms at f_N = 16,7 Hz for $2 \le I_2/{}_2I_P \le 20$ and $D_{I2P}/s \ge 1$	

The set definite times are pure delay times.

1) Secondary values based on I_N = 1 A; for I_N = 5 A they must be multiplied by 5.

2) with one 3-phase measuring location

Operating Times of the Definite Time Stages

Pickup time/dropout time

Pickup time at frequency	50 Hz	60 Hz	16,7 Hz
minimum	41 ms	34 ms	106 ms
Dropout time, approx.	23 ms	20 ms	60 ms

Drop-out Ratios	Current stages	approx. 0.95 for $I_2/I_N \ge 0.5$
Frequency	Frequency influence	1 % in the range $0.9 \le f/f_N \le 1.1$

4.9 Thermal Overload Protection

4.9.1 Overload Protection Using a Thermal Replica

Setting Ranges	Factor k acc. IEC 60255–8		0.10 to 4.00	(steps 0.01)
	Time constant	τ	1.0 min to 999.9 min	(steps 0.1 min)
	Cooling down factor at motor stand-still (for motors)	$K\tau$-factor	1.0 to 10.0	(steps 0.1)
	Thermal alarm stage	$\Theta_{alarm}/\Theta_{trip}$	50 % to 100 % referred to trip temperature rise	(steps 1 %)
	Current alarm stage	I_{alarm}	0.10 A to 4.00 A ^{1})	(steps 0.01 A)
	Start-up recognition (for motors)	$I_{start-up}$	0.60 A to 10.00 A ^{1}) or ∞ (no start-up recognition)	(steps 0.01 A)
	Emergency start run-on time (for motors)	T_{run-on}	10 s to 15000 s	(steps 1 s)

^{1}) Secondary values based on I_N = 1 A; for I_N = 5 A they must be multiplied by 5.

Tripping Characteristics

see Figure 4-12

Tripping characteristic

for $I/(k \cdot I_N) \leq 8$

$$t = \tau \cdot ln \frac{\left(\frac{I}{k \cdot I_N}\right)^2 - \left(\frac{I_{pre}}{k \cdot I_N}\right)^2}{\left(\frac{I}{k \cdot I_N}\right)^2 - 1}$$

Meaning of abbreviations:

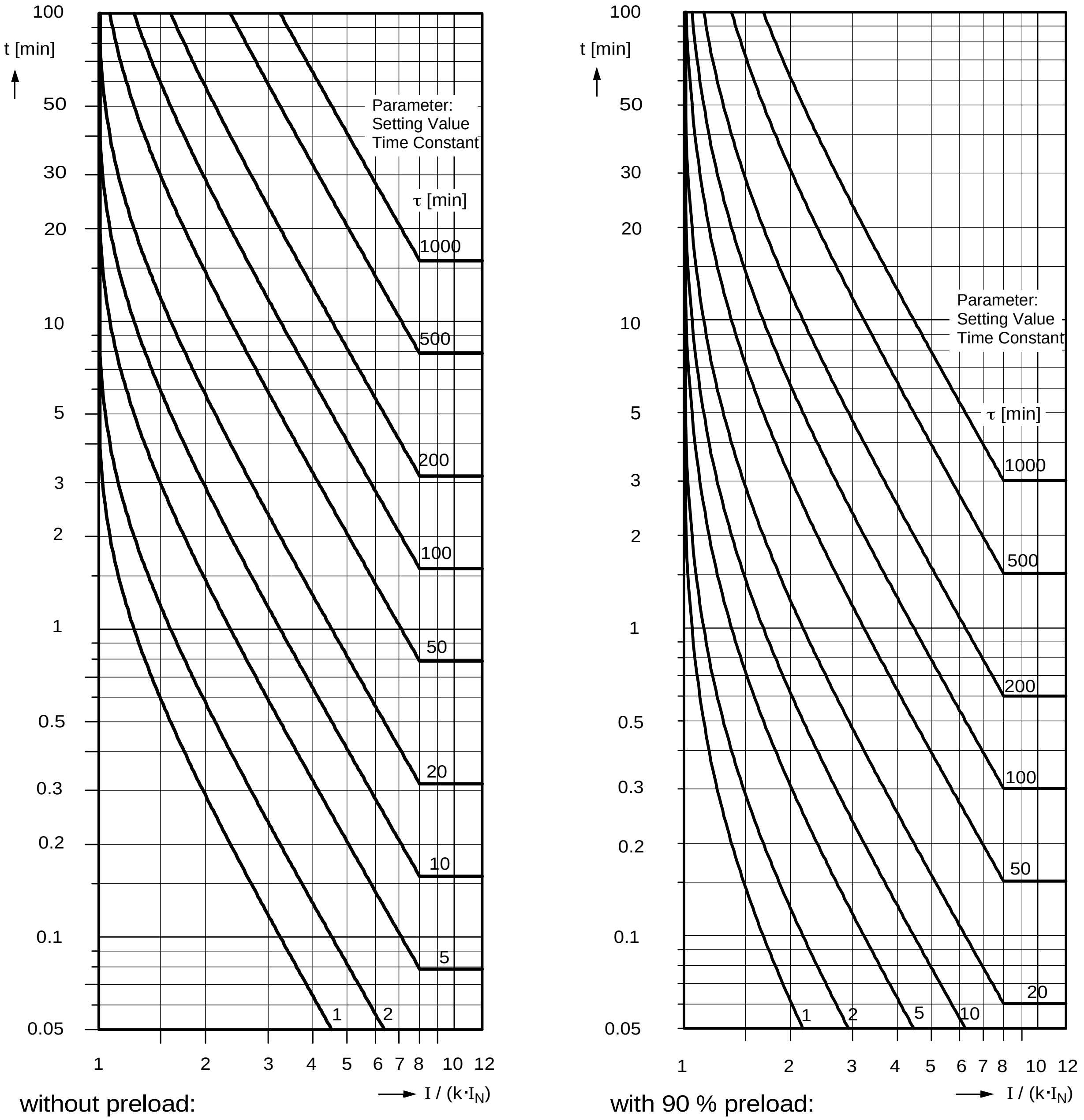
t	tripping time
τ	heating-up time constant
I	actual load current
I_{pre}	preload current
k	setting factor IEC 60255–8
I_N	nominal current of the protected object

Dropout Ratios	Θ/Θ_{trip}	dropout at Θ_{alarm}
	Θ/Θ_{alarm}	approx. 0.99
	I/I_{alarm}	approx. 0.97

Tolerances	with one 3-phase measuring location		
	Referring to $k \cdot I_N$	3 % or 10 mA ^{1});	class 3 % acc. IEC 60255–8
	Referring to tripping time	3 % or 1.2 s at f_N = 50/60 Hz 5 % or 1.2 s at f_N = 16,7 Hz for $I/(k \cdot I_N) > 1.25$	

^{1}) Secondary values based on I_N = 1 A; for I_N = 5 A they must be multiplied by 5.

Freq. Influence Referring to $k \cdot I_N$	In the range $0.9 \leq f/f_N \leq 1.1$	1 % at f_N = 50/60 Hz 3 % at f_N = 16,7 Hz



without preload:

$$t = \tau \cdot ln \frac{\left(\frac{I}{k \cdot I_N}\right)^2}{\left(\frac{I}{k \cdot I_N}\right)^2 - 1} \text{ [min]}$$

with 90 % preload:

$$t = \tau \cdot ln \frac{\left(\frac{I}{k \cdot I_N}\right)^2 - \left(\frac{I_{pre}}{k \cdot I_N}\right)^2}{\left(\frac{I}{k \cdot I_N}\right)^2 - 1} \text{ [min]}$$

Figure 4-12 Trip time characteristics of the overload protection with thermal replica

4.9.2 Hot Spot Calculation and Determination of the Ageing Rate

Temperature Detectors	Number of measuring points		from 1 RTD-box (up to 6 measuring points) or from 2 RTD-boxes (up to 12 measuring points)	
	For hot-spot calculation *one* temperature detector must be connected.			
Cooling	Cooling method		ON (oil natural) OF (oil forced) OD (oil directed)	
	Oil exponent	Y	1.6 to 2.0	(steps 0.1)
	Hot-spot to top-oil gradient	H_{gr}	22 to 29	(steps 1)
Annunciation Thresholds	Warning temperature hot-spot		98 °C to 140 °C	(steps 1 °C)
		or	208 °F to 284 °F	(steps 1 °F)
	Alarm temperature hot-spot		98 °C to 140 °C	(steps 1 °C)
		or	208 °F to 284 °F	(steps 1 °F)
	Warning aging rate		0.125 to 128.000	(steps 0.001)
	Alarm aging rate		0.125 to 128.000	(steps 0.001)

4.10 RTD-Boxes for Overload Detection

Temperature Detectors	RTD-boxes (connectable)		1 or 2	
	Number of temperature detectors per RTD-box		max. 6	
	Measuring type		Pt 100 Ω or Ni 100 Ω or Ni 120 Ω	
Annunciation Thresholds	For each measuring point:			
	Warning temperature (stage 1)		–50 °C to 250 °C	(steps 1 °C)
		or	–58 °F to 482 °F or ∞ (no warning)	(steps 1 °F)
	Alarm temperature (stage 2)		–50 °C to 250 °C	(steps 1 °C)
		or	–58 °F to 482 °F or ∞ (no alarm)	(steps 1 °F)

4.11 Overexcitation Protection

Setting Ranges	Overexcitation (warning stage)	(ratio $\frac{U / U_N}{f / f_N}$ >)	1.00 to 1.20	(Steps 0.01)
	Overexcitation (stepped characteristic)	(ratio $\frac{U / U_N}{f / f_N}$ >)	1.00 to 1.40	(Steps 0.01)
	Time delay (warning stage and stepped charact.	T U/f>; T U/f>>	0.00 s to 60.00 s or ∞ (ineffective)	(Steps 0.01 s)
	Pair of values for characteristic of	U/f	1.05 / 1.10 / 1.15 / 1.20 / 1.25 / 1.30 / 1.35 / 1.40	
	Thermal replica	t(U/f)	0 s to 20000 s	(Steps 0.01 s)
	Time for cool down	$T_{COOL\ DOWN}$	0 s to 20000 s	(Steps 1 s)

Inherent Operating Times

Pickup time/dropout time: Warning stage and stepped characteristic

Pickup time at frequency	50 Hz	60 Hz	16,7 Hz
at 1.1 × setting value	36 ms	31 ms	91 ms
Dropout time, approx.	28 ms	23 ms	70 ms

Dropout	Dropout-to-pickup ratio	approx. 0.95
Tripping time characteristic	Thermal replica	refer to Figure 4-13 for presetting
Tolerances	Pickup on U/f	3 % of setting value
	Delay times T	1 % of setting value or 10 ms
	Thermal replica	5 %, related to U/f ± 600 ms
Influencing Variables for Pickup	Power supply direct voltage in range $0.8 \leq U_{PS} / U_{PS\ nominal} \leq 1.15$	1 %
	Temperature in range $-5\ °C \leq \vartheta_{amb} \leq 55\ °C$	0.5 % / 10 K
	Frequency in range $0.95 \leq f/f_N \leq 1.05$	< 1 %
	Harmonic currents – Up to 10 % 3rd harmonic – Up to 10 % 5th harmonic	 < 1 % < 1 %

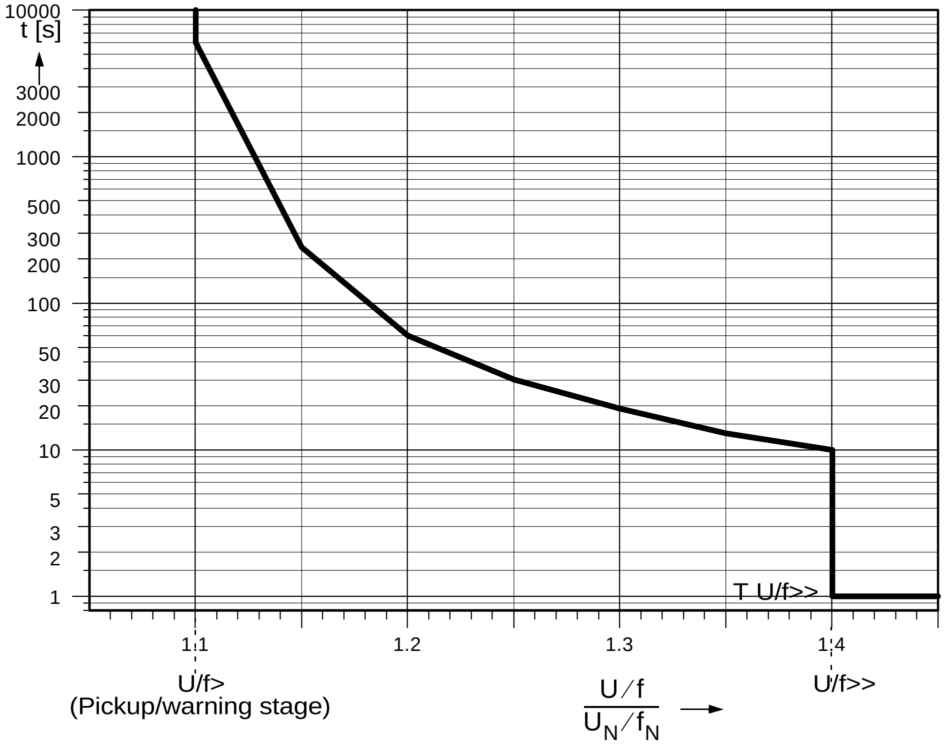


Figure 4-13 Tripping time characteristic of thermal replica and of stepped stage of the overexcitation protection (pre-settings)

4.12 Circuit Breaker Failure Protection

Circuit Breaker Supervision	Current flow monitoring	0.04 A to 1.00 A 1) for the respective side	(steps 0.01 A)
	Dropoff to pickup ratio	approx. 0.9 for $I \geq 0.25$ A 1)	
	Pickup tolerance	5 % of set value or 0.01 A 1)	
	Breaker status monitoring	binary input for CB auxiliary contact	
	1) Secondary values based on I_N = 1 A; for I_N = 5 A they must be multiplied by 5.		
Starting Conditions	for beaker failure protection	internal trip external trip (via binary input)	
Times	Pickup time	approx. 3 ms with measured quantities present; approx. 30 ms after switch-on of measured quantities, f_N = 50/60 Hz; approx. 60 ms after switch-on of measured quantities, f_N = 16,7 Hz	
	Reset time (incl. output relay)	≤30 ms at f_N = 50/60 Hz, ≤90 ms at f_N = 16,7 Hz	
	Delay times for all stages	0.00 s to 60.00 s; ∞	(steps 0.01 s)
	Time tolerance	1 % of setting value or 10 ms	

4.13 External Trip Commands

Binary Inputs for Direct Tripping	Number	2
	Operating time	approx. min. approx. typical
	Dropout time	approx.
	Delay time	0.00 s to 60.00 s (steps 0.01 s)
	Expiration tolerance	1 % of set value or 10 ms
	The set definite times are pure delay times.	
Transformer Annunciations	External annunciations	Buchholz warning Buchholz tank Buchholz tripping

4.14 Monitoring Functions

Measured Quantities	Current symmetry (for each measuring location)	$\lvert I_{min} \rvert / \lvert I_{max} \rvert <$ **BAL. FAKT. I** if $I_{max} / I_N >$ **BAL. I LIMIT** / I_N
	– BAL. FAKT. I	0.10 to 0.90 (steps 0.01)
	– BAL. I LIMIT	0.10 A to 1.00 A 1) (steps 0.01 A)
	Voltage symmetry (if voltages applied)	$\lvert U_{min} \rvert / \lvert U_{max} \rvert <$ **BAL. FACTOR U** if $\lvert Umax \rvert >$ **BALANCE U-LIMIT**
	Voltage sum (if voltages applied)	$\lvert \underline{U}_{L1} + \underline{U}_{L2} + \underline{U}_{L3} - k_U \cdot \underline{U}_{EN} \rvert > 25$ V
	Current phase sequence	$\underline{I}_{L1}$ before $\underline{I}_{L2}$ before $\underline{I}_{L3}$ (clockwise) or $\underline{I}_{L1}$ before $\underline{I}_{L3}$ before $\underline{I}_{L2}$ (counter-clockwise) if $\lvert \underline{I}_{L1} \rvert, \lvert \underline{I}_{L2} \rvert, \lvert \underline{I}_{L3} \rvert > 0.5\ I_N$
	Voltage phase sequence (if voltages applied)	$\underline{U}_{L1}$ before $\underline{U}_{L2}$ before $\underline{U}_{L3}$ (clockwise) or $\underline{U}_{L1}$ before $\underline{U}_{L3}$ before $\underline{U}_{L2}$ (counter-clock) if $\lvert \underline{U}_{L1} \rvert, \lvert \underline{U}_{L2} \rvert, \lvert \underline{U}_{L3} \rvert > 40\ V/\sqrt{3}$
	Broken wire	unexpected instantaneous current value and current interruption or missing zero crossing

1) Secondary values based on $I_N = 1$ A; for $I_N = 5$ A they must be multiplied by 5.

Trip Circuit Supervision	Number of supervised trip circuits	1
	Operation of each trip circuit	with 1 binary input or with 2 binary inputs

4.15 Ancillary Functions

Note:
The tolerances stated in the following apply to one measuring location or one side with 2 measuring locations. All values ± 1 digit.

Operational Measured Values	Operational measured values of currents	I_{L1}; I_{L2}; I_{L3}
	3-phase for each measuring location	in A primary and secondary
	– Tolerance at I_N = 1 A or 5 A	1 % of measured value or 1 % of I_N
	– Tolerance at I_N = 0.1 A	2 % of measured value or 2 % of I_N
	Operational measured values of currents	$3I_0$; I_1; I_2
	3-phase for each measuring location	in A primary and secondary
	– Tolerance	2 % of measured value or 2 % of I_N
	Operational measured values of currents	I_{L1}; I_{L2}; I_{L3}
	3-phase for each side	in A primary and % of $I_{N side}$
	– Tolerance at I_N = 1 A or 5 A	1 % of measured value or 1 % of I_N
	– Tolerance at I_N = 0.1 A	2 % of measured value or 2 % of I_N
	Operational measured values of currents	$3I_0$; I_1; I_2
	3-phase for each side	in A primary and % of $I_{N side}$
	– Tolerance	2 % of measured value or 2 % of I_N
	Operational measured values of currents	I_1 to I_{12} or I_{X1} to I_{X4}
	1-phase for each measuring location	in A primary and secondary
	– Tolerance	2 % of measured value or 2 % of I_N
	Operational measured values of currents	for high-sensitivity inputs
	1-phase	in A primary and mA secondary
	– Tolerance	1 % of measured value or 2 mA
	Phase angles of currents	$\varphi(I_{L1})$; $\varphi(I_{L2})$; $\varphi(I_{L3})$ in °
	3-phase for each measuring location	referred to $\varphi(I_{L1})$
	– Tolerance	1° at rated current
	Phase angles of currents	$\varphi(I_1)$ to $\varphi(I_{12})$ or $\varphi(I_{X1})$ to $\varphi(I_{X4})$ in °
	1-phase for each measuring location	referred to $\varphi(I_{L1})$
	– Tolerance	1° at rated current
	Operational measured values of voltages	U_{L1-E}; U_{L2-E}; U_{L3-E}; U_{L1-L2}; U_{L2-L3}; U_{L3-L1}
	(3-phase, if voltages applied)	in kV primary and V second. and % of U_{Nop}
	– Tolerance	0.2 % of measured value or 0.2 V
	Operational measured values of voltages	U_1; U_2; U_0
	(3-phase, if voltages applied)	in kV primary and V second. and % of U_{Nop}
	– Tolerance	0.4 % of measured value or 0.4 V
	Operational measured values of voltage	U_{EN} or U_4
	(1-phase, if voltages applied)	in kV primary and V second. and % of U_{Nop}
	– Tolerance	0.2 % of measured value or 0.2 V
	Phase angles of voltages	$\varphi(U_{L1})$; $\varphi(U_{L2})$; $\varphi(U_{L3})$ in °
	(if voltages applied)	referred to $\varphi(I_{L1})$
	– Tolerance	1° at rated voltage
	Phase angles of voltages	$\varphi(U_{EN})$ or $\varphi(U_4)$; in °
	(if voltages applied)	referred to $\varphi(I_{L1})$
	– Tolerance	1° at rated voltage

	Overexcitation factor	$(U/f)/(U_N/f_N)$
	– Tolerance	2 % of measured value
	Operational measured values of frequency	f in Hz and % of f_N
	– Range	10 Hz to 75 Hz
	– Tolerance	1 % within range $f_N \pm 10$ % at $I = I_N$
	Operational measured values of power (3-phase if voltages applied)	P; Q; S (active, reactive, apparent power) in kW; MW; kVA; MVA primary
	– Tolerance	1.2 % of measured value or 0,25 % of S_N
	Operational measured values of power (1-phase with meas. or rated voltage)	S (apparent power) in kVA; MVA primary
	Operational measured values of power factor (3-phase if voltages applied)	cos φ

Tolerances are based on the preset matching parameters. Higher tolerances are to be expected for calculated values dependent on the matching factors for currents and voltages.

Thermal values	Operational measured values for thermal value	Θ_{L1}; Θ_{L2}; Θ_{L3}; Θ_{res} referred to tripping temperature rise Θ_{trip}
	Operational measured values (Temperature acc. IEC 60354)	Θ_{RTD1} to Θ_{RTD12} in °C or °F relative aging rate, load reserve
Differential Current Values	Measured values of differential protection	$I_{DIFF L1}$; $I_{DIFF L2}$; $I_{DIFF L3}$; $I_{REST L1}$; $I_{REST L2}$; $I_{REST L3}$ in % of operational rated current
	– Tolerance (with preset values)	2 % of meas. value or 2 % of I_N (50/60 Hz) 3 % of meas. value or 3 % of I_N (16,7 Hz)
	Measured values of restricted earth fault protection	$I_{diff REF}$; $I_{Rest REF}$ in % of operational rated current
	– Tolerance (with preset values)	2 % of meas. value or 2 % of I_N (50/60 Hz) 3 % of meas. value or 3 % of I_N (16,7 Hz)

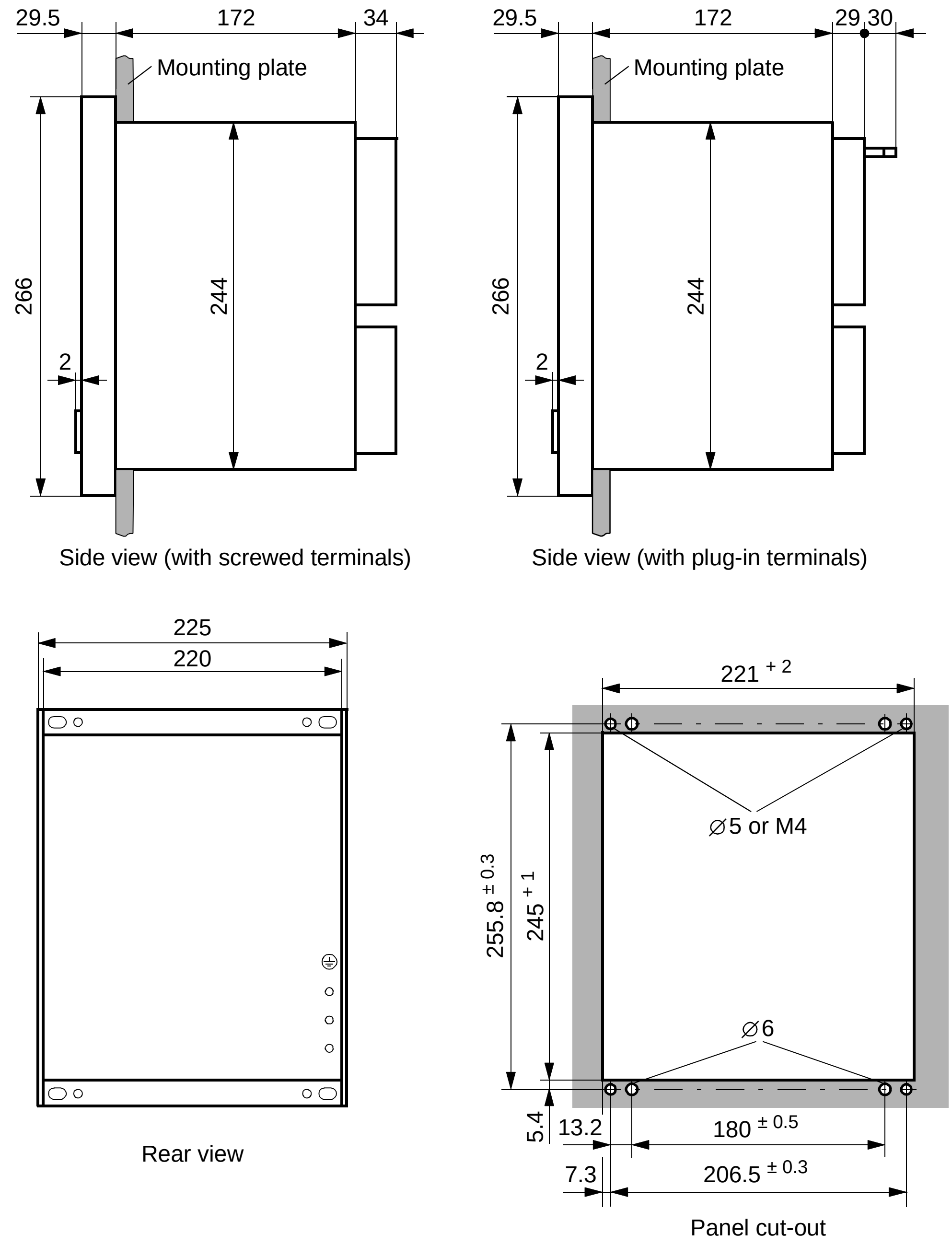
Tolerances are based on the preset matching parameters for a protected object with 2 sides and 1 measuring location per side. Higher tolerances are to be expected for calculated values dependent on the matching factors for the currents and the number of measuring locations.

Fault Event Data Log	Storage of the messages of the last 8 faults	with a total of max. 200 messages
Fault Recording	Number of stored fault records	max. 8
	Storage period (start with pickup or trip)	max. 5 s for each fault approx. 5 s in total
	Sampling rate at f_N = 50 Hz	1.25 ms
	Sampling rate at f_N = 60 Hz	1.04 ms
	Sampling rate at f_N = 16,7 Hz	3.75 ms
Statistics	Number of trip events caused by 7UT6	

	Total of interrupted currents caused by 7UT6	segregated for each pole and each side
	Operating hours	Up to 7 decimal digits
	criterion	Excess of current threshold
Real Time Clock and Buffer Battery	Resolution for operational messages	1 ms
	Resolution for fault messages	1 ms
	Buffer battery	3 V/1 Ah, type CR 1/2 AA Self-discharging time approx. 10 years
Time Synchronization	Operation modes:	
	Internal	Internal via RTC
	IEC 60870–5–103	External via system interface (IEC 60870–5–103)
	Time signal IRIG B	External via IRIG B
	Time signal DCF77	External, via time signal DCF77
	Time signal synchro-box	External, via synchro-box
	Pulse via binary input	External with pulse via binary input
User-configurable Functions (CFC)	Processing times for function blocks:	
	Block, Basic requirements	5 TICKS
	Beginning with the 3rd additional input for generic blocks per input	1 TICK
	Connection with input margin	6 TICKS
	Connection with output margin	7 TICKS
	In addition to each chart	1 TICK
	Maximum number of TICKS in sequence levels:	
	MW_BEARB (processing of meas. values)	10000 TICKS
	PLC1_BEARB (slow PLC processing)	2000 TICKS
	PLC_BEARB (fast PLC processing)	200 TICKS
	SFS_BEARB (switchgear interlocking)	10000 TICKS

4.16 Dimensions

Housing for Panel Flush Mounting or Cubicle Installation Size $^1/_2$ (of 19")



Side view (with screwed terminals)

Side view (with plug-in terminals)

Rear view

Panel cut-out

Dimensions in mm

Figure 4-14 Dimensions 7UT6 for panel flush mounting or cubicle installation (size $^1/_2$)

Housing for Panel Flush Mounting or Cubicle Installation Size $^1/_1$ (of 19")

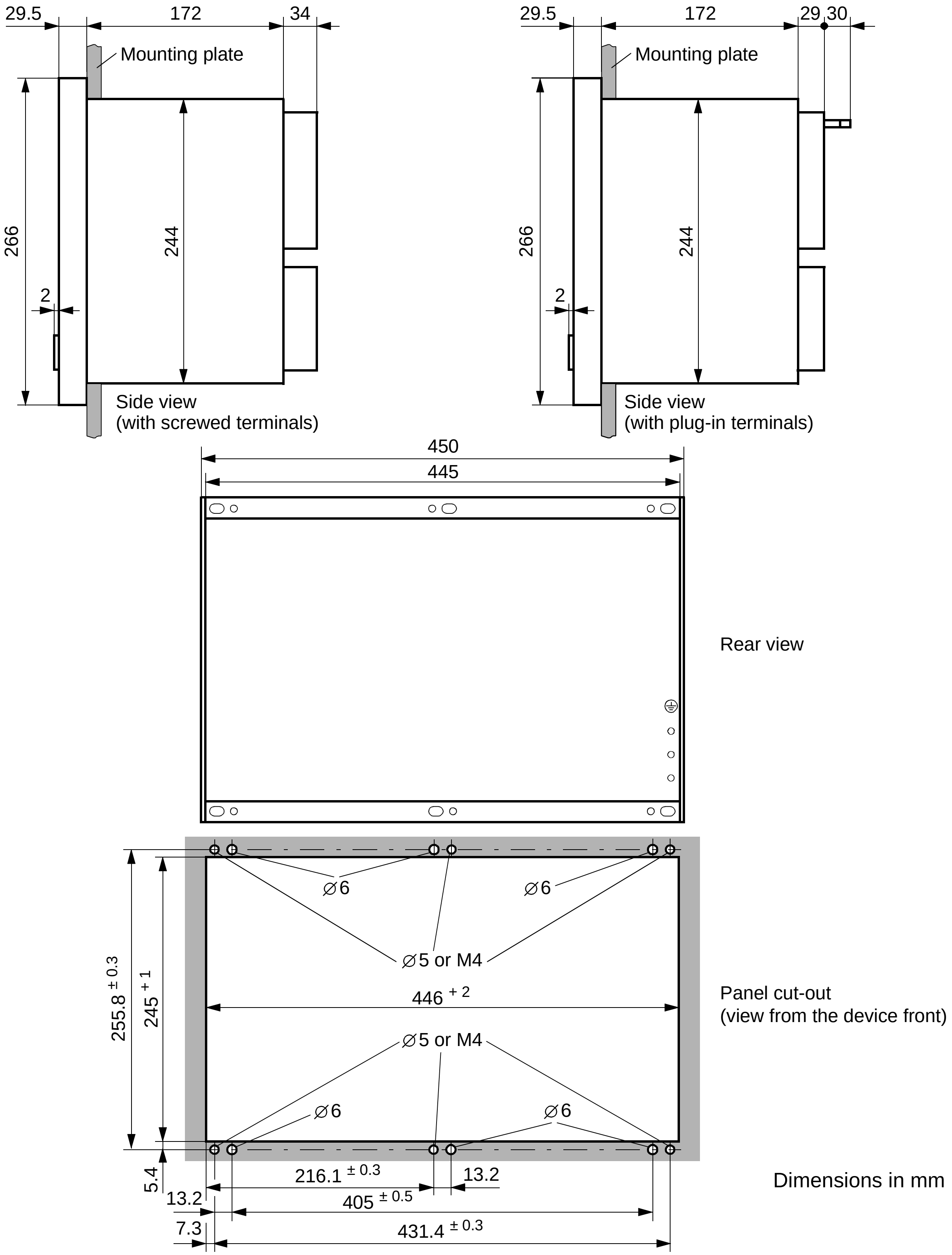


Figure 4-15 Dimensions 7UT6 for panel flush mounting or cubicle installation (size $^1/_1$)

Housing for Panel Surface Mounting Size $^1/_2$ (of 19")

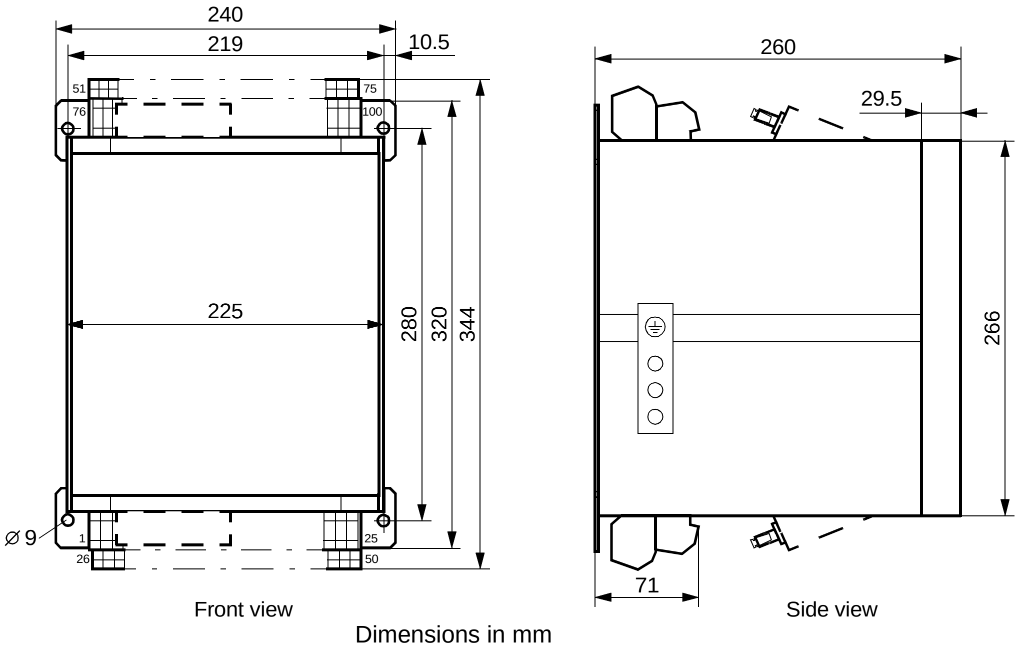


Figure 4-16 Dimensions 7UT613 for panel surface mounting (size $^1/_2$)

Housing for Panel Surface Mounting Size $^1/_1$ (of 19")

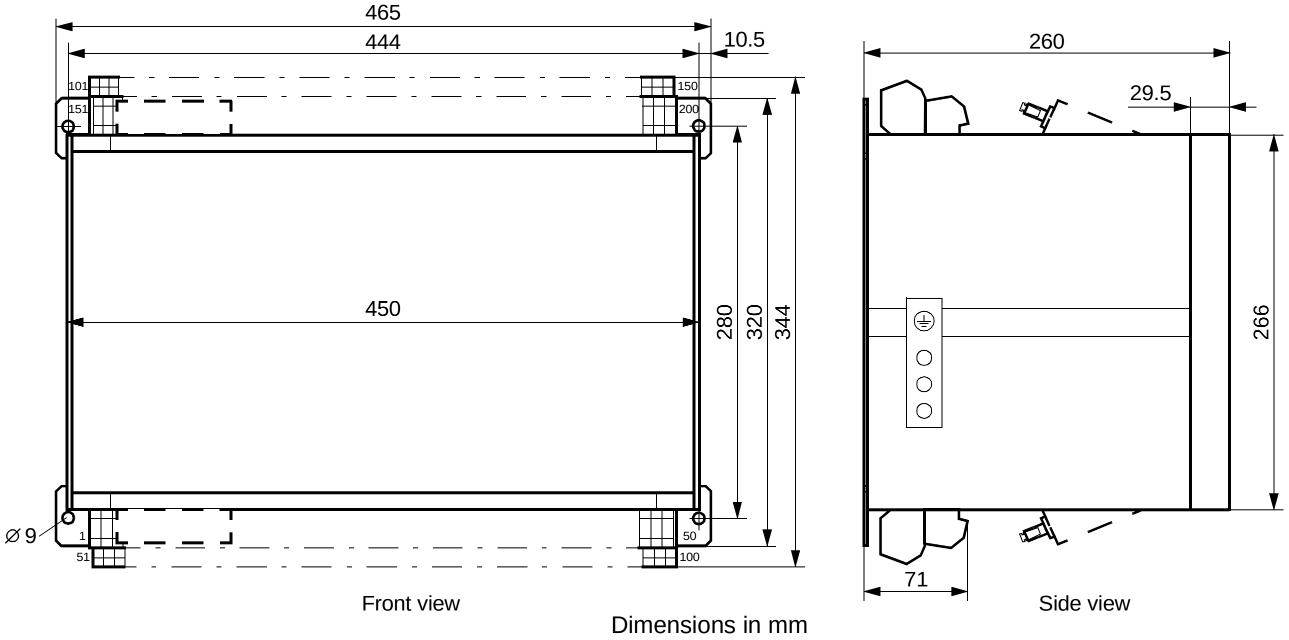
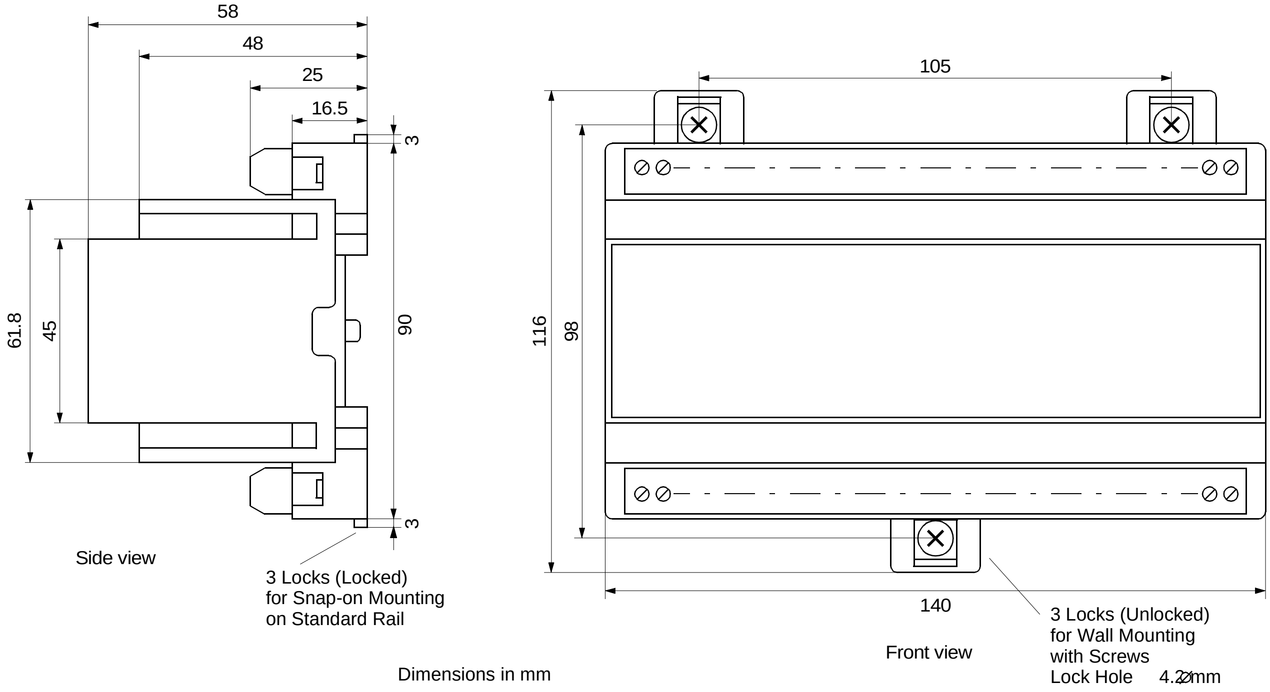


Figure 4-17 Dimensions 7UT633 or 7UT635 for panel surface mounting (size $^1/_1$)

RTD-Box



3 Locks (Locked)
for Snap-on Mounting
on Standard Rail

3 Locks (Unlocked)
for Wall Mounting
with Screws
Lock Hole 4.2∅mm

Dimensions in mm

Figure 4-18 Dimensions RTD-box 7XV5662–∗AD10–0000

■

Appendix A

This appendix is primarily a reference for the experienced user. This Chapter provides ordering information for the models of 7UT6. General diagrams indicating the terminal connections of the 7UT6 models are included. Connection examples show the proper connections of the device to primary equipment in typical power system configurations. Tables with all settings and all information available in a 7UT6 equipped with all options are provided.

A.1 Ordering Information and Accessories

A.1.1 Differential Protection 7UT613 for Three Measuring Locations

	7		8	9	10	11	12		13	14	15	16
Differential Protection	**7UT613** ☐	–	☐	☐	☐	☐	☐	–	☐	☐	☐	**0**

Rated Current	
$I_N = 1$ A	1
$I_N = 5$ A	5

Auxiliary Voltage (Power Supply, Pick-up Threshold of Binary Inputs)	
DC 24 V to 48 V, binary input threshold 17 V 2)	2
DC 60 V to 125 V 1), binary input threshold 17 V 2)	4
DC 110 V to 250 V 1), AC 115 to 230 V, binary input threshold 73 V 2)	5

Housing / Number of In- and Outputs **BI: Binary Inputs, BO: Binary Outputs**	
Surface mounting housing with two-tier terminals, $^1/_2$ × 19", 5 BI, 8 BO, 1 life contact	B
Flush mounting housing with plug-in terminals, $^1/_2$ × 19", 5 BI, 8 BO, 1 life contact	D
Flush mounting housing with screwed terminals, $^1/_2$ × 19", 5 BI, 8 BO, 1 life contact	E

Region-Specific Default / Language Settings and Function Versions	
Region GE, 50/60 Hz, 16,7 Hz, language German (language can be changed)	A
Region world, 50/60 Hz, 16,7 Hz, language English, (language can be changed)	B
Region US, 60/50 Hz, language US-English (language can be changed)	C
Region world, 50/60 Hz, 16,7Hz, language Spanish (language can be changed)	E

System Interface: Functionality and Hardware (Port B)	
No system interface	0
IEC Protocol, electrical RS232	1
IEC Protocol, electrical RS485	2
IEC Protocol, optical 820 nm, ST-plug	3
Profibus FMS Slave, electrical RS485	4
Profibus FMS Slave, optical, single-ring, ST-connector 3)	5
Profibus FMS Slave, optical, double-ring, ST-connector 3)	6
For further interfaces see additional specification L	9

Additional Specification L	+ L 0 ☐
Port B	
Profibus DP Slave, RS485	A
Profibus DP Slave, optical 820 nm, double-ring, ST-connector 3)	B
Modbus, electrical RS485	D
Modbus, optical 820 nm, ST-connector 3)	E
DNP3.0, electrical RS485	G
DNP3.0, optical 820 nm, ST-connector 3)	H

1) with plug-in jumper one of 2 voltage ranges can be selected

2) for each binary input one of 2 pickup threshold ranges can be selected with plug-in jumpers

3) not possible for models with surface mounted housing (9th digit = B). For this pupose, please order a model with the corresponding electrical RS485 inteface, and additionally supplementary parts according to Subsection A.1.3 under “External Converters”

see next page

Differential Protection

7 8 9 10 11 12 13 14 15 16

7UT613 ☐ – ☐☐☐☐☐ – ☐☐☐ **0**

DIGSI / Modem Interface / RTD-box (only Port C)	
DIGSI / Modem/Browser, electrical RS232	1
DIGSI / Modem/Browser/RTD-box, electrical RS485	2
DIGSI / Modem Interface / RTD-box (Port C and D)	
For further interfaces see additional specification M	9

\+ M☐☐

Additional specification M	
Port **C**	
DIGSI/Modem/Browser, electrical RS232	1
DIGSI/Modem/Browser/RTD-box, electrical RS485	2
Port **D** (Additional interface)	
RTD-box, optical 820 nm, ST-connector	A
RTD-box, electrical RS485	F

Functionality	
Measured Values/Monitor functions	
Basic measured values	1
Basic measured values, transformer monitoring functions (connection to RTD-box / hot spot, overload factor) [4]	4
Differential Protection + Basic Functions	A
Differential protection for transformer, generator, motor, busbar (87) Overload protection according to IEC 60354 for one side (49) [4] Lock out (86) Time overcurrent protection phases (50/51): I>, I>>, Ip (inrush stabilization) Time overcurrent protection 3I0 (50N/51N): 3I0>, 3I0>>, 3I0p (inrush stabilization) Time overcurrent protection earth (50G/51G): IE>, IE>>, IEp (inrush stabilization)	
Differential Protection + Basic Functions + Additional Current Functions	B
Restricted earth fault protection, low impedance (87G) O/C 1-phase, e.g. for restricted earth fault protection, high impedance (87G without resistor and varistor [5]) Unbalanced load protection (46) Breaker failure protection (50BF) Trip circuit supervision (74TC)	
Additional Voltage Functions	
Without voltage functions	A
With overexcitation protection and voltage/power/energy measurement	B

---

[4] external RTD-box necessary

[5] external resistor and varistor necessary

Ordering example: 7UT6131–4EB91–1AA0 +L0A

Differential protection
here: pos. 11 = 9 pointing at L0A, i.e. version with Profibus-interface DP Slave, RS485

A.1.2 Differential Protection 7UT633 and 7UT635 for 3 to 5 Measuring Locations

	6	7		8	9	10	11	12		13	14	15	16
Differential Protection **7UT63**	□	□	–	□	□	□	□	□	–	□	□	□	**0**

Inputs and Outputs

12 current inputs (3×3-phase + 3×1-phase); 4 voltage inputs (1×3-phase + 1×1-phase) Housing $^1/_1$ × 19", 21 BI, 24 BO, 1 life contact	3
16 current inputs (5×3-phase + 1×1-phase or 4×3-phase + 4×1-phase) Housing $^1/_1$ × 19", 29 BI, 24 BO, 1 life contact	5

Rated Current

I_N = 1 A	1
I_N = 5 A	5

Auxiliary Voltage (Power Supply, Pick-up Threshold of Binary Inputs)

DC 24 V to 48 V, binary input threshold 17 V [2]	2
DC 60 V to 125 V [1], binary input threshold 17 V [2]	4
DC 110 V to 250 V [1], AC 115 to 230 V, binary input threshold 73 V [2]	5

Housing Design

Surface mounting housing with two-tier terminals, $^1/_1$ × 19"	B
Flush mounting housing with plug-in terminals, $^1/_1$ × 19"	D
Flush mounting housing with screwed terminals, $^1/_1$ × 19"	E

Region-Specific Default / Language Settings and Function Versions

Region GE, 50/60 Hz, 16,7 Hz, language German (language can be changed)	A
Region world, 50/60 Hz, 16,7 Hz, language English, (language can be changed)	B
Region US, 60/50 Hz, language US-English (language can be changed)	C
Region world, 50/60 Hz, 16,7 Hz, language Spanish (language can be changed)	E

System Interface: Functionality and Hardware (Port B)

No system interface	0
IEC Protocol, electrical RS232	1
IEC Protocol, electrical RS485	2
IEC Protocol, optical 820 nm, ST-plug	3
Profibus FMS Slave, electrical RS485	4
Profibus FMS Slave, optical, single-ring, ST-connector [3]	5
Profibus FMS Slave, optical, double-ring, ST-connector [3]	6
For further interfaces see additional specification L	9

+ L 0 □

Additional Specification L

Profibus DP Slave, RS485	A
Profibus DP Slave, optical 820 nm, double-ring, ST-connector [3]	B
Modbus, electrical RS485	D
Modbus, optical 820 nm, ST-connector [3]	E
DNP, electrical RS485	G
DNP, optical 820 nm, ST-connector [3]	H

---

[1] with plug-in jumper one of 2 voltage ranges can be selected

[2] for each binary input one of 2 pickup threshold ranges can be selected with plug-in jumpers

[3] not possible for models with surface mounted housing (9th digit = B). For this pupose, please order a model with the corresponding electrical RS485 inteface, and additionally supplementary parts according to Subsection A.1.3 under “External Converters”

see next page

Differential Protection

6 7 – 8 9 10 11 12 – 13 14 15 16

7UT63 □□ – □□□□□ – □□□ **0**

DIGSI / Modem Interface / RTD-box (only Port C)

DIGSI / Modem, electrical RS232	1
DIGSI / Modem / RTD-box, electrical RS485	2

DIGSI / Modem Interface / RTD-box (Port C and D)

For further interfaces see additional specification M	9

Additional specification M + M□□

Port **C**	
DIGSI / Modem, electrical RS232	1
DIGSI / Modem / RTD-box, electrical RS485	2
Port **D** (Additional interface)	
RTD-box, optical 820 nm, ST-connector	A
RTD-box, electrical RS485	F

Functionality

Measured Values/Monitor functions

Basic measured values	1
Basic measured values, transformer monitoring functions (connection to RTD-box / hot spot, overload factor) 4)	4

Differential Protection + Basic Functions	A
Differential protection for transformer, generator, motor, busbar (87) Overload protection according to IEC for one side (49) 4) Lock out (86) Time overcurrent protection phases (50/51): I>, I>>, Ip (inrush stabilization) Time overcurrent protection 3I0 (50N/51N): 3I0>, 3I0>>, 3I0p (inrush stabilization) Time overcurrent protection earth (50G/51G): IE>, IE>>, IEp (inrush stabilization)	
Differential Protection + Basic Functions + Additional Current Functions	B
Restricted earth fault protection, low impedance (87G) O/C 1-phase, e.g. for restricted earth fault protection, high impedance (87G without resistor and varistor 5)) Unbalanced load protection (46) Breaker failure protection (50BF) Trip circuit supervision (74TC)	

Additional Voltage Functions

Without voltage functions	A
With overexcitation protection and voltage/power/energy measurement (**only with 7UT633**)	B

---

4) external RTD-box necessary

5) external resistor and varistor necessary

Ordering example: 7UT6331–4EB91–1AA0 +L0A

Differential protection
here: pos. 11 = 9 pointing at L0A, i.e. version with Profibus-interface DP Slave, RS485

A.1.3 Accessories and Spare Parts

RTD-Box

For up to 6 temperature measuring points (at most 2 devices can be connected to 7UT6)

Designation	Order No.
RTD-box, U_N = 24 to 60 V AC/DC	7XV5662–2AD10
RTD-box, U_N = 90 to 240 V AC/DC	7XV5662–5AD10

Matching / Summation Transformer

For single-phase busbar connection

Designation	Order No.
Matching / summation transformer I_N = 1 A	4AM5120–3DA00–0AN2
Matching / summation transformer I_N = 5 A	4AM5120–4DA00–0AN2

External Converters

Optical connectors for Profibus, Modbus, and DNP3.0 are not available in surface mounting housings. Please order a device with the corresponding electrical RS485 interface and the matching converter according to the following table:

For Interface Type	Order Device with	Additional Accessories
Profibus FMS single ring	Profibus FMS RS485	6GK1502–3AB10 7XV5810–0BA00
Profibus FMS double ring	Profibus FMS RS485	6GK1502–4AB10 7XV5810–0BA00
Profibus DP double ring	Profibus DP RS485	6GK1502–4AB10 7XV5810–0BA00
Modbus 820 nm	Modbus RS485	7XV5650–0BA00
DNP3.0 820 nm	DNP3.0 RS485	7XV5650–0BA00

Interface Modules

Replacement interface modules

Designation	Order No.
RS232	C53207–A351–D641–1
RS485	C53207–A351–D642–1
Optical 820 nm	C53207–A351–D643–1
Profibus FMS RS485	C53207–A351–D603–1
Profibus FMS double ring	C53207–A351–D606–1
Profibus FMS single ring	C53207–A351–D609–1
Profibus DP RS485	C53207–A351–D611–1
Profibus DP double ring	C53207–A351–D613–1
Modbus RS485	C53207–A351–D621–1
Modbus 820 nm	C53207–A351–D623–1
DNP 3.0 RS485	C53207–A351–D631–1
DNP 3.0 820 nm	C53207–A351–D633–1

Terminal Block Covering Caps

Covering cap for terminal block type	Order No.
18 terminal voltage block, 12 terminal current block	C73334-A1–C31–1
12 terminal voltage block, 8 terminal current block	C73334-A1–C32–1

Short-Circuit Links

Short-circuit links as Jumper-Kit	Order No.
3 links for current terminals plus 6 links for voltage terminals	C73334-A1–C40–1

Plug-in Socket Boxes

For Connector Type	Order No.
2 pin	C73334–A1–C35–1
3 pin	C73334–A1–C36–1

Mounting Bracket for 19"-Racks

Designation	Order No.
Angle strip (mounting rail)	C73165-A63-C200-3

Battery

Lithium battery 3 V/1 Ah, Type CR 1/2 AA	Order No.
VARTA	6127 101 501

Interface Cable

An interface cable is necessary for the communication between the SIPROTEC device and a computer. Requirements for the computer are Windows 95 or Windows NT4 and the operating software DIGSI®.

Interface cable between PC or SIPROTEC device	Order No.
Cable with 9-pin male / female connections	7XV5100–4

Operating Software DIGSI®

Software for setting and operating SIPROTEC® 4 devices

Operating Software DIGSI®	Order No.
DIGSI®, basic version with license for 10 computers	7XS5400–0AA00
DIGSI®, complete version with all option packages	7XS5402–0AA0

Graphical Analysis Program SIGRA

Software for graphical visualization, analysis, and evaluation of fault data. Option package of the complete version of DIGSI®

Graphical analysis program DIGRA®	Order No.
Full version with license for 10 machines	7XS5410–0AA0

Graphic Tools

Software for graphically supported configuration of characteristic curves and provide zone diagrams for overcurrent and distance protection devices.
(Option package for the complete version of DIGSI®)

Graphic Tools 4	Order No.
Full version with license for 10 machines	7XS5430–0AA0

DIGSI REMOTE

Software for remotely operating protection devices via a modem (and possibly a star connector) using DIGSI®. (Option package for the complete version of DIGSI®).

DIGSI REMOTE 4	Order No.
Full version with license for 10 machines	7XS5440–1AA0

SIMATIC CFC 4

Software for graphical configuration of interlocking (latching) conditions and creating additional functions in SIPROTEC® 4 devices. (Option package for the complete version of DIGSI®).

SIMATIC CFC 4	Order No.
Full version with license for 10 machines	7XS5450–0AA0

Varistor

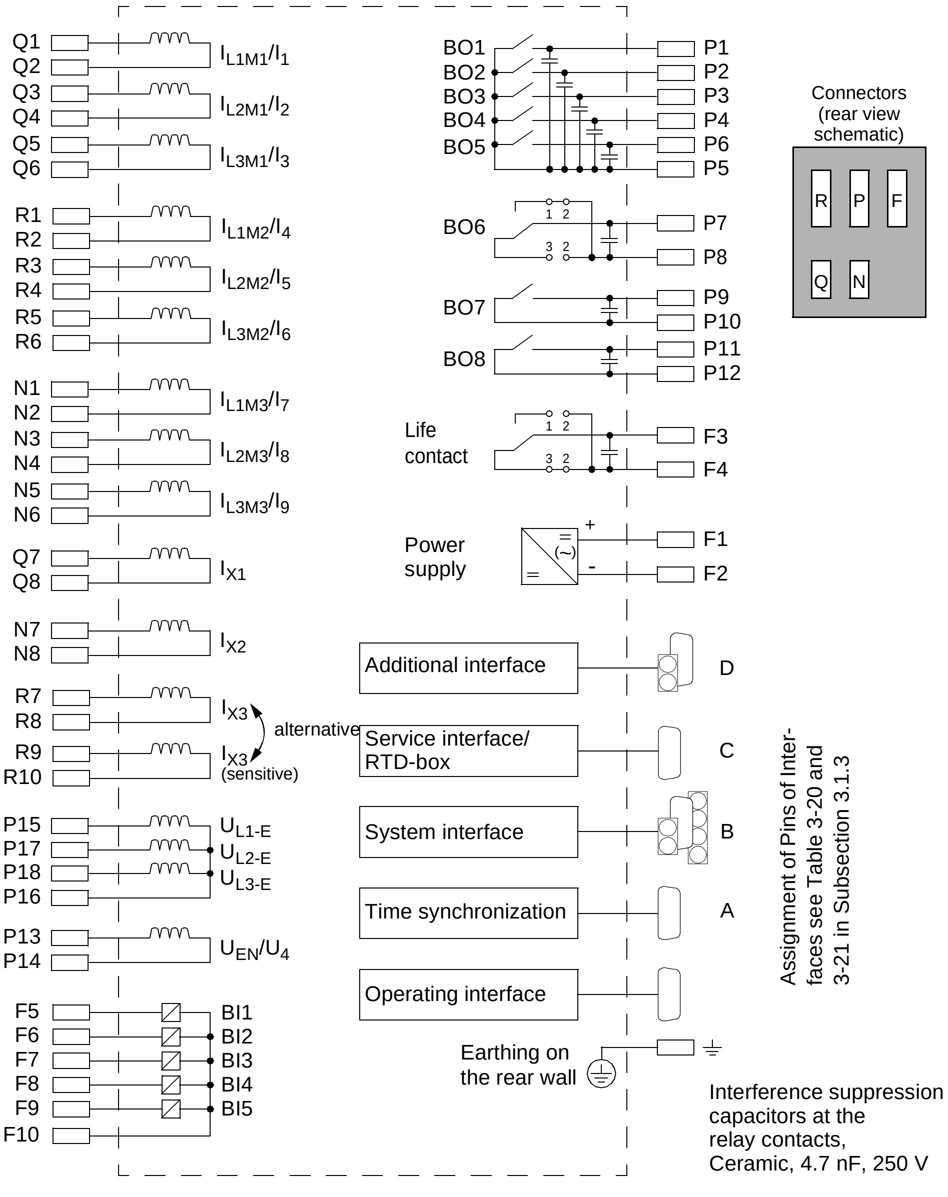
Voltage arrester for high-impedance protection

Varistor	Order No.
125 Vrms; 600 A; 1S/S256	C53207–A401–D76–1
240 Vrms; 600 A; 1S/S1088	C53207–A401–D77–1

A.2 General Diagrams

A.2.1 Panel Flush Mounting or Cubicle Mounting

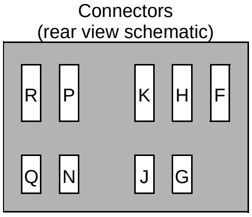
7UT613

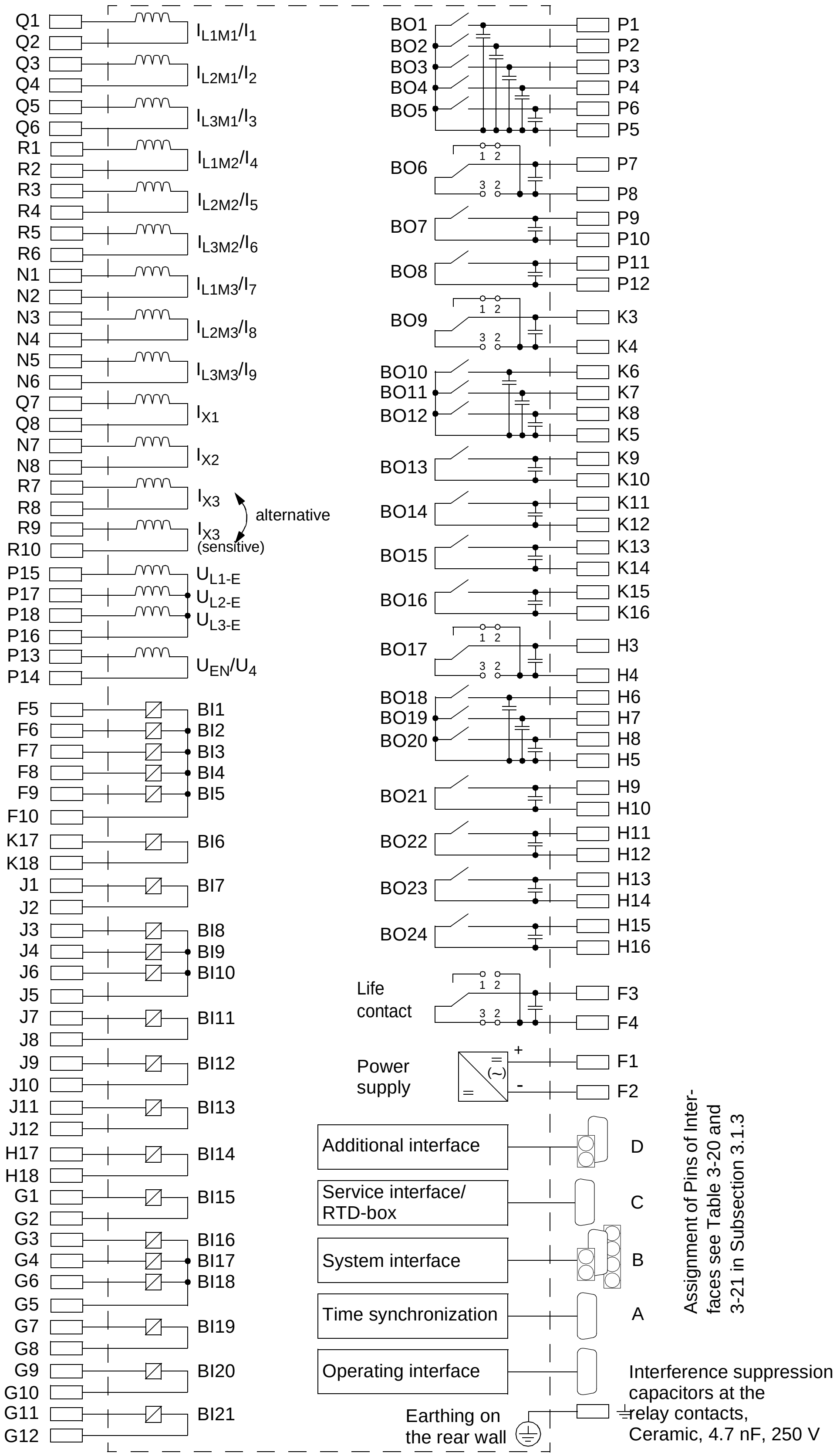


Interference suppression capacitors at the relay contacts, Ceramic, 4.7 nF, 250 V

Figure A-1 General Diagram 7UT613 (panel flush mounted or cubicle mounted)

7UT633



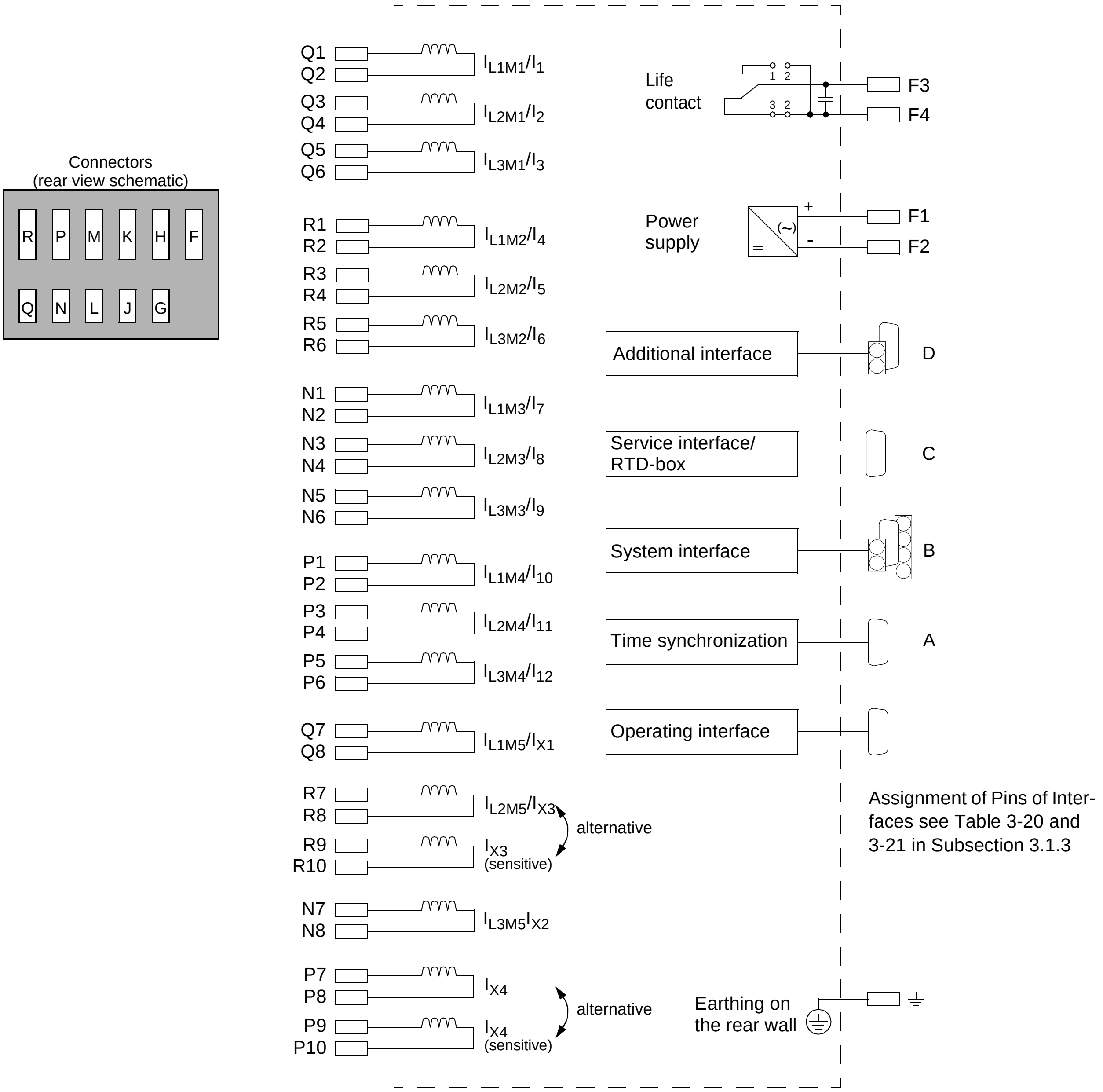


Assignment of Pins of Interfaces see Table 3-20 and 3-21 in Subsection 3.1.3

Interference suppression capacitors at the relay contacts, Ceramic, 4.7 nF, 250 V

Figure A-2 General Diagram 7UT633 (panel flush mounted or cubicle mounted)

7UT635



Assignment of Pins of Interfaces see Table 3-20 and 3-21 in Subsection 3.1.3

Continued Figure A-4

Figure A-3 General Diagram 7UT635 (panel flush mounted or cubicle mounted) (Sheet 1 of 2)

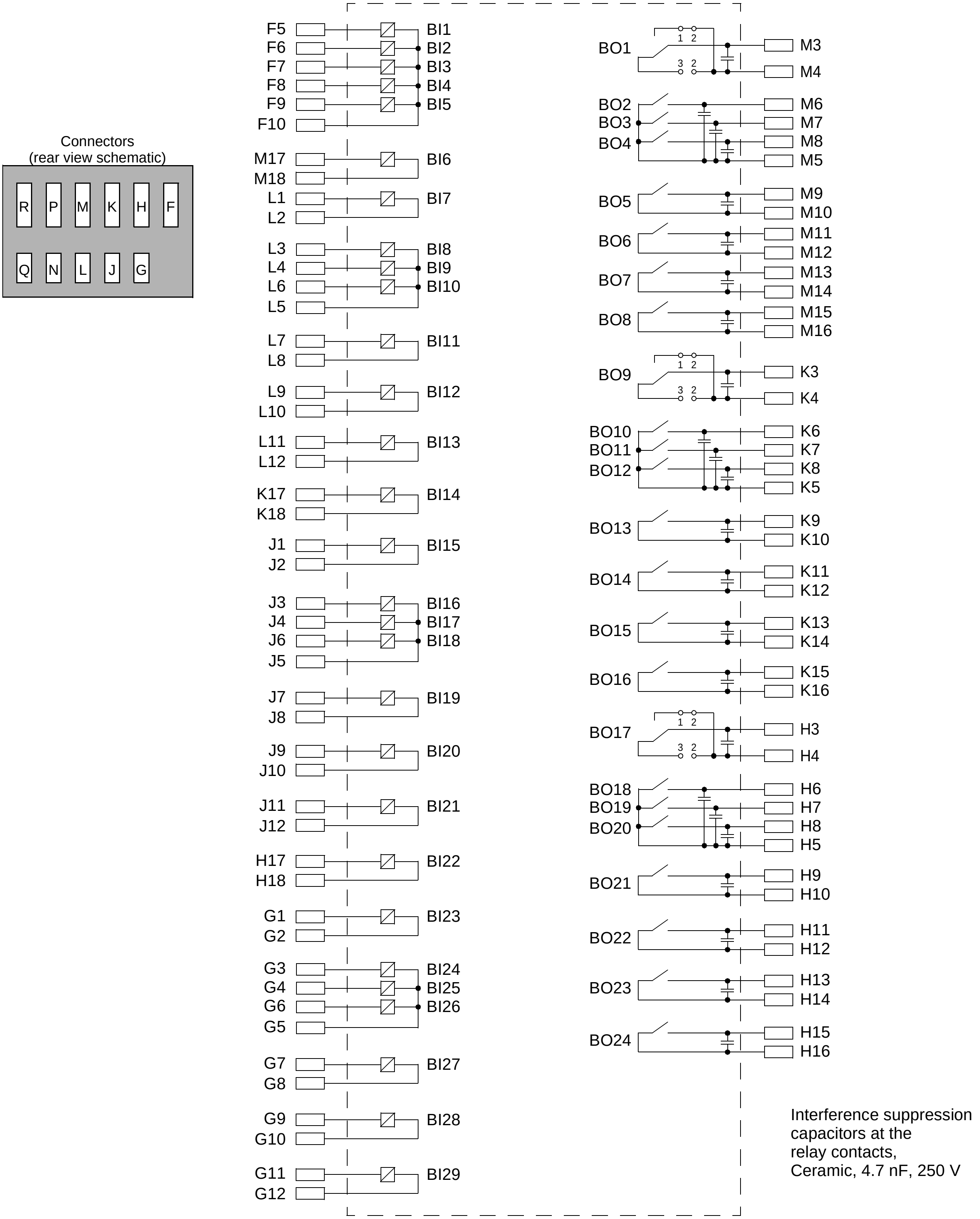
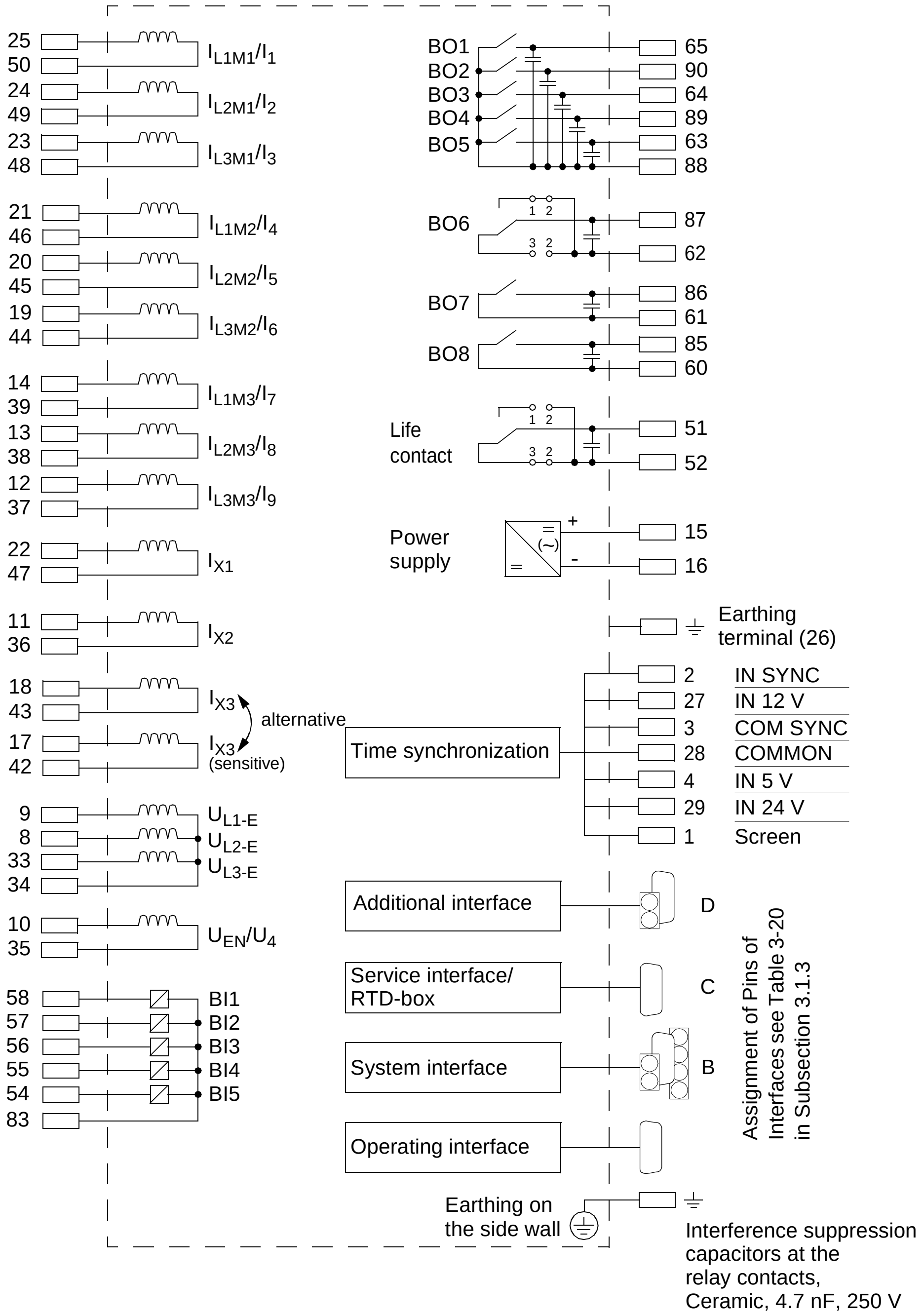


Figure A-4 General Diagram 7UT635 (panel flush mounted or cubicle mounted) (Sheet 2 of 2)

A.2.2 Panel Surface Mounting

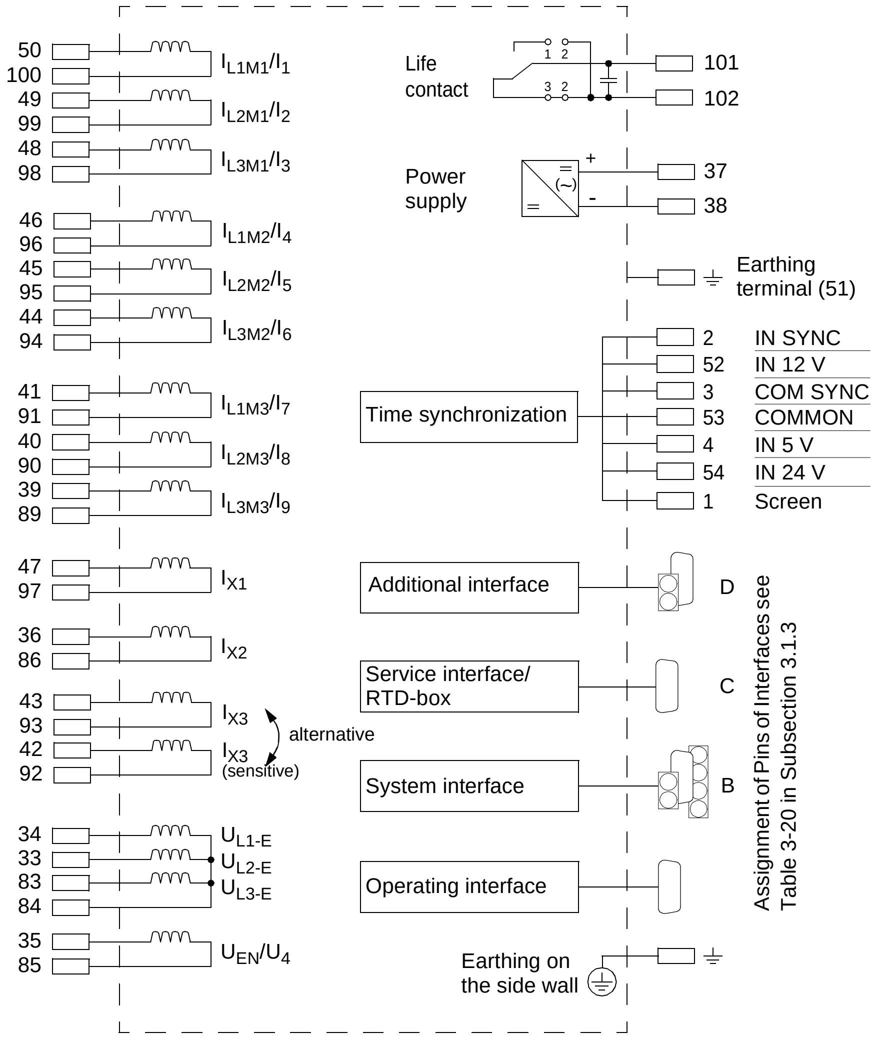
7UT613



Interference suppression capacitors at the relay contacts, Ceramic, 4.7 nF, 250 V

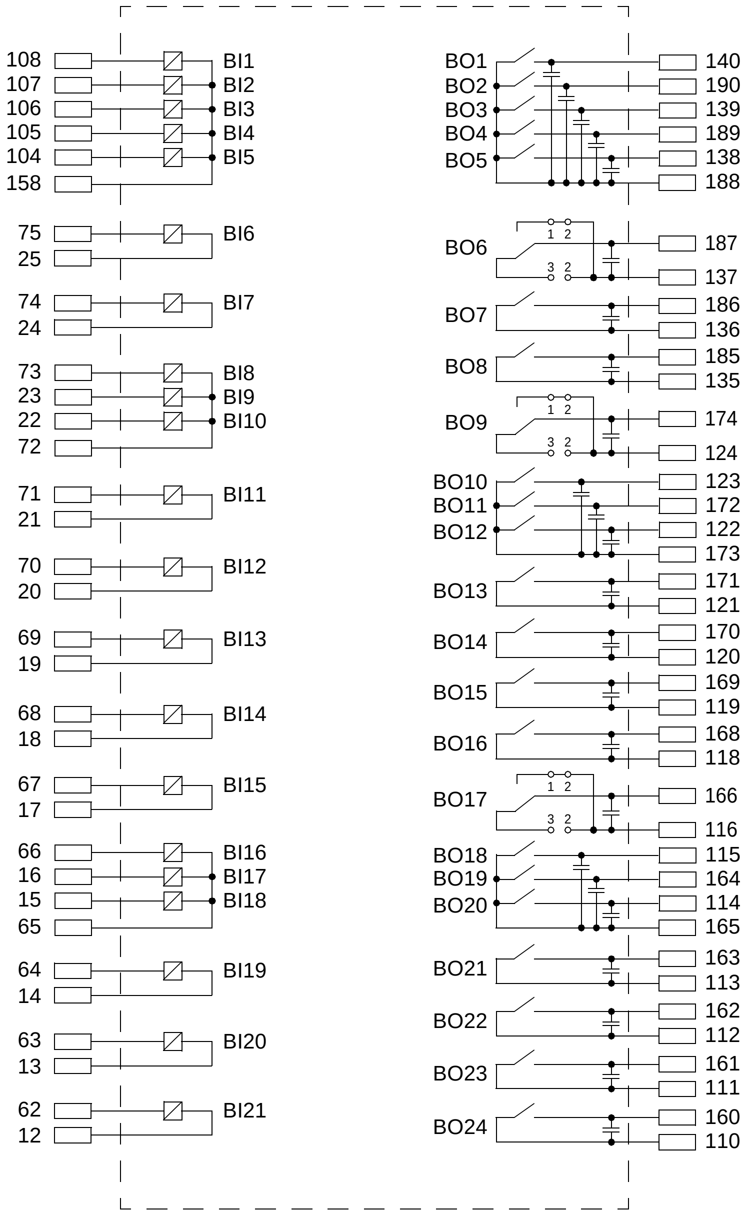
Figure A-5 General diagram 7UT613 (panel surface mounting)

7UT633



Continued in Figure A-7

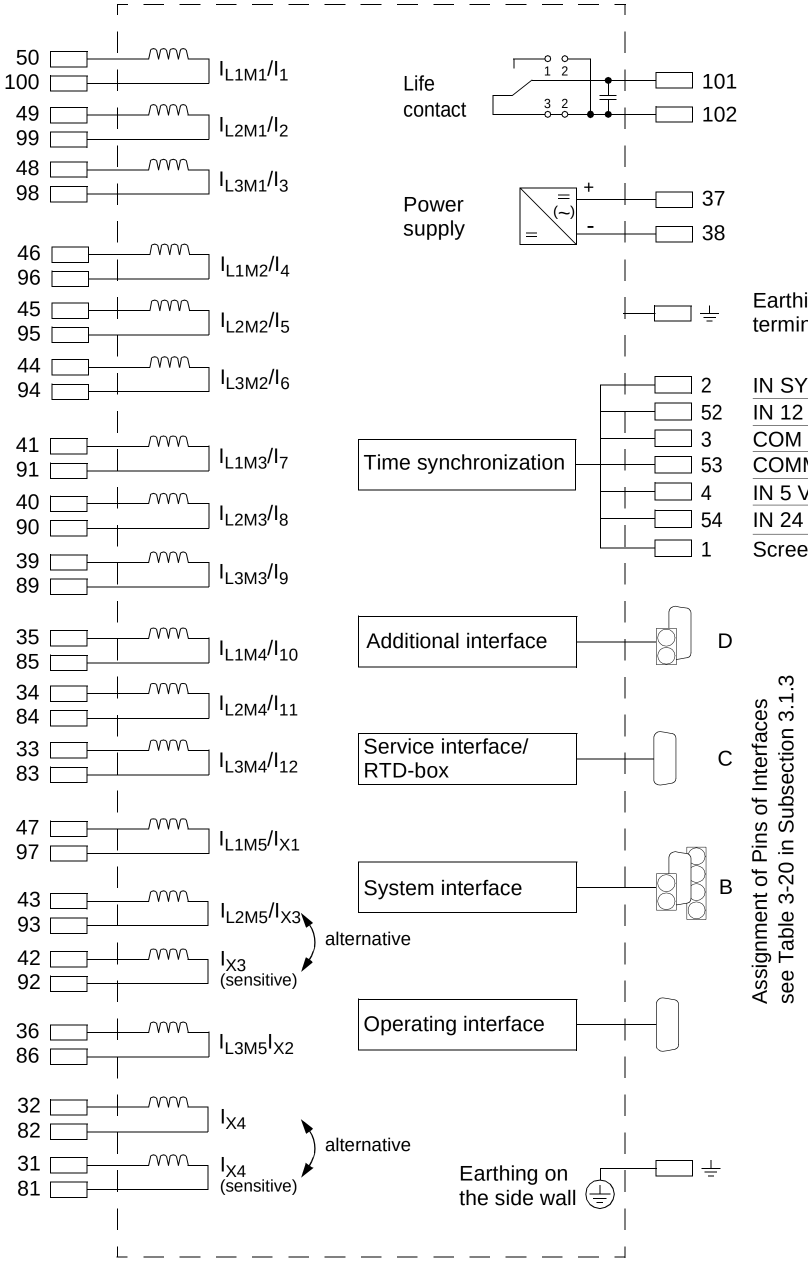
Figure A-6 General Diagram 7UT633 (panel surface mounting) (Sheet 1 of 2)



Interference suppression capacitors at the relay contacts, Ceramic, 4.7 nF, 250 V

Figure A-7 General Diagram 7UT633 (panel surface mounting) (Sheet 2 of 2)

7UT635



Continued in Figure A-9

Figure A-8 General Diagram 7UT635 (panel surface mounting) (Sheet 1 of 2)

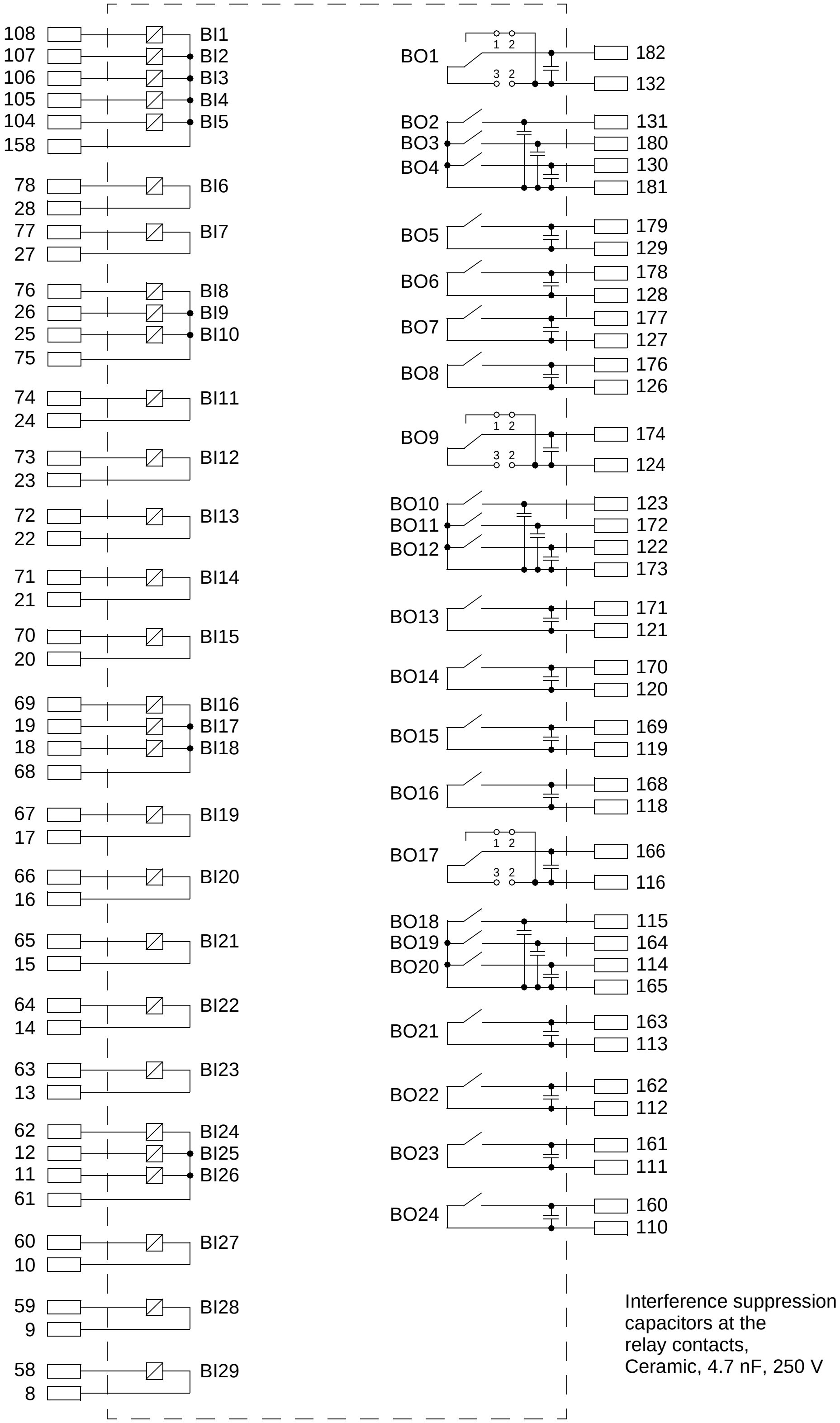


Figure A-9 General Diagram 7UT635 (panel surface mounting) (Sheet 2 of 2)

A.3 Connection Examples

Current Transformer Connection Examples

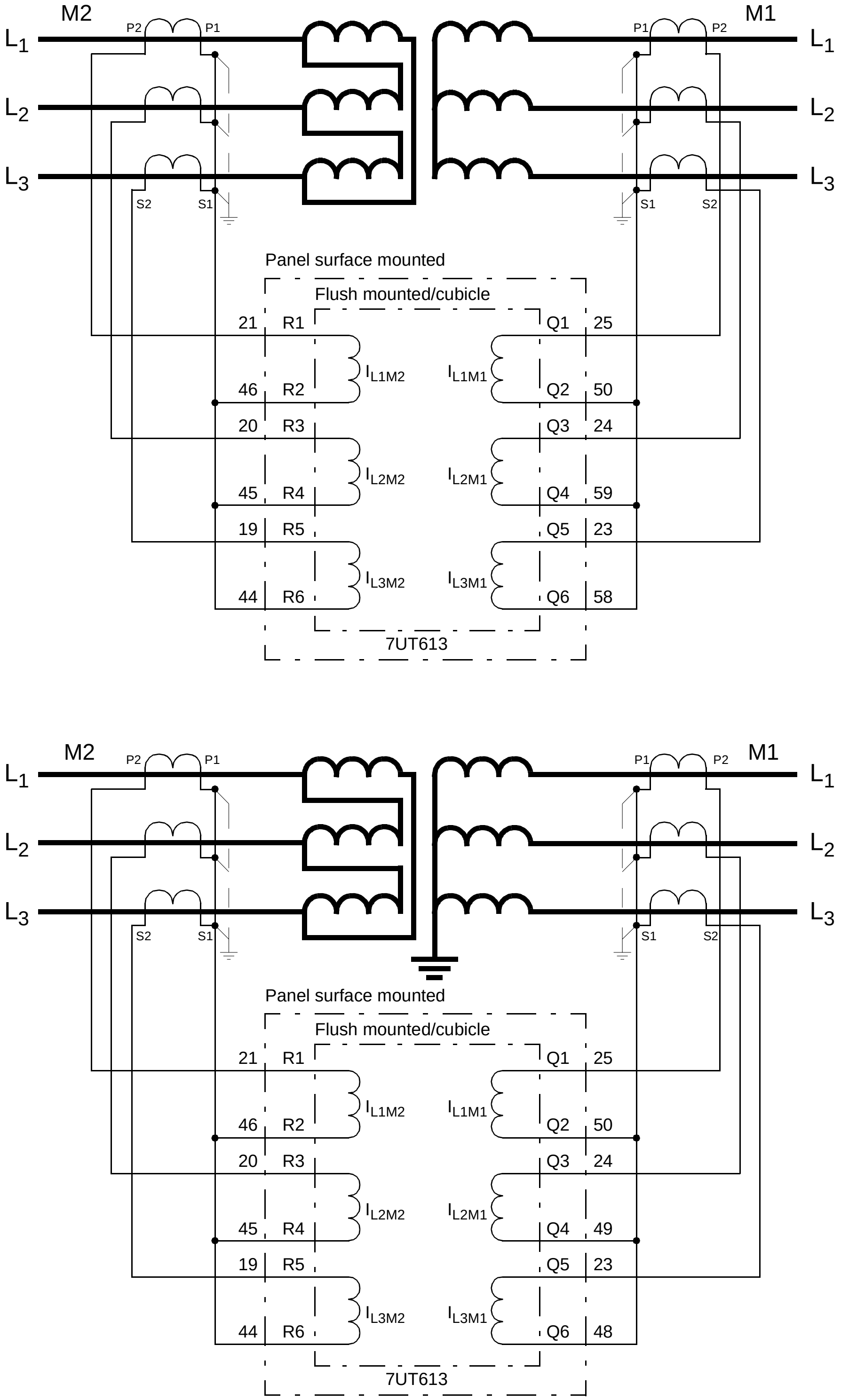


Figure A-10 Connection example 7UT613 for a three-phase power transformer without (above) and with (below) earthed starpoint

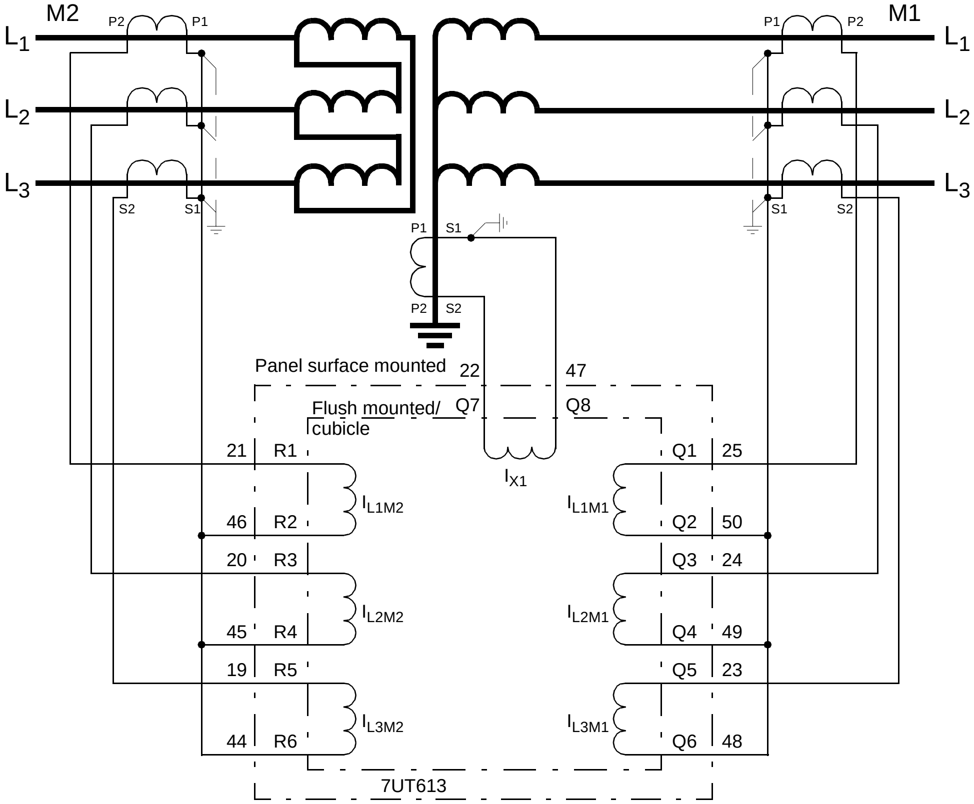


Figure A-11 Connection example 7UT613 for a three-phase power transformer with an earthed starpoint and current transformer between starpoint and earthing point

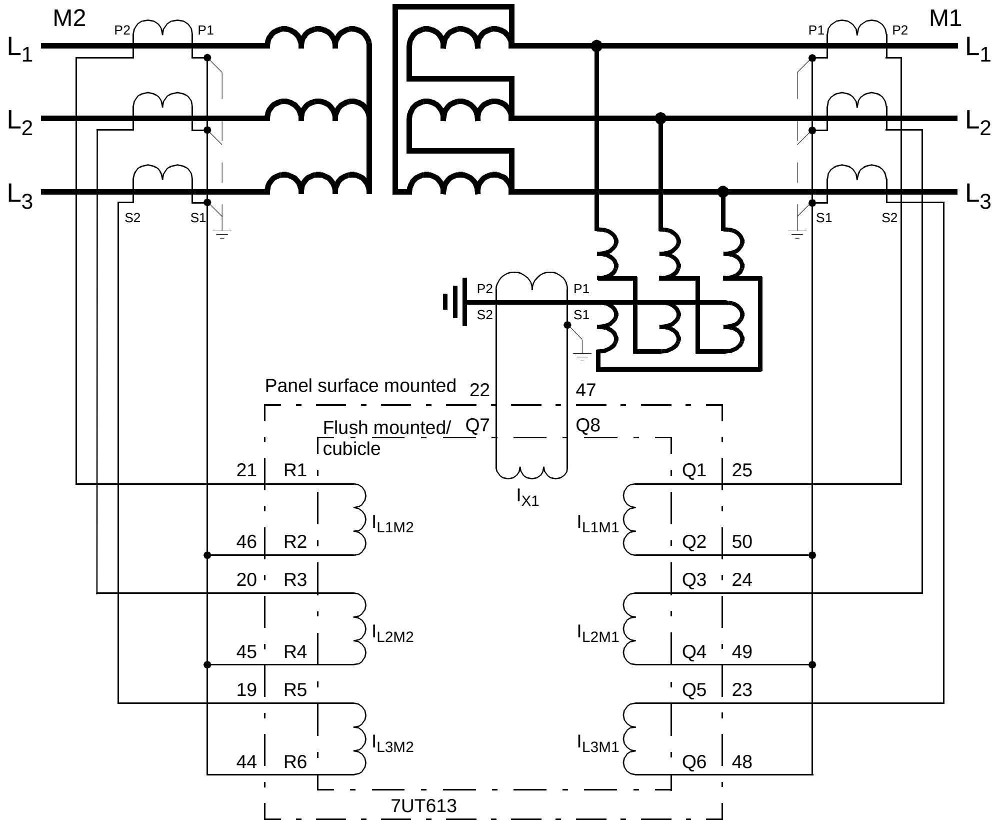


Figure A-12 Connection example 7UT613 for a three-phase power transformer with neutral earthing reactor and current transformer between starpoint and earthing point

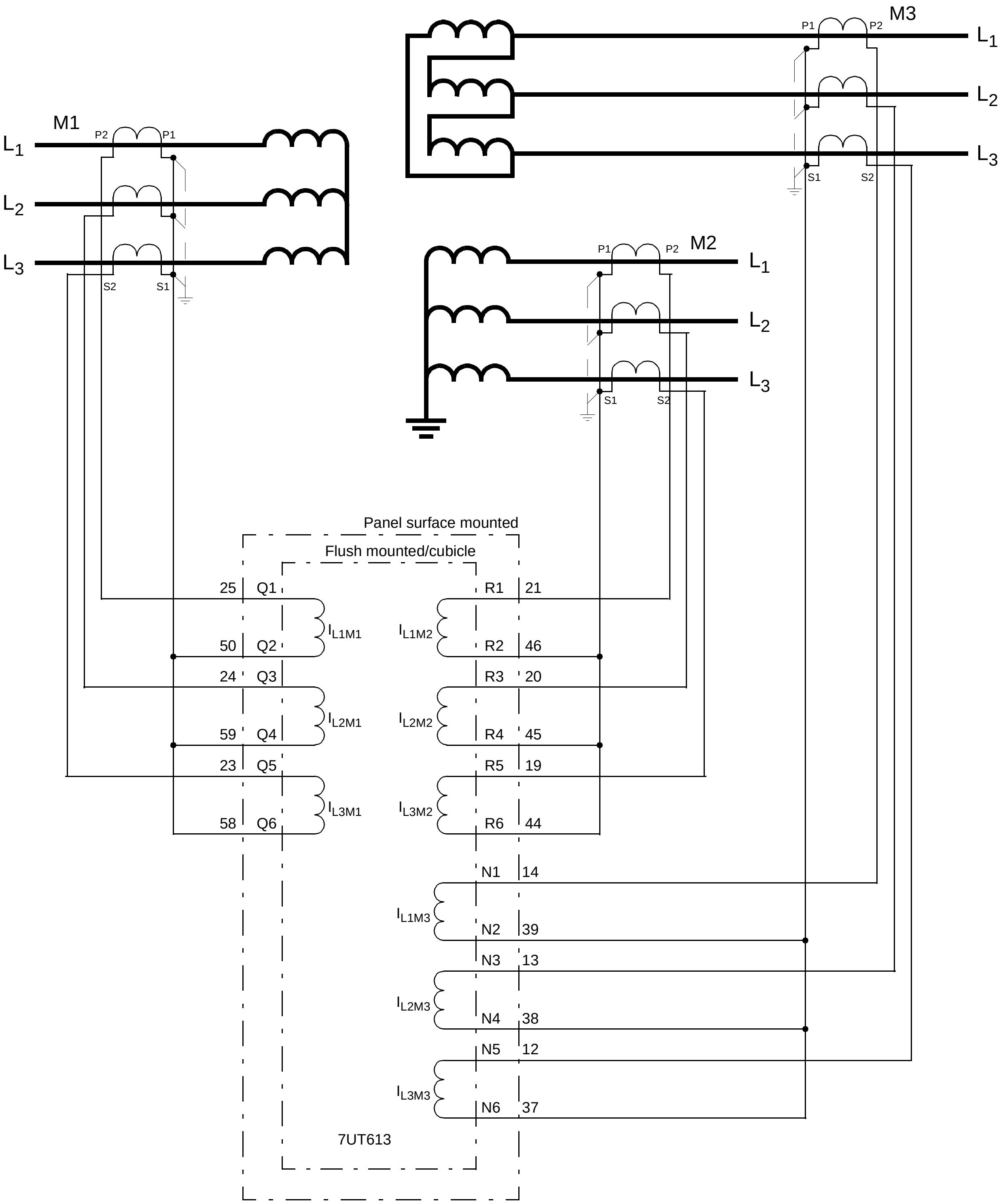


Figure A-13   Connection example 7UT613 for a three-winding power transformer

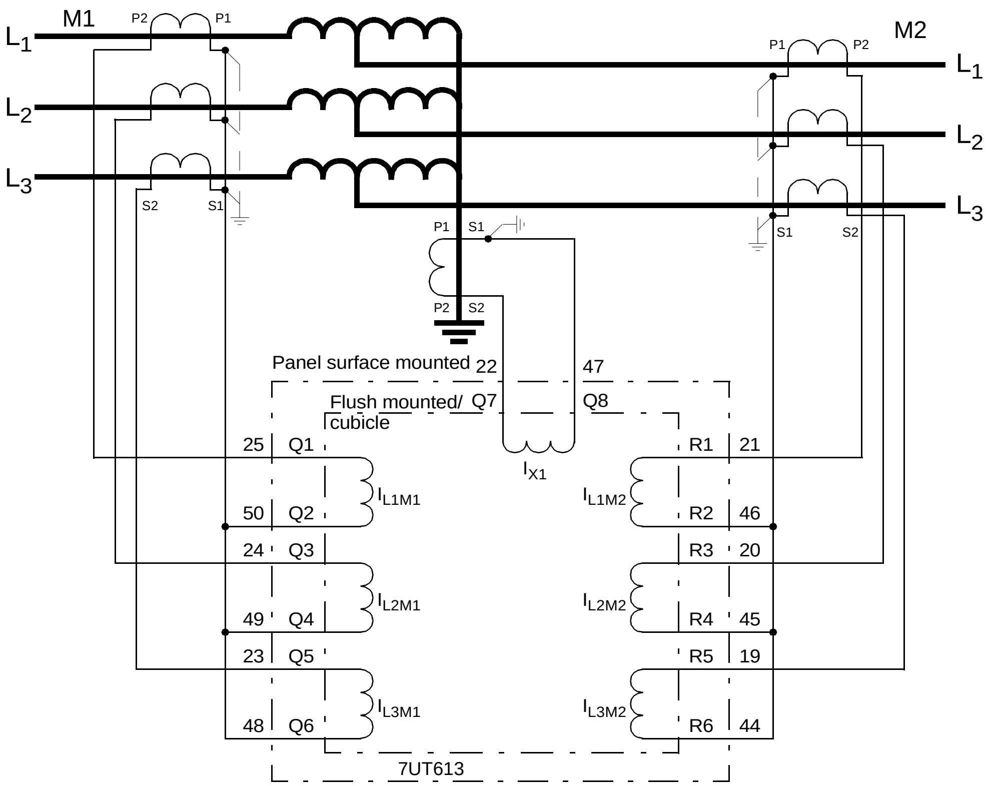


Figure A-14 Connection example 7UT613 for a three-phase auto-transformer with an earthed starpoint and current transformer between starpoint and earthing point

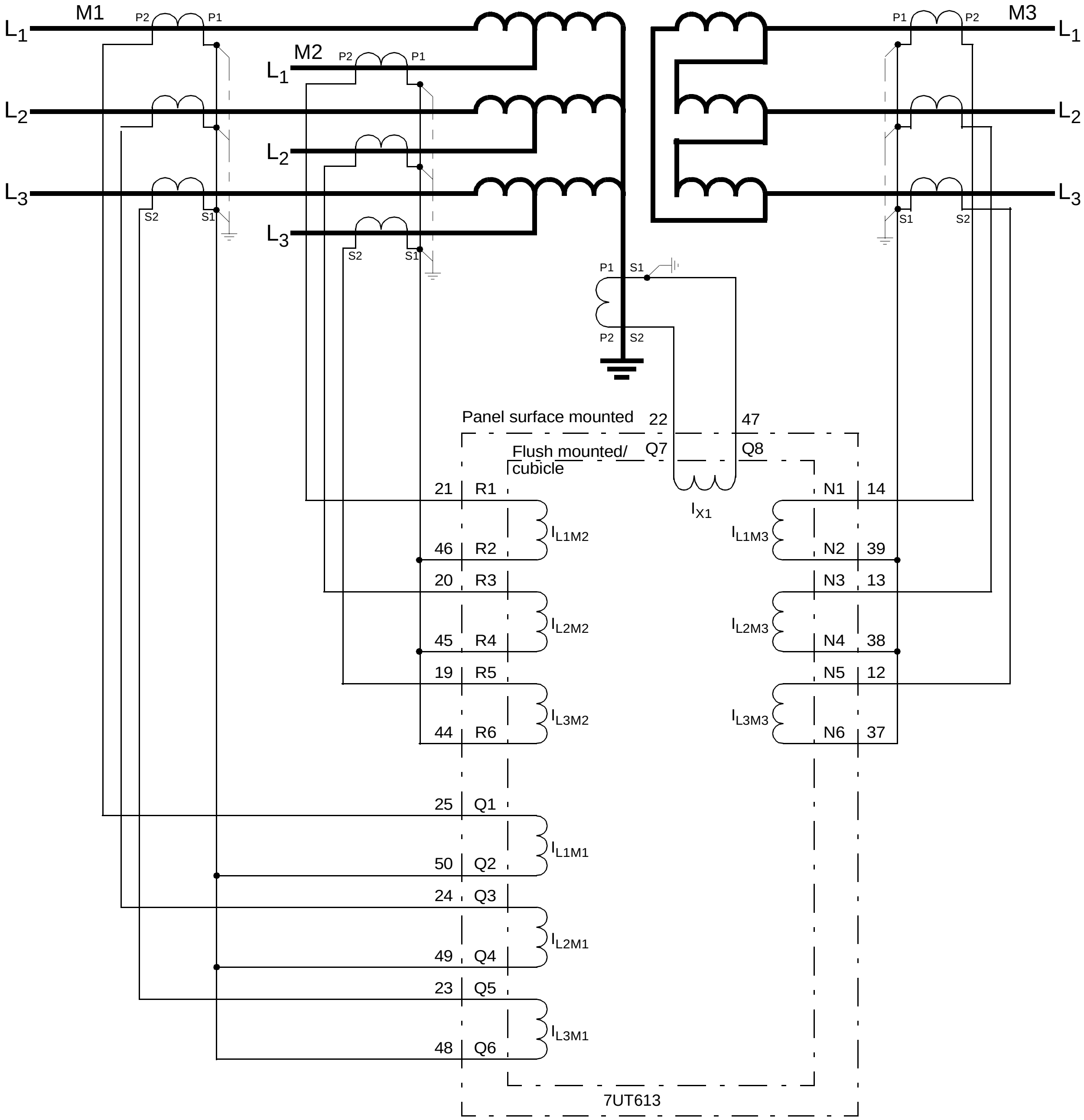


Figure A-15 Connection example 7UT613 for a three-phase auto-transformer with tertiary winding and current transformer between starpoint and earthing point

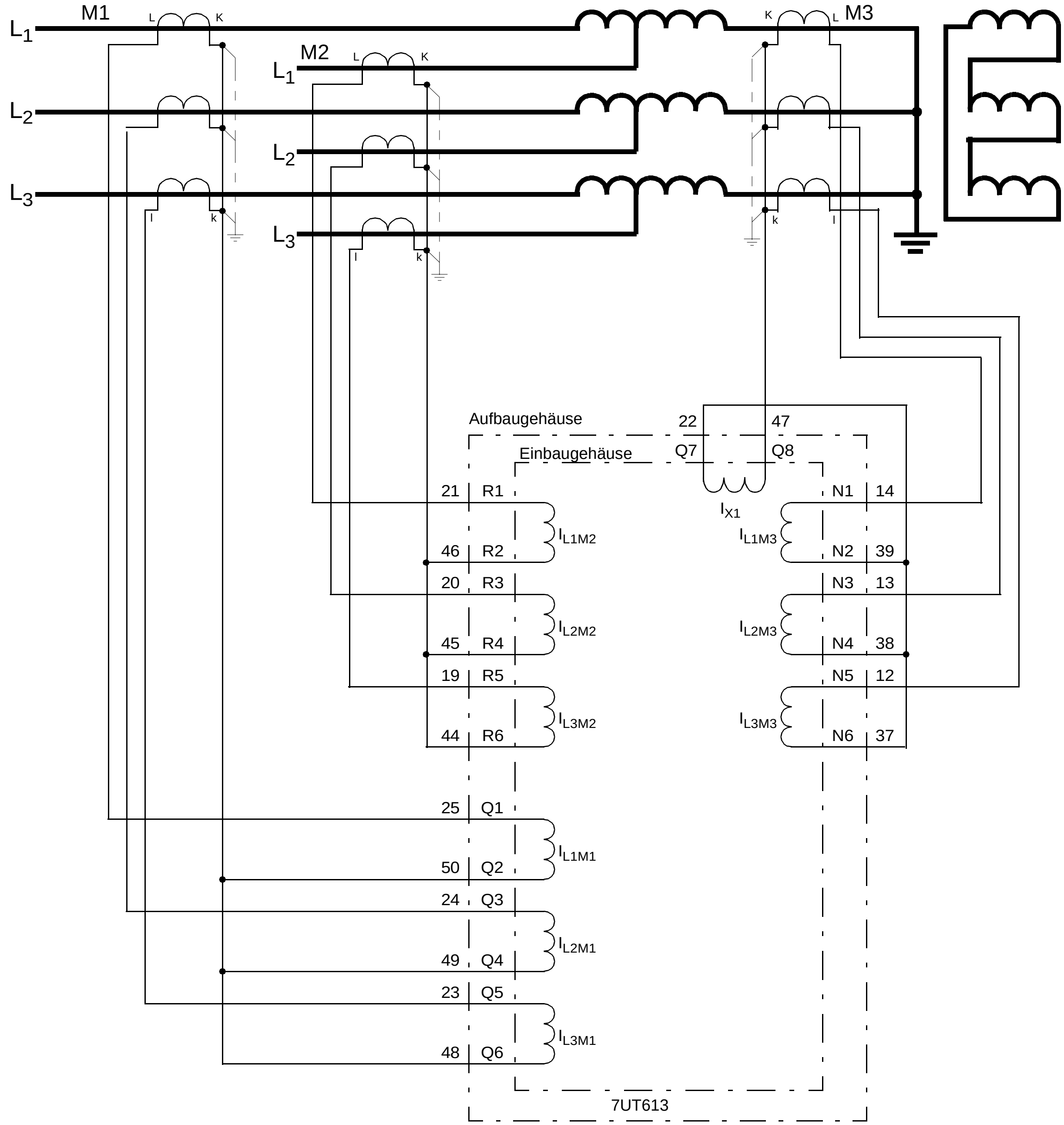


Figure A-16 Connection example 7UT613 for 3 single-phase auto-transformers arranged as a three-phase transformer bank with accessible earth connections fitted with current transformers (M3).
The current transformers in line with the earth connections form a separate side of the protected object allowing current comparison for each transformer of the bank.
The starpoint connection of the current transformers at M3 is fed via an auxiliary 1-phase current input (I_{X1}) which allows for use of the restricted earth fault protection and/or the earth overcurrent protection.

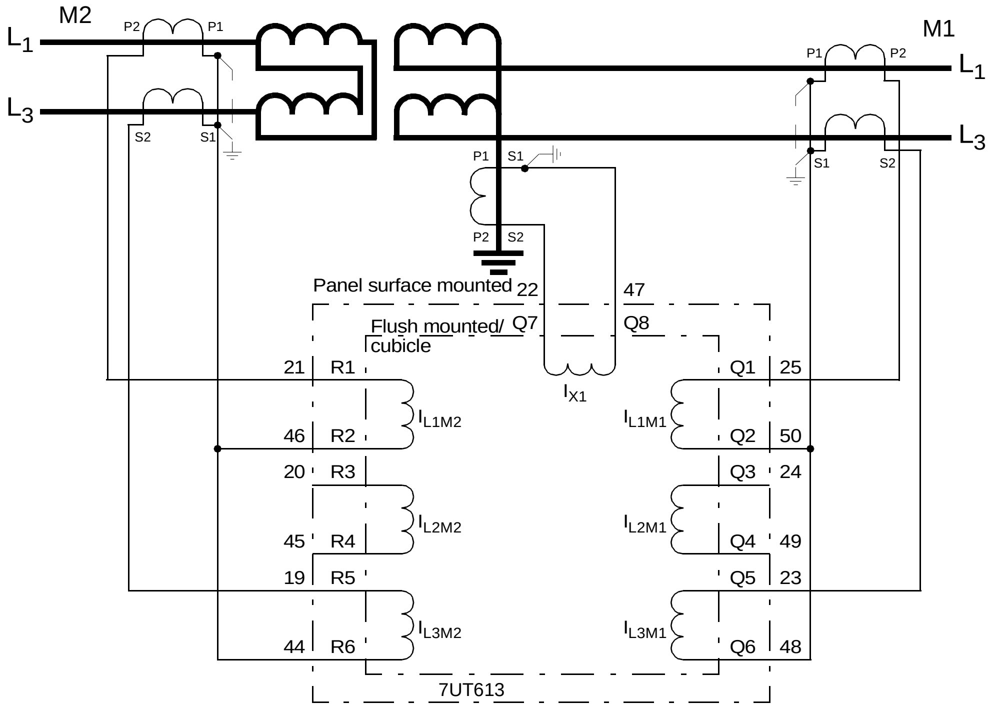


Figure A-17 Connection example 7UT613 for a single-phase power transformer with current transformer between starpoint and earthing point

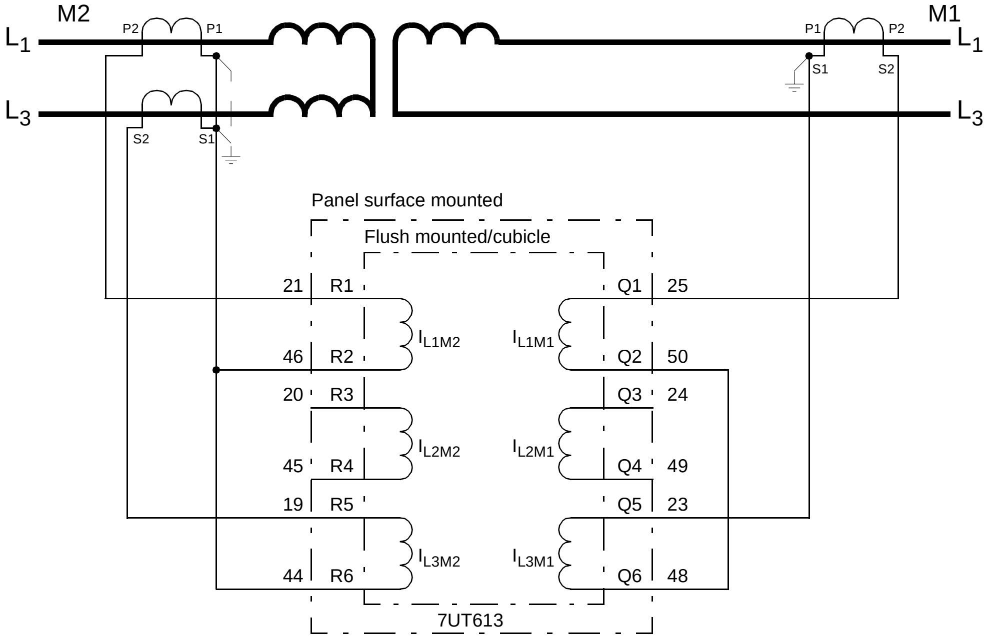


Figure A-18 Connection example 7UT613 for a single-phase power transformer with only one current transformer (right side)

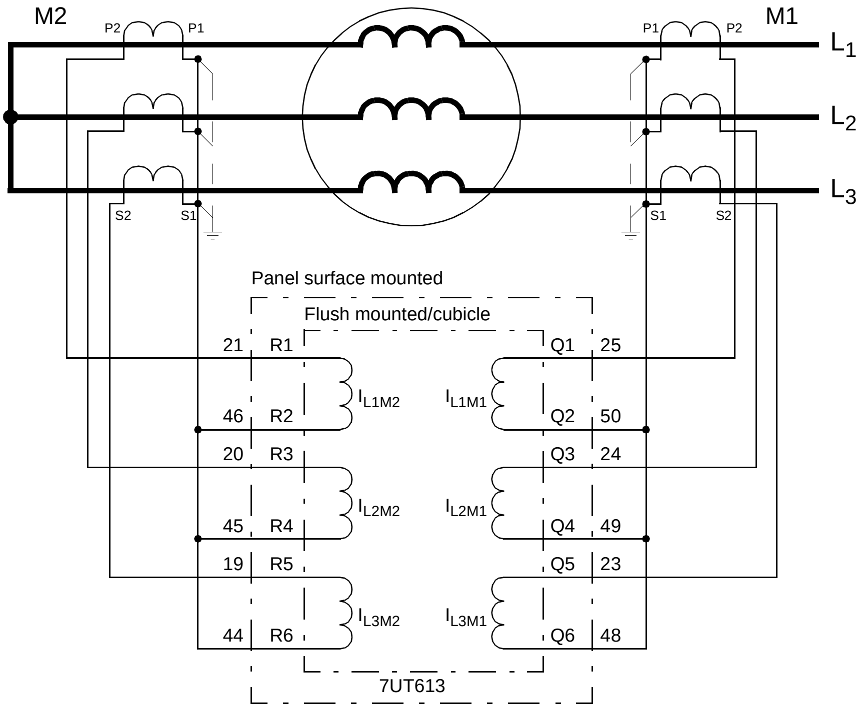


Figure A-19 Connection example 7UT613 for a generator or motor

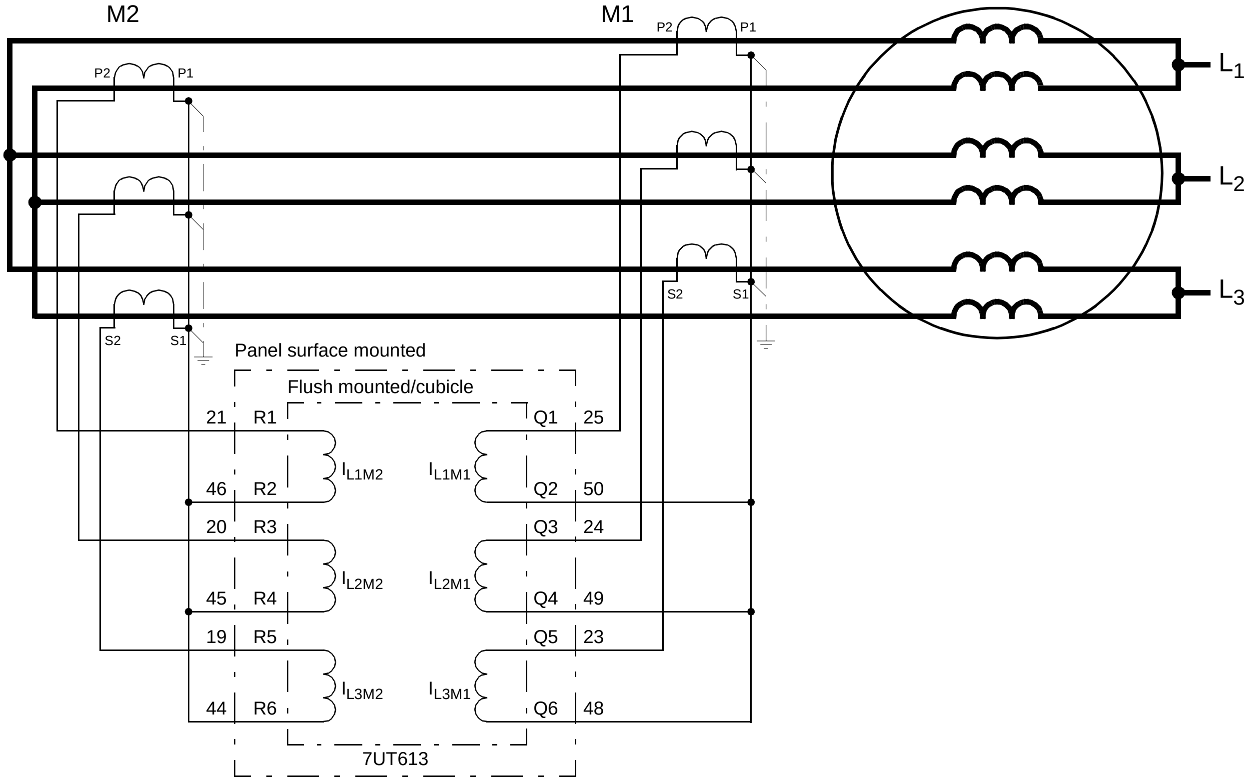


Figure A-20 Connection example 7UT613 as transversal differential protection for a generator with two windings per phase

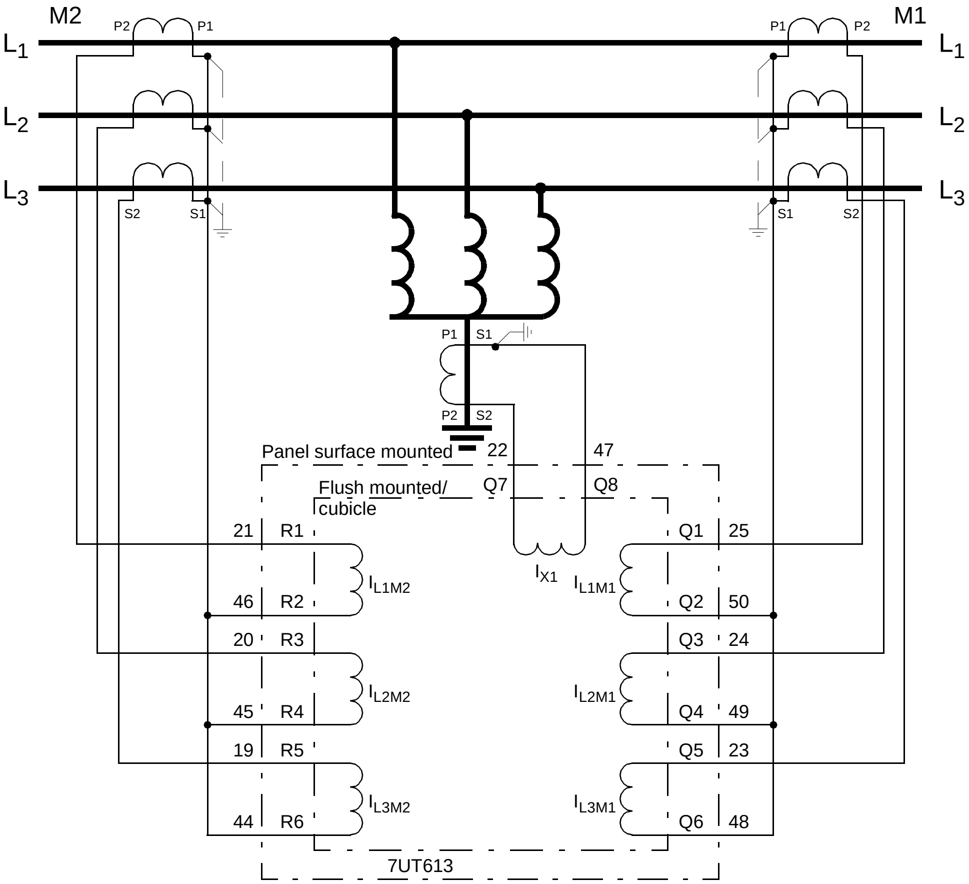


Figure A-21 Connection example 7UT613 for an earthed shunt reactor with current transformer between starpoint and earthing point

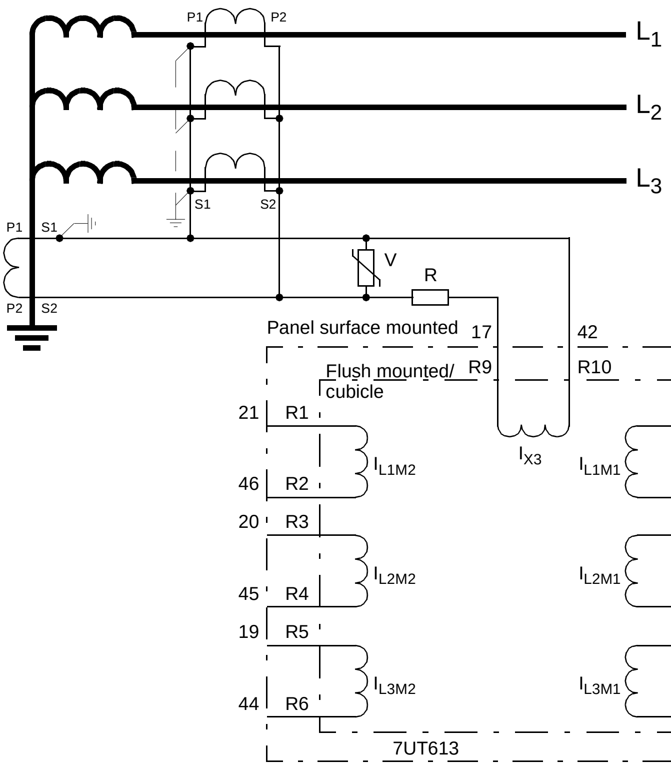


Figure A-22 Connection example 7UT613 as high-impedance protection on a transformer winding with earthed starpoint (the illustration shows the partial connection of the high-impedance protection); I_{X3} connected as high-sensitivity input

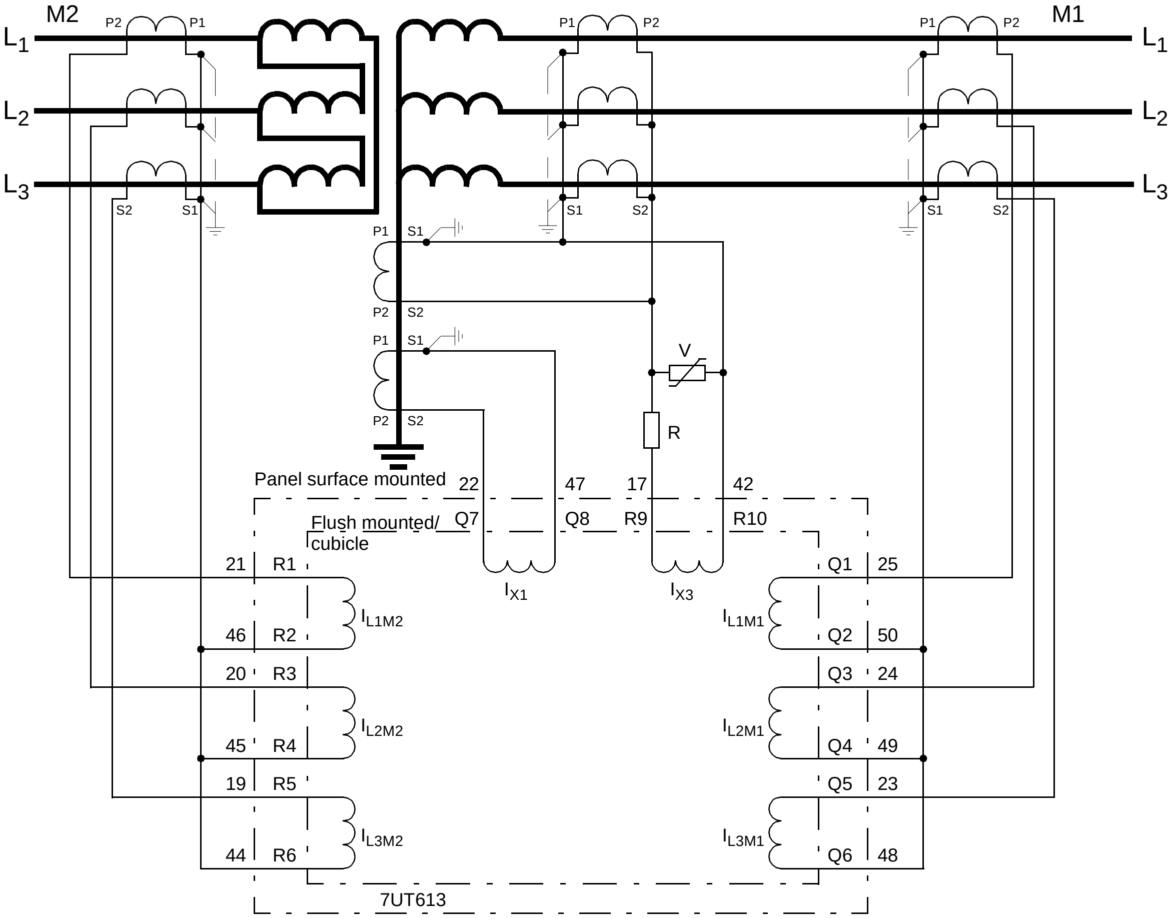


Figure A-23 Connection example 7UT613 for a three-phase power transformer with current transformers between starpoint and earthing point, additional connection for high-impedance protection; I_{X3} connected as high-sensitivity input

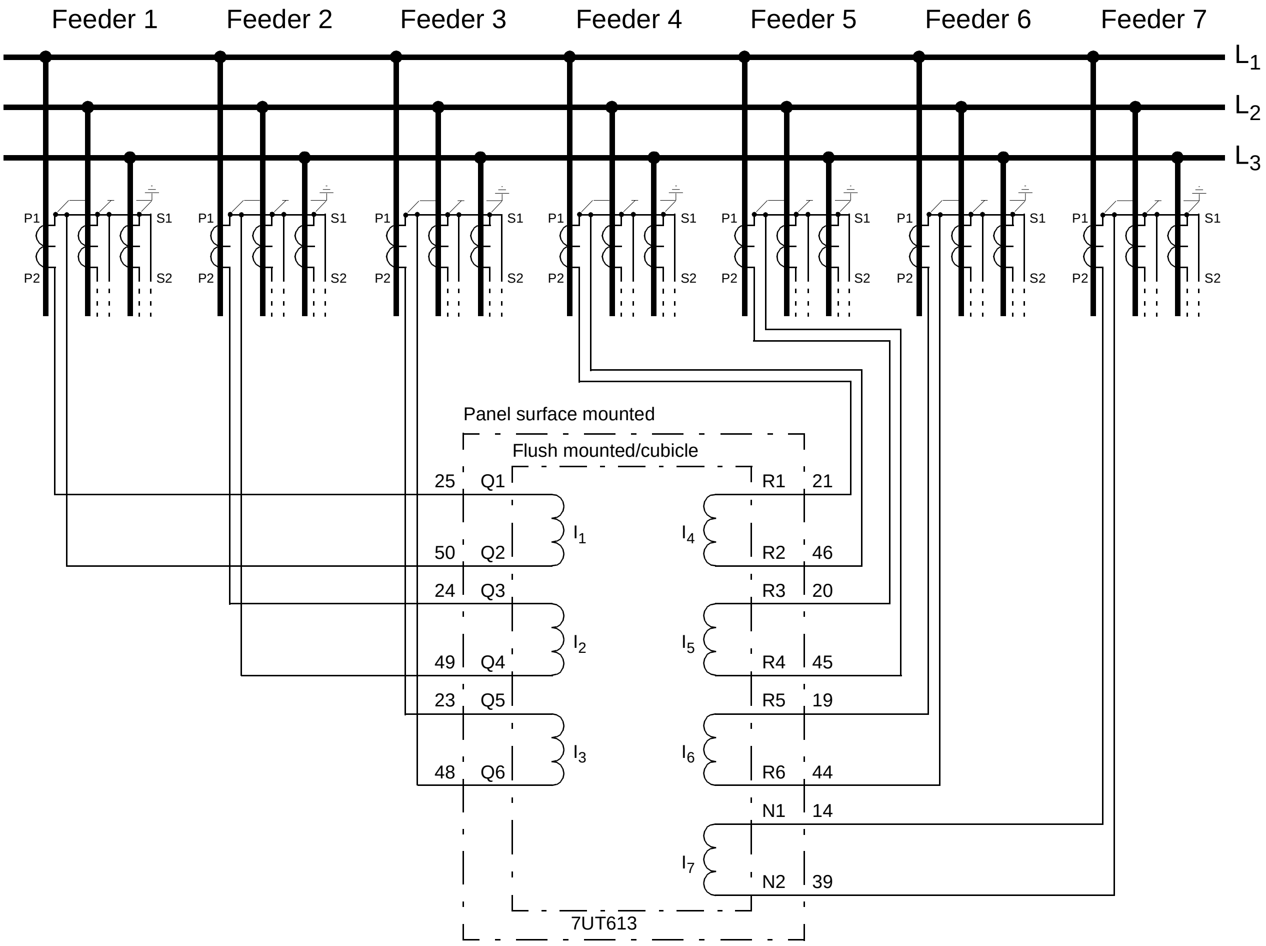


Figure A-24 Connection example 7UT613 as single-phase busbar protection for 7 feeders, illustrated for phase L1

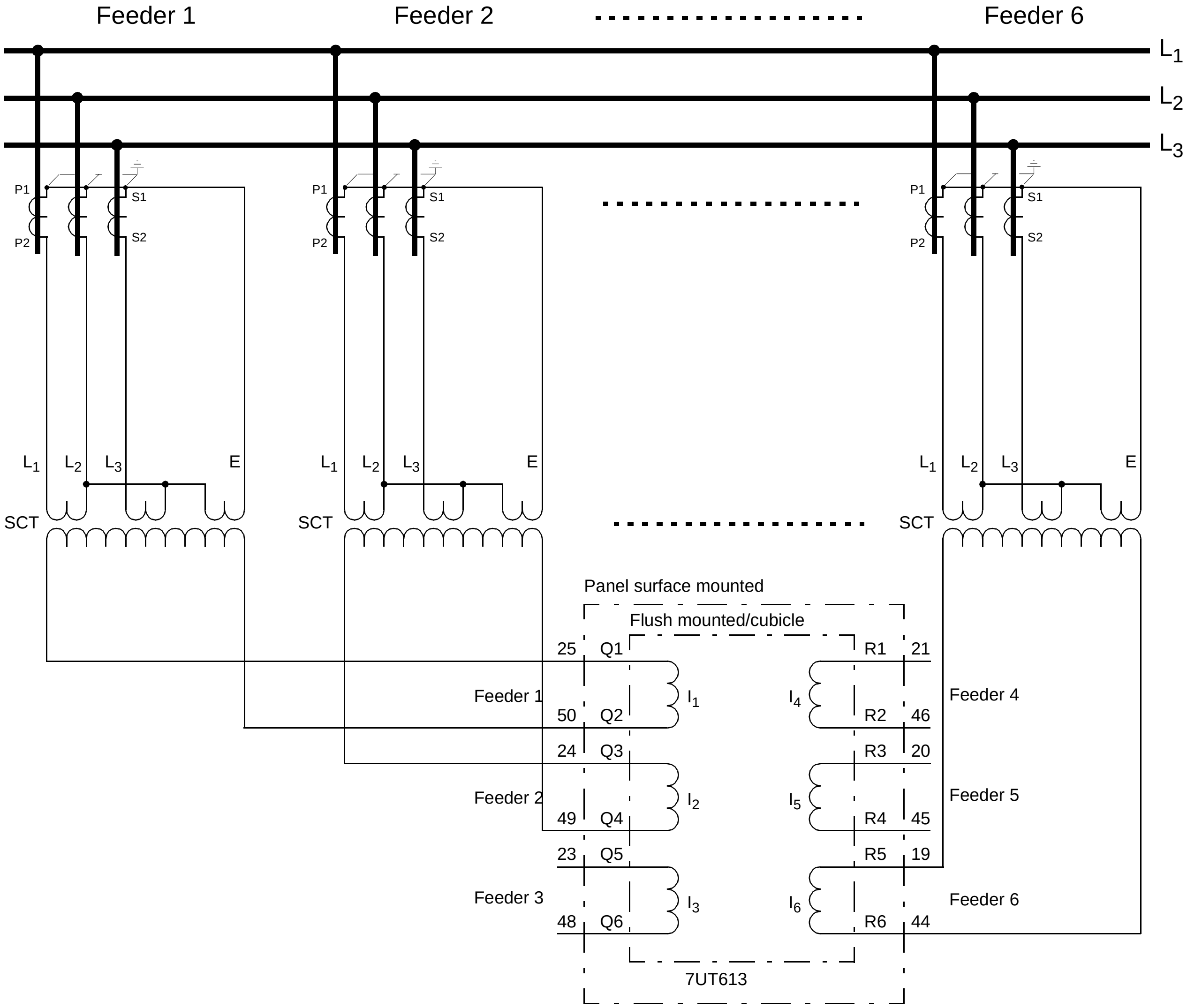
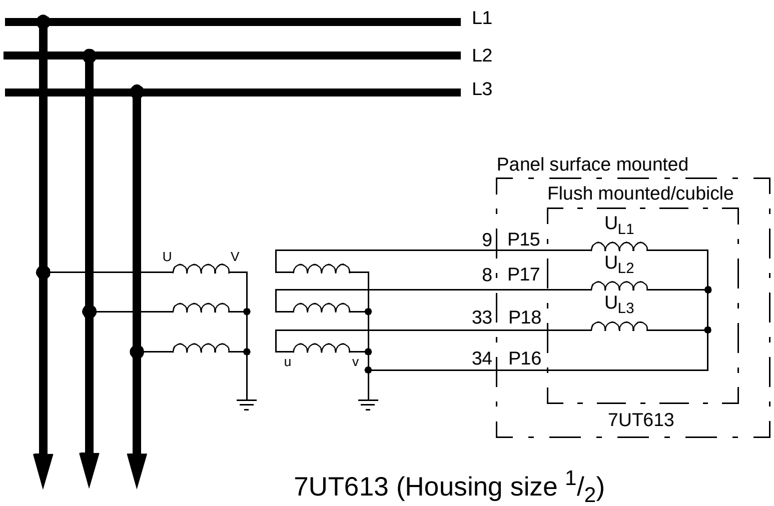
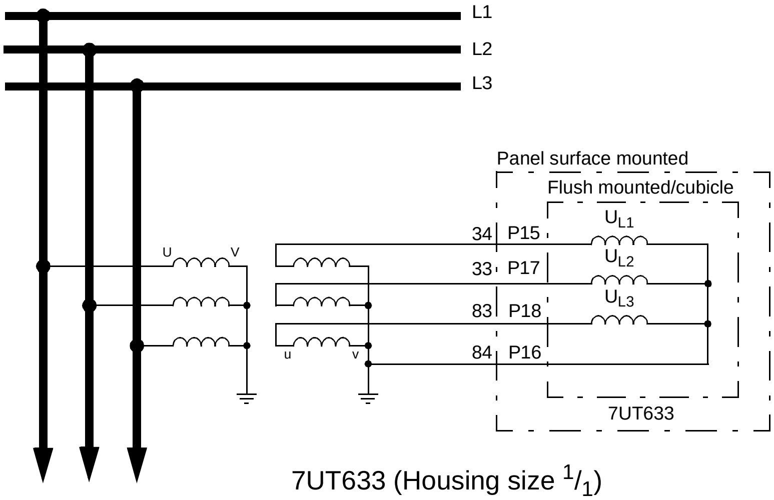


Figure A-25 Connection example 7UT613 as busbar protection for 6 feeders, connected via external summation current transformers (SCT) — partial illustration for feeders 1, 2 and 6

Voltage Transformer Connection Examples

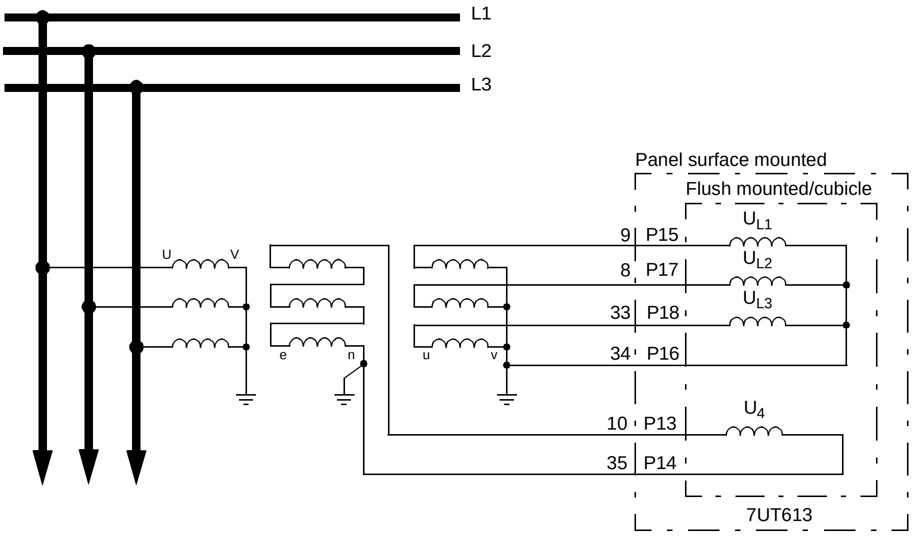


7UT613 (Housing size $^1/_2$)

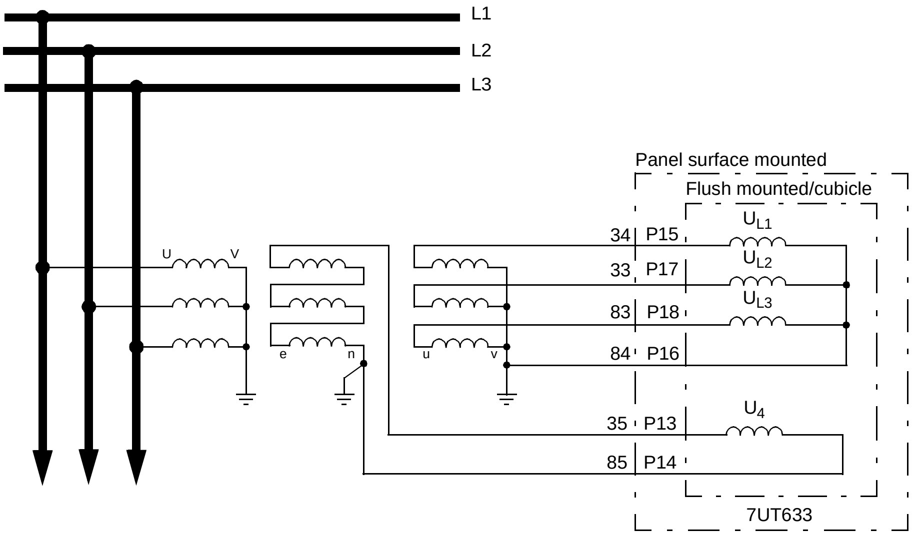


7UT633 (Housing size $^1/_1$)

Figure A-26 Voltage transformer connection to 3 star-connected voltage transformers (7UT613 and 7UT633 only)



7UT613 (Housing size $^1/_2$)



7UT633 (Housing size $^1/_1$)

Figure A-27 Voltage transformer connection to 3 star-connected voltage transformers with additional open-delta winding (e-n-winding) (7UT613 and 7UT633 only)

A.4 Assignment of the Protection Functions to Protected Objects

Not every implemented protection function of 7UT6 is sensible or available for each protected object. Table A-1 lists the corresponding protection functions for each protected object. Once a protected object is configured (according to Section 2.1.1), only the corresponding protective functions specified in the table below will be available and settable.

Table A-1 Overview of protection functions available in protected objects

Protection Function	**Two-Winding Transformer**	**1-Phase Transformer**	**Auto-Transformer**	**Generator / Motor**	**Busbar 3-phase**	**Busbar 1-phase**
Differential protection	X	X	X	X	X	X
Restricted earth fault protection	X	X	—	X	—	—
Time overcurrent protection phases	X	X	X	X	X	—
Time overcurrent protection 3I0	X	—	X	X	X	—
Time overcurrent protection earth	X	X	X	X	X	X
Time overcurrent protection 1-phase	X	X	X	X	X	X
Unbalanced load protection	X	—	X	X	X	—
Overload protection IEC 60255–8	X	X	X	X	X	—
Overload protection IEC 60354	X	X	X	X	X	—
Overexcitation protection	X	X	X	X	X	—
Circuit breaker failure protection	X	X	X	X	X	—
Measured value monitoring	X	X	X	X	X	X
Trip circuit supervision	X	X	X	X	X	X
External trip command 1	X	X	X	X	X	X
External trip command 2	X	X	X	X	X	X
Measured values	X	X	X	X	X	X
Legend:	X Function available			— Function not available		

A.5 Preset Configurations

Binary Inputs

The number of binary inputs depends on the device version. 7UT613 provides 5, 7UT633 has 21, 7UT635 has 29 binary inputs. The inputs BI1 and BI2 are preset:

Table A-2 Preset binary inputs

Binary Input	LCD Text	FNo	Remarks
BI1	>Reset LED	00005	Reset of latched indications, H-active
BI2	>Buchh. Trip	00392	Buchholz protection trip, H-active
further	—	—	No presetting

Binary Outputs (Output Relays)

The number of binary outputs depends on the device version. 7UT613 provides 8, 7UT633 and 7UT635 provide 24 binary outputs. The outputs BO1 to BO4 are preset:

Table A-3 Preset binary outputs

Binary Output	LCD Text	FNo	Remarks
BO1	Relay TRIP	00511	Device (general) trip command, non-latched
BO2	Relay PICKUP	00501	Device (general) pickup, non-latched
BO3	>Buchh. Trip	00392	Buchholz protection trip, non-latched
BO4	Error Sum Alarm Alarm Sum Event	00140 00160	Group alarm of errors and disturbances, non-latched
further	—	—	No presetting

LED Indicators

LED indicators are available on all versions. LED1 to LED3, LED13 and LED14 have the following presetting:

Table A-4 Preset LED indicators

LED	LCD Text	FNo	Remarks
LED1	Relay TRIP	00511	Device (general) trip command, latched
LED2	Relay PICKUP	00501	Device (general) pickup, latched
LED3	>Buchh. Trip	00392	Buchholz protection trip, latched
LED4 to LED12	—	—	no presetting
LED13	Error Sum Alarm Alarm Sum Event	00140 00160	Group alarm of errors and disturbances, non-latched
LED14	FaultConfig/Set	00311	Errors during configuration or setting (inconsistent settings), non-latched

Function keys

The 4 function keys on the front have the following presetting:

Table A-5 Preset function keys

Function key	Brief Text	Remarks
`F1`		Jump to the menu “`Event Log`”
`F2`		Jump to the menu “`Meas. Values pri`” (Measured values, primary)
`F3`		Jump to the menu “`Trip Log`” → “`Last Fault`”
`F4`	>QuitG-TRP	Acknowledge reclosure lock-out (see also Figure A-29)

Default Indications with 4-Line Display

Devices with 4-line alphanumerical display allow the following default indications. The numerical values are examples. Only those display can appear that are reasonable for the actual application. For example, voltages can only displayed if the device provides measured voltage inputs which are configured. Phase L2 not with single-phase power transformers.

3-phase protected objects

```
Pri    Side 1  Side 2
L1     200A    2.00kA
L2     200A    2.00kA
L3     200A    2.00kA
```

```
Pri    Side 1  Side 3
L1     200A     525A
L2     200A     525A
L3     200A     525A
```

```
%      Side 1  Side 2
L1     100.0    100.0
L2     100.0    100.0
L3     100.0    100.0
```

```
%      Side 1  Side 3
L1     100.0    100.0
L2     100.0    100.0
L3     100.0    100.0
```

```
U        Pri       %
L1      63.5kV  100.0
L2      63.5kV  100.0
L3      63.5kV  100.0
```

```
        Diff     Rest
L1      0.00     2.00
L2      0.00     2.00
L3      0.00     2.00
```

```
f= 50.0Hz cosφ= 1.00
S=      38.1MVA
P=      38.1MW
Q=       0.0MVAR
```

1-phase busbar protection

```
Pri
I1= 200A   I4= 200A
I2= 200A   I5= 200A
I3= 200A   I6= 200A
```

```
Pri
I7= 200A   f= 50.0Hz
I8= 200A
I9= 200A
```

```
%
I1= 100.0  I4= 100.0
I2= 100.0  I5= 100.0
I3= 100.0  I6= 100.0
```

```
%
I7= 100.0
I8= 100.0
I9= 100.0
```

```
U        Pri       %
L1      63.5kV  100.0
L2      63.5kV  100.0
L3      63.5kV  100.0
```

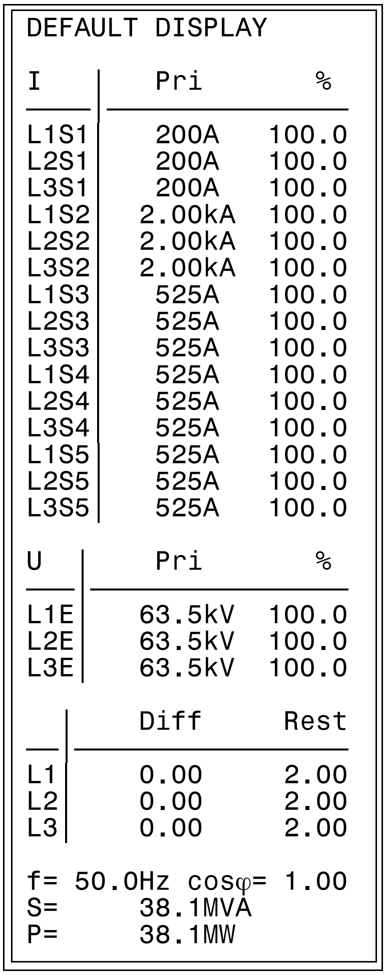
```
        Diff     Rest
L1      0.00     2.00
L2 *)
L3 *)
```

*) depending on connected phase
(Address 396 **PHASE SELECTION**)

Default Indications with Graphic Display

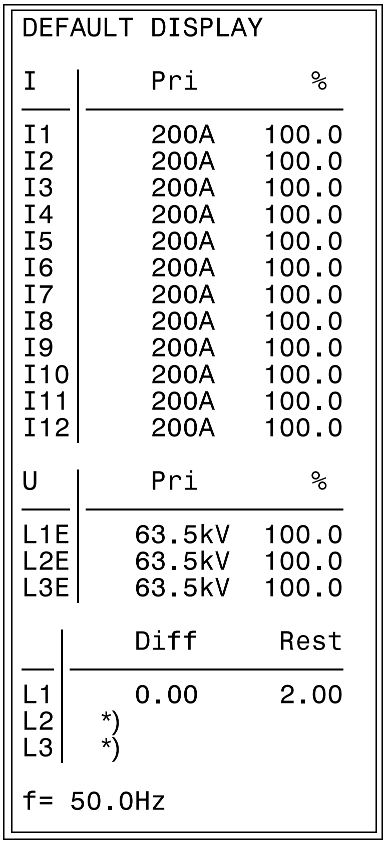
Devices with graphical display allow the following default indications. The numerical values are examples. Only those display can appear that are reasonable for the actual application. For example, voltages can only displayed if the device provides measured voltage inputs which are configured. Phase L2 not with single-phase power transformers.

3-phase protected objects



```
DEFAULT DISPLAY

I    |   Pri       %
-----|---------------
L1S1 |   200A   100.0
L2S1 |   200A   100.0
L3S1 |   200A   100.0
L1S2 | 2.00kA   100.0
L2S2 | 2.00kA   100.0
L3S2 | 2.00kA   100.0
L1S3 |   525A   100.0
L2S3 |   525A   100.0
L3S3 |   525A   100.0
L1S4 |   525A   100.0
L2S4 |   525A   100.0
L3S4 |   525A   100.0
L1S5 |   525A   100.0
L2S5 |   525A   100.0
L3S5 |   525A   100.0

U   |    Pri       %
----|----------------
L1E |  63.5kV  100.0
L2E |  63.5kV  100.0
L3E |  63.5kV  100.0

   |   Diff     Rest
---|-----------------
L1 |   0.00     2.00
L2 |   0.00     2.00
L3 |   0.00     2.00

f= 50.0Hz cosφ= 1.00
S=     38.1MVA
P=     38.1MW
```

1-phase busbar protection



```
DEFAULT DISPLAY

I    |   Pri       %
-----|---------------
I1   |   200A   100.0
I2   |   200A   100.0
I3   |   200A   100.0
I4   |   200A   100.0
I5   |   200A   100.0
I6   |   200A   100.0
I7   |   200A   100.0
I8   |   200A   100.0
I9   |   200A   100.0
I10  |   200A   100.0
I11  |   200A   100.0
I12  |   200A   100.0

U    |   Pri       %
-----|---------------
L1E  | 63.5kV   100.0
L2E  | 63.5kV   100.0
L3E  | 63.5kV   100.0

   |   Diff     Rest
---|-----------------
L1 |   0.00     2.00
L2 | *)
L3 | *)

f= 50.0Hz
```

*) depending on connected phase (Address 396 **PHASE SELECTION**)

Preset CFC-Charts

7UT6 provides worksheets with preset CFC-charts. Figure A-28 shows a chart which changes binary input “>`DataStop`” from single point indication (SP) to internal single point indication (IntSP). According to Figure A-29 an reclosure interlocking will be produced. It interlocks the closure of the circuit breaker after tripping of the device until manual acknowledgement.

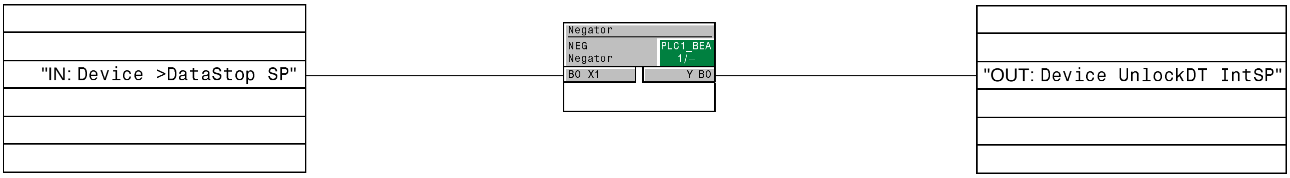


Figure A-28 CFC-chart for transmission block and testing mode

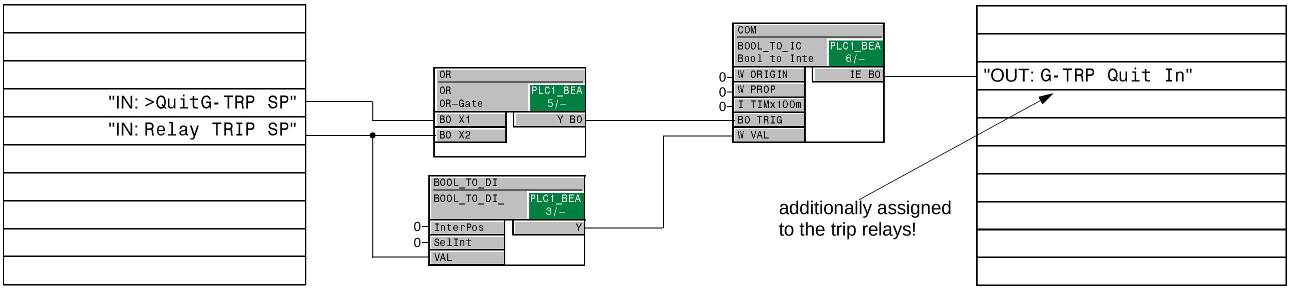


Figure A-29 CFC chart for reclosure lockout

A.6 Protocol Dependent Functions

Protocol → Function ⇓	IEC 60870–5–103	Profibus FMS	Profibus DP	DNP3.0	Modbus ASCII/RTU	Additional Service Interface (optional)
Operational Measured Values	Yes	Yes	Yes	Yes	Yes	Yes
Metered Values	Yes	Yes	Yes	Yes	Yes	Yes
Fault Recording	Yes	Yes	No Only via additional service interface	No Only via additional service interface	No Only via additional service interface	Yes
Protection Setting from Remote	No Only via additional service interface	Yes	No Only via additional service interface	No Only via additional service interface	No Only via additional service interface	Yes
User-specified annunciations and switching objects	Yes	Yes	“User-defined annuncia-tions” in CFC (pre-defined)	“User-defined annuncia-tions” in CFC (pre-defined)	“User-defined annuncia-tions” in CFC (pre-defined)	Yes
Time Synchronization	Via protocol; DCF77/IRIG B; Interface; Binary inputs	Via protocol; DCF77/IRIG B; Interface; Binary inputs	Via DCF77/IRIG B; Interface; Binary inputs	Via protocol; DCF77/IRIG B; Interface; Binary inputs	Via DCF77/IRIG B; Interface; Binary inputs	–
Annunciations with Time stamp	Yes	Yes	No	Yes	No	Yes
Commissioning Aids Alarm and Measured Value Transmission Blocking	Yes	Yes	No	No	No	Yes
Generate Test Annunciations	Yes	Yes	No	No	No	Yes
Physical Mode	Asynchronous	Asynchronous	Asynchronous	Asynchronous	Asynchronous	–
Transmission Mode	cyclical / event	cyclical / event	cyclical	cyclical / event	cyclical	–
Baudrate	4800 to 38400	Up to 1.5 MBaud	Up to 1.5 MBaud	2400 to 19200	2400 to 19200	2400 to 38400
Type	RS232 RS485 Optical fibre	RS485 Optical fibre • Single ring • Double ring	RS485 Optical fibre • Double ring	RS485 Optical fibre	RS485 Optical fibre	RS232 RS485 Optical fibre
Temperature Measuring Device 7XV565						Yes

A.7 List of Settings

Notes:

Depending on the version and the variant ordered some addresses may be missing or have different default settings.

The setting ranges and presettings listed in the following tables refer to a nominal current value I_N = 1 A. For a secondary nominal current value I_N = 5 A the current values are to be multiplied by 5. Referred values are based on the nominal current of the respective side or measuring location, or on the rating of the protected object.

Addresses which have an “A” attached to their end can only be changed in DIGSI®, under “**Additional Settings**”.

Addr.	Setting Title	Setting Options	Default Setting	Comments
103	Grp Chge OPTION	Disabled Enabled	Disabled	Setting Group Change Option
105	PROT. OBJECT	3 phase Transformer 1 phase Transformer Autotransformer Generator/Motor 3 phase Busbar 1 phase Busbar	3 phase Transformer	Protection Object
112	DIFF. PROT.	Disabled Enabled	Enabled	Differential Protection
113	REF PROT.	Disabled Enabled	Disabled	Restricted earth fault protection
117	COLDLOAD PICKUP	Disabled Enabled	Disabled	Cold Load Pickup
120	DMT/IDMT Phase	Disabled Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Disabled	DMT / IDMT Phase
122	DMT/IDMT 3I0	Disabled Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Disabled	DMT / IDMT 3I0

Addr.	Setting Title	Setting Options	Default Setting	Comments
124	DMT/IDMT Earth	Disabled Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Disabled	DMT / IDMT Earth
127	DMT 1PHASE	Disabled Enabled	Disabled	DMT 1Phase
140	UNBALANCE LOAD	Disabled Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI	Disabled	Unbalance Load (Negative Sequence)
142	THERM. OVERLOAD	Disabled using a thermal replica according IEC354	Disabled	Thermal Overload Protection
143	OVEREXC. PROT.	Disabled Enabled	Disabled	Overexcitation Protection (U/f)
170	BREAKER FAILURE	Disabled Enabled	Disabled	Breaker Failure Protection
180	DISCON.MEAS.LOC	Disabled Enabled	Disabled	Disconnect measurment location
181	M.V. SUPERV	Disabled Enabled	Enabled	Measured Values Supervision
182	Trip Cir. Sup.	Disabled with 2 Binary Inputs with 1 Binary Input	Disabled	Trip Circuit Supervision
186	EXT. TRIP 1	Disabled Enabled	Disabled	External Trip Function 1
187	EXT. TRIP 2	Disabled Enabled	Disabled	External Trip Function 2
190	RTD-BOX INPUT	Disabled Port C Port D	Disabled	External Temperature Input
191	RTD CONNECTION	6 RTD simplex operation 6 RTD half duplex operation 12 RTD half duplex operation	6 RTD simplex operation	Ext. Temperature Input Connection Type

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
201	FltDisp.LED/LCD	Device	Display Targets on every Pickup Display Targets on TRIP only	Display Targets on every Pickup	Fault Display on LED / LCD
202	Spont. FltDisp.	Device	NO YES	NO	Spontaneous display of flt.annunciations
204	Start image DD	Device	image 1 image 2 image 3 image 4 image 5 image 6 image 7	image 1	Start image Default Display
211	No Conn.MeasLoc	Power System Data 1	2 3 4 5	3	Number of connected Measuring Locations
212	No AssigMeasLoc	Power System Data 1	2 3 4 5	3	Number of assigned Measuring Locations
213	NUMBER OF SIDES	Power System Data 1	2 3 4 5	3	Number of Sides
216	NUMBER OF ENDS	Power System Data 1	3 4 5 6 7 8 9 10 11 12	6	Number of Ends for 1 Phase Busbar
220	ASSIGNM. 2M,2S	Power System Data 1	S1:M1, S2:M2	S1:M1, S2:M2	Assignment at 2 assig.Meas.Loc./ 2 Sides
221	ASSIGNM. 3M,2S	Power System Data 1	S1:M1+M2, S2:M3 S1:M1, S2:M2+M3	S1:M1+M2, S2:M3	Assignment at 3 assig.Meas.Loc./ 2 Sides
222	ASSIGNM. 3M,3S	Power System Data 1	S1:M1, S2:M2, S3:M3	S1:M1, S2:M2, S3:M3	Assignment at 3 assig.Meas.Loc./ 3 Sides
223	ASSIGNM. 4M,2S	Power System Data 1	S1:M1+M2, S2:M3+M4 S1:M1+M2+M3, S2:M4 S1:M1, S2:M2+M3+M4	S1:M1+M2, S2:M3+M4	Assignment at 4 assig.Meas.Loc./ 2 Sides

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
224	ASSIGNM. 4M,3S	Power System Data 1	S1:M1+M2, S2:M3, S3:M4 S1:M1, S2:M2+M3, S3:M4 S1:M1, S2:M2, S3:M3+M4	S1:M1+M2, S2:M3, S3:M4	Assignment at 4 assig.Meas.Loc./ 3 Sides
225	ASSIGNM. 4M,4S	Power System Data 1	S1:M1, S2:M2, S3:M3, S4:M4	S1:M1, S2:M2, S3:M3, S4:M4	Assignment at 4 assig.Meas.Loc./ 4 Sides
226	ASSIGNM. 5M,2S	Power System Data 1	S1:M1+M2+M3, S2:M4+M5 S1:M1+M2, S2:M3+M4+M5 S1:M1+M2+M3+M4, S2:M5 S1:M1, S2:M2+M3+M4+M5	S1:M1+M2+M3, S2:M4+M5	Assignment at 5 assig.Meas.Loc./ 2 Sides
227	ASSIGNM. 5M,3S	Power System Data 1	S1:M1+M2, S2:M3+M4, S3:M5 S1:M1+M2, S2:M3, S3:M4+M5 S1:M1, S2:M2+M3, S3:M4+M5 S1:M1+M2+M3, S2:M4, S3:M5 S1:M1, S2:M2+M3+M4, S3:M5 S1:M1, S2:M2, S3:M3+M4+M5	S1:M1+M2, S2:M3+M4, S3:M5	Assignment at 5 assig.Meas.Loc./ 3 Sides
228	ASSIGNM. 5M,4S	Power System Data 1	S1:M1+M2, S2:M3, S3:M4, S4:M5 S1:M1, S2:M2+M3, S3:M4, S4:M5 S1:M1, S2:M2, S3:M3+M4, S4:M5 S1:M1, S2:M2, S3:M3, S4:M4+M5	S1:M1+M2, S2:M3, S3:M4, S4:M5	Assignment at 5 assig.Meas.Loc./ 4 Sides
229	ASSIGNM. 5M,5S	Power System Data 1	S1:M1, S2:M2, S3:M3, S4:M4, S5:M5	S1:M1, S2:M2, S3:M3, S4:M4, S5:M5	Assignment at 5 assig.Meas.Loc./ 5 Sides
230	ASSIGNM. ERROR	Power System Data 1	number of assigned measuring locations number of sides	without	Assignment Error
241	SIDE 1	Power System Data 1	auto-connected	auto-connected	Side 1 is assigned to
242	SIDE 2	Power System Data 1	auto-connected	auto-connected	Side 2 is assigned to
243	SIDE 3	Power System Data 1	auto-connected compensation earthing electrode	auto-connected	Side 3 is assigned to

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
244	SIDE 4	Power System Data 1	auto-connected compensation earthing electrode	compensation	Side 4 is assigned to
251	AUX. CT IX1	Power System Data 1	not connected connected / not assigned Side 1 earth Side 2 earth Side 3 earth Side 4 earth Measurement location 1 earth Measurement location 2 earth Measurement location 3 earth Measurement location 4 earth	not connected	Auxiliary CT IX1 is used as
252	AUX. CT IX2	Power System Data 1	not connected connected / not assigned Side 1 earth Side 2 earth Side 3 earth Side 4 earth Measurement location 1 earth Measurement location 2 earth Measurement location 3 earth Measurement location 4 earth	not connected	Auxiliary CT IX2 is used as
253	AUX. CT IX3	Power System Data 1	not connected connected / not assigned Side 1 earth Side 2 earth Side 3 earth Side 4 earth Measurement location 1 earth Measurement location 2 earth Measurement location 3 earth Measurement location 4 earth	not connected	Auxiliary CT IX3 is used as

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
254	AUX. CT IX4	Power System Data 1	not connected connected / not assigned Side 1 earth Side 2 earth Side 3 earth Side 4 earth Side 5 earth Measurement location 1 earth Measurement location 2 earth Measurement location 3 earth Measurement location 4 earth Measurement location 5 earth	not connected	Auxiliary CT IX4 is used as
255	AUX CT IX3 TYPE	Power System Data 1	1A/5A current input sensitiv current input	1A/5A current input	Type of auxiliary CT IX3
256	AUX CT IX4 TYPE	Power System Data 1	1A/5A current input sensitiv current input	1A/5A current input	Type of auxiliary CT IX4
261	VT SET	Power System Data 1	not connected Side 1 Side 2 Side 3 Measuring location 1 Measuring location 2 Measuring location 3 Busbar	Measuring location 1	VT set UL1, UL2, UL3 is connected to
262	VT U4	Power System Data 1	not connected connected / not assigned Side 1 Side 2 Side 3 Measuring location 1 Measuring location 2 Measuring location 3 Busbar	Measuring location 1	VT U4 is connected to
263	VT U4 TYPE	Power System Data 1	Udelta transformer UL1E transformer UL2E transformer UL3E transformer UL12 transformer UL23 transformer UL31 transformer Ux reference transformer	Udelta transformer	VT U4 is used as
270	Rated Frequency	Power System Data 1	50 Hz 60 Hz 16,7 Hz	50 Hz	Rated Frequency

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
271	PHASE SEQ.	Power System Data 1	L1 L2 L3 L1 L3 L2	L1 L2 L3	Phase Sequence
276	TEMP. UNIT	Power System Data 1	Degree Celsius Degree Fahrenheit	Degree Celsius	Unit of temperature measurement
302	CHANGE	Change Group	Group A Group B Group C Group D Binary Input Protocol	Group A	Change to Another Setting Group
311	UN-PRI SIDE 1	Power System Data 1	0.4..800.0 kV	110.0 kV	Rated Primary Voltage Side 1
312	SN SIDE 1	Power System Data 1	0.20..5000.00 MVA	38.10 MVA	Rated Apparent Power of Transf. Side 1
313	STARPNT SIDE 1	Power System Data 1	Solid Earthed Isolated	Solid Earthed	Starpoint of Side 1 is
314	CONNECTION S1	Power System Data 1	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 1
321	UN-PRI SIDE 2	Power System Data 1	0.4..800.0 kV	11.0 kV	Rated Primary Voltage Side 2
322	SN SIDE 2	Power System Data 1	0.20..5000.00 MVA	38.10 MVA	Rated Apparent Power of Transf. Side 2
323	STARPNT SIDE 2	Power System Data 1	Solid Earthed Isolated	Solid Earthed	Starpoint of Side 2 is
324	CONNECTION S2	Power System Data 1	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 2
325	VECTOR GRP S2	Power System Data 1	0 1 2 3 4 5 6 7 8 9 10 11	0	Vector Group Numeral of Side 2
331	UN-PRI SIDE 3	Power System Data 1	0.4..800.0 kV	11.0 kV	Rated Primary Voltage Side 3
332	SN SIDE 3	Power System Data 1	0.20..5000.00 MVA	10.00 MVA	Rated Apparent Power of Transf. Side 3
333	STARPNT SIDE 3	Power System Data 1	Solid Earthed Isolated	Solid Earthed	Starpoint of Side 3 is

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
334	CONNECTION S3	Power System Data 1	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 3
335	VECTOR GRP S3	Power System Data 1	0 1 2 3 4 5 6 7 8 9 10 11	0	Vector Group Numeral of Side 3
341	UN-PRI SIDE 4	Power System Data 1	0.4..800.0 kV	11.0 kV	Rated Primary Voltage Side 4
342	SN SIDE 4	Power System Data 1	0.20..5000.00 MVA	10.00 MVA	Rated Apparent Power of Transf. Side 4
343	STARPNT SIDE 4	Power System Data 1	Solid Earthed Isolated	Solid Earthed	Starpoint of Side 4 is
344	CONNECTION S4	Power System Data 1	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 4
345	VECTOR GRP S4	Power System Data 1	0 1 2 3 4 5 6 7 8 9 10 11	0	Vector Group Numeral of Side 4
351	UN-PRI SIDE 5	Power System Data 1	0.4..800.0 kV	11.0 kV	Rated Primary Voltage Side 5
352	SN SIDE 5	Power System Data 1	0.20..5000.00 MVA	10.00 MVA	Rated Apparent Power of Transf. Side 5
353	STARPNT SIDE 5	Power System Data 1	Solid Earthed Isolated	Solid Earthed	Starpoint of Side 5 is
354	CONNECTION S5	Power System Data 1	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 5

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
355	VECTOR GRP S5	Power System Data 1	0 1 2 3 4 5 6 7 8 9 10 11	0	Vector Group Numeral of Side 5
361	UN GEN/MOTOR	Power System Data 1	0.4..800.0 kV	21.0 kV	Rated Primary Voltage Generator/Motor
362	SN GEN/MOTOR	Power System Data 1	0.20..5000.00 MVA	70.00 MVA	Rated Apparent Power of the Generator
370	UN BUSBAR	Power System Data 1	0.4..800.0 kV	110.0 kV	Rated Primary Voltage Busbar
371	I PRIMARY OP.	Power System Data 1	1..100000 A	200 A	Primary Operating Current of Busbar
372	I PRIMARY OP S1	Power System Data 1	1..100000 A	200 A	Primary Operating Current Side 1
373	I PRIMARY OP S2	Power System Data 1	1..100000 A	200 A	Primary Operating Current Side 2
374	I PRIMARY OP S3	Power System Data 1	1..100000 A	200 A	Primary Operating Current Side 3
375	I PRIMARY OP S4	Power System Data 1	1..100000 A	200 A	Primary Operating Current Side 4
376	I PRIMARY OP S5	Power System Data 1	1..100000 A	200 A	Primary Operating Current Side 5
381	I PRIMARY OP 1	Power System Data 1	1..100000 A	200 A	Primary Operating Current End 1
382	I PRIMARY OP 2	Power System Data 1	1..100000 A	200 A	Primary Operating Current End 2
383	I PRIMARY OP 3	Power System Data 1	1..100000 A	200 A	Primary Operating Current End 3
384	I PRIMARY OP 4	Power System Data 1	1..100000 A	200 A	Primary Operating Current End 4
385	I PRIMARY OP 5	Power System Data 1	1..100000 A	200 A	Primary Operating Current End 5
386	I PRIMARY OP 6	Power System Data 1	1..100000 A	200 A	Primary Operating Current End 6
387	I PRIMARY OP 7	Power System Data 1	1..100000 A	200 A	Primary Operating Current End 7

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
388	I PRIMARY OP 8	Power System Data 1	1..100000 A	200 A	Primary Operating Current End 8
389	I PRIMARY OP 9	Power System Data 1	1..100000 A	200 A	Primary Operating Current End 9
390	I PRIMARY OP 10	Power System Data 1	1..100000 A	200 A	Primary Operating Current End 10
391	I PRIMARY OP 11	Power System Data 1	1..100000 A	200 A	Primary Operating Current End 11
392	I PRIMARY OP 12	Power System Data 1	1..100000 A	200 A	Primary Operating Current End 12
396	PHASE SELECTION	Power System Data 1	Phase 1 Phase 2 Phase 3	Phase 1	Phase selection
403	I PRIMARY OP M3	Power System Data 1	1..100000 A	200 A	Primary Operating Current Meas. Loc. 3
404	I PRIMARY OP M4	Power System Data 1	1..100000 A	200 A	Primary Operating Current Meas. Loc. 4
405	I PRIMARY OP M5	Power System Data 1	1..100000 A	200 A	Primary Operating Current Meas. Loc. 5
408	UN-PRI M3	Power System Data 1	0.4..800.0 kV	110.0 kV	Rated Primary Voltage Measuring Loc. 3
409	UN-PRI U4	Power System Data 1	0.4..800.0 kV	110.0 kV	Rated Primary Voltage U4
413	REF PROT. AT	Power System Data 1	Side 1 Side 2 Side 3 Side 4 Side 5 auto-connected not assigned measuring location 3 not assigned measuring location 4 not assigned measuring location 5	Side 1	Restricted earth fault prot. assigned to
420	DMT/IDMT Ph AT	Power System Data 1	Side 1 Side 2 Side 3 Side 4 Side 5 Measuring location 1 Measuring location 2 Measuring location 3 Measuring location 4 Measuring location 5	Side 1	DMT / IDMT Phase assigned to

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
422	DMT/IDMT 3I0 AT	Power System Data 1	Side 1 Side 2 Side 3 Side 4 Side 5 Measuring location 1 Measuring location 2 Measuring location 3 Measuring location 4 Measuring location 5	Side 1	DMT / IDMT 3I0 assigned to
424	DMT/IDMT E AT	Power System Data 1	no assignment possible Auxiliary CT IX1 Auxiliary CT IX2 Auxiliary CT IX3 Auxiliary CT IX4	Auxiliary CT IX1	DMT / IDMT Earth assigned to
427	DMT 1PHASE AT	Power System Data 1	no assignment possible Auxiliary CT IX1 Auxiliary CT IX2 Auxiliary CT IX3 Auxiliary CT IX4	Auxiliary CT IX1	DMT 1Phase assigned to
440	UNBAL. LOAD AT	Power System Data 1	Side 1 Side 2 Side 3 Side 4 Side 5 Measuring location 1 Measuring location 2 Measuring location 3 Measuring location 4 Measuring location 5	Side 1	Unbalance Load (Neg. Seq.) assigned to
442	THERM. O/L AT	Power System Data 1	Side 1 Side 2 Side 3 Side 4 Side 5	Side 1	Thermal Overload Protection assigned to
470	BREAKER FAIL.AT	Power System Data 1	Side 1 Side 2 Side 3 Side 4 Side 5 Measuring location 1 Measuring location 2 Measuring location 3 Measuring location 4 Measuring location 5 External switchgear 1	Side 1	Breaker Failure Protection assigned to
511	STRPNT->OBJ M1	Power System Data 1	YES NO	YES	CT-Strpnt. Meas. Loc.1 in Dir. of Object
512	IN-PRI CT M1	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current Meas. Loc. 1

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
513	IN-SEC CT M1	Power System Data 1	1A 5A	1A	CT Rated Secondary Current Meas. Loc. 1
521	STRPNT->OBJ M2	Power System Data 1	YES NO	YES	CT-Strpnt. Meas. Loc.2 in Dir. of Object
522	IN-PRI CT M2	Power System Data 1	1..100000 A	2000 A	CT Rated Primary Current Meas. Loc. 2
523	IN-SEC CT M2	Power System Data 1	1A 5A	1A	CT Rated Secondary Current Meas. Loc. 2
531	STRPNT->OBJ M3	Power System Data 1	YES NO	YES	CT-Strpnt. Meas. Loc.3 in Dir. of Object
532	IN-PRI CT M3	Power System Data 1	1..100000 A	2000 A	CT Rated Primary Current Meas. Loc. 3
533	IN-SEC CT M3	Power System Data 1	1A 5A	1A	CT Rated Secondary Current Meas. Loc. 3
541	STRPNT->OBJ M4	Power System Data 1	YES NO	YES	CT-Strpnt. Meas. Loc.4 in Dir. of Object
542	IN-PRI CT M4	Power System Data 1	1..100000 A	2000 A	CT Rated Primary Current Meas. Loc. 4
543	IN-SEC CT M4	Power System Data 1	1A 5A	1A	CT Rated Secondary Current Meas. Loc. 4
551	STRPNT->OBJ M5	Power System Data 1	YES NO	YES	CT-Strpnt. Meas. Loc.5 in Dir. of Object
552	IN-PRI CT M5	Power System Data 1	1..100000 A	2000 A	CT Rated Primary Current Meas. Loc. 5
553	IN-SEC CT M5	Power System Data 1	1A 5A	1A	CT Rated Secondary Current Meas. Loc. 5
561	STRPNT->BUS I1	Power System Data 1	YES NO	YES	CT-Starpoint I1 in Direction of Busbar
562	IN-PRI CT I1	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I1
563	IN-SEC CT I1	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I1
571	STRPNT->BUS I2	Power System Data 1	YES NO	YES	CT-Starpoint I2 in Direction of Busbar
572	IN-PRI CT I2	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I2
573	IN-SEC CT I2	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I2
581	STRPNT->BUS I3	Power System Data 1	YES NO	YES	CT-Starpoint I3 in Direction of Busbar

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
582	IN-PRI CT I3	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I3
583	IN-SEC CT I3	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I3
591	STRPNT->BUS I4	Power System Data 1	YES NO	YES	CT-Starpoint I4 in Direction of Busbar
592	IN-PRI CT I4	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I4
593	IN-SEC CT I4	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I4
601	STRPNT->BUS I5	Power System Data 1	YES NO	YES	CT-Starpoint I5 in Direction of Busbar
602	IN-PRI CT I5	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I5
603	IN-SEC CT I5	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I5
611	STRPNT->BUS I6	Power System Data 1	YES NO	YES	CT-Starpoint I6 in Direction of Busbar
612	IN-PRI CT I6	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I6
613	IN-SEC CT I6	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I6
621	STRPNT->BUS I7	Power System Data 1	YES NO	YES	CT-Starpoint I7 in Direction of Busbar
622	IN-PRI CT I7	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I7
623	IN-SEC CT I7	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I7
631	STRPNT->BUS I8	Power System Data 1	YES NO	YES	CT-Starpoint I8 in Direction of Busbar
632	IN-PRI CT I8	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I8
633	IN-SEC CT I8	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I8
641	STRPNT->BUS I9	Power System Data 1	YES NO	YES	CT-Starpoint I9 in Direction of Busbar
642	IN-PRI CT I9	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I9

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
643	IN-SEC CT I9	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I9
651	STRPNT->BUS I10	Power System Data 1	YES NO	YES	CT-Starpoint I10 in Direction of Busbar
652	IN-PRI CT I10	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I10
653	IN-SEC CT I10	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I10
661	STRPNT->BUS I11	Power System Data 1	YES NO	YES	CT-Starpoint I11 in Direction of Busbar
662	IN-PRI CT I11	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I11
663	IN-SEC CT I11	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I11
671	STRPNT->BUS I12	Power System Data 1	YES NO	YES	CT-Starpoint I12 in Direction of Busbar
672	IN-PRI CT I12	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I12
673	IN-SEC CT I12	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I12
711	EARTH IX1 AT	Power System Data 1	Terminal Q7 Terminal Q8	Terminal Q7	Earthing electrod IX1 connected to
712	IN-PRI CT IX1	Power System Data 1	1..100000 A	200 A	CT rated primary current IX1
713	IN-SEC CT IX1	Power System Data 1	1A 5A	1A	CT rated secondary current IX1
721	EARTH IX2 AT	Power System Data 1	Terminal N7 Terminal N8	Terminal N7	Earthing electrod IX2 connected to
722	IN-PRI CT IX2	Power System Data 1	1..100000 A	200 A	CT rated primary current IX2
723	IN-SEC CT IX2	Power System Data 1	1A 5A	1A	CT rated secondary current IX2
731	EARTH IX3 AT	Power System Data 1	Terminal R7 Terminal R8	Terminal R7	Earthing electrod IX3 connected to
732	IN-PRI CT IX3	Power System Data 1	1..100000 A	200 A	CT rated primary current IX3
733	IN-SEC CT IX3	Power System Data 1	1A 5A	1A	CT rated secondary current IX3
734	FACTOR CT IX3	Power System Data 1	1.0..300.0	60.0	Factor: prim. over sek. current IX3

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
741	EARTH IX4 AT	Power System Data 1	Terminal P7 Terminal P8	Terminal P7	Earthing electrod IX4 connected to
742	IN-PRI CT IX4	Power System Data 1	1..100000 A	200 A	CT rated primary current IX4
743	IN-SEC CT IX4	Power System Data 1	1A 5A	1A	CT rated secondary current IX4
744	FACTOR CT IX4	Power System Data 1	1.0..300.0	60.0	Factor: prim. over sek. current IX4
801	UN-PRI VT SET	Power System Data 1	1.0..1200.0 kV	110.0 kV	VT Rated Prim. Voltage Set UL1, UL2, UL3
802	UN-SEC VT SET	Power System Data 1	80..125 V	100 V	VT Rated Sec. Voltage Set UL1, UL2, UL3
811	UN-PRI VT U4	Power System Data 1	1.0..1200.0 kV	110.0 kV	VT Rated Primary Voltage U4
812	UN-SEC VT U4	Power System Data 1	80..125 V	100 V	VT Rated Secondary Voltage U4
816	Uph / Udelta	Power System Data 1	0.10..9.99	1.73	Matching ratio Phase-VT to Open-Delta-VT
817	Uph(U4)/Udelta	Power System Data 1	0.10..9.99	1.73	Matching ratio Ph-VT(U4) to Open-DeltaVT
831	SwitchgCBaux S1	Power System Data 1			Switchgear / CBaux at Side 1
832	SwitchgCBaux S2	Power System Data 1			Switchgear / CBaux at Side 2
833	SwitchgCBaux S3	Power System Data 1			Switchgear / CBaux at Side 3
834	SwitchgCBaux S4	Power System Data 1			Switchgear / CBaux at Side 4
835	SwitchgCBaux S5	Power System Data 1			Switchgear / CBaux at Side 5
836	SwitchgCBaux M1	Power System Data 1			Switchgear / CBaux at Measuring Loc. M1
837	SwitchgCBaux M2	Power System Data 1			Switchgear / CBaux at Measuring Loc. M2
838	SwitchgCBaux M3	Power System Data 1			Switchgear / CBaux at Measuring Loc. M3
839	SwitchgCBaux M4	Power System Data 1			Switchgear / CBaux at Measuring Loc. M4
840	SwitchgCBaux M5	Power System Data 1			Switchgear / CBaux at Measuring Loc. M5
841	SwitchgCBaux E1	Power System Data 1			Switchgear / CBaux at ext. location 1

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
851A	TMin TRIP CMD	Power System Data 1	0.01..32.00 sec	0.15 sec	Minimum TRIP Command Duration
901	WAVEFORMTRIGGER	Oscillographic Fault Records	Save with Pickup Save with TRIP Start with TRIP	Save with Pickup	Waveform Capture
903	MAX. LENGTH	Oscillographic Fault Records	0.30..5.00 sec	1.00 sec	Max. length of a Waveform Capture Record
904	PRE. TRIG. TIME	Oscillographic Fault Records	0.05..0.50 sec	0.10 sec	Captured Waveform Prior to Trigger
905	POST REC. TIME	Oscillographic Fault Records	0.05..0.50 sec	0.10 sec	Captured Waveform after Event
906	BinIn CAPT.TIME	Oscillographic Fault Records	0.10..5.00 sec; ∞	0.50 sec	Capture Time via Binary Input
1107	P,Q sign	Power System Data 2	not reversed reversed	not reversed	P,Q operational measured values sign
1111	PoleOpenCurr.S1	Power System Data 2	0.04..1.00 I/InS	0.10 I/InS	Pole Open Current Threshold Side 1
1112	PoleOpenCurr.S2	Power System Data 2	0.04..1.00 I/InS	0.10 I/InS	Pole Open Current Threshold Side 2
1113	PoleOpenCurr.S3	Power System Data 2	0.04..1.00 I/InS	0.10 I/InS	Pole Open Current Threshold Side 3
1114	PoleOpenCurr.S4	Power System Data 2	0.04..1.00 I/InS	0.10 I/InS	Pole Open Current Threshold Side 4
1115	PoleOpenCurr.S5	Power System Data 2	0.04..1.00 I/InS	0.10 I/InS	Pole Open Current Threshold Side 5
1121	PoleOpenCurr.M1	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold Meas.Loc. M1
1122	PoleOpenCurr.M2	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold Meas.Loc. M2
1123	PoleOpenCurr.M3	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold Meas.Loc. M3
1124	PoleOpenCurr.M4	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold Meas.Loc. M4
1125	PoleOpenCurr.M5	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold Meas.Loc. M5
1131	PoleOpenCurr I1	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 1
1132	PoleOpenCurr I2	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 2
1133	PoleOpenCurr I3	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 3
1134	PoleOpenCurr I4	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 4

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
1135	PoleOpenCurr I5	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 5
1136	PoleOpenCurr I6	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 6
1137	PoleOpenCurr I7	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 7
1138	PoleOpenCurr I8	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 8
1139	PoleOpenCurr I9	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 9
1140	PoleOpenCurrI10	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 10
1141	PoleOpenCurrI11	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 11
1142	PoleOpenCurrI12	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold End 12
1151	PoleOpenCurrIX1	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold AuxiliaryCT1
1152	PoleOpenCurrIX2	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold AuxiliaryCT2
1153	PoleOpenCurrIX3	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold AuxiliaryCT3
1154	PoleOpenCurrIX4	Power System Data 2	0.04..1.00 A	0.04 A	Pole Open Current Threshold AuxiliaryCT4
1201	DIFF. PROT.	Differential Protection	OFF ON Block relay for trip commands	OFF	Differential Protection
1205	INC.CHAR.START	Differential Protection	OFF ON	OFF	Increase of Trip Char. During Start
1206	INRUSH 2.HARM.	Differential Protection	OFF ON	ON	Inrush with 2. Harmonic Restraint
1207	RESTR. n.HARM.	Differential Protection	OFF 3. Harmonic 5. Harmonic	OFF	n-th Harmonic Restraint
1208	I-DIFF> MON.	Differential Protection	OFF ON	ON	Differential Current monitoring
1210	I> CURR. GUARD	Differential Protection	0.20..2.00 I/InS; 0	0.00 I/InS	I> for Current Guard
1211A	DIFFw.IE1-MEAS	Differential Protection	NO YES	NO	Diff-Prot. with meas. Earth Current S1
1212A	DIFFw.IE2-MEAS	Differential Protection	NO YES	NO	Diff-Prot. with meas. Earth Current S2

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
1213A	DIFFw.IE3-MEAS	Differential Protection	NO YES	NO	Diff-Prot. with meas. Earth Current S3
1214A	DIFFw.IE4-MEAS	Differential Protection	NO YES	NO	Diff-Prot. with meas. Earth Current S4
1215A	DIFFw.IE5-MEAS	Differential Protection	NO YES	NO	Diff-Prot. with meas. Earth Current S5
1221	I-DIFF>	Differential Protection	0.05..2.00 I/InO	0.20 I/InO	Pickup Value of Differential Curr.
1226A	T I-DIFF>	Differential Protection	0.00..60.00 sec; ∞	0.00 sec	T I-DIFF> Time Delay
1231	I-DIFF>>	Differential Protection	0.5..35.0 I/InO; ∞	7.5 I/InO	Pickup Value of High Set Trip
1236A	T I-DIFF>>	Differential Protection	0.00..60.00 sec; ∞	0.00 sec	T I-DIFF>> Time Delay
1241A	SLOPE 1	Differential Protection	0.10..0.50	0.25	Slope 1 of Tripping Characteristic
1242A	BASE POINT 1	Differential Protection	0.00..2.00 I/InO	0.00 I/InO	Base Point for Slope 1 of Charac.
1243A	SLOPE 2	Differential Protection	0.25..0.95	0.50	Slope 2 of Tripping Characteristic
1244A	BASE POINT 2	Differential Protection	0.00..10.00 I/InO	2.50 I/InO	Base Point for Slope 2 of Charac.
1251A	I-REST. STARTUP	Differential Protection	0.00..2.00 I/InO	0.10 I/InO	I-RESTRAINT for Start Detection
1252A	START-FACTOR	Differential Protection	1.0..2.0	1.0	Factor for Increasing of Char. at Start
1253	T START MAX	Differential Protection	0.0..180.0 sec	5.0 sec	Maximum Permissible Starting Time
1261A	I-ADD ON STAB.	Differential Protection	2.00..15.00 I/InO	4.00 I/InO	Pickup for Add-on Stabilization
1262A	T ADD ON-STAB.	Differential Protection	2..250 Cycle; ∞	15 Cycle	Duration of Add-on Stabilization
1263A	CROSSB. ADD ON	Differential Protection	2..1000 Cycle; 0; ∞	15 Cycle	Time for Cross-blocking Add-on Stabiliz.
1271	2. HARMONIC	Differential Protection	10..80 %	15 %	2nd Harmonic Content in I-DIFF
1272A	CROSSB. 2. HARM	Differential Protection	2..1000 Cycle; 0; ∞	3 Cycle	Time for Cross-blocking 2nd Harm.
1276	n. HARMONIC	Differential Protection	10..80 %	30 %	n-th Harmonic Content in I-DIFF
1277A	CROSSB. n.HARM	Differential Protection	2..1000 Cycle; 0; ∞	0 Cycle	Time for Cross-blocking n-th Harm.

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
1278A	IDIFFmax n.HM	Differential Protection	0.5..20.0 I/InO	1.5 I/InO	Limit IDIFFmax of n-th Harm.Restraint
1281	I-DIFF> MON.	Differential Protection	0.15..0.80 I/InO	0.20 I/InO	Pickup Value of diff. Current Monitoring
1282	T I-DIFF> MON.	Differential Protection	1..10 sec	2 sec	T I-DIFF> Monitoring Time Delay
1301	REF PROT.	Restricted Earth Fault Protection	OFF ON Block relay for trip commands	OFF	Restricted Earth Fault Protection
1311	I-REF>	Restricted Earth Fault Protection	0.05..2.00 I/InS	0.15 I/InS	Pick up value I REF>
1312A	T I-REF>	Restricted Earth Fault Protection	0.00..60.00 sec; ∞	0.00 sec	T I-REF> Time Delay
1313A	SLOPE	Restricted Earth Fault Protection	0.00..0.95	0.00	Slope of Charac. I-REF> = f(I-SUM)
1701	COLDLOAD PIKKUP	Cold Load Pickup	OFF ON	OFF	Cold-Load-Pickup Function
1702	Start CLP Phase	Cold Load Pickup	No Current Breaker Contact	No Current	Start Condition CLP for O/C Phase
1703	Start CLP 3I0	Cold Load Pickup	No Current Breaker Contact	No Current	Start Condition CLP for O/C 3I0
1704	Start CLP Earth	Cold Load Pickup	No Current Breaker Contact	No Current	Start Condition CLP for O/C Earth
1711	CB Open Time	Cold Load Pickup	0..21600 sec	3600 sec	Circuit Breaker OPEN Time
1712	Active Time	Cold Load Pickup	1..21600 sec	3600 sec	Active Time
1713	Stop Time	Cold Load Pickup	1..600 sec; ∞	600 sec	Stop Time
2001	PHASE O/C	Time overcurrent Phase	ON OFF Block relay for trip commands	OFF	Phase Time Overcurrent
2002	InRushRest. Ph	Time overcurrent Phase	ON OFF	OFF	InRush Restrained O/C Phase
2008A	MANUAL CLOSE	Time overcurrent Phase	I>> instantaneously I> instantaneously Ip instantaneously Inactive	I>> instantaneously	O/C Manual Close Mode
2011	I>>	Time overcurrent Phase	0.10..35.00 A; ∞	4.00 A	I>> Pickup
2012	I>>	Time overcurrent Phase	0.10..35.00 I/InS; ∞	4.00 I/InS	I>> Pickup

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
2013	T I>>	Time overcurrent Phase	0.00..60.00 sec; ∞	0.10 sec	T I>> Time Delay
2014	I>	Time overcurrent Phase	0.10..35.00 A; ∞	2.00 A	I> Pickup
2015	I>	Time overcurrent Phase	0.10..35.00 I/InS; ∞	2.00 I/InS	I> Pickup
2016	T I>	Time overcurrent Phase	0.00..60.00 sec; ∞	0.30 sec	T I> Time Delay
2021	Ip	Time overcurrent Phase	0.10..4.00 A	2.00 A	Ip Pickup
2022	Ip	Time overcurrent Phase	0.10..4.00 I/InS	2.00 I/InS	Ip Pickup
2023	T Ip	Time overcurrent Phase	0.05..3.20 sec; ∞	0.50 sec	T Ip Time Dial
2024	D Ip	Time overcurrent Phase	0.50..15.00; ∞	5.00	D Ip Time Dial
2025	TOC DROP-OUT	Time overcurrent Phase	Instantaneous Disk Emulation	Disk Emulation	TOC Drop-out characteristic
2026	IEC CURVE	Time overcurrent Phase	Normal Inverse Very Inverse Extremely Inverse Long Inverse	Normal Inverse	IEC Curve
2027	ANSI CURVE	Time overcurrent Phase	Very Inverse Inverse Short Inverse Long Inverse Moderately Inverse Extremely Inverse Definite Inverse	Very Inverse	ANSI Curve
2031	I/Ip PU T/Tp	Time overcurrent Phase	1.00..20.00 I / Ip; ∞ 0.01..999.00 Time Dial		Pickup Curve I/Ip - TI/TIp
2032	MofPU Res T/Tp	Time overcurrent Phase	0.05..0.95 I / Ip; ∞ 0.01..999.00 Time Dial		Multiple of Pickup <-> TI/TIp
2041	2.HARM. Phase	Time overcurrent Phase	10..45 %	15 %	2nd harmonic O/C Ph. in % of fundamental
2042	I Max InRr. Ph.	Time overcurrent Phase	0.30..25.00 A	7.50 A	Maximum Current for Inr. Rest. O/C Phase
2043	I Max InRr. Ph.	Time overcurrent Phase	0.30..25.00 I/InS	7.50 I/InS	Maximum Current for Inr. Rest. O/C Phase
2044	CROSS BLK.Phase	Time overcurrent Phase	NO YES	NO	CROSS BLOCK O/C Phase
2045	T CROSS BLK.Ph	Time overcurrent Phase	0.00..180.00 sec	0.00 sec	CROSS BLOCK Time O/C Phase

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
2111	I>>	Time overcurrent Phase	0.10..35.00 A; ∞	10.00 A	I>> Pickup
2112	I>>	Time overcurrent Phase	0.10..35.00 I/InS; ∞	10.00 I/InS	I>> Pickup
2113	T I>>	Time overcurrent Phase	0.00..60.00 sec; ∞	0.10 sec	T I>> Time Delay
2114	I>	Time overcurrent Phase	0.10..35.00 A; ∞	4.00 A	I> Pickup
2115	I>	Time overcurrent Phase	0.10..35.00 I/InS; ∞	4.00 I/InS	I> Pickup
2116	T I>	Time overcurrent Phase	0.00..60.00 sec; ∞	0.30 sec	T I> Time Delay
2121	Ip	Time overcurrent Phase	0.10..4.00 A	4.00 A	Ip Pickup
2122	Ip	Time overcurrent Phase	0.10..4.00 I/InS	4.00 I/InS	Ip Pickup
2123	T Ip	Time overcurrent Phase	0.05..3.20 sec; ∞	0.50 sec	T Ip Time Dial
2124	D Ip	Time overcurrent Phase	0.50..15.00; ∞	5.00	D Ip Time Dial
2201	3I0 O/C	Time overcurrent 3I0	ON OFF Block relay for trip commands	OFF	3I0 Time Overcurrent
2202	InRushRest. 3I0	Time overcurrent 3I0	ON OFF	OFF	InRush Restrained O/C 3I0
2208A	3I0 MAN. CLOSE	Time overcurrent 3I0	3I0>> instantaneously 3I0> instantaneously 3I0p instantaneously Inactive	3I0>> instantaneously	O/C 3I0 Manual Close Mode
2211	3I0>>	Time overcurrent 3I0	0.05..35.00 A; ∞	1.00 A	3I0>> Pickup
2212	3I0>>	Time overcurrent 3I0	0.05..35.00 I/InS; ∞	1.00 I/InS	3I0>> Pickup
2213	T 3I0>>	Time overcurrent 3I0	0.00..60.00 sec; ∞	1.50 sec	T 3I0>> Time Delay
2214	3I0>	Time overcurrent 3I0	0.05..35.00 A; ∞	0.40 A	3I0> Pickup
2215	3I0>	Time overcurrent 3I0	0.05..35.00 I/InS; ∞	0.40 I/InS	3I0> Pickup
2216	T 3I0>	Time overcurrent 3I0	0.00..60.00 sec; ∞	2.00 sec	T 3I0> Time Delay

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
2221	3I0p	Time overcurrent 3I0	0.05..4.00 A	0.40 A	3I0p Pickup
2222	3I0p	Time overcurrent 3I0	0.05..4.00 I/InS	0.40 I/InS	3I0p Pickup
2223	T 3I0p	Time overcurrent 3I0	0.05..3.20 sec; ∞	0.50 sec	T 3I0p Time Dial
2224	D 3I0p	Time overcurrent 3I0	0.50..15.00; ∞	5.00	D 3I0p Time Dial
2225	TOC DROP-OUT	Time overcurrent 3I0	Instantaneous Disk Emulation	Disk Emulation	TOC Drop-out Characteristic
2226	IEC CURVE	Time overcurrent 3I0	Normal Inverse Very Inverse Extremely Inverse Long Inverse	Normal Inverse	IEC Curve
2227	ANSI CURVE	Time overcurrent 3I0	Very Inverse Inverse Short Inverse Long Inverse Moderately Inverse Extremely Inverse Definite Inverse	Very Inverse	ANSI Curve
2231	I/I0p PU T/TI0p	Time overcurrent 3I0	1.00..20.00 I / Ip; ∞ 0.01..999.00 Time Dial		Pickup Curve 3I0/3I0p - T3I0/T3I0p
2232	MofPU ResT/TI0p	Time overcurrent 3I0	0.05..0.95 I / Ip; ∞ 0.01..999.00 Time Dial		Multiple of Pickup <-> T3I0/T3I0p
2241	2.HARM. 3I0	Time overcurrent 3I0	10..45 %	15 %	2nd harmonic O/C 3I0 in % of fundamental
2242	I Max InRr. 3I0	Time overcurrent 3I0	0.30..25.00 A	7.50 A	Maximum Current for Inr. Rest. O/C 3I0
2243	I Max InRr. 3I0	Time overcurrent 3I0	0.30..25.00 I/InS	7.50 I/InS	Maximum Current for Inr. Rest. O/C 3I0
2311	3I0>>	Time overcurrent 3I0	0.05..35.00 A; ∞	7.00 A	3I0>> Pickup
2312	3I0>>	Time overcurrent 3I0	0.05..35.00 I/InS; ∞	7.00 I/InS	3I0>> Pickup
2313	T 3I0>>	Time overcurrent 3I0	0.00..60.00 sec; ∞	1.50 sec	T 3I0>> Time Delay
2314	3I0>	Time overcurrent 3I0	0.05..35.00 A; ∞	1.50 A	3I0> Pickup
2315	3I0>	Time overcurrent 3I0	0.05..35.00 I/InS; ∞	1.50 I/InS	3I0> Pickup
2316	T 3I0>	Time overcurrent 3I0	0.00..60.00 sec; ∞	2.00 sec	T 3I0> Time Delay

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
2321	3I0p	Time overcurrent 3I0	0.05..4.00 A	1.00 A	3I0p Pickup
2322	3I0p	Time overcurrent 3I0	0.05..4.00 I/InS	1.00 I/InS	3I0p Pickup
2323	T 3I0p	Time overcurrent 3I0	0.05..3.20 sec; ∞	0.50 sec	T 3I0p Time Dial
2324	D 3I0p	Time overcurrent 3I0	0.50..15.00; ∞	5.00	D 3I0p Time Dial
2401	EARTH O/C	Time overcurrent Earth	ON OFF Block relay for trip commands	OFF	Earth Time Overcurrent
2402	InRushRestEarth	Time overcurrent Earth	ON OFF	OFF	InRush Restrained O/C Earth
2408A	IE MAN. CLOSE	Time overcurrent Earth	IE>> instantaneously IE> instantaneously IEp instantaneously Inactive	IE>> instantaneously	O/C IE Manual Close Mode
2411	IE>>	Time overcurrent Earth	0.05..35.00 A; ∞	1.00 A	IE>> Pickup
2412	T IE>>	Time overcurrent Earth	0.00..60.00 sec; ∞	1.50 sec	T IE>> Time Delay
2413	IE>	Time overcurrent Earth	0.05..35.00 A; ∞	0.40 A	IE> Pickup
2414	T IE>	Time overcurrent Earth	0.00..60.00 sec; ∞	2.00 sec	T IE> Time Delay
2421	IEp	Time overcurrent Earth	0.05..4.00 A	0.40 A	IEp Pickup
2422	T IEp	Time overcurrent Earth	0.05..3.20 sec; ∞	0.50 sec	T IEp Time Dial
2423	D IEp	Time overcurrent Earth	0.50..15.00; ∞	5.00	D IEp Time Dial
2424	TOC DROP-OUT	Time overcurrent Earth	Instantaneous Disk Emulation	Disk Emulation	TOC Drop-out Characteristic
2425	IEC CURVE	Time overcurrent Earth	Normal Inverse Very Inverse Extremely Inverse Long Inverse	Normal Inverse	IEC Curve
2426	ANSI CURVE	Time overcurrent Earth	Very Inverse Inverse Short Inverse Long Inverse Moderately Inverse Extremely Inverse Definite Inverse	Very Inverse	ANSI Curve

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
2431	I/IEp PU T/TEp	Time overcurrent Earth	1.00..20.00 I / Ip; ∞ 0.01..999.00 Time Dial		Pickup Curve IE/IEp - TIE/TIEp
2432	MofPU Res T/TEp	Time overcurrent Earth	0.05..0.95 I / Ip; ∞ 0.01..999.00 Time Dial		Multiple of Pickup <-> TI/TIEp
2441	2.HARM. Earth	Time overcurrent Earth	10..45 %	15 %	2nd harmonic O/C E in % of fundamental
2442	I Max InRr. E	Time overcurrent Earth	0.30..25.00 A	7.50 A	Maximum Current for Inr. Rest. O/C Earth
2511	IE>>	Time overcurrent Earth	0.05..35.00 A; ∞	7.00 A	IE>> Pickup
2512	T IE>>	Time overcurrent Earth	0.00..60.00 sec; ∞	1.50 sec	T IE>> Time Delay
2513	IE>	Time overcurrent Earth	0.05..35.00 A; ∞	1.50 A	IE> Pickup
2514	T IE>	Time overcurrent Earth	0.00..60.00 sec; ∞	2.00 sec	T IE> Time Delay
2521	IEp	Time overcurrent Earth	0.05..4.00 A	1.00 A	IEp Pickup
2522	T IEp	Time overcurrent Earth	0.05..3.20 sec; ∞	0.50 sec	T IEp Time Dial
2523	D IEp	Time overcurrent Earth	0.50..15.00; ∞	5.00	D IEp Time Dial
2701	1Phase O/C	Time overcurrent 1Phase	OFF ON Block relay for trip commands	OFF	1Phase Time Overcurrent
2702	1Phase I>>	Time overcurrent 1Phase	0.05..35.00 A; ∞	0.50 A	1Phase O/C I>> Pickup
2703	1Phase I>>	Time overcurrent 1Phase	0.003..1.500 A; ∞	0.300 A	1Phase O/C I>> Pickup
2704	T 1Phase I>>	Time overcurrent 1Phase	0.00..60.00 sec; ∞	0.10 sec	T 1Phase O/C I>> Time Delay
2705	1Phase I>	Time overcurrent 1Phase	0.05..35.00 A; ∞	0.20 A	1Phase O/C I> Pickup
2706	1Phase I>	Time overcurrent 1Phase	0.003..1.500 A; ∞	0.100 A	1Phase O/C I> Pickup
2707	T 1Phase I>	Time overcurrent 1Phase	0.00..60.00 sec; ∞	0.50 sec	T 1Phase O/C I> Time Delay
4001	UNBALANCE LOAD	Unbalanced Load	OFF ON Block relay for trip commands	OFF	Unbalance Load (Negative Sequence)

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
4011	I2>>	Unbalanced Load	0.10..3.00 A; ∞	0.50 A	I2>> Pickup
4012	I2>>	Unbalanced Load	0.10..3.00 I/InS; ∞	0.50 I/InS	I2>> Pickup
4013	T I2>>	Unbalanced Load	0.00..60.00 sec; ∞	1.50 sec	T I2>> Time Delay
4014	I2>	Unbalanced Load	0.10..3.00 A; ∞	0.10 A	I2> Pickup
4015	I2>	Unbalanced Load	0.10..3.00 I/InS; ∞	0.10 I/InS	I2> Pickup
4016	T I2>	Unbalanced Load	0.00..60.00 sec; ∞	1.50 sec	T I2> Time Delay
4021	I2p	Unbalanced Load	0.10..2.00 A	0.90 A	I2p Pickup
4022	I2p	Unbalanced Load	0.10..2.00 I/InS	0.90 I/InS	I2p Pickup
4023	T I2p	Unbalanced Load	0.05..3.20 sec; ∞	0.50 sec	T I2p Time Dial
4024	D I2p	Unbalanced Load	0.50..15.00; ∞	5.00	D I2p Time Dial
4025	I2p DROP-OUT	Unbalanced Load	Instantaneous Disk Emulation	Instantaneous	I2p Drop-out Characteristic
4026	IEC CURVE	Unbalanced Load	Normal Inverse Very Inverse Extremely Inverse	Extremely Inverse	IEC Curve
4027	ANSI CURVE	Unbalanced Load	Extremely Inverse Inverse Moderately Inverse Very Inverse	Extremely Inverse	ANSI Curve
4201	THERM. OVERLOAD	Thermal Overload Protection	OFF ON Block relay for trip commands Alarm Only	OFF	Thermal Overload Protection
4202	K-FACTOR	Thermal Overload Protection	0.10..4.00	1.10	K-Factor
4203	TIME CONSTANT	Thermal Overload Protection	1.0..999.9 min	100.0 min	Thermal Time Constant
4204	Θ ALARM	Thermal Overload Protection	50..100 %	90 %	Thermal Alarm Stage
4205	I ALARM	Thermal Overload Protection	0.10..4.00 I/InS	1.00 I/InS	Current Overload Alarm Setpoint
4207A	Kτ-FACTOR	Thermal Overload Protection	1.0..10.0	1.0	Kt-FACTOR when motor stops

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
4208A	T EMERGENCY	Thermal Overload Protection	10..15000 sec	100 sec	Emergency Time
4209A	I MOTOR START	Thermal Overload Protection	0.60..10.00 I/InS; ∞	∞ I/InS	Current Pickup Value of Motor Starting
4221	OIL-DET. RTD	Thermal Overload Protection	1..6	1	Oil-Detector conected at RTD
4222	HOT SPOT ST. 1	Thermal Overload Protection	98..140 °C	98 °C	Hot Spot Temperature Stage 1 Pickup
4223	HOT SPOT ST. 1	Thermal Overload Protection	208..284 °F	208 °F	Hot Spot Temperature Stage 1 Pickup
4224	HOT SPOT ST. 2	Thermal Overload Protection	98..140 °C	108 °C	Hot Spot Temperature Stage 2 Pickup
4225	HOT SPOT ST. 2	Thermal Overload Protection	208..284 °F	226 °F	Hot Spot Temperature Stage 2 Pickup
4226	AG. RATE ST. 1	Thermal Overload Protection	0.200..128.000	1.000	Aging Rate STAGE 1 Pikkup
4227	AG. RATE ST. 2	Thermal Overload Protection	0.200..128.000	2.000	Aging Rate STAGE 2 Pikkup
4231	METH. COOLING	Thermal Overload Protection	ON (Oil-Natural) OF (Oil-Forced) OD (Oil-Directed)	ON (Oil-Natural)	Method of Cooling
4232	Y-WIND.EXPONENT	Thermal Overload Protection	1.6..2.0	1.6	Y-Winding Exponent
4233	HOT-SPOT GR	Thermal Overload Protection	22..29	22	Hot-spot to top-oil gradient
4301	OVEREXC. PROT.	Overexcitation Protection (U/f)	OFF ON Block relay for trip commands	OFF	Overexcitation Protection (U/f)
4302	U/f >	Overexcitation Protection (U/f)	1.00..1.20	1.10	U/f > Pickup
4303	T U/f >	Overexcitation Protection (U/f)	0.00..60.00 sec; ∞	10.00 sec	T U/f > Time Delay
4304	U/f >>	Overexcitation Protection (U/f)	1.00..1.40	1.40	U/f >> Pickup
4305	T U/f >>	Overexcitation Protection (U/f)	0.00..60.00 sec; ∞	1.00 sec	T U/f >> Time Delay
4306	t(U/f=1.05)	Overexcitation Protection (U/f)	0..20000 sec	20000 sec	U/f = 1.05 Time Delay
4307	t(U/f=1.10)	Overexcitation Protection (U/f)	0..20000 sec	6000 sec	U/f = 1.10 Time Delay
4308	t(U/f=1.15)	Overexcitation Protection (U/f)	0..20000 sec	240 sec	U/f = 1.15 Time Delay

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
4309	t(U/f=1.20)	Overexcitation Protection (U/f)	0..20000 sec	60 sec	U/f = 1.20 Time Delay
4310	t(U/f=1.25)	Overexcitation Protection (U/f)	0..20000 sec	30 sec	U/f = 1.25 Time Delay
4311	t(U/f=1.30)	Overexcitation Protection (U/f)	0..20000 sec	19 sec	U/f = 1.30 Time Delay
4312	t(U/f=1.35)	Overexcitation Protection (U/f)	0..20000 sec	13 sec	U/f = 1.35 Time Delay
4313	t(U/f=1.40)	Overexcitation Protection (U/f)	0..20000 sec	10 sec	U/f = 1.40 Time Delay
4314	T COOL DOWN	Overexcitation Protection (U/f)	0..20000 sec	3600 sec	Time for cool down
7001	BREAKER FAILURE	Breaker Failure Protection	OFF ON Block relay for trip commands	OFF	Breaker Failure Protection
7011	START WITH REL.	Breaker Failure Protection	0..8	0	Start with Relay (intern)
7012	START WITH REL.	Breaker Failure Protection	0..24	0	Start with Relay (intern)
7015	T1	Breaker Failure Protection	0.00..60.00 sec; ∞	0.15 sec	T1, Delay of 1st stage (local trip)
7016	T2	Breaker Failure Protection	0.00..60.00 sec; ∞	0.30 sec	T2, Delay of 2nd stage (busbar trip)
7601	POWER CALCUL.	Measurement	with V setting with V measuring	with V setting	Calculation of Power
8101	BALANCE I	Measurement Supervision	ON OFF	OFF	Current Balance Supervision
8102	BALANCE U	Measurement Supervision	ON OFF	OFF	Voltage Balance Supervision
8104	SUMMATION U	Measurement Supervision	ON OFF	OFF	Voltage Summation Supervision
8105	PHASE ROTAT. I	Measurement Supervision	ON OFF	OFF	Current Phase Rotation Supervision
8106	PHASE ROTAT. U	Measurement Supervision	ON OFF	OFF	Voltage Phase Rotation Supervision
8111	BAL. I LIMIT M1	Measurement Supervision	0.10..1.00 A	0.50 A	Current Balance Monitor Meas. Loc. 1
8112	BAL. FACT. I M1	Measurement Supervision	0.10..0.90	0.50	Bal. Factor for Curr. Monitor Meas.Loc.1
8121	BAL. I LIMIT M2	Measurement Supervision	0.10..1.00 A	0.50 A	Current Balance Monitor Meas. Loc. 2

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
8122	BAL. FACT. I M2	Measurement Supervision	0.10..0.90	0.50	Bal. Factor for Curr. Monitor Meas.Loc.2
8131	BAL. I LIMIT M3	Measurement Supervision	0.10..1.00 A	0.50 A	Current Balance Monitor Meas. Loc. 3
8132	BAL. FACT. I M3	Measurement Supervision	0.10..0.90	0.50	Bal. Factor for Curr. Monitor Meas.Loc.3
8141	BAL. I LIMIT M4	Measurement Supervision	0.10..1.00 A	0.50 A	Current Balance Monitor Meas. Loc. 4
8142	BAL. FACT. I M4	Measurement Supervision	0.10..0.90	0.50	Bal. Factor for Curr. Monitor Meas.Loc.4
8151	BAL. I LIMIT M5	Measurement Supervision	0.10..1.00 A	0.50 A	Current Balance Monitor Meas. Loc. 5
8152	BAL. FACT. I M5	Measurement Supervision	0.10..0.90	0.50	Bal. Factor for Curr. Monitor Meas.Loc.5
8161	BALANCE U-LIMIT	Measurement Supervision	10..100 V	50 V	Voltage Threshold for Balance Monitoring
8162	BAL. FACTOR U	Measurement Supervision	0.58..0.90	0.75	Balance Factor for Voltage Monitor
8201	TRIP Cir. SUP.	Trip Circuit Supervision	ON OFF	OFF	TRIP Circuit Supervision
8401	BROKEN WIRE	Supervision	OFF ON	OFF	Fast broken current-wire supervision
8601	EXTERN TRIP 1	External Trip Functions	OFF ON Block relay for trip commands	OFF	External Trip Function 1
8602	T DELAY	External Trip Functions	0.00..60.00 sec; ∞	1.00 sec	Ext. Trip 1 Time Delay
8701	EXTERN TRIP 2	External Trip Functions	OFF ON Block relay for trip commands	OFF	External Trip Function 2
8702	T DELAY	External Trip Functions	0.00..60.00 sec; ∞	1.00 sec	Ext. Trip 2 Time Delay
9011A	RTD 1 TYPE	RTD-Box	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	Pt 100 Ohm	RTD 1: Type
9012A	RTD 1 LOCATION	RTD-Box	Oil Ambient Winding Bearing Other	Oil	RTD 1: Location
9013	RTD 1 STAGE 1	RTD-Box	-50..250 °C; ∞	100 °C	RTD 1: Temperature Stage 1 Pickup

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
9014	RTD 1 STAGE 1	RTD-Box	-58..482 °F; ∞	212 °F	RTD 1: Temperature Stage 1 Pickup
9015	RTD 1 STAGE 2	RTD-Box	-50..250 °C; ∞	120 °C	RTD 1: Temperature Stage 2 Pickup
9016	RTD 1 STAGE 2	RTD-Box	-58..482 °F; ∞	248 °F	RTD 1: Temperature Stage 2 Pickup
9021A	RTD 2 TYPE	RTD-Box	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 2: Type
9022A	RTD 2 LOCATION	RTD-Box	Oil Ambient Winding Bearing Other	Other	RTD 2: Location
9023	RTD 2 STAGE 1	RTD-Box	-50..250 °C; ∞	100 °C	RTD 2: Temperature Stage 1 Pickup
9024	RTD 2 STAGE 1	RTD-Box	-58..482 °F; ∞	212 °F	RTD 2: Temperature Stage 1 Pickup
9025	RTD 2 STAGE 2	RTD-Box	-50..250 °C; ∞	120 °C	RTD 2: Temperature Stage 2 Pickup
9026	RTD 2 STAGE 2	RTD-Box	-58..482 °F; ∞	248 °F	RTD 2: Temperature Stage 2 Pickup
9031A	RTD 3 TYPE	RTD-Box	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 3: Type
9032A	RTD 3 LOCATION	RTD-Box	Oil Ambient Winding Bearing Other	Other	RTD 3: Location
9033	RTD 3 STAGE 1	RTD-Box	-50..250 °C; ∞	100 °C	RTD 3: Temperature Stage 1 Pickup
9034	RTD 3 STAGE 1	RTD-Box	-58..482 °F; ∞	212 °F	RTD 3: Temperature Stage 1 Pickup
9035	RTD 3 STAGE 2	RTD-Box	-50..250 °C; ∞	120 °C	RTD 3: Temperature Stage 2 Pickup
9036	RTD 3 STAGE 2	RTD-Box	-58..482 °F; ∞	248 °F	RTD 3: Temperature Stage 2 Pickup
9041A	RTD 4 TYPE	RTD-Box	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 4: Type

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
9042A	RTD 4 LOCATION	RTD-Box	Oil Ambient Winding Bearing Other	Other	RTD 4: Location
9043	RTD 4 STAGE 1	RTD-Box	-50..250 °C; ∞	100 °C	RTD 4: Temperature Stage 1 Pickup
9044	RTD 4 STAGE 1	RTD-Box	-58..482 °F; ∞	212 °F	RTD 4: Temperature Stage 1 Pickup
9045	RTD 4 STAGE 2	RTD-Box	-50..250 °C; ∞	120 °C	RTD 4: Temperature Stage 2 Pickup
9046	RTD 4 STAGE 2	RTD-Box	-58..482 °F; ∞	248 °F	RTD 4: Temperature Stage 2 Pickup
9051A	RTD 5 TYPE	RTD-Box	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 5: Type
9052A	RTD 5 LOCATION	RTD-Box	Oil Ambient Winding Bearing Other	Other	RTD 5: Location
9053	RTD 5 STAGE 1	RTD-Box	-50..250 °C; ∞	100 °C	RTD 5: Temperature Stage 1 Pickup
9054	RTD 5 STAGE 1	RTD-Box	-58..482 °F; ∞	212 °F	RTD 5: Temperature Stage 1 Pickup
9055	RTD 5 STAGE 2	RTD-Box	-50..250 °C; ∞	120 °C	RTD 5: Temperature Stage 2 Pickup
9056	RTD 5 STAGE 2	RTD-Box	-58..482 °F; ∞	248 °F	RTD 5: Temperature Stage 2 Pickup
9061A	RTD 6 TYPE	RTD-Box	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 6: Type
9062A	RTD 6 LOCATION	RTD-Box	Oil Ambient Winding Bearing Other	Other	RTD 6: Location
9063	RTD 6 STAGE 1	RTD-Box	-50..250 °C; ∞	100 °C	RTD 6: Temperature Stage 1 Pickup
9064	RTD 6 STAGE 1	RTD-Box	-58..482 °F; ∞	212 °F	RTD 6: Temperature Stage 1 Pickup
9065	RTD 6 STAGE 2	RTD-Box	-50..250 °C; ∞	120 °C	RTD 6: Temperature Stage 2 Pickup

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
9066	RTD 6 STAGE 2	RTD-Box	-58..482 °F; ∞	248 °F	RTD 6: Temperature Stage 2 Pickup
9071A	RTD 7 TYPE	RTD-Box	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 7: Type
9072A	RTD 7 LOCATION	RTD-Box	Oil Ambient Winding Bearing Other	Other	RTD 7: Location
9073	RTD 7 STAGE 1	RTD-Box	-50..250 °C; ∞	100 °C	RTD 7: Temperature Stage 1 Pickup
9074	RTD 7 STAGE 1	RTD-Box	-58..482 °F; ∞	212 °F	RTD 7: Temperature Stage 1 Pickup
9075	RTD 7 STAGE 2	RTD-Box	-50..250 °C; ∞	120 °C	RTD 7: Temperature Stage 2 Pickup
9076	RTD 7 STAGE 2	RTD-Box	-58..482 °F; ∞	248 °F	RTD 7: Temperature Stage 2 Pickup
9081A	RTD 8 TYPE	RTD-Box	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 8: Type
9082A	RTD 8 LOCATION	RTD-Box	Oil Ambient Winding Bearing Other	Other	RTD 8: Location
9083	RTD 8 STAGE 1	RTD-Box	-50..250 °C; ∞	100 °C	RTD 8: Temperature Stage 1 Pickup
9084	RTD 8 STAGE 1	RTD-Box	-58..482 °F; ∞	212 °F	RTD 8: Temperature Stage 1 Pickup
9085	RTD 8 STAGE 2	RTD-Box	-50..250 °C; ∞	120 °C	RTD 8: Temperature Stage 2 Pickup
9086	RTD 8 STAGE 2	RTD-Box	-58..482 °F; ∞	248 °F	RTD 8: Temperature Stage 2 Pickup
9091A	RTD 9 TYPE	RTD-Box	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD 9: Type
9092A	RTD 9 LOCATION	RTD-Box	Oil Ambient Winding Bearing Other	Other	RTD 9: Location
9093	RTD 9 STAGE 1	RTD-Box	-50..250 °C; ∞	100 °C	RTD 9: Temperature Stage 1 Pickup

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
9094	RTD 9 STAGE 1	RTD-Box	-58..482 °F; ∞	212 °F	RTD 9: Temperature Stage 1 Pickup
9095	RTD 9 STAGE 2	RTD-Box	-50..250 °C; ∞	120 °C	RTD 9: Temperature Stage 2 Pickup
9096	RTD 9 STAGE 2	RTD-Box	-58..482 °F; ∞	248 °F	RTD 9: Temperature Stage 2 Pickup
9101A	RTD10 TYPE	RTD-Box	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD10: Type
9102A	RTD10 LOCATION	RTD-Box	Oil Ambient Winding Bearing Other	Other	RTD10: Location
9103	RTD10 STAGE 1	RTD-Box	-50..250 °C; ∞	100 °C	RTD10: Temperature Stage 1 Pickup
9104	RTD10 STAGE 1	RTD-Box	-58..482 °F; ∞	212 °F	RTD10: Temperature Stage 1 Pickup
9105	RTD10 STAGE 2	RTD-Box	-50..250 °C; ∞	120 °C	RTD10: Temperature Stage 2 Pickup
9106	RTD10 STAGE 2	RTD-Box	-58..482 °F; ∞	248 °F	RTD10: Temperature Stage 2 Pickup
9111A	RTD11 TYPE	RTD-Box	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD11: Type
9112A	RTD11 LOCATION	RTD-Box	Oil Ambient Winding Bearing Other	Other	RTD11: Location
9113	RTD11 STAGE 1	RTD-Box	-50..250 °C; ∞	100 °C	RTD11: Temperature Stage 1 Pickup
9114	RTD11 STAGE 1	RTD-Box	-58..482 °F; ∞	212 °F	RTD11: Temperature Stage 1 Pickup
9115	RTD11 STAGE 2	RTD-Box	-50..250 °C; ∞	120 °C	RTD11: Temperature Stage 2 Pickup
9116	RTD11 STAGE 2	RTD-Box	-58..482 °F; ∞	248 °F	RTD11: Temperature Stage 2 Pickup
9121A	RTD12 TYPE	RTD-Box	not connected Pt 100 Ohm Ni 120 Ohm Ni 100 Ohm	not connected	RTD12: Type

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
9122A	RTD12 LOCATION	RTD-Box	Oil Ambient Winding Bearing Other	Other	RTD12: Location
9123	RTD12 STAGE 1	RTD-Box	-50..250 °C; ∞	100 °C	RTD12: Temperature Stage 1 Pickup
9124	RTD12 STAGE 1	RTD-Box	-58..482 °F; ∞	212 °F	RTD12: Temperature Stage 1 Pickup
9125	RTD12 STAGE 2	RTD-Box	-50..250 °C; ∞	120 °C	RTD12: Temperature Stage 2 Pickup
9126	RTD12 STAGE 2	RTD-Box	-58..482 °F; ∞	248 °F	RTD12: Temperature Stage 2 Pickup

A.8 List of Information

Notes:

The following tables list all data which are available in the maximum complement of the device. Depending on the version and the variant ordered only those data may be present which are valid for the actual version.

The leading ‘>’ sign indicates a binary input as a source.

Indications according to IEC 60870-5-103 are always announced “ON” and “OFF” if they are mandatory for general interrogation, otherwise only “ON”.

User-specified indications or indications which are user-allocated to the IEC 60870-5-103 protocol, are announced “ON” and “OFF” only in case they are not configured as pulse outputs.

The following terminology applies for the columns under “Log-Buffers”:

CAPITAL LETTERS:	preset ON/OFF indication, cannot be changed
lowercase letters:	preset ON/OFF indication, can be changed
*:	not preset, can be allocated and configured
<blank>:	neither preset nor allocatable

F.No.	Description	Function	Type of Information	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
00003	>Synchronize Internal Real Time Clock (>Time Synch)	Device	SP_Ev	*	*			LED	BI		BO		135	48	1	
00004	>Trigger Waveform Capture (>Trig.Wave.Cap.)	Oscillographic Fault Records	SP	*	*		M	LED	BI		BO		135	49	1	GI
00005	>Reset LED (>Reset LED)	Device	SP	*	*			LED	BI		BO		135	50	1	GI
00007	>Setting Group Select Bit 0 (>Set Group Bit0)	Change Group	SP	*	*			LED	BI		BO		135	51	1	GI
00008	>Setting Group Select Bit 1 (>Set Group Bit1)	Change Group	SP	*	*			LED	BI		BO		135	52	1	GI
00015	>Test mode (>Test mode)	Device	SP	*	*			LED	BI		BO		135	53	1	GI
00016	>Stop data transmission (>DataStop)	Device	SP	*	*			LED	BI		BO		135	54	1	GI
00051	Device is Operational and Protecting (Device OK)	Device	OUT	ON OFF	*			LED			BO		135	81	1	GI
00052	At Least 1 Protection Funct. is Active (ProtActive)	Device	IntSP	ON OFF	*			LED			BO		176	18	1	GI
00055	Reset Device (Reset Device)	Device	OUT	*	*			LED			BO		176	4	5	
00056	Initial Start of Device (Initial Start)	Device	OUT	ON	*			LED			BO		176	5	5	
00060	Reset LED (Reset LED)	Device	OUT_Ev	ON	*			LED			BO		176	19	1	
00067	Resume (Resume)	Device	OUT	ON	*			LED			BO		135	97	1	
00068	Clock Synchronization Error (Clock SyncError)	Supervision	OUT	ON OFF	*			LED			BO					

F.No.	Description	Function	Type of Information	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
00069	Daylight Saving Time (DayLightSav-Time)	Device	OUT	ON OFF	*			LED			BO					
00070	Setting calculation is running (Settings Calc.)	Device	OUT	ON OFF	*			LED			BO		176	22	1	GI
00071	Settings Check (Settings Check)	Device	OUT	*	*			LED			BO					
00072	Level-2 change (Level-2 change)	Device	OUT	ON OFF	*			LED			BO					
00109	Frequency out of range (Frequ. o.o.r.)	Device	OUT	ON OFF	*			LED			BO					
00110	Event lost (Event Lost)	Supervision	OUT_Ev	ON	*			LED			BO		135	130	1	
00113	Flag Lost (Flag Lost)	Supervision	OUT	ON	*		M	LED			BO		135	136	1	GI
00125	Chatter ON (Chatter ON)	Device	OUT	ON OFF	*			LED			BO		135	145	1	GI
00126	Protection ON/OFF (via system port) (ProtON/OFF)	Power System Data 2	IntSP	ON OFF	*			LED			BO					
00140	Error with a summary alarm (Error Sum Alarm)	Supervision	OUT	*	*			LED			BO		176	47	1	GI
00160	Alarm Summary Event (Alarm Sum Event)	Supervision	OUT	*	*			LED			BO		176	46	1	GI
00161	Failure: General Current Supervision (Fail I Superv.)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
00163	Failure: Current Balance (Fail I balance)	Measurement Supervision	OUT	ON OFF	*			LED			BO		135	183	1	GI
00164	Failure: General Voltage Supervision (Fail U Superv.)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
00165	Failure: Voltage Summation Phase-Earth (Fail Σ U Ph-E)	Measurement Supervision	OUT	ON OFF	*			LED			BO		135	184	1	GI
00167	Failure: Voltage Balance (Fail U balance)	Measurement Supervision	OUT	ON OFF	*			LED			BO		135	186	1	GI
00171	Failure: Phase Sequence (Fail Ph. Seq.)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
00175	Failure: Phase Sequence Current (Fail Ph. Seq. I)	Measurement Supervision	OUT	ON OFF	*			LED			BO		135	191	1	GI
00176	Failure: Phase Sequence Voltage (Fail Ph. Seq. U)	Measurement Supervision	OUT	ON OFF	*			LED			BO		135	192	1	GI
00177	Failure: Battery empty (Fail Battery)	Supervision	OUT	ON OFF	*			LED			BO		135	193	1	GI
00181	Error: Measurement system (Error MeasurSys)	Supervision	OUT	ON OFF	*			LED			BO		135	178	1	GI
00183	Error Board 1 (Error Board 1)	Supervision	OUT	ON OFF	*			LED			BO		135	171	1	GI
00184	Error Board 2 (Error Board 2)	Supervision	OUT	ON OFF	*			LED			BO		135	172	1	GI

F.No.	Description	Function	Type of Information	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
00185	Error Board 3 (Error Board 3)	Supervision	OUT	ON OFF	*			LED			BO		135	173	1	GI
00186	Error Board 4 (Error Board 4)	Supervision	OUT	ON OFF	*			LED			BO		135	174	1	GI
00187	Error Board 5 (Error Board 5)	Supervision	OUT	ON OFF	*			LED			BO		135	175	1	GI
00188	Error Board 6 (Error Board 6)	Supervision	OUT	ON OFF	*			LED			BO		135	176	1	GI
00189	Error Board 7 (Error Board 7)	Supervision	OUT	ON OFF	*			LED			BO		135	177	1	GI
00190	Error Board 0 (Error Board 0)	Supervision	OUT	ON OFF	*			LED			BO		135	210	1	GI
00191	Error: Offset (Error Offset)	Supervision	OUT	ON OFF	*			LED			BO					
00192	Error:1A/5Ajumper different from setting (Error1A/5Awrong)	Supervision	OUT	ON OFF	*			LED			BO		135	169	1	GI
00193	Alarm: Analog input adjustment invalid (Alarm adjustm.)	Supervision	OUT	ON OFF	*			LED			BO		135	181	1	GI
00198	Error: Communication Module B (Err. Module B)	Supervision	OUT	ON OFF	*			LED			BO		135	198	1	GI
00199	Error: Communication Module C (Err. Module C)	Supervision	OUT	ON OFF	*			LED			BO		135	199	1	GI
00200	Error: Communication Module D (Err. Module D)	Supervision	OUT	ON OFF	*			LED			BO		135	200	1	GI
00251	Broken wire detected (Broken wire)	Supervision	OUT	ON OFF	*			LED			BO					
00264	Failure: RTD-Box 1 (Fail: RTD-Box 1)	Supervision	OUT	ON OFF	*			LED			BO		135	208	1	GI
00267	Failure: RTD-Box 2 (Fail: RTD-Box 2)	Supervision	OUT	ON OFF	*			LED			BO		135	209	1	GI
00272	Set Point Operating Hours (SP. Op Hours>)	Set Points (Statistic)	OUT	ON OFF	*			LED			BO		135	229	1	GI
00311	Fault in configuration / setting (FaultConfig/Set)	Power System Data 2	OUT	ON OFF	*			LED			BO					
00312	Gen.err.: Inconsistency group/connection (GenErrGroupConn)	Power System Data 2	OUT	ON	*			LED			BO					
00313	Gen.err.: Sev. earth-CTs with equal typ (GenErrEarthCT)	Power System Data 2	OUT	ON	*			LED			BO					
00314	Gen.err.: Number of sides / measurements (GenErrSidesMeas)	Power System Data 2	OUT	ON	*			LED			BO					
00390	>Warning stage from gas in oil detector (>Gas in oil)	External Annunciations of Transformer	SP	ON OFF	*			LED	BI		BO					

F.No.	Description	Function	Type of Information	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
00391	>Warning stage from Buchholz protection (>Buchh. Warn)	External Annunciations of Transformer	SP	ON OFF	*			LED	BI		BO		150	41	1	GI
00392	>Tripp. stage from Buchholz protection (>Buchh. Trip)	External Annunciations of Transformer	SP	ON OFF	*			LED	BI		BO		150	42	1	GI
00393	>Tank supervision from Buchh. protect. (>Buchh. Tank)	External Annunciations of Transformer	SP	ON OFF	*			LED	BI		BO		150	43	1	GI
00409	>BLOCK Op Counter (>BLOCK Op Count)	Statistics	SP	ON OFF	*			LED	BI		BO					
00501	Relay PICKUP (Relay PICKUP)	Power System Data 2	OUT	*	ON		M	LED			BO		150	151	2	GI
00511	Relay GENERAL TRIP command (Relay TRIP)	Power System Data 2	OUT	*	ON		M	LED			BO		150	161	2	GI
00545	Time from Pickup to drop out (PU Time)	Power System Data 2	OUT													
00546	Time from Pickup to TRIP (TRIP Time)	Power System Data 2	OUT													
00576	Primary fault current IL1 side1 (IL1S1:)	Power System Data 2	OUT	*	*											
00577	Primary fault current IL2 side1 (IL2S1:)	Power System Data 2	OUT	*	*											
00578	Primary fault current IL3 side1 (IL3S1:)	Power System Data 2	OUT	*	*											
00579	Primary fault current IL1 side2 (IL1S2:)	Power System Data 2	OUT	*	*											
00580	Primary fault current IL2 side2 (IL2S2:)	Power System Data 2	OUT	*	*											
00581	Primary fault current IL3 side2 (IL3S2:)	Power System Data 2	OUT	*	*											
00582	Primary fault current I1 (I1:)	Power System Data 2	OUT	*	*											
00583	Primary fault current I2 (I2:)	Power System Data 2	OUT	*	*											
00584	Primary fault current I3 (I3:)	Power System Data 2	OUT	*	*											
00585	Primary fault current I4 (I4:)	Power System Data 2	OUT	*	*											
00586	Primary fault current I5 (I5:)	Power System Data 2	OUT	*	*											
00587	Primary fault current I6 (I6:)	Power System Data 2	OUT	*	*											
00588	Primary fault current I7 (I7:)	Power System Data 2	OUT	*	*											

F.No.	Description	Function	Type of Information	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
01000	Number of breaker TRIP commands (# TRIPs=)	Statistics	OUT													
01020	Counter of operating hours (Op.Hours=)	Statistics	OUT													
01403	>BLOCK Breaker failure (>BLOCK BkrFail)	Breaker Failure Protection	SP	*	*			LED	BI		BO		166	103	1	GI
01431	>Breaker failure initiated externally (>BrkFail extSRC)	Breaker Failure Protection	SP	ON OFF	*			LED	BI		BO		166	104	1	GI
01451	Breaker failure is switched OFF (BkrFail OFF)	Breaker Failure Protection	OUT	ON OFF	*			LED			BO		166	151	1	GI
01452	Breaker failure is BLOCKED (BkrFail BLOCK)	Breaker Failure Protection	OUT	ON OFF	ON OFF			LED			BO		166	152	1	GI
01453	Breaker failure is ACTIVE (BkrFail ACTIVE)	Breaker Failure Protection	OUT	ON OFF	*			LED			BO		166	153	1	GI
01456	Breaker failure (internal) PICKUP (BkrFail int PU)	Breaker Failure Protection	OUT	*	ON OFF			LED			BO		166	156	2	GI
01457	Breaker failure (external) PICKUP (BkrFail ext PU)	Breaker Failure Protection	OUT	*	ON OFF			LED			BO		166	157	2	GI
01488	Breaker failure Not avail. for this obj. (BkrFail Not av.)	Breaker Failure Protection	OUT	ON	*			LED			BO					
01492	BF TRIP T1 (local trip) (BF T1-TRIP(loc))	Breaker Failure Protection	OUT	*	ON		M	LED			BO		166	192	2	GI
01494	BF TRIP T2 (busbar trip) (BF T2-TRIP(bus))	Breaker Failure Protection	OUT	*	ON		M	LED			BO		166	194	2	GI
01503	>BLOCK Thermal Overload Protection (>BLK ThOverload)	Thermal Overload Protection	SP	*	*			LED	BI		BO		167	3	1	GI
01507	>Emergency start Th. Overload Protection (>Emer.Start O/L)	Thermal Overload Protection	SP	ON OFF	*			LED	BI		BO		167	7	1	GI
01511	Thermal Overload Protection OFF (Th.Overload OFF)	Thermal Overload Protection	OUT	ON OFF	*			LED			BO		167	11	1	GI
01512	Thermal Overload Protection BLOKKED (Th.Overload BLK)	Thermal Overload Protection	OUT	ON OFF	ON OFF			LED			BO		167	12	1	GI
01513	Thermal Overload Protection ACTIVE (Th.Overload ACT)	Thermal Overload Protection	OUT	ON OFF	*			LED			BO		167	13	1	GI
01515	Th. Overload Current Alarm (I alarm) (O/L I Alarm)	Thermal Overload Protection	OUT	ON OFF	*			LED			BO		167	15	1	GI
01516	Thermal Overload Alarm (O/L Θ Alarm)	Thermal Overload Protection	OUT	ON OFF	*			LED			BO		167	16	1	GI
01517	Thermal Overload picked up (O/L Th. pick.up)	Thermal Overload Protection	OUT	ON OFF	*			LED			BO		167	17	1	GI
01521	Thermal Overload TRIP (ThOverload TRIP)	Thermal Overload Protection	OUT	*	ON OFF		M	LED			BO		167	21	2	GI
01541	Thermal Overload hot spot Th. Alarm (O/L ht.spot Al.)	Thermal Overload Protection	OUT	ON OFF	*			LED			BO		167	41	1	GI

F.No.	Description	Function	Type of Infor-mation	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
01542	Thermal Overload hot spot Th. TRIP (O/L h.spot TRIP)	Thermal Overload Protection	OUT	ON OFF	*			LED			BO		167	42	2	GI
01543	Thermal Overload aging rate Alarm (O/L ag.rate Al.)	Thermal Overload Protection	OUT	ON OFF	*			LED			BO		167	43	1	GI
01544	Thermal Overload aging rate TRIP (O/L ag.rt. TRIP)	Thermal Overload Protection	OUT	ON OFF	*			LED			BO		167	44	1	GI
01545	Th. Overload No temperature mesured (O/L No Th.meas.)	Thermal Overload Protection	OUT	ON	*			LED			BO					
01546	Th. Overload err.:adverse Adap.factor CT (O/L Adap.fact.)	Thermal Overload Protection	OUT	ON	*			LED			BO					
01549	Th. Overload Not available for this obj. (O/L Not avail.)	Thermal Overload Protection	OUT	ON	*			LED			BO					
01704	>BLOCK Phase time overcurrent (>BLK Phase O/C)	Time overcurrent Phase	SP	*	*			LED	BI		BO					
01714	>BLOCK Earth time overcurrent (>BLK Earth O/C)	Time overcurrent Earth	SP	*	*			LED	BI		BO					
01721	>BLOCK I>> (>BLOCK I>>)	Time overcurrent Phase	SP	*	*			LED	BI		BO		60	1	1	GI
01722	>BLOCK I> (>BLOCK I>)	Time overcurrent Phase	SP	*	*			LED	BI		BO		60	2	1	GI
01723	>BLOCK Ip (>BLOCK Ip)	Time overcurrent Phase	SP	*	*			LED	BI		BO		60	3	1	GI
01724	>BLOCK IE>> (>BLOCK IE>>)	Time overcurrent Earth	SP	*	*			LED	BI		BO		60	4	1	GI
01725	>BLOCK IE> (>BLOCK IE>)	Time overcurrent Earth	SP	*	*			LED	BI		BO		60	5	1	GI
01726	>BLOCK IEp (>BLOCK IEp)	Time overcurrent Earth	SP	*	*			LED	BI		BO		60	6	1	GI
01730	>BLOCK Cold-Load-Pickup (>BLOCK CLP)	Cold Load Pickup	SP	*	*			LED	BI		BO					
01731	>BLOCK Cold-Load-Pickup stop timer (>BLK CLP stpTim)	Cold Load Pickup	SP	ON OFF	ON OFF			LED	BI		BO		60	243	1	GI
01741	>BLOCK 3I0 time overcurrent (>BLK 3I0 O/C)	Time overcurrent 3I0	SP	*	*			LED	BI		BO					
01742	>BLOCK 3I0>> time overcurrent (>BLOCK 3I0>>)	Time overcurrent 3I0	SP	*	*			LED	BI		BO		60	9	1	GI
01743	>BLOCK 3I0> time overcurrent (>BLOCK 3I0>)	Time overcurrent 3I0	SP	*	*			LED	BI		BO		60	10	1	GI
01744	>BLOCK 3I0p time overcurrent (>BLOCK 3I0p)	Time overcurrent 3I0	SP	*	*			LED	BI		BO		60	11	1	GI
01748	Time Overcurrent 3I0 is OFF (O/C 3I0 OFF)	Time overcurrent 3I0	OUT	ON OFF	*			LED			BO		60	151	1	GI
01749	Time Overcurrent 3I0 is BLOCKED (O/C 3I0 BLK)	Time overcurrent 3I0	OUT	ON OFF	ON OFF			LED			BO		60	152	1	GI

F.No.	Description	Function	Type of Infor-mation	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
01750	Time Overcurrent 3I0 is ACTIVE (O/C 3I0 ACTIVE)	Time overcurrent 3I0	OUT	ON OFF	*			LED			BO		60	153	1	GI
01751	Time Overcurrent Phase is OFF (O/C Phase OFF)	Time overcurrent Phase	OUT	ON OFF	*			LED			BO		60	21	1	GI
01752	Time Overcurrent Phase is BLOCKED (O/C Phase BLK)	Time overcurrent Phase	OUT	ON OFF	ON OFF			LED			BO		60	22	1	GI
01753	Time Overcurrent Phase is ACTIVE (O/C Phase ACT)	Time overcurrent Phase	OUT	ON OFF	*			LED			BO		60	23	1	GI
01756	Time Overcurrent Earth is OFF (O/C Earth OFF)	Time overcurrent Earth	OUT	ON OFF	*			LED			BO		60	26	1	GI
01757	Time Overcurrent Earth is BLOCKED (O/C Earth BLK)	Time overcurrent Earth	OUT	ON OFF	ON OFF			LED			BO		60	27	1	GI
01758	Time Overcurrent Earth is ACTIVE (O/C Earth ACT)	Time overcurrent Earth	OUT	ON OFF	*			LED			BO		60	28	1	GI
01761	Time Overcurrent picked up (Overcurrent PU)	General O/C	OUT	*	ON OFF			LED			BO		60	69	2	GI
01762	Time Overcurrent Phase L1 picked up (O/C Ph L1 PU)	Time overcurrent Phase	OUT	*	ON OFF		M	LED			BO		60	112	2	GI
01763	Time Overcurrent Phase L2 picked up (O/C Ph L2 PU)	Time overcurrent Phase	OUT	*	ON OFF		M	LED			BO		60	113	2	GI
01764	Time Overcurrent Phase L3 picked up (O/C Ph L3 PU)	Time overcurrent Phase	OUT	*	ON OFF		M	LED			BO		60	114	2	GI
01765	Time Overcurrent Earth picked up (O/C Earth PU)	Time overcurrent Earth	OUT	*	ON OFF		M	LED			BO		60	67	2	GI
01766	Time Overcurrent 3I0 picked up (O/C 3I0 PU)	Time overcurrent 3I0	OUT	*	ON OFF		M	LED			BO		60	154	2	GI
01791	Time Overcurrent TRIP (Overcurrent-TRIP)	General O/C	OUT	*	ON		M	LED			BO		60	68	2	GI
01800	I>> picked up (I>> picked up)	Time overcurrent Phase	OUT	*	ON OFF			LED			BO		60	75	2	GI
01804	I>> Time Out (I>> Time Out)	Time overcurrent Phase	OUT	*	*			LED			BO		60	49	2	GI
01805	I>> TRIP (I>> TRIP)	Time overcurrent Phase	OUT	*	ON			LED			BO		60	70	2	GI
01810	I> picked up (I> picked up)	Time overcurrent Phase	OUT	*	ON OFF			LED			BO		60	76	2	GI
01814	I> Time Out (I> Time Out)	Time overcurrent Phase	OUT	*	*			LED			BO		60	53	2	GI
01815	I> TRIP (I> TRIP)	Time overcurrent Phase	OUT	*	ON			LED			BO		60	71	2	GI
01820	Ip picked up (Ip picked up)	Time overcurrent Phase	OUT	*	ON OFF			LED			BO		60	77	2	GI
01824	Ip Time Out (Ip Time Out)	Time overcurrent Phase	OUT	*	*			LED			BO		60	57	2	GI

F.No.	Description	Function	Type of Infor-mation	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
01825	Ip TRIP (Ip TRIP)	Time overcurrent Phase	OUT	*	ON			LED			BO		60	58	2	GI
01831	IE>> picked up (IE>> picked up)	Time overcurrent Earth	OUT	*	ON OFF			LED			BO		60	59	2	GI
01832	IE>> Time Out (IE>> Time Out)	Time overcurrent Earth	OUT	*	*			LED			BO		60	60	2	GI
01833	IE>> TRIP (IE>> TRIP)	Time overcurrent Earth	OUT	*	ON			LED			BO		60	61	2	GI
01834	IE> picked up (IE> picked up)	Time overcurrent Earth	OUT	*	ON OFF			LED			BO		60	62	2	GI
01835	IE> Time Out (IE> Time Out)	Time overcurrent Earth	OUT	*	*			LED			BO		60	63	2	GI
01836	IE> TRIP (IE> TRIP)	Time overcurrent Earth	OUT	*	ON			LED			BO		60	72	2	GI
01837	IEp picked up (IEp picked up)	Time overcurrent Earth	OUT	*	ON OFF			LED			BO		60	64	2	GI
01838	IEp Time Out (IEp TimeOut)	Time overcurrent Earth	OUT	*	*			LED			BO		60	65	2	GI
01839	IEp TRIP (IEp TRIP)	Time overcurrent Earth	OUT	*	ON			LED			BO		60	66	2	GI
01843	Cross blk: PhX blocked PhY (INRUSH X-BLK)	Time overcurrent Phase	OUT	*	ON OFF			LED			BO					
01851	I> BLOCKED (I> BLOCKED)	Time overcurrent Phase	OUT	ON OFF	ON OFF			LED			BO		60	105	1	GI
01852	I>> BLOCKED (I>> BLOCKED)	Time overcurrent Phase	OUT	ON OFF	ON OFF			LED			BO		60	106	1	GI
01853	IE> BLOCKED (IE> BLOCKED)	Time overcurrent Earth	OUT	ON OFF	ON OFF			LED			BO		60	107	1	GI
01854	IE>> BLOCKED (IE>> BLOCKED)	Time overcurrent Earth	OUT	ON OFF	ON OFF			LED			BO		60	108	1	GI
01855	Ip BLOCKED (Ip BLOCKED)	Time overcurrent Phase	OUT	ON OFF	ON OFF			LED			BO		60	109	1	GI
01856	IEp BLOCKED (IEp BLOCKED)	Time overcurrent Earth	OUT	ON OFF	ON OFF			LED			BO		60	110	1	GI
01857	3I0> BLOCKED (3I0> BLOCKED)	Time overcurrent 3I0	OUT	ON OFF	ON OFF			LED			BO		60	159	1	GI
01858	3I0>> BLOCKED (3I0>> BLOCKED)	Time overcurrent 3I0	OUT	ON OFF	ON OFF			LED			BO		60	155	1	GI
01859	3I0p BLOCKED (3I0p BLOCKED)	Time overcurrent 3I0	OUT	ON OFF	ON OFF			LED			BO		60	163	1	GI
01860	O/C Phase: Not available for this objekt (O/C Ph. Not av.)	Time overcurrent Phase	OUT	ON	*			LED			BO					
01861	O/C 3I0: Not available for this objekt (O/C 3I0 Not av.)	Time overcurrent 3I0	OUT	ON	*			LED			BO					

F.No.	Description	Function	Type of Infor-mation	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
01862	O/C Earth err.: No auxiliary CT assigned (O/C Earth ErrCT)	Time overcurrent Earth	OUT	ON	*			LED			BO					
01901	3I0>> picked up (3I0>> picked up)	Time overcurrent 3I0	OUT	*	ON OFF			LED			BO		60	156	2	GI
01902	3I0>> Time Out (3I0>> Time Out)	Time overcurrent 3I0	OUT	*	*			LED			BO		60	157	2	GI
01903	3I0>> TRIP (3I0>> TRIP)	Time overcurrent 3I0	OUT	*	ON			LED			BO		60	158	2	GI
01904	3I0> picked up (3I0> picked up)	Time overcurrent 3I0	OUT	*	ON OFF			LED			BO		60	160	2	GI
01905	3I0> Time Out (3I0> Time Out)	Time overcurrent 3I0	OUT	*	*			LED			BO		60	161	2	GI
01906	3I0> TRIP (3I0> TRIP)	Time overcurrent 3I0	OUT	*	ON			LED			BO		60	162	2	GI
01907	3I0p picked up (3I0p picked up)	Time overcurrent 3I0	OUT	*	ON OFF			LED			BO		60	164	2	GI
01908	3I0p Time Out (3I0p TimeOut)	Time overcurrent 3I0	OUT	*	*			LED			BO		60	165	2	GI
01909	3I0p TRIP (3I0p TRIP)	Time overcurrent 3I0	OUT	*	ON			LED			BO		60	166	2	GI
01994	Cold-Load-Pickup switched OFF (CLP OFF)	Cold Load Pickup	OUT	ON OFF	*			LED			BO		60	244	1	GI
01995	Cold-Load-Pickup is BLOCKED (CLP BLOCKED)	Cold Load Pickup	OUT	ON OFF	ON OFF			LED			BO		60	245	1	GI
01996	Cold-Load-Pickup is RUNNING (CLP running)	Cold Load Pickup	OUT	ON OFF	*			LED			BO		60	246	1	GI
01998	Dynamic settings O/C Phase are ACTIVE (I Dyn.set. ACT)	Cold Load Pickup	OUT	ON OFF	ON OFF			LED			BO		60	248	1	GI
01999	Dynamic settings O/C 3I0 are ACTIVE (3I0 Dyn.set.ACT)	Cold Load Pickup	OUT	ON OFF	ON OFF			LED			BO		60	249	1	GI
02000	Dynamic settings O/C Earth are ACTIVE (IE Dyn.set. ACT)	Cold Load Pickup	OUT	ON OFF	ON OFF			LED			BO		60	250	1	GI
04523	>Block external trip 1 (>BLOCK Ext 1)	External Trip Functions	SP	*	*			LED	BI		BO					
04526	>Trigger external trip 1 (>Ext trip 1)	External Trip Functions	SP	ON OFF	*			LED	BI		BO		51	126	1	GI
04531	External trip 1 is switched OFF (Ext 1 OFF)	External Trip Functions	OUT	ON OFF	*			LED			BO		51	131	1	GI
04532	External trip 1 is BLOCKED (Ext 1 BLOCKED)	External Trip Functions	OUT	ON OFF	ON OFF			LED			BO		51	132	1	GI
04533	External trip 1 is ACTIVE (Ext 1 ACTIVE)	External Trip Functions	OUT	ON OFF	*			LED			BO		51	133	1	GI
04536	External trip 1: General picked up (Ext 1 picked up)	External Trip Functions	OUT	*	ON OFF			LED			BO		51	136	2	GI

F.No.	Description	Function	Type of Infor-ma-tion	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
04537	External trip 1: General TRIP (Ext 1 Gen. TRIP)	External Trip Functions	OUT	*	ON			LED			BO		51	137	2	GI
04543	>BLOCK external trip 2 (>BLOCK Ext 2)	External Trip Functions	SP	*	*			LED	BI		BO					
04546	>Trigger external trip 2 (>Ext trip 2)	External Trip Functions	SP	ON OFF	*			LED	BI		BO		51	146	1	GI
04551	External trip 2 is switched OFF (Ext 2 OFF)	External Trip Functions	OUT	ON OFF	*			LED			BO		51	151	1	GI
04552	External trip 2 is BLOCKED (Ext 2 BLOCKED)	External Trip Functions	OUT	ON OFF	ON OFF			LED			BO		51	152	1	GI
04553	External trip 2 is ACTIVE (Ext 2 ACTIVE)	External Trip Functions	OUT	ON OFF	*			LED			BO		51	153	1	GI
04556	External trip 2: General picked up (Ext 2 picked up)	External Trip Functions	OUT	*	ON OFF			LED			BO		51	156	2	GI
04557	External trip 2: General TRIP (Ext 2 Gen. TRIP)	External Trip Functions	OUT	*	ON			LED			BO		51	157	2	GI
05143	>BLOCK I2 (Unbalance Load) (>BLOCK I2)	Unbalance Load (Negative Sequence)	SP	*	*			LED	BI		BO		70	126	1	GI
05145	>Reverse Phase Rotation (>Reverse Rot.)	Power System Data 1	SP	ON OFF	*			LED	BI		BO		71	34	1	GI
05147	Phase Rotation L1L2L3 (Rotation L1L2L3)	Power System Data 1	OUT	ON OFF	*			LED			BO		70	128	1	GI
05148	Phase Rotation L1L3L2 (Rotation L1L3L2)	Power System Data 1	OUT	ON OFF	*			LED			BO		70	129	1	GI
05151	I2 switched OFF (I2 OFF)	Unbalance Load (Negative Sequence)	OUT	ON OFF	*			LED			BO		70	131	1	GI
05152	I2 is BLOCKED (I2 BLOCKED)	Unbalance Load (Negative Sequence)	OUT	ON OFF	ON OFF			LED			BO		70	132	1	GI
05153	I2 is ACTIVE (I2 ACTIVE)	Unbalance Load (Negative Sequence)	OUT	ON OFF	*			LED			BO		70	133	1	GI
05159	I2>> picked up (I2>> picked up)	Unbalance Load (Negative Sequence)	OUT	*	ON OFF			LED			BO		70	138	2	GI
05165	I2> picked up (I2> picked up)	Unbalance Load (Negative Sequence)	OUT	*	ON OFF			LED			BO		70	150	2	GI
05166	I2p picked up (I2p picked up)	Unbalance Load (Negative Sequence)	OUT	*	ON OFF			LED			BO		70	141	2	GI
05168	I2 err.: adverse Adaption factor CT (I2 Adap.fact.)	Unbalance Load (Negative Sequence)	OUT	ON	*			LED			BO					

F.No.	Description	Function	Type of Infor-ma-tion	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
05170	I2 TRIP (I2 TRIP)	Unbalance Load (Negative Sequence)	OUT	*	ON		M	LED			BO		70	149	2	GI
05172	I2 err.: Not available for this objekt (I2 Not avail.)	Unbalance Load (Negative Sequence)	OUT	ON	*			LED			BO					
05353	>BLOCK overexcitation protection (>U/f BLOCK)	Overexcitation Protection (U/f)	SP	*	*			LED	BI		BO					
05357	>Reset memory of thermal replica U/f (>RM th.rep. U/f)	Overexcitation Protection (U/f)	SP	*	*			LED	BI		BO					
05361	Overexcitation protection is swiched OFF (U/f> OFF)	Overexcitation Protection (U/f)	OUT	ON OFF	*			LED			BO		71	83	1	GI
05362	Overexcitation protection is BLOKKED (U/f> BLOCKED)	Overexcitation Protection (U/f)	OUT	ON OFF	ON OFF			LED			BO		71	84	1	GI
05363	Overexcitation protection is ACTIVE (U/f> ACTIVE)	Overexcitation Protection (U/f)	OUT	ON OFF	*			LED			BO		71	85	1	GI
05367	Overexc. prot.: U/f warning stage (U/f> warn)	Overexcitation Protection (U/f)	OUT	ON OFF	*			LED			BO		71	86	1	GI
05369	Reset memory of thermal replica U/f (RM th.rep. U/f)	Overexcitation Protection (U/f)	OUT	ON OFF	*			LED			BO		71	88	1	GI
05370	Overexc. prot.: U/f> picked up (U/f> picked up)	Overexcitation Protection (U/f)	OUT	*	ON OFF			LED			BO		71	89	2	GI
05371	Overexc. prot.: TRIP of U/f>> stage (U/f>> TRIP)	Overexcitation Protection (U/f)	OUT	*	ON		M	LED			BO		71	90	2	GI
05372	Overexc. prot.: TRIP of th. stage (U/f> th.TRIP)	Overexcitation Protection (U/f)	OUT	*	ON			LED			BO		71	91	2	GI
05373	Overexc. prot.: U/f>> picked up (U/f>> pick.up)	Overexcitation Protection (U/f)	OUT	*	ON OFF			LED			BO		71	92	2	GI
05376	Overexc. err: No VT assigned (U/f Err No VT)	Overexcitation Protection (U/f)	OUT	ON	*			LED			BO					
05377	Overexc. err: Not avail. for this object (U/f Not avail.)	Overexcitation Protection (U/f)	OUT	ON	*			LED			BO					
05603	>BLOCK differential protection (>Diff BLOCK)	Differential Protection	SP	*	*			LED	BI		BO					
05615	Differential protection is switched OFF (Diff OFF)	Differential Protection	OUT	ON OFF	*			LED			BO		75	15	1	GI
05616	Differential protection is BLOCKED (Diff BLOCKED)	Differential Protection	OUT	ON OFF	ON OFF			LED			BO		75	16	1	GI
05617	Differential protection is ACTIVE (Diff ACTIVE)	Differential Protection	OUT	ON OFF	*			LED			BO		75	17	1	GI
05620	Diff err.: adverse Adaption factor CT (Diff Adap.fact.)	Differential Protection	OUT	ON	*			LED			BO					
05631	Differential protection picked up (Diff picked up)	Differential Protection	OUT	*	ON OFF		M	LED			BO		75	31	2	GI

F.No.	Description	Function	Type of Information	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
05644	Diff: Blocked by 2.Harmon. L1 (Diff 2.Harm L1)	Differential Protection	OUT	*	ON OFF			LED			BO		75	44	2	GI
05645	Diff: Blocked by 2.Harmon. L2 (Diff 2.Harm L2)	Differential Protection	OUT	*	ON OFF			LED			BO		75	45	2	GI
05646	Diff: Blocked by 2.Harmon. L3 (Diff 2.Harm L3)	Differential Protection	OUT	*	ON OFF			LED			BO		75	46	2	GI
05647	Diff: Blocked by n.Harmon. L1 (Diff n.Harm L1)	Differential Protection	OUT	*	ON OFF			LED			BO		75	47	2	GI
05648	Diff: Blocked by n.Harmon. L2 (Diff n.Harm L2)	Differential Protection	OUT	*	ON OFF			LED			BO		75	48	2	GI
05649	Diff: Blocked by n.Harmon. L3 (Diff n.Harm L3)	Differential Protection	OUT	*	ON OFF			LED			BO		75	49	2	GI
05651	Diff. prot.: Blocked by ext. fault L1 (Diff Bl. exF.L1)	Differential Protection	OUT	*	ON OFF			LED			BO		75	51	2	GI
05652	Diff. prot.: Blocked by ext. fault L2 (Diff Bl. exF.L2)	Differential Protection	OUT	*	ON OFF			LED			BO		75	52	2	GI
05653	Diff. prot.: Blocked by ext. fault.L3 (Diff Bl. exF.L3)	Differential Protection	OUT	*	ON OFF			LED			BO		75	53	2	GI
05657	Diff: Crossblock by 2.Harmonic (DiffCrosBlk 2HM)	Differential Protection	OUT	*	ON OFF			LED			BO					
05658	Diff: Crossblock by n.Harmonic (DiffCrosBlk nHM)	Differential Protection	OUT	*	ON OFF			LED			BO					
05660	Diff: Crossblock by ext. fault (DiffCrosBlk exF)	Differential Protection	OUT	*	ON OFF			LED			BO					
05662	Diff. prot.: Blocked by CT fault L1 (Block Iflt.L1)	Differential Protection	OUT	ON OFF	ON OFF			LED			BO		75	62	2	GI
05663	Diff. prot.: Blocked by CT fault L2 (Block Iflt.L2)	Differential Protection	OUT	ON OFF	ON OFF			LED			BO		75	63	2	GI
05664	Diff. prot.: Blocked by CT fault L3 (Block Iflt.L3)	Differential Protection	OUT	ON OFF	ON OFF			LED			BO		75	64	2	GI
05666	Diff: Increase of char. phase (start) L1 (DiffStrtInChaL1)	Differential Protection	OUT	ON OFF	ON OFF			LED			BO					
05667	Diff: Increase of char. phase (start) L2 (DiffStrtInChaL2)	Differential Protection	OUT	ON OFF	ON OFF			LED			BO					
05668	Diff: Increase of char. phase (start) L3 (DiffStrtInChaL3)	Differential Protection	OUT	ON OFF	ON OFF			LED			BO					
05670	Diff: Curr-Release for Trip (Diff I-Release)	Differential Protection	OUT	*	ON OFF			LED			BO					
05671	Differential protection TRIP (Diff TRIP)	Differential Protection	OUT	*	*			LED			BO		176	68	2	
05672	Differential protection: TRIP L1 (Diff TRIP L1)	Differential Protection	OUT	*	*			LED			BO		176	86	2	
05673	Differential protection: TRIP L2 (Diff TRIP L2)	Differential Protection	OUT	*	*			LED			BO		176	87	2	

F.No.	Description	Function	Type of Information	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
05674	Differential protection: TRIP L3 (Diff TRIP L3)	Differential Protection	OUT	*	*			LED			BO		176	88	2	
05681	Diff. prot.: IDIFF> L1 (without Tdelay) (Diff> L1)	Differential Protection	OUT	*	ON OFF			LED			BO		75	81	2	GI
05682	Diff. prot.: IDIFF> L2 (without Tdelay) (Diff> L2)	Differential Protection	OUT	*	ON OFF			LED			BO		75	82	2	GI
05683	Diff. prot.: IDIFF> L3 (without Tdelay) (Diff> L3)	Differential Protection	OUT	*	ON OFF			LED			BO		75	83	2	GI
05684	Diff. prot: IDIFF>> L1 (without Tdelay) (Diff>> L1)	Differential Protection	OUT	*	ON OFF			LED			BO		75	84	2	GI
05685	Diff. prot: IDIFF>> L2 (without Tdelay) (Diff>> L2)	Differential Protection	OUT	*	ON OFF			LED			BO		75	85	2	GI
05686	Diff. prot: IDIFF>> L3 (without Tdelay) (Diff>> L3)	Differential Protection	OUT	*	ON OFF			LED			BO		75	86	2	GI
05691	Differential prot.: TRIP by IDIFF> (Diff> TRIP)	Differential Protection	OUT	*	ON		M	LED			BO		75	91	2	GI
05692	Differential prot.: TRIP by IDIFF>> (Diff>> TRIP)	Differential Protection	OUT	*	ON		M	LED			BO		75	92	2	GI
05701	Diff. curr. in L1 at trip without Tdelay (Dif L1 :)	Differential Protection	OUT	*	ON OFF								75	101	4	
05702	Diff. curr. in L2 at trip without Tdelay (Dif L2 :)	Differential Protection	OUT	*	ON OFF								75	102	4	
05703	Diff. curr. in L3 at trip without Tdelay (Dif L3 :)	Differential Protection	OUT	*	ON OFF								75	103	4	
05704	Restr.curr. in L1 at trip without Tdelay (Res L1 :)	Differential Protection	OUT	*	ON OFF								75	104	4	
05705	Restr.curr. in L2 at trip without Tdelay (Res L2 :)	Differential Protection	OUT	*	ON OFF								75	105	4	
05706	Restr.curr. in L3 at trip without Tdelay (Res L3 :)	Differential Protection	OUT	*	ON OFF								75	106	4	
05721	Diff. prot: Adaption factor CT I1 (Dif CT-I1:)	Differential Protection	OUT	ON OFF												
05722	Diff. prot: Adaption factor CT I2 (Dif CT-I2:)	Differential Protection	OUT	ON OFF												
05723	Diff. prot: Adaption factor CT I3 (Dif CT-I3:)	Differential Protection	OUT	ON OFF												
05724	Diff. prot: Adaption factor CT I4 (Dif CT-I4:)	Differential Protection	OUT	ON OFF												
05725	Diff. prot: Adaption factor CT I5 (Dif CT-I5:)	Differential Protection	OUT	ON OFF												
05726	Diff. prot: Adaption factor CT I6 (Dif CT-I6:)	Differential Protection	OUT	ON OFF												
05727	Diff. prot: Adaption factor CT I7 (Dif CT-I7:)	Differential Protection	OUT	ON OFF												

F.No.	Description	Function	Type of Infor-ma-tion	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
05728	Diff. prot: Adaption factor CT I8 (Dif CT-I8:)	Differential Protection	OUT	ON OFF												
05729	Diff. prot: Adaption factor CT I9 (Dif CT-I9:)	Differential Protection	OUT	ON OFF												
05730	Diff. prot: Adaption factor CT I10 (Dif CT-I10:)	Differential Protection	OUT	ON OFF												
05731	Diff. prot: Adaption factor CT I11 (Dif CT-I11:)	Differential Protection	OUT	ON OFF												
05732	Diff. prot: Adaption factor CT I12 (Dif CT-I12:)	Differential Protection	OUT	ON OFF												
05733	Diff. prot: Adaption factor CT M1 (Dif CT-M1:)	Differential Protection	OUT	ON OFF												
05734	Diff. prot: Adaption factor CT M2 (Dif CT-M2:)	Differential Protection	OUT	ON OFF												
05735	Diff. prot: Adaption factor CT M3 (Dif CT-M3:)	Differential Protection	OUT	ON OFF												
05736	Diff. prot: Adaption factor CT M4 (Dif CT-M4:)	Differential Protection	OUT	ON OFF												
05737	Diff. prot: Adaption factor CT M5 (Dif CT-M5:)	Differential Protection	OUT	ON OFF												
05738	Diff. prot: Adaption factor aux. CT IX1 (Dif CT-IX1:)	Differential Protection	OUT	ON OFF												
05739	Diff. prot: Adaption factor aux. CT IX2 (Dif CT-IX2:)	Differential Protection	OUT	ON OFF												
05740	Diff. prot: Adaption factor aux. CT IX3 (Dif CT-IX3:)	Differential Protection	OUT	ON OFF												
05741	Diff. prot: Adaption factor aux. CT IX4 (Dif CT-IX4:)	Differential Protection	OUT	ON OFF												
05742	Diff: DC L1 (Diff DC L1)	Differential Protection	OUT	*	ON OFF			LED			BO					
05743	Diff: DC L2 (Diff DC L2)	Differential Protection	OUT	*	ON OFF			LED			BO					
05744	Diff: DC L3 (Diff DC L3)	Differential Protection	OUT	*	ON OFF			LED			BO					
05745	Diff: Increase of char. phase (DC) (Diff DC InCha)	Differential Protection	OUT	*	ON OFF			LED			BO					
05803	>BLOCK restricted earth fault prot. (>BLOCK REF)	Restricted Earth Fault Protection	SP	*	*			LED	BI		BO					
05811	Restricted earth fault is switched OFF (REF OFF)	Restricted Earth Fault Protection	OUT	ON OFF	*			LED			BO		76	11	1	GI
05812	Restricted earth fault is BLOCKED (REF BLOCKED)	Restricted Earth Fault Protection	OUT	ON OFF	ON OFF			LED			BO		76	12	1	GI
05813	Restricted earth fault is ACTIVE (REF ACTIVE)	Restricted Earth Fault Protection	OUT	ON OFF	*			LED			BO		76	13	1	GI

F.No.	Description	Function	Type of Infor-ma-tion	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
05816	Restr. earth flt.: Time delay started (REF T start)	Restricted Earth Fault Protection	OUT	*	ON OFF			LED			BO		76	16	2	GI
05817	Restr. earth flt.: picked up (REF picked up)	Restricted Earth Fault Protection	OUT	*	ON OFF		M	LED			BO		76	17	2	GI
05821	Restr. earth flt.: TRIP (REF TRIP)	Restricted Earth Fault Protection	OUT	*	ON		M	LED			BO		176	89	2	
05826	REF: Value D at trip (without Tdelay) (REF D:)	Restricted Earth Fault Protection	OUT	*	ON OFF								76	26	4	
05827	REF: Value S at trip (without Tdelay) (REF S:)	Restricted Earth Fault Protection	OUT	*	ON OFF								76	27	4	
05830	REF err.: No starpoint CT (REF Err CTstar)	Restricted Earth Fault Protection	OUT	ON	*			LED			BO					
05833	REF: Adaption factor CT starpnt. wind. (REF CTstar:)	Restricted Earth Fault Protection	OUT	ON OFF												
05835	REF err.: Not available for this objekt (REF Not avail.)	Restricted Earth Fault Protection	OUT	ON	*			LED			BO					
05836	REF err.: adverse Adaption factor CT (REF Adap.fact.)	Restricted Earth Fault Protection	OUT	ON	*			LED			BO					
05951	>BLOCK Time Overcurrent 1Phase (>BLK 1Ph. O/C)	Time overcurrent 1Phase	SP	*	*			LED	BI		BO					
05952	>BLOCK Time Overcurrent 1Ph. I> (>BLK 1Ph. I>)	Time overcurrent 1Phase	SP	*	*			LED	BI		BO					
05953	>BLOCK Time Overcurrent 1Ph. I>> (>BLK 1Ph. I>>)	Time overcurrent 1Phase	SP	*	*			LED	BI		BO					
05961	Time Overcurrent 1Phase is OFF (O/C 1Ph. OFF)	Time overcurrent 1Phase	OUT	ON OFF	*			LED			BO		76	161	1	GI
05962	Time Overcurrent 1Phase is BLOKKED (O/C 1Ph. BLK)	Time overcurrent 1Phase	OUT	ON OFF	ON OFF			LED			BO		76	162	1	GI
05963	Time Overcurrent 1Phase is ACTIVE (O/C 1Ph. ACT)	Time overcurrent 1Phase	OUT	ON OFF	*			LED			BO		76	163	1	GI
05966	Time Overcurrent 1Phase I> BLOKKED (O/C 1Ph I> BLK)	Time overcurrent 1Phase	OUT	ON OFF	ON OFF			LED			BO		76	166	1	GI
05967	Time Overcurrent 1Phase I>> BLOKKED (O/C 1Ph I>> BLK)	Time overcurrent 1Phase	OUT	ON OFF	ON OFF			LED			BO		76	167	1	GI
05971	Time Overcurrent 1Phase picked up (O/C 1Ph PU)	Time overcurrent 1Phase	OUT	*	ON OFF			LED			BO		76	171	2	GI
05972	Time Overcurrent 1Phase TRIP (O/C 1Ph TRIP)	Time overcurrent 1Phase	OUT	*	ON			LED			BO		76	172	2	GI
05974	Time Overcurrent 1Phase I> picked up (O/C 1Ph I> PU)	Time overcurrent 1Phase	OUT	*	ON OFF			LED			BO		76	174	2	GI
05975	Time Overcurrent 1Phase I> TRIP (O/C 1Ph I> TRIP)	Time overcurrent 1Phase	OUT	*	ON		M	LED			BO		76	175	2	GI
05977	Time Overcurrent 1Phase I>> picked up (O/C 1Ph I>> PU)	Time overcurrent 1Phase	OUT	*	ON OFF			LED			BO		76	177	2	GI

F.No.	Description	Function	Type of Infor-mation	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
05979	Time Overcurrent 1Phase I>> TRIP (O/C1Ph I>> TRIP)	Time overcurrent 1Phase	OUT	*	ON		M	LED			BO		76	179	2	GI
05980	Time Overcurrent 1Phase: I at pick up (O/C 1Ph I:)	Time overcurrent 1Phase	OUT		ON OFF								76	180	4	
05981	O/C 1Phase err.:No auxiliary CT assigned (O/C 1Ph Err CT)	Time overcurrent 1Phase	OUT	ON	*			LED			BO					
06851	>BLOCK Trip circuit supervision (>BLOCK TripC)	Trip Circuit Supervision	SP	*	*			LED	BI		BO					
06852	>Trip circuit supervision: trip relay (>TripC trip rel)	Trip Circuit Supervision	SP	ON OFF	*			LED	BI		BO		170	51	1	GI
06853	>Trip circuit supervision: breaker relay (>TripC brk rel.)	Trip Circuit Supervision	SP	ON OFF	*			LED	BI		BO		170	52	1	GI
06861	Trip circuit supervision OFF (TripC OFF)	Trip Circuit Supervision	OUT	ON OFF	*			LED			BO		170	53	1	GI
06862	Trip circuit supervision is BLOCKED (TripC BLOCKED)	Trip Circuit Supervision	OUT	ON OFF	ON OFF			LED			BO		153	16	1	GI
06863	Trip circuit supervision is ACTIVE (TripC ACTIVE)	Trip Circuit Supervision	OUT	ON OFF	*			LED			BO		153	17	1	GI
06864	Trip Circuit blk. Bin. input is not set (TripC ProgFail)	Trip Circuit Supervision	OUT	ON OFF	*			LED			BO		170	54	1	GI
06865	Failure Trip Circuit (FAIL: Trip cir.)	Trip Circuit Supervision	OUT	ON OFF	*			LED			BO		170	55	1	GI
07551	I> InRush picked up (I> InRush PU)	Time overcurrent Phase	OUT	*	ON OFF			LED			BO		60	80	2	GI
07552	IE> InRush picked up (IE> InRush PU)	Time overcurrent Earth	OUT	*	ON OFF			LED			BO		60	81	2	GI
07553	Ip InRush picked up (Ip InRush PU)	Time overcurrent Phase	OUT	*	ON OFF			LED			BO		60	82	2	GI
07554	IEp InRush picked up (IEp InRush PU)	Time overcurrent Earth	OUT	*	ON OFF			LED			BO		60	83	2	GI
07564	Earth InRush picked up (Earth InRush PU)	Time overcurrent Earth	OUT	*	ON OFF			LED			BO		60	88	2	GI
07565	Phase L1 InRush picked up (L1 InRush PU)	Time overcurrent Phase	OUT	*	ON OFF			LED			BO		60	89	2	GI
07566	Phase L2 InRush picked up (L2 InRush PU)	Time overcurrent Phase	OUT	*	ON OFF			LED			BO		60	90	2	GI
07567	Phase L3 InRush picked up (L3 InRush PU)	Time overcurrent Phase	OUT	*	ON OFF			LED			BO		60	91	2	GI
07568	3I0 InRush picked up (3I0 InRush PU)	Time overcurrent 3I0	OUT	*	ON OFF			LED			BO		60	95	2	GI
07569	3I0> InRush picked up (3I0> InRush PU)	Time overcurrent 3I0	OUT	*	ON OFF			LED			BO		60	96	2	GI
07570	3I0p InRush picked up (3I0p InRush PU)	Time overcurrent 3I0	OUT	*	ON OFF			LED			BO		60	97	2	GI

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				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
07571	>BLOCK time overcurrent Phase InRush (>BLK Ph.O/C Inr)	Time overcurrent Phase	SP	ON OFF	ON OFF			LED	BI		BO		60	98	1	GI
07572	>BLOCK time overcurrent 3I0 InRush (>BLK 3I0O/C Inr)	Time overcurrent 3I0	SP	ON OFF	ON OFF			LED	BI		BO		60	99	1	GI
07573	>BLOCK time overcurrent Earth InRush (>BLK E O/C Inr)	Time overcurrent Earth	SP	ON OFF	ON OFF			LED	BI		BO		60	100	1	GI
07581	Phase L1 InRush detected (L1 InRush det.)	Time overcurrent Phase	OUT	*	ON OFF			LED			BO					
07582	Phase L2 InRush detected (L2 InRush det.)	Time overcurrent Phase	OUT	*	ON OFF			LED			BO					
07583	Phase L3 InRush detected (L3 InRush det.)	Time overcurrent Phase	OUT	*	ON OFF			LED			BO					
14101	Fail: RTD (broken wire/shorted) (Fail: RTD)	RTD-Box	OUT	ON OFF	*			LED			BO					
14111	Fail: RTD 1 (broken wire/shorted) (Fail: RTD 1)	RTD-Box	OUT	ON OFF	*			LED			BO					
14112	RTD 1 Temperature stage 1 picked up (RTD 1 St.1 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14113	RTD 1 Temperature stage 2 picked up (RTD 1 St.2 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14121	Fail: RTD 2 (broken wire/shorted) (Fail: RTD 2)	RTD-Box	OUT	ON OFF	*			LED			BO					
14122	RTD 2 Temperature stage 1 picked up (RTD 2 St.1 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14123	RTD 2 Temperature stage 2 picked up (RTD 2 St.2 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14131	Fail: RTD 3 (broken wire/shorted) (Fail: RTD 3)	RTD-Box	OUT	ON OFF	*			LED			BO					
14132	RTD 3 Temperature stage 1 picked up (RTD 3 St.1 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14133	RTD 3 Temperature stage 2 picked up (RTD 3 St.2 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14141	Fail: RTD 4 (broken wire/shorted) (Fail: RTD 4)	RTD-Box	OUT	ON OFF	*			LED			BO					
14142	RTD 4 Temperature stage 1 picked up (RTD 4 St.1 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14143	RTD 4 Temperature stage 2 picked up (RTD 4 St.2 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14151	Fail: RTD 5 (broken wire/shorted) (Fail: RTD 5)	RTD-Box	OUT	ON OFF	*			LED			BO					
14152	RTD 5 Temperature stage 1 picked up (RTD 5 St.1 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14153	RTD 5 Temperature stage 2 picked up (RTD 5 St.2 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					

F.No.	Description	Function	Type of Infor-ma-tion	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
14161	Fail: RTD 6 (broken wire/shorted) (Fail: RTD 6)	RTD-Box	OUT	ON OFF	*			LED			BO					
14162	RTD 6 Temperature stage 1 picked up (RTD 6 St.1 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14163	RTD 6 Temperature stage 2 picked up (RTD 6 St.2 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14171	Fail: RTD 7 (broken wire/shorted) (Fail: RTD 7)	RTD-Box	OUT	ON OFF	*			LED			BO					
14172	RTD 7 Temperature stage 1 picked up (RTD 7 St.1 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14173	RTD 7 Temperature stage 2 picked up (RTD 7 St.2 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14181	Fail: RTD 8 (broken wire/shorted) (Fail: RTD 8)	RTD-Box	OUT	ON OFF	*			LED			BO					
14182	RTD 8 Temperature stage 1 picked up (RTD 8 St.1 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14183	RTD 8 Temperature stage 2 picked up (RTD 8 St.2 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14191	Fail: RTD 9 (broken wire/shorted) (Fail: RTD 9)	RTD-Box	OUT	ON OFF	*			LED			BO					
14192	RTD 9 Temperature stage 1 picked up (RTD 9 St.1 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14193	RTD 9 Temperature stage 2 picked up (RTD 9 St.2 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14201	Fail: RTD10 (broken wire/shorted) (Fail: RTD10)	RTD-Box	OUT	ON OFF	*			LED			BO					
14202	RTD10 Temperature stage 1 picked up (RTD10 St.1 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14203	RTD10 Temperature stage 2 picked up (RTD10 St.2 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14211	Fail: RTD11 (broken wire/shorted) (Fail: RTD11)	RTD-Box	OUT	ON OFF	*			LED			BO					
14212	RTD11 Temperature stage 1 picked up (RTD11 St.1 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14213	RTD11 Temperature stage 2 picked up (RTD11 St.2 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14221	Fail: RTD12 (broken wire/shorted) (Fail: RTD12)	RTD-Box	OUT	ON OFF	*			LED			BO					
14222	RTD12 Temperature stage 1 picked up (RTD12 St.1 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
14223	RTD12 Temperature stage 2 picked up (RTD12 St.2 p.up)	RTD-Box	OUT	ON OFF	*			LED			BO					
30054	Broken wire is switched OFF (Broken wire OFF)	Supervision	OUT	ON OFF	*			LED			BO					

F.No.	Description	Function	Type of Infor-mation	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
30060	General: Adaption factor CT M1 (Gen CT-M1:)	Power System Data 2	OUT	ON OFF												
30061	General: Adaption factor CT M2 (Gen CT-M2:)	Power System Data 2	OUT	ON OFF												
30062	General: Adaption factor CT M3 (Gen CT-M3:)	Power System Data 2	OUT	ON OFF												
30063	General: Adaption factor CT M4 (Gen CT-M4:)	Power System Data 2	OUT	ON OFF												
30064	General: Adaption factor CT M5 (Gen CT-M5:)	Power System Data 2	OUT	ON OFF												
30065	General: Adaption factor VT UL123 (Gen VT-U1:)	Power System Data 2	OUT	ON OFF												
30067	parameter too low: (par too low:)	Power System Data 2	OUT	ON OFF												
30068	parameter too high: (par too high:)	Power System Data 2	OUT	ON OFF												
30069	setting fault: (settingFault:)	Power System Data 2	OUT	ON OFF												
30070	Manual close signal meas.loc. 1 detected (Man.Clos.Det.M1)	Power System Data 2	OUT	ON	*			LED			BO					
30071	Manual close signal meas.loc. 2 detected (Man.Clos.Det.M2)	Power System Data 2	OUT	ON	*			LED			BO					
30072	Manual close signal meas.loc. 3 detected (Man.Clos.Det.M3)	Power System Data 2	OUT	ON	*			LED			BO					
30073	Manual close signal meas.loc. 4 detected (Man.Clos.Det.M4)	Power System Data 2	OUT	ON	*			LED			BO					
30074	Manual close signal meas.loc. 5 detected (Man.Clos.Det.M5)	Power System Data 2	OUT	ON	*			LED			BO					
30075	Manual close signal side 1 is detected (Man.Clos.Det.S1)	Power System Data 2	OUT	ON	*			LED			BO					
30076	Manual close signal side 2 is detected (Man.Clos.Det.S2)	Power System Data 2	OUT	ON	*			LED			BO					
30077	Manual close signal side 3 is detected (Man.Clos.Det.S3)	Power System Data 2	OUT	ON	*			LED			BO					
30078	Manual close signal side 4 is detected (Man.Clos.Det.S4)	Power System Data 2	OUT	ON	*			LED			BO					
30079	Manual close signal side 5 is detected (Man.Clos.Det.S5)	Power System Data 2	OUT	ON	*			LED			BO					
30080	Measurment location 1 is disconnected (M1 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30081	Measurment location 2 is disconnected (M2 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30082	Measurment location 3 is disconnected (M3 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					

F.No.	Description	Function	Type of Infor-ma-tion	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
30083	Measurment location 4 is disconnected (M4 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30084	Measurment location 5 is disconnected (M5 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30085	End 1 is disconnected (I1 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30086	End 2 is disconnected (I2 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30087	End 3 is disconnected (I3 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30088	End 4 is disconnected (I4 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30089	End 5 is disconnected (I5 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30090	End 6 is disconnected (I6 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30091	End 7 is disconnected (I7 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30092	End 8 is disconnected (I8 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30093	End 9 is disconnected (I9 disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30094	End 10 is disconnected (I10disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30095	End 11 is disconnected (I11disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30096	End 12 is disconnected (I12disconnected)	Disconnect measurment location	OUT	ON OFF	*			LED			BO					
30097	Err: inconsist. jumper/setting CT M1 (Err. IN CT M1)	Supervision	OUT	ON OFF	*			LED			BO					
30098	Err: inconsist. jumper/setting CT M2 (Err. IN CT M2)	Supervision	OUT	ON OFF	*			LED			BO					
30099	Err: inconsist. jumper/setting CT M3 (Err. IN CT M3)	Supervision	OUT	ON OFF	*			LED			BO					
30100	Err: inconsist. jumper/setting CT M4 (Err. IN CT M4)	Supervision	OUT	ON OFF	*			LED			BO					
30101	Err: inconsist. jumper/setting CT M5 (Err. IN CT M5)	Supervision	OUT	ON OFF	*			LED			BO					
30102	Err: inconsist. jumper/setting CT I1..3 (Err.IN CT1..3)	Supervision	OUT	ON OFF	*			LED			BO					
30103	Err: inconsist. jumper/setting CT I4..6 (Err.IN CT4..6)	Supervision	OUT	ON OFF	*			LED			BO					
30104	Err: inconsist. jumper/setting CT I7..9 (Err.IN CT7..9)	Supervision	OUT	ON OFF	*			LED			BO					

F.No.	Description	Function	Type of Infor-ma-tion	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
30105	Err:inconsist. jumper/setting CT I10..12 (Err.IN CT10..12)	Supervision	OUT	ON OFF	*			LED			BO					
30106	Err: inconsist. jumper/setting CT IX1 (Err. IN CT IX1)	Supervision	OUT	ON OFF	*			LED			BO					
30107	Err: inconsist. jumper/setting CT IX2 (Err. IN CT IX2)	Supervision	OUT	ON OFF	*			LED			BO					
30108	Err: inconsist. jumper/setting CT IX3 (Err. IN CT IX3)	Supervision	OUT	ON OFF	*			LED			BO					
30109	Err: inconsist. jumper/setting CT IX4 (Err. IN CT IX4)	Supervision	OUT	ON OFF	*			LED			BO					
30110	Fail.: Current Balance meas. location 1 (Fail balan. IM1)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
30111	Fail.: Current Balance meas. location 2 (Fail balan. IM2)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
30112	Fail.: Current Balance meas. location 3 (Fail balan. IM3)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
30113	Fail.: Current Balance meas. location 4 (Fail balan. IM4)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
30114	Fail.: Current Balance meas. location 5 (Fail balan. IM5)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
30115	Failure: Phase Sequence I meas. loc. 1 (FailPh.Seq IM1)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
30116	Failure: Phase Sequence I meas. loc. 2 (FailPh.Seq IM2)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
30117	Failure: Phase Sequence I meas. loc. 3 (FailPh.Seq IM3)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
30118	Failure: Phase Sequence I meas. loc. 4 (FailPh.Seq IM4)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
30119	Failure: Phase Sequence I meas. loc. 5 (FailPh.Seq IM5)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
30120	Broken wire IL1 measurement location 1 (brk. wire IL1M1)	Supervision	OUT	ON OFF	*			LED			BO					
30121	Broken wire IL2 measurement location 1 (brk. wire IL2M1)	Supervision	OUT	ON OFF	*			LED			BO					
30122	Broken wire IL3 measurement location 1 (brk. wire IL3M1)	Supervision	OUT	ON OFF	*			LED			BO					
30123	Broken wire IL1 measurement location 2 (brk. wire IL1M2)	Supervision	OUT	ON OFF	*			LED			BO					
30124	Broken wire IL2 measurement location 2 (brk. wire IL2M2)	Supervision	OUT	ON OFF	*			LED			BO					
30125	Broken wire IL3 measurement location 2 (brk. wire IL3M2)	Supervision	OUT	ON OFF	*			LED			BO					
30126	Broken wire IL1 measurement location 3 (brk. wire IL1M3)	Supervision	OUT	ON OFF	*			LED			BO					

F.No.	Description	Function	Type of Infor-mation	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
30127	Broken wire IL2 measurement location 3 (brk. wire IL2M3)	Supervision	OUT	ON OFF	*			LED			BO					
30128	Broken wire IL3 measurement location 3 (brk. wire IL3M3)	Supervision	OUT	ON OFF	*			LED			BO					
30129	Broken wire IL1 measurement location 4 (brk. wire IL1M4)	Supervision	OUT	ON OFF	*			LED			BO					
30130	Broken wire IL2 measurement location 4 (brk. wire IL2M4)	Supervision	OUT	ON OFF	*			LED			BO					
30131	Broken wire IL3 measurement location 4 (brk. wire IL3M4)	Supervision	OUT	ON OFF	*			LED			BO					
30132	Broken wire IL1 measurement location 5 (brk. wire IL1M5)	Supervision	OUT	ON OFF	*			LED			BO					
30133	Broken wire IL2 measurement location 5 (brk. wire IL2M5)	Supervision	OUT	ON OFF	*			LED			BO					
30134	Broken wire IL3 measurement location 5 (brk. wire IL3M5)	Supervision	OUT	ON OFF	*			LED			BO					
30135	Incons. M1: CBaux open/ curr. persistent (Incons.CBaux M1)	Supervision	OUT	ON OFF	*			LED			BO					
30136	Incons. M2: CBaux open/ curr. persistent (Incons.CBaux M2)	Supervision	OUT	ON OFF	*			LED			BO					
30137	Incons. M3: CBaux open/ curr. persistent (Incons.CBaux M3)	Supervision	OUT	ON OFF	*			LED			BO					
30138	Incons. M4: CBaux open/ curr. persistent (Incons.CBaux M4)	Supervision	OUT	ON OFF	*			LED			BO					
30139	Incons. M5: CBaux open/ curr. persistent (Incons.CBaux M5)	Supervision	OUT	ON OFF	*			LED			BO					
30140	Incons. S1: CBaux open/ curr. persistent (Incons.CBaux S1)	Supervision	OUT	ON OFF	*			LED			BO					
30141	Incons. S2: CBaux open/ curr. persistent (Incons.CBaux S2)	Supervision	OUT	ON OFF	*			LED			BO					
30142	Incons. S3: CBaux open/ curr. persistent (Incons.CBaux S3)	Supervision	OUT	ON OFF	*			LED			BO					
30143	Incons. S4: CBaux open/ curr. persistent (Incons.CBaux S4)	Supervision	OUT	ON OFF	*			LED			BO					
30144	Incons. S5: CBaux open/ curr. persistent (Incons.CBaux S5)	Supervision	OUT	ON OFF	*			LED			BO					
30145	Failure: disconnect measurment location (Fail.Disconnect)	Supervision	OUT	ON OFF	*			LED			BO					
30251	Primary fault current IL1 meas. loc. 1 (IL1M1:)	Power System Data 2	OUT	*	*											
30252	Primary fault current IL2 meas. loc. 1 (IL2M1:)	Power System Data 2	OUT	*	*											
30253	Primary fault current IL3 meas. loc. 1 (IL3M1:)	Power System Data 2	OUT	*	*											

F.No.	Description	Function	Type of Infor-mation	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
30254	Primary fault current IL1 meas. loc. 2 (IL1M2:)	Power System Data 2	OUT	*	*											
30255	Primary fault current IL2 meas. loc. 2 (IL2M2:)	Power System Data 2	OUT	*	*											
30256	Primary fault current IL3 meas. loc. 2 (IL3M2:)	Power System Data 2	OUT	*	*											
30257	Primary fault current IL1 meas. loc. 3 (IL1M3:)	Power System Data 2	OUT	*	*											
30258	Primary fault current IL2 meas. loc. 3 (IL2M3:)	Power System Data 2	OUT	*	*											
30259	Primary fault current IL3 meas. loc. 3 (IL3M3:)	Power System Data 2	OUT	*	*											
30260	Primary fault current IL1 meas. loc. 4 (IL1M4:)	Power System Data 2	OUT	*	*											
30261	Primary fault current IL2 meas. loc. 4 (IL2M4:)	Power System Data 2	OUT	*	*											
30262	Primary fault current IL3 meas. loc. 4 (IL3M4:)	Power System Data 2	OUT	*	*											
30263	Primary fault current IL1 meas. loc. 5 (IL1M5:)	Power System Data 2	OUT	*	*											
30264	Primary fault current IL2 meas. loc. 5 (IL2M5:)	Power System Data 2	OUT	*	*											
30265	Primary fault current IL3 meas. loc. 5 (IL3M5:)	Power System Data 2	OUT	*	*											
30266	Primary fault current IL1 side3 (IL1S3:)	Power System Data 2	OUT	*	*											
30267	Primary fault current IL2 side3 (IL2S3:)	Power System Data 2	OUT	*	*											
30268	Primary fault current IL3 side3 (IL3S3:)	Power System Data 2	OUT	*	*											
30269	Primary fault current IL1 side4 (IL1S4:)	Power System Data 2	OUT	*	*											
30270	Primary fault current IL2 side4 (IL2S4:)	Power System Data 2	OUT	*	*											
30271	Primary fault current IL3 side4 (IL3S4:)	Power System Data 2	OUT	*	*											
30272	Primary fault current IL1 side5 (IL1S5:)	Power System Data 2	OUT	*	*											
30273	Primary fault current IL2 side5 (IL2S5:)	Power System Data 2	OUT	*	*											
30274	Primary fault current IL3 side5 (IL3S5:)	Power System Data 2	OUT	*	*											
30275	Primary fault current I8 (I8:)	Power System Data 2	OUT	*	*											

F.No.	Description	Function	Type of Information	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
30276	Primary fault current I9 (I9:)	Power System Data 2	OUT	*	*											
30277	Primary fault current I10 (I10:)	Power System Data 2	OUT	*	*											
30278	Primary fault current I11 (I11:)	Power System Data 2	OUT	*	*											
30279	Primary fault current I12 (I12:)	Power System Data 2	OUT	*	*											
30351	>Manual close signal measurement loc. 1 (>ManualClose M1)	Power System Data 2	SP	*	*			LED	BI		BO					
30352	>Manual close signal measurement loc. 2 (>ManualClose M2)	Power System Data 2	SP	*	*			LED	BI		BO					
30353	>Manual close signal measurement loc. 3 (>ManualClose M3)	Power System Data 2	SP	*	*			LED	BI		BO					
30354	>Manual close signal measurement loc. 4 (>ManualClose M4)	Power System Data 2	SP	*	*			LED	BI		BO					
30355	>Manual close signal measurement loc. 5 (>ManualClose M5)	Power System Data 2	SP	*	*			LED	BI		BO					
30356	>Manual close signal side 1 (>Manual-Close S1)	Power System Data 2	SP	*	*			LED	BI		BO					
30357	>Manual close signal side 2 (>Manual-Close S2)	Power System Data 2	SP	*	*			LED	BI		BO					
30358	>Manual close signal side 3 (>Manual-Close S3)	Power System Data 2	SP	*	*			LED	BI		BO					
30359	>Manual close signal side 4 (>Manual-Close S4)	Power System Data 2	SP	*	*			LED	BI		BO					
30360	>Manual close signal side 5 (>Manual-Close S5)	Power System Data 2	SP	*	*			LED	BI		BO					
30361	>disconnect without test: current = 0 (>disconn. I>=0)	Disconnect measurment location	SP	on off	*			LED	BI		BO					
30362	>disconnect measurment location 1 (>disconnect M1)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30363	>disconnect measurment location 2 (>disconnect M2)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30364	>disconnect measurment location 3 (>disconnect M3)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30365	>disconnect measurment location 4 (>disconnect M4)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30366	>disconnect measurment location 5 (>disconnect M5)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30367	>disconnect end 1 (>disconnect I1)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30368	>disconnect end 2 (>disconnect I2)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					

F.No.	Description	Function	Type of Information	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
30369	>disconnect end 3 (>disconnect I3)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30370	>disconnect end 4 (>disconnect I4)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30371	>disconnect end 5 (>disconnect I5)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30372	>disconnect end 6 (>disconnect I6)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30373	>disconnect end 7 (>disconnect I7)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30374	>disconnect end 8 (>disconnect I8)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30375	>disconnect end 9 (>disconnect I9)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30376	>disconnect end 10 (>disconnect I10)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30377	>disconnect end 11 (>disconnect I11)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30378	>disconnect end 12 (>disconnect I12)	Disconnect measurment location	SP	ON OFF	*			LED	BI		BO					
30607	Accumulation of interrupted curr. L1 S1 (ΣIL1S1:)	Statistics	OUT													
30608	Accumulation of interrupted curr. L2 S1 (ΣIL2S1:)	Statistics	OUT													
30609	Accumulation of interrupted curr. L3 S1 (ΣIL3S1:)	Statistics	OUT													
30610	Accumulation of interrupted curr. L1 S2 (ΣIL1S2:)	Statistics	OUT													
30611	Accumulation of interrupted curr. L2 S2 (ΣIL2S2:)	Statistics	OUT													
30612	Accumulation of interrupted curr. L3 S2 (ΣIL3S2:)	Statistics	OUT													
30620	Accumulation of interrupted curr. I1 (ΣI1:)	Statistics	OUT													
30621	Accumulation of interrupted curr. I2 (ΣI2:)	Statistics	OUT													
30622	Accumulation of interrupted curr. I3 (ΣI3:)	Statistics	OUT													
30623	Accumulation of interrupted curr. I4 (ΣI4:)	Statistics	OUT													
30624	Accumulation of interrupted curr. I5 (ΣI5:)	Statistics	OUT													
30625	Accumulation of interrupted curr. I6 (ΣI6:)	Statistics	OUT													

F.No.	Description	Function	Type of Infor-mation	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
30626	Accumulation of interrupted curr. I7 (ΣI7:)	Statistics	OUT													
30763	Accumulation of interrupted curr. L1 M1 (ΣIL1M1:)	Statistics	OUT													
30764	Accumulation of interrupted curr. L2 M1 (ΣIL2M1:)	Statistics	OUT													
30765	Accumulation of interrupted curr. L3 M1 (ΣIL3M1:)	Statistics	OUT													
30766	Accumulation of interrupted curr. L1 M2 (ΣIL1M2:)	Statistics	OUT													
30767	Accumulation of interrupted curr. L2 M2 (ΣIL2M2:)	Statistics	OUT													
30768	Accumulation of interrupted curr. L3 M2 (ΣIL3M2:)	Statistics	OUT													
30769	Accumulation of interrupted curr. L1 M3 (ΣIL1M3:)	Statistics	OUT													
30770	Accumulation of interrupted curr. L2 M3 (ΣIL2M3:)	Statistics	OUT													
30771	Accumulation of interrupted curr. L3 M3 (ΣIL3M3:)	Statistics	OUT													
30772	Accumulation of interrupted curr. L1 M4 (ΣIL1M4:)	Statistics	OUT													
30773	Accumulation of interrupted curr. L2 M4 (ΣIL2M4:)	Statistics	OUT													
30774	Accumulation of interrupted curr. L3 M4 (ΣIL3M4:)	Statistics	OUT													
30775	Accumulation of interrupted curr. L1 M5 (ΣIL1M5:)	Statistics	OUT													
30776	Accumulation of interrupted curr. L2 M5 (ΣIL2M5:)	Statistics	OUT													
30777	Accumulation of interrupted curr. L3 M5 (ΣIL3M5:)	Statistics	OUT													
30778	Accumulation of interrupted curr. L1 S3 (ΣIL1S3:)	Statistics	OUT													
30779	Accumulation of interrupted curr. L2 S3 (ΣIL2S3:)	Statistics	OUT													
30780	Accumulation of interrupted curr. L3 S3 (ΣIL3S3:)	Statistics	OUT													
30781	Accumulation of interrupted curr. L1 S4 (ΣIL1S4:)	Statistics	OUT													
30782	Accumulation of interrupted curr. L2 S4 (ΣIL2S4:)	Statistics	OUT													
30783	Accumulation of interrupted curr. L3 S4 (ΣIL3S4:)	Statistics	OUT													

F.No.	Description	Function	Type of Infor-mation	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
30784	Accumulation of interrupted curr. L1 S5 (ΣIL1S5:)	Statistics	OUT													
30785	Accumulation of interrupted curr. L2 S5 (ΣIL2S5:)	Statistics	OUT													
30786	Accumulation of interrupted curr. L3 S5 (ΣIL3S5:)	Statistics	OUT													
30787	Accumulation of interrupted curr. I8 (ΣI8:)	Statistics	OUT													
30788	Accumulation of interrupted curr. I9 (ΣI9:)	Statistics	OUT													
30789	Accumulation of interrupted curr. I10 (ΣI10:)	Statistics	OUT													
30790	Accumulation of interrupted curr. I11 (ΣI11:)	Statistics	OUT													
30791	Accumulation of interrupted curr. I12 (ΣI12:)	Statistics	OUT													
	>Back Light on (>Light on)	Device	SP	ON OFF	*			LED	BI		BO					
	>Quitt Lock Out: General Trip (>QuitG-TRP)	Power System Data 2	IntSP	*	*			LED	BI	FK	BO					
	circuit breaker Q0 (Q0)	Control Device	CF_D12	on off							BO					
	circuit breaker Q0 (Q0)	Control Device	DP	on off	*				BI			CB				
	Clock Synchronization (SynchClock)	Device	IntSP_Ev	*	*			LED			BO					
	Control Authority (Cntrl Auth)	Control Authorization	IntSP	ON OFF	*			LED								
	Control Authority (Cntrl Auth)	Control Authorization	DP	ON OFF	*			LED					101	85	1	GI
	Controlmode LOCAL (ModeLOCAL)	Control Authorization	IntSP	ON OFF	*			LED								
	Controlmode LOCAL (ModeLOCAL)	Control Authorization	DP	ON OFF	*			LED					101	86	1	GI
	Controlmode REMOTE (ModeREMOTE)	Control Authorization	IntSP	ON OFF	*			LED								
	Error FMS FO 1 (Error FMS1)	Supervision	OUT	ON OFF	*			LED			BO					
	Error FMS FO 2 (Error FMS2)	Supervision	OUT	ON OFF	*			LED			BO					
	Error Systeminterface (SysIntErr.)	Supervision	IntSP	ON OFF	*			LED			BO					
	Fault Recording Start (FltRecSta)	Oscillographic Fault Records	IntSP	ON OFF	*			LED			BO					

F.No.	Description	Function	Type of Infor-ma-tion	Log-Buffers				Configurable in Matrix					IEC 60870-5-103			
				Event Log On/Off	Trip (Fault) Log On/Off	Ground Fault Log On/Off	Marked in Oscill. Record	LED	Binary Input	Function Key	Binary Output	Chatter Blocking	Type	Information-No	Data Unit (ASDU)	General Interrogation
	Group A (Group A)	Change Group	IntSP	ON OFF	*			LED			BO		176	23	1	GI
	Group B (Group B)	Change Group	IntSP	ON OFF	*			LED			BO		176	24	1	GI
	Group C (Group C)	Change Group	IntSP	ON OFF	*			LED			BO		176	25	1	GI
	Group D (Group D)	Change Group	IntSP	ON OFF	*			LED			BO		176	26	1	GI
	Hardware Test Mode (HWTestMod)	Device	IntSP	ON OFF	*			LED			BO					
	Lock Out: General TRIP (G-TRP Quit)	Power System Data 2	IntSP	*	*			LED			BO					
	Stop data transmission (DataStop)	Device	IntSP	ON OFF	*			LED			BO		176	20	1	GI
	Test mode (Test mode)	Device	IntSP	ON OFF	*			LED			BO		176	21	1	GI
	Threshold Value 1 (ThreshVal1)	Threshold-Switch	IntSP	ON OFF	*			LED		FK	BO	CB				
	Unlock data transmission via BI (UnlockDT)	Device	IntSP	*	*			LED			BO					

A.9 List of Measured Values

F.No.	Description	Function	IEC 60870-5-103					Configurable in Matrix		
			Function type	Information-No	Compatibility	Data Unit (ASDU)	Position	CFC	Control Display	Default Display
00621	U L1-E (UL1E=)	Measurement						CFC	CD	DD
00622	U L2-E (UL2E=)	Measurement						CFC	CD	DD
00623	U L3-E (UL3E=)	Measurement						CFC	CD	DD
00624	U L12 (UL12=)	Measurement						CFC	CD	DD
00625	U L23 (UL23=)	Measurement						CFC	CD	DD
00626	U L31 (UL31=)	Measurement						CFC	CD	DD
00627	Displacement voltage UE (UE =)	Measurement						CFC	CD	DD
00629	U1 (positive sequence) (U1 =)	Measurement						CFC	CD	DD
00630	U2 (negative sequence) (U2 =)	Measurement						CFC	CD	DD
00641	P (active power) (P =)	Measurement						CFC	CD	DD
00642	Q (reactive power) (Q =)	Measurement						CFC	CD	DD
00644	Frequency (Freq=)	Measurement						CFC	CD	DD
00645	S (apparent power) (S =)	Measurement						CFC	CD	DD
00721	Operat. meas. current IL1 side 1 (IL1S1=)	Measurement	134	139	priv	9	1	CFC	CD	DD
00722	Operat. meas. current IL2 side 1 (IL2S1=)	Measurement	134	139	priv	9	5	CFC	CD	DD
00723	Operat. meas. current IL3 side 1 (IL3S1=)	Measurement	134	139	priv	9	3	CFC	CD	DD
00724	Operat. meas. current IL1 side 2 (IL1S2=)	Measurement	134	139	priv	9	2	CFC	CD	DD
00725	Operat. meas. current IL2 side 2 (IL2S2=)	Measurement	134	139	priv	9	6	CFC	CD	DD
00726	Operat. meas. current IL3 side 2 (IL3S2=)	Measurement	134	139	priv	9	4	CFC	CD	DD
00727	Operat. meas. current IL1 side 3 (IL1S3=)	Measurement						CFC	CD	DD
00728	Operat. meas. current IL2 side 3 (IL2S3=)	Measurement						CFC	CD	DD
00729	Operat. meas. current IL3 side 3 (IL3S3=)	Measurement						CFC	CD	DD
00765	(U/Un) / (f/fn) (U/f =)	Measurement						CFC	CD	DD
00766	Calculated temperature (U/f) (U/f th. =)	Thermal Measurement						CFC	CD	DD
00801	Temperat. rise for warning and trip (Θ /Θtrip =)	Thermal Measurement						CFC	CD	DD
00802	Temperature rise for phase L1 (Θ /ΘtripL1=)	Thermal Measurement						CFC	CD	DD
00803	Temperature rise for phase L2 (Θ /ΘtripL2=)	Thermal Measurement						CFC	CD	DD
00804	Temperature rise for phase L3 (Θ /ΘtripL3=)	Thermal Measurement						CFC	CD	DD
00888	Pulsed Energy Wp (active) (Wp(puls)=)	Energy							CD	DD
00889	Pulsed Energy Wq (reactive) (Wq(puls)=)	Energy							CD	DD
00901	Power Factor (PF =)	Measurement						CFC	CD	DD

F.No.	Description	Function	IEC 60870-5-103					Configurable in Matrix		
			Function type	Information-No	Compatibility	Data Unit (ASDU)	Position	CFC	Control Display	Default Display
00924	Wp Forward (Wp+=)	Energy							CD	DD
00925	Wq Forward (Wq+=)	Energy							CD	DD
00928	Wp Reverse (Wp-=)	Energy							CD	DD
00929	Wq Reverse (Wq-=)	Energy							CD	DD
01063	Aging Rate (Ag.Rate=)	Thermal Measurement						CFC	CD	DD
01066	Load Reserve to warning level (ResWARN=)	Thermal Measurement						CFC	CD	DD
01067	Load Reserve to alarm level (ResALARM=)	Thermal Measurement						CFC	CD	DD
01068	Temperature of RTD 1 (Θ RTD 1 =)	Thermal Measurement	134	146	priv	9	1	CFC	CD	DD
01069	Temperature of RTD 2 (Θ RTD 2 =)	Thermal Measurement	134	146	priv	9	2	CFC	CD	DD
01070	Temperature of RTD 3 (Θ RTD 3 =)	Thermal Measurement	134	146	priv	9	3	CFC	CD	DD
01071	Temperature of RTD 4 (Θ RTD 4 =)	Thermal Measurement	134	146	priv	9	4	CFC	CD	DD
01072	Temperature of RTD 5 (Θ RTD 5 =)	Thermal Measurement	134	146	priv	9	5	CFC	CD	DD
01073	Temperature of RTD 6 (Θ RTD 6 =)	Thermal Measurement	134	146	priv	9	6	CFC	CD	DD
01074	Temperature of RTD 7 (Θ RTD 7 =)	Thermal Measurement	134	146	priv	9	7	CFC	CD	DD
01075	Temperature of RTD 8 (Θ RTD 8 =)	Thermal Measurement	134	146	priv	9	8	CFC	CD	DD
01076	Temperature of RTD 9 (Θ RTD 9 =)	Thermal Measurement	134	146	priv	9	9	CFC	CD	DD
01077	Temperature of RTD10 (Θ RTD10 =)	Thermal Measurement	134	146	priv	9	10	CFC	CD	DD
01078	Temperature of RTD11 (Θ RTD11 =)	Thermal Measurement	134	146	priv	9	11	CFC	CD	DD
01079	Temperature of RTD12 (Θ RTD12 =)	Thermal Measurement	134	146	priv	9	12	CFC	CD	DD
07742	IDiffL1(I/Inominal object [%]) (IDiffL1=)	Diff- and Rest. Measurement						CFC	CD	DD
07743	IDiffL2(I/Inominal object [%]) (IDiffL2=)	Diff- and Rest. Measurement						CFC	CD	DD
07744	IDiffL3(I/Inominal object [%]) (IDiffL3=)	Diff- and Rest. Measurement						CFC	CD	DD
07745	IRestL1(I/Inominal object [%]) (IRestL1=)	Diff- and Rest. Measurement						CFC	CD	DD
07746	IRestL2(I/Inominal object [%]) (IRestL2=)	Diff- and Rest. Measurement						CFC	CD	DD
07747	IRestL3(I/Inominal object [%]) (IRestL3=)	Diff- and Rest. Measurement						CFC	CD	DD
30633	Phase angle of current I1 (φI1=)	Measurement						CFC	CD	DD
30634	Phase angle of current I2 (φI2=)	Measurement						CFC	CD	DD
30635	Phase angle of current I3 (φI3=)	Measurement						CFC	CD	DD
30636	Phase angle of current I4 (φI4=)	Measurement						CFC	CD	DD
30637	Phase angle of current I5 (φI5=)	Measurement						CFC	CD	DD
30638	Phase angle of current I6 (φI6=)	Measurement						CFC	CD	DD
30639	Phase angle of current I7 (φI7=)	Measurement						CFC	CD	DD
30640	3I0 (zero sequence) of side 1 (3I0S1=)	Measurement						CFC	CD	DD
30641	I1 (positive sequence) of side 1 (I1S1=)	Measurement						CFC	CD	DD

F.No.	Description	Function	IEC 60870-5-103					Configurable in Matrix		
			Function type	Information-No	Compatibility	Data Unit (ASDU)	Position	CFC	Control Display	Default Display
30642	I2 (negative sequence) of side 1 (I2S1=)	Measurement						CFC	CD	DD
30643	3I0 (zero sequence) of side 2 (3I0S2=)	Measurement						CFC	CD	DD
30644	I1 (positive sequence) of side 2 (I1S2=)	Measurement						CFC	CD	DD
30645	I2 (negative sequence) of side 2 (I2S2=)	Measurement						CFC	CD	DD
30646	Operat. meas. current I1 (I1=)	Measurement						CFC	CD	DD
30647	Operat. meas. current I2 (I2=)	Measurement						CFC	CD	DD
30648	Operat. meas. current I3 (I3=)	Measurement						CFC	CD	DD
30649	Operat. meas. current I4 (I4=)	Measurement						CFC	CD	DD
30650	Operat. meas. current I5 (I5=)	Measurement						CFC	CD	DD
30651	Operat. meas. current I6 (I6=)	Measurement						CFC	CD	DD
30652	Operat. meas. current I7 (I7=)	Measurement						CFC	CD	DD
30653	Operat. meas. current I8 (I8=)	Measurement						CFC	CD	DD
30654	Idiff REF (I/Inominal object [%]) (IdiffREF=)	Diff- and Rest. Measurement						CFC	CD	DD
30655	Irest REF (I/Inominal object [%]) (IrestREF=)	Diff- and Rest. Measurement						CFC	CD	DD
30656	Operat. meas. voltage Umeas. (Umeas.=)	Measurement						CFC	CD	DD
30661	Operat. meas. current IL1 meas. loc. 1 (IL1M1=)	Measurement	134	149	priv	9	2	CFC	CD	DD
30662	Operat. meas. current IL2 meas. loc. 1 (IL2M1=)	Measurement	134	149	priv	9	1	CFC	CD	DD
30663	Operat. meas. current IL3 meas. loc. 1 (IL3M1=)	Measurement	134	149	priv	9	3	CFC	CD	DD
30664	3I0 (zero sequence) of meas. loc. 1 (3I0M1=)	Measurement						CFC	CD	DD
30665	I1 (positive sequence) of meas. loc. 1 (I1M1=)	Measurement						CFC	CD	DD
30666	I2 (negative sequence) of meas. loc. 1 (I2M1=)	Measurement						CFC	CD	DD
30667	Operat. meas. current IL1 meas. loc. 2 (IL1M2=)	Measurement	134	149	priv	9	5	CFC	CD	DD
30668	Operat. meas. current IL2 meas. loc. 2 (IL2M2=)	Measurement	134	149	priv	9	4	CFC	CD	DD
30669	Operat. meas. current IL3 meas. loc. 2 (IL3M2=)	Measurement	134	149	priv	9	6	CFC	CD	DD
30670	3I0 (zero sequence) of meas. loc. 2 (3I0M2=)	Measurement						CFC	CD	DD
30671	I1 (positive sequence) of meas. loc. 2 (I1M2=)	Measurement						CFC	CD	DD
30672	I2 (negative sequence) of meas. loc. 2 (I2M2=)	Measurement						CFC	CD	DD
30673	Operat. meas. current IL1 meas. loc. 3 (IL1M3=)	Measurement	134	149	priv	9	8	CFC	CD	DD
30674	Operat. meas. current IL2 meas. loc. 3 (IL2M3=)	Measurement	134	149	priv	9	7	CFC	CD	DD
30675	Operat. meas. current IL3 meas. loc. 3 (IL3M3=)	Measurement	134	149	priv	9	9	CFC	CD	DD
30676	3I0 (zero sequence) of meas. loc. 3 (3I0M3=)	Measurement						CFC	CD	DD
30677	I1 (positive sequence) of meas. loc. 3 (I1M3=)	Measurement						CFC	CD	DD
30678	I2 (negative sequence) of meas. loc. 3 (I2M3=)	Measurement						CFC	CD	DD
30679	Operat. meas. current IL1 meas. loc. 4 (IL1M4=)	Measurement	134	149	priv	9	11	CFC	CD	DD

F.No.	Description	Function	IEC 60870-5-103					Configurable in Matrix		
			Function type	Information-No	Compatibility	Data Unit (ASDU)	Position	CFC	Control Display	Default Display
30680	Operat. meas. current IL2 meas. loc. 4 (IL2M4=)	Measurement	134	149	priv	9	10	CFC	CD	DD
30681	Operat. meas. current IL3 meas. loc. 4 (IL3M4=)	Measurement	134	149	priv	9	12	CFC	CD	DD
30682	3I0 (zero sequence) of meas. loc. 4 (3I0M4=)	Measurement						CFC	CD	DD
30683	I1 (positive sequence) of meas. loc. 4 (I1M4=)	Measurement						CFC	CD	DD
30684	I2 (negative sequence) of meas. loc. 4 (I2M4=)	Measurement						CFC	CD	DD
30685	Operat. meas. current IL1 meas. loc. 5 (IL1M5=)	Measurement	134	149	priv	9	14	CFC	CD	DD
30686	Operat. meas. current IL2 meas. loc. 5 (IL2M5=)	Measurement	134	149	priv	9	13	CFC	CD	DD
30687	Operat. meas. current IL3 meas. loc. 5 (IL3M5=)	Measurement	134	149	priv	9	15	CFC	CD	DD
30688	3I0 (zero sequence) of meas. loc. 5 (3I0M5=)	Measurement						CFC	CD	DD
30689	I1 (positive sequence) of meas. loc. 5 (I1M5=)	Measurement						CFC	CD	DD
30690	I2 (negative sequence) of meas. loc. 5 (I2M5=)	Measurement						CFC	CD	DD
30691	Hot spot temperature of leg L1 (Θ leg L1=)	Thermal Measurement						CFC	CD	DD
30692	Hot spot temperature of leg L2 (Θ leg L2=)	Thermal Measurement						CFC	CD	DD
30693	Hot spot temperature of leg L3 (Θ leg L3=)	Thermal Measurement						CFC	CD	DD
30694	Hot spot temperature of leg L12 (Θ leg L12=)	Thermal Measurement						CFC	CD	DD
30695	Hot spot temperature of leg L23 (Θ leg L23=)	Thermal Measurement						CFC	CD	DD
30696	Hot spot temperature of leg L31 (Θ leg L31=)	Thermal Measurement						CFC	CD	DD
30713	3I0 (zero sequence) of side 3 (3I0S3=)	Measurement						CFC	CD	DD
30714	I1 (positive sequence) of side 3 (I1S3=)	Measurement						CFC	CD	DD
30715	I2 (negative sequence) of side 3 (I2S3=)	Measurement						CFC	CD	DD
30716	Operat. meas. current IL1 side 4 (IL1S4=)	Measurement						CFC	CD	DD
30717	Operat. meas. current IL2 side 4 (IL2S4=)	Measurement						CFC	CD	DD
30718	Operat. meas. current IL3 side 4 (IL3S4=)	Measurement						CFC	CD	DD
30719	3I0 (zero sequence) of side 4 (3I0S4=)	Measurement						CFC	CD	DD
30720	I1 (positive sequence) of side 4 (I1S4=)	Measurement						CFC	CD	DD
30721	I2 (negative sequence) of side 4 (I2S4=)	Measurement						CFC	CD	DD
30722	Operat. meas. current IL1 side 5 (IL1S5=)	Measurement						CFC	CD	DD
30723	Operat. meas. current IL2 side 5 (IL2S5=)	Measurement						CFC	CD	DD
30724	Operat. meas. current IL3 side 5 (IL3S5=)	Measurement						CFC	CD	DD
30725	3I0 (zero sequence) of side 5 (3I0S5=)	Measurement						CFC	CD	DD
30726	I1 (positive sequence) of side 5 (I1S5=)	Measurement						CFC	CD	DD
30727	I2 (negative sequence) of side 5 (I2S5=)	Measurement						CFC	CD	DD
30728	Operat. meas. auxiliary current IX1 (IX1=)	Measurement						CFC	CD	DD
30729	Operat. meas. auxiliary current IX2 (IX2=)	Measurement						CFC	CD	DD

F.No.	Description	Function	IEC 60870-5-103					Configurable in Matrix		
			Function type	Information-No	Compatibility	Data Unit (ASDU)	Position	CFC	Control Display	Default Display
30730	Operat. meas. auxiliary current IX3 (IX3=)	Measurement						CFC	CD	DD
30731	Operat. meas. auxiliary current IX4 (IX4=)	Measurement						CFC	CD	DD
30732	Operat. meas. current I9 (I9=)	Measurement						CFC	CD	DD
30733	Operat. meas. current I10 (I10=)	Measurement						CFC	CD	DD
30734	Operat. meas. current I11 (I11=)	Measurement						CFC	CD	DD
30735	Operat. meas. current I12 (I12=)	Measurement						CFC	CD	DD
30736	Phase angle in phase IL1 meas. loc. 1 (φIL1M1=)	Measurement						CFC	CD	DD
30737	Phase angle in phase IL2 meas. loc. 1 (φIL2M1=)	Measurement						CFC	CD	DD
30738	Phase angle in phase IL3 meas. loc. 1 (φIL3M1=)	Measurement						CFC	CD	DD
30739	Phase angle in phase IL1 meas. loc. 2 (φIL1M2=)	Measurement						CFC	CD	DD
30740	Phase angle in phase IL2 meas. loc. 2 (φIL2M2=)	Measurement						CFC	CD	DD
30741	Phase angle in phase IL3 meas. loc. 2 (φIL3M2=)	Measurement						CFC	CD	DD
30742	Phase angle in phase IL1 meas. loc. 3 (φIL1M3=)	Measurement						CFC	CD	DD
30743	Phase angle in phase IL2 meas. loc. 3 (φIL2M3=)	Measurement						CFC	CD	DD
30744	Phase angle in phase IL3 meas. loc. 3 (φIL3M3=)	Measurement						CFC	CD	DD
30745	Phase angle in phase IL1 meas. loc. 4 (φIL1M4=)	Measurement						CFC	CD	DD
30746	Phase angle in phase IL2 meas. loc. 4 (φIL2M4=)	Measurement						CFC	CD	DD
30747	Phase angle in phase IL3 meas. loc. 4 (φIL3M4=)	Measurement						CFC	CD	DD
30748	Phase angle in phase IL1 meas. loc. 5 (φIL1M5=)	Measurement						CFC	CD	DD
30749	Phase angle in phase IL2 meas. loc. 5 (φIL2M5=)	Measurement						CFC	CD	DD
30750	Phase angle in phase IL3 meas. loc. 5 (φIL3M5=)	Measurement						CFC	CD	DD
30751	Phase angle in auxiliary current IX1 (φIX1=)	Measurement						CFC	CD	DD
30752	Phase angle in auxiliary current IX2 (φIX2=)	Measurement						CFC	CD	DD
30753	Phase angle in auxiliary current IX3 (φIX3=)	Measurement						CFC	CD	DD
30754	Phase angle in auxiliary current IX4 (φIX4=)	Measurement						CFC	CD	DD
30755	Phase angle of current I8 (φI8=)	Measurement						CFC	CD	DD
30756	Phase angle of current I9 (φI9=)	Measurement						CFC	CD	DD
30757	Phase angle of current I10 (φI10=)	Measurement						CFC	CD	DD
30758	Phase angle of current I11 (φI11=)	Measurement						CFC	CD	DD
30759	Phase angle of current I12 (φI12=)	Measurement						CFC	CD	DD
30760	Operat. meas. voltage U4 (U4 =)	Measurement						CFC	CD	DD
30761	Operat. meas. voltage U0 measured (U0meas.=)	Measurement						CFC	CD	DD
30762	Operat. meas. voltage U0 calculated (U0calc.=)	Measurement						CFC	CD	DD
30792	Phase angle of voltage UL1E (φUL1E=)	Measurement						CFC	CD	DD

F.No.	Description	Function	IEC 60870-5-103					Configurable in Matrix		
			Function type	Information-No	Compatibility	Data Unit (ASDU)	Position	CFC	Control Display	Default Display
30793	Phase angle of voltage UL2E (φUL2E=)	Measurement						CFC	CD	DD
30794	Phase angle of voltage UL3E (φUL3E=)	Measurement						CFC	CD	DD
30795	Phase angle of voltage U4 (φU4=)	Measurement						CFC	CD	DD
30796	Phase angle of voltage UE (φUE=)	Measurement						CFC	CD	DD
	Operating hours greater than (OpHour>)								CD	DD

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Index

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To

Siemens AG
Dept. PTD PA D DM
D–13623 Berlin
Germany

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