SIPROTEC

Differential Protection
7UT612

V4.0

Manual

C53000–G1176–C148–1

Liability statement

4.00.01

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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® 7UT612 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 50081 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 standards DIN 57435 part 303 (corresponding to VDE 0435 part 303).

Further Standards

ANSI 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:

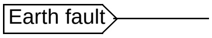
`Parameter names`, i.e. designators of configuration or function parameters which may appear word-for-word in the display of the device or on the screen of a personal computer (with operation software DIGSI® 4), are marked in bold letters of a monospace type style.

`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® 4), are written in italic style, additionally.

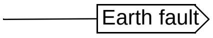
“`Annunciations`”, i.e. designators for information, which may be output by the relay or required from other devices or from the switch gear, are marked in a monospace type style in quotation marks.

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

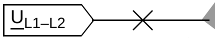
The following symbols are used in drawings:



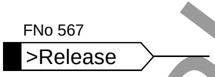
device-internal logical input signal



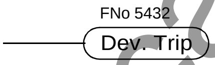
device-internal logical output signal



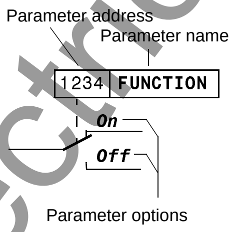
internal input signal of an analogue quantity



external binary input signal with function number Fno

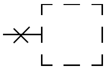


external binary output signal with function number Fno

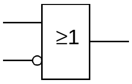


example of a parameter switch designated **`FUNCTION`** with the address 1234 and the possible settings ***`On`*** and ***`Off`***

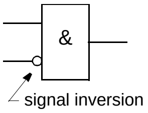
Besides these, graphical symbols are used according to IEC 60617–12 and IEC 60617–13 or similar. Some of the most frequently used are listed below:



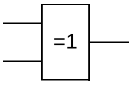
Input signal of an analogue quantity



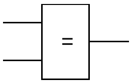
OR gate



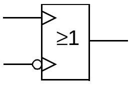
AND gate



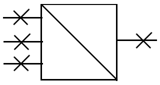
Exclusive–OR gate (antivalence): output is active, if only *one* of the inputs is active



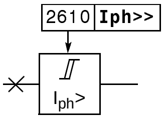
Coincidence gate (equivalence): output is active, if *both* input are active or inactive at the same time



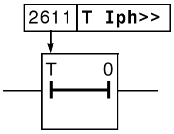
Dynamic inputs (edge–triggered)
above with positive, below with negative edge



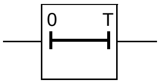
Formation of one analogue output signal from a number of analogue input signals (example: 3)



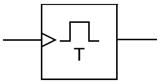
Limit stage with setting address and parameter designator (name)



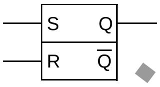
Timer (pickup delay T, example adjustable)
with setting address and parameter designator (name)



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 7UT612 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® 7UT612 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 the device.

Analog Inputs

The measuring inputs “MI” transform the currents derived from the instrument transformers and match them to the internal signal levels for processing in the device. The device includes 8 current inputs.

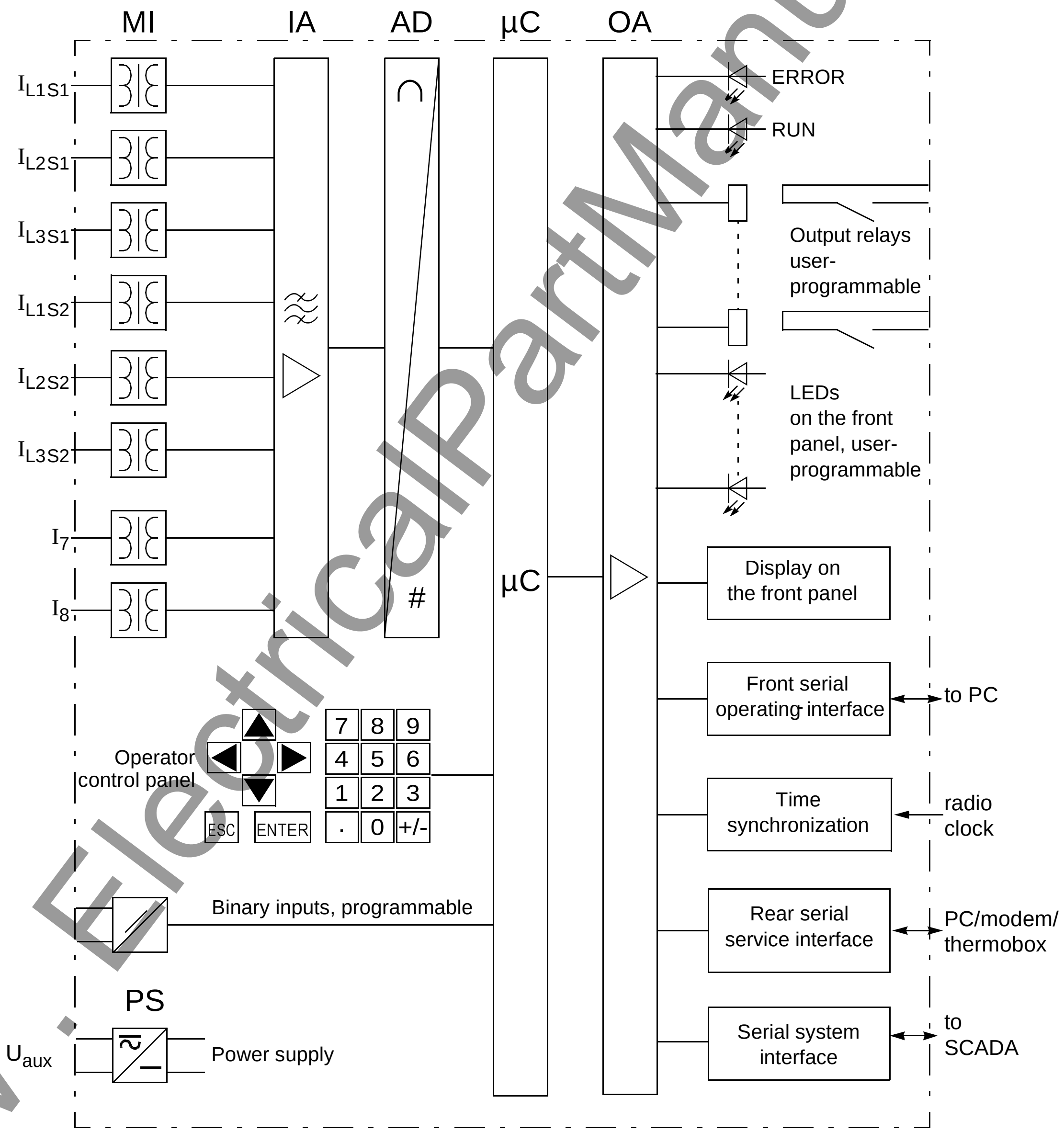


Figure 1-1 Hardware structure of the numerical differential protection 7UT612 — example for a two-winding transformer with sides S1 and S2

Three current inputs are provided for the input of the phase currents at each end of the protected zone, a further measuring input (I_7) may be used for any desired current, e.g. the earth current measured between the starpoint of a transformer winding and ground. The input I_8 is 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 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” has 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 each protection function.
- Conditioning of the measured signals, i.e. conversion of currents according to the connection group of the protected 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.
- Reaching trip command decisions.
- Storage of fault messages, fault annunciations as well as oscillographic fault data for system fault analysis.
- 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 7UT612.

Integrated control and numeric keys in conjunction with the LCD facilitate local interaction with the 7UT612. 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.

If the device incorporates switchgear control functions, the control of circuit breakers and other equipment is possible from the 7UT612 front panel.

Serial Interfaces

A serial **operating** interface on the front panel is provided for local communications with the 7UT612 through a personal computer. Convenient operation of all functions of the device is possible using the SIPROTEC® 4 operating program DIGSI® 4.

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 7UT612. DIGSI® 4 is required.

All 7UT612 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 thermobox in order to process external temperatures, e.g. in overload protection.

Power Supply

The 7UT612 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 7UT612 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 two feeders. It can also be used as a single-phase protection for busbars with up to seven feeders. The individual application can be configured, which ensures optimum matching to the protected object.

The device is also suited for two-phase connection for use in systems with $16^2/_3$ 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 at the higher voltage side and the lower voltage side of the power transformer. 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.

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 two feeders can be protected either. “Short” means that the connection 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 seven measured current inputs of the device allow for a single-phase protection for busbars with up to seven feeders. One 7UT612 is used per phase in this case. Alternatively, (external) summation transformers can be installed in order to allow a busbar protection for up to seven feeders with *one* single 7UT612 relay.

An additional current input I_8 is 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.

For transformers (including auto-transformers), generators, and shunt reactors, a high-impedance unit protection system can be formed using 7UT612. 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 the high-sensitive current input I_8 of 7UT612.

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

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 thermobox to allow for the inclusion of the oil temperature.

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

A version for $16^2/_3$ 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 of the 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 7UT612 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, branch-points, or smaller busbar arrangements.
- Simple device operation using the integrated operator panel or a connected personal computer running DIGSI® 4.

Differential Protection for Transformers

- Current restraint tripping characteristic.
- Stabilized against in-rush currents using the second harmonic.
- Stabilized against transient and steady-state fault 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 detection 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.

Bus-Bar Protection

- Single-phase differential protection for up to seven feeders 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.
- 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 earthed generators, motors, shunt reactors, and transformers, including auto-transformers.
- Suitable for any voltage measurement (via the resistor current) for application of high-impedance unit protection.

Tank Leakage Protection

- For 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.
- 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 the 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 current input I_7 (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 the current input I_7 or the highly sensitive current input I_8.
- 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.
- 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 temperature sensors via thermobox).

Circuit Breaker Failure Protection

- With monitoring of current flow through each breaker pole of the assigned side of the protected object.
- Supervision of the breaker position possible (if breaker auxiliary contacts available).
- Initiation by each of the internal protection functions.
- Initiation by external trip functions possible via binary input.

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.
- Connection 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

- 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 at all ends 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 checks.
- Check of the consistency of protection settings as to the protected object and the assignment of the current inputs: blocking of the differential protection system in case of inconsistent settings which could lead to a malfunction.
- Trip circuit supervision is possible.

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 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.

■

Functions

2

This chapter describes the numerous functions available on the SIPROTEC® 7UT612 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 initial display appears in the LCD. In the 7UT612 the measured values are displayed.

Configuration settings (Subsection 2.1.1) may be entered using a PC and the software program DIGSI® 4 and transferred via the operating interface on the device front, or via the serial service interface. Operation via DIGSI® 4 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 utilising the DIGSI® 4 software package. The level 5 password (individual parameters) is required.

2.1.1 Configuration of the Scope of Functions

General

The 7UT612 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.

Example for the configuration of the scope of functions:

7UT612 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 some functions, a choice may be presented between several options which are explained below.

Functions configured as ***Disabled*** are not processed by the 7UT612. 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 for details).

Determination of Functional Scope

Configuration settings may be entered using a PC and the software program DIGSI® 4 and transferred via the operating interface on the device front, or via the serial service interface. Operation via DIGSI® 4 is described in the SIPROTEC® 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.

First determine which side of the protected object will be named *side 1* and which one will be named *side 2*. Determination is up to you. If several 7UT612 are used, the sides should be denominated consistently to be able to assign them more easily later on. For *side 1* we recommend the following:

- for transformers the upper voltage side, but, if the starpoint of the lower voltage side is earthed this side is preferred as side 1 (reference side);
- for generators the terminal side;
- for motors and shunt reactors the current supply side;
- for series reactors, lines and busbars there is no side which is preferred.

Side determination plays a role for some of the following configuration settings.

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 possible setting parameters and for the assignment of the inputs and outputs of the device to the protection functions:

- For normal power transformers with isolated windings set **PROT. OBJECT** = ***3 phase transf.*** regardless of the connection group (winding interconnection) and the earthing conditions of the starpoint(s). This is even valid if an earthing reactor is situated within the protected zone (cf. Figure 2-18, page 45).
- The option ***Autotransf.*** is selected for auto-transformers. This option is also applicable for shunt reactors if current transformers are installed at both sides of the connection points (cf. Figure 2-25 right side, page 50).
- For a ***1 phase transf.***, the phase input L2 is not connected. This option is suited especially to single-phase power transformers with $16^2/_3$ 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 sides.
- Select the option ***3ph Busbar*** if the device is used for mini-busbars or branch-points with two ends. This setting applies also for short lines which are terminated by two sets of current transformers. “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 with up to 7 feeders, either using one device per phase or one device connected via external summation CTs. Select the option ***1ph Busbar*** in this case. You must inform the device about the number of feeders under address 107 **NUMBER OF ENDS**.

The measuring input I_7 serves often to acquire a starpoint current. Carrying out configurations in address 108 **I7-CT CONNECT.** the device will be informed on the side the current is assigned to. For transformers select the side where the starpoint is earthed and where the starpoint current is to be measured. For earthed generators and motors it is the side which is looking towards the earthed starpoint. For auto-transformers any side can be selected since there is only one starpoint current for both sides. If the starpoint current is not used for differential protection or for restricted earth fault protection, pre-set the following: ***not used***.

If restricted earth fault protection is applied, it must be assigned to an earthed side in address 113 **REF PROT.**. Otherwise this protection function has to be set to ***Disabled***. For auto-transformers any side can be used.

The overcurrent time protection functions must also be assigned to a specific side of the protected object.

- For phase overcurrent time protection select the side relevant for this protection in address 120 **DMT/IDMT Phase**. For generators usually the starpoint side is selected, for motors the terminal side. Otherwise, for single-side infeed we recommend the feeding side. Often, however, an external overcurrent time protection is used for the feeding side. The internal overcurrent time protection of 7UT612 should then be activated for the outgoing side. It is then used as backup protection for faults beyond the outgoing side.
- To select the characteristic group according to which the phase overcurrent time protection is to operate use address 121 **DMT/IDMT PH. CH**. 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.
- In address 122 the zero sequence (residual) current time overcurrent protection **DMT/IDMT 3I0** can be assigned to any side of the protected object. This does not have to be the same side as for phase overcurrent protection (address 120, see above). For characteristics the same options are available as for the phase overcurrent protection using address 123 **DMT/IDMT 3I0 CH**. However, for zero sequence current time overcurrent protection the settings may be different to the settings selected for phase time overcurrent protection. This protection function always acquires the residual current $3I_0$ of the supervised side. This current is calculated from the sum of the corresponding phase currents.
- There is another earth current time overcurrent protection which is independent from the before-described zero sequence time overcurrent protection. This protection, to be configured in address 124 **DMT/IDMT Earth**, acquires the current connected to the current measuring input I_7. In most cases, it is the starpoint current of an earthed starpoint (for transformers, generators, motors or shunt reactors). No assignment to a specific side is necessary since this type of protection always acquires the I_7 current, no matter where it originates from. For this protection you may select one of the characteristic groups using address 125 **DMT/IDMT E CHR.**, 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. The protection function offers two options.

It either acquires the measured current at the "normal" input I_7 (***unsens. CT7***) or at highly sensitive input I_8 (***sens. CT8***). The latter case is very interesting since input I_8 is able to detect even very small currents (from 3 mA at the input). This protection function is very 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). This protection is not bound to a specific side or application. Usage is up to the user's requirements.

In address 140 **UNBALANCE LOAD** the unbalanced load protection can be assigned to a specific side of the protected object, i.e. it supervises the negative sequence current and checks if there is any unbalanced load. The trip time characteristics can be set to definite time (***Definite Time***) according to address 141 **UNBAL. LOAD CHR**, additionally operate according to an IEC–characteristic (***TOC IEC***) or to an ANSI–characteristic (***TOC ANSI***).

For overload protection select the side whose currents are relevant for overload detection. Use address 142 **Therm.Overload**. 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 effective 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.

In address 143 **Therm.O/L CHR.** the user can additionally choose between two methods of overload detection:

- Overload protection with thermal replica according to IEC 60255-8 (***classical***),
- 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 integrated temperature detectors. For more information see also Section 2.9.

If overload protection with calculation of hot-spot temperature is used according to IEC 60354 (address 143 **Therm.O/L CHR.** = ***IEC354***), at least one thermobox must be connected to the service interface. The thermobox informs the device about the temperature of the coolant. The interface is set in address 190 **RTD-BOX INPUT**. For 7UT612 this is ***Port C***. The number of resistance temperature detectors and the way the thermobox(es) transmit information is set in address 191 **RTD CONNECTION**: ***6 RTD simplex*** or ***6 RTD HDX*** (with 1 thermobox) or ***12 RTD HDX*** (with 2 thermoboxes). This must comply with the settings at the thermobox(es).

Note: The temperature measuring point relevant for the calculation of the hot-spot temperature should be fed via the first thermobox.

For the circuit breaker failure protection set in address 170 **`BREAKER FAILURE`** which side is to be monitored. This has to be the side feeding onto an internal fault.

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.

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
106	NUMBER OF SIDES	2	2	Number of Sides for Multi Phase Object
107	NUMBER OF ENDS	3 4 5 6 7	7	Number of Ends for 1 Phase Busbar
108	I7-CT CONNECT.	not used Side 1 Side 2	not used	I7-CT connected to
112	DIFF. PROT.	Disabled Enabled	Enabled	Differential Protection
113	REF PROT.	Disabled Side 1 Side 2	Disabled	Restricted earth fault protection
117	Coldload Pickup	Disabled Enabled	Disabled	Cold Load Pickup
120	DMT/IDMT Phase	Disabled Side 1 Side 2	Disabled	DMT / IDMT Phase
121	DMT/IDMT PH. CH	Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Definite Time only	DMT / IDMT Phase Pick Up Characteristic
122	DMT/IDMT 3I0	Disabled Side 1 Side 2	Disabled	DMT / IDMT 3I0

Addr.	Setting Title	Setting Options	Default Setting	Comments
123	DMT/IDMT 3I0 CH	Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Definite Time only	DMT / IDMT 3I0 Pick Up Characteristic
124	DMT/IDMT Earth	Disabled unsensitive Current Transformer I7	Disabled	DMT / IDMT Earth
125	DMT/IDMT E CHR.	Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Definite Time only	DMT / IDMT Earth Pick Up Characteristic
127	DMT 1PHASE	Disabled unsensitive Current Transformer I7 sensitive Current Transformer I8	Disabled	DMT 1Phase
140	UNBALANCE LOAD	Disabled Side 1 Side 2	Disabled	Unbalance Load (Negative Sequence)
141	UNBAL. LOAD CHR	Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI	Definite Time only	Unbalance Load (Neg. Sequ.) Characteris.
142	Therm.Overload	Disabled Side 1 Side 2	Disabled	Thermal Overload Protection
143	Therm.O/L CHR.	classical (according IEC60255) according IEC354	classical (according IEC60255)	Thermal Overload Protec. Characteristic
170	BREAKER FAILURE	Disabled Side 1 Side 2	Disabled	Breaker Failure Protection
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	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 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. These data can only be changed from a PC running DIGSI® 4 and are discussed in this Subsection.

Rated Frequency

The rated frequency of the power system is set under address 270 **Rated Frequency**. The default setting is made in the factory in accordance with the design variant and needs to be changed only if the device is to be used for a different purpose than ordered for.

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 2-1 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 for 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 assignment of the sides when determining winding 1, as abovementioned (Subsection 2.1.1, margin heading “Special Cases”). 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 device needs the following information:

- The rated voltage U_N in kV (phase-to-phase) under address 240 **UN-PRI SIDE 1**.
- The starpoint condition under address 241 **STARPNT SIDE 1**: ***Solid Earthed*** or ***Isolated***. If the starpoint is earthed via a current-limiting circuit (e.g. low-resistive) or via a Petersen-coil (high-reactive), set ***Solid Earthed***, too.
- The mode of connection of the transformer windings under address 242 **CONNECTION S1**. This is normally the capital letter of the vector group according to IEC.

If the transformer winding is regulated then the actual rated voltage of the winding is not used as U_N 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 240)

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

For the side 2, the same considerations apply as for the side 1: The rated voltage U_N in kV (phase-to-phase) under address 243 **UN-PRI SIDE 2**, the starpoint condition under address 244 **STARPNT SIDE 2**, and the mode of connection of the transformer windings under address 245 **CONNECTION S2**.

Additionally, the vector group numeral is set under address 246 **VECTOR GRP S2** which 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 set the numeral directly, e.g. ***5*** for vector group Yd5 or Dy5. 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).

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 2-2).

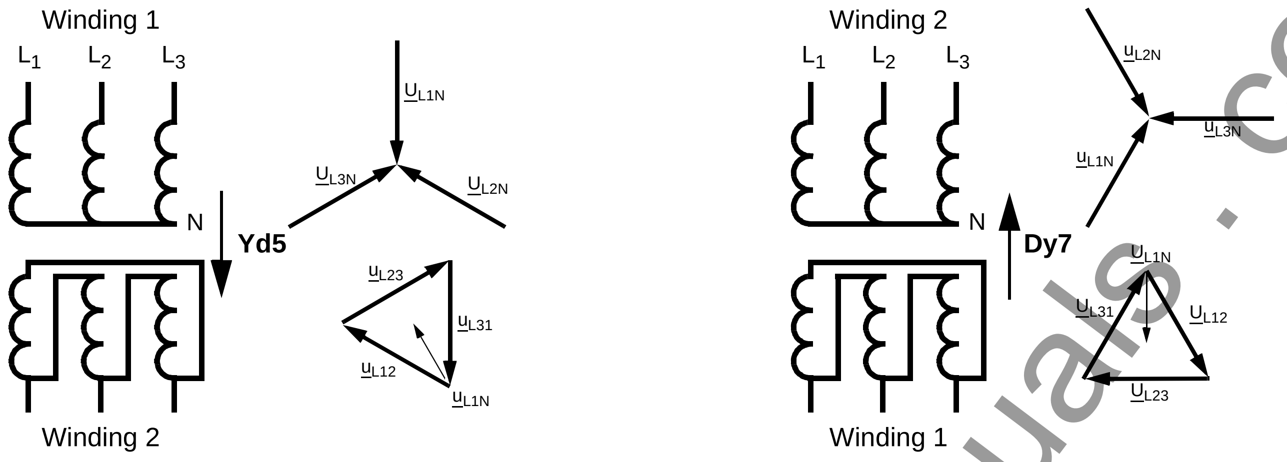


Figure 2-2 Change of the transformer vector group if the lower voltage side is the reference side — example

The primary rated power **SN TRANSFORMER** (address 249) is the direct primary rated apparent power for transformers. 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. This is the reference for all referred values.

The device automatically computes from the rated data of the protected transformer 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. Therefore, 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 and Reactors

Using the 7UT612 for protection of generators or motors, the following must have been set when configuring the protection functions (see Subsection 2.1.1, address 105): **PROT. OBJECT** = ***Generator/Motor***. These settings also go 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 251 **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 252) 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 from this power and the rated voltage. This is the reference for all referred values.

Object Data with Mini-Busbars, Branch-Points, Short Lines

These data are only required if the device is used for differential protection of mini busbars or short lines with two ends. When configuring the protection 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 261 **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 display of the operational measured values.

Since both sides or feeders may be equipped with current transformers of different rated primary currents, a uniform rated operational current **I PRIMARY OP.** is defined as rated object current (address 265) which will then be considered as a reference value for all currents. The currents are converted such that the settings of the protection function always refer to the rated operational current. In general, if current transformers differ, the higher rated primary current is selected for operational rated current.

Object Data with Busbars with up to 7 Feeders

Busbar data are only required if the device is used for single-phase busbar differential protection for up to 7 feeders. 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.

With address 261 **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.

Since the feeders of a busbar may be equipped with current transformers of different rated primary currents, a uniform operational nominal current **I PRIMARY OP.** is defined as rated busbar current (address 265) which will then be considered as a reference value for all currents. The feeder currents are converted such that the settings of the protection functions always refer to the rated operational current. Usually no external matching equipment is required. In general, if current transformers differ, the higher rated primary current of the feeders is selected for rated operational current.

If the device is connected via summation transformers, the latter are to be connected between the current transformer set of each feeder and the device inputs. In this case the summation transformers can also be used for matching of currents. For the rated operational current of the busbar also use the highest of the rated primary currents of the feeders. Rated currents of each individual feeder are matched later on.

If one 7UT612 is used per phase, set the same currents and voltages 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 266.

Current Transformer Data for 2 Sides

The rated primary operational currents for the protected object 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 that the differential protection applies the correct function.

Therefore the device must be informed on the current transformer data. If there are 2 sides (i.e. all applications, except for single-phase busbar protection for up to 7 feeders), this is ensured by indication of rated currents and the secondary starpoint formation of the current transformer sets.

In address 202 **IN-PRI CT S1** the rated primary current of the current transformer set of side 1 of the protected object is set. In address 203 **IN-SEC CT S1** the rated secondary current is set. Please make sure that the sides were defined correctly (see Subsection 2.1.1, margin heading “Special Cases”, page 15). 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 A–I/O–3”. 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 current transformers. To inform the device on the location of the starpoint in relation to the protected object use address 201 **STRPNT->OBJ S1**. Figure 2-3 shows some examples for this setting.

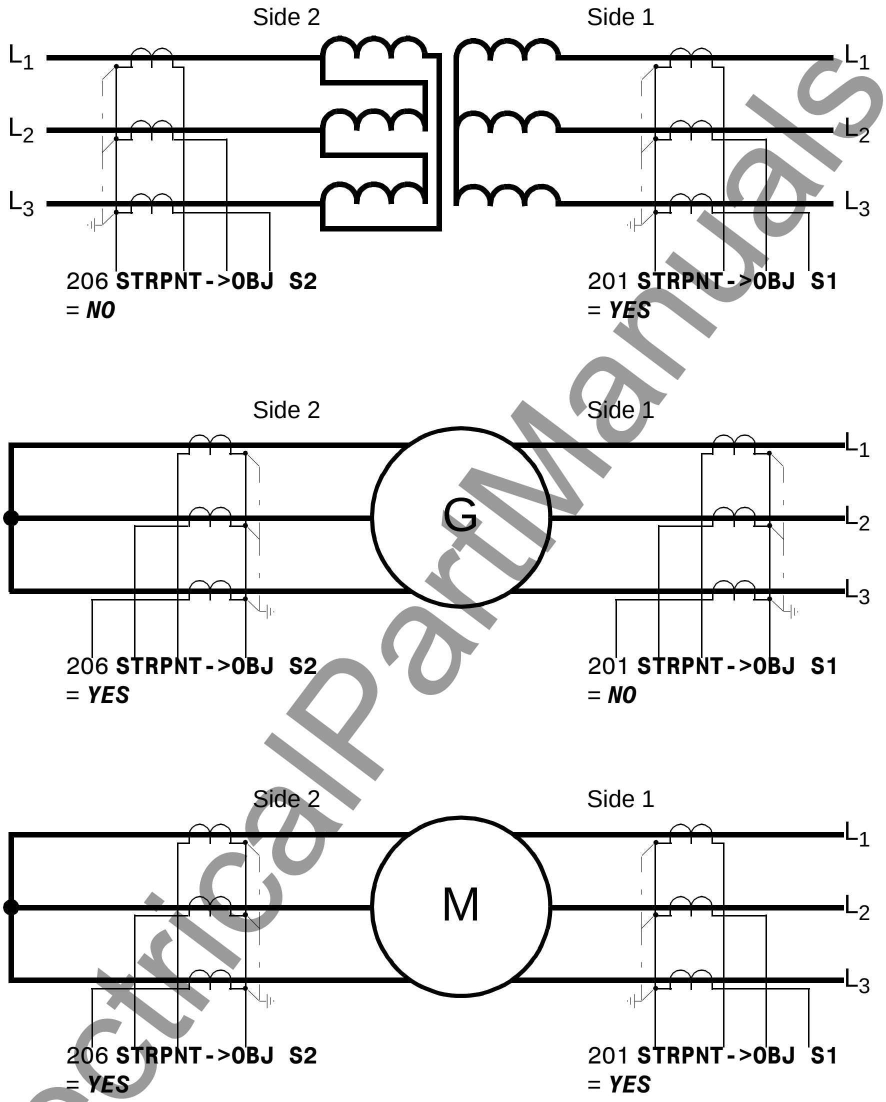


Figure 2-3 Position of the CT starpoints — example

For side 2 of the protected object the same applies. For side 2 set the nominal primary current **IN-PRI CT S2** (address 207), nominal secondary current **IN-SEC CT S2** (address 208) and the position of the current transformer starpoint **STRPNT->OBJ S2** (address 206). Side 2 requires the same considerations as side 1.

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 2-4 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 S2** = ***NO***.

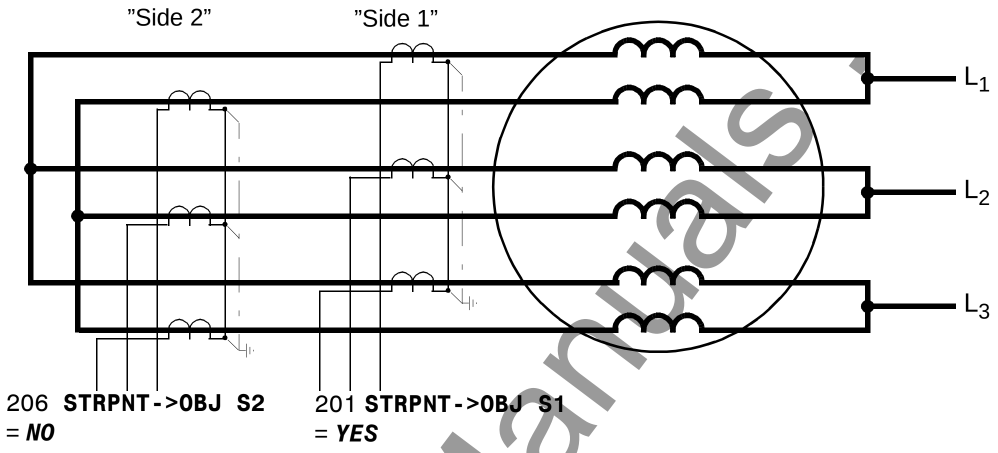


Figure 2-4 Definition of current direction for transverse differential protection - example

Current Transformer Data for Single-phase Busbar Protection

Current transformer sets in the feeders of a busbar can have different rated currents. Therefore, a uniform rated operational object current has been determined in the before-described paragraph “Object Data with Busbars with up to 7 Feeders”. The currents of each individual feeder have to be matched to this rated operational current.

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 2.1.1 (address 107 **NUMBER OF ENDS**).

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.

Hereinafter the parameters for rated primary currents:
Address 212 **IN-PRI CT I1** = rated primary transformer current for feeder 1,
Address 215 **IN-PRI CT I2** = rated primary transformer current for feeder 2,
Address 218 **IN-PRI CT I3** = rated primary transformer current for feeder 3,
Address 222 **IN-PRI CT I4** = rated primary transformer current for feeder 4,
Address 225 **IN-PRI CT I5** = rated primary transformer current for feeder 5,
Address 228 **IN-PRI CT I6** = rated primary transformer current for feeder 6,
Address 232 **IN-PRI CT I7** = rated primary transformer current for feeder 7.

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 A–I/O–3”).

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.

Hereinafter the parameters for rated secondary currents:
Address 213 **IN-SEC CT I1** = rated secondary transformer current for feeder 1,
Address 216 **IN-SEC CT I2** = rated secondary transformer current for feeder 2,

Address 219 **IN-SEC CT I3** = rated secondary transformer current for feeder 3,
Address 223 **IN-SEC CT I4** = rated secondary transformer current for feeder 4,
Address 226 **IN-SEC CT I5** = rated secondary transformer current for feeder 5,
Address 229 **IN-SEC CT I6** = rated secondary transformer current for feeder 6,
Address 233 **IN-SEC CT I7** = rated secondary transformer current for feeder 7.

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 2-5 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.

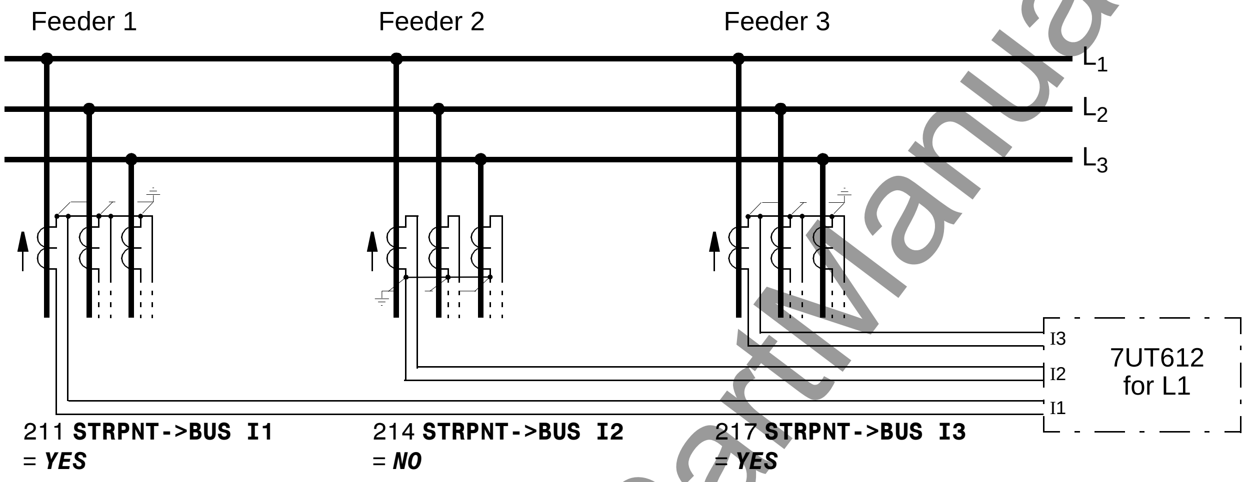


Figure 2-5 Position of the CT starpoints — example for phase L1 of a busbar with 3 feeders

Hereinafter the parameters for the polarity:
Address 211 **STRPNT->BUS I1** = transformer starpoint versus busbar for feeder 1,
Address 214 **STRPNT->BUS I2** = transformer starpoint versus busbar for feeder 2,
Address 217 **STRPNT->BUS I3** = transformer starpoint versus busbar for feeder 3,
Address 221 **STRPNT->BUS I4** = transformer starpoint versus busbar for feeder 4,
Address 224 **STRPNT->BUS I5** = transformer starpoint versus busbar for feeder 5,
Address 227 **STRPNT->BUS I6** = transformer starpoint versus busbar for feeder 6,
Address 231 **STRPNT->BUS I7** = transformer starpoint versus busbar for feeder 7.

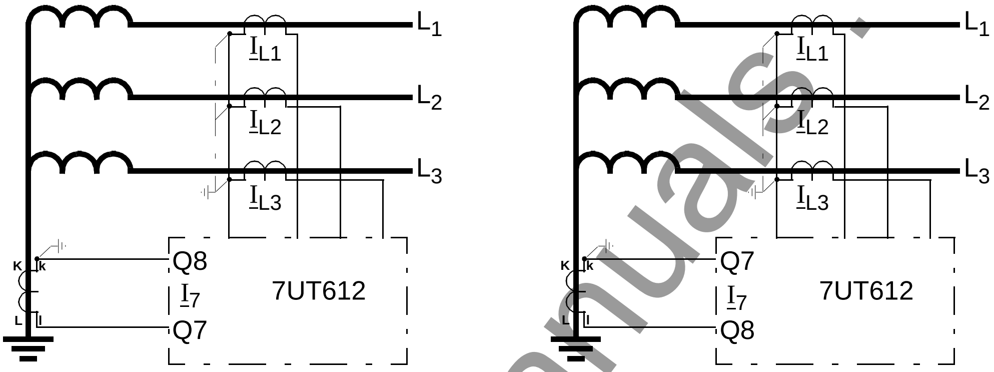
Current Transformer Data for Current Input I_7

The current measuring input I_7 is normally used for the detection of the starpoint current of an earthed winding of a transformer, shunt reactor, generator or motor. Only for single-phase busbar protection this is not available since I_7 is reserved for feeder currents.

I_7 can be used for zero sequence current compensation when performing differential protection for transformers and/or restricted earth fault protection. It can be processed by the earth current time overcurrent protection, as an alternative or additionally.

For matching the current magnitude set in address 232 **IN-PRI CT I7** the rated primary current of the current transformer which is powered at this measuring input. The rated secondary current of this current transformer in address 233 **IN-SEC CT I7** has to be in correspondence with the rated device current for this measuring input.

Address 230 **`EARTH. ELECTROD`** is relevant for the polarity of the current. In this address, 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. Figure 2-6 shows the alternatives using an earthed transformer winding as an example.



230 **`EARTH. ELECTROD`**
= ***`Terminal Q7`***

230 **`EARTH. ELECTROD`**
= ***`Terminal Q8`***

Figure 2-6 Polarity setting for the measured current input I_7

Note:

For devices in panel surface mounted case:
Terminal Q7 corresponds to housing terminal 12
Terminal Q8 corresponds to housing terminal 27

Current Transformer Data for Current Input I_8

The current measuring input I_8 is a very sensitive input which enables to also acquire very weak currents (beginning with 3 mA at input).

To also be able to indicate primary values for this measuring input (e. g. for setting in primary currents, for output of primary measured values), the conversion factor $I_{N\,prim}/I_{N\,sec}$ of the current transformer connected is set in address 235 **`Factor I8`**.

Trip Command Duration

The minimum trip command duration **`TMin TRIP CMD`** is set in address 280A. This duration is valid for all protection functions which can issue a trip command. This parameter can only be changed with DIGSI® 4 under “**Additional Settings**”.

Circuit Breaker Status

Various protection and ancillary functions require information on the status of the circuit breaker for faultless operation.

For the circuit breaker of side 1 of the protected object a current threshold **`Breaker S1 I>`** is to be set in address 283. When the circuit breaker is open, this threshold is likely to be undershot. The threshold may be very small if stray currents (e. g. due to induction) are excluded when the protected object is switched off. Otherwise the threshold value must be increased. Normally the pre-setting is sufficient.

For the circuit breaker of side 2 of the protected object setting is done in address 284 **`Breaker S2 I>`**.

2.1.2.1 Setting Overview

Note: The setting ranges and presettings listed in this table 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. For setting primary values, the transformation ratio of the transformers must also be taken into consideration.

The presetting of the nominal frequency corresponds to the nominal frequency according to the device version.

Addr.	Setting Title	Setting Options	Default Setting	Comments
270	Rated Frequency	50 Hz 60 Hz 16 2/3 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 temparature measurement
240	UN-PRI SIDE 1	0.4..800.0 kV	110.0 kV	Rated Primary Voltage Side 1
241	STARPNT SIDE 1	Solid Earthed Isolated	Solid Earthed	Starpoint of Side 1 is
242	CONNECTION S1	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 1
243	UN-PRI SIDE 2	0.4..800.0 kV	11.0 kV	Rated Primary Voltage side 2
244	STARPNT SIDE 2	Solid Earthed Isolated	Solid Earthed	Starpoint of side 2 is
245	CONNECTION S2	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 2
246	VECTOR GRP S2	0..11	0	Vector Group Numeral of Side 2
249	SN TRANSFORMER	0.20..5000.00 MVA	38.10 MVA	Rated Apparent Power of the Transformer
251	UN GEN/MOTOR	0.4..800.0 kV	21.0 kV	Rated Primary Voltage Generator/ Motor
252	SN GEN/MOTOR	0.20..5000.00 MVA	70.00 MVA	Rated Apparent Power of the Generator
261	UN BUSBAR	0.4..800.0 kV	110.0 kV	Rated Primary Voltage Busbar
265	I PRIMARY OP.	1..100000 A	200 A	Primary Operating Current
266	PHASE SELECTION	Phase 1 Phase 2 Phase 3	Phase 1	Phase selection
201	STRPNT->OBJ S1	YES NO	YES	CT-Strpnt. Side1 in Direct. of Object
202	IN-PRI CT S1	1..100000 A	200 A	CT Rated Primary Current Side 1

Addr.	Setting Title	Setting Options	Default Setting	Comments
203	IN-SEC CT S1	1A 5A	1A	CT Rated Secondary Current Side 1
206	STRPNT->OBJ S2	YES NO	YES	CT-Strpnt. Side2 in Direct. of Object
207	IN-PRI CT S2	1..100000 A	2000 A	CT Rated Primary Current Side 2
208	IN-SEC CT S2	1A 5A	1A	CT Rated Secondary Current Side 2
211	STRPNT->BUS I1	YES NO	YES	CT-Starpoint I1 in Direction of Busbar
212	IN-PRI CT I1	1..100000 A	200 A	CT Rated Primary Current I1
213	IN-SEC CT I1	1A 5A 0.1A	1A	CT Rated Secondary Current I1
214	STRPNT->BUS I2	YES NO	YES	CT-Starpoint I2 in Direction of Busbar
215	IN-PRI CT I2	1..100000 A	200 A	CT Rated Primary Current I2
216	IN-SEC CT I2	1A 5A 0.1A	1A	CT Rated Secondary Current I2
217	STRPNT->BUS I3	YES NO	YES	CT-Starpoint I3 in Direction of Busbar
218	IN-PRI CT I3	1..100000 A	200 A	CT Rated Primary Current I3
219	IN-SEC CT I3	1A 5A 0.1A	1A	CT Rated Secondary Current I3
221	STRPNT->BUS I4	YES NO	YES	CT-Starpoint I4 in Direction of Busbar
222	IN-PRI CT I4	1..100000 A	200 A	CT Rated Primary Current I4
223	IN-SEC CT I4	1A 5A 0.1A	1A	CT Rated Secondary Current I4
224	STRPNT->BUS I5	YES NO	YES	CT-Starpoint I5 in Direction of Busbar
225	IN-PRI CT I5	1..100000 A	200 A	CT Rated Primary Current I5
226	IN-SEC CT I5	1A 5A 0.1A	1A	CT Rated Secondary Current I5
227	STRPNT->BUS I6	YES NO	YES	CT-Starpoint I6 in Direction of Busbar
228	IN-PRI CT I6	1..100000 A	200 A	CT Rated Primary Current I6
229	IN-SEC CT I6	1A 5A 0.1A	1A	CT Rated Secondary Current I6

Addr.	Setting Title	Setting Options	Default Setting	Comments
230	EARTH. ELEC-TROD	Terminal Q7 Terminal Q8	Terminal Q7	Earthing Electrod versus
231	STRPNT->BUS I7	YES NO	YES	CT-Starpoint I7 in Direction of Busbar
232	IN-PRI CT I7	1..100000 A	200 A	CT Rated Primary Current I7
233	IN-SEC CT I7	1A 5A 0.1A	1A	CT Rated Secondary Current I7
235	Factor I8	1.0..300.0	60.0	Factor: Prim. Current over Sek. Curr. I8
280A	TMin TRIP CMD	0.01..32.00 sec	0.15 sec	Minimum TRIP Command Duration
283	Breaker S1 I>	0.04..1.00 A	0.04 A	Clos. Breaker Min. Current Thresh. S1
284	Breaker S2 I>	0.04..1.00 A	0.04 A	Clos. Breaker Min. Current Thresh. S2
285	Breaker I7 I>	0.04..1.00 A	0.04 A	Clos. Breaker Min. Current Thresh. I7

2.1.2.2 Information Overview

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

2.1.3 Setting Groups

Purpose of Setting Groups

In the 7UT612 relay, four independent setting groups (A to D) are possible. The user can 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.

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 allows a specific relay to be used for more than one application. 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.

2.1.3.1 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

2.1.3.2 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

2.1.4 General Protection Data (Power System Data 2)

No settings are necessary for the general protection data in 7UT612. The following table shows the possible information. Only the applicable information can appear, depending on the version and the selected protected object.

2.1.4.1 Information Overview

F.No.	Alarm	Comments
00311	Fault Configur.	Fault in configuration of the Protection
00356	>Manual Close	>Manual close signal
00561	Man.Clos.Detect	Manual close signal detected
00410	>CB1 3p Closed	>CB1 aux. 3p Closed
00411	>CB1 3p Open	>CB1 aux. 3p Open
00413	>CB2 3p Closed	>CB2 aux. 3p Closed
00414	>CB2 3p Open	>CB2 aux. 3p Open
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
00126	ProtON/OFF	Protection ON/OFF (via system port)
00576	IL1S1:	Primary fault current IL1 side1
00577	IL2S1:	Primary fault current IL2 side1
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
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

2.2 Differential Protection

The differential protection represents the main feature of the device. It is based on current comparison. 7UT612 is suitable for unit protection of transformers, generators, motors, reactors, short lines, and (under observance of the available number of analog current inputs) for branch points (smaller busbar arrangements). Generator/transformer units may also be protected.

7UT612 can be used as a single-phase differential protection relay for protected objects with up to 7 sides, e.g. as busbars protection with up to 7 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 necessary for the various types of protected object are covered in the following subsections.

Basic Principle with Two Sides

Differential protection is based on current comparison. It makes use of the fact that a protected object (Figure 2-7) 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 section. If the actual current transformation ratio is the same, the secondary windings of the current transformers **CT1** and **CT2** at the line ends can be connected to form a closed electric circuit with a secondary current $\underline{I}$; a measuring element **M** which is connected to the electrical balance point remains at zero current in healthy operation.

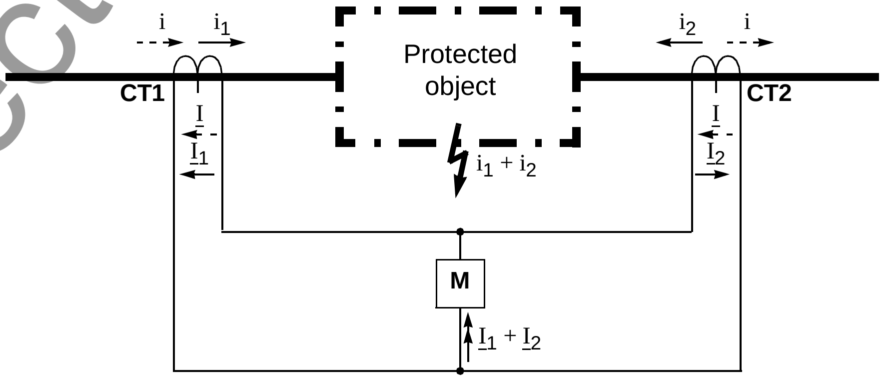


Figure 2-7 Basic principle of differential protection for two ends (single-line illustration)

When a fault occurs in the zone limited by the 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 2-7 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.

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 (see Figure 2-8 as an example for four ends).

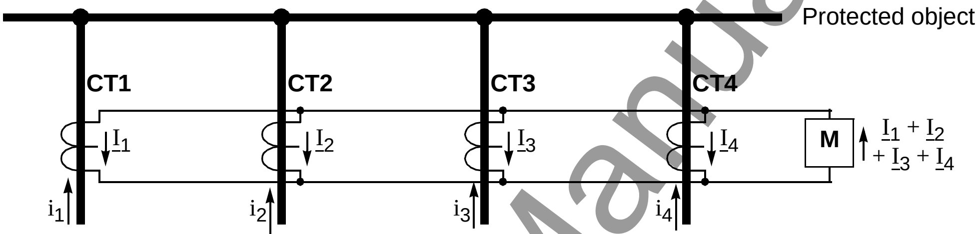


Figure 2-8 Basic principle of differential protection for four ends (single-line illustration)

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** 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. 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. The latter method is used in 7UT612 for all protected objects. The following definitions apply:

a tripping effect or differential current

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

and a stabilization or restraining current

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

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 2-9):

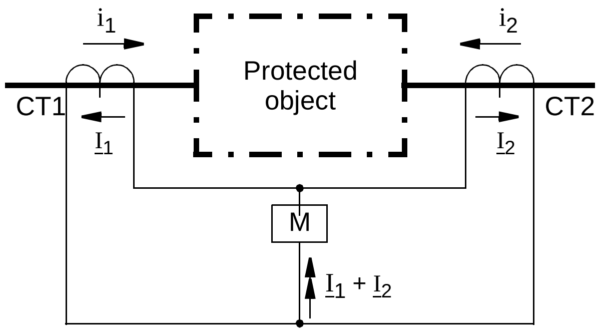


Figure 2-9 Definition of current direction

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

$\underline{I}_2$ reverses its direction i.e. thus changes its 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 end 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 2-10 (dash-dotted line).

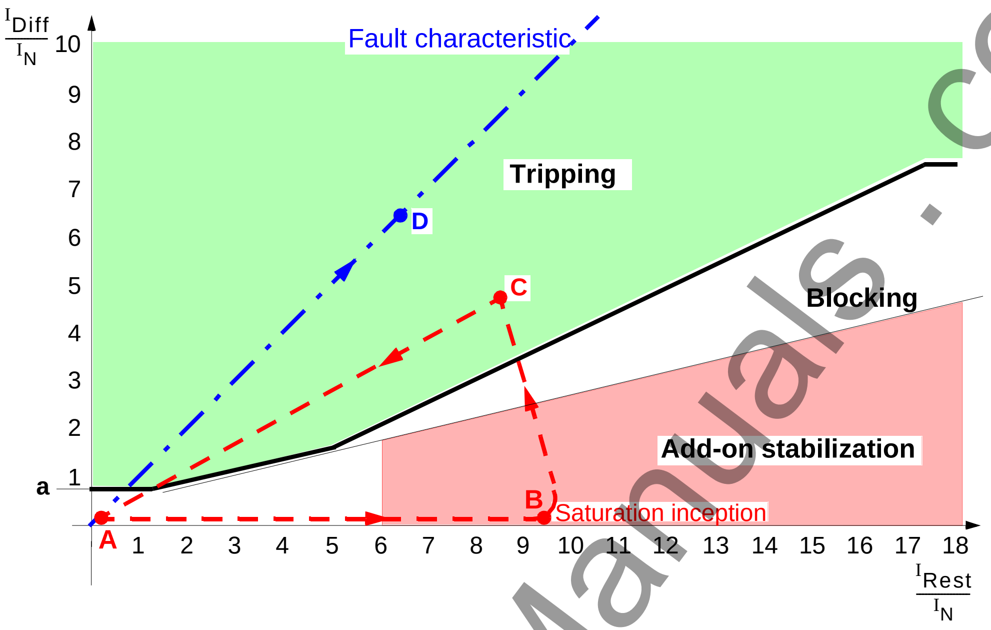


Figure 2-10 Operation characteristic of differential protection and fault characteristic

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 2-10 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 2-10).

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 2-10), trip signal would be the consequence if there were no special measures.

7UT612 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 2-10 shows an example of the shape of the instantaneous quantities during a through-fault current with current transformer 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 restraining current which moves the operating point briefly into the “add-on stabilization” area (Figure 2-10). The saturation indicator makes its decision within the first quarter cycle after fault inception. When an external fault is detected, the differential protection 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. This allows to detect evolving faults in the protected zone reliably even after an external fault with current transformer saturation.

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 second harmonic content exceeds a selectable threshold, trip is blocked.

Besides the second harmonic, another harmonic can be selected to cause blocking. A choice can be made between the third and fifth harmonic.

Overexcitation of the transformer iron is characterized by the presence of odd harmonics in the current. Thus, the third or fifth harmonic are suitable to detect such phenomena. But, as the third harmonic is often eliminated in power transformers (e.g. by the delta winding), the use of the fifth 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, $\frac{1}{u_{\mathrm{sc\ transf}}} \cdot I_{\mathrm{Ntransf}}$.

The differential protection 7UT612 provides such unstabilized high-current trip stage. This can operate even when, for example, a considerable second 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 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 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 2-11). The other branches of the I_{Diff}> stage are shifted proportionally.

The return of the restraint current indicates the startup. After a settable time **T START MAX** the increase of the characteristic is undone.

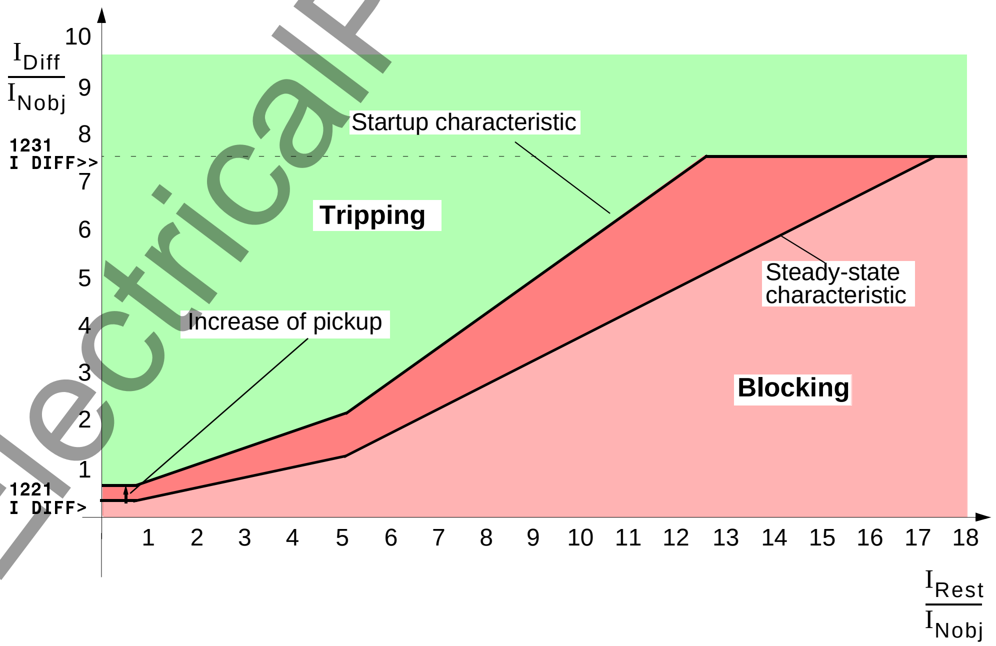


Figure 2-11 Increase of pickup value of the stage on startup

Tripping Characteristic

Figure 2-12 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”.

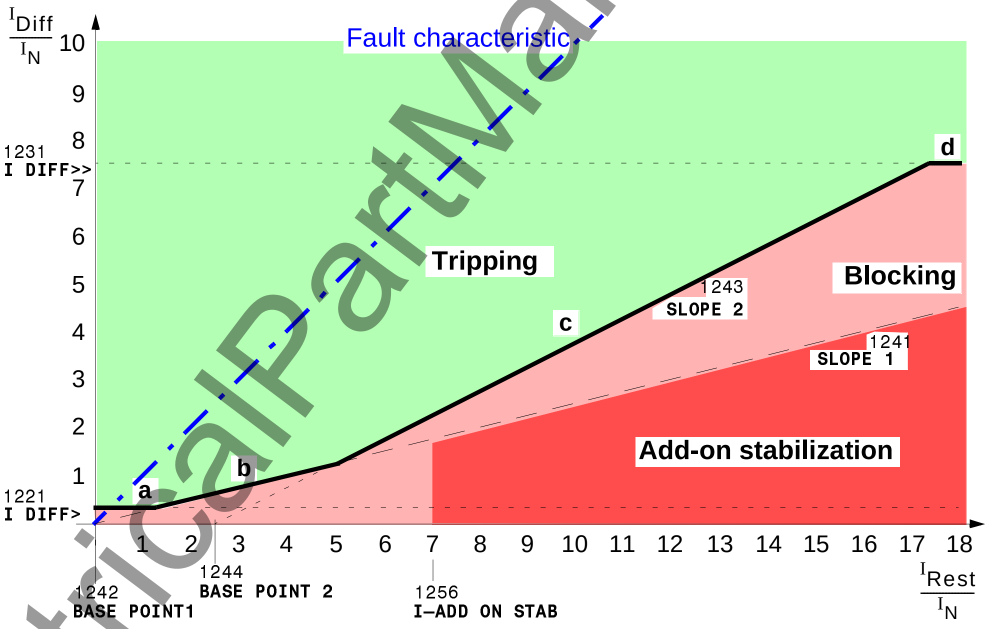


Figure 2-12 Tripping characteristic of differential protection

The quantities I_{Diff} and I_{Rest} are compared by the differential protection with the operating characteristic according to Figure 2-12. If the quantities result into a locus in the tripping area, trip signal is given.

Fault Detection, Drop-off

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, 7UT612 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 70 % of the set value or the restraining current reaches 70 % of the add-on stabilization area, the protection picks up (Figure 2-13). Pickup of the fast high-current stage causes a fault detection, too.

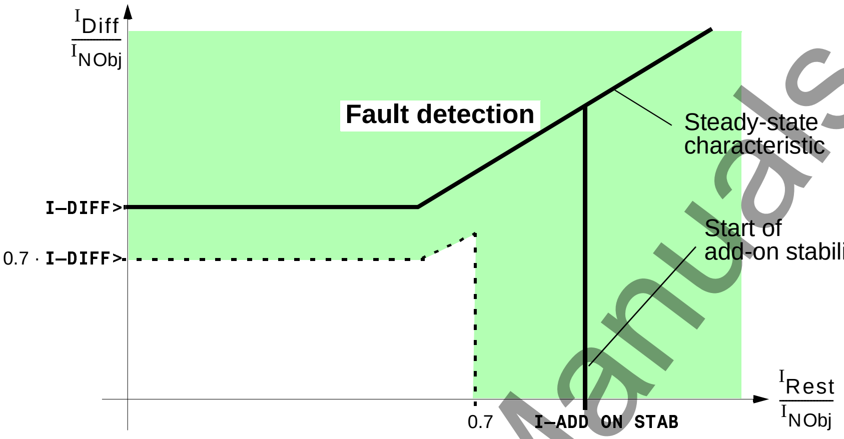


Figure 2-13 Fault detection area of the differential protection

If the harmonic restraint is effective, the harmonic analysis is carried out (approx. one AC cycle) in order to examine the stabilizing conditions. Otherwise, tripping occurs as soon as the tripping conditions are fulfilled (tripping area in Figure 2-12).

For special cases, the trip command can be delayed.

Figure 2-14 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 trip 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 2.1.2 under margin header “Trip Command Duration”, page 27).

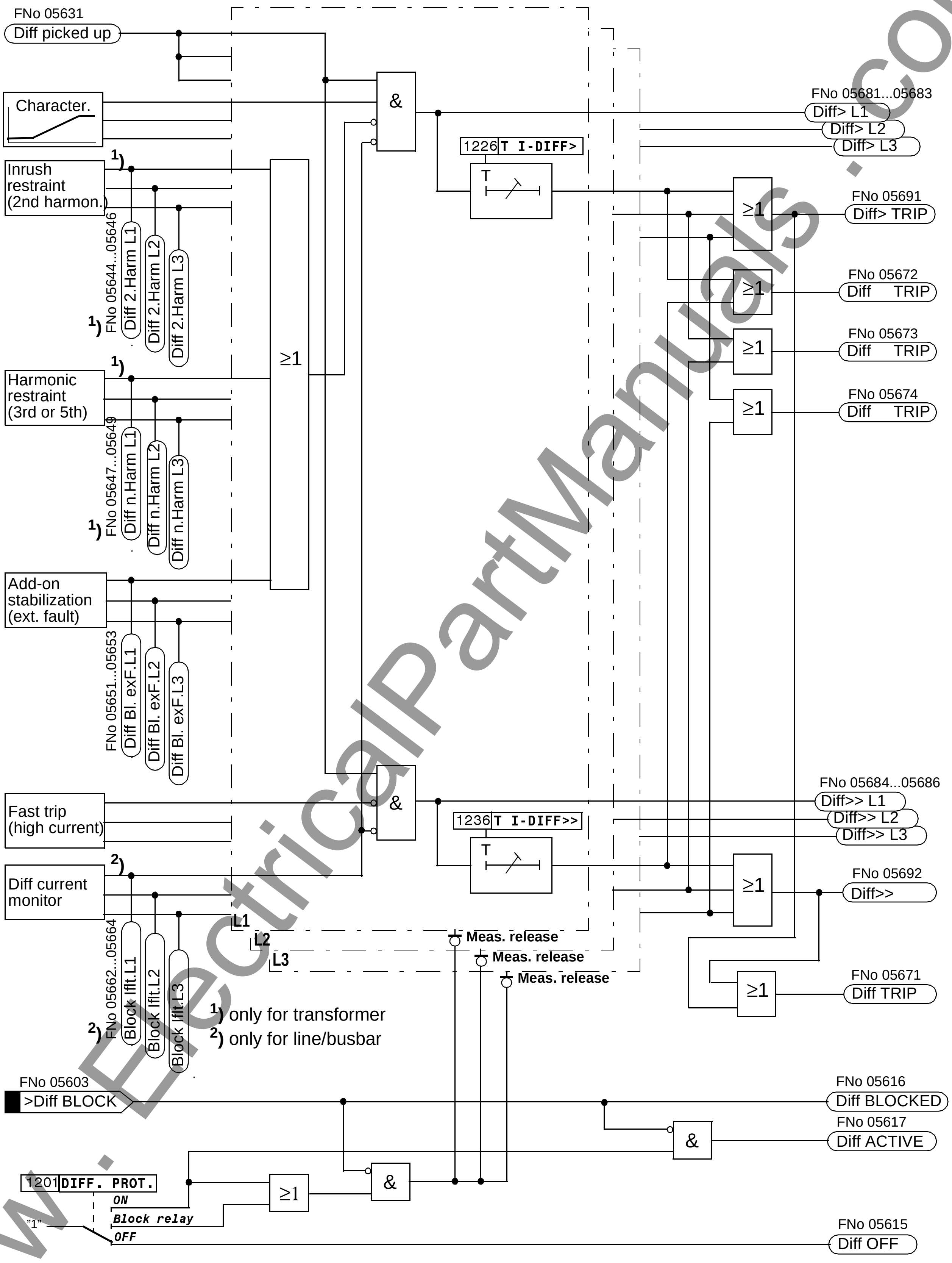


Figure 2-14 Tripping logic of the differential protection

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 at both sides of the power transformer. 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 current. This is achieved by entering the rated transformer data, such as rated power, rated voltage and rated primary current of the current transformers, into the protection device.

Once the vector group has been entered, 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 difference currents 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

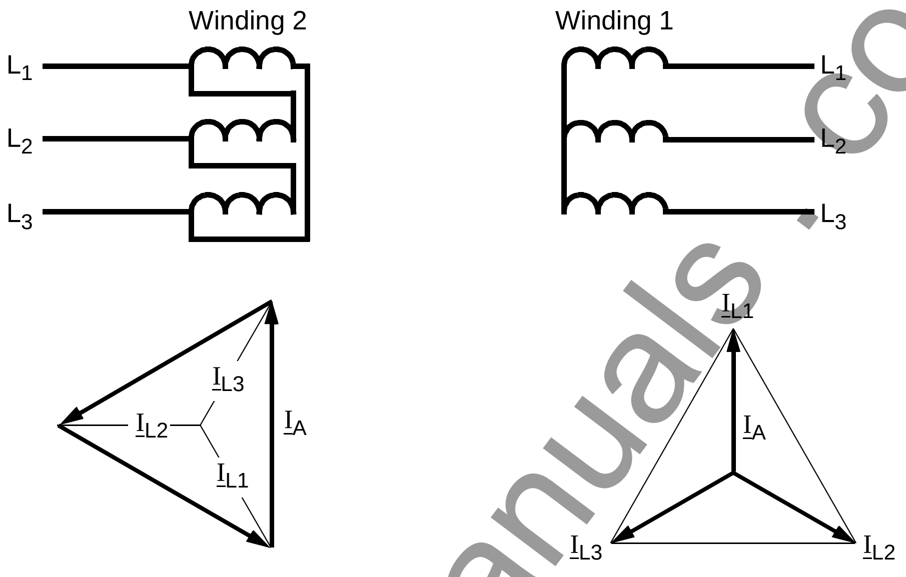
Figure 2-15 illustrates an example for a power transformer Yd5 (wye-delta with 150 ° phase displacement) without any earthed starpoint. The figure shows the windings and the phasor diagrams of symmetrical currents and, at the bottom, the matrix equations. The general form of these equations is

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

where

$(\underline{I}_m)$ – matrix of the matched currents $\underline{I}_A$, $\underline{I}_B$, $\underline{I}_C$,
k – constant factor,
(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).



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

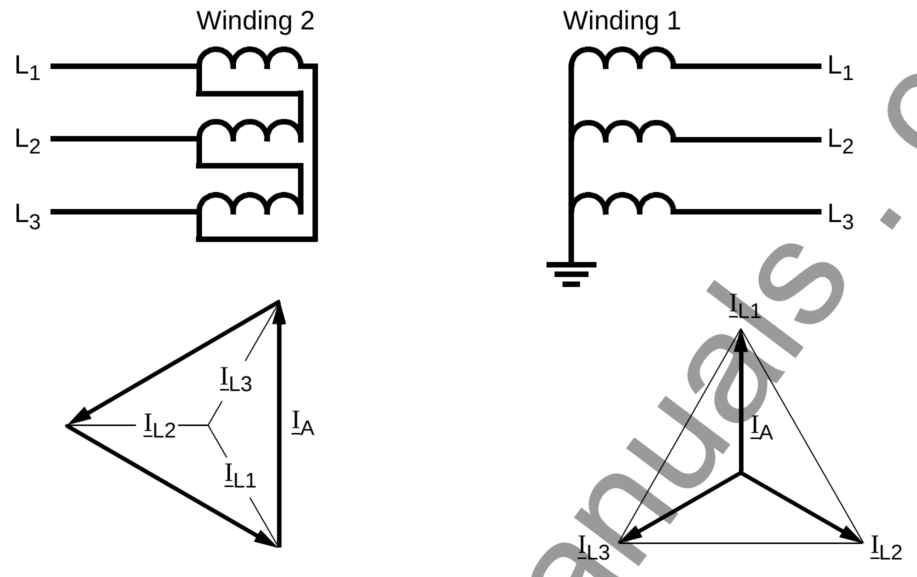
Figure 2-15 Matching the transformer vector group, example Yd5 (magnitudes not considered)

Earthed Starpoint

Figure 2-16 illustrates an example for a transformer YNd5 with an earthed starpoint on the Y–side.

In this case, the zero sequence currents are eliminated. On the left side, the zero sequence currents cancel each other because of the calculation 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 is eliminated by the calculation rule of the matrix, 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 2-17: 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, 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 2-16 Matching the transformer vector group, example YNd5 (magnitudes not considered)

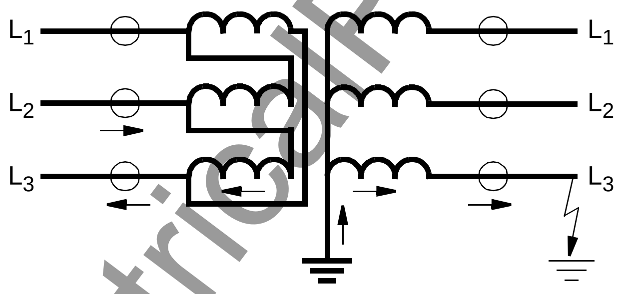


Figure 2-17 Example of an earth fault outside the protected transformer and current distribution

Figure 2-18 shows an example of an earth fault on the delta side *outside* the protected zone if an earthed starpoint former (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.

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 2-15).

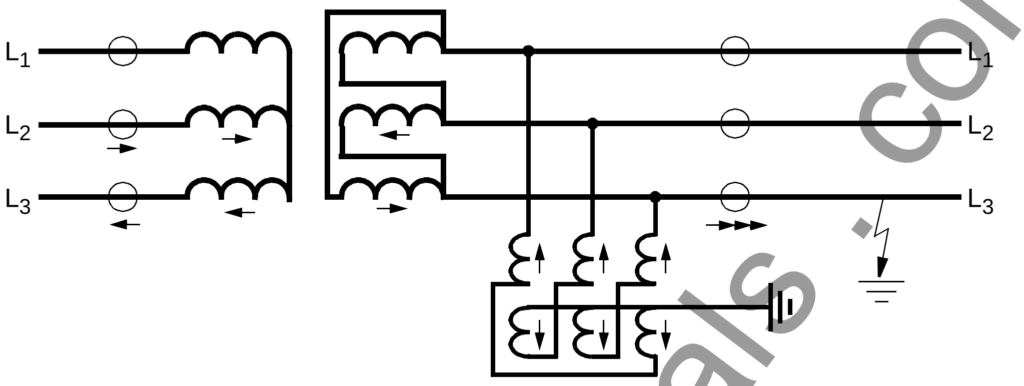


Figure 2-18 Example of an earth fault outside the protected transformer with a neutral earthing reactor within the protected zone

Increasing the Ground Fault Sensitivity

Higher earth fault sensitivity in case of an earthed winding can be achieved if the starpoint current is available, i.e. if a current transformer is installed in the starpoint connection to earth and this current is fed to the device (current input I_7).

Figure 2-19 shows an example of a power transformer the starpoint of which is earthed on the Y–side. In this case, the zero sequence current is not eliminated. Instead of this, $^1/_3$ of the starpoint current I_{SP} is added for each phase.

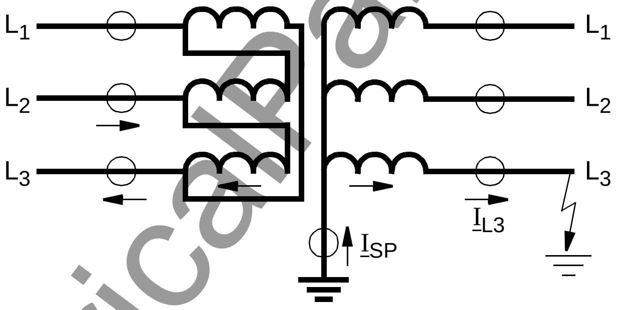


Figure 2-19 Example of a earth fault outside the transformer with current distribution

The matrix equation is in this case:

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

I_{SP} corresponds to $-3I_0$ but is measured in the starpoint connection of the winding and not in the phase lines. The effect is that the zero sequence current is considered in case of an *internal* fault (from $\underline{I}_0 = -^1/_3\underline{I}_{SP}$), whilst the zero sequence current is eliminated in case of an *external* fault because the zero sequence current on the terminal side $\underline{I}_0 = {}^1/_3 \cdot (\underline{I}_{L1} + \underline{I}_{L2} + \underline{I}_{L3})$ 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.

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. Current magnitude and distribution is also dependent on whether or not the transformer is provided with a stabilizing winding.

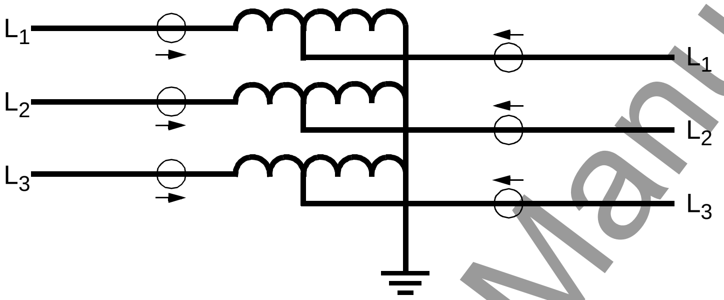


Figure 2-20 Auto-transformer with earthed starpoint

The zero sequence current must be 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.

Increased earth fault sensitivity during internal earth fault can be achieved by using the restricted earth fault protection as described in Section 2.3 and/or by the high-impedance differential protection described in Subsection 2.7.2.

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 2-21 shows an example of a single-phase power transformer with two phases per side with the definition of the direction of the currents.

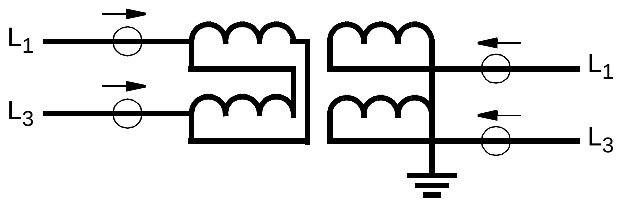


Figure 2-21 Example of a single-phase transformer with current definition

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,
- (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 2-21 left side), the phase currents can directly be used.

If a “starpoint” is earthed (Figure 2-21 right side), the zero sequence current must be eliminated by forming the current differences. Thus, 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 2-21):

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

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 (current input I_7).

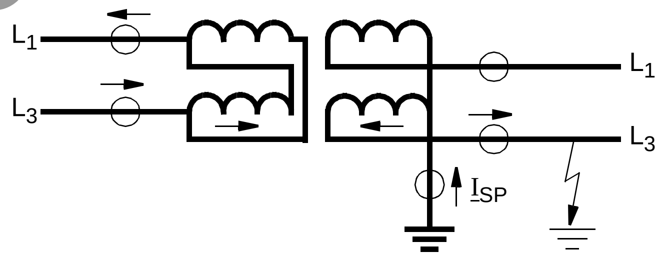


Figure 2-22 Example of an earth fault outside a single-phase transformer with current distribution

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.

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 2-23). Since the current direction is normally defined as positive in the direction of the protected object, for differential protection schemes, the definitions of Figure 2-23 apply.

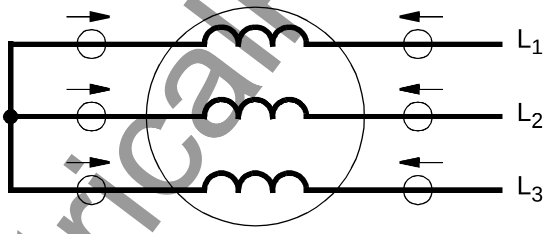


Figure 2-23 Definition of current direction with longitudinal differential protection

In 7UT612, 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. Measured value matching is reduced to magnitude factors, therefore.

A special case is the use as transverse differential protection. The definition of the current direction is shown in Figure 2-24 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.

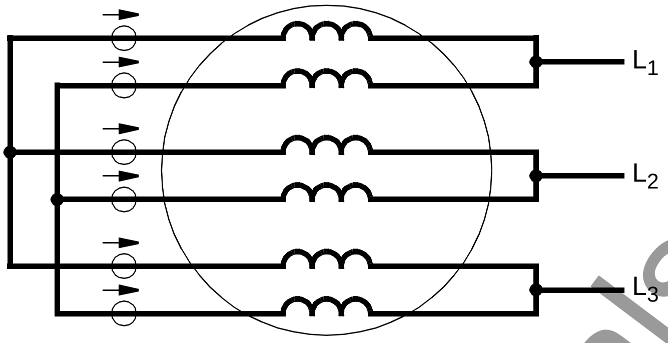


Figure 2-24 Definition of current direction with transverse differential protection

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 2.1.2 under “Current Transformer Data for 2 Sides”, page 23.

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 points 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 differential 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 2-25 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 2-25 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.

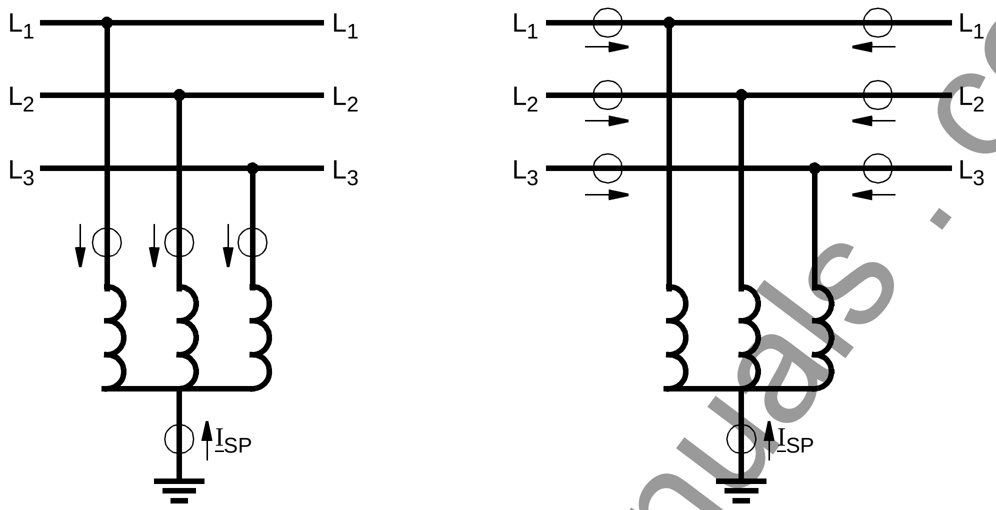


Figure 2-25 Definition of current direction on a shunt reactor

2.2.5 Differential Protection for Mini-Busbars, Branch-Points and Short Lines

A 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 2-26). 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 inductances, like series or shunt reactors, the branch point 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 less sensitive 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 2-26 and 2-27 apply.

If 7UT612 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. Measured value matching is reduced to magnitude factors, therefore. No external matching devices are necessary if the current transformer sets at the ends of the protected zone have different primary current.

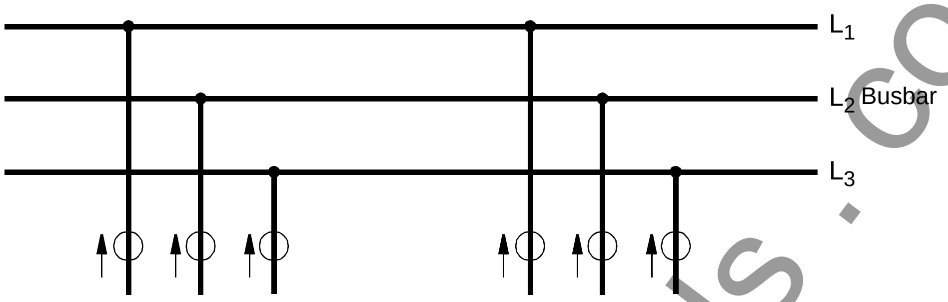


Figure 2-26 Definition of current direction at a branch-point (busbar with 2 feeders)

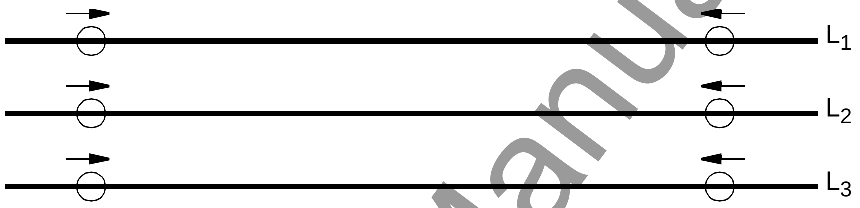


Figure 2-27 Definition of current direction at short lines

Differential Current Monitoring

Whereas a 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 side 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

Besides the high-sensitivity current input I_8, 7UT612 provides 7 current inputs of equal design. This allows for a single-phase busbar protection for up to 7 feeders.

Two possibilities exist:

1. One 7UT612 is used for each phase (Figure 2-28). 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 2-29). These currents are fed to one 7UT612.

Phase Dedicated Connection

For each of the phases, a 7UT612 is used in case of single-phase connection. The fault current sensitivity is equal for all types of fault.

The differential protection refers all measured quantities to the nominal current of the protected object. Therefore, a common nominal current must be defined for the entire busbar even if the feeder CTs have different nominal currents. The nominal busbar current and the nominal currents of all feeder CTs must be set on the relay. Matching of the current magnitudes is performed in the device. No external matching devices are necessary even if the current transformer sets at the ends of the protected zone have different primary current.

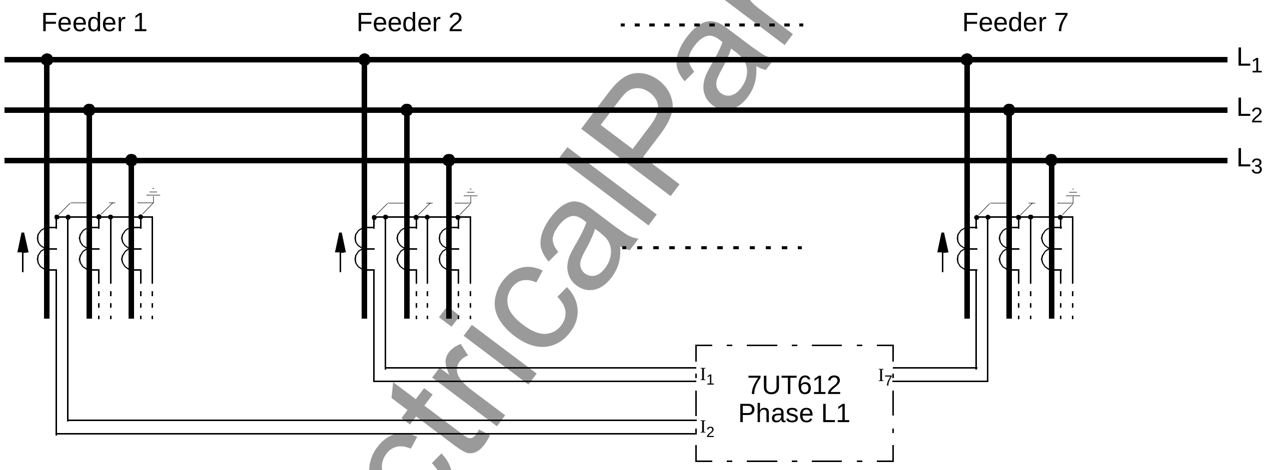


Figure 2-28 Single-phase busbar protection, illustrated for phase L1

Connection via Summation CT's

One single device 7UT612 is sufficient for a busbar with up to 7 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 2-29). 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.

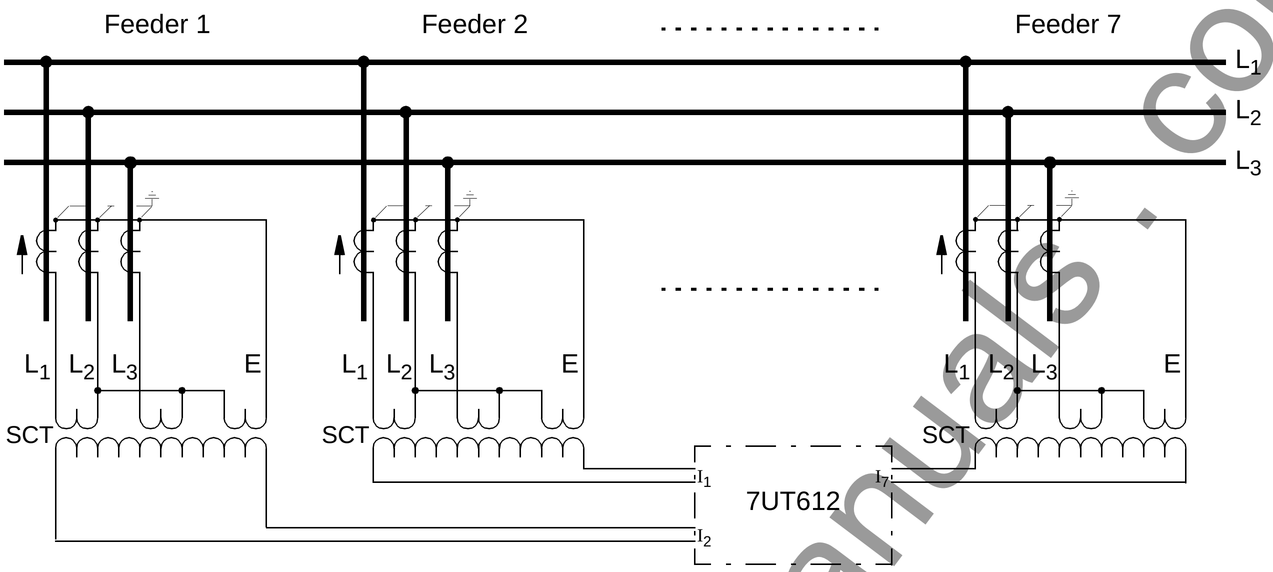


Figure 2-29 Busbar protection with connection via summation current transformers (SCT)

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 2-30 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.

For a symmetrical three-phase fault (where the earth residual component, $I_E = 0$) the single-phase summation current is, as illustrated in Figure 2-30, $\sqrt{3}$ times the winding unit value. That is, the summation flux (ampere turns) is the same as it would be for single-phase current $\sqrt{3}$ 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 relay characteristic operating values are based on this type of fault and these currents.

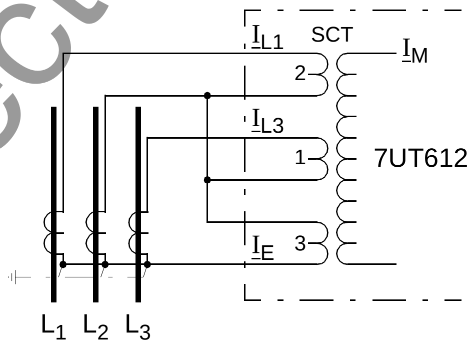


Figure 2-30 CT connection L1−L3−E

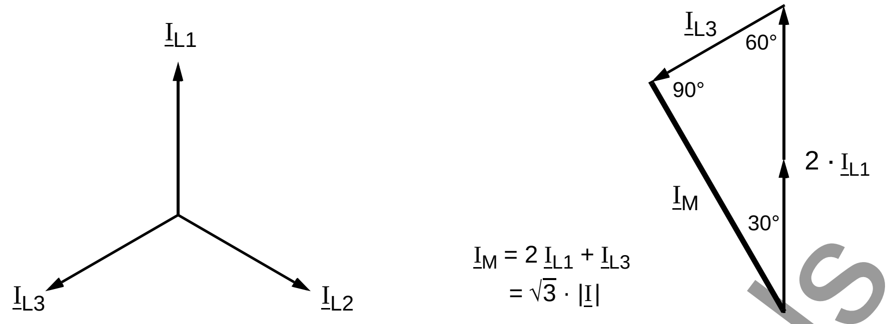


Figure 2-31 Summation of the currents L1–L3–E in the summation transformer

For the connection shown in Figure 2-30, 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 2-1. 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 2-1 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 · I_N
L1–L2	2	1,15	0.87 · I_N
L2–L3	1	0,58	1.73 · I_N
L3–L1	1	0,58	1.73 · I_N
L1–E	5	2,89	0.35 · I_N
L2–E	3	1,73	0.58 · I_N
L3–E	4	2,31	0.43 · I_N

The table shows that 7UT612 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 2-30) 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 2-32 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 2-2 can be re-calculated for the seven possible fault conditions in solidly earthed networks.

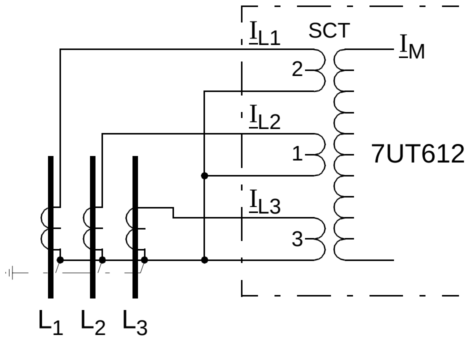


Figure 2-32 CT connection L1−L2−L3 with decreased earth fault sensitivity

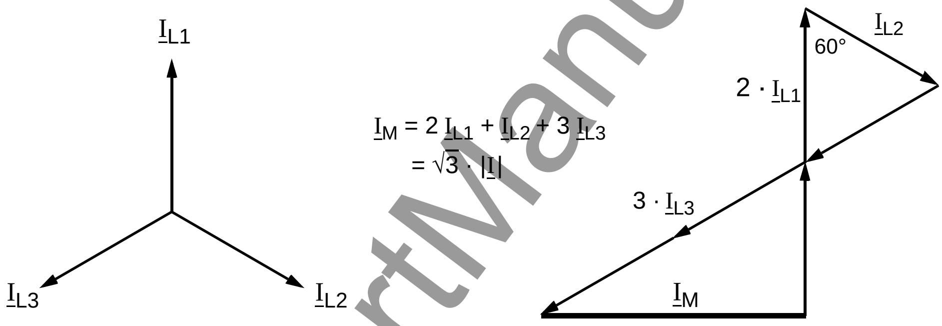


Figure 2-33 Summation of the currents L1−L2−L3 in the summation transformer

Table 2-2 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	$1.00 \cdot I_N$
L1–L2	1	0,58	$1.73 \cdot I_N$
L2–L3	2	1,15	$0.87 \cdot I_N$
L3–L1	1	0,58	$1.73 \cdot I_N$
L1–E	2	1,15	$0.87 \cdot I_N$
L2–E	1	0,58	$1.73 \cdot I_N$
L3–E	3	1,73	$0.58 \cdot I_N$

Comparison with Table 2-1 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 2-34 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 7UT612) amounts to I_N = 0.1 A at nominal conditions, with correct matching.

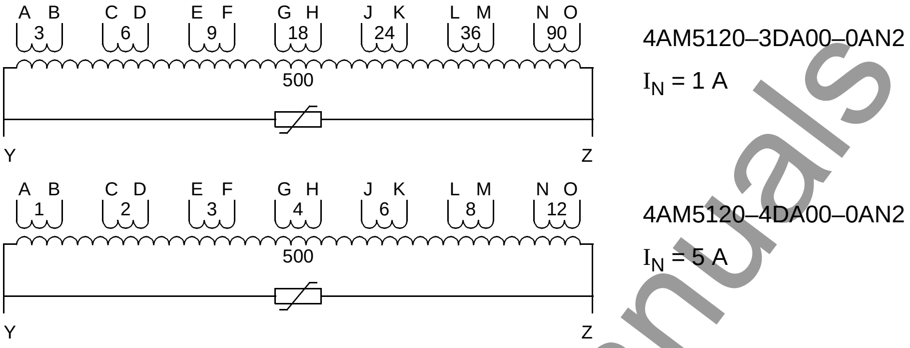


Figure 2-34 Winding arrangement of summation and matching transformers 4AM5120

Differential Current Monitoring

Whereas a 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 (refer to Subsection 2.1.1, 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 operated 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 earth electrode, the starpoint current may be taken into consideration for calculations of the differential protection (see also Subsection 2.2.2, margin heading “Increasing the Ground Fault Sensitivity”, page 45). Thus, the earth fault sensitivity is increased.

In addresses 1211A **DIFFw.IE1-MEAS** for side 1 or 1212A **DIFFw.IE2-MEAS** for side 2 the user informs the device on whether the earth current of the earthed starpoint is included or not. This parameter can only be changed with DIGSI® 4 under “**Additional Settings**”.

With setting ***YES*** the corresponding earth current will be considered by the differential protection. This setting only applies for transformers with two separate windings. Its use only makes sense if the corresponding starpoint current actually is connected to the device (current input I_7). When configuring the protection functions (see Subsection 2.1.1, page 16) address 108 must have been set accordingly. In addition to that, the starpoint of the corresponding side has to be earthed (Subsection 2.1.2 under margin heading “Object Data with Transformers”, page 20, addresses 241 and/or 244).

Differential Current Monitoring

With busbar 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 transformer 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. 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 1256A. Figure 2-35 illustrates the meaning of the different settings. The numbers signify the addresses of the settings.

`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, reactors, generators, or motors, (presetting $0.2 \cdot I_{NObj}$). A higher value (above nominal current) should 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.

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 (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, $\frac{1}{u_{sc\ transf}} \cdot I_{Ntransf}$.

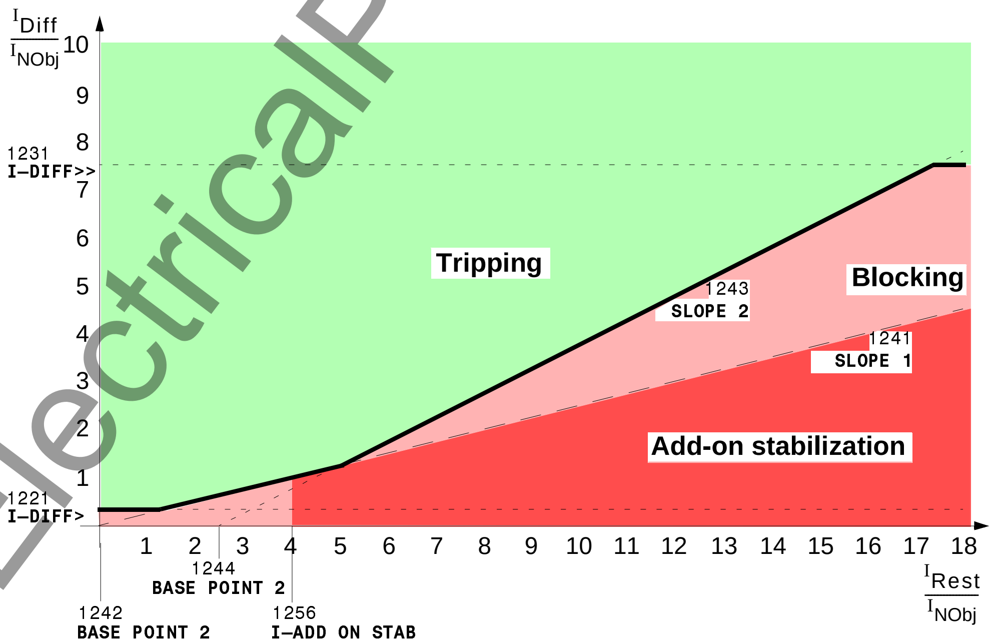


Figure 2-35 Tripping characteristic of the differential protection

The tripping characteristic forms two more branches (Figure 2-35) 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 changed with DIGSI® 4 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, differential currents which occur due to the transformer regulating range.

The percentage of this differential current is equal to the percentage of the regulating range provided the rated voltage is corrected according to Subsection 2.1.2 under margin “Object Data with Transformers” (page 20).

The second branch produces a higher stabilization 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 changed with DIGSI® 4 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 changed with DIGSI® 4 under “**Additional Settings**”. 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 block 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. in case of standstill). This parameter can only be changed with DIGSI® 4 under “**Additional Settings**”. Please be aware of the fact that the restraint current is twice the traversing operational current. The pre-set 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 value. The I_{Diff}>>–stage is not affected. For motors or motor/transformer in block connection, a value of 2 is normally adequate. This parameter can only be changed with DIGSI® 4 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 2-35). The initial value is set in address 1256A **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 changed with DIGSI® 4 under “**Additional Settings**”. Please be aware of the fact that the restraint current is the arithmetical sum of the currents flowing into the protected object, i. e. it is twice the traversing current.

The maximum duration of the add-on stabilization after detection of an external fault is set to multiples of an AC-cycle (address 1257A **T ADD ON-STAB.**). This parameter can only be changed with DIGSI® 4 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. via at least one cycle) within the tripping zone.

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 2-25, 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 1261) 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

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 1262A **CROSSB. 2. HARM**. Setting is in multiple of the AC-cycle. This parameter can only be changed with DIGSI® 4 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, 7UT612 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.

The harmonic content which blocks the differential stage I_{Diff}> is set under address 1271 **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 1272A **CROSSB. n.HARM**. Setting is in multiple of the AC-cycle. This parameter can only be changed with DIGSI® 4 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 1273A **IDIFFmax n.HM** no n-th harmonic restraint takes place. This parameter can only be changed with DIGSI® 4 under “**Additional Settings**”.

2.2.8 Setting Overview

Note: Addresses which have an “A” attached to its end can only be changed in DIGSI® 4, under “**Additional Settings**”.

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
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/InO; 0	0.00 I/InO	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
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

Addr.	Setting Title	Setting Options	Default Setting	Comments
1253	T START MAX	0.0..180.0 sec	5.0 sec	Maximum Permissible Starting Time
1256A	I-ADD ON STAB.	2.00..15.00 I/InO	4.00 I/InO	Pickup for Add-on Stabilization
1257A	T ADD ON-STAB.	2..250 Cycle; ∞	15 Cycle	Duration of Add-on Stabilization
1261	2. HARMONIC	10..80 %	15 %	2nd Harmonic Content in I-DIFF
1262A	CROSSB. 2. HARM	2..1000 Cycle; 0; ∞	3 Cycle	Time for Cross-blocking 2nd Harm.
1271	n. HARMONIC	10..80 %	30 %	n-th Harmonic Content in I-DIFF
1272A	CROSSB. n.HARM	2..1000 Cycle; 0; ∞	0 Cycle	Time for Cross-blocking n-th Harm.
1273A	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: adverse Adaption factor CT
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	DiffCrosBlk2HM	Diff: Crossblock by 2.Harmonic

F.No.	Alarm	Comments
05658	DiffCrosBlknHM	Diff: Crossblock by n.Harmonic
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	Diff in.char.L1	Diff: Increase of char. phase L1
05667	Diff in.char.L2	Diff: Increase of char. phase L2
05668	Diff in.char.L3	Diff: Increase of char. phase L3
05670	Diff I-Release	Diff: Curr-Release for Trip
05671	Diff TRIP	Differential protection TRIP
05672	Diff TRIP L1	Differential protection: TRIP L1
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 grounding transformers/reactors, or rotating machines, the starpoint of which is led to earth. It is also suitable when a starpoint former 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 earth. The starpoint CT and the three phase CTs define the limits of the protected zone exactly.

Examples are illustrated in the Figures 2-36 to 2-40.

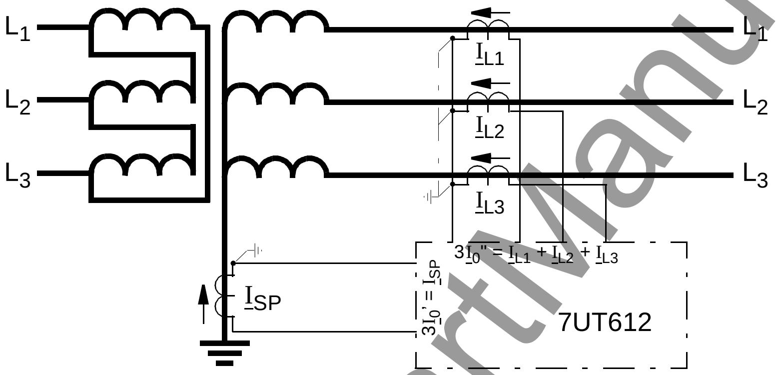


Figure 2-36 Restricted earth fault protection on an earthed transformer winding

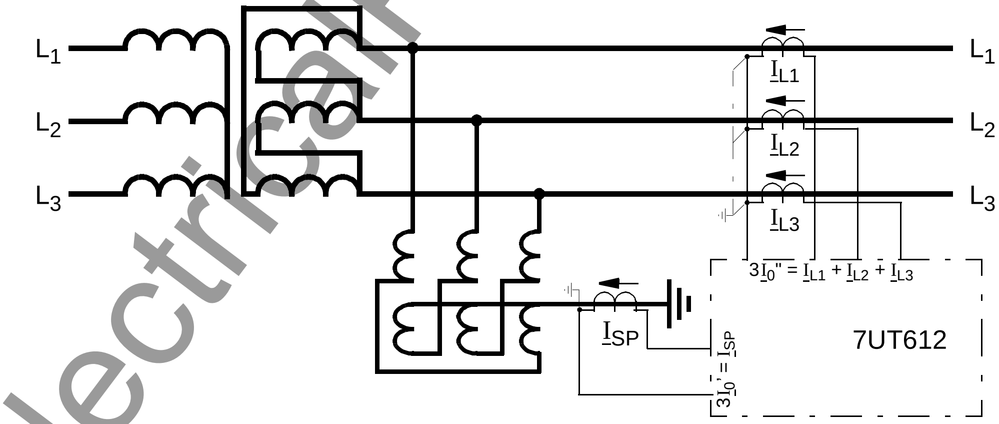


Figure 2-37 Restricted earth fault protection on a non-earthed transformer winding with neutral reactor (starpoint former) within the protected zone

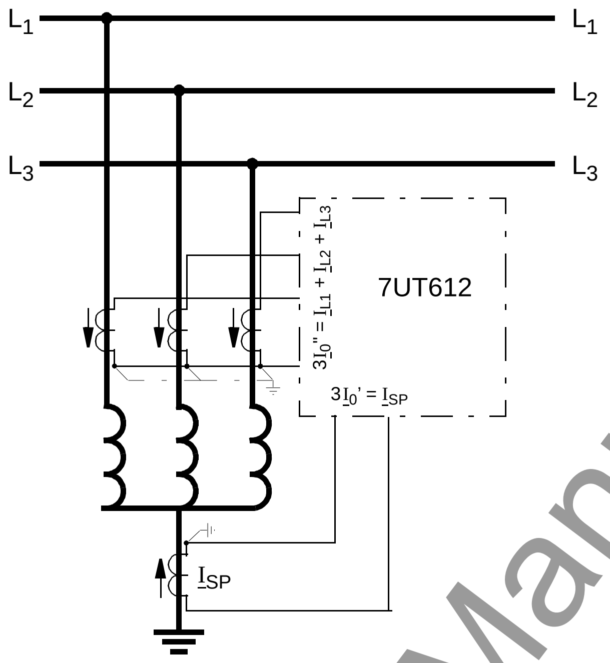


Figure 2-38 Restricted earth fault protection on an earthed shunt reactor with CTs in the reactor leads

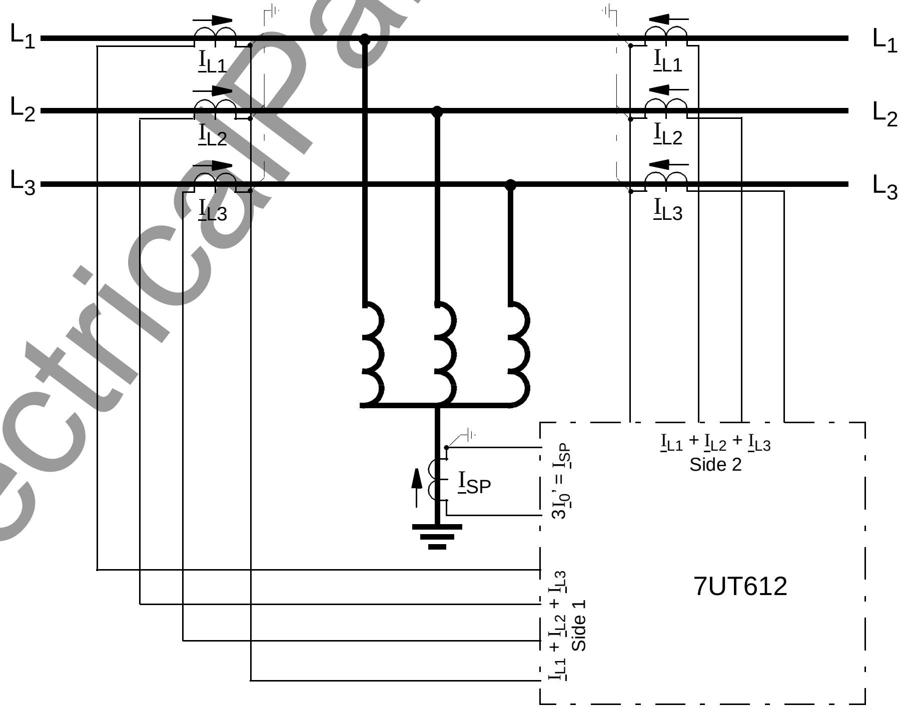


Figure 2-39 Restricted earth fault protection on an earthed shunt reactor with 2 CT sets (treated like an auto-transformer)

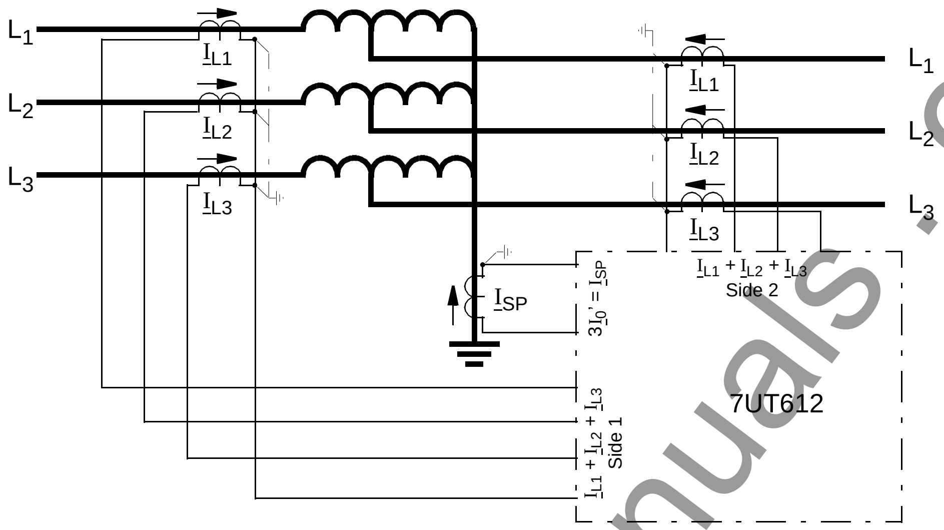


Figure 2-40 Restricted earth fault protection on an earthed auto-transformer

2.3.1 Function Description

Basic Principle

During healthy operation, no starpoint current 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 zero, too.

When an earth fault occurs in the protected zone (Figure 2-41), a starpoint current 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.

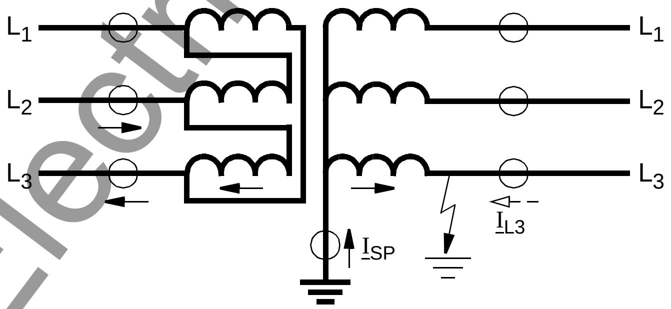


Figure 2-41 Example for an earth fault in a transformer with current distribution

When an earth fault occurs outside the protected zone (Figure 2-42), 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.

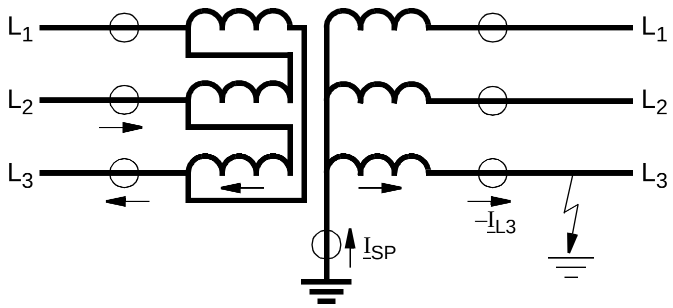


Figure 2-42 Example for an earth fault outside a transformer with current distribution

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 2-43):

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

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

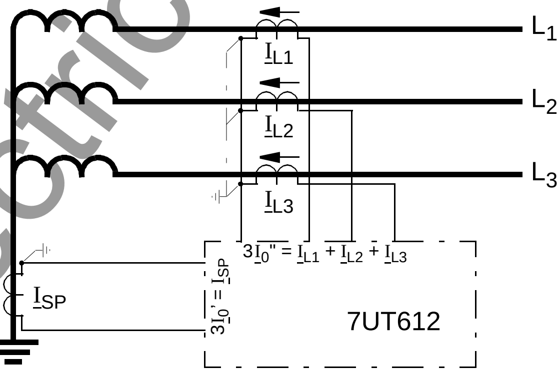


Figure 2-43 Principle of restricted earth fault protection

When an earth fault occurs outside the protected zone, another earth current $3\underline{I}_0''$ flows though the phase current transformers. This is, on the primary side, in counterphase 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 2-44 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 $3I_0'$.

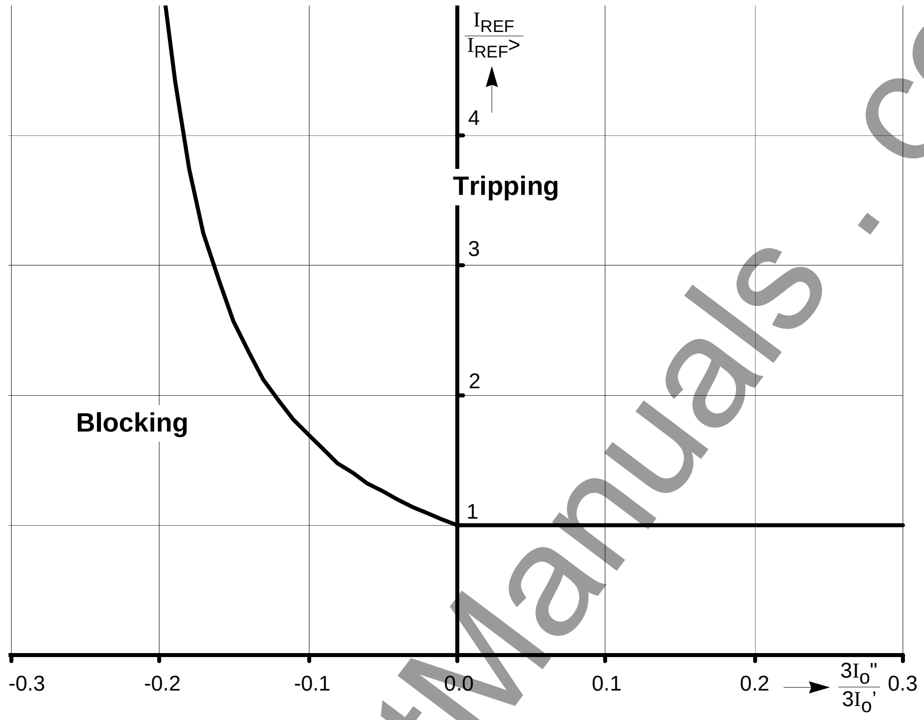


Figure 2-44 Tripping characteristic of the restricted earth fault protection depending on the earth current ratio $3I_0"/3I_0'$ (both currents in phase + or counter-phase –); I_{REF} = tripping effect current; $I_{REF}>$ = setting value

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 2-45).

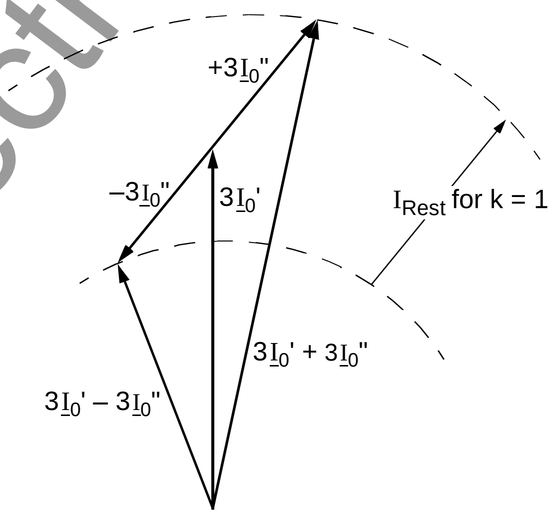


Figure 2-45 Phasor diagram of the restraint quantity during external fault

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 7UT612 is k = 2, i.e. the restraint quantity in the above example a) is redoubled once more: the restraint quantity I_{Rest} is 4 times the tripping effect quantity I_{REF}. The limit angle is $\varphi_{limit} = 110°$. That means no trip is possible for phase displacement $\varphi(3\underline{I}_0"; 3\underline{I}_0') \geq 110°$.

Figure 2-46 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 $|3\underline{I}_0"| = |3\underline{I}_0'|$.

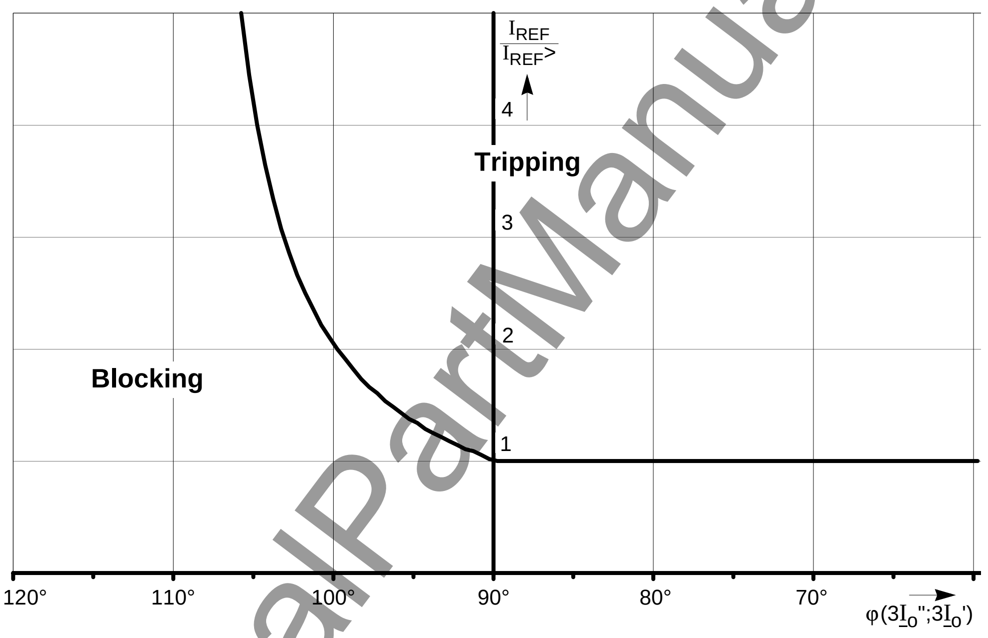


Figure 2-46 Tripping characteristic of the restricted earth fault protection depending on the phase displacement between $3\underline{I}_0$" and $3\underline{I}_0$' at $3I_0" = 3I_0'$ (180° = external fault)

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 2-47). The slope of this stabilization can be set.

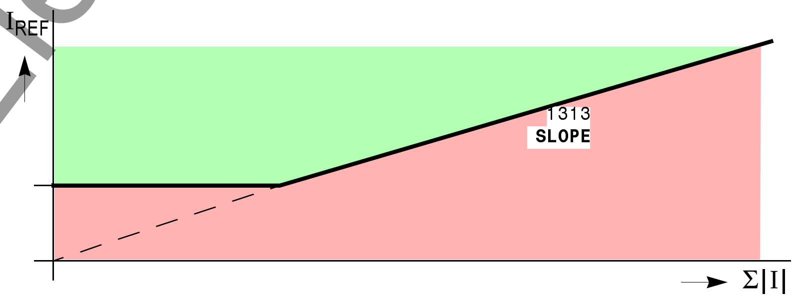


Figure 2-47 Increasing the pickup value

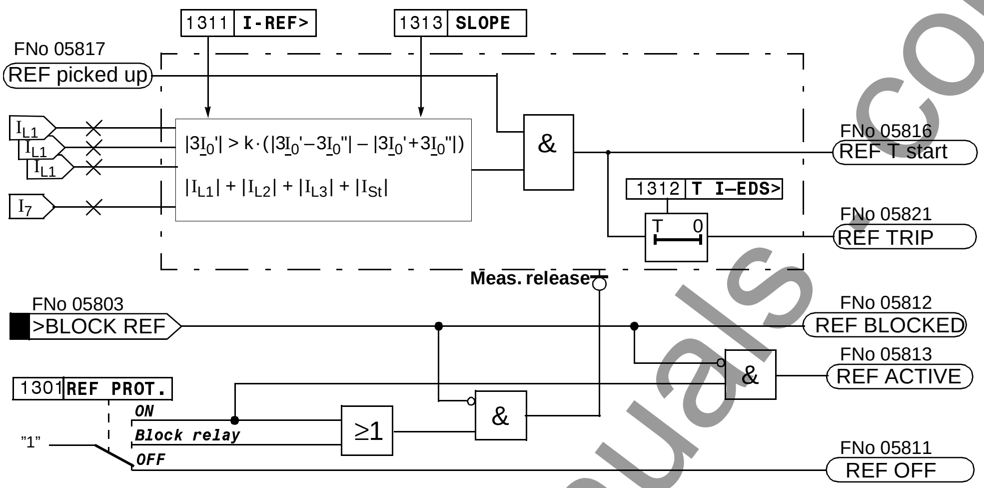


Figure 2-48 Logic diagram of the restricted earth fault protection

2.3.2 Setting the Function Parameters

The restricted earth fault protection can only operate if this function is assigned during configuration (refer to Subsection 2.1.1, address 113) **REF PROT.** to one of the sides of the protected object. Additionally, the measured current input I_7 must be assigned to the same side (address 108). The restricted earth fault protection can be set effective (***ON***) or ineffective (***OFF***) in address 1301 **REF PROT.**. When set to ***Block relay***, the protection function operates but no trip command is issued.

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.

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 changed with DIGSI® 4 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 its end can only be changed in DIGSI® 4, under “**Additional Settings**”.

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 / In	0.15 I / In	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
05836	REF Adap.fact.	REF: adverse Adaption factor CT
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)
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

The time overcurrent protection is used as backup protection for the short-circuit protection of the protected object and provides backup protection for external faults which are not promptly disconnected and thus may endanger the protected object.

Information on the connection and viewpoints for the assignment to the sides of the protected object are given in Subsection 2.1.1 under “Special Cases” (page 15). The assigned side and the type of characteristics have been decided under addresses 120 to 123.

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

If the 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 121 and/or 123).

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 $> 0.3 \cdot I_N$.

Figure 2-49 shows the logic diagram for the high-current stages I>> and $3I_0$>>.

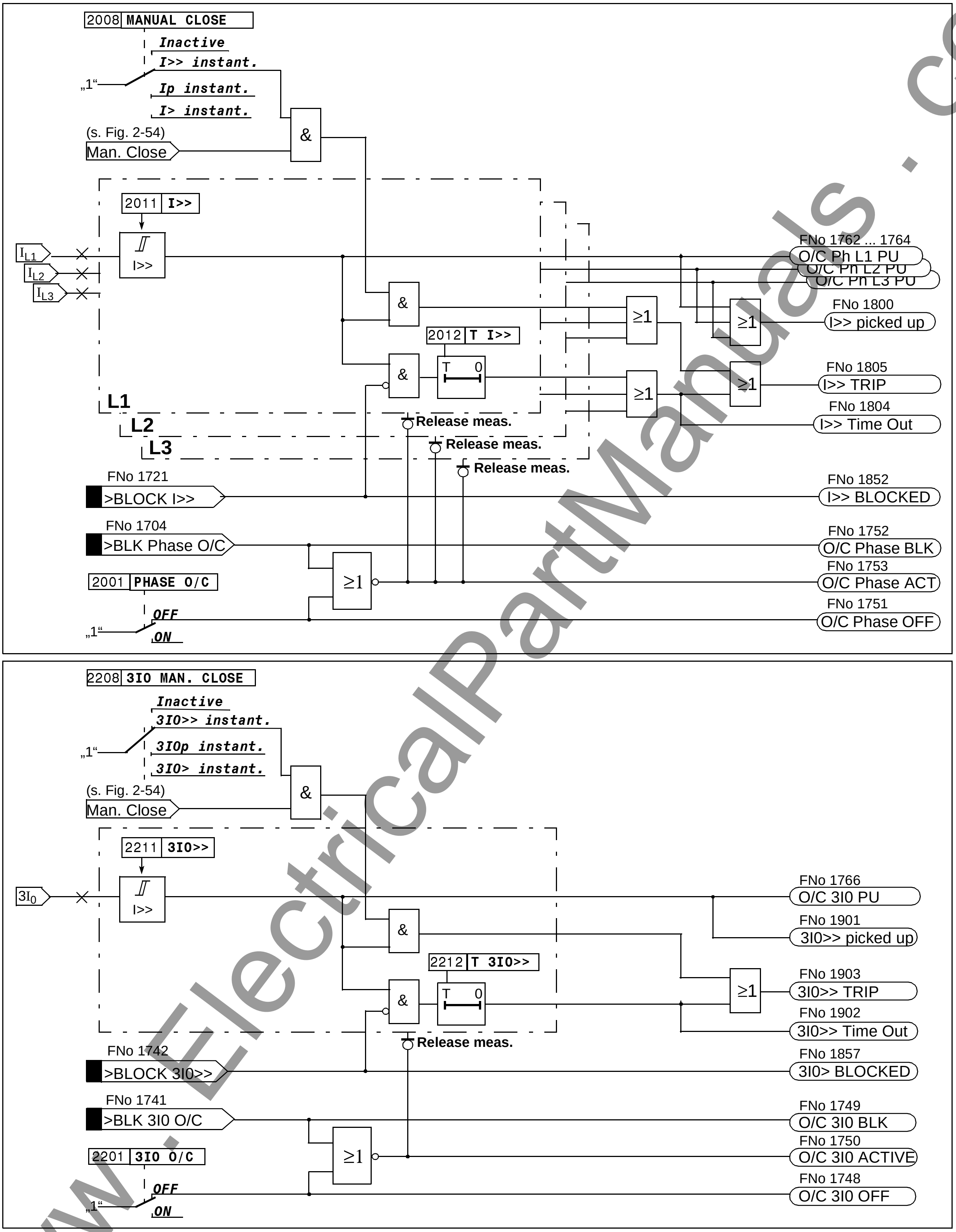


Figure 2-49 Logic diagram of the high-set stages I>> for phase currents and residual current

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 > $0{,}3 \cdot I_N$.

Figure 2-50 shows the logic diagram of the stages I> for phase currents, Figure 2-51 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.

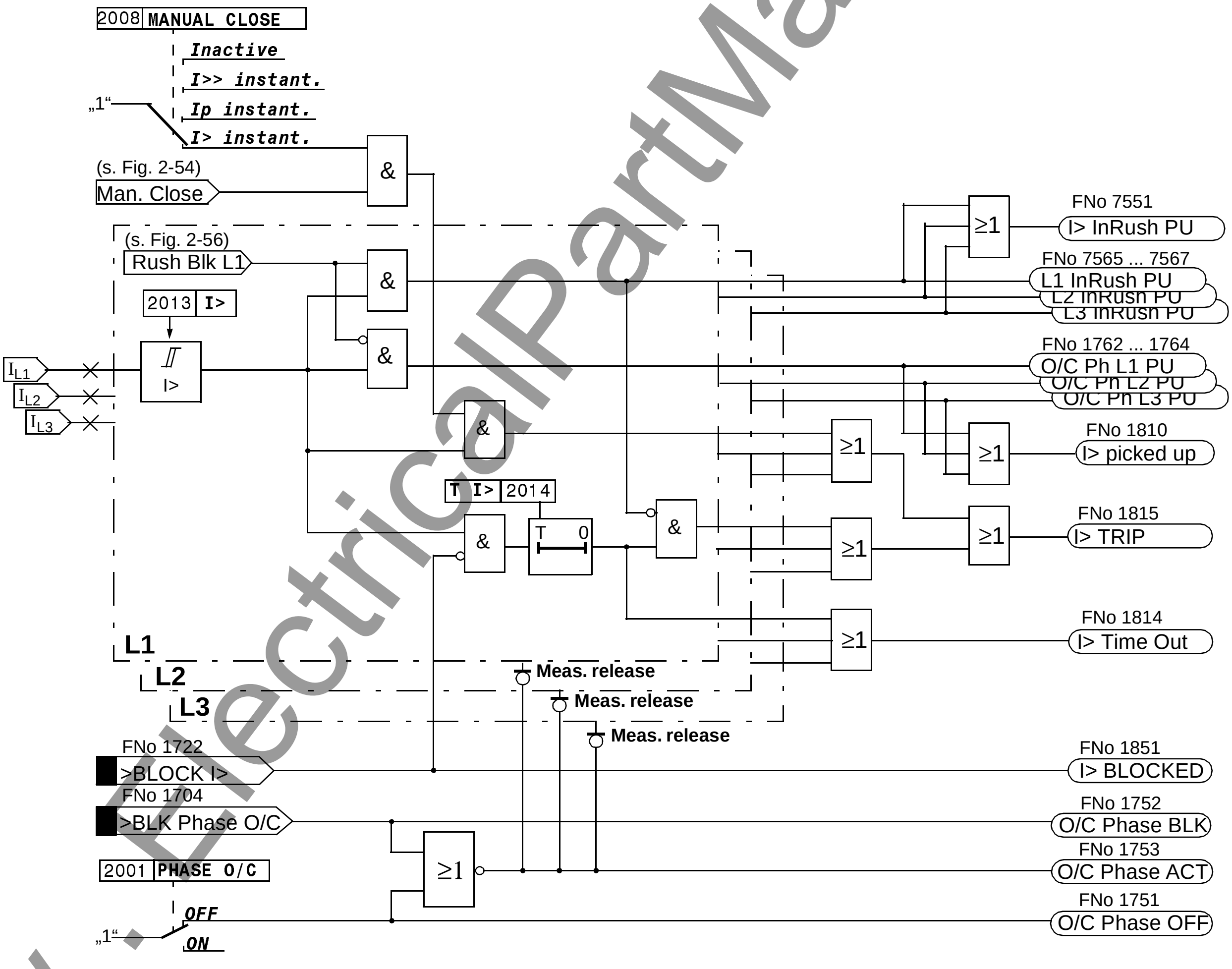


Figure 2-50 Logic diagram of the overcurrent stages I> for phase currents

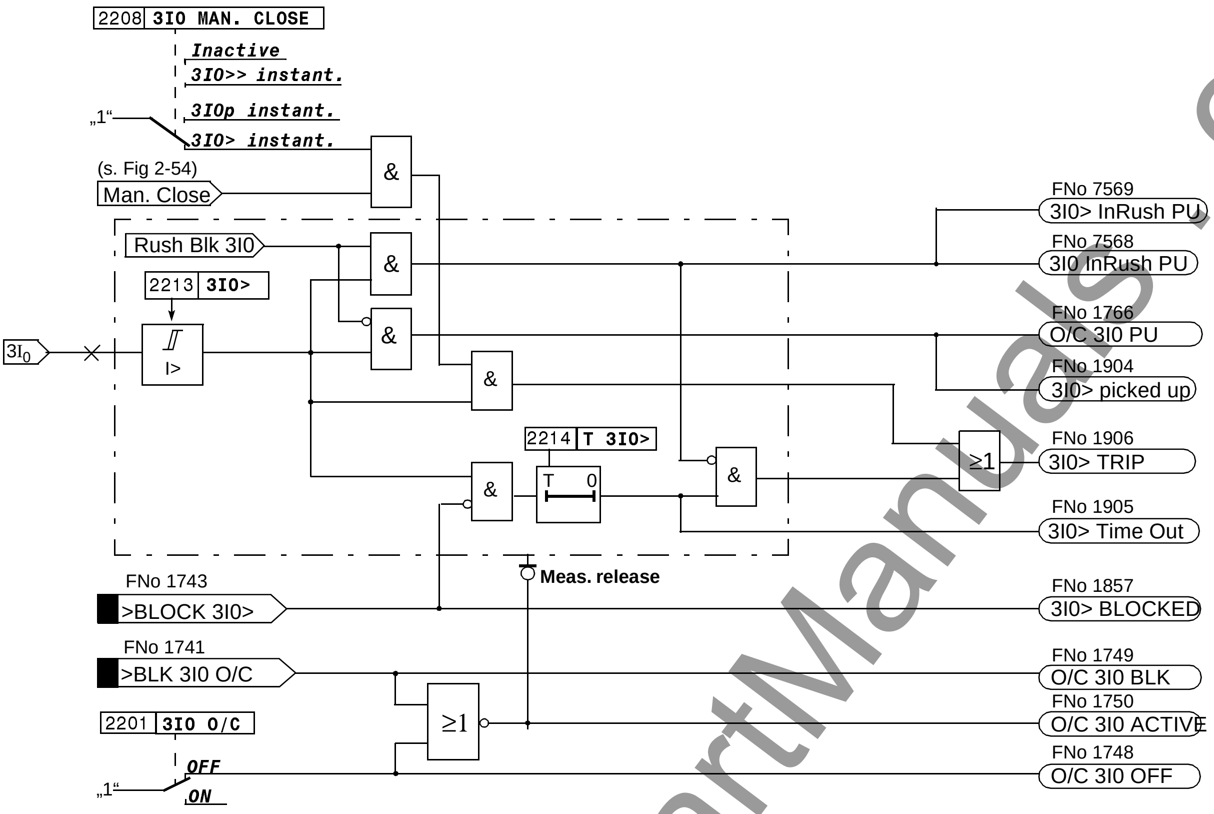


Figure 2-51 Logic diagram of the overcurrent stage $3I_0$> for residual current

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 enabled (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 selectively. 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 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 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 2-52 shows the logic diagram of the inverse time stages for phase currents, Figure 2-53 for residual current.

Dropout for IEC Curves

Dropout of a stage using an IEC curves occurs when the respective current decreases below about 95 % of the pickup value. A renewed pickup will cause a renewed start of the delay timers.

Dropout for ANSI Curves

Using the ANSI-characteristics 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.

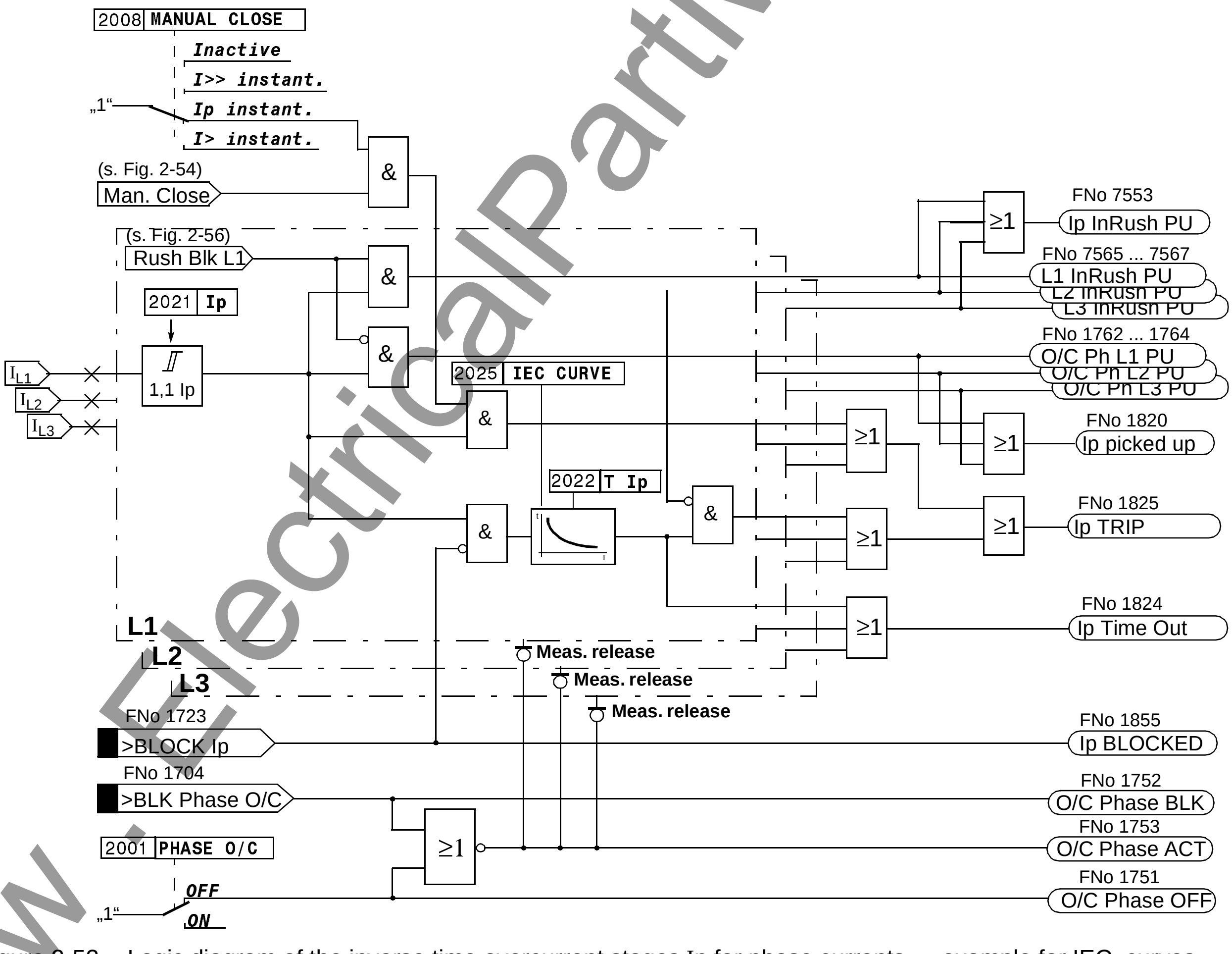


Figure 2-52 Logic diagram of the inverse time overcurrent stages Ip for phase currents — example for IEC–curves

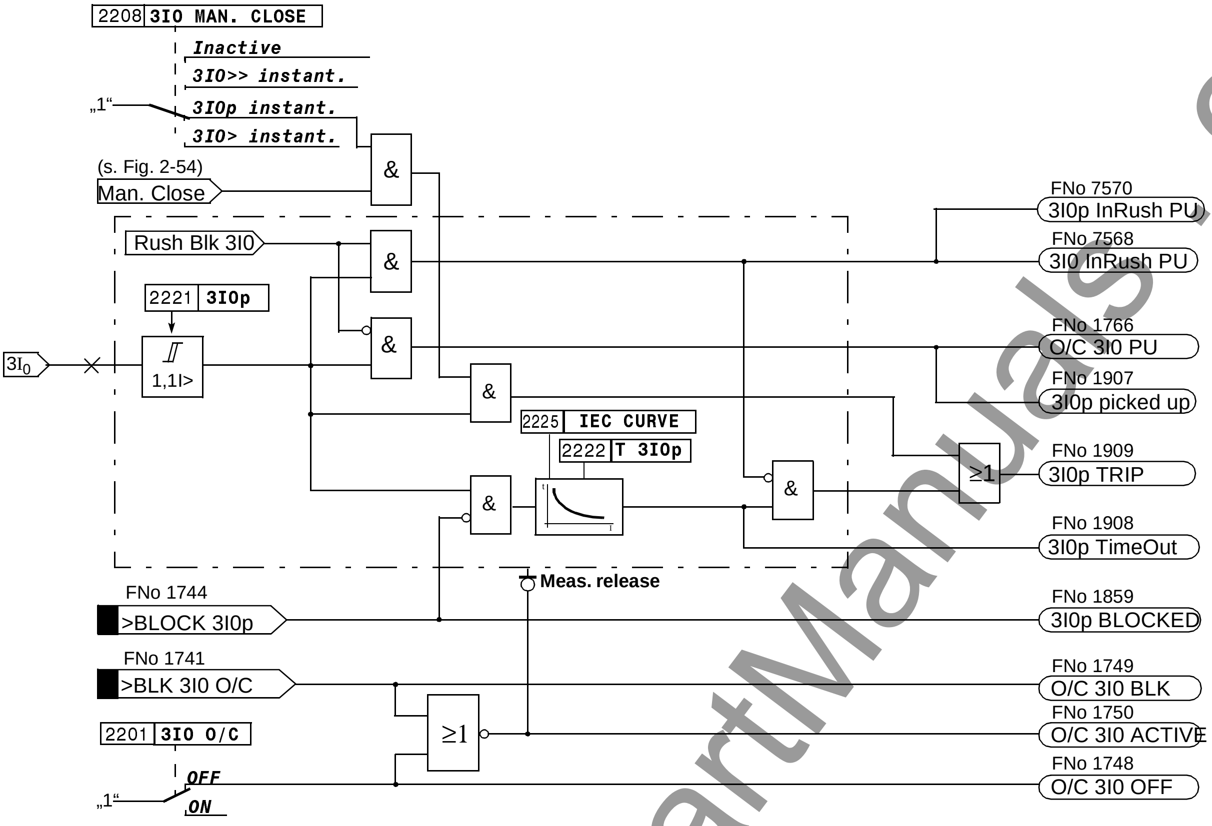


Figure 2-53 Logic diagram of the inverse time overcurrent stage for residual current — example for IEC–curves

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 for ANSI Curves”. If no user-configurable dropout characteristic is desired, dropout is initiated when approx. a 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 2-54). Addresses 2008A **`MANUAL CLOSE`** and/or 2208A **`3I0 MAN. CLOSE`** determine for which stages the delay is defeated under manual close condition.

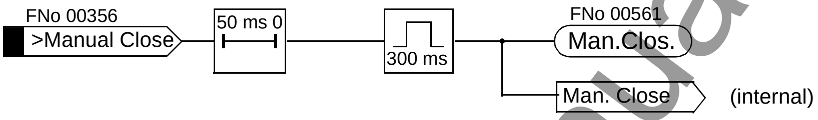


Figure 2-54 Manual close processing

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 common for all time overcurrent stages, and is explained in Section 2.6 (page 108). 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 (0.2 I_N).

Figure 2-55 shows a simplified logic diagram.

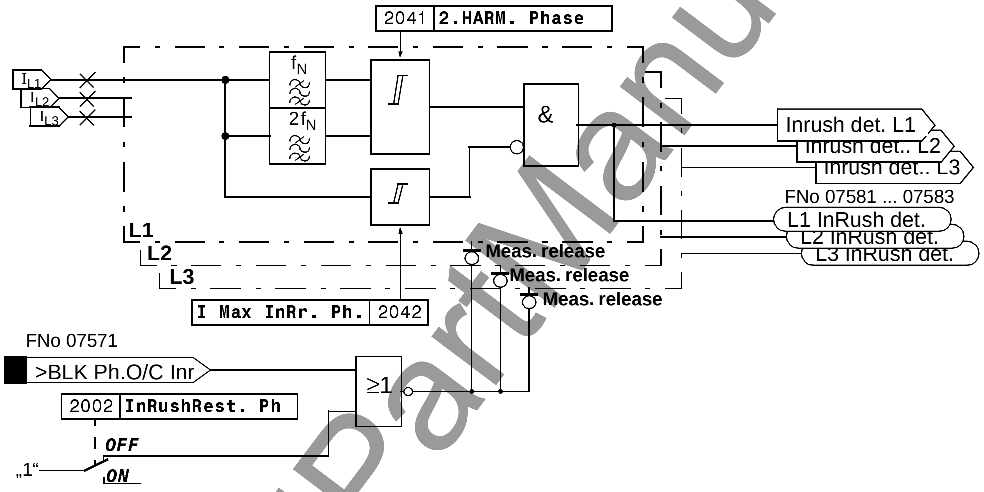


Figure 2-55 Logic diagram of the inrush restraint feature — example for phase currents

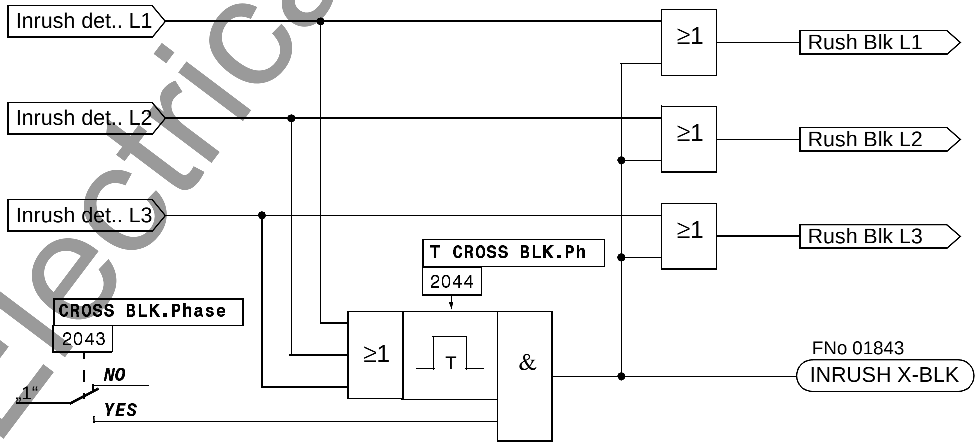


Figure 2-56 Logic diagram of the crossblock function for the phase currents

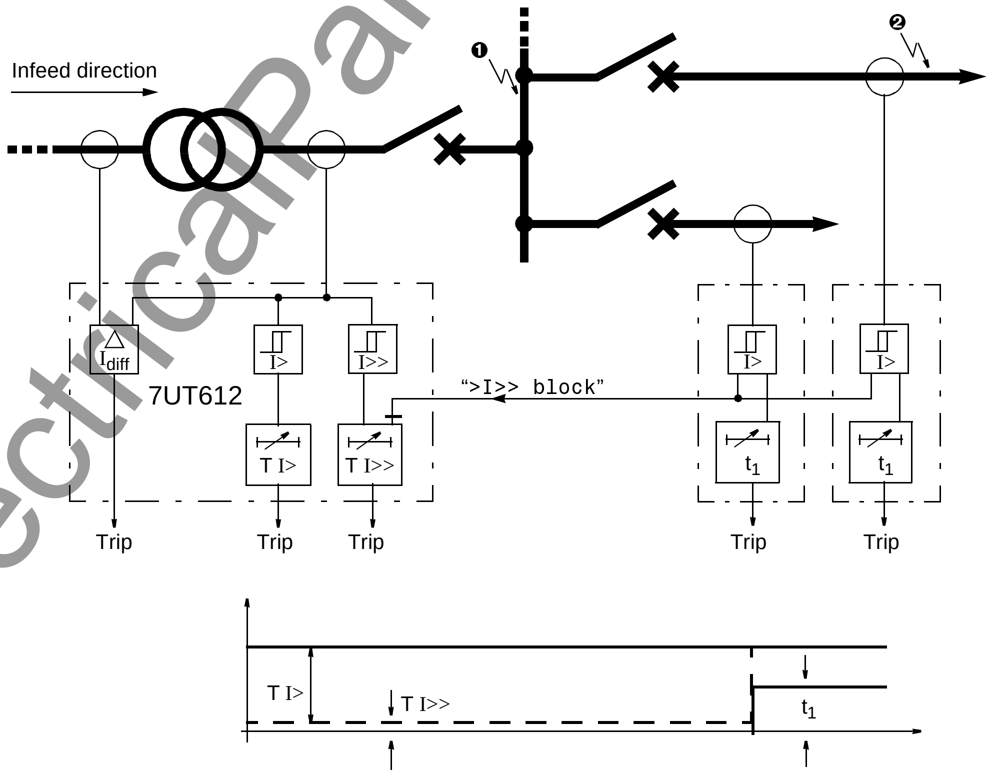
Since the harmonic restraint operates individually per phase, the protection is fully operative even when e.g. the transformer is switched onto a single-phase fault, whereby inrush currents may possibly be present in one of the healthy phases. However, it is also possible to set the protection such that 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 2-56 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.

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 2-57).



Fault location ❶: Tripping time T I>>

Fault location ❷: Tripping time t_1
Backup time T I>

Figure 2-57 Fast busbar protection using reverse interlock — principle

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 2-57). 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.

2.4.2 Setting the Function Parameters

During configuration of the functional scope (Subsection 2.1.1, margin heading “Special Cases”, page 16) in addresses 120 to 123 the sides of the protected object and the type of characteristic were determined, separately for the phase current stages and zero sequence current stage. Only the settings for the characteristic selected can be performed here. The definite time stages I>>, 3I0>>, I> and 3I0> are always available.

2.4.2.1 Phase Current Stages

General

In address 2001 **PHASE O/C** time overcurrent protection for phase currents can be switched ***ON*** or ***OFF***.

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 changed with DIGSI® 4 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) 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.

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 a constant 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® 4 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.

Increased inrush currents, if their fundamental oscillation exceeds the setting value, are rendered harmless by delay times (address 2012 **T I>>**). The inrush restraint does not apply to stages I>>.

Using reverse interlocking (Subsection 2.4.1.6, see also Figure 2-57) 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 overvoltage 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 2013) 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 2014 **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 121), enable the user to select different characteristics. With the IEC characteristics (address 121 **DMT/IDMT PH. CH** = ***TOC IEC***) the following is made available in address 2025 **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 function will reset as soon as the value undershoots 95 % of the pickup value.

The current value is set in address 2021 **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 2022 **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 121 **DMT/IDMT PH. CH** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

Inverse Time Overcurrent Stages Ip with ANSI curves

The inverse time stages, depending on the configuration (Subsection 2.1.1, address 121), enable the user to select different characteristics. With the ANSI characteristics (address 121 **DMT/IDMT PH. CH** = ***TOC ANSI***) the following is made available in address 2026 **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 **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 2023 **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 121 **DMT/IDMT PH. CH** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

If ***Disk Emulation*** is set in address 2024 **TOC DROP-OUT**, dropout is being produced according to the dropout characteristic. For more information see Subsection 2.4.1.2, margin heading “Dropout for ANSI Curves” (page 77).

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 108).

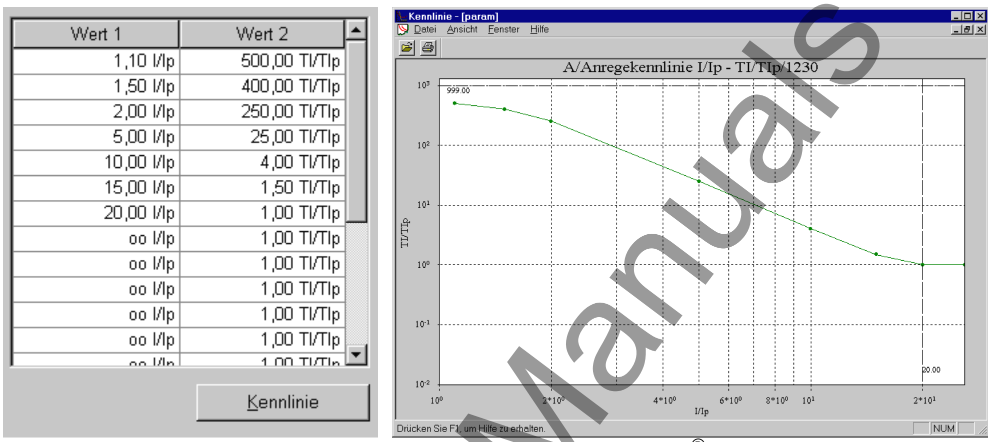
For the stages the following alternative values are set:

- for definite time overcurrent protection (phases):
  address 2111 pickup value **I>>**,
  address 2112 delay time **T I>>**,
  address 2113 pickup value **I>**,
  address 2114 delay time **T I>**;
- for inverse time overcurrent protection (phases) acc. IEC curves:
  address 2121 pickup value **Ip**,
  address 2122 time multiplier **T Ip**;
- for inverse time overcurrent protection (phases) acc. ANSI curves:
  address 2121 pickup value **Ip**,
  address 2123 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® 4 a dialog box is to appear. Enter up to 20 pairs of current value and tripping time value (Figure 2-58).

In DIGSI® 4 the characteristic can also be viewed as an illustration, see the right part of Figure 2-58.



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
oo I/Ip	1,00 TI/TIp

Figure 2-58 Entering a user specified tripping curve using DIGSI® 4 — example

To create a user-defined tripping characteristic, the following must be set for configuration of the functional scope (Subsection 2.1.1): address 121 **DMT/IDMT PH. CH**, 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 2-3), we recommend to use exactly the same preferred current values you can find in this table.

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Table 2-3 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 2-3 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 2-59, right side) goes parallel to the current axis, up to the *smallest* characteristic point.

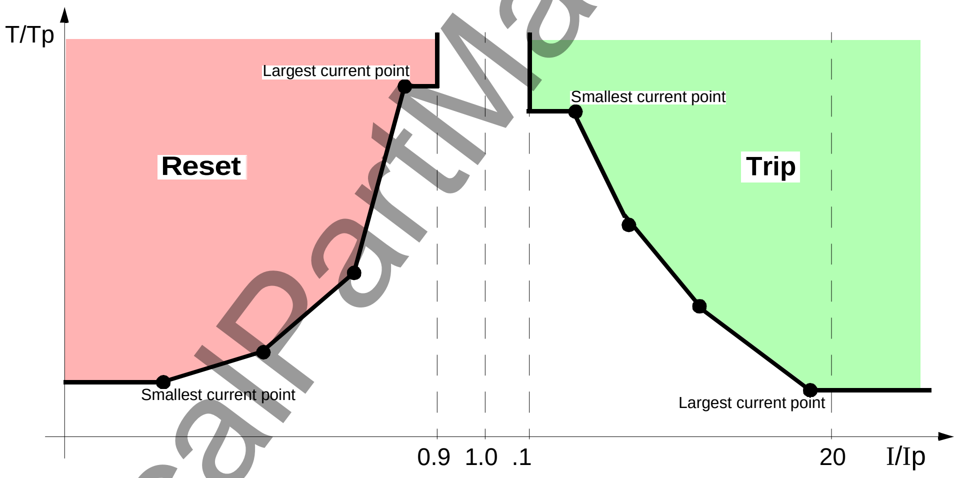

Figure 2-59 User specified characteristic — example

- 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 2-59, 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 2-4 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 2-59, 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 2-59, 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 2-4 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 82, 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 2043 **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 2044 **T CROSS BLK.Ph**.

2.4.2.2 Residual Current Stages

General

In address 2201 **3I0 O/C**, time overcurrent protection for residual current can be set to ***ON*** or ***OFF***.

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 changed with DIGSI® 4 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 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 of importance. For transformers with separate windings, zero sequence systems are usually kept separate (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 2212 **T 3I0>>**).

“Reverse interlocking” (Subsection 2.4.1.6, see Figure 2-57) 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 2213) the minimum appearing earth fault current is relevant.

The settable time delay (parameter 2214 **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 20 % nominal current (lower limit of harmonic filtering). An adequate time delay could be reasonable.

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 123), enables the user to select different characteristics. With the IEC characteristics (address 123 **DMT/IDMT 3I0 CH** = ***TOC IEC***) the following is made available in address 2225 **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 function will reset as soon as the value undershoots 95 % of the pickup value.

The current value is set in address 2221 **3I0p**. The most relevant for this setting is the minimum appearing earth fault current.

The corresponding time multiplier is accessible via address 2222 **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 20 % nominal current (lower limit of harmonic filtering). An adequate time delay could be reasonable.

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 123 **DMT/IDMT 3I0 CH** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

Inverse Time Overcurrent Stage 3I0p with ANSI curves

The inverse time stages, depending on the configuration (Subsection 2.1.1, address 123), enable the user to select different characteristics. With the ANSI characteristics (address 123 **DMT/IDMT 3I0 CH** = ***TOC ANSI***) the following is made available in address 2226 **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 **3I0p**. The most relevant for this setting is the minimum appearing earth fault current.

The corresponding time multiplier is set in address 2223 **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 20 % nominal current (lower limit of harmonic filtering). An adequate time delay could be reasonable.

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 123 **DMT/IDMT 3I0 CH** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

If ***Disk Emulation*** is set in address 2224 **TOC DROP-OUT**, dropout is being produced according to the dropout characteristic. For more information see Subsection 2.4.1.2, margin heading “Dropout for ANSI Curves” (page 77).

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 108).

For the stages the following alternative values are set:

- for definite time overcurrent protection $3I_0$:
  address 2311 pickup value **3I0>>**,
  address 2312 delay time **T 3I0>>**,
  address 2313 pickup value **3I0>**,
  address 2314 delay time **T 3I0>**;
- for inverse time overcurrent protection $3I_0$ acc. IEC curves:
  address 2321 pickup value **3I0p**,
  address 2322 time multiplier **T 3I0p**;
- for inverse time overcurrent protection $3I_0$ acc. ANSI curves:
  address 2321 pickup value **3I0p**,
  address 2323 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® 4 a dialog box is to appear. Enter up to 20 pairs of current and tripping time values (Figure 2-58, page 86).

The procedure is the same as for phase current stages. See Subsection 2.4.2.1, margin heading “User Specified Curves”, page 86.

To create a user defined tripping characteristic, the following must have been set for configuration of the functional scope (Subsection 2.1.1): address 123 **DMT/IDMT 3I0 CH**, 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 88, 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

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. For settings in primary values, a conversion rate from current transformers has to be considered additionally.

Note: Addresses which have an “A” attached to their end can only be changed in DIGSI® 4, Section „**Additional Settings**“.

Phase Currents

Addr.	Setting Title	Setting Options	Default Setting	Comments
2001	PHASE O/C	ON OFF	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	T I>>	0.00..60.00 sec; ∞	0.00 sec	T I>> Time Delay
2013	I>	0.10..35.00 A; ∞	1.00 A	I> Pickup
2014	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	T I>>	0.00..60.00 sec; ∞	0.00 sec	T I>> Time Delay
2113	I>	0.10..35.00 A; ∞	2.00 A	I> Pickup
2114	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	T Ip	0.05..3.20 sec; ∞	0.50 sec	T Ip Time Dial
2023	D Ip	0.50..15.00; ∞	5.00	D Ip Time Dial
2024	TOC DROP-OUT	Instantaneous Disk Emulation	Disk Emulation	TOC Drop-out characteristic

Addr.	Setting Title	Setting Options	Default Setting	Comments
2025	IEC CURVE	Normal Inverse Very Inverse Extremely Inverse Long Inverse	Normal Inverse	IEC Curve
2026	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	T Ip	0.05..3.20 sec; ∞	0.50 sec	T Ip Time Dial
2123	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	CROSS BLK.Phase	NO YES	NO	CROSS BLOCK O/C Phase
2044	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	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	T 3I0>>	0.00..60.00 sec; ∞	0.10 sec	T 3I0>> Time Delay
2213	3I0>	0.05..35.00 A; ∞	0.20 A	3I0> Pickup
2214	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

Addr.	Setting Title	Setting Options	Default Setting	Comments
2312	T 3I0>>	0.00..60.00 sec; ∞	0.00 sec	T 3I0>> Time Delay
2313	3I0>	0.05..35.00 A; ∞	1.50 A	3I0> Pickup
2314	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	T 3I0p	0.05..3.20 sec; ∞	0.20 sec	T 3I0p Time Dial
2223	D 3I0p	0.50..15.00; ∞	5.00	D 3I0p Time Dial
2224	TOC DROP-OUT	Instantaneous Disk Emulation	Disk Emulation	TOC Drop-out Characteristic
2225	IEC CURVE	Normal Inverse Very Inverse Extremely Inverse Long Inverse	Normal Inverse	IEC Curve
2226	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	T 3I0p	0.05..3.20 sec; ∞	0.50 sec	T 3I0p Time Dial
2323	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

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
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
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 always assigned to the current input I_7 of the device. Principally, it can be used for any desired application of 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.

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 2-60 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.

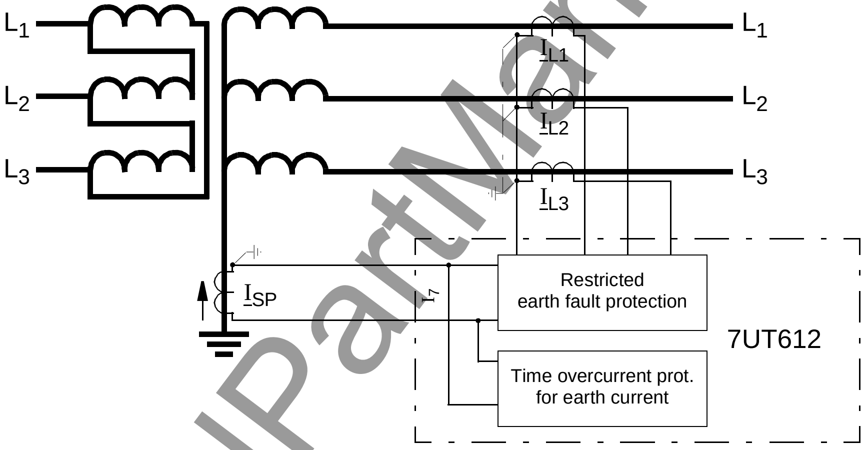


Figure 2-60 Time overcurrent protection as backup protection for restricted earth fault protection

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 125).

Pickup, Trip

Two definite time stages are available for the earth current I_E.

The current measured at the input I_7 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 > $0.3 \cdot I_N$.

Figure 2-61 shows the logic diagram for the high-current stage I_E>>.

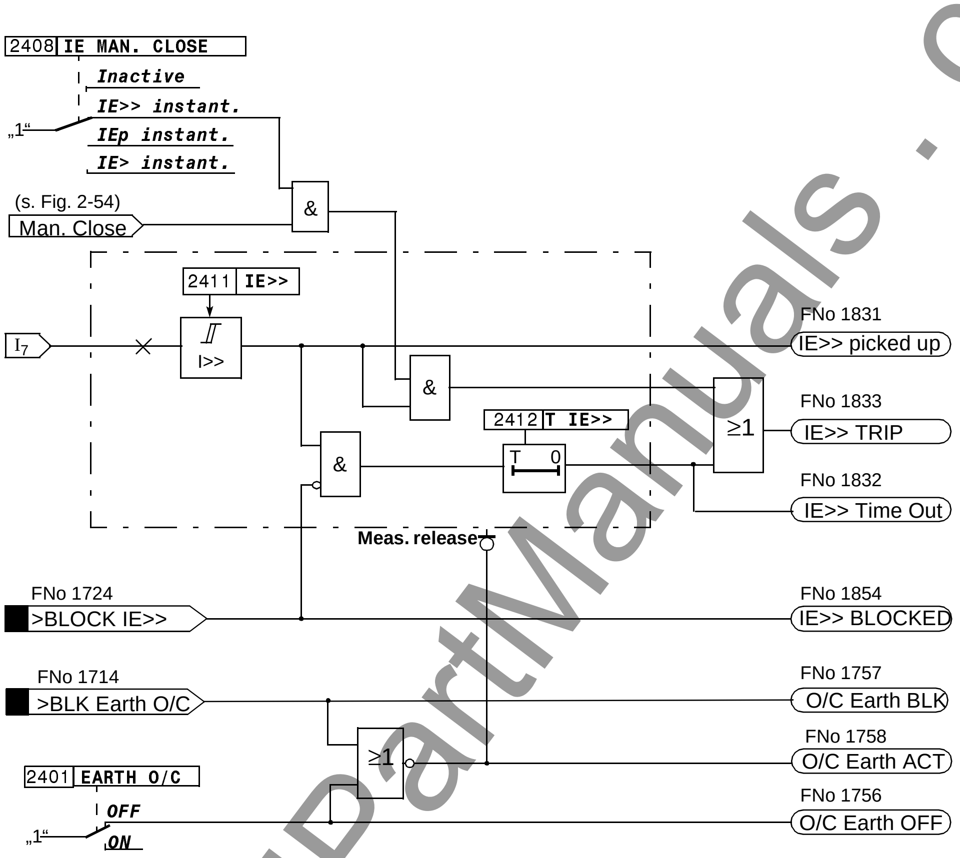


Figure 2-61 Logic diagram of the high-current stage I_E>> for earth current

The current detected at the current measuring input I_7 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 dropout value is approx. a 95 % of the pickup value for currents greater than $0.3 \cdot I_N$.

Figure 2-62 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.

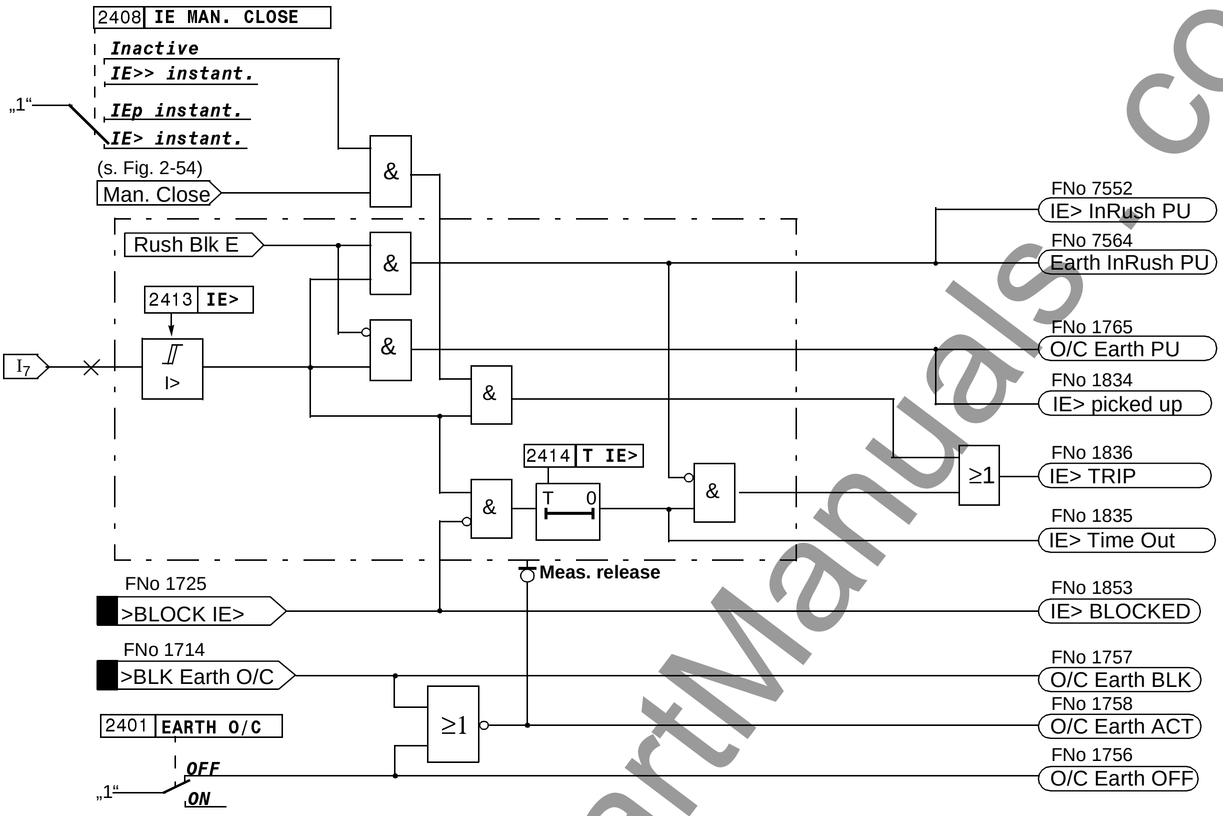


Figure 2-62 Logic diagram of the overcurrent stage I_E> for earth current

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 detected at the current measuring input I_7 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 2-63 shows the logic diagram of the inverse time overcurrent protection.

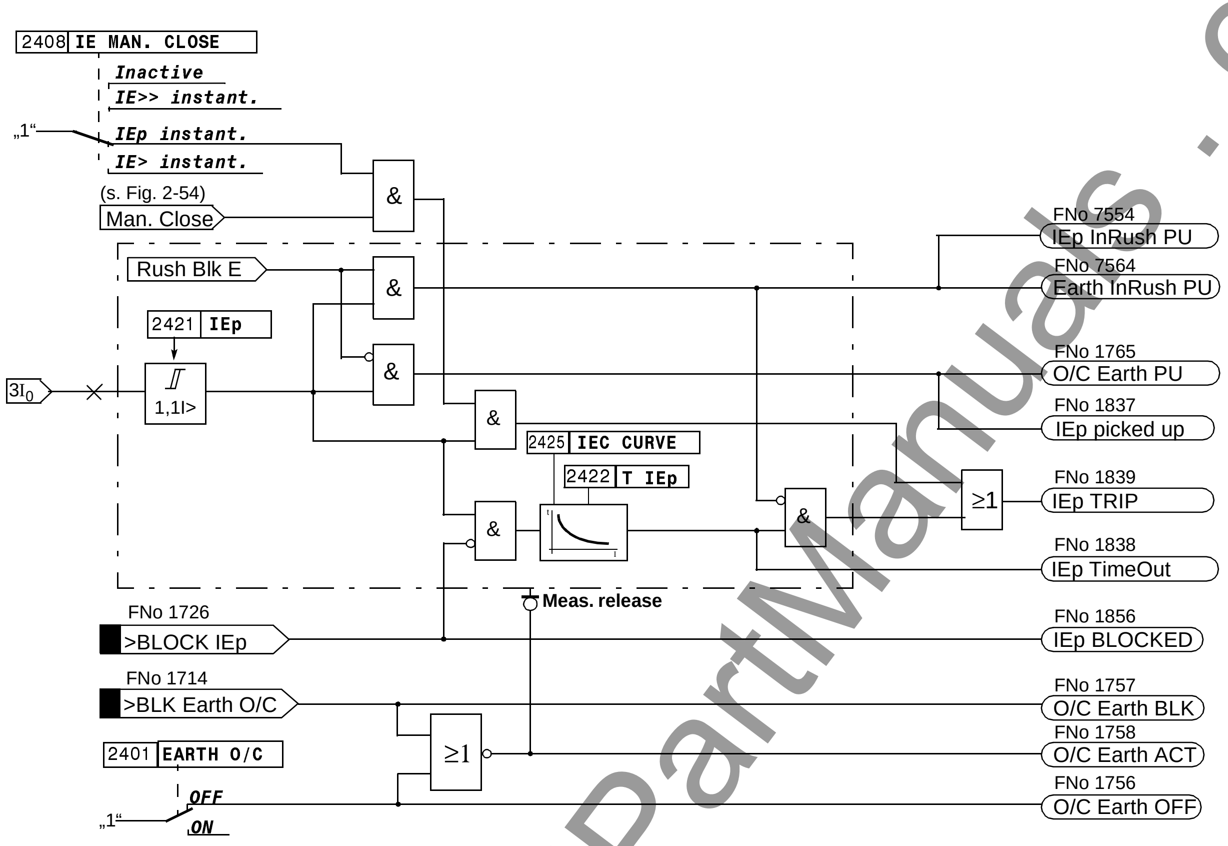


Figure 2-63 Logic diagram of the inverse time overcurrent protection stage I_{Ep} — example for IEC–curves

Dropout for IEC Curves

Dropout of the stage using an IEC curves occurs when the respective current decreases below about 95 % of the pickup value. A renewed pickup will cause a renewed start of the delay timers.

Dropout for ANSI Curves

Using the ANSI-characteristics 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 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 for ANSI Curves”. 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 2-54, page 79). Address 2408A **IE MAN. CLOSE** determines for which stages the delay is defeated under manual close condition.

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 common for all time overcurrent stages, and is explained in Section 2.6 (page 108). 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 (0.2 I_N).

Figure 2-64 shows a simplified logic diagram.

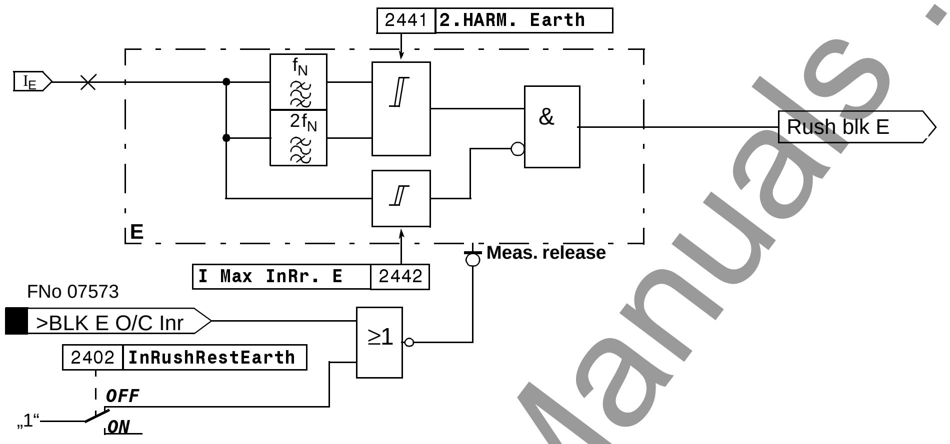


Figure 2-64 Logic diagram of the inrush restraint feature

2.5.2 Setting the Function Parameters

General

When configuring the protection functions (see Subsection 2.1.1, margin heading “Special Cases”, page 16) the type of characteristic was set (address 125). Only settings for the characteristic selected can be performed. Definite time stages I_E>> and I_E> are always available.

In address 2401 **EARTH O/C**, time overcurrent protection for earth current can be set to ***ON*** or ***OFF***.

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 changed with DIGSI® 4 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 of exactness, 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 be able to 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 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 20 % 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 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 125), enables the user to select different characteristics. With the IEC characteristics (address 125 **DMT/IDMT E CHR.** = ***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. The function will reset as soon as the value undershoots 95 % of the pickup value.

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 20 % 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 125 **DMT/IDMT E CHR.** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

Inverse Time Overcurrent Stages Ip with ANSI curves

The inverse time stages, depending on the configuration (Subsection 2.1.1, address 125), enable the user to select different characteristics. With the ANSI characteristics (address 125 **DMT/IDMT E CHR.** = ***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. Consider that the inrush restraint function cannot operate below 20 % 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 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 125 **DMT/IDMT E CHR.** = ***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 for ANSI Curves" (page 100).

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 108).

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® 4 a dialog box is to appear. Enter up to 20 pairs of current and tripping time values (Figure 2-58, page 86).

The procedure is the same as for phase current stages. See Subsection 2.4.2.1, margin heading "User Specified Curves", page 86.

To create a user-defined tripping characteristic for earth current, the following has to be set for configuration of the functional scope: address 125 (Subsection 2.1.1) **DMT/IDMT E CHR.**, 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 102, 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

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. For settings in primary values, a conversion rate of the current transformers has to be considered additionally.

Note: Addresses which have an “A” attached to their end can only be changed in DIGSI® 4, Section „**Additional Settings**“.

Addr.	Setting Title	Setting Options	Default Setting	Comments
2401	EARTH O/C	ON OFF	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
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

Addr.	Setting Title	Setting Options	Default Setting	Comments
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
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

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 primary methods used by the device 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 for current detection or the breaker auxiliary contact. 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 (address `108`, see also Section 2.1.1 under margin header “Special Cases”, page 16); 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 2-66 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`”.

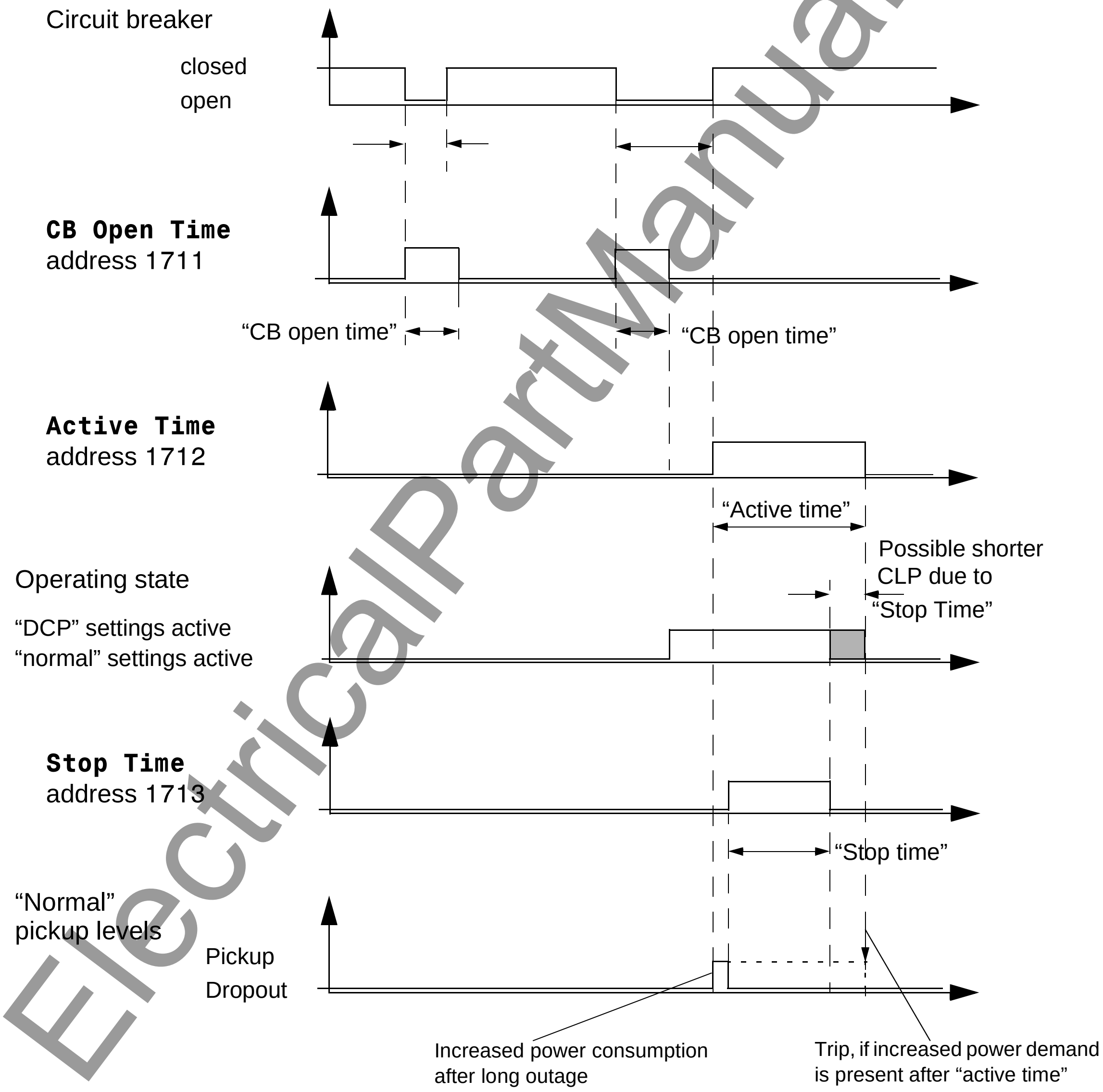


Figure 2-65 Cold load pickup timing sequence

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 drop out 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 2-65 shows a timing diagram, Figure 2-66 describes the logic for cold load pickup function.

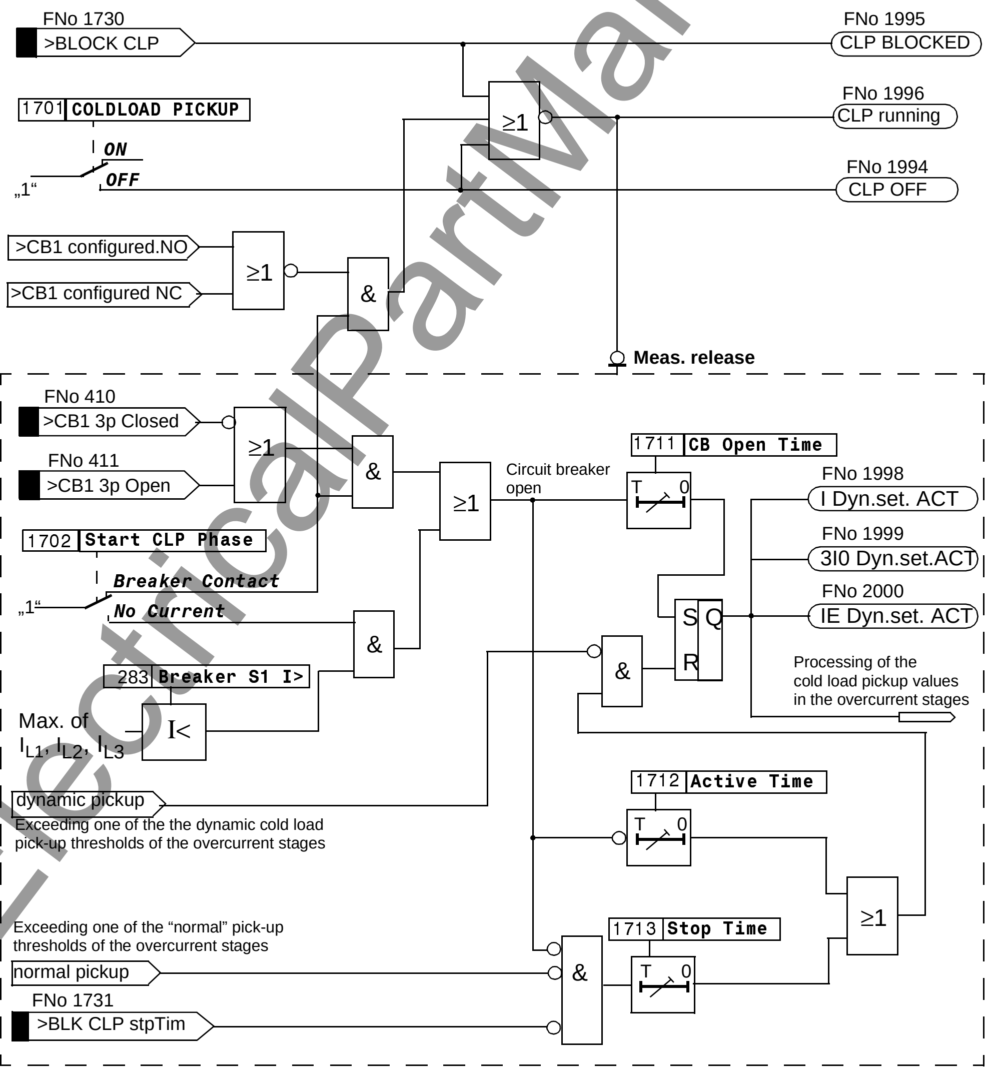


Figure 2-66 Logic diagram for dynamic cold load pickup feature — illustrated for phase overcurrent protection stage on side 1

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.

The current criterion takes the currents of that side where the corresponding protective function is assigned to. When using the breaker position criterion, the auxiliary contact of the assigned side must inform the device via a binary input about the breaker position.

The time overcurrent protection for earth current allows only the current criterion because it cannot assigned to any circuit breaker. (address 1704 **Start CLP Earth** is always ***No Current***).

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 either to the measured current input I_7 or I_8. It can be used for any desired single-phase application. If assigned to I_8 a very sensitive pickup threshold is possible (smallest setting 3 mA at the current input).

Examples for application 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 configured current input (I_7 or I_8) 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 $> 0.3 \cdot I_N$.

For the single-phase I> stage, the current measured at the configured 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 $> 0.3 \cdot I_N$.

Both stages form a two-stage definite time overcurrent protection whose tripping characteristic is illustrated in Figure 2-67.

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 $2 \cdot \sqrt{2}$.

The logic diagram of the single-phase time overcurrent protection is shown in Figure 2-68.

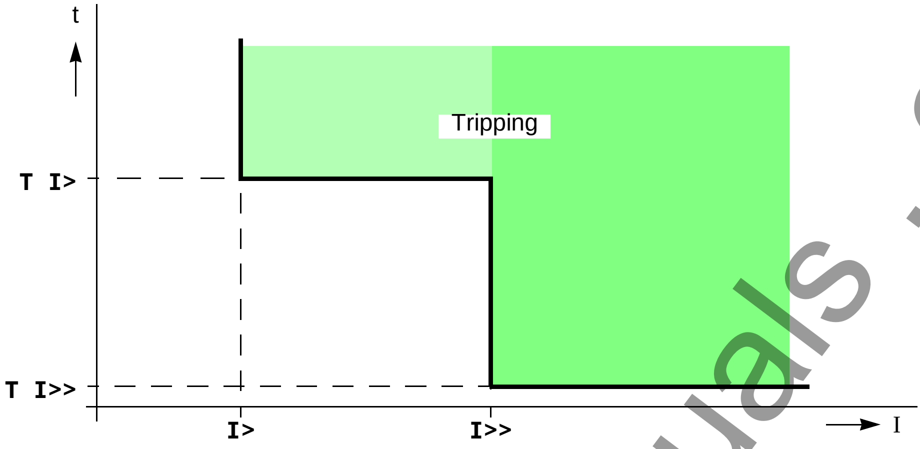


Figure 2-67 Two-stage tripping characteristic of the single-phase time overcurrent protection

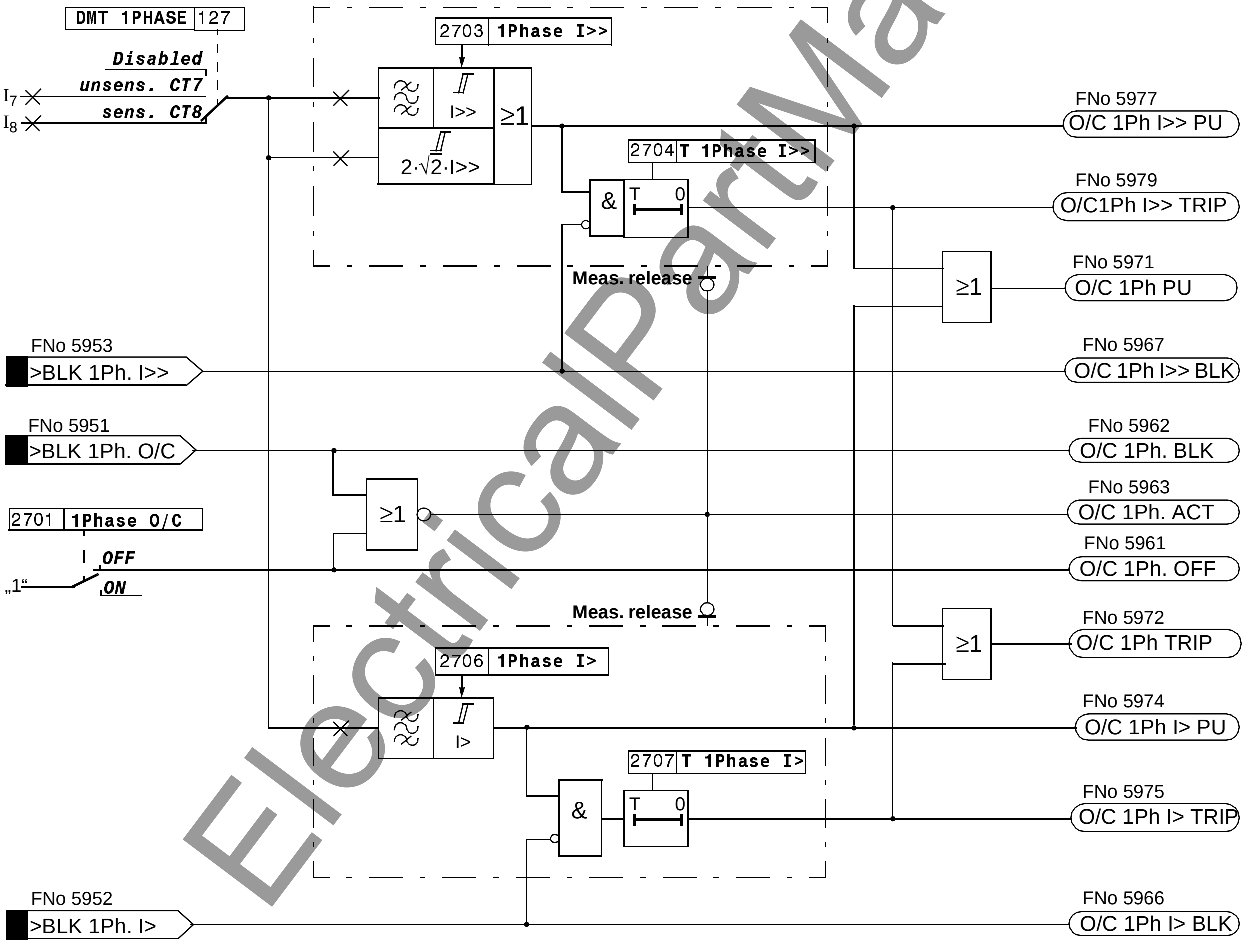


Figure 2-68 Logic diagram of the single-phase time overcurrent protection — example for detection of the current at input I_8

2.7.2 High-Impedance Differential 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 7UT612 the voltage is registered by measuring the current through the external resistor R at the sensitive current measuring input I_8.

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 7UT612 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). Of course, the sensitive current measuring input I_8 can only be used for high-impedance protection *or* tank leakage protection (Subsection 2.7.3).

Figure 2-69 (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.

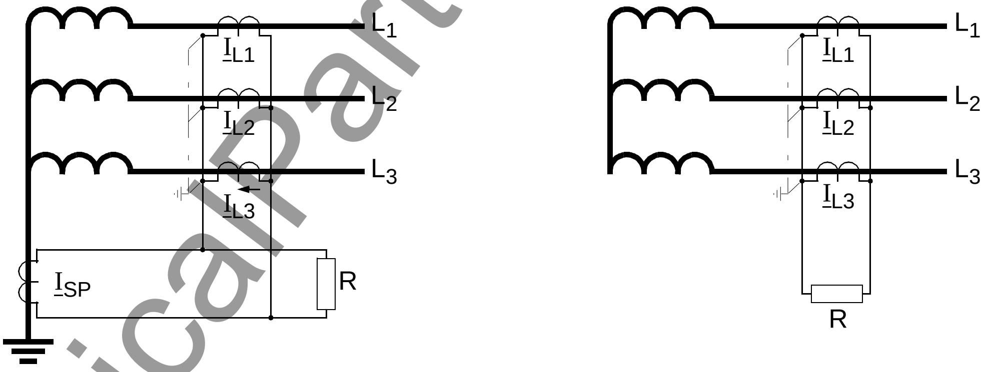


Figure 2-69 Earth fault protection according to the high-impedance scheme

High-Impedance Principle

The high-impedance principle is explained on the basis of an earthed transformer winding (Figure 2-70).

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 2-70, 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 to the high-ohmic resistor R.

Thus, the high resistance of the resistor also has an stabilizing effect (the so-called resistance stabilization).

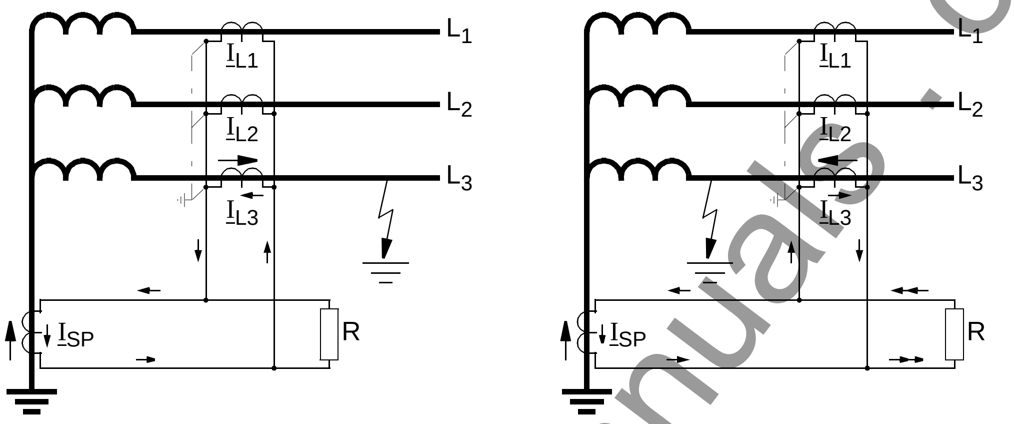


Figure 2-70 Earth fault protection using the high-impedance principle

In case there is an earth fault in the protection zone (Figure 2-70, 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 7UT612

With 7UT612 the sensitive measuring input I_8 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 2-71 shows the connection example. The 7UT612 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 overvoltages 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 can be 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.

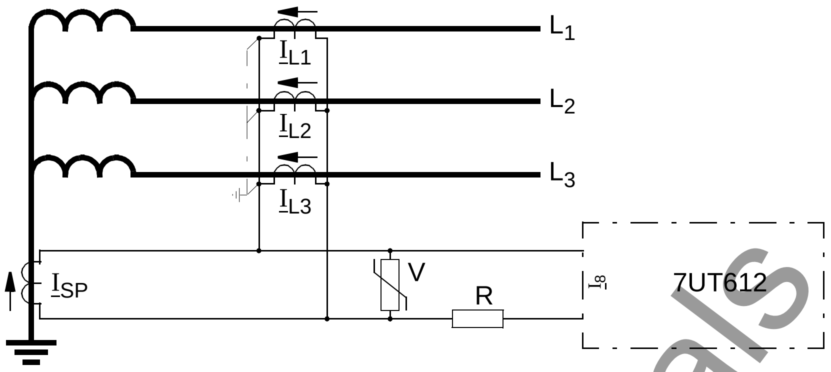


Figure 2-71 Connection scheme for earth fault protection according to the high-impedance principle

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 2-72). 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.

The high-sensitivity current input I_8 is used for tank leakage protection. Of course, this current input can only be used once: either for tank leakage protection or for high-impedance differential protection according to Subsection 2.7.2.

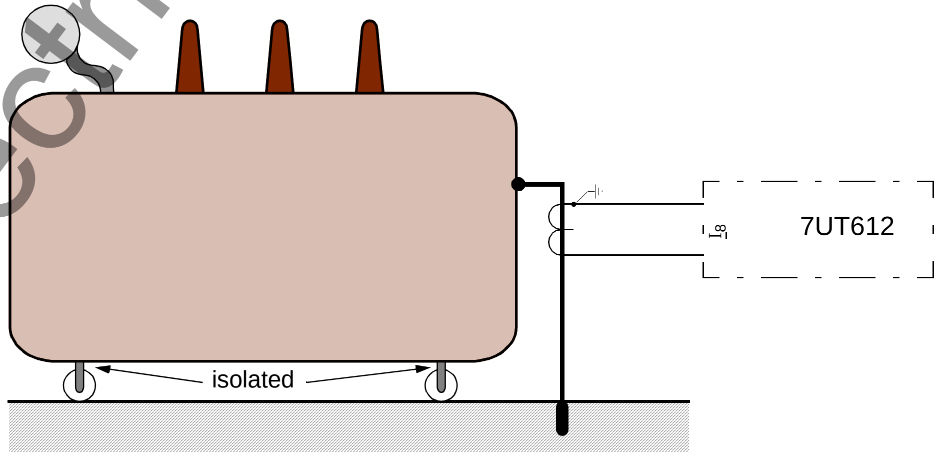


Figure 2-72 Principle of tank leakage protection

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 settings depend on the application. The setting ranges depend on whether the current at input I_7 or at I_8 is used. This was determined during configuration of the protective functions (Subsection 2.1.1 under “Special Cases”, page 16) in address 127:

DMT 1PHASE = ***unsens. CT7***
In this case 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 ∞.

DMT 1PHASE = ***sens. CT8***
In this case 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 7UT612 to detect overcurrent at the current input I_8. Consequently, during configuration of the protective functions (Subsection 2.1.1 under “Special Cases”, page 16), address 127 is set **DMT 1PHASE** = ***sens. CT8***.

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 7UT612 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 2-73 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.

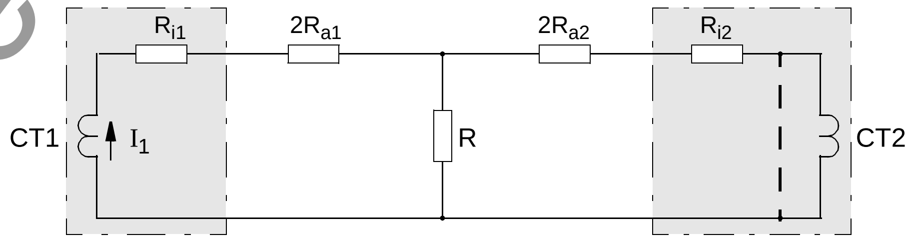


Figure 2-73 Simplified equivalent circuit of a circulating current system for high-impedance differential protection

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 7UT612 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 Ω
longest CT connection lead 22 m with 4 mm^2 cross-section, results in $R_a \approx$ 0,1 Ω

$$I_{SL} = \frac{U_{KPV}/2}{2 \cdot R_{a2} + R_{i2}} = \frac{37.5\ V}{2 \cdot 0.1\ \Omega + 0.3\ \Omega} = 75\ A$$

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 Ω
longest CT connection lead 107 m with 2.5 mm^2 cross-section, results in $R_a \approx$ 0.75 Ω

$$I_{SL} = \frac{U_{KPV}/2}{2 \cdot R_{a2} + R_{i2}} = \frac{175\ V}{2 \cdot 0.75\ \Omega + 5\ \Omega} = 27\ A$$

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 2-71). 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)

$$R = \frac{U_{KPV}/2}{I_{pu}} = \frac{75\ V/2}{0.1\ A} = 375\ \Omega$$

For the 1 A CT like above
required pickup value I_{pu} = 0.05 A (corresponding to 40 A primary)

$$R = \frac{U_{KPV}/2}{I_{pu}} = \frac{350\ V/2}{0.05\ A} = 3500\ \Omega$$

The required short-term power of the resistor is derived from the knee-point voltage and the resistance:

$$P_R = \frac{U_{KPV}^2}{R} = \frac{(75\ V)^2}{375\ \Omega} = 15\ W \qquad \text{for the 5 A CT example}$$

$$P_R = \frac{U_{KPV}^2}{R} = \frac{(350\ V)^2}{3500\ \Omega} = 35\ W \qquad \text{for the 1 A CT example}$$

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 2-71) 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 7UT612, 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 anymore. 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 current at the input I_8 is set on 7UT612. Consequently, during configuration of the protective functions (Subsection 2.1.1 under “Special Cases”, page 16) had been set under address 127: **DMT 1PHASE** = ***sens. CT8***.

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. For settings in primary values, a conversion rate of the current transformers has to be considered additionally.

Addr.	Setting Title	Setting Options	Default Setting	Comments
2701	1Phase O/C	OFF ON	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

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 impedance to negative sequence voltages, small voltage imbalances can lead to large negative sequence currents.

The unbalanced load protection operates always on the side of the protected object to which it is assigned during configuration of the protective functions. (see Subsection 2.1.1 under “Special Cases”, page 17, address `141`).

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 7UT612 uses numerical filters to dissect the phase currents into their symmetrical components. If the negative sequence component of the phase currents is at least 10 % of the nominal device current, and all phase currents are less than four times the nominal device current, 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 2-74).

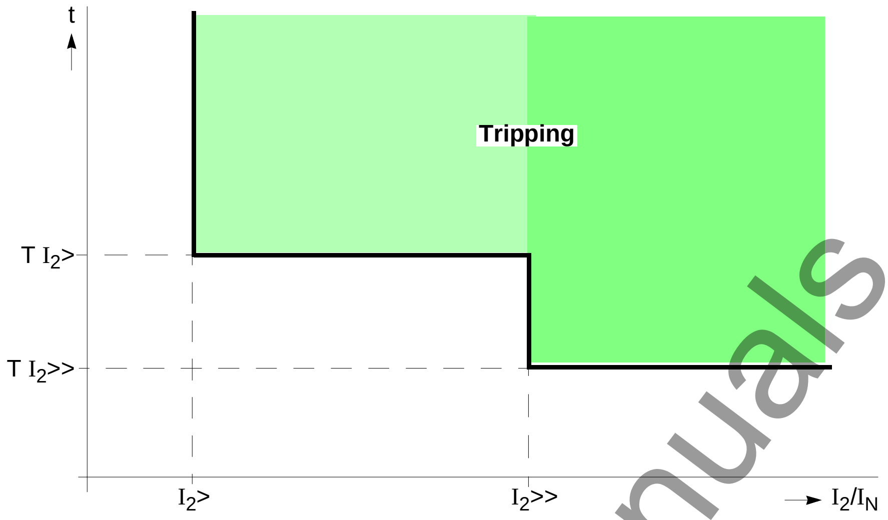


Figure 2-74 Trip characteristic of the definite time unbalanced load protection

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 2-75 shows the qualitative course of the characteristic. In this figure the overlapping stage I_2>> is represented as a dashed line.

Dropout for IEC Curves

Dropout of the stage using an IEC curves occurs when the current decreases below about 95 % of the pickup value. A renewed pickup will cause a renewed start of the delay timers.

Dropout for ANSI Curves

Using the ANSI-characteristics 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 (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.

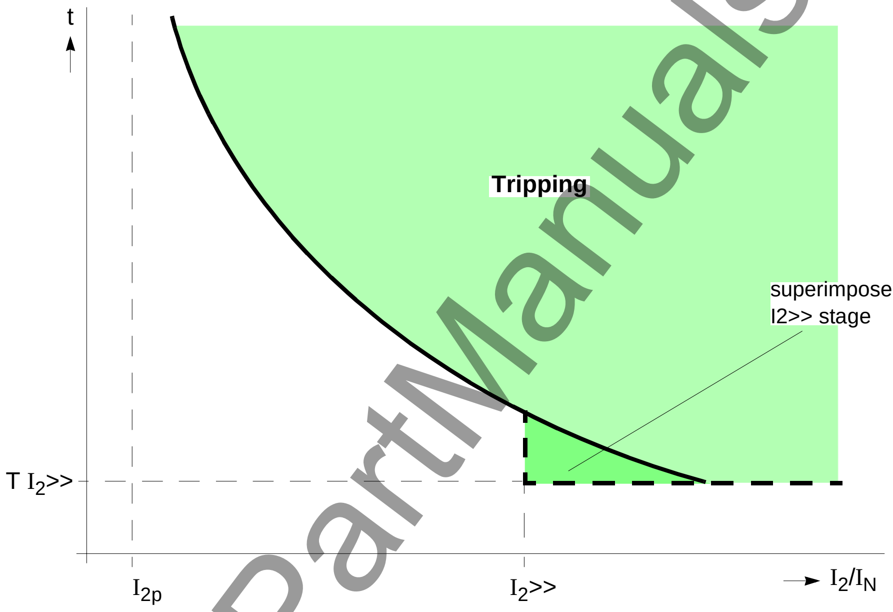


Figure 2-75 Trip characteristic of the inverse time unbalanced load protection (with superimposed definite time stage)

Logic

Figure 2-76 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 overload protection (all phase currents below 0.1 · I_N or at least one phase current is greater than 4 · I_N), the pickups of all unbalanced load stages drop off.

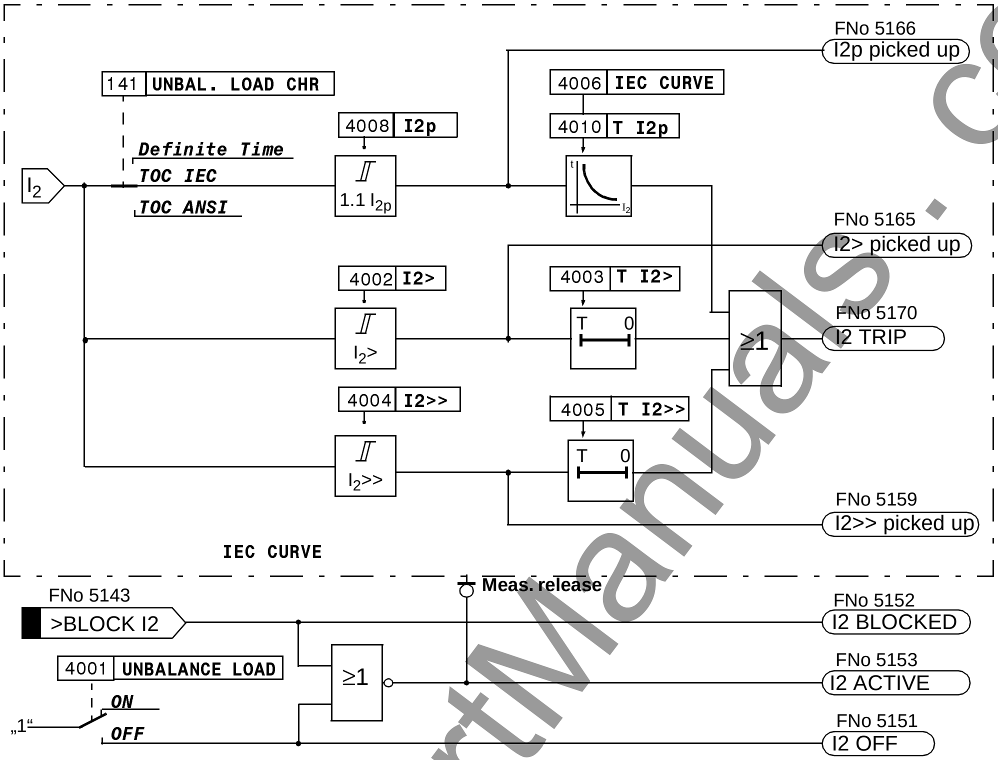


Figure 2-76 Logic diagram of the unbalanced load protection — illustrated for IEC–characteristic

2.8.2 Setting the Function Parameters

General

During configuration of the functional scope (Subsection 2.1.1, margin heading “Special Cases”, page 17) the sides of the protected object were determined in address 140. The corresponding characteristic type was selected in address 141. In the following only settings for the characteristic selected can be performed. The definite time stages I_2>> and I_2> are always available.

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.

In address 4001 **UNBALANCE LOAD** the function can be set to ***ON*** or ***OFF***.

Definite Time Stages I_2>>, I_2>

A two-stage characteristic enables the user to set a short time delay (address 4005 **T I2>>**) for the upper stage (address 4004 **I2>>**) and longer time delay (address 4003 **T I2>**) for the lower stage (address 4002 **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

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 phase-to-ground fault current of I = 3 · (110 kV/20 kV) · **`I2>`** = 3 · 0.1 · 100 A = 165 A and a phase-to-phase fault of $\sqrt{3}$ · (110/20) · 0.1 · 100 A = 95 A can be detected on the low 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
	$I_{2 prim}$ / $I_{N motor}$	= 0,11 continuous
	$I_{2 prim}$ /$I_{N motor}$	= 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 141 **UNBAL. LOAD CHR** = ***TOC IEC***, see also Subsection 2.1.1) the following characteristics are made available in address 4006 **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 4008) is present. The function will reset as soon as the value undershoots 95 % of the pickup value.

The corresponding time multiplier is accessible via address 4010 **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 141 **UNBAL. LOAD CHR** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

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 141 **UNBAL. LOAD CHR** = ***TOC ANSI***) the following is made available in address 4007 **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 4008) is present.

The corresponding time multiplier is accessible via address 4009 **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 141 **UNBAL. LOAD CHR** = ***Definite Time*** when configuring the protection functions (Subsection 2.1.1).

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>”).

If ***Disk Emulation*** is set in address 4011 **I2p DROP-OUT**, dropout is being produced according to the dropout characteristic. For more information see Subsection 2.8.1.2, margin heading “Dropout for ANSI Curves” (page 124).

2.8.3 Setting Overview

Note: The following list indicates the setting ranges and default settings for a rated secondary current of I_N = 1 A. For a rated secondary current of I_N = 5 A, these values must be multiplied by 5. When performing settings in primary values, the current transformer ratios have to be taken into consideration.

Addr.	Setting Title	Setting Options	Default Setting	Comments
4001	UNBALANCE LOAD	OFF ON	OFF	Unbalance Load (Negative Sequence)
4002	I2>	0.10..3.00 A	0.10 A	I2> Pickup
4003	T I2>	0.00..60.00 sec; ∞	1.50 sec	T I2> Time Delay
4004	I2>>	0.10..3.00 A	0.50 A	I2>> Pickup
4005	T I2>>	0.00..60.00 sec; ∞	1.50 sec	T I2>> Time Delay
4006	IEC CURVE	Normal Inverse Very Inverse Extremely Inverse	Extremely Inverse	IEC Curve
4007	ANSI CURVE	Extremely Inverse Inverse Moderately Inverse Very Inverse	Extremely Inverse	ANSI Curve

Addr.	Setting Title	Setting Options	Default Setting	Comments
4008	I2p	0.10..2.00 A	0.90 A	I2p Pickup
4009	D I2p	0.50..15.00; ∞	5.00	D I2p Time Dial
4010	T I2p	0.05..3.20 sec; ∞	0.50 sec	T I2p Time Dial
4011	I2p DROP-OUT	Instantaneous Disk Emulation	Instantaneous	I2p Drop-out Characteristic

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
05172	I2 Not avalia.	I2 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 7UT612:

- 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 7UT612 can be assigned to one of the sides of the 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 – currently valid temperature rise referred to the final temperature rise for the maximum permissible phase current $k \cdot I_{Nobj}$,

τ_{th} – thermal time constant for heating up,

k – k–factor which states the maximum permissible continuous current, referred to the rated current of the protected object,

I – currently valid RMS current,

I_{Nobj} – rated current of 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}:

$I_{max} = k \cdot I_{Nobj}$

I_{Nobj} is the rated current 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 **`Breaker S1 I>`** or **`Breaker S2 I>`** (depending on the assigned side for overload protection, refer also to "Circuit Breaker Status" in Subsection 2.1.2).

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.

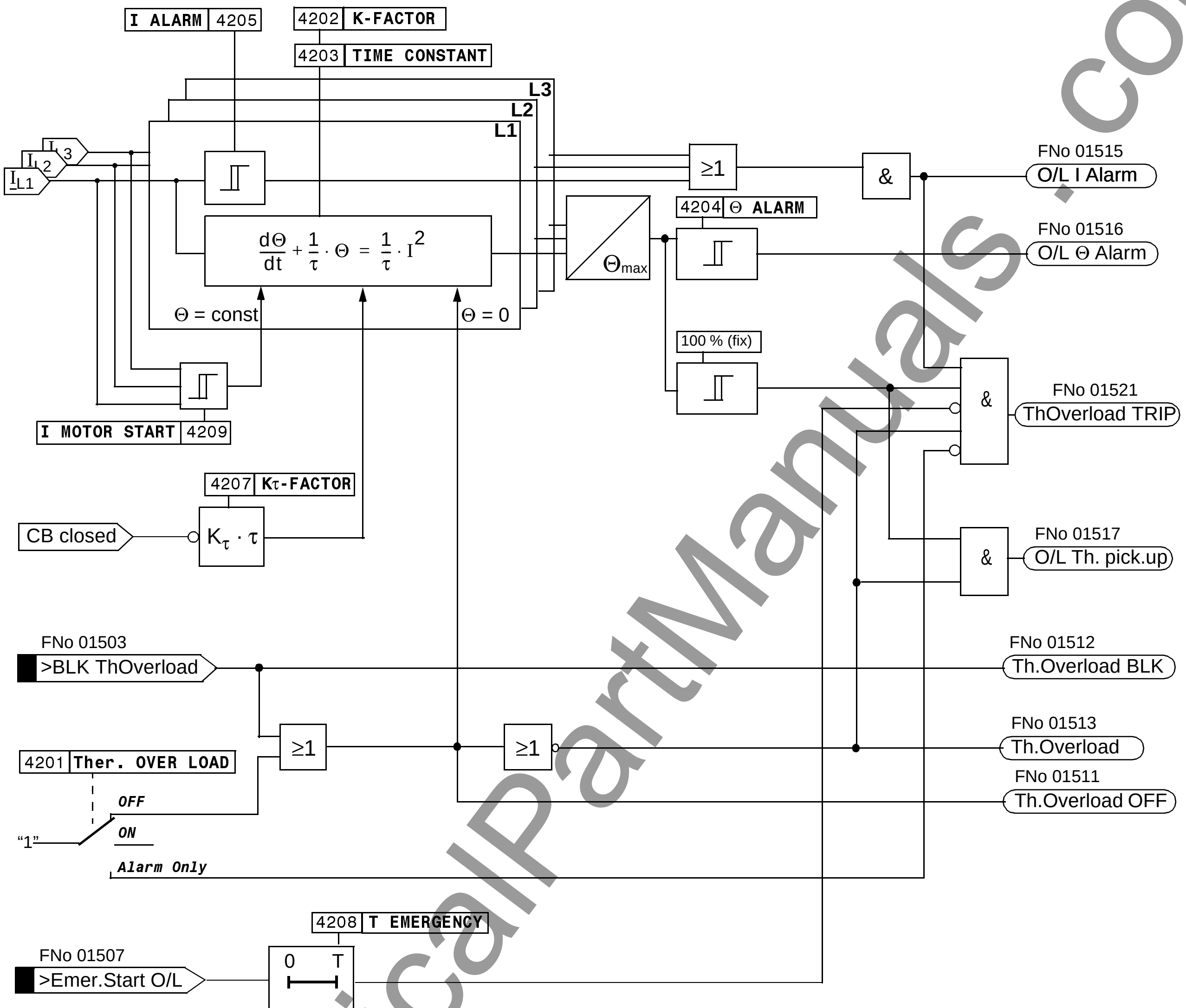


Figure 2-77 Logic diagram of the thermal overload protection

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 in the protected object. Via one or two thermoboxes and a serial data connection the measuring points inform the overload protection of the 7UT612 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 are available:

- **ON** (**O**il **N**atural = naturally circulating oil): Because of emerging differences in temperature the coolant (oil) moves 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-sensitive. Therefore, the cooling effect is very good. This method has the lowest temperature rise.

Figures 2-78 to 2-80 show examples of the cooling methods.

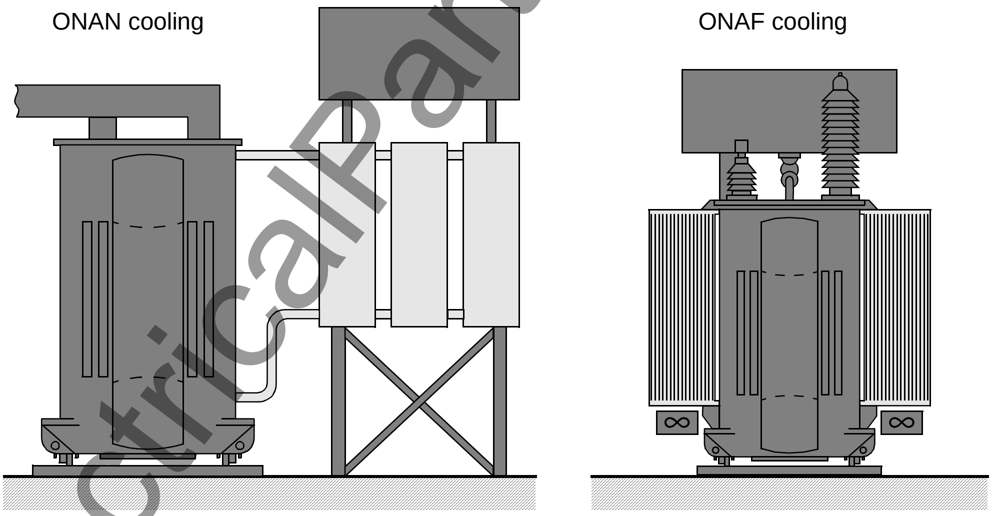


Figure 2-78 ON cooling (Oil Natural)

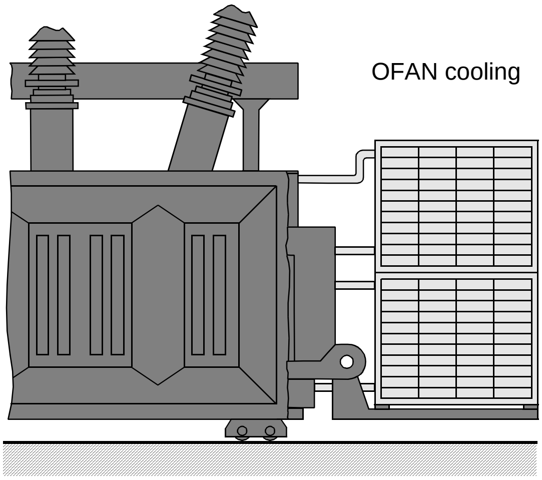


Figure 2-79 OF cooling (Oil Forced)

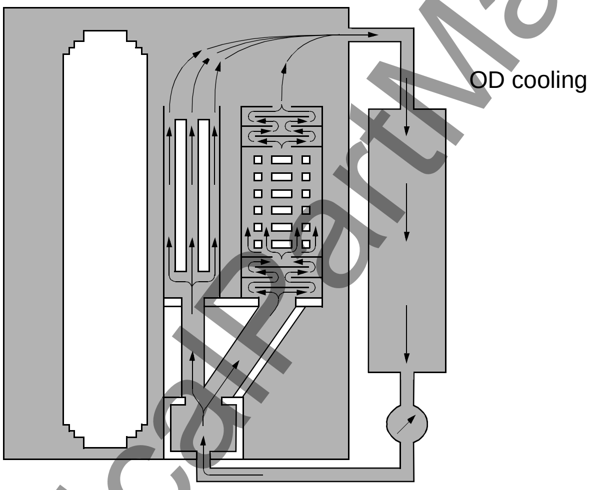


Figure 2-80 OD cooling (Oil Directed)

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 rate of the temperature drop.

The hot-spot temperature is composed of two parts:
the temperature at the hottest spot of the coolant (included via thermobox),
the temperature rise of the winding turn caused by the transformer load.

Thermobox 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 7UT612. The thermobox is able to acquire the temperature at up to 6 points of the transformer tank. Up to two thermoboxes of this types can be connected to a 7UT612.

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:

$$\Theta_h = \Theta_o + H_{gr} \cdot k^Y \qquad \text{for } k \le 1$$

$$\Theta_h = \Theta_o + H_{gr} \cdot k^Y + 0{,}15 \cdot [(\Theta_o + H_{gr} \cdot k^Y) - 98\ °C] \qquad \text{for } k > 1$$

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 means 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

$$V = \frac{\text{Ageing at } \Theta_h}{\text{Ageing at } 98°\ C} = 2^{(\Theta_h - 98)/6}$$

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 7UT612: 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 protected object configured for overload protection (Subsection 2.1.1, address 142). The calculation includes the current of that side and the cooling temperature measured at a certain measuring point. There are two thresholds which can be set. They 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 backup up to warning signal (Stage 1) expressed in per cent,
- load backup 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 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.

- For transformers with voltage regulation, i.e. with tap changer, the overload protection must be assigned to the non-regulated side as only this winding allows a defined relationship between the rated current and the rated power.
- For generators, the overload protection is, normally, assigned to the starpoint side.
- For motors and shunt reactors, the overload protection is assigned to the feeding side.
- For series reactors or short cables, nor preferable side exists.
- For busbar sections or overhead lines, the overload protection is, generally, not used since calculation of a temperature rise is not reasonable because of the widely varying ambient conditions (air temperature, wind). But, in these applications, the current warning stage may be useful to announce overload currents.

The side of the protected object which is to be assigned to the overload protection, was selected under address 142 **Therm.Overload** during configuration of the protection functions (Subsection 2.1.1).

There are two method for evaluation of overload conditions in 7UT612, as explained above. During configuration of the protection function (Subsection 2.1.1), you had already decided under address 143 **Therm.O/L CHR.**, whether the protection shall operate according to the “classical” method of a thermal replica (**Therm.O/L CHR.** = ***classical***) or whether the calculation of the hot-spot temperature according to IEC 60354 (**Therm.O/L CHR.** = ***IEC354***) shall be carried out. In the latter case, at least one thermobox 7XV566 must be connected to the device in order to inform the device about the cooling medium temperature. The data concerning the thermobox 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**. 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 protected object is taken as the base current for detecting an overload. The setting 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 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 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 for determining the time constant are stated which can be converted into the time constant as follows:

- 1–s current

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

- permissible current for application time other than 1 s, e.g. for 0.5 s

  $$\frac{\tau_{th}}{\text{min}} = \frac{0.5}{60} \cdot \left(\frac{\text{permissible 0.5–s current}}{\text{permissible continuous current}}\right)^2$$

- 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

  $$\frac{\tau_{th}}{\text{min}} = 0.6 \cdot t_6$$

Calculation examples:

Cable with

permissible continuous current	322 A
permissible 1–s current	13.5 kA

$$\frac{\tau_{th}}{\text{min}} = \frac{1}{60} \cdot \left(\frac{13500\text{ A}}{322\text{ A}}\right)^2 = \frac{1}{60} \cdot 42^2 = 29.4$$

Setting value **TIME CONSTANT** = ***29.4*** min.

Motor with t_6–time 12 s

$$\frac{\tau_{th}}{\text{min}} = 0.6 \cdot 12\text{ s} = 7.2$$

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. Stand-still of the machine is assumed when the currents fall below the threshold **Breaker S1 I>** or **Breaker S2 I>**, depending on the side to which the overload protection is assigned, (see margin “Circuit Breaker Status” in Subsection 2.1.2). This parameter can only be changed with DIGSI® 4 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.

<u>Example:</u>

k–factor = 1.1
Alarm shall be given when the temperature rise reaches the final (steady-state) temperature rise at nominal current.

$$\Theta_{alarn} = \frac{1}{1.1^2} = 0.826$$

Setting value Θ **ALARM** = ***82*** %.

The current overload alarm setpoint **I ALARM** (address 4205) is stated in amps (primary or secondary) and should be set equal to or slightly below the permissible continuous current $k \cdot I_{Nobj}$. 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 changed with DIGSI® 4 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 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 thermobox 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 2.1.2, margin heading "Temperature Unit"), thresholds for warning and alarm temperatures have to be expressed in Fahrenheit (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 corresponding table of the standard with the technical data relevant for this project can be found hereinafter (Table 2-5).

Table 2-5 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: The following list indicates the setting ranges and default settings for a rated secondary current of I_N = 1 A. For a rated secondary current of I_N = 5 A, these values must be multiplied by 5. When setting the device using primary values, the current transformer ratios have to be taken into consideration.

Note: Addresses which have an “A” attached to its end can only be changed in DIGSI® 4, under “**Additional Settings**”.

Addr.	Setting Title	Setting Options	Default Setting	Comments
4201	Ther. OVER LOAD	OFF ON 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	Time Constant
4204	Θ ALARM	50..100 %	90 %	Thermal Alarm Stage
4205	I ALARM	0.10..4.00 A	1.00 A	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 A; ∞	∞ A	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
01545	O/L No Th.meas.	Th. Overload No temperature mesured
01549	O/L Not avalia.	Th. Overload Not avaliable for this obj.

2.10 Thermoboxes for Overload Protection

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 thermoboxes 7XV566. One thermobox is able to process up to 6 RTDs. One or two thermoboxes can be connected to the 7UT612.

2.10.1 Function Description

A thermobox 7XV566 is suited for up to 6 measuring points (RTDs) in the protected object, e.g. in the transformer tank. The thermobox 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 thermoboxes can be connected to the service interface of the 7UT612. 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 thermobox 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 thermobox.

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 changed with DIGSI® 4 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 changed with DIGSI® 4 under "**Additional Settings**".

Furthermore, alarm and trip temperature can be set. Depending on the temperature unit selected in the Power System Data (Subsection 2.1.2 in address 276 **TEMP. UNIT**, page 20), 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 thermobox 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 thermoboxes 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 its end can only be changed in DIGSI$^{®}$ 4, Section „**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
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

Addr.	Setting Title	Setting Options	Default Setting	Comments
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
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

Addr.	Setting Title	Setting Options	Default Setting	Comments
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
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

Addr.	Setting Title	Setting Options	Default Setting	Comments
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
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

Addr.	Setting Title	Setting Options	Default Setting	Comments
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
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 thresholds of each measuring point are available at the thermobox 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
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

F.No.	Alarm	Comments
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 Circuit Breaker Failure Protection

2.11.1 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 short-circuit protection relay of a feeder issues a trip command to the circuit breaker, this is repeated to the breaker failure protection (Figure 2-81). 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.

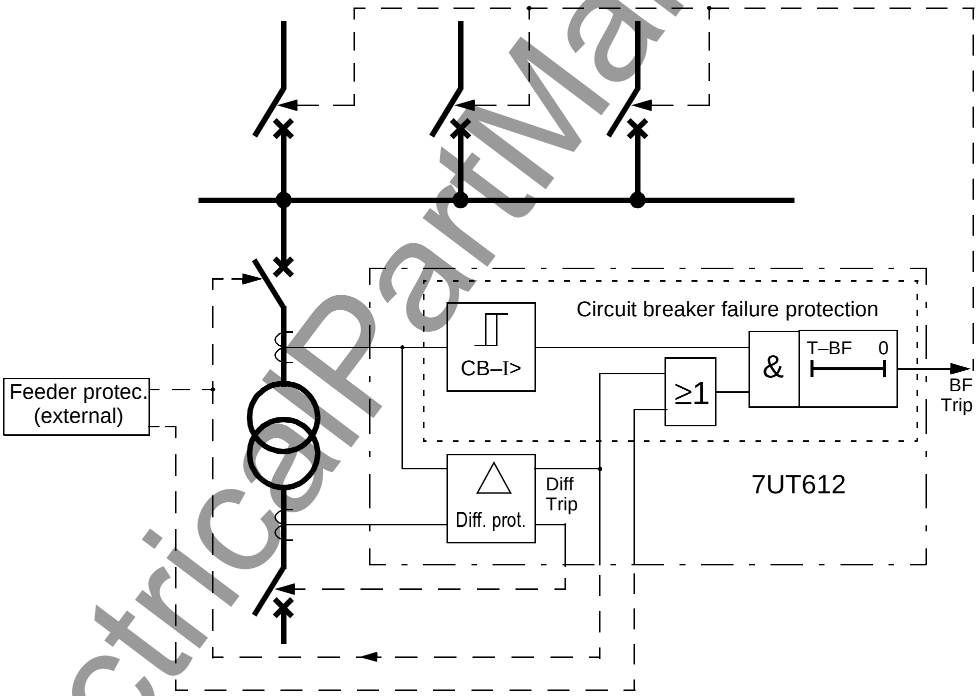


Figure 2-81 Simplified function diagram of circuit breaker failure protection with current flow monitoring

Normally, the breaker will open and interrupt the fault current. The current monitoring stage CB–I> resets 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 backup 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.

Please make sure that the measuring point of the current and the supervised circuit breaker belong together! Both must be located at the supply side of the protected object. In Figure 2-81 the current is measured at the busbar side of the transformer (= supply side), therefore the circuit breaker at the busbar side is supervised. 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 2-82 shows a logic diagram of the circuit breaker failure protection.

The breaker failure protection can be initiated by two different sources:

- Internal protective function of the 7UT612, e.g. trip commands of protective functions or via CFC (internal logic functions),
- External trip signals via binary input.

In both cases, the breaker failure protection checks the continuation of current flow. Additionally, the breaker position (read from the auxiliary contact) can be checked.

The current criterion is fulfilled if at least one of the three phase currents exceeds a set threshold value: **`Breaker S1 I>`** or **`Breaker S2 I>`**, depending on the side to which the breaker failure protection is assigned, see also Subsection 2.1.2 under margin “Circuit Breaker Status” (page 27).

Processing of the auxiliary contact criterion depends on which auxiliary contacts are available and how they are arranged to the binary inputs of the device. If both the normally closed (NC) as well as the normally open (NO) auxiliary contacts are available, an intermediate position of the breaker can be detected. In this case, disappearance of the current flow is always the only criterion for the breaker response.

Initiation can be blocked via the binary input “`>BLOCK BkrFail`” (e.g. during testing of the feeder protection relay).

Delay Time and Breaker Failure Trip

For each of the two sources, a unique pickup message is generated, a unique time delay is initiated, and a unique tripping signal is generated. The setting value for the delay applies to both sources.

When the associated time has elapsed, trip command is issued. The two commands are combined with an OR–gate and form the output information “`BrkFailure TRIP`” which is used to trip the adjacent breakers so that the fault current will be interrupted. The adjacent breakers are those which can feed the same busbar or busbar section to which the breaker is connected.

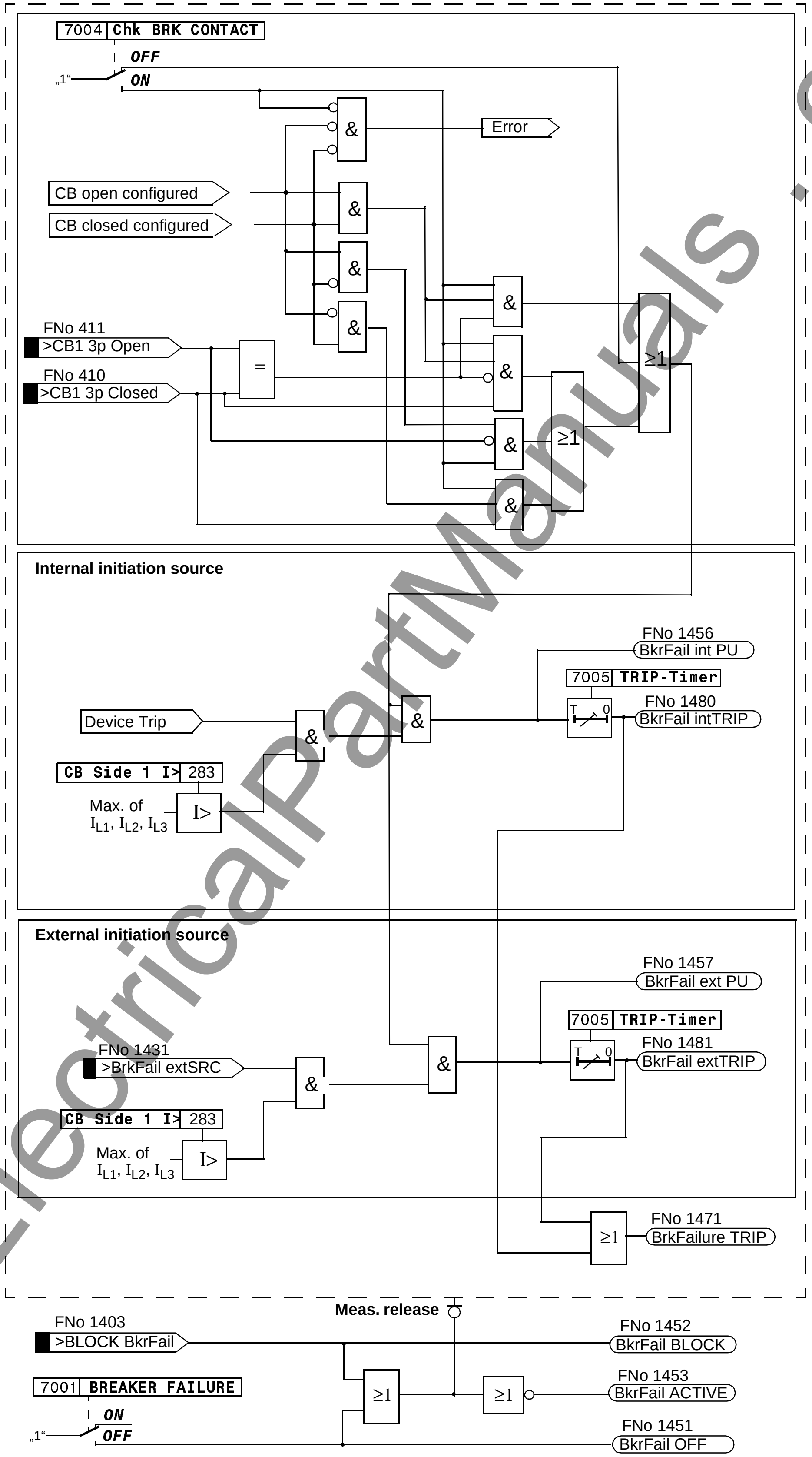


Figure 2-82 Logic diagram of the breaker failure protection, illustrated for side 1

2.11.2 Setting the Function Parameters

General

With the determination of the functional scope (Subsection 2.1.1) in address 170 **BREAKER FAILURE**, it was defined to which side of the protected object the circuit breaker failure protection shall operate. Please make sure that the measuring point of the current and the supervised circuit breaker are assigned to the same side! 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**.

Initiation

Current flow monitoring uses the values set in the Power System Data 1 (Subsection 2.1.2 under margin “Circuit Breaker Status”, page 27). Depending on the side of the protected object to which the breaker failure protection is assigned, address 283 **Breaker S1 I>** or address 284 **Breaker S2 I>** is decisive.

Normally, the breaker failure protection evaluates the current flow criterion as well as the position of the breaker auxiliary contact(s). If the auxiliary contact(s) status is not available in the device, this criterion cannot be processed. In this case, set address 7004 **Chk BRK CONTACT** to ***NO***.

Time delay

The delay times are 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 2-83. For the reset time, $1^1/_2$ cycle can be assumed.

The time delay is set under address 7005 **TRIP-Timer**.

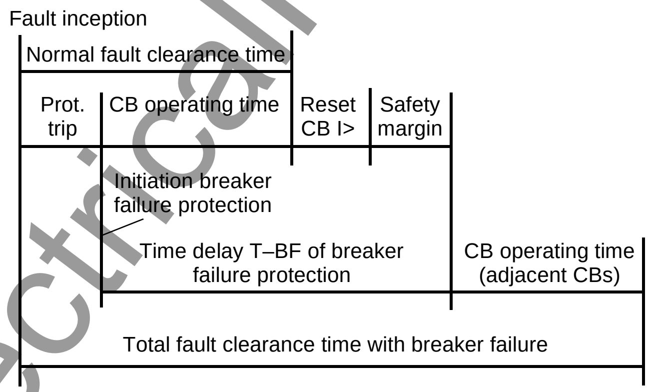


Figure 2-83 Time sequence example for normal clearance of a fault, and with circuit breaker failure

2.11.3 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. When setting the device using primary values, the current transformer ratios have to be taken into consideration.

Addr.	Setting Title	Setting Options	Default Setting	Comments
7001	BREAKER FAILURE	OFF ON	OFF	Breaker Failure Protection
7004	Chk BRK CONTACT	OFF ON	OFF	Check Breaker contacts
7005	TRIP-Timer	0.06..60.00 sec; ∞	0.25 sec	TRIP-Timer

2.11.4 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
01471	BrkFailure TRIP	Breaker failure TRIP
01480	BkrFail intTRIP	Breaker failure (internal) TRIP
01481	BkrFail extTRIP	Breaker failure (external) TRIP
01488	BkrFail Not av.	Breaker failure Not aval. for this obj.

2.12 Processing of External Signals

2.12.1 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 7UT612. 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 7UT612.

The minimum trip command duration set for all protective functions are also valid for these external trip commands. (Subsection 2.1.2 under “Trip Command Duration”, page 27, address 280A).

Figure 2-84 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.

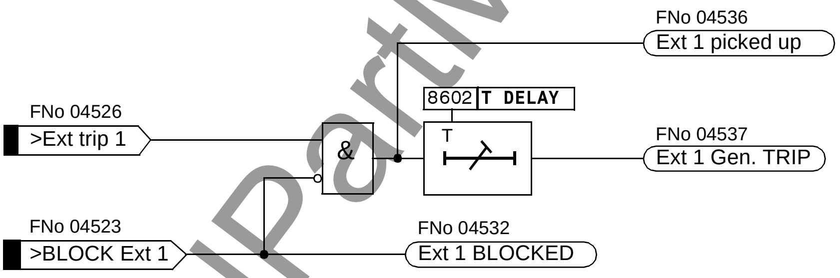


Figure 2-84 Logic diagram of external trip feature — illustrated for External Trip 1

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 7UT612 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 7UT612 (refer also to Subsection 2.2.1, margin heading “Add-on Stabilization during External Fault”, page 36). 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 2-85, for example.

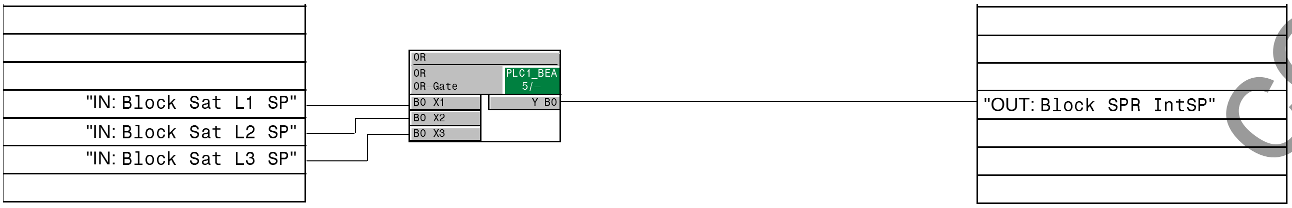


Figure 2-85 CFC chart for blocking of a pressure sensor during external fault

2.12.2 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**.

2.12.3 Setting Overview

Addr.	Setting Title	Setting Options	Default Setting	Comments
8601	EXTERN TRIP 1	ON OFF	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	ON OFF	OFF	External Trip Function 2
8702	T DELAY	0.00..60.00 sec; ∞	1.00 sec	Ext. Trip 2 Time Delay

2.12.4 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.

2.13 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.

2.13.1 Function Description

2.13.1.1 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`” 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 (EPROM), the cross-check sum is cyclically generated and compared to a stored reference program cross-check sum.

For the parameter memory (EEPROM), the cross-check sum is cyclically generated and compared to the cross-check sum that is refreshed after each parameterization change.

If a fault occurs the processor system is restarted.

Sampling Frequency

The sampling frequency 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 healthy status contact.

2.13.1.2 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.

2.13.1.3 Monitoring of Measured Quantities

The device detects and signals most of the interruptions, short-circuits, or wrong connections in the secondary circuits of current 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 side of a three-phase object. For this the lowest phase current is set in relation to the highest. An unbalance is detected, e.g. for side 1, when

$|I_{min}| / |I_{max}| <$ **`BAL. FACT. I S1`** provided that

$I_{max} / I_N >$ **`BAL. I LIMIT S1`** $/ I_N$

I_{max} is the highest, I_{min} the lowest of the three phase currents. The balance factor **`BAL. FACT. I S1`** represets the degree of unbalance of the phase currents, the limiting value **`BAL. I LIMIT S1`** is the lower threshold of the operating range of this monitoring function (see Figure 2-86). Both parameters can be set. The resetting ratio is approx. 97 %.

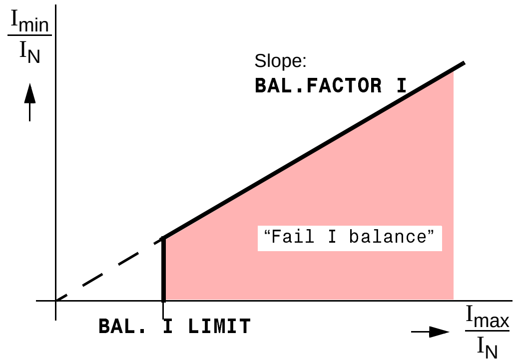


Figure 2-86 Current balance monitoring

Current balance monitoring is available separate for each side of the protected object. It has no meaning with single-phase busbar protection and does not operate in this case. Unsymmetrical condition is indicated for the corresponding side with the alarm "`Fail. Isym 1`" (FNo 00571) or "`Fail. Isym 2`" (FNo 00572). The common message "`Fail I balance`" (FNo 00163) appears in both cases.

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 side of the protected object. For single-phase differential busbar 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 for the configuration of the Power System Data 1 (Subsection 2.1.2, margin heading "Phase sequence").

Phase rotation is checked by supervising the phase sequence of the currents.

$\underline{I}_{L1}$ before $\underline{I}_{L2}$ before $\underline{I}_{L3}$

Supervision of current rotation requires a maximum current of

$|\underline{I}_{L1}|, |\underline{I}_{L2}|, |\underline{I}_{L3}| > 0.5\ I_N$.

If the rotation measured differs from the rotation set, the annunciation "`FailPh.Seq I S1`" (FNo 00265) or "`FailPh.Seq I S2`" (FNo 00266) is output. At the same time, the following annunciation appears: "`Fail Ph. Seq. I`" (FNo 00175).

2.13.1.4 Trip Circuit Supervision

The differential protection relay 7UT612 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.

Supervision Using Two Binary Inputs

If two binary inputs are used, they are connected according to Figure 2-87, one in parallel to the assigned command relay contact of the protection and the other parallel to the circuit breaker auxiliary contact.

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.

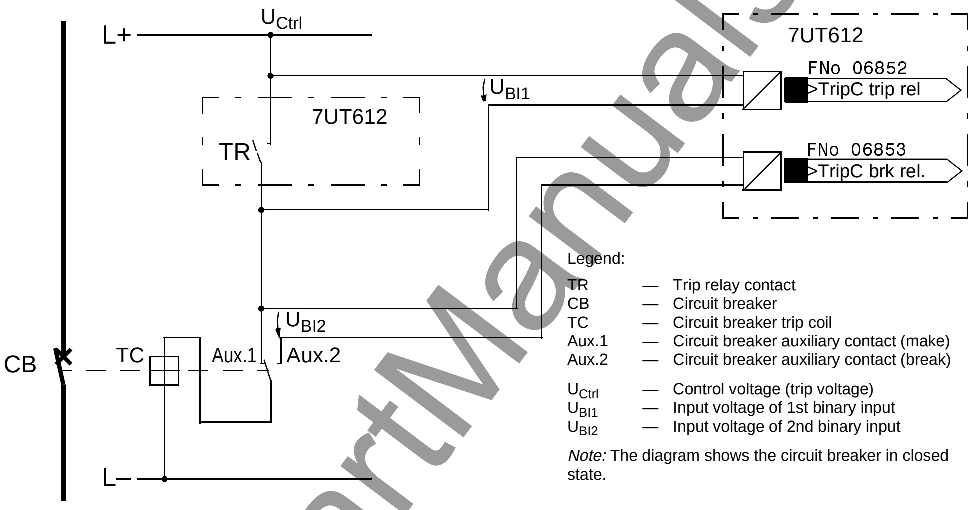


Figure 2-87 Principle of the trip circuit supervision with two binary inputs

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 2-6) 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 2-6 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 2-88). 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.

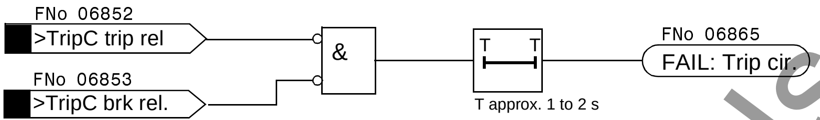


Figure 2-88 Logic diagram of the trip circuit supervision with two binary inputs

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 2-89. 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”.

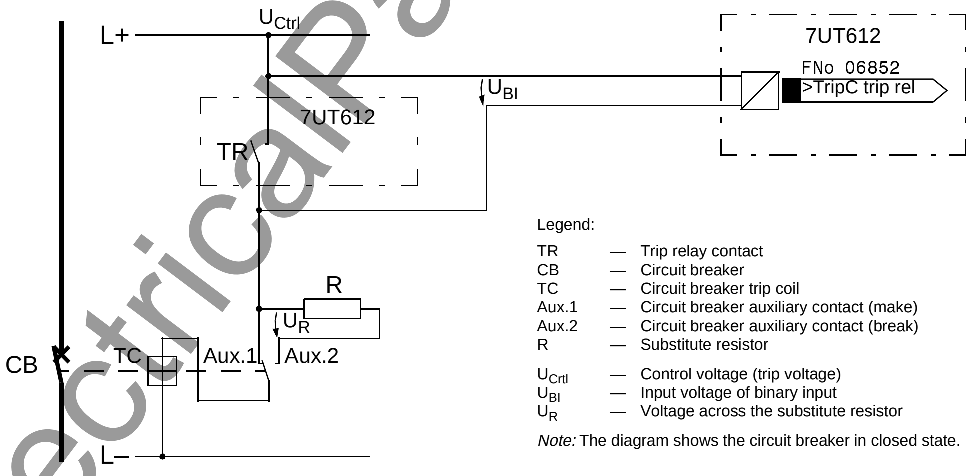


Figure 2-89 Principle of the trip circuit supervision with one binary input

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 2-90). After the fault in the trip circuit is removed, the alarm is reset automatically after the same time.

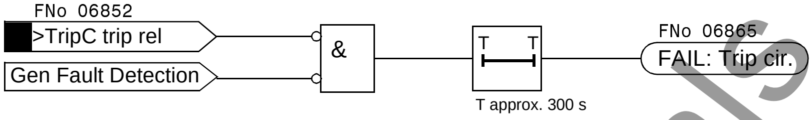


Figure 2-90 Logic diagram of the trip circuit supervision with one binary input

2.13.1.5 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 “Device OK” relay, 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 2-7 shows a summary of the monitoring functions and the fault reactions of the device.

Table 2-7 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 A/D-conv.`“	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) After three unsuccessful attempts the device is put out of operation
²) DOK = “Device OK” relay

Table 2-7 Summary of the fault reactions of the device

Supervision	Possible causes	Fault reaction	Alarm	Output
1 A/5 A/0.1 A–setting	1/5/0.1 A jumper wrong	Alarms Protection out of operation	“Error1A/5Awrong“ LED “ERROR“	DOK2) drops off
Calibration data	Internal (device not calibrated)	Alarm Using default values	“Alarm NO calibr”	as allocated
Backup battery	Internal (backup battery)	Alarm	“Fail Battery“	as allocated
Time clock	Time synchronization	Alarm	“Clock SyncError”	as allocated
Modules	Module does not comply with ordering number	Alarms Protection out of operation	“Error Board 0...1” and if applicable “Error A/D-conv.”	DOK2) drops off
Thermobox connection	Thermobox 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 symmetry	External (system or current transformers)	Alarm with identification of the side	“Fail. Isym 1” or “Fail. Isym 2”, “Fail I balance”	as allocated
Phase sequence	External (system or connections)	Alarm with identification of the side	“FailPh.Seq I S1” or “FailPh.Seq I S1”, “Fail Ph. Seq. I”	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

2.13.1.6 Group Alarms

Certain messages of the monitoring functions are already combined to group alarms. Table 2-8 shows an overview of these group alarms an their composition.

Table 2-8 Group alarms

Group alarm		Composed of	
FNo	Designation	FNo	Designation
00161	Failure I Supervision (Measured value supervision without consequences on protection functions)	00571 00572 00265 00266	Fail. Isym 1 Fail. Isym 2 FailPh.Seq I S1 FailPh.Seq I S2
00160	Alarm Sum Event (Failures or configuration errors without consequences on protection functions)	00161 00068 00177 00193 00198 00199	Fail I Superv. Clock SyncError Fail Battery Alarm NO calibr Err. Module B Err. Module C

Table 2-8 Group alarms

Group alarm		Composed of	
FNo	Designation	FNo	Designation
	Failure measured values (Fatal configuration or measured value errors with blocking of all protection functions)	00181 00190 00183 00192	Error A/D-conv. Error Board 0 Error Board 1 Error1A/5Awrong
00140	Error Sum Alarm (Problems which can lead to part blocking of protection functions)	00161 00191 00264 00267	Fail I Superv. Error Offset Fail: RTD-Box 1 Fail: RTD-Box 2

2.13.1.7 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 7UT612 checks settings for inconsistencies and reports them. For instance, the restricted earth fault protection cannot be applied if there is no measuring input 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 3-10 (Subsection 3.3.4, page 227) gives an overview.

2.13.2 Setting the Function Parameters

The sensitivity of the measurement supervision can be altered. Experiential values set ex works are sufficient in most cases. If an extremely high operational unbalance of the currents 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.

Measured Value Supervision

The symmetry supervision can be switched ***ON*** or ***OFF*** in address 8101 **BALANCE I**.

In address 8102 **PHASE ROTATION** phase rotation supervision can be set to ***ON*** or ***OFF***.

Address 8111 **BAL. I LIMIT S1** determines the threshold current for side 1 above which the current balance supervision is effective (also see Figure 2-86). Address 8112 **BAL. FACT. I S1** is the associated balance factor, i.e. the gradient of the balance characteristic (Figure 2-86).

Address 8121 **BAL. I LIMIT S2** determines the threshold current for side 1 above which the current balance supervision is effective (also see Figure 2-86). Address 8122 **BAL. FACT. I S2** is the associated balance factor, i.e. the gradient of the balance characteristic (Figure 2-86).

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.**.

2.13.3 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. When setting the device using primary values, the current transformer ratios have to be taken into consideration.

Addr.	Setting Title	Setting Options	Default Setting	Comments
8101	BALANCE I	ON OFF	OFF	Current Balance Supervision
8102	PHASE ROTATION	ON OFF	OFF	Phase Rotation Supervision
8111	BAL. I LIMIT S1	0.10..1.00 A	0.50 A	Current Balance Monitor Side 1
8112	BAL. FACT. I S1	0.10..0.90	0.50	Balance Factor for Current Monitor S1
8121	BAL. I LIMIT S2	0.10..1.00 A	0.50 A	Current Balance Monitor Side 2
8122	BAL. FACT. I S2	0.10..0.90	0.50	Balance Factor for Current Monitor S2

Addr.	Setting Title	Setting Options	Default Setting	Comments
8201	TRIP Cir. SUP.	ON OFF	OFF	TRIP Circuit Supervision

2.13.4 Information Overview

F.No.	Alarm	Comments
00161	Fail I Superv.	Failure: General Current Supervision
00163	Fail I balance	Failure: Current Balance
00571	Fail. Isym 1	Fail.: Current symm. supervision side 1
00572	Fail. Isym 2	Fail.: Current symm. supervision side 2
00175	Fail Ph. Seq. I	Failure: Phase Sequence Current
00265	FailPh.Seq I S1	Failure: Phase Sequence I side 1
00266	FailPh.Seq I S2	Failure: Phase Sequence I side 2

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 A/D-conv.	Error: A/D converter
00190	Error Board 0	Error Board 0
00183	Error Board 1	Error Board 1
00192	Error1A/5Awrong	Error:1A/5Ajumper different from setting
00191	Error Offset	Error: Offset
00264	Fail: RTD-Box 1	Failure: RTD-Box 1
00267	Fail: RTD-Box 2	Failure: RTD-Box 2
00160	Alarm Sum Event	Alarm Summary Event
00193	Alarm NO calibr	Alarm: NO calibration data available
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

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

2.14 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.

2.14.1 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 7UT612 they are the following:

• “`Relay PICKUP`”:	pickup of any protection function with phase indication;
• “`Relay 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.

2.14.2 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 side of the protected object (Figure 2-91). 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 activated) *AND* the minimum trip command duration is over.

A further condition for terminating the trip command is that the circuit breaker is recognized to be open. The current through the tripped breaker must have fallen below the value that corresponds to the setting value **Breaker S1 I>** (address 283 for side 1), or **Breaker S2 I>** (address 284 for side 2), refer to “Circuit Breaker Status” in Subsection 2.1.2, page 27) plus 10 % of the fault current.

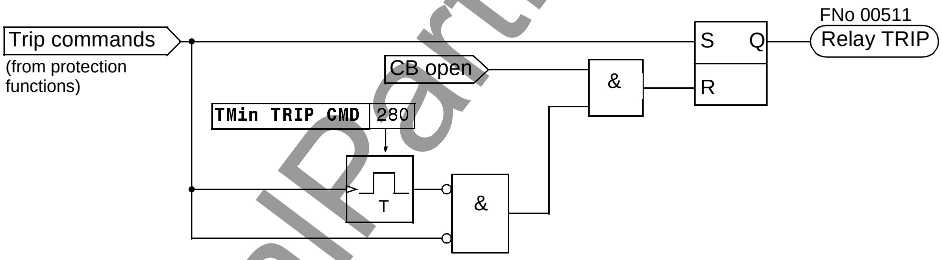


Figure 2-91 Storage and termination of the trip command

Reclosure Interlocking

When tripping the circuit breaker by a protection function the manual reclosure must often be blocked until the cause for the protection function operation is found.

Using the user-configurable logic functions (CFC) an automatic reclosure interlocking function can be created. The default setting of 7UT612 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 306). 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.

"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 removed 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 2-92 shows the logic diagram of this function.

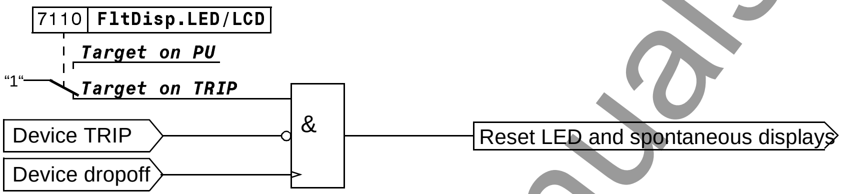


Figure 2-92 Logic diagram of the "no–trip–no–flag" feature (command-dependent alarms)

CB Operation Statistics

The number of trips caused by the device 7UT612 is counted.

Furthermore, the current interrupted for each pole is acquired, provided as an information and accumulated in a memory.

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.

2.14.3 Setting the Function Parameters

The parameters for the tripping logic of the entire device and the circuit breaker test have already been set in Subsection 2.1.2.

Address 7110 **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***).

2.14.4 Setting Overview

Addr.	Setting Title	Setting Options	Default Setting	Comments
7110	FltDisp.LED/LCD	Display Targets on every Pickup Display Targets on TRIP only	Display Targets on every Pickup	Fault Display on LED / LCD

2.14.5 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
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

2.15 Ancillary Functions

The auxiliary functions of the 7UT612 relay include:

- processing of messages,
- processing of operational measured values,
- storage of fault record data.

2.15.1 Processing of Messages

2.15.1.1 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® 4. This feature is used to verify wiring from the device to plant equipment during commissioning (refer also to Subsection 3.3.3).

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). 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 has 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® 4 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® 4.

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 306).

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 trip 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.

2.15.1.2 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 2.15.1.3.

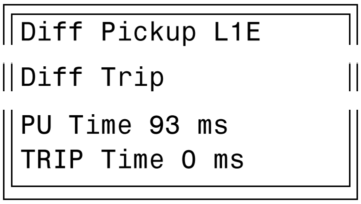
2.15.1.3 Trip Log (Fault Messages)

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, or after the expiry of the auto-reclose reclaim time, so that several unsuccessful auto-reclose cycles are also stored cohesively. Accordingly a system fault may contain several individual fault events (from fault detection up to reset of fault detection).

Spontaneous Displays

The 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 2-93.



`Diff Pickup L1E`	Protection function that had picked up, e.g. differential protection, with phase information;
`Diff Trip`	Protection function that had tripped, e.g. differential protection;
`PU Time 93 ms`	Elapsed time from pickup until dropoff;
`TRIP Time 0 ms`	Elapsed time from pickup until the first trip command of a protection function.

Figure 2-93 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.

2.15.1.4 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® 4. For further information see the SIPROTEC® 4 System Manual (order-no. E50417–H1176–C151).

2.15.1.5 General Interrogation

The present condition of a SIPROTEC® device can be examined by using DIGSI® 4 to view 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.

2.15.1.6 Switching Statistics

The messages in switching statistics are counters for the accumulation of interrupted currents by each of the breaker poles, the number of trips 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® 4 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).

2.15.2 Measurement during Operation

Display and Transmission of Measured Values

Operating measured 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® 4, or transferred to a central master station via the system interface (if available).

Precondition for a correct display of primary and percentage values is the complete and correct entry of the nominal values of the instrument transformers and the power system according to Subsection 2.1.2. Table 2-9 shows a survey of the operational measured values. The scope of measured values depends on the ordered version, the configured functions and the connection of the device.

To be able to output a measured voltage "`Umeas`", a measured voltage has to be connected to one of the current inputs I_7 or I_8 via an external series resistor. Via a user-configurable CFC logic (CFC block "Life_Zero") the current proportional to the voltage can be measured and indicated as voltage "`Umeas`". For more information see the manual CFC.

The apparent power "S" is 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 phase angles are listed in Table 2-10, the measured thermal values in Table 2-11. The latter can only appear if the overload protection is set to ***Enabled***. Which measured values are available to the user also depends on the method of overload detection selected and maybe on the number of temperature detectors interconnected between device and thermobox.

The operational measured values are also calculated during a running fault in intervals of approx. 0.6 s.

The referred values are always based on the nominal values of the protected object (cf. also the footnotes of the tables), the temperature rise is based on the trip temperature rise. The phase angles and the temperature degrees have actually no base values. But, processing of these values in the CFC-logic or transmission via the serial interfaces requires values without dimension, therefore, base values are defined arbitrarily. These are stated in the Tables 2-10 and 2-11 in the column titled "%–Conversion".

Table 2-9 Operational measured values (magnitudes primary, secondary, percent)

Measured values		primary	secondary	% referred to
IL1S1, IL2S1, IL3S1 3)	Phase currents of side 1	A; kA	A	Operating nominal current 1)
3I0S1 3)	Residual current of side 1	A; kA	A	Operating nominal current 1)
I1S1, I2S1 3)	Positive and negative sequence component currents of side 1	A; kA	A	Operating nominal current 1)
IL1S2, IL2S2, IL3S2 3)	Phase currents of side 2	A; kA	A	Operating nominal current 1)
3I0S2 3)	Residual current of side 2	A; kA	A	Operating nominal current 1)
I1S2, I2S2 3)	Positive and negative sequence component currents of side 2	A; kA	A	Operating nominal current 1)
I7 3)	Current at current input I_7	A; kA	A	Operating nominal current 1)
I1 ... I7 4)	Currents at the current inputs	A; kA	A	Operating nominal current 1)
I8	Current at current input I_8	A	mA	Operating nominal current 1) 2)
Umeas 5)	Voltage from current at I_7 or I_8	V; kV; MV	—	—
S 6)	Apparent power	kVA; MVA; GVA	—	—
f	Frequency	Hz	Hz	Rated frequency

1) for transformers acc. to addresses 240, 243, and 249 (see Subsection 2.1.2) $I_N = S_N/(\sqrt{3}\cdot U_N)$ or $I_N = S_N/U_N$ (1-phase)
for generators/motors/reactors acc. to addresses 251 and 252 (see Subsection 2.1.2) $I_N = S_N/(\sqrt{3}\cdot U_N)$;
for busbars and lines acc. to address 265 (see Subsection 2.1.2)

2) with consideration of the factor address 235 `Factor I8` (see Subsection 2.1.2)

3) only for three-phase objects

4) only for single-phase busbar protection

5) if configured and prepared in CFC

6) calculated from phase currents and nominal voltage or measured voltage Umeas

Table 2-10 Operational measured values (phase relationship)

Measured values		Dimension	%–Conversion 5)
φIL1S1, φIL2S1, φIL3S1 3)	Phase angle of the currents of side 1, towards I_{L1S1}	°	0° = 0 % 360° = 100 %
φIL1S2, φIL2S2, φIL3S2 3)	Phase angle of the currents of side 2, towards I_{L1S1}	°	0° = 0 % 360° = 100 %
φI1 ... φI7 4)	Phase angle of the currents at the current inputs, towards I_1	°	0° = 0 % 360° = 100 %
φI7 3)	Phase angle of the current at the current input I_7, towards I_1	°	0° = 0 % 360° = 100 %

3) only for three-phase objects

4) only for single-phase busbar protection

5) only for CFC and serial interfaces

Table 2-11 Thermal values

Measured values		Dimension	%–Conversion 5)
$\Theta_{L1}/\Theta_{trip}$, $\Theta_{L2}/\Theta_{trip}$, $\Theta_{L3}/\Theta_{trip}$ 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	p.u.	
ResWARN 2) 3)	Load reserve to hot-spot warning (stage 1)	%	
ResALARM 2) 3)	Load reserve to hot-spot alarm (stage 2)	%	
Θ_{leg1},Θ_{leg2}, Θ_{leg3} 2) 3)	Hot-spot temperature for each phase	°C or °F	0 °C = 0 % 500 °C = 100 % 0 °F = 0 % 1000 °F = 100 %
Θ_{RTD1} ... 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 143 **`Therm.O/L CHR.`** = ***`classical`*** (Subsection 2.1.1)
2) only for overload protection with hot-spot calculation (IEC 60354): address 143 **`Therm.O/L CHR.`** = ***`IEC354`*** (Subsection 2.1.1)
3) only if thermobox(es) available (Section 2.10)
5) 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 2-12.

Table 2-12 Values of the differential protection

Measured values		% referred to
I_{DiffL1}, I_{DiffL2}, I_{DiffL3}	Calculated differential currents of the three phases	Operating nominal current 1)
I_{RestL1}, I_{RestL2}, I_{RestL3}	Calculated restraining currents of the three phases	Operating nominal current 1)
$I_{DiffEDS}$	Calculated differential current of the restricted earth fault protection	Operating nominal current 1)
$I_{RestEDS}$	Calculated restraining current of the restricted earth fault protection	Operating nominal current 1)

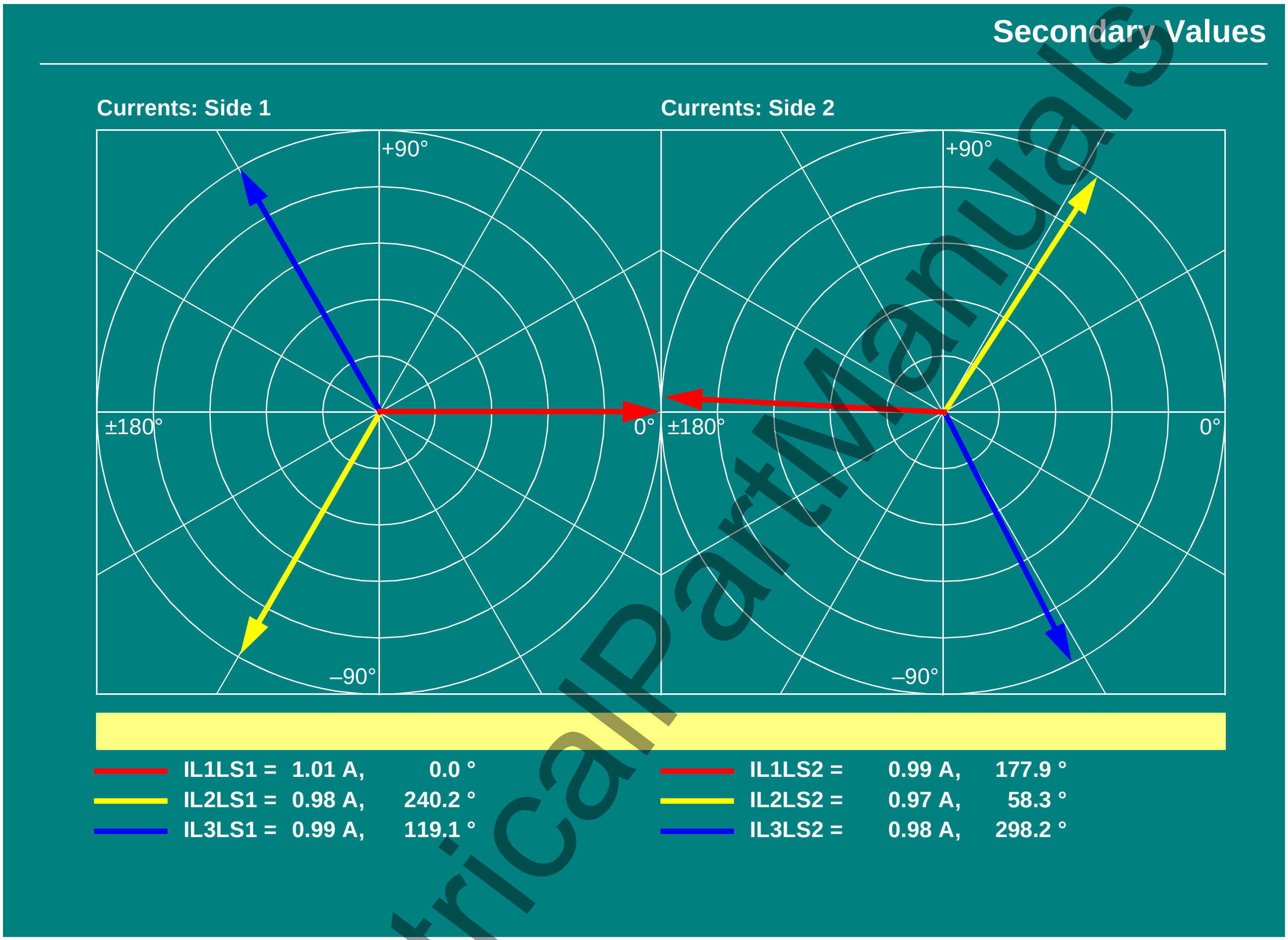
1) for transformers acc. to addresses 240, 243, and 249 (see Subsection 2.1.2) $I_N = S_N/(\sqrt{3} \cdot U_N)$ or $I_N = S_N/U_N$ (1-phase);
for generators/motors/reactors acc. to addresses 251 and 252 (see Subsection 2.1.2) $I_N = S_N/(\sqrt{3} \cdot U_N)$;
for busbars and lines acc. to address 265 (see Subsection 2.1.2)

The IBS-Tool

The commissioning help “IBS-tool” offers a wide range of commissioning and monitoring functions that allows 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. The “Online Help” can be downloaded from the INTERNET.

This tool allows to illustrate the measured values of all ends of the protected object during commissioning and during operation. The currents appear as vector diagrams and are indicated as numerical values. Figure 2-94 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 2-94 Measured values of the sides of the protected object — example for through-flowing currents

User Defined Set-Points

In SIPROTEC® 7UT612, 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. The set-points are supervised by the processor system in the background, so they are not suitable for protection purposes.

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).

2.15.3 Fault Recording

The differential protection 7UT612 is equipped with a fault recording function. The instantaneous values of the measured quantities

i_{L1S1}, i_{L2S1}, i_{L3S1}, i_{L1S2}, i_{L2S2}, i_{L3S2}, $3i_{0S1}$, $3i_{0S2}$, i_7, i_8, and
I_{DiffL1}, I_{DiffL2}, I_{DiffL3}, I_{RestL1}, I_{RestL2}, I_{RestL3}

are sampled at $1^2/_3$ ms intervals (for a frequency of 50 Hz) and stored in a cyclic buffer (12 samples per period). When used as single-phase busbar protection, the first six 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® 4 and the graphic analysis software SIGRA 4. 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.

2.15.4 Setting the Function Parameters

Measured Values In addition to the values measured directly and the measured values calculated from currents and maybe from temperatures the 7UT612 can also output the voltage and the apparent power.

To get the voltage values, a voltage must be connected to the current measuring input I_7 or I_8 via an external series resistor. Additionally, a user-defined logic must be created in CFC (see Subsection 2.15.2, margin heading “Display and Transmission of Measured Values”).

The apparent power is either calculated from this voltage 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 401 **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 401 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 404 **PRE. TRIG. TIME** and address 405 **POST REC. TIME.**

The maximum length of time of a record is entered in address 403 **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 406 **BinIn CAPT.TIME** (upper bound is address 403). Pre-trigger and post-dropout settings in Addresses 404 and 405 are included. If address 406 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 403, whichever is shorter.

2.15.5 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..5.00 sec	1.00 sec	Max. length of a Waveform Capture Record

Addr.	Setting Title	Setting Options	Default Setting	Comments
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

2.15.6 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
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
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

Measured Values

F.No.	Alarm	Comments
00721	IL1S1=	Operat. meas. current IL1 side 1
00722	IL2S1=	Operat. meas. current IL2 side 1
00723	IL3S1=	Operat. meas. current IL3 side 1
30640	3I0S1=	3I0 (zero sequence) of side 1
30641	I1S1=	I1 (positive sequence) of side 1

F.No.	Alarm	Comments
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
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
30653	I8=	Operat. meas. current I8
07740	φIL1S1=	Phase angle in phase IL1 side 1
07741	φIL2S1=	Phase angle in phase IL2 side 1
07749	φIL3S1=	Phase angle in phase IL3 side 1
07750	φIL1S2=	Phase angle in phase IL1 side 2
07759	φIL2S2=	Phase angle in phase IL2 side 2
07760	φIL3S2=	Phase angle in phase IL3 side 2
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
30656	Umeas.=	Operat. meas. voltage Umeas.
00645	S =	S (apparent power)
00644	Freq=	Frequency

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
01060	Θ leg 1=	Hot spot temperature of leg 1
01061	Θ leg 2=	Hot spot temperature of leg 2
01062	Θ leg 3=	Hot spot temperature of leg 3
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

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
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

Puls metering

if configured (CFC)

F.No.	Alarm	Comments
00888	Wp(puls)	Pulsed Energy Wp (active)
00889	Wq(puls)	Pulsed Energy Wq (reactive)

2.16 Processing of Commands

General

In addition to the protective functions described so far, control command processing is integrated in the SIPROTEC® 7UT612 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® 4,

– 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.

2.16.1 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.

2.16.2 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).

2.16.3 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 intelocking)

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.

2.16.3.1 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® 4.

Deactivated interlock switching means the configured interlocking conditions are bypassed in the relay.

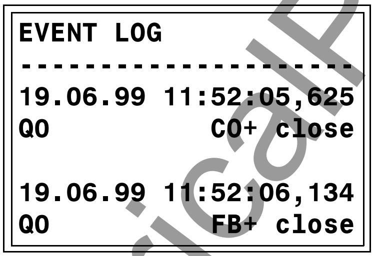
Interlocked switching means that all configured interlocking conditions are checked in the command check routines. If a condition could not be fulfilled, the command will be rejected by a message with a minus added to it (e.g. “**CO-**”), followed by an operation response information. Table 2-13 shows some types of commands and messages. For the device the messages designated with *) are displayed in the event logs, for DIGSI® 4 they appear in spontaneous messages.

Table 2-13 Types of command and messages

Type of command	Abbrev.	Message
Control issued	CO	CO+/–
Manual tagging (positive / negative)	MT	MT+/–
Input blocking	IB	IB+/– *)
Output blocking	OB	OB+/– *)
Control abortion	CA	CA+/–

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 2-95 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.



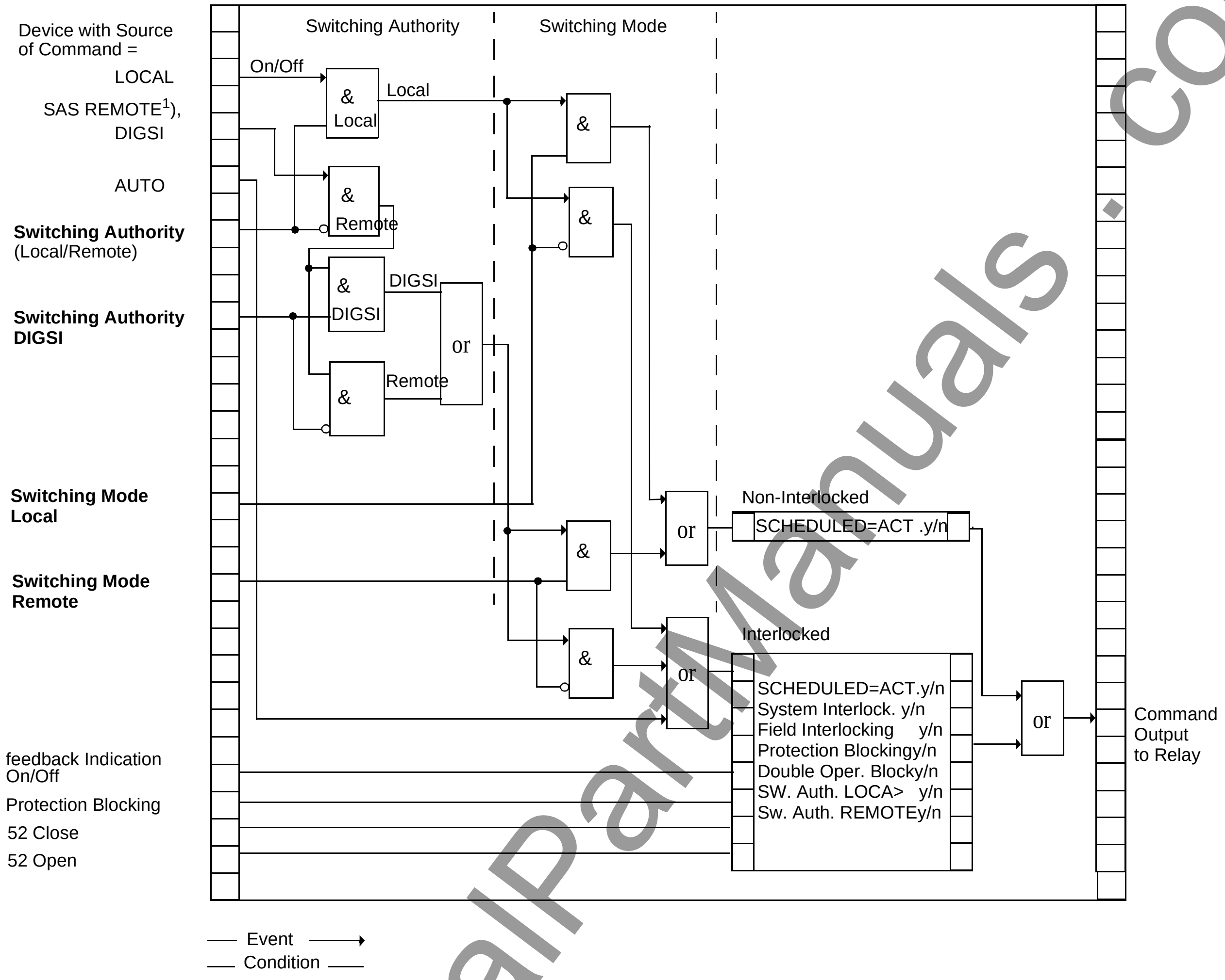
```
EVENT LOG
----------------------
19.06.99 11:52:05,625
Q0           CO+ close

19.06.99 11:52:06,134
Q0           FB+ close
```

Figure 2-95 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 2-96.



[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.

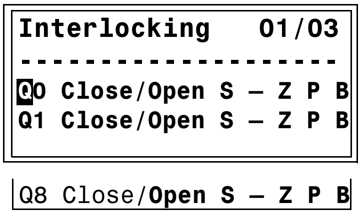
Figure 2-96 Standard Interlocking Arrangements

The display shows the configured interlocking reasons. The are marked by letters explained in the following Table 2-14.

Table 2-14 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 2-97 shows all interlocking conditions (which usually appear in the display of the device) for three switchgear items with the relevant abbreviations explained in Table 2-14. All parameterized interlocking conditions are indicated (see Figure 2-97).



```
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 2-97 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.

2.16.4 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.

2.16.5 Information Overview

F.No.	Alarm	Comments
	Cntrl Auth	Control Authority
	ModeREMOTE	Controlmode REMOTE
	ModeLOCAL	Controlmode LOCAL

■

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 7UT612 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, ANSI, 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

Verification of the ratings of the 7UT612 as well as matching to ratings of the power equipment must have been completed.

3.1.1 Installation

Panel Flush Mounting

- Remove the 4 covering caps located on the corners of the front cover, reveal the 4 slots in the mounting flange.
- Insert the device into the panel cut-out and fasten with four screws. Refer to Figure 4-13 in Section 4.15 for dimensions.
- Replace the four covers.
- Connect the ground on the rear plate of the device to the protective ground of the panel. Use at least one M4 screw for the device ground. 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.
- 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.
  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.

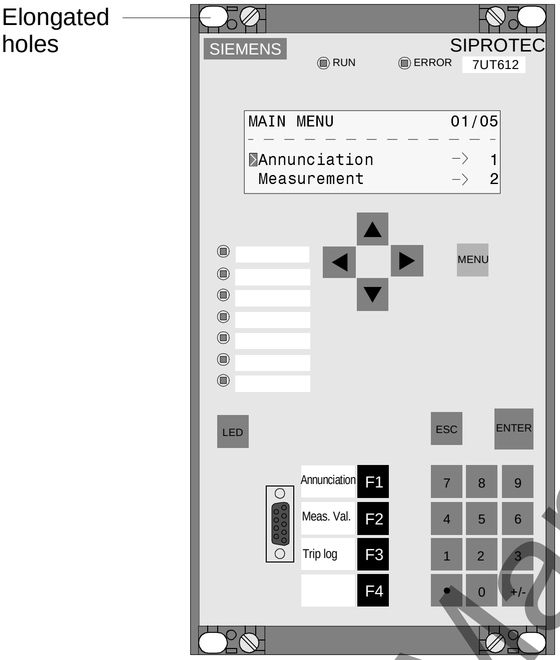


Figure 3-1 Panel mounting of a 7UT612

Rack Mounting and Cubicle Mounting

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.1.1.

- ☐ Loosely screw the two mounting brackets in the rack with four screws.
- ☐ Remove the 4 covers at the corners of the front cover. The 4 slots in the mounting flange are revealed and can be accessed.
- ☐ Fasten the device to the mounting brackets with four screws.
- ☐ Replace the four covers.
- ☐ Tighten the mounting brackets to the rack using eight 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-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.
- ☐ 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.

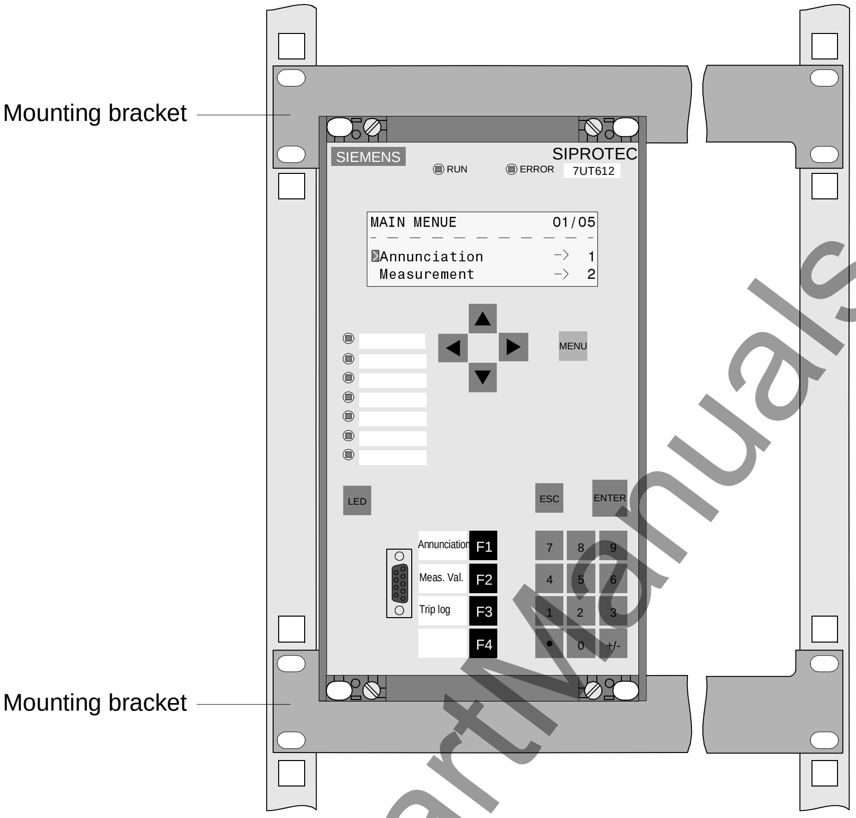


Figure 3-2 Installing a 7UT612 in a rack or cubicle

Panel Surface Mounting

❑ Secure the device to the panel with four screws. Refer to Figure 4-14 in Section 4.15 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.

3.1.2 Termination Variants

General diagrams are shown in Appendix A.2. Connection examples for current 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) 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.***, not ***3 phase transf.***. 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 side of the protected object. For connection examples see Appendix A.3, Figures A-3 to A-6 and A-9 to A-13 referring to the protected object types.

With two-phase connection of a single-phase transformer the centre phase will not be used (I_{L2}). Figure A-7 in Appendix A.3 shows a connection diagram. 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-8.

For single-phase busbar protection every measuring input (except I_8) is allocated to a busbar feeder. Figure A-14 in Appendix A.3 illustrates an example for one phase. The other phases are to be connected correspondingly. If the device is connected via summation transformers, see Figure A-15. With the latter 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).

The allocation of the current inputs I_7 and I_8 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-4 to A-7 and A-11 to A-15) which refer to different applications.

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 goes for the circuit breaker failure protection whose measuring point (side) must correspond with the side of the circuit breaker to be monitored.

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.

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 3-3. 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

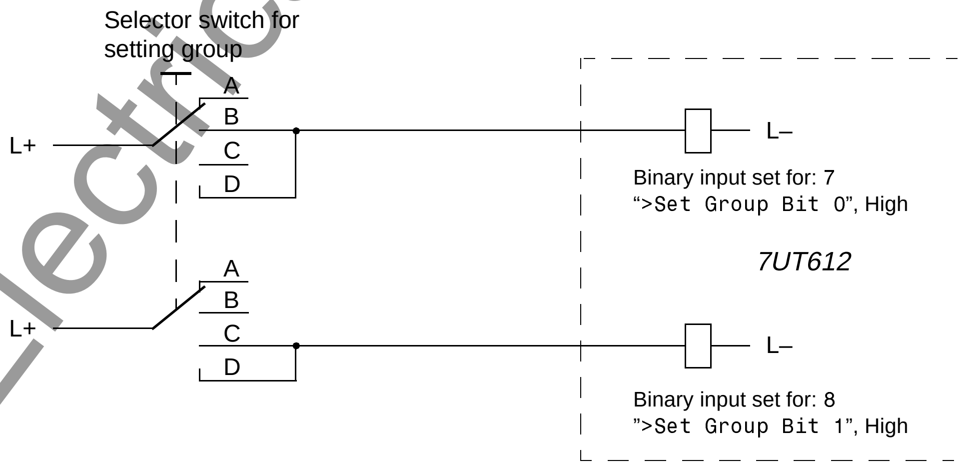


Figure 3-3 Connection diagram (example) for setting group switching with binary inputs

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 3-4). 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.

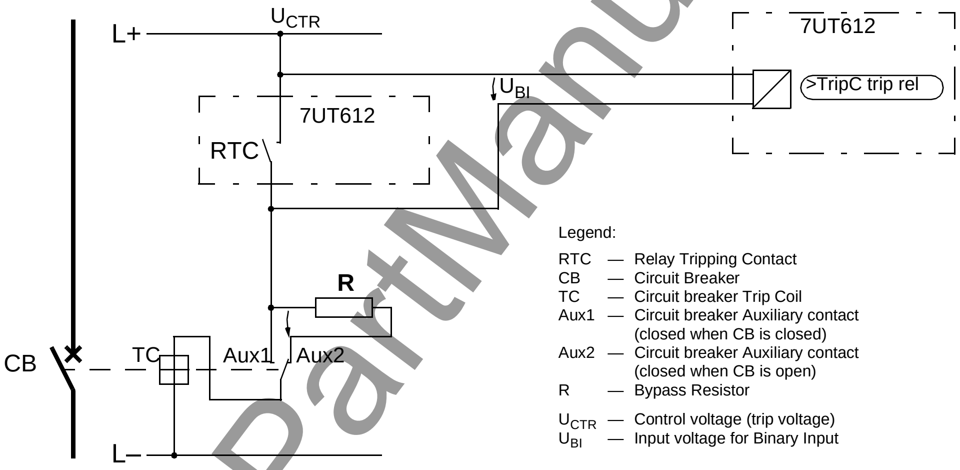


Figure 3-4 Trip circuit supervision with one binary input

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® 7UT612)
$U_{BI\ min}$	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)

$$R_{max} = \left(\frac{110\ \text{V} - 19\ \text{V}}{1.7\ \text{mA}}\right) - 500\ \Omega$$

$$R_{max} = 53\ \text{k}\Omega$$

$$R_{min} = 500\ \Omega \left(\frac{110\ \text{V} - 2\ \text{V}}{2\ \text{V}}\right) - 500\ \Omega$$

$$R_{min} = 27\ \text{k}\Omega$$

$$R = \frac{R_{max} + R_{min}}{2} = 40\ \text{k}\Omega$$

The closed standard value of 39 kΩ is selected; the power is:

$$P_R = \left(\frac{110\ \text{V}}{39\ \text{k}\Omega + 0.5\ \text{k}\Omega}\right)^2 \cdot 39\ \text{k}\Omega$$

$$P_R \geq 0.3\ \text{W}$$

Thermoboxes

If the overload protection operates with processing of the coolant temperature (overload protection with hot-spot calculation), one or two thermoboxes 7XV5662 can be connected to the serial service interface at port C.

3.1.3 Hardware Modifications

3.1.3.1 General

Hardware modifications might be necessary or desired. For example, a change of 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 7UT612 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 A–CPU". 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 input transducers of the device. When the relay is delivered, these jumpers are set according to the name-plate sticker to 1 A or 5 A, for the current inputs I_1 to I_7; the input I_8 is independent of the rated current.

If the current transformer sets have different rated secondary currents at the sides of the protected object and/or of current input I_7, the device 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 summation transformers interconnected, rated currents for current inputs I_1 to I_7 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 "Input/Output Board A–I/O–3".

When performing changes, please make sure that the device is always informed about them:

- Using three-phase applications and single-phase transformers, changes for side 1 are to be set in address 203 **IN-SEC CT S1** and changes for side 2 in address 208 **IN-SEC CT S2** in the Power System Data (refer to Subsection 2.1.2, margin heading "Current Transformer Data for 2 Sides", page 23).
- Using three-phase applications and single-phase transformers, changes for current input I_7 are to be performed in address 233 **IN-SEC CT I7** (refer to Subsection 2.1.2, margin heading "Current Transformer Data for Current Input I_7", page 26).
- Using single-phase busbar protection, changes are made in addresses 213 **IN-SEC CT I1** to 233 **IN-SEC CT I7** (refer to Subsection 2.1.2, margin heading "Current Transformer Data for Single-phase Busbar Protection", page 25).

The current measuring input I_8 — disregarding the rated current of the device — is suited for highly sensitive current measurement (approx. 3 mA to 1.6 A).

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 A–CPU”.

Note:

If the 7UT612 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

The processor module A–CPU contains 2 output relays the contact of which can be set as normally closed or normally open contact. Therefore it might be necessary to rearrange a jumper. Subsection 3.1.3.3, margin heading margin “Processor Board A–CPU” describes 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 on the interface modules. The physical arrangement and jumper positions on the interface modules see 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 3-6. The ratings of the fuse are printed on the module next to the fuse itself. 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 nameplates.

☐ 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,
- 4.5 mm socket or nut driver.

☐ Unfasten the screw-posts of the D-subminiature connector on the back panel at location “A”.
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 four caps on the front cover and loosen the screws that become accessible.

☐ Carefully pull off the front cover. The front cover is connected to the CPU board with a short ribbon-cable. Refer to Figure 3-5 for the physical arrangement of the printed boards.

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 order of the boards is shown in Figure 3-5.

☐ Disconnect the ribbon-cable between the front cover and the A–CPU 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 A–CPU board (❶) and the A–I/O–3 board (❷).

☐ Remove the boards and set them on the grounded mat to protect them from electrostatic damage. A greater effort is required to withdraw the A–CPU board, especially in versions of the device for surface mounting, because of the plug connectors.

☐ Check the jumpers according to Figures 3-6 and 3-7 and the following notes. Change or remove the jumpers as necessary.

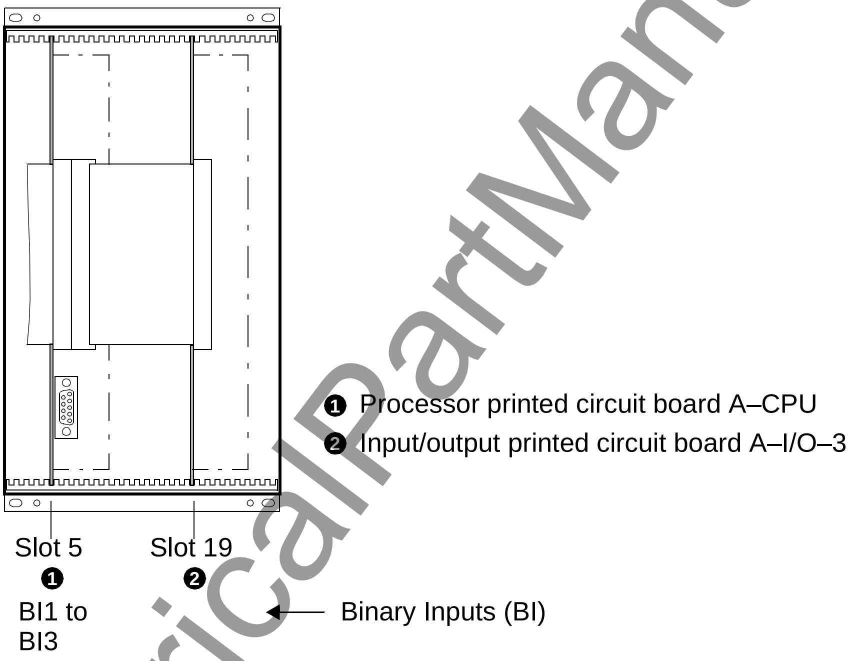


Figure 3-5 Front view of the device after removal of the front cover (simplified and scaled down)

3.1.3.3 Jumper Settings on Printed Circuit Boards

Processor Board A–CPU

The design of a jumper setting for the processor board A–CPU is shown in Figure 3-6.

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 BI3 are checked according to Table 3-3, and the quiescent state of the binary outputs (BO1 and BO2) is checked according to Table 3-4.

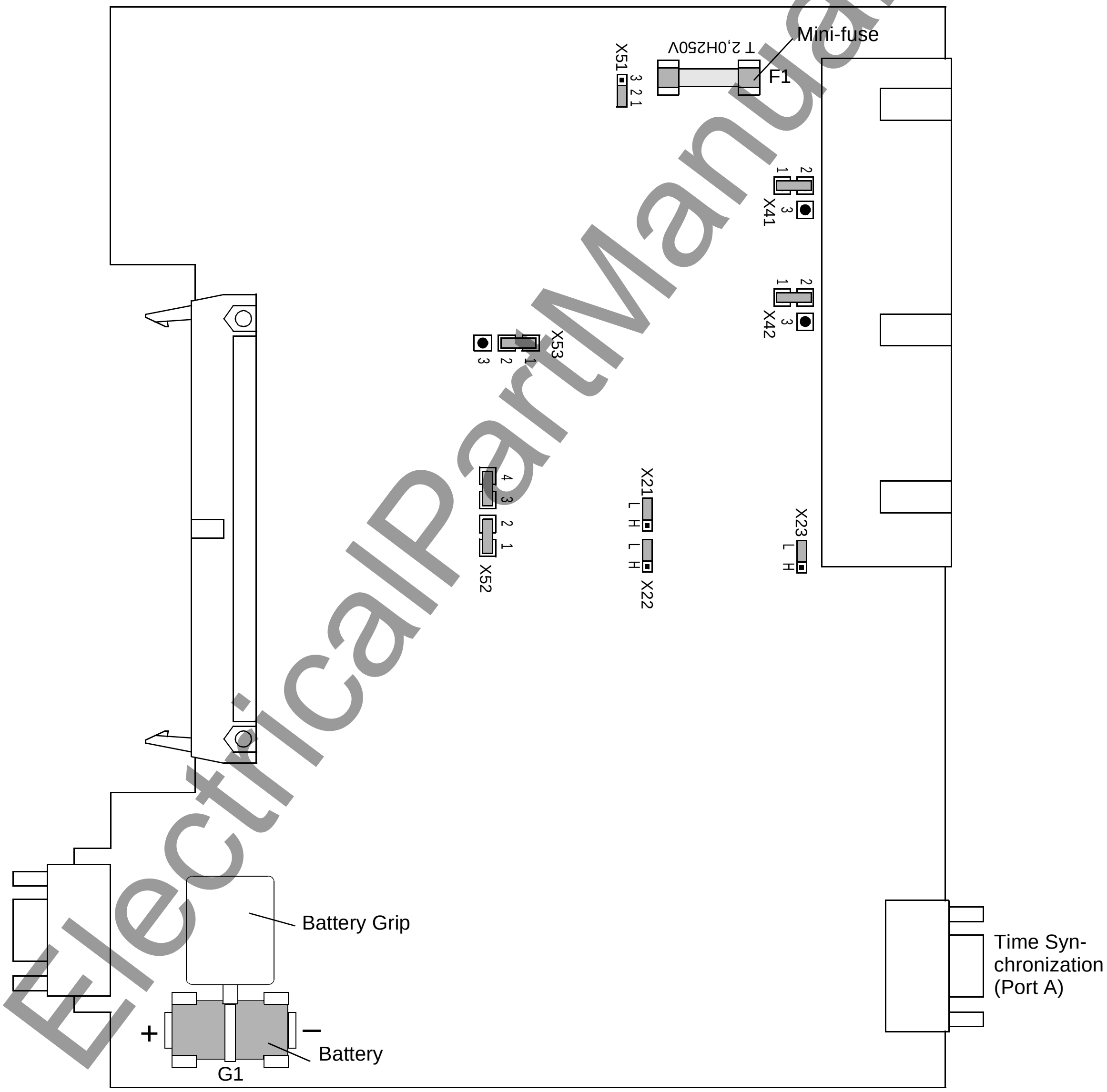


Figure 3-6 Processor board A–CPU (without interface modules) with representation of the jumper settings required for the module configuration

Table 3-2 Jumper settings for the nominal voltage of the integrated **power supply** on the processor board A–CPU

Jumper	Nominal voltage		
	24 to 48 VDC	60 to 125 VDC	110 to 250 VDC; 115 to 230 VDC
X51	not fitted	1–2	2–3
X52	not fitted	1–2 and 3–4	2–3
X53	not fitted	1–2	2–3

Table 3-3 Jumper settings for the **pickup voltages** of the binary inputs BI1 through BI3 on the processor board A–CPU

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

[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 setting for the quiescent state of the **Binary Outputs** on the processor-board A–CPU

For	Jumper	Open in the quiescent state (NO contact)	Closed in the quiescent state (NC contact)	Presetting
BO1	X41	1–2	2–3	1–2
BO2	X42	1–2	2–3	1–2

Input/Output Board A–I/O–3

The design of a jumper setting for the processor board A–I/O–3 is shown in Figure 3-7.

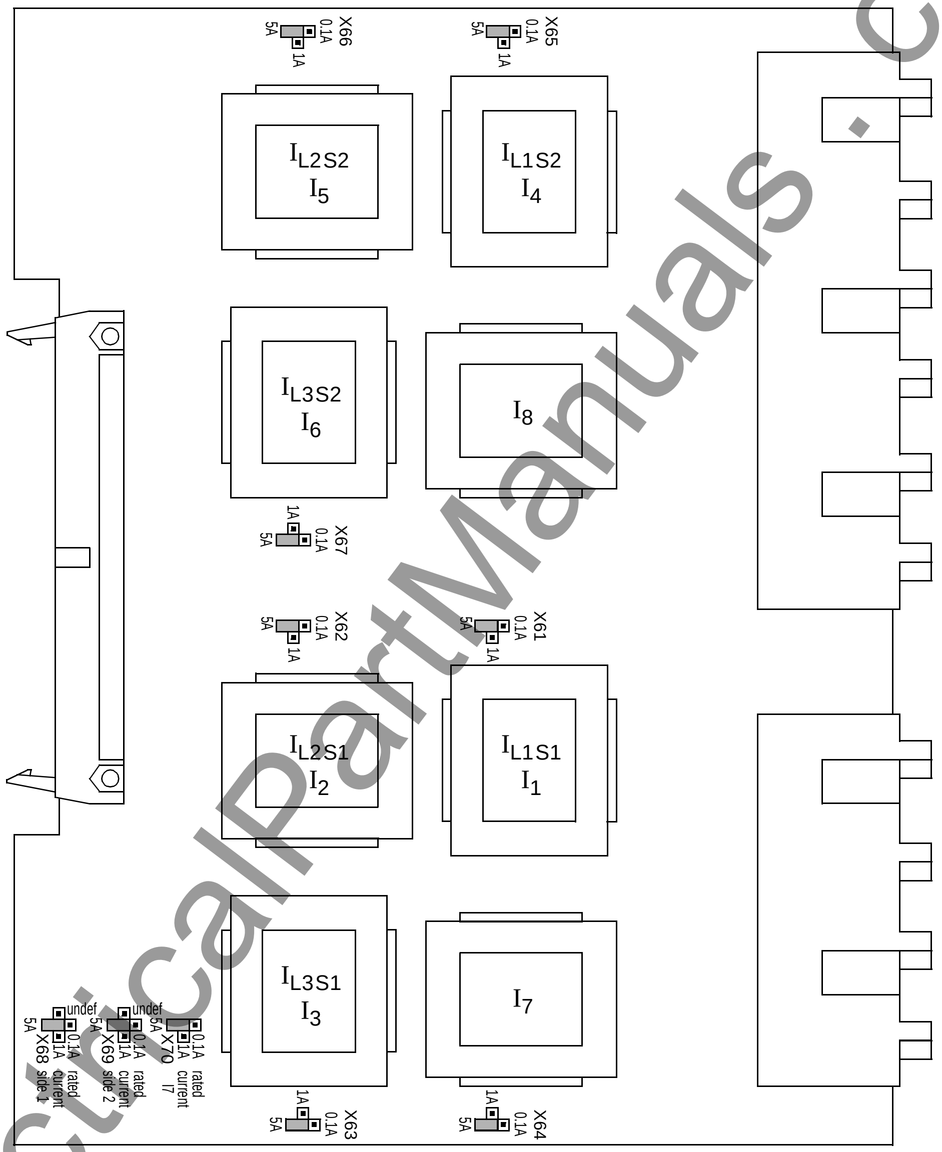


Figure 3-7 Input/output board A–I/O–3 with representation of the jumper settings required for the module configuration

The rated current settings of the input current transformers are checked on the A–I/O–3 board.

With default settings all jumpers (X61 to X70) are set to the same rated current (according to the order number of the device). However, rated currents can be changed for each individual input transformer.

To do so you have to change the location of the jumpers next to the transformers. Additionally, settings of the common jumpers X68 to X70 must be changed correspondingly. Table 3-5 shows the assignment of the jumpers to the current measuring inputs.

- For three-phase applications and single-phase transformers:
  There are 3 measuring inputs for each side. The jumpers belonging to one side must be plugged to the same rated current. Furthermore, the corresponding common jumper (X68 for side 1 and X69 for side 2) has to be plugged to the same rated current.
  For measuring input I_7 the individual and the common jumper are plugged to the same rated current.
- For single-phase busbar protection:
  Each input can be set individually.
  Only if measuring inputs I_1 to I_3 have the same rated current, X68 is plugged to the same rated current.
  Only if measuring inputs I_4 to I_6 have the same rated current, X69 is plugged to the same rated current.
  If different rated currents are reigning within the input groups, the corresponding common jumper is plugged to “undef”.
  For interposed summation transformers with 100 mA output, jumpers of all measuring inputs, including the common jumpers, are plugged to “0.1A”.

Table 3-5 Assignment of the jumpers to the measuring inputs

Application		Jumper	
3-phase	1-phase	Individual	Common
I_{L1S1}	I_1	X61	X68
I_{L2S1}	I_2	X62	
I_{L3S1}	I_3	X63	
I_{L1S2}	I_4	X65	X69
I_{L2S2}	I_5	X66	
I_{L3S2}	I_6	X67	
I_7	I_7	X64	X70
I_8	I_8	—	—

3.1.3.4 Interface Modules

Replacing Interface Modules

The interface modules are located on the processor board A–CPU. Figure 3-8 shows the CPU board and the location of the interface modules.

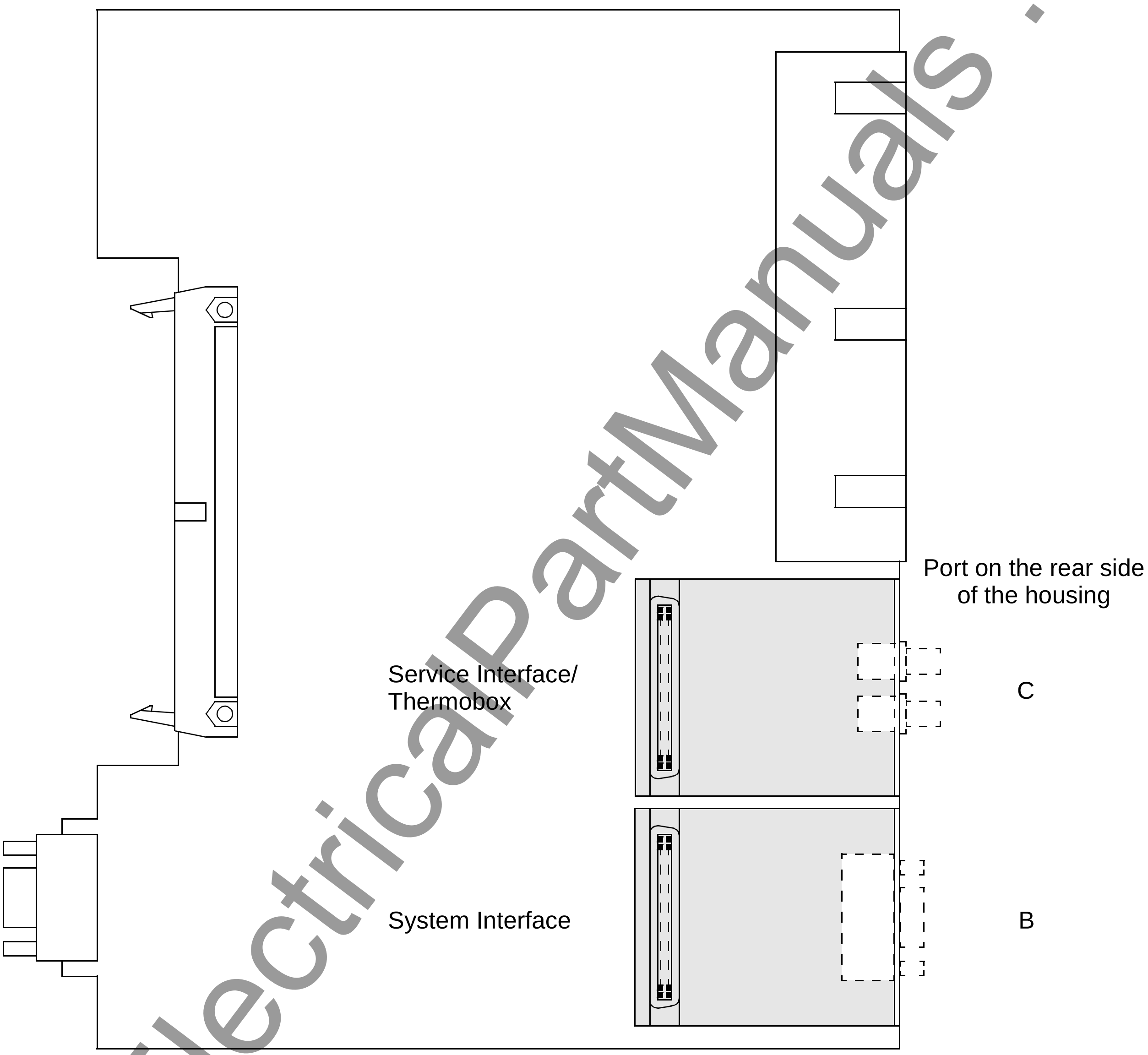


Figure 3-8 Processor board A–CPU with interface modules

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 3-6 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
Service Interface/ Thermobox	C	RS232
		RS485
		Optical 820 nm

The ordering numbers of the exchange modules are listed in Appendix A.1.1, (Accessories).

RS232 Interface

The RS232 interface can be transformed into a RS485 interface according to Figure 3-10.

Figure 3-8 shows the PCB of the A–CPU with the location of the modules. Figure 3-9 shows how jumpers of interface RS232 are located on the interface module.

Here, terminating resistors are not required. They are always disabled.

Jumpers illustrated in factory position

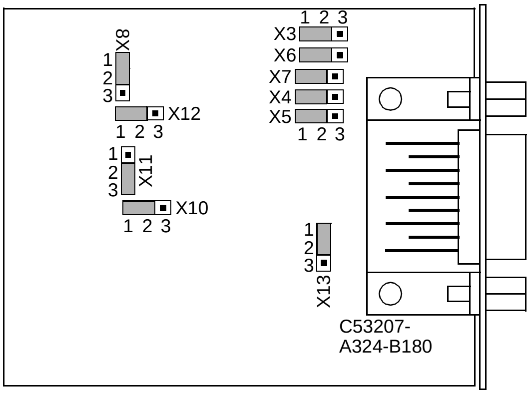


Figure 3-9 Location of the jumpers on interface module for RS232

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 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).

Table 3-7 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

RS 485 Interface

The interface RS 485 can be transformed into interface RS 232 according to Figure 3-9.

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 A–CPU. Figure 3-8 shows the printed circuit board of the A–CPU and the allocation of the modules.

The module for the RS 485 interface is illustrated in Figure 3-10, for the profibus interface in Figure 3-11. 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 th resistors are disconnected.
Exception: Connecting one or two temperature measuring devices 7XV566 to the service interface, the terminating resistors are switched onto the line since this is the standard for this application. This only goes for Port C for devices with order number 7UT612*–******2**–**4***** (position 12 = 2; position 13 = 4).

Jumper	Terminating Resistors	
	Connected	Disconnected
X3	2–3	1–2 *)
X4	2–3	1–2 *)

*) Factory setting (exception see text)

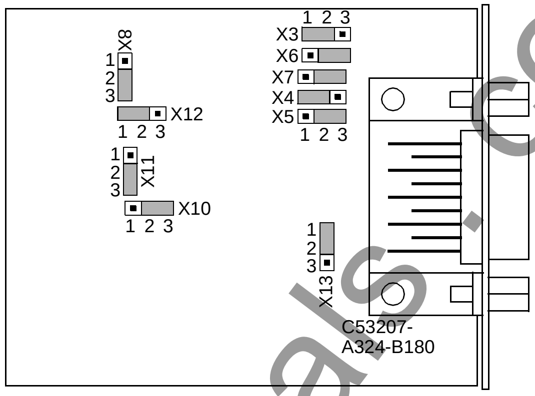


Figure 3-10 Location of the jumpers of the RS485 interface module

Jumper	Terminating Resistors	
	Connected	Disconnected
X3	1–2	2–3 *)
X4	1–2	2–3 *)

*) Factory Setting

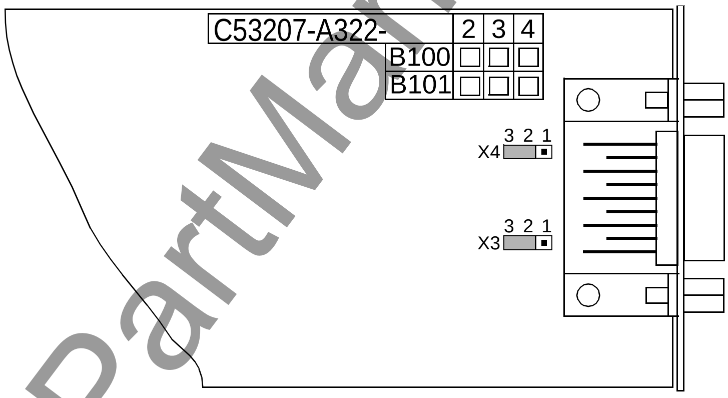


Figure 3-11 Location of the jumpers of the Profibus interface module

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.

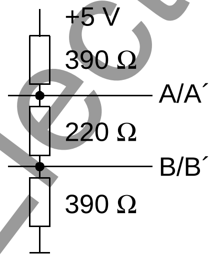


Figure 3-12 External terminating resistors

3.1.3.5 To Reassemble 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 Figure 3-5.
For the model of the device designed for surface mounting, use the metal lever to insert the A–CPU board. The installation is easier with the lever.

☐ First insert the plug connectors on the ribbon cable in the input/output board A–I/O–3 and then on the processor board A–CPU. 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 A–CPU 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.

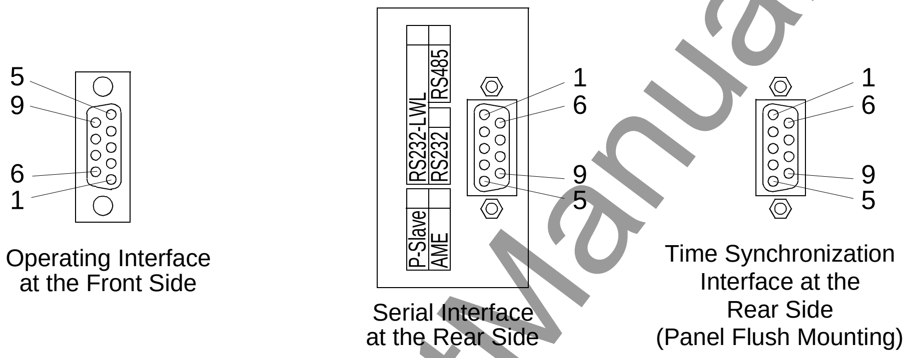
☐ Replace the covers.

☐ 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 3-13.



Operating Interface at the Front Side

Serial Interface at the Rear Side

Time Synchronization Interface at the Rear Side (Panel Flush Mounting)

Figure 3-13 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.1.1 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 3-8):

– 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 3-8 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 interface is 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 are on the interface module RS 485 (Figure 3-10) or on the Profibus module (Figure 3-11). It is also possible that the terminating resistors are arranged externally (Figure 3-12).

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 3-9.

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Table 3-9 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® 4, as described in the SIPROTEC® System Manual, order-no. E50417–H1176–C151.

Warning!

Laser injection! Do not look directly into the fibre-optic elements!

Thermoboxes

If one or two thermoboxes 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).

Check also for the termination: The terminating resistors must be connected to the device 7UT612 (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** thermobox 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** thermoboxes 7XV566:
  bus number = ***1*** for the 1st thermobox (to be set at 7XV566 for RTD1 to 6),
  bus number = ***2*** for the 2nd thermobox (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 transformer circuits are given in the Appendix Section A.3. Please observe the plant diagrams, too.

☐ Protective switches (e.g. test switches, fuses, or miniature circuit breakers) for the power supply must be opened.

☐ Check the continuity of all current transformer connections against the switch-gear and connection diagrams:

  - ☐ Are the current transformers grounded properly?
  - ☐ Are the polarities of the current transformers the same for each CT set?
  - ☐ Is the phase relationship of the current transformers correct?
  - ☐ Is the polarity for current input I_7 correct (if used)?
  - ☐ Is the polarity for current input I_8 correct (if used)?

☐ 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.

  - ☐ Remove the front panel of the device (see Figure 3-5).
  - ☐ Remove the ribbon cable connected to the A–I/O–3 board 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. Carefully connect the ribbon cable. Do not bend any connector pins! Do not use force!
  - ☐ Check continuity for each of the current terminal-pairs again.
  - ☐ 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.

☐ 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 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® 4 operational function if messages are transmitted correctly. Do **not** apply this test feature while the device is in service on a live system!

DANGER!

The transmission and reception of messages via the system (SCADA) interface by means of the testing mode is the real exchange of information between the SIPROTEC®4 device and the substation. Connected equipment such as circuit breakers or disconnectors can be operated as a result of these actions!

Note:

After termination of this test, the device will reboot. All annunciation buffers are erased. If required, these buffers should be extracted with DIGSI® 4 prior to the test.

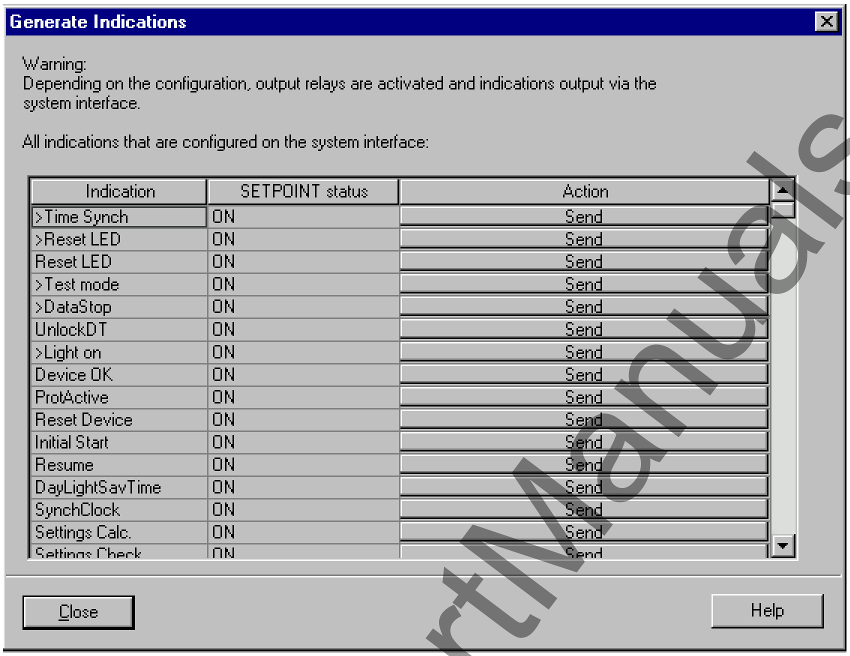
The system interface test is carried out **`Online`** using DIGSI® 4:

- ❑ Double-click on the **`Online`** directory to open the required dialogue 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 3-14).

Structure of the 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 3-14 Dialogue box: Generate indications — example

Changing the Operating State

Clicking for the first time onto one of the field in 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 Message Direction

For all information that is transmitted to the central station the following is to be checked under **SETPOINT status**:

- ❑ Make sure that each checking process is carried out carefully without causing any danger (see above and refer to **DANGER!**).
- ❑ Click on **Send** and check whether the transmitted information reaches the central station and shows the desired reaction.

Exiting the Test Mode

To end the system interface test, click on **Close**. The device is briefly out of service while the processor system starting up. The dialogue box closes.

Test in Command Direction

Information in command direction must be sent by the central station. Check whether the reaction is correct.

3.3.3 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® 4. 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.

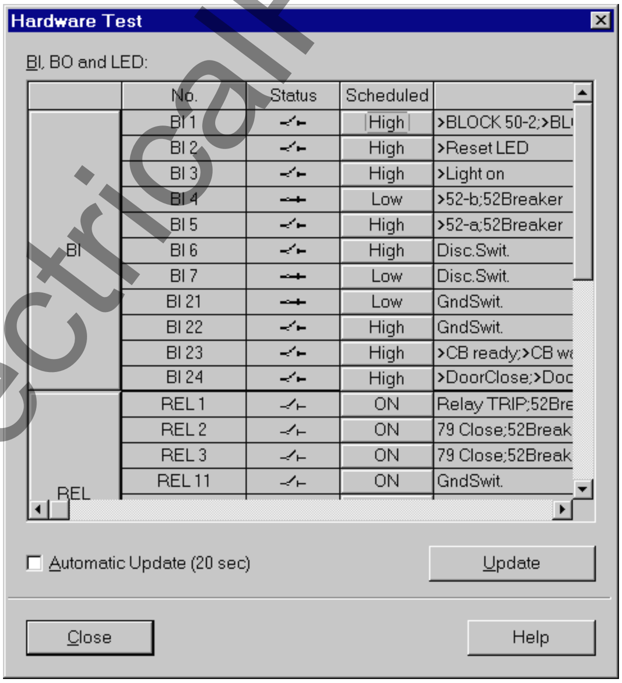
DANGER!

Changing the status of a binary input or output using the test feature of DIGSI® 4 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® 4 prior to the test.

The hardware test can be done using DIGSI® 4 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 3-15).



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 3-15 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 7UT612 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 7UT612 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.

3.3.4 Checking the Setting Consistency

The device 7UT612 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.

In the operational or spontaneous annunciations check if there is any information on inconsistencies. Table 3-10 shows such inconsistency annunciations.

Table 3-10 Annunciations on Inconsistencies

Message	FNo	Description	See Section
Error1A/ 5Awrong	00192	Setting of the rated secondary currents on Input/Output Board A–I/O–3 inconsistent	2.1.2 3.1.3.3
Diff Adap.fact.	05620	The matching factor of the current transformers for differential protection is too great or too small.	2.1.2 2.2
REF Adap.fact.	05836	The matching factor of the current transformers for restricted earth fault protection is too great or too small.	2.1.2
REF Err CTstar	05830*	There is no measuring input assigned for restricted earth fault protection	2.1.1

Table 3-10 Annunciations on Inconsistencies

Message	FNo	Description	See Section
REF Not avalia.	05835*	Restricted earth fault protection is not available for the configured protected object	2.1.1
O/C Ph. Not av.	01860*	Time overcurrent protection for phase currents is not available for the configured protected object	2.1.1
O/C 3I0 Not av.	01861*	Time overcurrent protection for residual current is not available for the configured protected object	2.1.1
I2 Not avalia.	05172*	Unbalanced load protection is not available for the configured protected object	2.1.1
O/L No Th.meas.	01545*	Temperature reception for overload protection is missing (from thermobox)	2.1.1 2.9.3
O/L Not avalia.	01549*	Overload protection is not available for the configured protected object	2.1.1
BkrFail Not av.	01488*	Breaker failure protection is not available for the configured protected object	2.1.1
TripC ProgFail	06864	For trip circuit supervision the number of binary inputs was set incorrectly	2.13.1.4 3.1.2
Fault Configur..	00311	Group indication of fault annunciations marked with "*".	

In the operational or spontaneous annunciations also check if there are any fault annunciations from the device.

3.3.5 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 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 3.3.3). Make sure that the measured currents for breaker failure protection (CTs), the tested circuit breaker, and its auxiliary contact(s) relate to the same 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.
- ☐ Trip command of the circuit breaker failure protection after the delay time **`TRIP-Timer`** (address `7005`).

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 message “`BkrFail ext PU`” (FNo `01457`) must appear in the fault annunciations (trip log) or in the spontaneous messages.
- ☐ Trip command of the circuit breaker failure protection after the delay time **`TRIP-Timer`** (address `7005`).

Reopen the local circuit breaker.

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).

3.3.6 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® 4 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 neede for the browser depends on the poert 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**

The following descriptions refer to read-out using DIGSI® 4.

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.

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 3-16). 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.

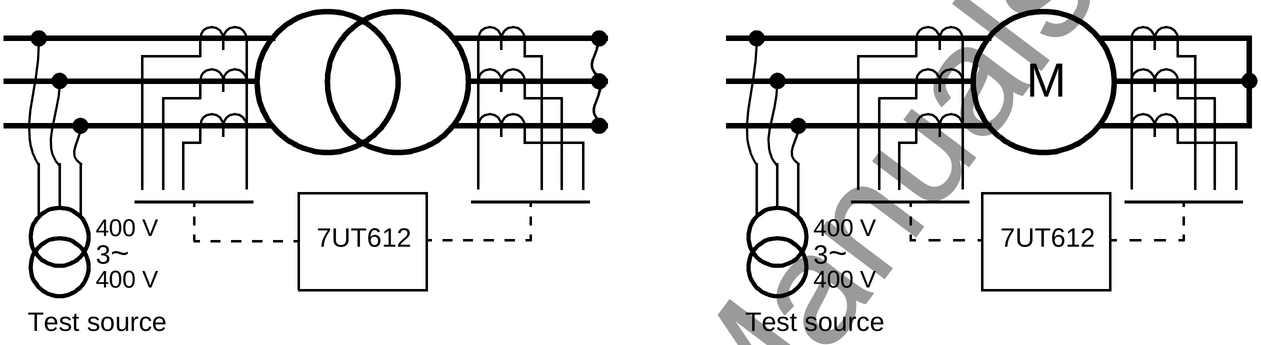


Figure 3-16 Current test with low-voltage test source — examples for a transformer and a motor

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 3-17). The current is produced by a three-pole short-circuit bridge which is installed outside of the protected zone and is capable to carry rated current for a short time.

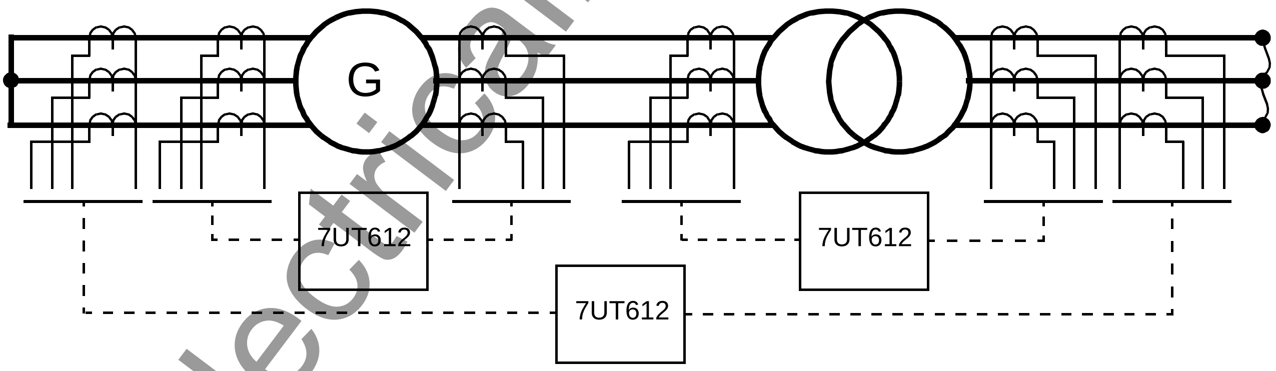


Figure 3-17 Current test in a power station with generator as test source — example

On busbars, branch points, 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. But, 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 3.3.8 (page 240).

Realization of Symmetrical Current Tests

For this commissioning tests, the test current must be at least 2 % of the rated relay current for each phase.

This test cannot replace visual inspection of the correct current transformer connections. Therefore, the inspection according to Section 3.2.2 is a prerequisite.

Since 7UT612 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). Example:
$I_{\mathbf{L1S1}}$ current in phase **L1** on **S**ide **1**.

The following procedure applies to three-phase protected objects. For transformers it is assumed that side 1 is the overvoltage side of the transformer.

☐ 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.

☐ Read out the current magnitudes:

Compare the measured values under **`Measurement`** → **`Secondary Values`** → **`Operational values, secondary`** with the real values:

I_{L1S1} =
I_{L2S1} =
I_{L3S1} =
$3I_{0S1}$ =
I_{L1S2} =
I_{L2S2} =
I_{L3S2} =
$3I_{0S2}$ =

Note: The “IBS Tool” provides comfortable read-out possibilities for all measured values with visualisation using phasor diagrams (Figure 3-18).

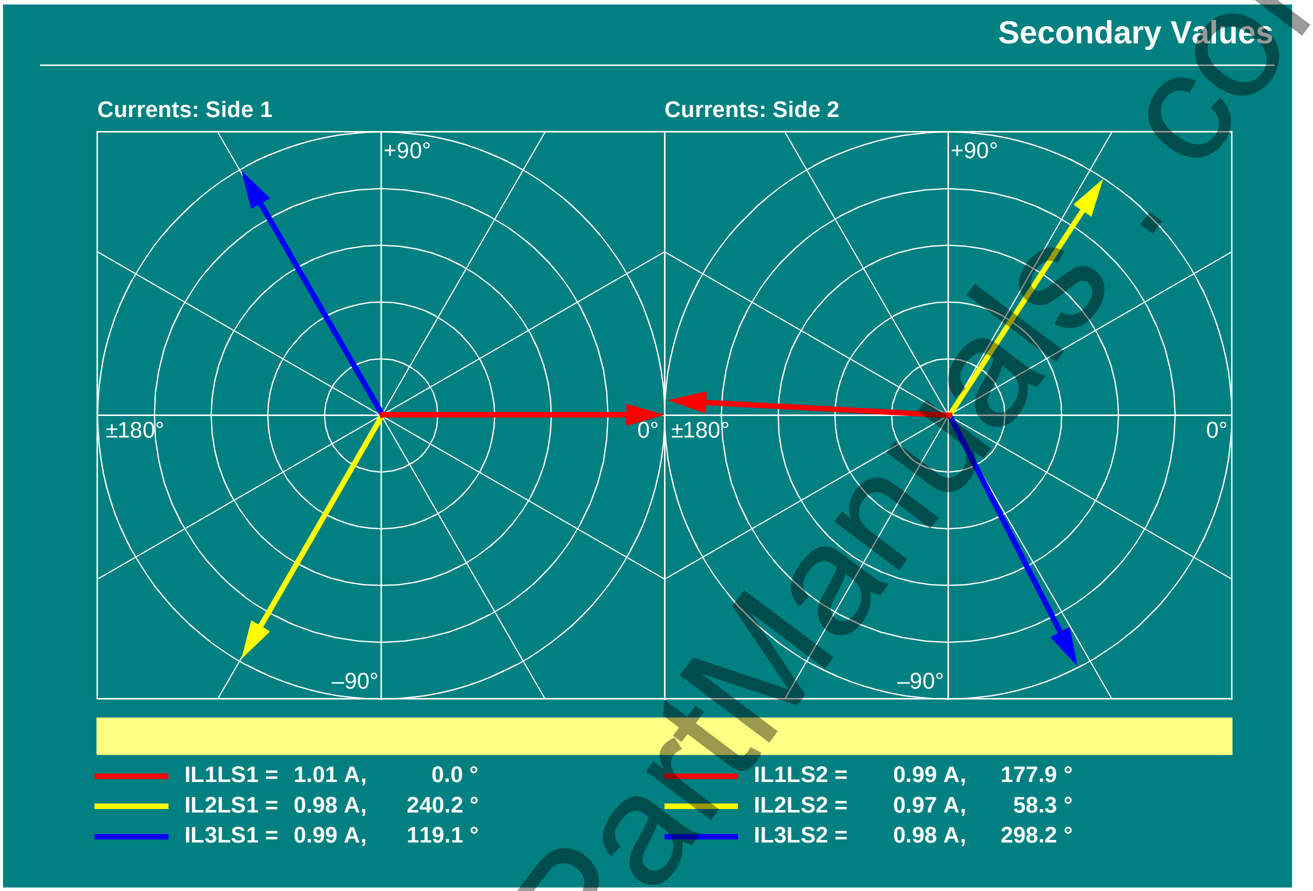
If deviations occur which cannot be explained by measuring tolerances, an error can be assumed in the device connections or in the test arrangement.

☐ Switch off the test source and the protected object (shut down the generator) and earth it.

☐ Re-check the plant connections to the device and the test arrangement and correct them.
If a substantial zero sequence current $3I_0$ occurs one two of the currents of the corresponding side must 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.



🟥	IL1LS1 =	1.01 A,	0.0 °	🟥	IL1LS2 =	0.99 A,	177.9 °
🟨	IL2LS1 =	0.98 A,	240.2 °	🟨	IL2LS2 =	0.97 A,	58.3 °
🟦	IL3LS1 =	0.99 A,	119.1 °	🟦	IL3LS2 =	0.98 A,	298.2 °

Figure 3-18 Measured values on the sides of the protected object — example for through-flowing currents

☐ Phase angle measurement for side 1 with test current:

Read out the phase angles under **`Measurement`** → **`Secondary Values`** → **`Angles`** of side 1 of the protected object. All angles are referred to I_{L1S1}. The following values must result approximately for a clockwise phase rotation:

$\varphi_{L1S1} \approx 0°$
$\varphi_{L2S1} \approx 240°$
$\varphi_{L3S1} \approx 120°$

If the angles are wrong, reverse polarity or swapped phase connections on side 1 of the protected object 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.

❑ Repeat test and re-check the current angles.

☐ Phase angle measurement for side 2 with test current:

Read out the phase angles under **`Measurement`** → **`Secondary Values`** → **`Angles`** of side 2 of the protected object. All angles are referred to I_{L1S1}.

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 side 2, have reversed polarity (180° phase displacement) against the corresponding in-flowing currents at side 1. *Exception:* With transverse differential protection, the currents of the corresponding phase have equal phase!

For clockwise phase rotation, approximately the values according to Table 3-11 result.

Table 3-11 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**
$\varphi_{L1\,S2}$	180°	180°	150°	120°	90°	60°	30°	0°	330°	300°	270°	240°	210°
$\varphi_{L2\,S2}$	60°	60°	30°	0°	330°	300°	270°	240°	210°	180°	150°	120°	90°
$\varphi_{L3\,S2}$	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 side 2.

❑ 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 side 2 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 2.1.2 under margin “Object Data with Transformers”, page 20) under addresses 242, 245, and 246.

❑ If all phase angles differ by 180°, the polarity of the complete CT set for side 2 is wrong. Check and correct the applicable power system data (cf. Subsection 2.1.2 under “Current Transformer Data for 2 Sides”, page 23):
address 201 **STRPNT->OBJ S1** for side 1,
address 206 **STRPNT->OBJ S2** for side 2.

For single-phase busbar protection refer to Subsection 2.1.2 under header margin “Current Transformer Data for Single-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.

❑ Repeat test and re-check the current angles.

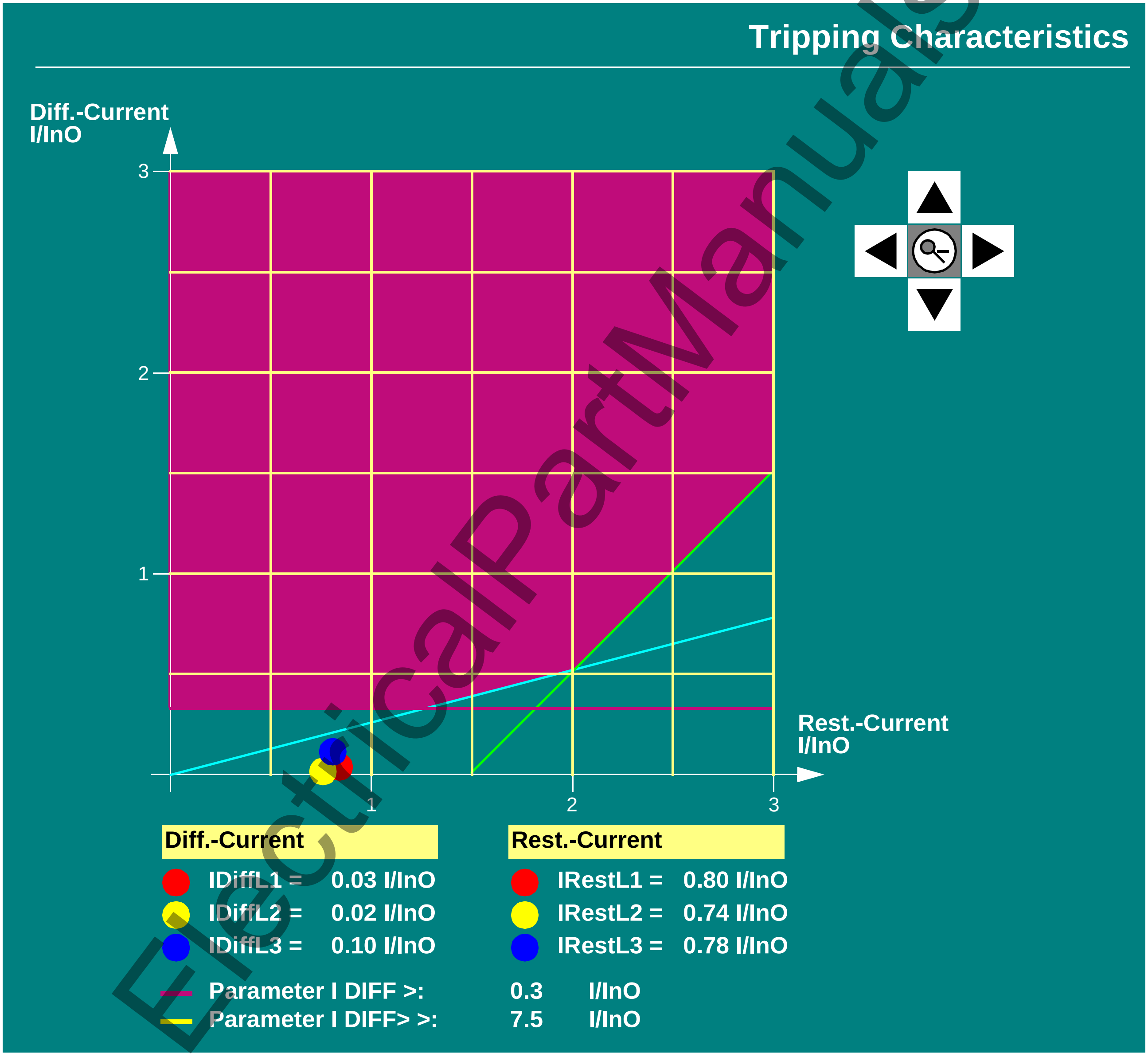
Measuring Differential and Restraint Currents

Before the tests with symmetrical currents 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.

☐ 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 3-19.



Diff.-Current		Rest.-Current	
● IDiffL1 =	0.03 I/InO	● IRestL1 =	0.80 I/InO
● IDiffL2 =	0.02 I/InO	● IRestL2 =	0.74 I/InO
● IDiffL3 =	0.10 I/InO	● IRestL3 =	0.78 I/InO

Parameter I DIFF >:	0.3	I/InO
Parameter I DIFF> >:	7.5	I/InO

Figure 3-19 Differential and restraint currents — example for plausible currents

☐ 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 240, 243 and 249 under “Object Data with Transformers”, (page 20) and addresses 202, 203, 207 and 208 under “Current Transformer Data for 2 Sides” (page 23).
  - – For generators, motors, reactors, addresses 251 and 252 under “Object Data with Generators, Motors and Reactors” (page 22) and addresses 202, 203, 207 and 208 under “Current Transformer Data for 2 Sides” (page 23).
  - – For mini-busbars, address 265 under “Object Data with Mini-Busbars, Branch-Points, Short Lines” (page 22) and addresses 202, 203, 207 and 208 under “Current Transformer Data for 2 Sides” (page 23).
  - – For single-phase busbar protection, addresses 261 and 265 under “Object Data with Busbars with up to 7 Feeders” (page 23) and addresses 212 to 233 under “Current Transformer Data for Single-phase Busbar Protection” (page 25). 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.

3.3.7 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 and if the current between starpoint and earth is available and fed to the current input I_7 of the device.

The polarity of this earth current (starpoint current) at I_7 is essential for zero sequence current correction of the differential protection (increased earth fault sensitivity) and the restricted earth fault protection.

No polarity check is necessary for I_7 (and/or I_8) if only the magnitude of the respective current is processed (e.g. for time overcurrent 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 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 (d–winding or compensating winding). The side which is not included in the tests remains open as the delta winding ensures low-ohmic termination of the current path.

The test arrangement varies with the application. Figures 3-20 to 3-24 show schematic examples of arrangements.

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.

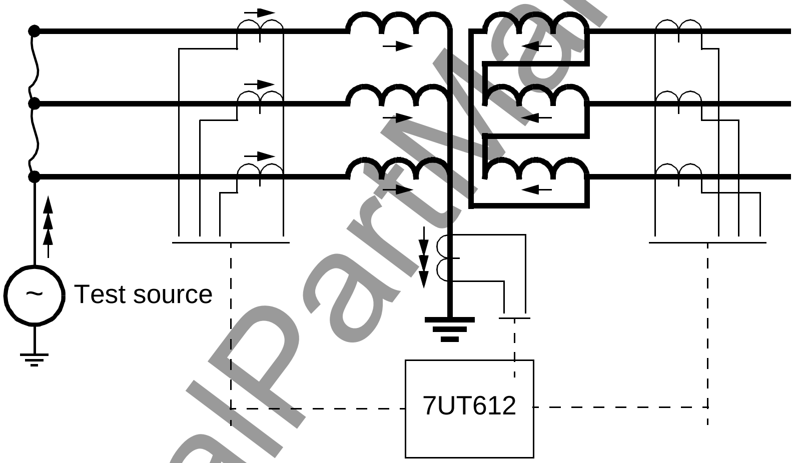


Figure 3-20 Zero sequence current measurement on a star-delta transformer

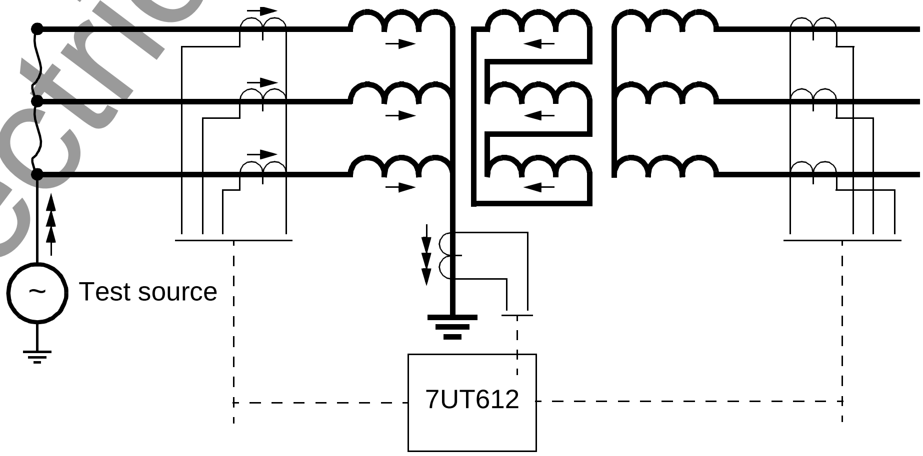


Figure 3-21 Zero sequence current measurement on a star-star transformer with compensation winding

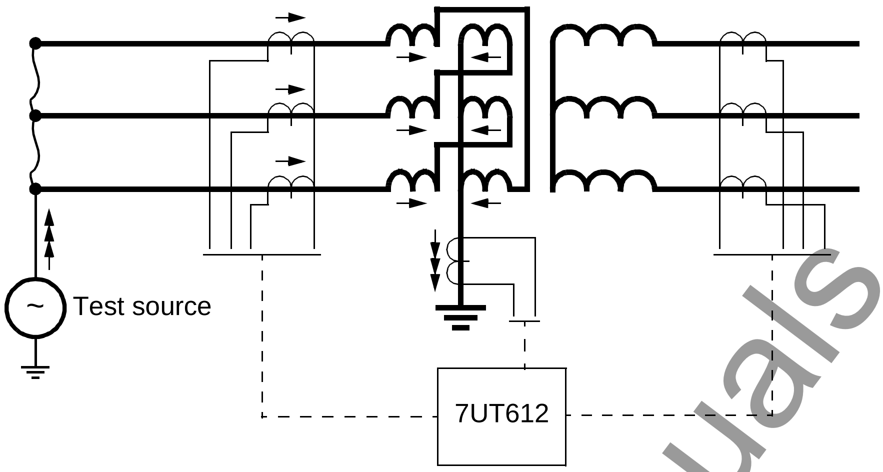


Figure 3-22 Zero sequence current measurement on a zig-zag-winding

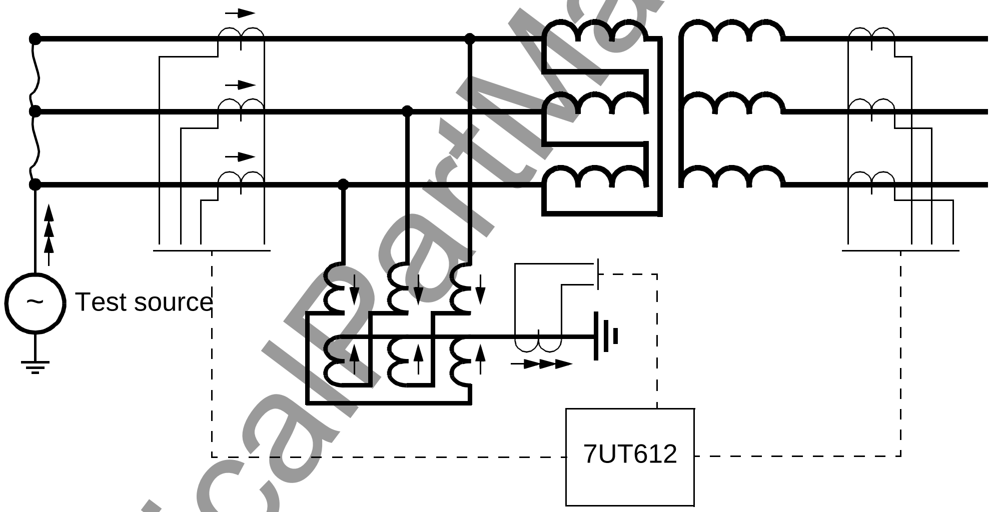


Figure 3-23 Zero sequence current measurement on a delta winding with neutral earthing reactor within the protected zone

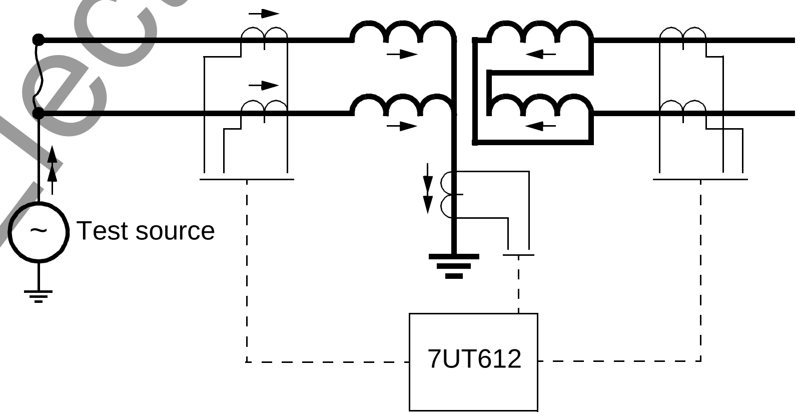


Figure 3-24 Zero sequence current measurement on an earthed single-phase transformer

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.

☐ Read out the current magnitudes under **`Measurement`** → **`Secondary Values`** → **`Operational values, secondary`** and compare them with the real values:

- All phase currents of the tested side correspond to approximately $^1/_3$ of the test current ($^1/_2$ with single-phase transformers).
- $3I_0$ of the tested side corresponds to the test current.
- Phase currents and zero sequence current of the other side are, on transformers, nearly 0.
- Current I_7 correspond to the test current.

Deviation can practically occur only for the current I_7 because the phase currents had been tested already during the symmetrical tests. When deviations are in I_7:

☐ Switch off the test source and the protected object (shut down the generator) and earth it.

☐ Re-check the I_7 connections 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 protected object. This must be considered when they are compared with the test currents.

☐ Switch on test current.

☐ 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 current transformer for I_7. Check the polarity again and compare it with the setting in address 230 **`EARTH. ELECTROD`** (cf. also Subsection 2.1.2 under margin “Current Transformer Data for Current Input I_7” (page 26).

☐ If there is a differential current which does not correspond to twice the test current, the matching factor for I_7 may be incorrect. Check the setting relevant for current matching. These are mainly the data of the protected object (Subsection 2.1.2):

- addresses 241 and 244 under “Object Data with Transformers”, (page 20) and
- addresses 232 and 233 under “Current Transformer Data for Current Input I_7” (page 26).

☐ Check also the differential currents I_{DiffL1}, I_{DiffL2}, I_{DiffL3}.

- ☐ The differential currents of the differential protection must either 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 241 `STARPNT SIDE 1`, 244 `STARPNT SIDE 2`, Subsection 2.1.2 under margin “Object Data with Transformers”, (page 20), as well as
  - the assignment of the starpoint current transformer to the input I_7: address 108 `I7-CT CONNECT.`, Subsection 2.1.1 under “Special Cases” (page 16).
- ☐ 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.

3.3.8 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 3.3.6 “Symmetrical Current Tests on the Protected Object”. Please observe the following 4 notes:

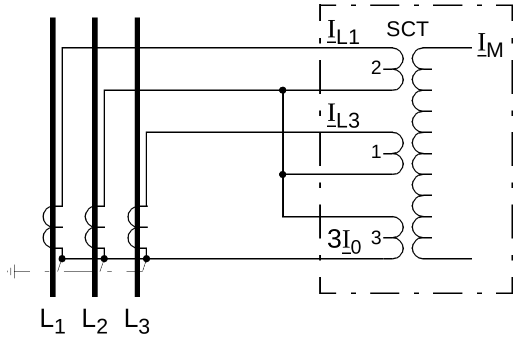
1. Checks are often done with operational currents or primary testing devices. Please take note of all warnings you can find in the sections and be aware of the fact that you will require a backup protection at the supplying point.
2. Checks have to be performed for every current path, beginning with 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 3-25. Figure 3-26 applies for connection L1–L2–L3.

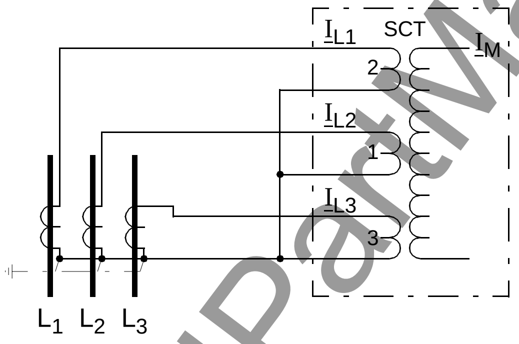
Single-phase primary tests are to be preferred, since they evoke clearer differences in the measured currents. They also detect connecting errors in the earth current path.

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 3-25 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 3-26 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 3-25 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 3-27.

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!

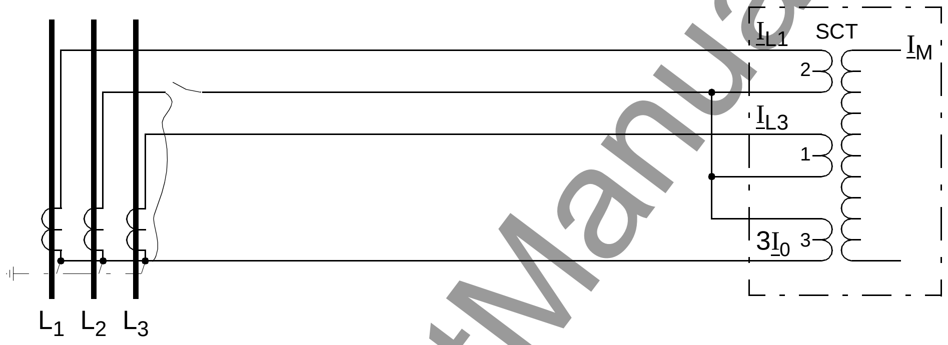


Figure 3-27 Unsymmetrical test with summation CT connection L1–L3–E

The measured current is now 2.65 times the current of the symmetrical test.

This test must be carried out for each summation CT.

3.3.9 Checking for Current Input I_8

Checks concerning the measured current input I_8 extremely depend on how this measuring input is applied.

By any means, the matching factor for the magnitude has to be checked (address 235, see also Subsection 2.1.2, margin heading “Current Transformer Data for Current Input I_8”, page 27). Polarity check is not required since only the current magnitude is detected.

With high-impedance protection the current at I_8 corresponds to the fault current in the protected object. Polarity of all current transformers supplying the resistor, whose current is measured at I_8, must be uniform. Here, traversing currents are used as for differential protection checks. Each current transformer must be included into a measurement. The current at I_8 must not exceed, by no means, the half of the pickup value of the single-phase time overcurrent protection.

3.3.10 Testing User Specified Functions

7UT612 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.

3.3.11 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 7UT612.

Requirements

Along with the capability of recording waveform data during system faults, the 7UT612 also has the capability of capturing the same data when commands are given to the device via the service program DIGSI® 4, 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® 4

To trigger oscillographic recording with DIGSI® 4, 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 3-28.

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.

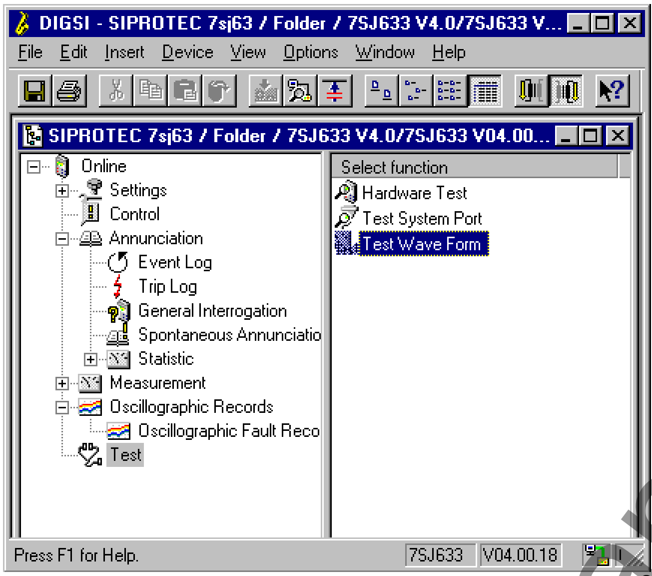


Figure 3-28 Triggering oscillographic recording with DIGSI® 4 — example

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 1261) when trip occurs or when the recorded data show that the second harmonic content does not safely exceed the restraining threshold (address 1261). A further method to increase inrush stability is to set the crossblock function effective or to increase the duration of the crossblock function (address 1262A **CROSSB. 2. HARM**). For further detail refer to Subsection 2.2.7 under “Harmonic Restraint”, page 60).

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 7UT612 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 7UT612 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 / $16^2/_3$ Hz (adjustable)
Current Inputs	Nominal current I_N	1 A or 5 A or 0.1 A (changeable)
	Power consumption per input I_1 to I_7	
	– at I_N = 1 A	approx. 0.02 VA
	– at I_N = 5 A	approx. 0.2 VA
	– at I_N = 0.1 A	approx. 1 mVA
	– for high-sensitivity input I_8 at 1 A	approx. 0.05 VA
	Current overload capability per input I_1 to I_7	
	– thermal (rms)	100 · I_N for 1 s 30 · I_N for 10 s 4 · I_N continuous
	– dynamic (pulse)	1250 A (half cycle)
	Current overload capability for high-sensitivity input I_8	
	– 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 $n' = n \cdot \frac{P_N + P_i}{P' + P_i}$	$n' \geq 4 \cdot \frac{I_{kd\ max}}{I_{N\ prim}}$ for $\tau \leq 100$ ms $n' \geq 5 \cdot \frac{I_{kd\ max}}{I_{N\ prim}}$ for $\tau > 100$ ms
	max. ratio of nominal primary current of the current transformers to nominal object current	$\frac{I_{N prim\ transf}}{I_{N prim\ obj}} \leq \begin{cases} 4 \text{ for phase currents} \\ 8 \text{ for earth current at I7} \end{cases}$

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. 5 W
– energized	approx. 7 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. 6.5 VA
– energized	approx. 8.5 VA
Bridging time for failure/short-circuit of the power supply	≥ 50 ms

4.1.3 Binary Inputs and Outputs

Binary Inputs

Number	3 (allocatable)
Nominal voltage	24 VDC to 250 VDC in 2 ranges, bipolar
Switching thresholds	adjustable with jumpers
– for nominal voltages 24/48 VDC 60/110/125 VDC	U_{pickup} ≥ 19 VDC $U_{dropoff}$ ≤ 14 VDC
– for nominal voltages 110/125/ 220/250 VDC	U_{pickup} ≥ 88 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:		4, each with 1 NO contact (volt-free) (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 NO or NC 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 30 A for 0.5 s
	Permissible total current on common paths	5 A continuous 30 A for 0.5 s

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® 4
	– Transmission speed	min. 4 800 Baud; max. 115200 Baud factory setting: 38400 Baud; parity: 8E1
	– Maximum transmission distance	15 m (50 ft)
Service/Modem Interface (optional)	RS232/RS485/Optical acc. ordered version	isolated interface for data transfer for operation with DIGSI® 4 or connection of a thermobox
	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	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	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	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. 4800 Bd, max. 38400 Bd factory setting: 19200 Bd
	– Maximum transmission distance	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. 4800 Bd, max. 38400 Bd factory setting: 19200 Bd
	– Maximum transmission distance	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	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	at the inclined housing on the case bottom
– Transmission speed recommended:	to 1.5 MBd > 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
– Permissible optical signal attenuation	max. 8 dB using glass fibre 62.5/125 µm
– Maximum transmission distance	1.5 km (1 mile)

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	1000 m (3300 ft)

DNP3.0 Optical

– Connector Type	ST–plug transmitter/receiver
– Connection for flush mounted case	rear panel, mounting location “B”
for surface mounted case	at the inclined housing on the case bottom
– Transmission speed	up to 19200 Bd
– 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 Bd
	– Maximum transmission distance	1000 m (3300 ft)

MODBUS LWL

	– Connector Type	ST–plug transmitter/receiver
	– Connection for flush mounted case for surface mounted case	rear panel, mounting location “B” at the inclined housing on the case bottom
	– Transmission speed	up to 19200 Bd
	– 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)
Time Synchronization	– Signal type	DCF77/IRIG B-Signal
	– Connection for flush mounted case for surface mounted case	rear panel, mounting location “A” 9-pin DSUB socket at the terminal on the case bottom
	– Nominal signal voltages	optional 5 V, 12 V or 24 V
	– Signal level and burden:	

	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) ANSI/IEEE C37.90.0; C37.90.0.1; C37.90.0.2 DIN 57435 Part 303 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 50082–2 (Generic standard) DIN 57435 Part 303
	– High frequency test IEC 60255–22–1, class III and VDE 0435 part 303, 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 class IV and 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, non-modulated IEC 60255–22–3 (report) class III	10 V/m; 27 MHz to 500 MHz
	– Irradiation with HF field, amplitude modulated; IEC 61000–4–3, class III	10 V/m; 80 MHz to 1000 MHz; 80 % AM; 1 kHz
	– Irradiation with HF field, pulse modulated IEC 61000–4–3/ENV 50204, class III	10 V/m; 900 MHz; repetition frequency 200 Hz; duty cycle of 50 %
	– Fast transient disturbance/burst IEC 60255–22–4 and 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, class IV; IEC 60255–6	30 A/m continuous; 300 A/m for 3 s; 50 Hz 0.5 mT; 50 Hz
	– Oscillatory surge withstand capability ANSI/IEEE C37.90.1	2.5 to 3 kV (peak value); 1 to 1.5 MHz decaying wave; 50 surges per s; duration 2 s; R_i = 150 Ω to 200 Ω
	– Fast transient surge withstand capability, ANSI/IEEE C37.90.1	4 kV to 5 kV; 10/150 ns; 50 surges per s; both polarities; duration 2 s; R_i = 80 Ω
	– Radiated electromagnetic interference ANSI/IEEE Std C37.90.2	35 V/m; 25 MHz to 1000 MHz amplitude and pulse modulated

	– Damped oscillations IEC 60694, IEC 61000–4–12	2.5 kV (peak value), polarity alternating; 100 kHz, 1 MHz, 10 MHz and 50 MHz; $R_i = 200\ \Omega$
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

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

4.1.7 Climatic Stress Tests

Ambient Temperatures	Standards:	IEC 60255–6
	– recommended operating temperature	–5 °C to +55 °C (+23 °F to +131 °F)
	– limiting temporary (transient) operating temperature	–20 °C to +70 °C (–4 °F to 158 °F) Visibility of display may be impaired above +55 °C/130 °F in quiescent state, i.e. no pickup and no indications
	– limiting temperature during storage	–25 °C to +55 °C (–13 °F to 131 °F)
	– limiting temperature during transport	–25 °C to +70 °C (–13 °F to 158 °F)
	Storage and transport of the device with factory 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 4.15
Weight (mass), approx.	
– in flush mounted case, size $^1/_2$	5.1 kg (11$^1/_4$ lb)
– in surface mounted case, size $^1/_2$	9.6 kg (21$^1/_4$ lb)
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	$I_{DIFF}>>/I_{Nobj}$	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) – $I_{DIFF}>$ stage and characteristic – $I_{DIFF}>>$ stage		 5 % of set value 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			

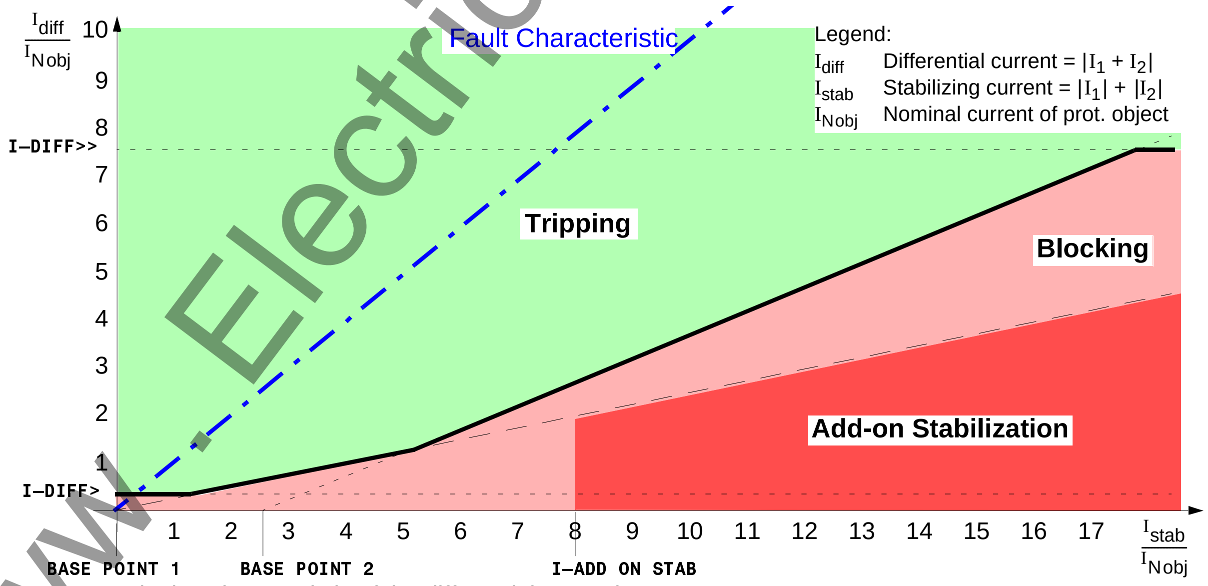


Figure 4-1 Tripping characteristic of the differential protection

4.2.2 Transformers

Harmonic Restraint	Inrush restaint 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 max. action time for Crossblock	can be activated / deactivated 2 to 1000 AC cycles or 0 (crossblock deactivated) or ∞ (active until dropout)	 (steps 1 cycles)

Operating Times Pickup time/dropout time with single-side infeed

Pickup time at frequency	50 Hz	60 Hz	$16^2/_3$ Hz
at 1.5 · setting value I_{DIFF}>	38 ms	35 ms	85 ms
at 1.5 · setting value I_{DIFF}>>	25 ms	22 ms	55 ms
at 5 · setting value I_{DIFF}>>	19 ms	17 ms	25 ms
Dropout time, approx.	35 ms	30 ms	80 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 Frequency influence	$0.9 \leq f/f_N \leq 1.1$ see Figure 4-4	

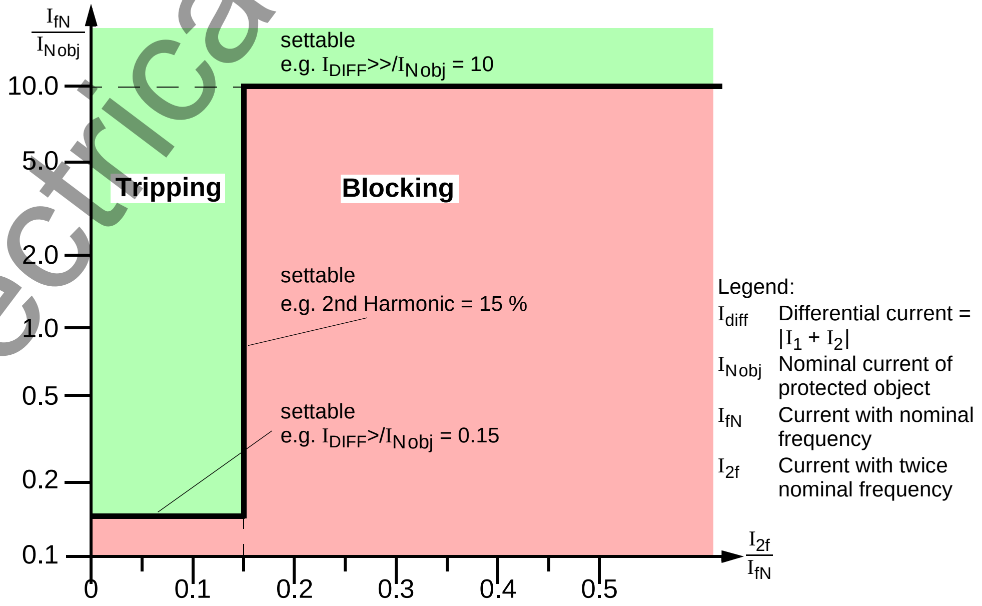


Figure 4-2 Stabilizing influence of 2nd harmonic (transformer protection)

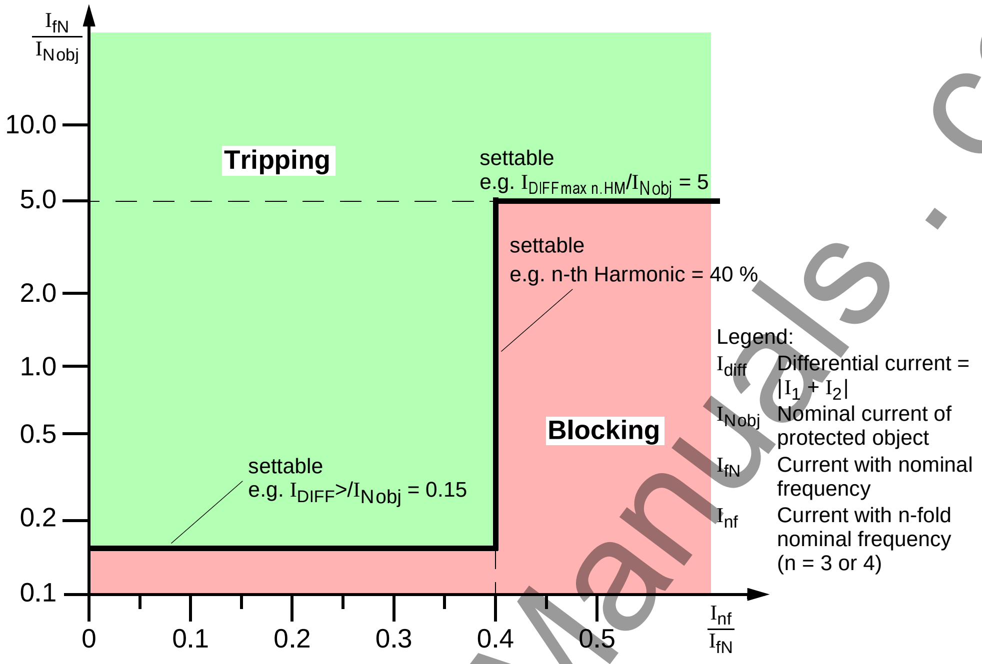


Figure 4-3 Stabilizing influence of n-th harmonic (transformer protection)

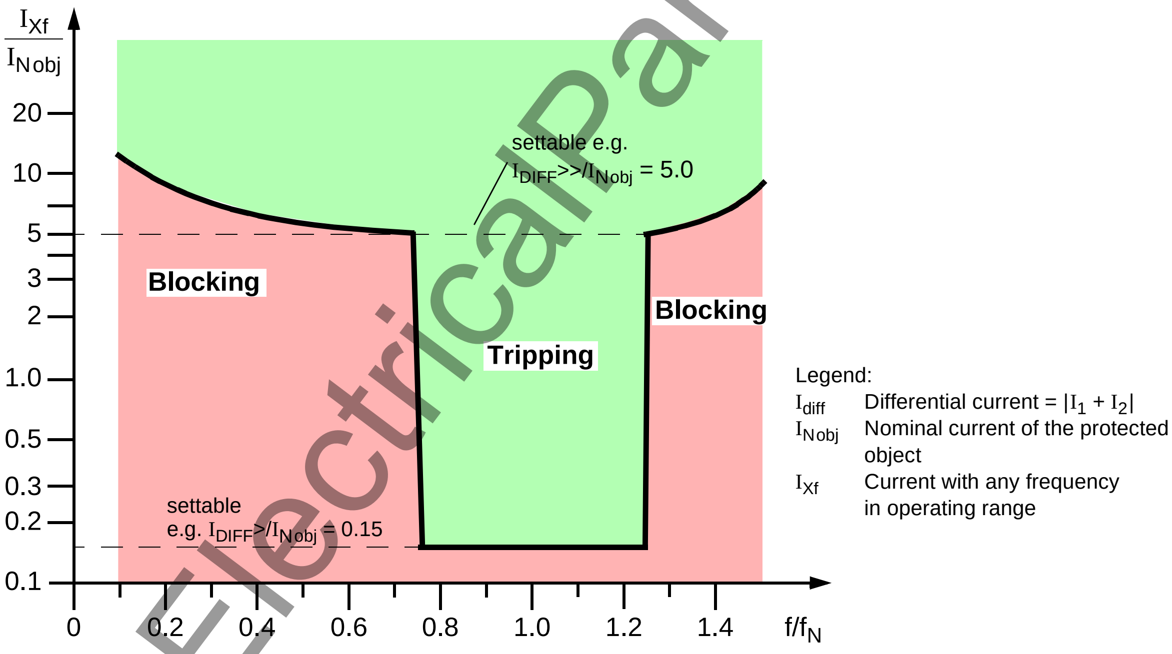


Figure 4-4 Frequency influence (transformer protection)

4.2.3 Generators, Motors, Reactors

Operating Times Pickup time/dropout time with single-side infeed

Pickup time at frequency	50 Hz	60 Hz	$16^2/_3$ Hz
at 1.5 · setting value $I_{DIFF}>$	38 ms	35 ms	85 ms
at 1.5 · setting value $I_{DIFF}>>$	25 ms	22 ms	55 ms
at 5 · setting value $I_{DIFF}>>$	19 ms	17 ms	25 ms
Dropout time, approx.	35 ms	30 ms	80 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

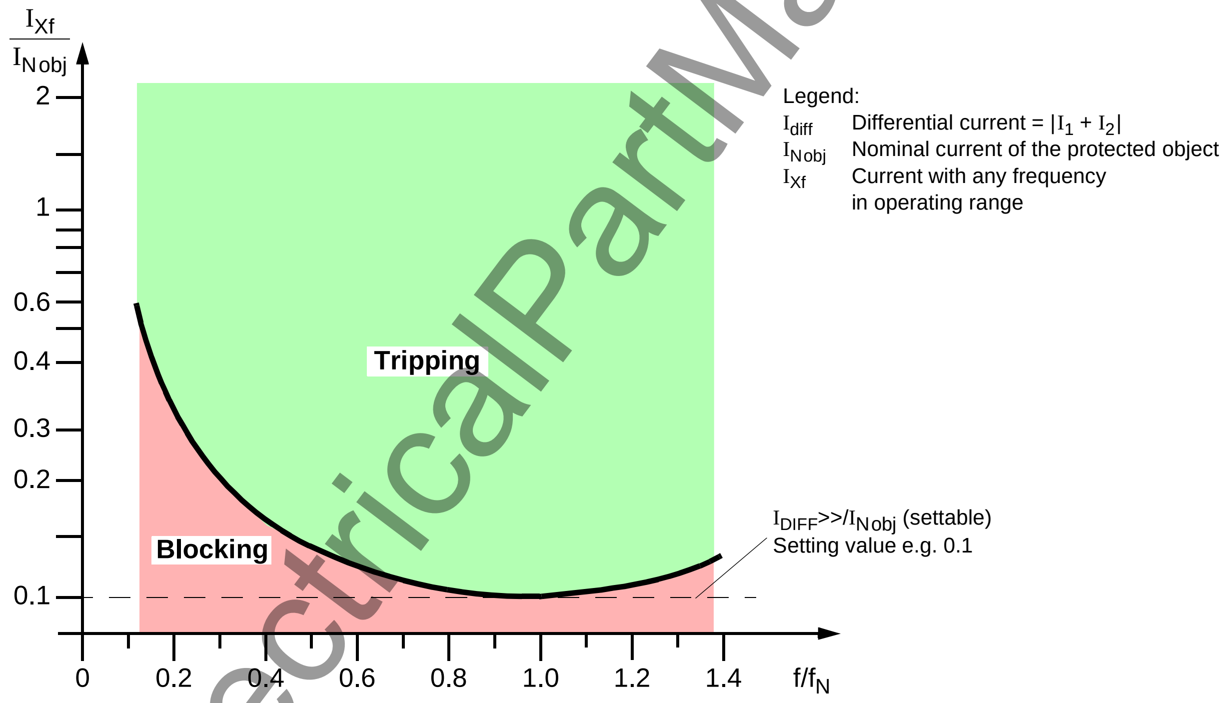


Figure 4-5 Frequency influence (generator / motor protection)

4.2.4 Busbars, Branch-Points, Short Lines

Differencial 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 by 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			
	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	

Pickup time at frequency	50 Hz	60 Hz	$16^2/_3$ Hz
at 1.5 · setting value I_{DIFF}>	25 ms	25 ms	50 ms
at 1.5 · setting value I_{DIFF}>>	20 ms	19 ms	45 ms
at 5 · setting value I_{DIFF}>>	19 ms	17 ms	35 ms
Dropout time, approx.	30 ms	30 ms	70 ms

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}	110° (fix)	
	Trip characteristic		see Figure 4-6	
	Pickup tolerance		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	$16^2/_3$ Hz
at 1.5 · setting value $I_{EDS}>$, approx. at 2.5 · setting value $I_{EDS}>$, approx.	40 ms 37 ms	38 ms 32 ms	100 ms 80 ms
Dropout time, approx.	40 ms	40 ms	80 ms

Dropout ratio, approx. 0.7

Frequency	Frequency influence	1 % in the range $0.9 \le f/f_N \le 1.1$

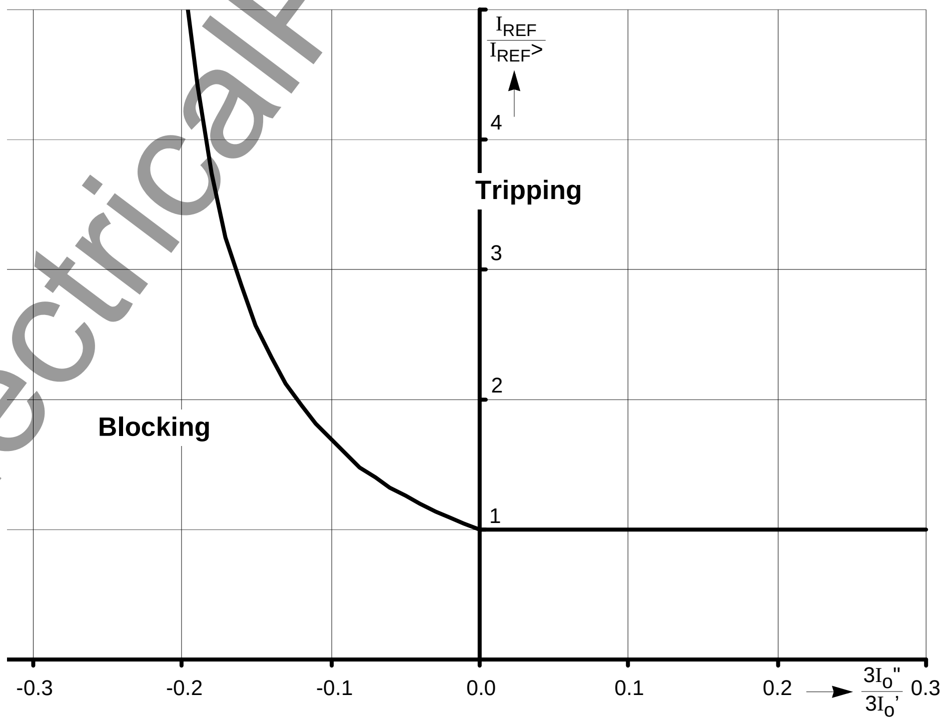


Figure 4-6 Tripping characteristic of the restricted earth fault protection dependent on zero sequence current ratio $3I_0''/3I_0'$ (both current in phase or counter-phase)

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 with definite time	currents times	3 % of set value or 1 % of nominal current 1 % of set value or 10 ms	

Tolerances 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 $f_N = 16^2/_3$ Hz for $2 \le I/I_P \le 20$ and $T_{IP}/s \ge 1$; or $2 \le I/3I_{0P} \le 20$ and $T_{3I0P}/s \ge 1$
(acc. ANSI)	times	5 % ± 15 ms at f_N = 50/60 Hz 5 % ± 45 ms at $f_N = 16^2/_3$ Hz for $2 \le I/I_P \le 20$ and $D_{IP}/s \ge 1$; or $2 \le I/3I_{0P} \le 20$ and $D_{3I0P}/s \ge 1$

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 phase current stages

Pickup time at frequency	50 Hz	60 Hz	$16^2/_3$ Hz
without inrush restraint, min.	20 ms	18 ms	30 ms
without inrush restraint, typical	25 ms	23 ms	45 ms
with inrush restraint, min.	40 ms	35 ms	85 ms
with inrush restraint, typical	45 ms	40 ms	100 ms
Dropout time, typical	30 ms	30 ms	80 ms

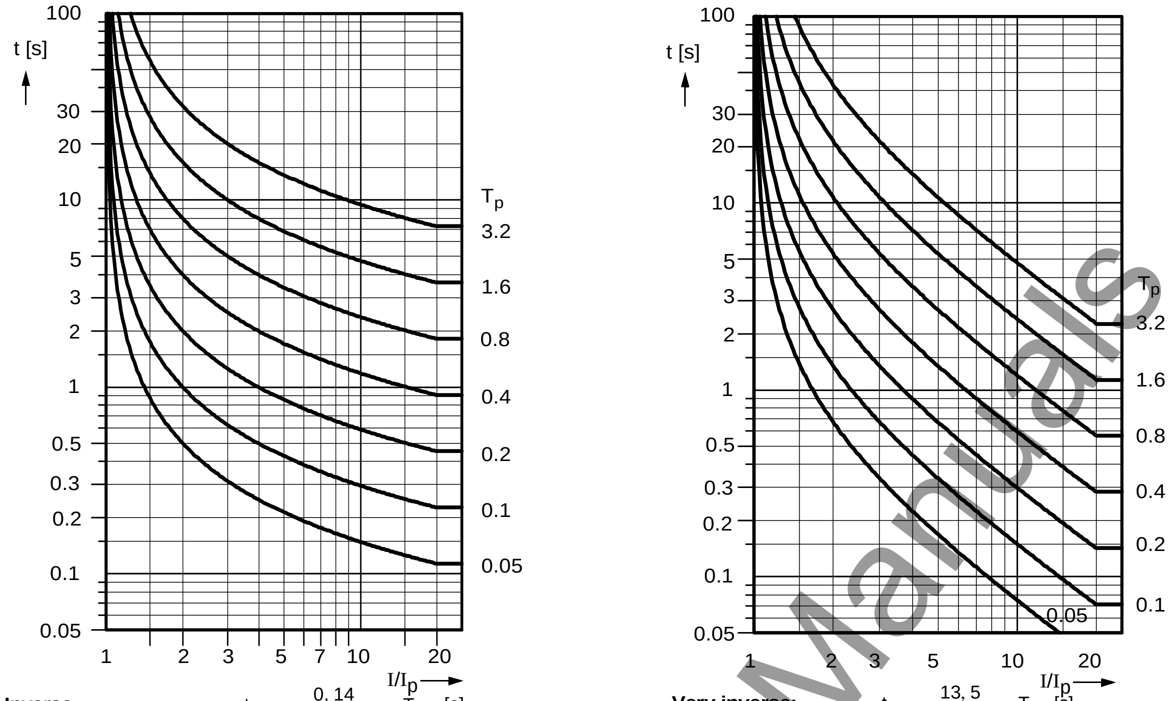
Pickup time/dropout time residual current stages

Pickup time at frequency	50 Hz	60 Hz	$16^2/_3$ Hz
without inrush restraint, min.	40 ms	35 ms	100 ms
without inrush restraint, typical	45 ms	40 ms	105 ms
with inrush restraint, min.	40 ms	35 ms	100 ms
with inrush restraint, typical	45 ms	40 ms	105 ms
Dropout time, typical	30 ms	30 ms	80 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 $0.9 \le f/f_N \le 1.1$

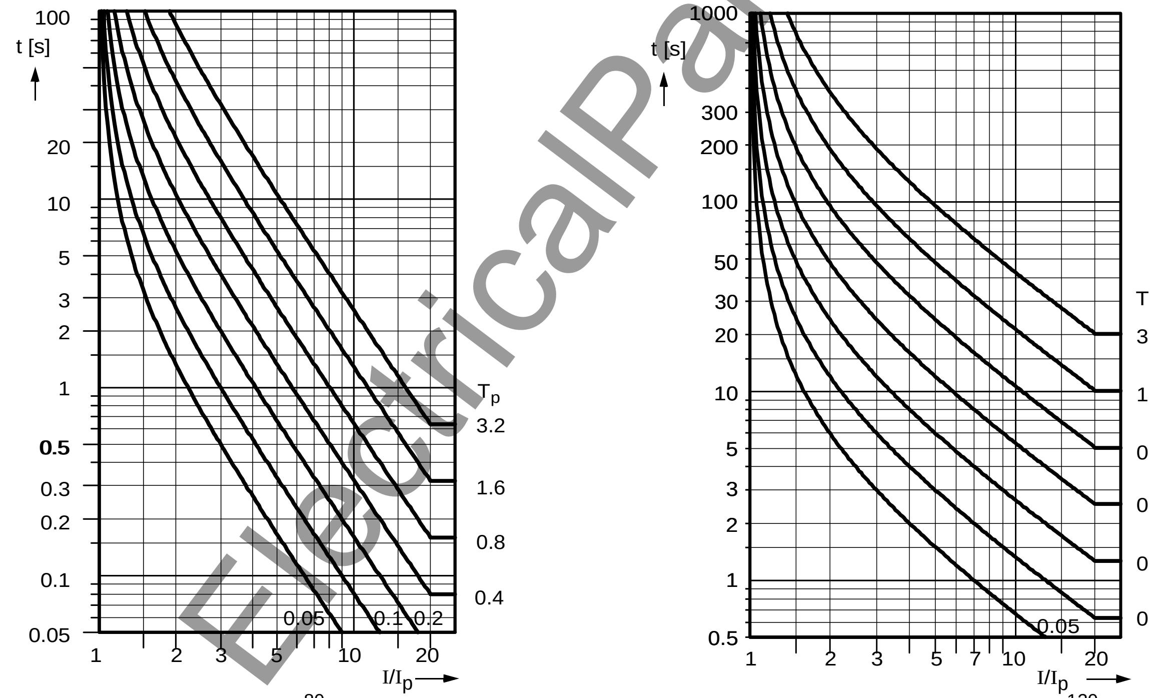


Inverse:
(type A)

$$t = \frac{0,14}{(I/I_p)^{0.02}-1} \cdot T_p \quad [s]$$

Very inverse:
(type B)

$$t = \frac{13,5}{(I/I_p)^{1}-1} \cdot T_p \quad [s]$$



Extremely inverse:
(type C)

$$t = \frac{80}{(I/I_p)^{2}-1} \cdot T_p \quad [s]$$

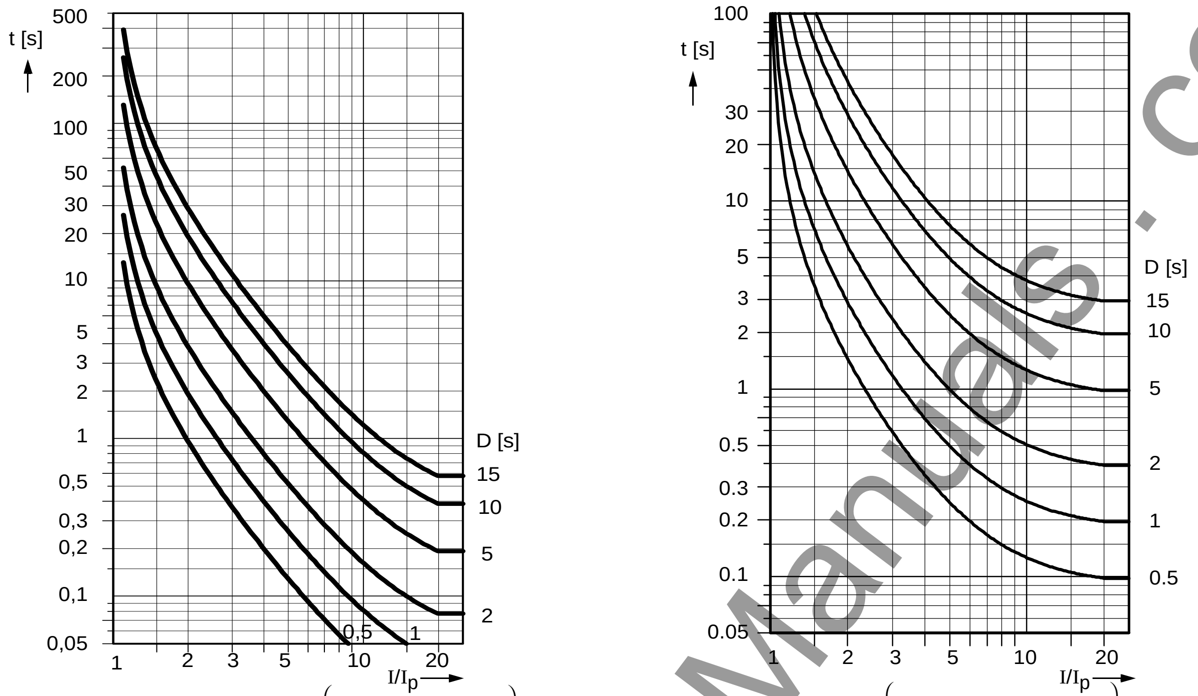
Longtime inverse:
not for unbalanced load protection

$$t = \frac{120}{(I/I_p)^{1}-1} \cdot T_p \quad [s]$$

t	tripping time
T_p	set time multiplier
I	fault current
I_p	set pickup value

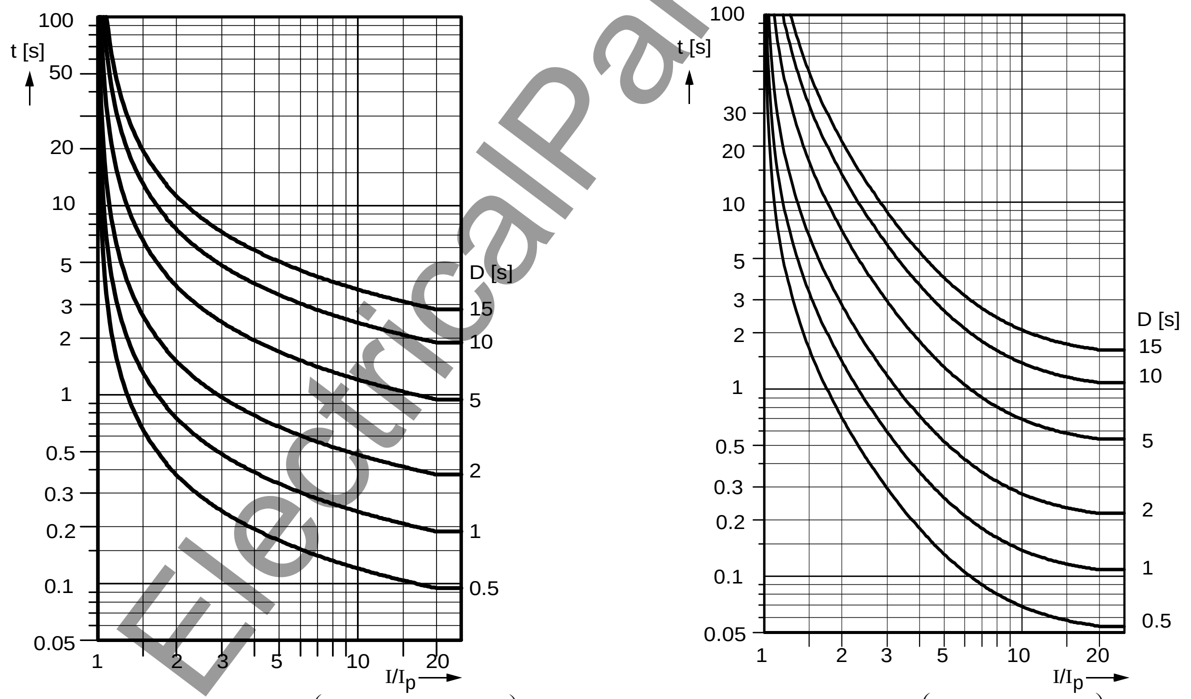
Notes: Shortest trip time for $16^2/_3$ Hz is 100 ms.
For residual current read $3I_{0p}$ instead of I_p and T_{3I0p} instead of T_p
for earth current read I_{Ep} instead of I_p and T_{IEp} instead of T_p
for unbalanced load read I_{2p} instead of I_p and T_{I2p} instead of T_p

Figure 4-7 Trip time characteristics of inverse time overcurrent protection and unbalanced load protection, according IEC



Extremely inverse $t = \left(\frac{5.64}{(I/I_p)^2 - 1} + 0.02434\right) \cdot D \quad [s]$

Inverse $t = \left(\frac{8.9341}{(I/I_p)^{2.0938} - 1} + 0.17966\right) \cdot D \quad [s]$



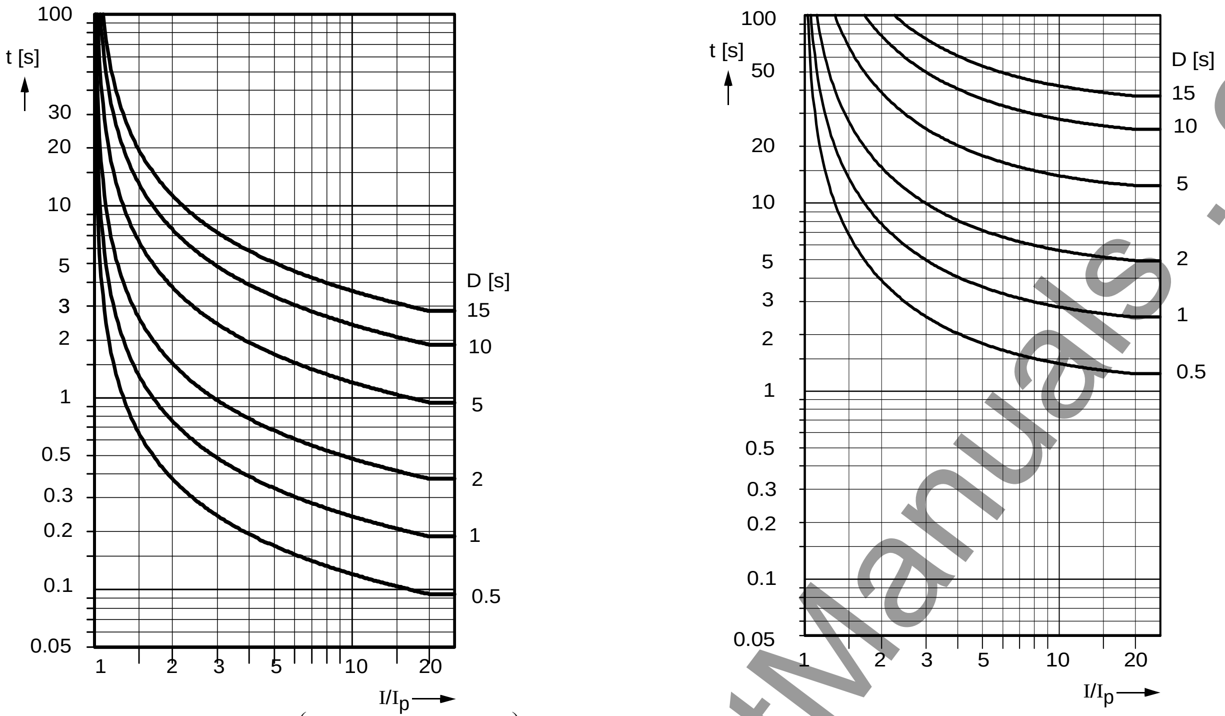
Moderately inverse $t = \left(\frac{0.0103}{(I/I_p)^{0.02} - 1} + 0.0228\right) \cdot D \quad [s]$

Very inverse $t = \left(\frac{3.992}{(I/I_p)^2 - 1} + 0.0982\right) \cdot D \quad [s]$

t	tripping time
D	set time dial
I	fault current
I_p	set pickup value

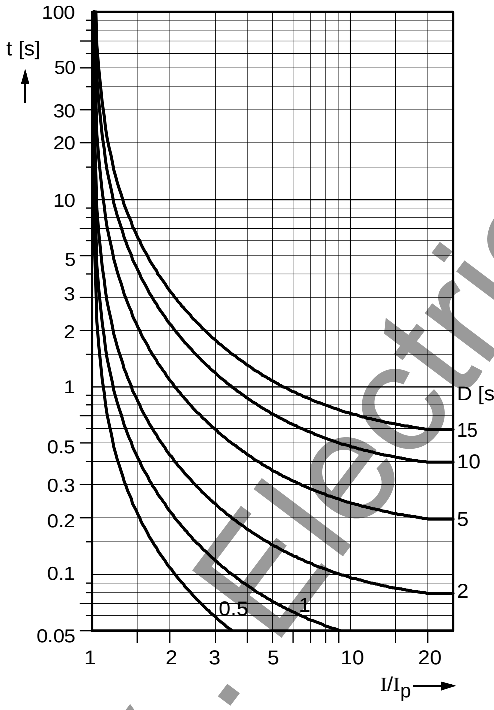
Notes: Shortest trip time for $16^2/_3$ Hz is 100 ms.
For residual current read $3I_{0p}$ instead of I_p
for earth current read I_{Ep} instead of I_p
for unbalanced load read I_{2p} instead of I_p

Figure 4-8 Trip time characteristics of inverse time overcurrent protection and unbalanced load protection, according ANSI/IEEE



Definite inverse $t = \left(\frac{0.4797}{(I/I_p)^{1.5625}-1} + 2.1359\right)\cdot D$ [s]

Long inverse $t = \left(\frac{5.6143}{(I/I_p)-1} + 2.18592\right)\cdot D$ [s]

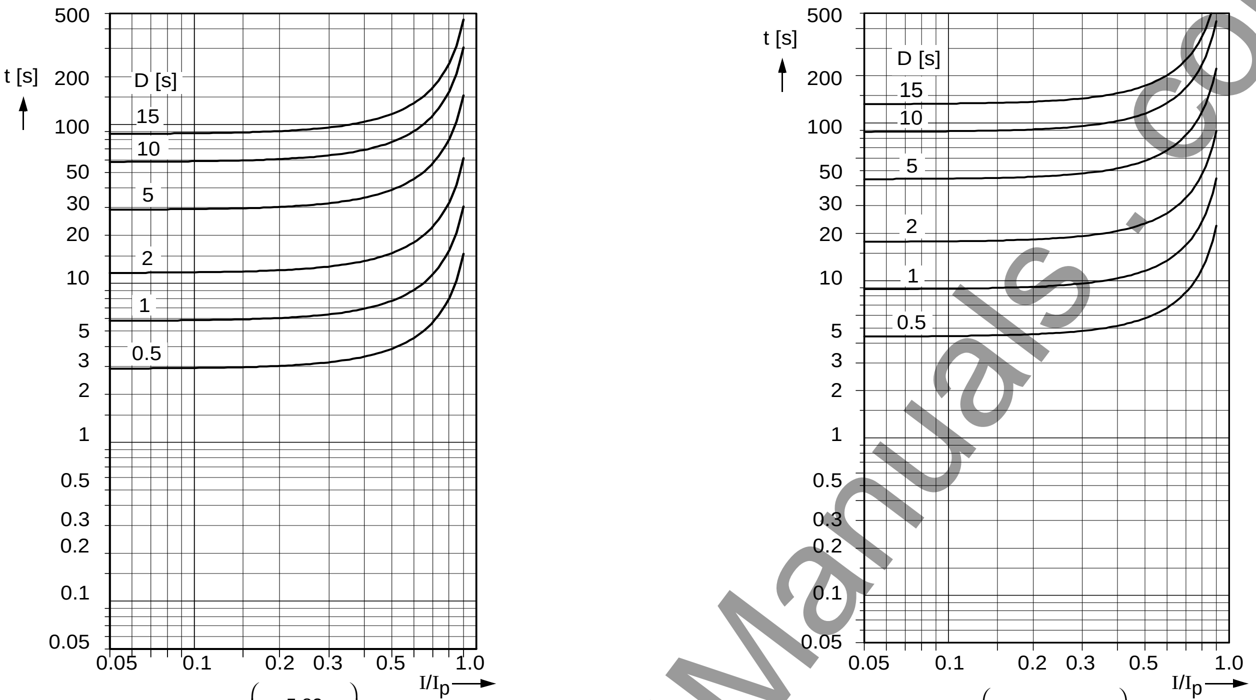


Short inverse $t = \left(\frac{0.2663}{(I/I_p)^{1.2969}-1} + 0.03393\right)\cdot D$ [s]

t	tripping time
D	set time dial
I	fault current
I_p	set pickup value

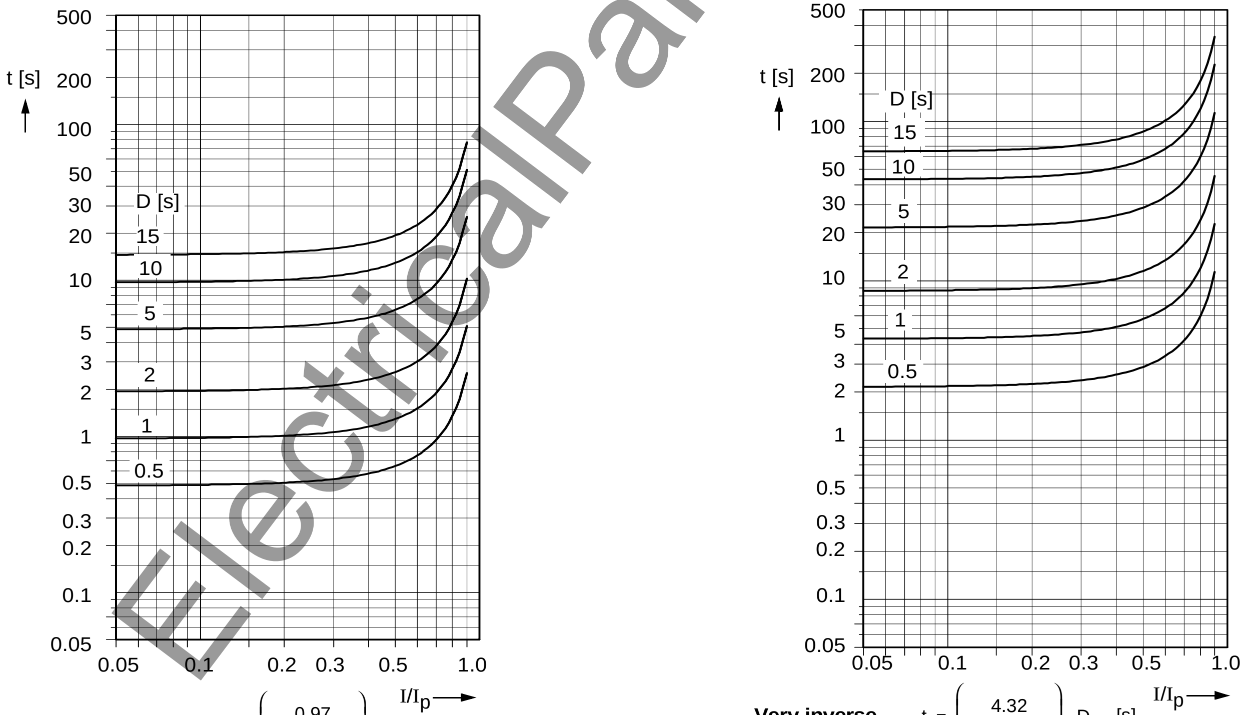
Notes: Shortest trip time for $16^2/_3$ Hz is 100 ms.
For residual current read $3I_{0p}$ instead of I_p
for earth current read I_{Ep} instead of I_p a

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]



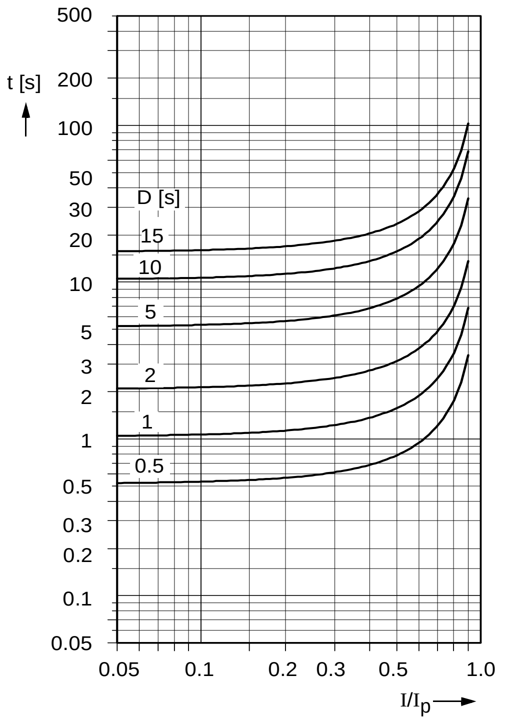
Moderately inverse $t = \left(\frac{0.97}{(I/I_p)^2 - 1}\right) \cdot D$ [s]

Very inverse $t = \left(\frac{4.32}{(I/I_p)^2 - 1}\right) \cdot D$ [s]

t reset time
D set time dial
I interrupted current
I_p set pickup value

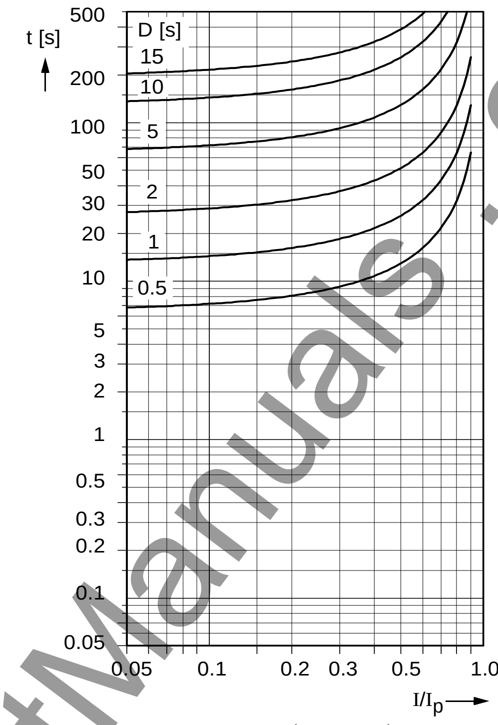
Notes: For residual current read $3I_{0p}$ instead of I_p
for earth current read I_{Ep} instead of I_p
for unbalanced load read I_{2p} instead of I_p

Figure 4-10 Reset time characteristics of inverse time overcurrent protection and unbalanced load protection with disk emulation, according ANSI/IEEE



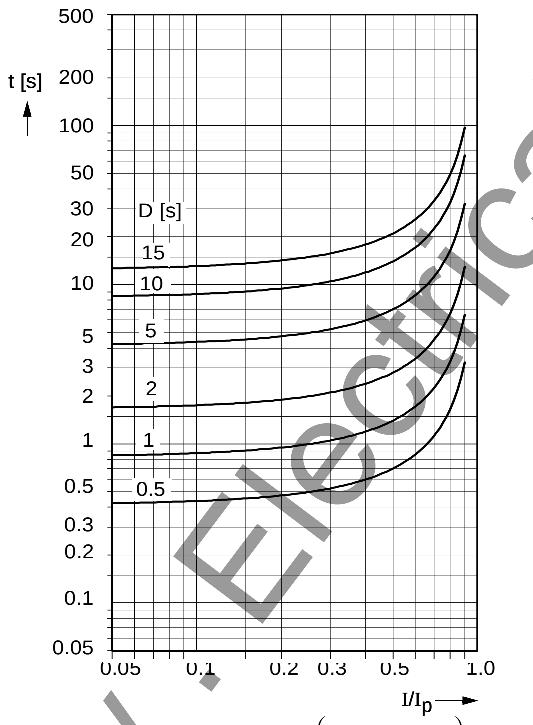
Definite inverse

$$t = \left(\frac{1.0394}{(I/I_p)^{1.5625}-1}\right)\cdot D \quad [s]$$



Long inverse

$$t = \left(\frac{12.9}{(I/I_p)^{1}-1}\right)\cdot D \quad [s]$$



Short inverse

$$t = \left(\frac{0.831}{(I/I_p)^{1.2969}-1}\right)\cdot D \quad [s]$$

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 $1.05 \leq I/I_{EP} \leq 1.15$ 5 % ± 15 ms at f_N = 50/60 Hz 5 % ± 45 ms at $f_N = 16^2/_3$ Hz for $2 \leq I/I_{EP} \leq 20$ and $T_{IEP}/s \geq 1$	
	(acc. ANSI)	times	5 % ± 15 ms at f_N = 50/60 Hz 5 % ± 45 ms at $f_N = 16^2/_3$ Hz for $2 \leq I/I_{EP} \leq 20$ and $D_{IEP}/s \geq 1$	

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	$16^2/_3$ Hz
without inrush restraint, min. without inrush restraint, typical	20 ms 25 ms	18 ms 23 ms	30 ms 45 ms
with inrush restraint, min. with inrush restraint, typical	40 ms 45 ms	35 ms 40 ms	85 ms 100 ms
Dropout time, typical	30 ms	30 ms	80 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	$16^2/_3$ Hz
minimum typical	20 ms 30 ms	18 ms 25 ms	35 ms 80 ms
Dropout time, typical	30 ms	27 ms	80 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 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 ≤ I_2/I_{2P} ≤ 1.15; 5 % ± 15 ms at f_N = 50/60 Hz 5 % ± 45 ms at f_N = $16^2/_3$ Hz for 2 ≤ $I_2/_2I_P$ ≤ 20 and T_{I2P}/s ≥ 1	
	(acc. ANSI)	times	5 % ± 15 ms at f_N = 50/60 Hz 5 % ± 45 ms at f_N = $16^2/_3$ Hz for 2 ≤ $I_2/_2I_P$ ≤ 20 and D_{I2P}/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.

Operating Times of the Definite Time Stages

Pickup time/dropout time

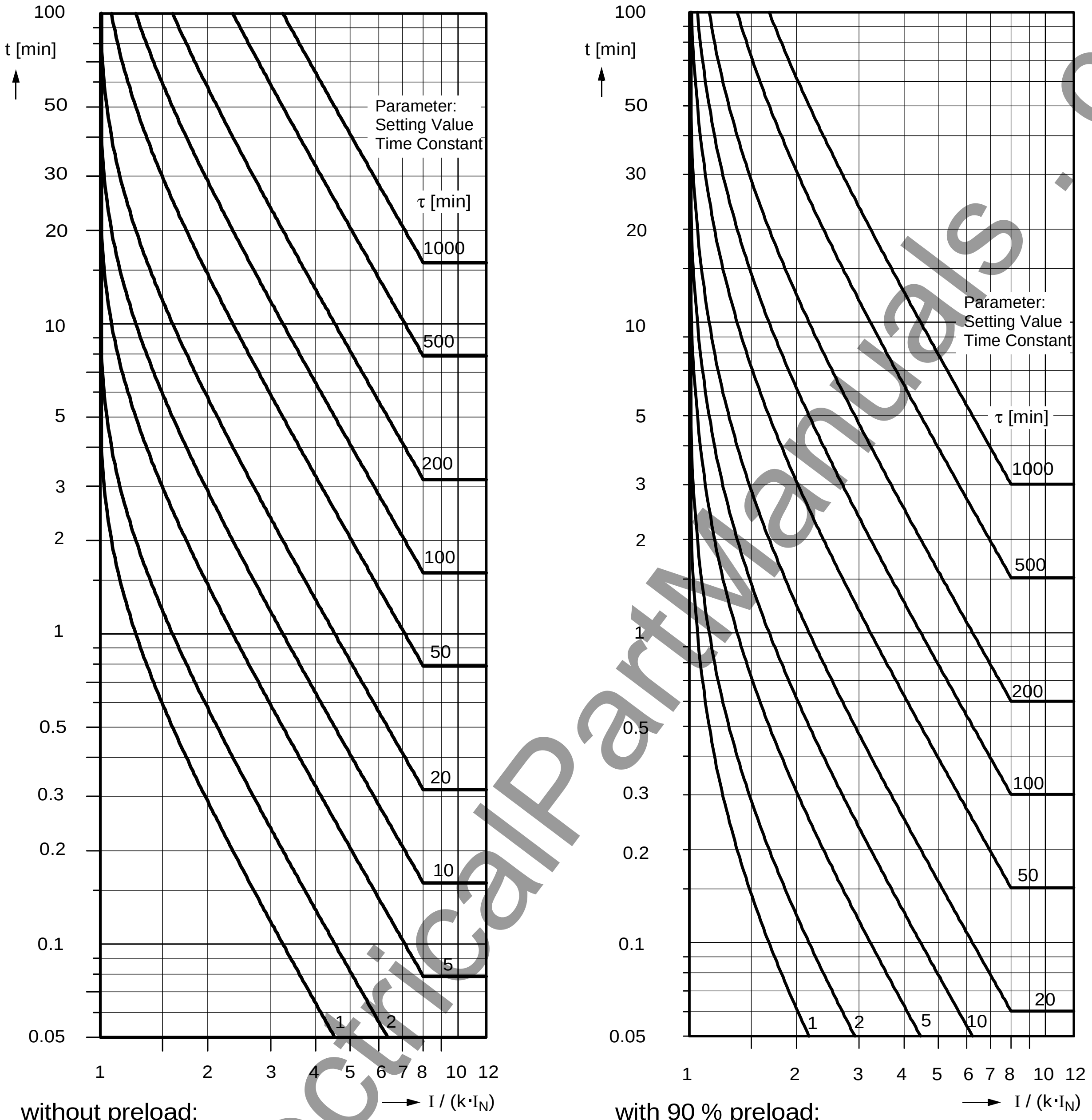
Pickup time at frequency	50 Hz	60 Hz	$16^2/_3$ Hz
minimum typical	50 ms 55 ms	45 ms 50 ms	100 ms 130 ms
Dropout time, typical	30 ms	30 ms	70 ms

Drop-out Ratios	Current stages	approx. 0.95 for I_2/I_N ≥ 0.5
Frequency	Frequency influence	1 % in the range 0.9 ≤ f/f_N ≤ 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 $I/(k \cdot I_N) \le 8$		$t = \tau \cdot ln\frac{\left(\frac{I}{k \cdot I_N}\right)^2 - \left(\frac{I_{pre}}{k \cdot I_N}\right)^2}{\left(\frac{I}{k \cdot I_N}\right)^2 - 1}$	
	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	Referring to $k \cdot I_N$		2 % or 10 mA 1);	class 2 % acc. IEC 60255–8
	Referring to tripping time		3 % or 1 s at f_N = 50/60 Hz 5 % or 1 s at f_N = 16 $^2/_3$ 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 $0.9 \le f/f_N \le 1.1$		1 % at f_N = 50/60 Hz 3 % at f_N = 16 $^2/_3$ Hz	



without preload:

with 90 % preload:

$$t = \tau \cdot ln\frac{\left(\frac{I}{k \cdot I_N}\right)^2}{\left(\frac{I}{k \cdot I_N}\right)^2 - 1} \text{ [min]}$$

$$t = \tau \cdot ln\frac{\left(\frac{I}{k \cdot I_N}\right)^2 - \left(\frac{I_{pre}}{k \cdot I_N}\right)^2}{\left(\frac{I}{k \cdot I_N}\right)^2 - 1} \text{ [min]}$$

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 thermobox (up to 6 measuring points) or from 2 thermoboxes (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	or	98 °C to 140 °C 208 °F to 284 °F	(steps 1 °C) (steps 1 °F)
	Alarm temperature hot-spot	or	98 °C to 140 °C 208 °F to 284 °F	(steps 1 °C) (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 Thermoboxes for Overload Protection

Temperature Detectors	Thermoboxes (connectable)		1 or 2	
	Number of temperature detectors per thermobox		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)	or	–50 °C to 250 °C –58 °F to 482 °F or ∞ (no warning)	(steps 1 °C) (steps 1 °F)
	Alarm temperature (stage 2)	or	–50 °C to 250 °C –58 °F to 482 °F or ∞ (no alarm)	(steps 1 °C) (steps 1 °F)

4.11 Circuit Breaker Failure Protection

Circuit Breaker Supervision	Current flow monitoring	0.04 A to 1.00 A 1) (steps 0.01 A) for the respective side
	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. 20 ms after switch-on of measured quantities, f_N = 50/60 Hz; approx. 60 ms after switch-on of measured quantities, $f_N = 16\,^2/_3$ Hz
	Reset time (incl. output relay)	≤30 ms at f_N = 50/60 Hz, ≤90 ms at $f_N = 16\,^2/_3$ 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

4.12 External Trip Commands

Binary Inputs for Direct Tripping	Number	2
	Operating time	approx. 12.5 ms min. approx. 25 ms typical
	Dropout time	approx. 25 ms
	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

4.13 Monitoring Functions

Measured Quantities	Current symmetry (for each side)	$\lvert I_{min}\rvert / \lvert I_{max}\rvert <$ **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)
	Phase rotation	$\underline{I}_{L1}$ before $\underline{I}_{L2}$ before $\underline{I}_{L3}$ (clockwise) or $\underline{I}_{L1}$ before $\underline{I}_{L3}$ before $\underline{I}_{L2}$ (counter-clockwise) if $\lvert\underline{I}_{L1}\rvert, \lvert\underline{I}_{L2}\rvert, \lvert\underline{I}_{L3}\rvert > 0.5\ I_N$	
Trip Circuit Supervision	Number of supervised trip circuits	1	
	Operation of each trip circuit	with 1 binary input or with 2 binary inputs	

1) Secondary values based on $I_N = 1$ A; for $I_N = 5$ A they must be multiplied by 5.

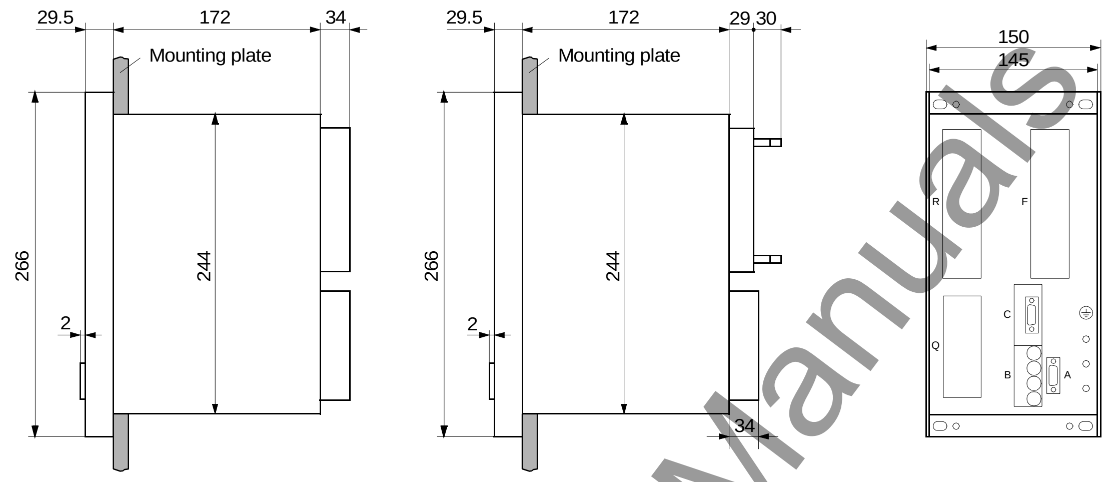
4.14 Ancillary Functions

Operational Measured Values	Operational measured values of currents	I_{L1}; I_{L2}; I_{L3}
	3-phase for each side	in A primary and secondary and % of I_{Nobj}
	– 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 secondary and % of I_{Nobj}
	– Tolerance	2 % of measured value or 2 % of I_N
	Operational measured values of currents	I_1 to I_7;
	1-phase for each feeder	in A primary and secondary and % of I_{Nobj}
	– Tolerance	2 % of measured value or 2 % of I_N
	Operational measured values of currents	I_8
	for high-sensitivity input	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 side	referred to $\varphi(I_{L1})$
	– Tolerance	1° at rated current
	Phase angles of currents	$\varphi(I_{L1})$ to $\varphi(I_{L7})$ in °
	1-phase for each feeder	referred to $\varphi(I_{L1})$
	– Tolerance	1° at rated current
	Operational measured values	f
	of frequency	in Hz and % of f_N
	– Range	10 Hz to 75 Hz
	– Tolerance	1 % within range f_N ±10 % at $I = I_N$
	Operational measured values of power	S (apparent power)
	with applied or nominal voltage	in kVA; MVA; GVA primary
	Operational measured values	Θ_{L1}; Θ_{L2}; Θ_{L3}; Θ_{res}
	for thermal value	referred to tripping temperature rise Θ_{trip}
	Operational measured values	Θ_{RTD1} to Θ_{RTD12}
	(Temperature acc. IEC 60354)	in °C or °F
		relative aging rate, load reserve
	Measured values of	
	differential protection	I_{DIFFL1}; I_{DIFFL2}; I_{DIFFL3};
		I_{RESTL1}; I_{RESTL2}; I_{RESTL3}
		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 ($16^2/_3$ Hz)
	Measured values of	$I_{diffREF}$; $I_{RestREF}$
	restricted earth fault protection	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 ($16^2/_3$ Hz)
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	1.67 ms
	Sampling rate at f_N = 60 Hz	1.83 ms
	Sampling rate at f_N = $16^2/_3$ Hz	5 ms
Statistics	Number of trip events caused by 7UT612	
	Total of interrupted currents caused by 7UT612	segregated for each pole and each side
	Operating hours	Up to 7 decimal digits
	criterion	Excess of current threshold (**Breaker S1 I>** or **Breaker S2 I>**)
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
	Logic function with input margin	6 TICKS
	Logical function 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)	1200 TICKS
	PLC1_BEARB (slow PLC processing)	255 TICKS
	PLC_BEARB (fast PLC processing)	90 TICKS
	SFS_BEARB (switchgear interlocking)	1000 TICKS

4.15 Dimensions

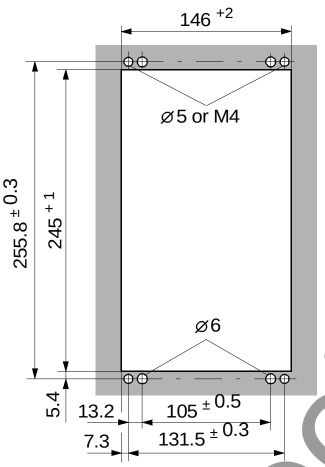
Housing for Panel Flush Mounting or Cubicle Installation



Side View (with screwed terminals)

Side View (with plug-in terminals)

Rear View



Dimensions in mm

Panel Cut-Out

Figure 4-13 Dimensions 7UT612 for panel flush mounting or cubicle installation

Housing for Panel Surface Mounting

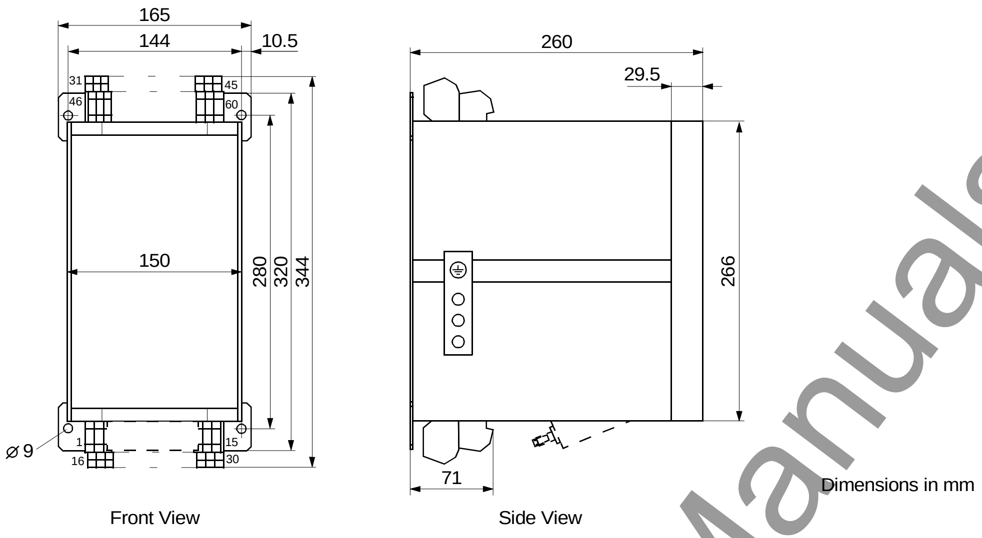


Figure 4-14 Dimensions 7UT612 for panel surface mounting

Thermobox

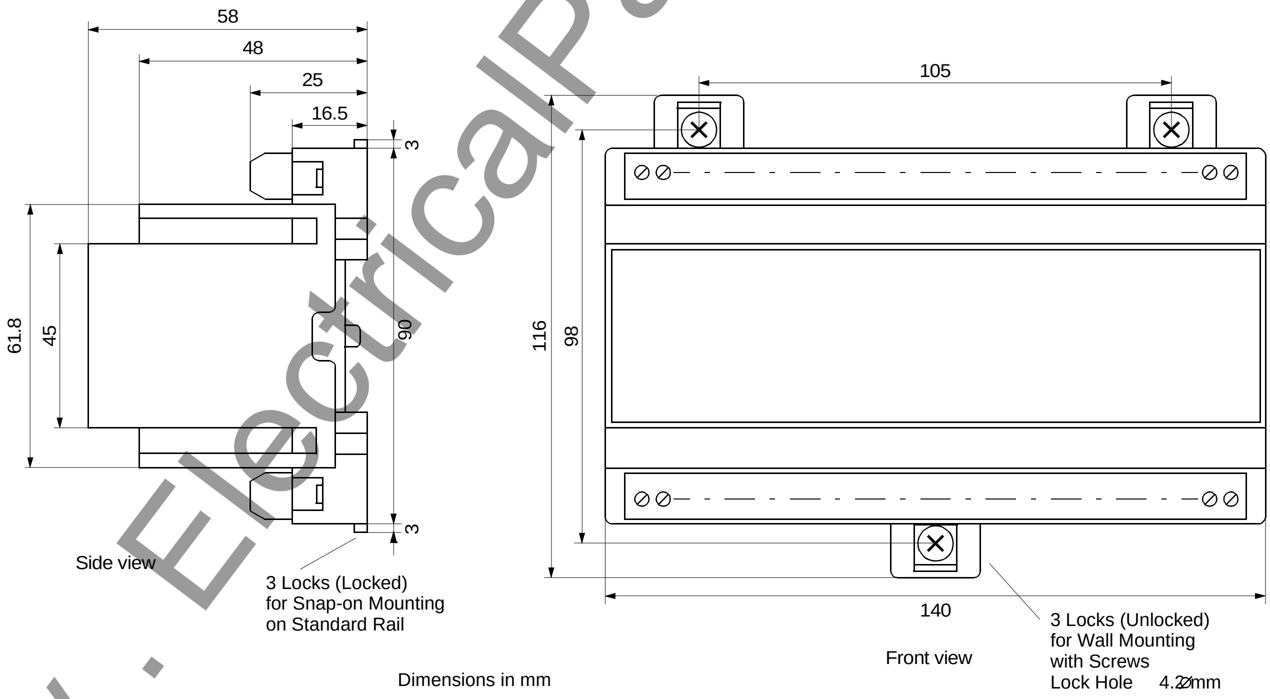


Figure 4-15 Dimensions Thermobox 7XV5662–∗AD10–0000

■

Appendix

A

This appendix is primarily a reference for the experienced user. This Chapter provides ordering information for the models of 7UT612. General diagrams indicating the terminal connections of the 7UT612 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 7UT612 equipped with all options are provided.

A.1 Ordering Information and Accessories

	7		8	9	10	11	12		13	14	15	16
Differential Protection **7UT612**	☐	–	☐	☐	☐	☐	☐	–	☐	☐	**A**	**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, $^{1}/_{3}$ × 19", 3 BI, 4 BO, 1 life contact	B
Flush mounting housing with plug-in terminals, $^{1}/_{3}$ × 19", 3 BI, 4 BO, 1 life contact	D
Flush mounting housing with screwed terminals, $^{1}/_{3}$ × 19", 3 BI, 4 BO, 1 life contact	E

Region-Specific Default / Language Settings and Function Versions

Region GE, 50/60 Hz, 16 $^{2}/_{3}$ Hz, language German (language can be changed)	A
Region world, 50/60 Hz, 16 $^{2}/_{3}$ 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 $^{2}/_{3}$ 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	5
Profibus FMS Slave, optical, double-ring, ST-connector	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	B
Modbus, RS485	D
Modbus, optical 820 nm, ST-connector	E
DNP, RS485	G
DNP, optical 820 nm, ST–connector	H

DIGSI / Modem Interface / Thermobox (Port C)

No DIGSI interface on the rear side	0
DIGSI / Modem, electrical RS232	1
DIGSI / Modem / Thermobox, electrical RS485	2
DIGSI / Modem / Thermobox, optical 820 nm, ST-connector	3

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

see page A-3

	7		8	9	10	11	12		13	14	15	16
Differential Protection **7UT612**	☐	–	☐	☐	☐	☐	☐	–	☐	☐	**A**	**0**

Functionality		
Measured Values		
Basic measured values	1	
Basic measured values, transformer monitoring functions (connection to thermobox / hot spot, overload factor)	4	
Differential Protection + Basic Functions		A
Differential protection for transformer, generator, motor, busbar (87) Overload protection according to IEC for 1 winding (49) 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 Functions		B
Restricted earth fault protection, low impedance (87G) Restricted earth fault protection, high impedance (87G without resistor and varistor), O/C 1-phase Trip circuit supervision (74TC) Unbalanced load protection (46) Breaker failure protection (50BF) High-sensitivity time overcurrent protection / tank leakage protection (64), O/C 1-phase		

Ordering example: 7UT6121–4EA91–1AA0 +L0A

Differential protection
here: pos. 11 = 9 pointing at L0A, i.e. version with Profibus-interface DP Slave, RS485

A.1.1 Accessories

Thermobox

For up to 6 temperature measuring points (at most 2 devices can be connected to 7UT612)

Name	Order No.
Thermobox, U_N = 24 to 60 V AC/DC	7XV5662–2AD10
Thermobox, U_N = 90 to 240 V AC/DC	7XV5662–5AD10

Matching / Summation Transformer

For single-phase busbar connection

Name	Order No.
Matching / summation transformer I_N = 1 A	4AM5120–3DA00–0AN2
Matching / summation transformer I_N = 5 A	4AM5120–4DA00–0AN2

Interface Modules

Exchange interface modules

Name	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 for purpose / terminal type	Order No.
Voltage block, 18 terminal, 12 terminal	C73334-A1–C34–1
Current block,12 terminal, 8 terminal	C73334-A1–C33–1

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

Name	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® 4.

Interface cable between PC or SIPROTEC device	Order No.
Cable with 9-pin male / female connections	7XV5100–4

Operating Software DIGSI® 4

Software for setting and operating SIPROTEC® 4 devices

Operating Software DIGSI® 4	Order No.
DIGSI® 4, basic version with license for 10 computers	7XS5400–0AA00
DIGSI® 4, 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® 4

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® 4)

Graphic Tools 4	Order No.
Full version with license for 10 machines	7XS5430–0AA0

DIGSI REMOTE 4

Software for remotely operating protection devices via a modem (and possibly a star connector) using DIGSI® 4. (Option package for the complete version of DIGSI® 4).

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® 4).

SIMATIC CFC 4	Order No.
Full version with license for 10 machines	7XS5450–0AA0

Varistor

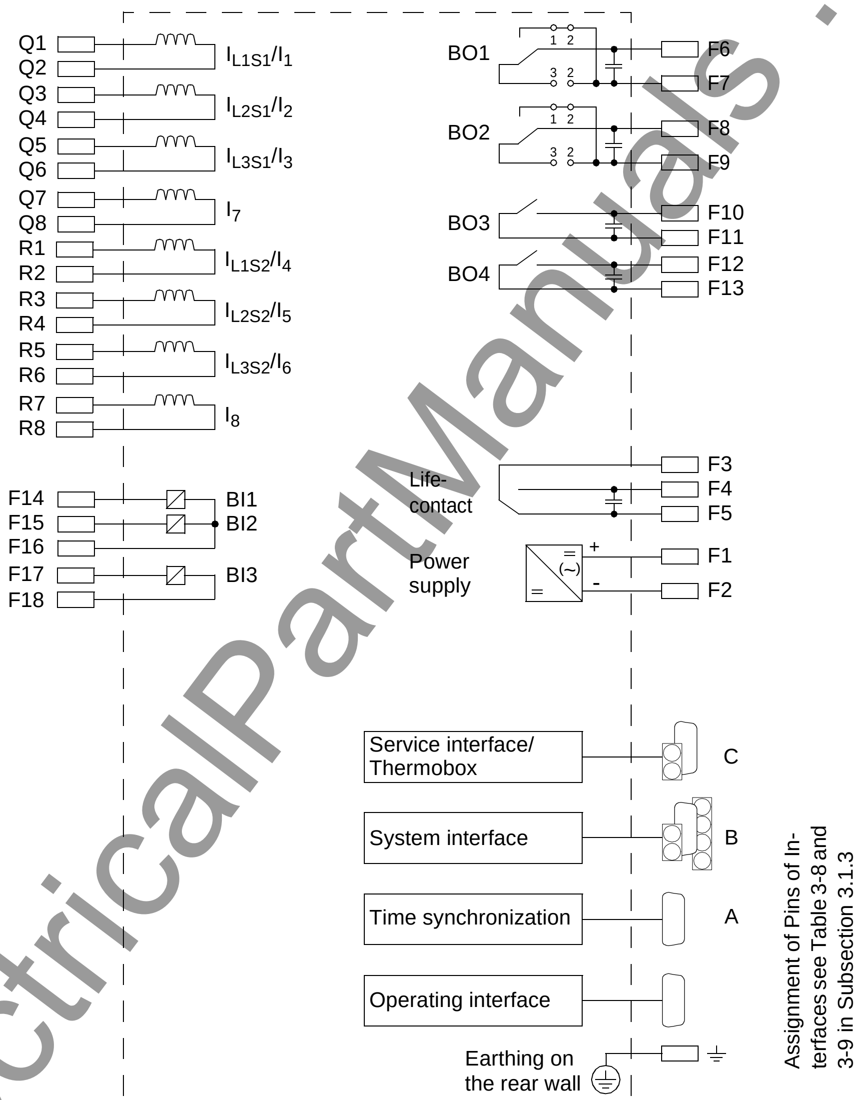
Voltage arrester for high-impedance protection

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

7UT612∗–∗D/E



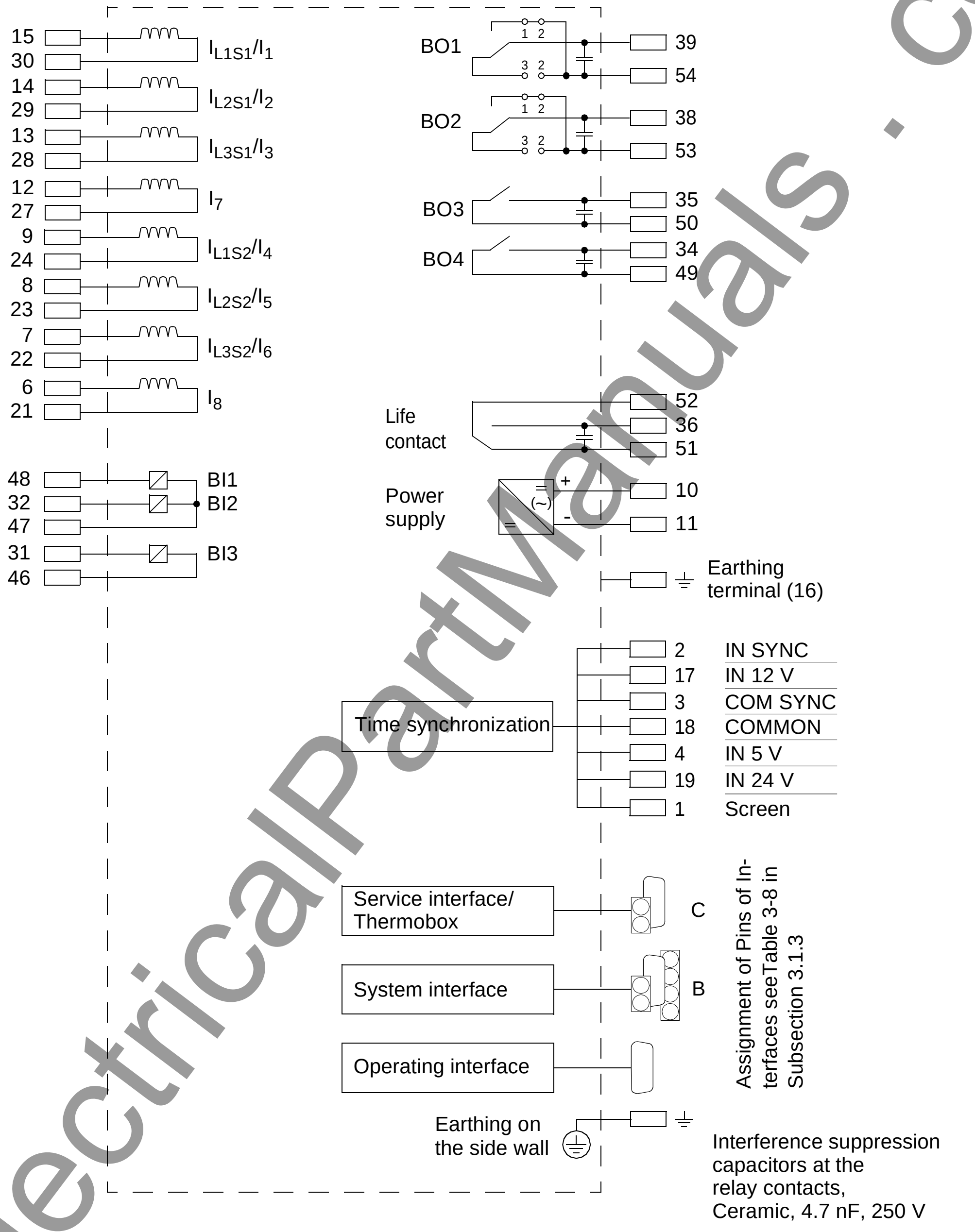
Assignment of Pins of Interfaces see Table 3-8 and 3-9 in Subsection 3.1.3

Interference suppression
capacitors at the
relay contacts,
Ceramic, 4.7 nF, 250 V

Figure A-1 General Diagram 7UT612*-*D/E (panel flush mounted or cubicle mounted)

A.2.2 Panel Surface Mounting

7UT612∗–∗B



Assignment of Pins of Interfaces seeTable 3-8 in Subsection 3.1.3

Interference suppression capacitors at the relay contacts, Ceramic, 4.7 nF, 250 V

Figure A-2 General diagram 7UT612∗–∗B (panel surface mounting)

A.3 Connection Examples

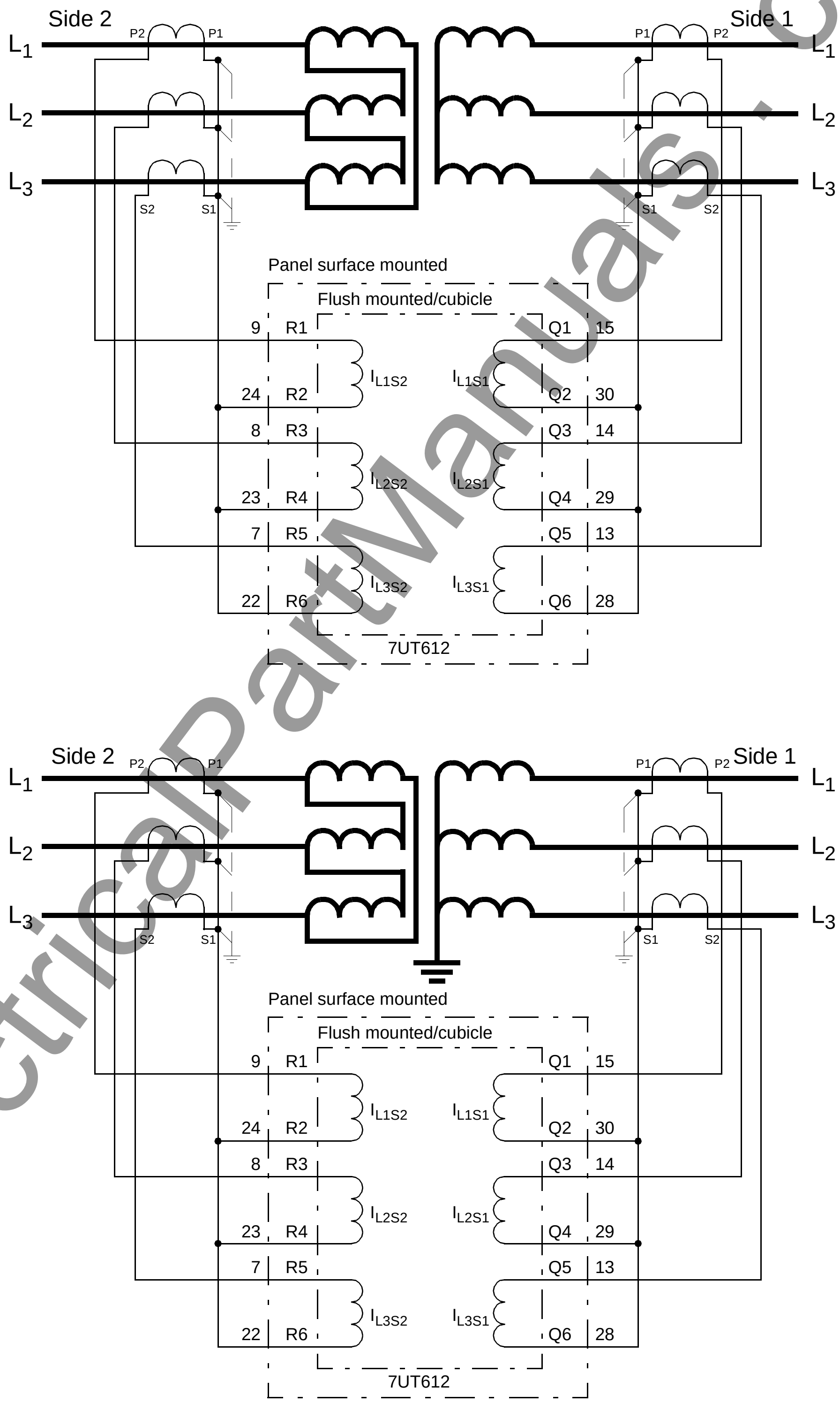


Figure A-3 Connection example 7UT612 for a three-phase power transformer without (above) and with (below) earthed starpoint

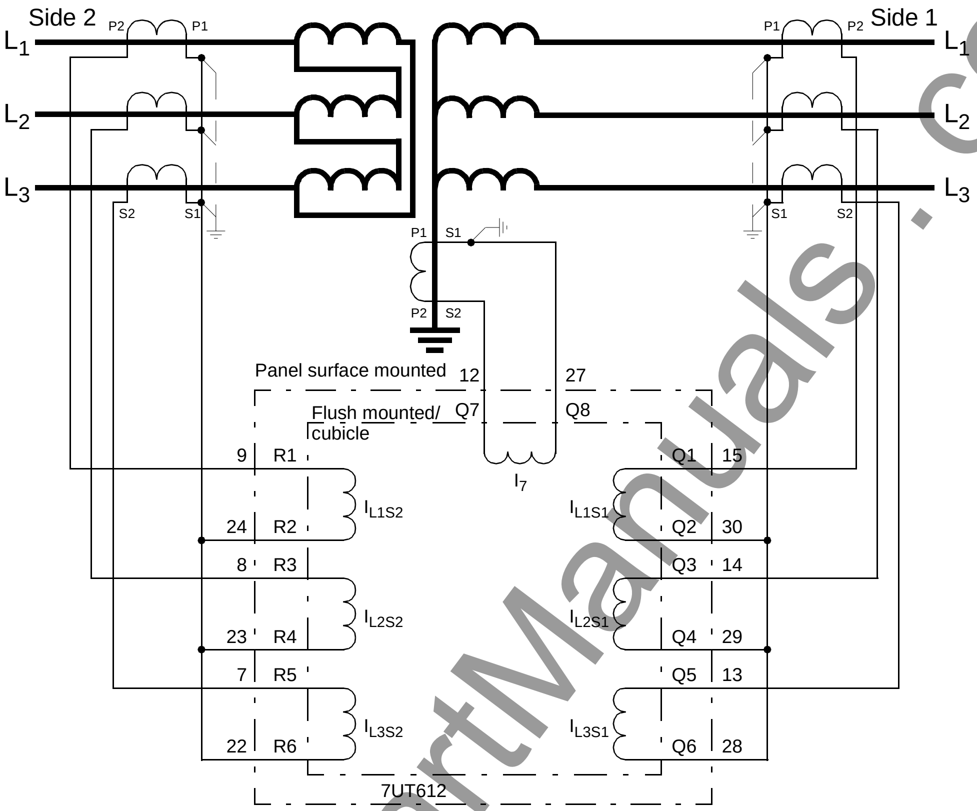


Figure A-4 Connection example 7UT612 for a three-phase power transformer with current transformer between starpoint and earthing point

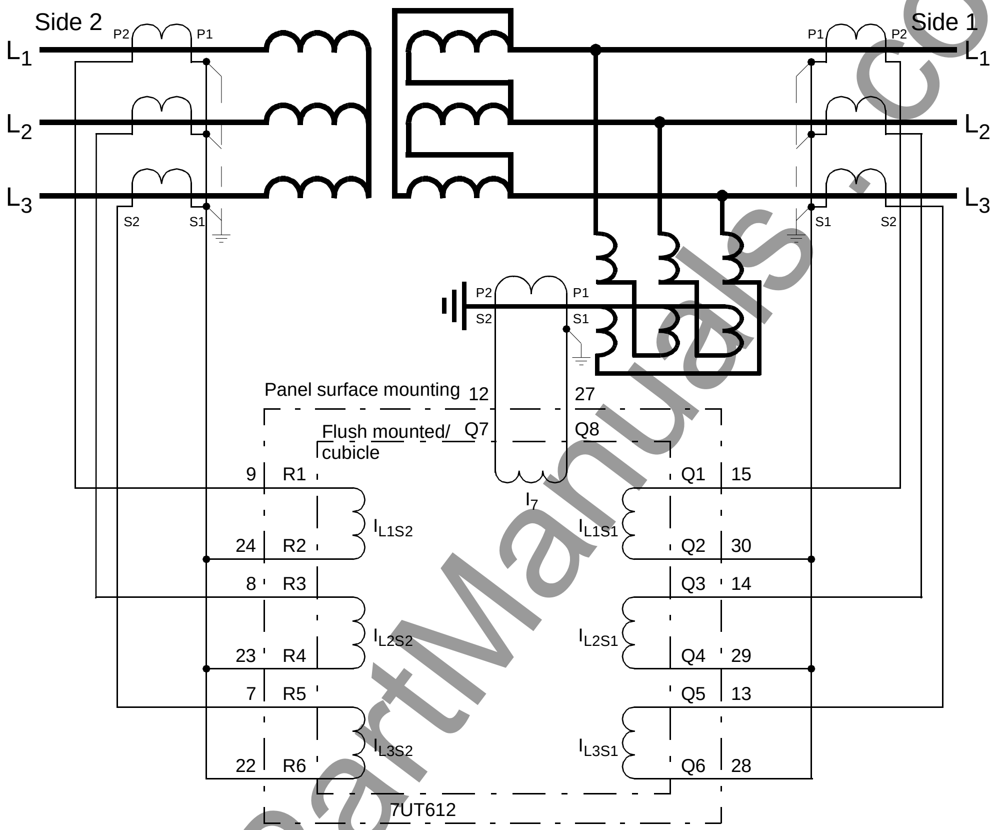


Figure A-5 Connection example 7UT612 for a three-phase power transformer with neutral earthing reactor and current transformer between starpoint and earthing point

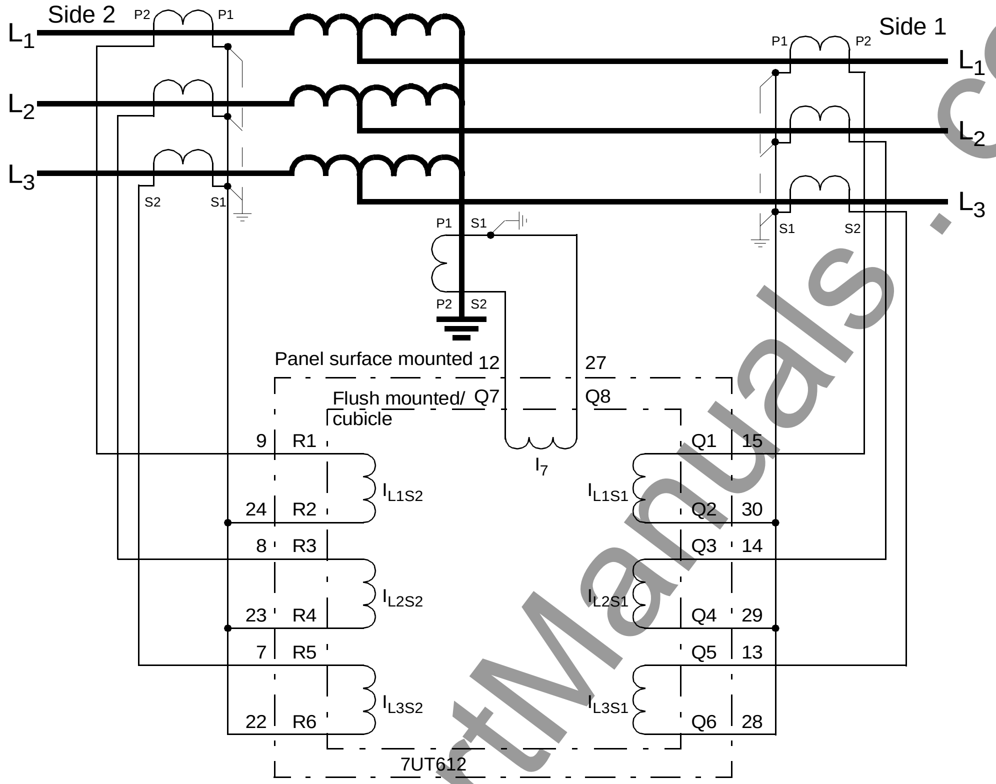


Figure A-6 Connection example 7UT612 for a three-phase auto-transformer with current transformer between starpoint and earthing point

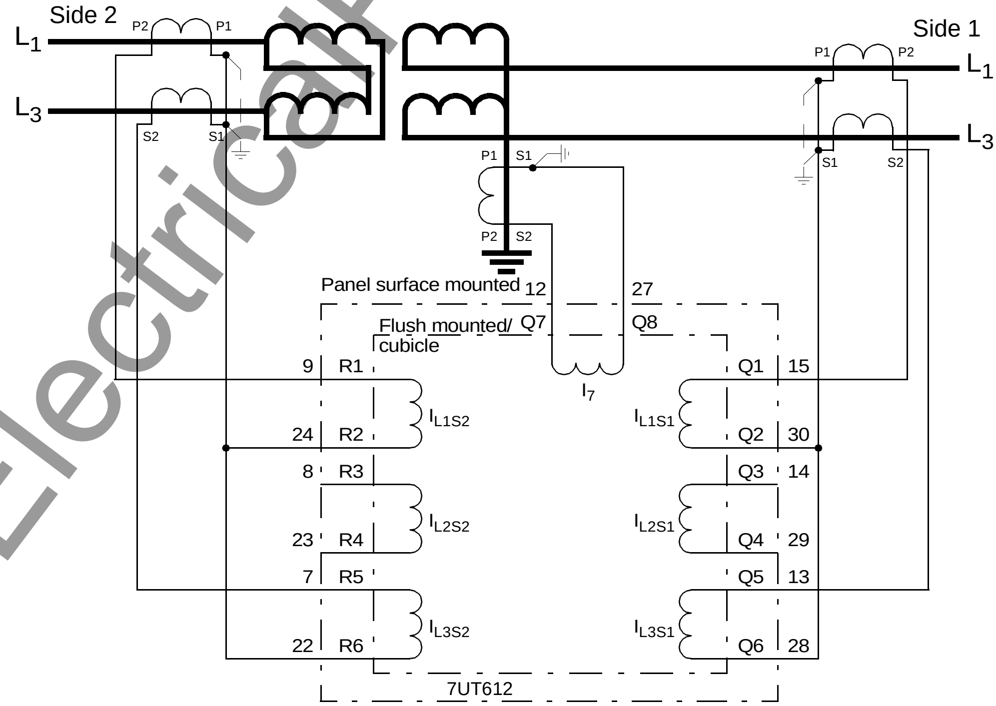


Figure A-7 Connection example 7UT612 for a single-phase power transformer with current transformer between starpoint and earthing point

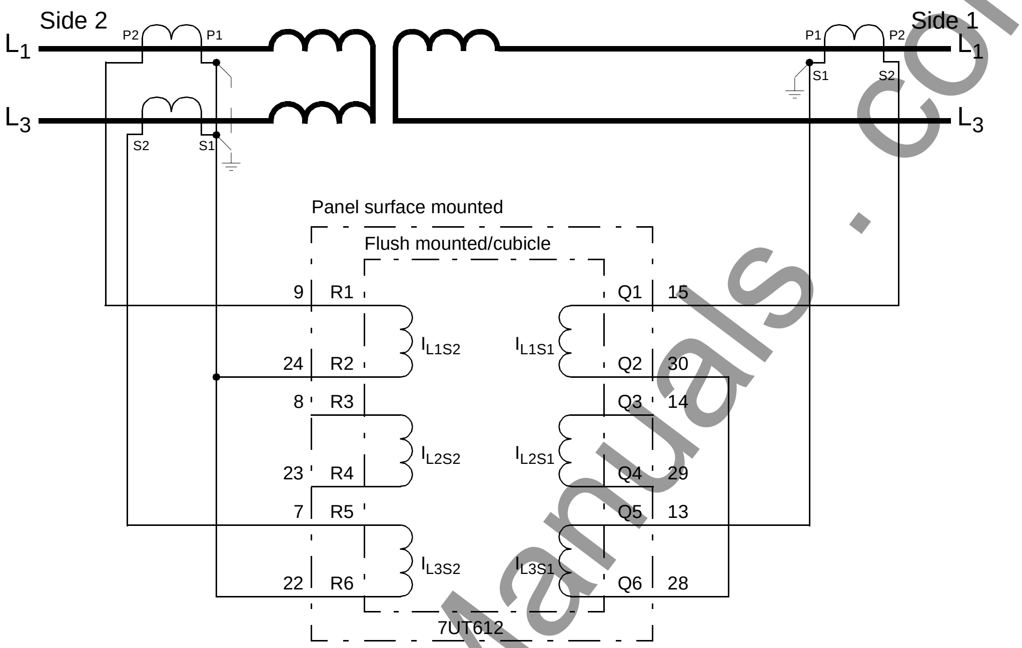


Figure A-8 Connection example 7UT612 for a single-phase power transformer with only one current transformer (right side)

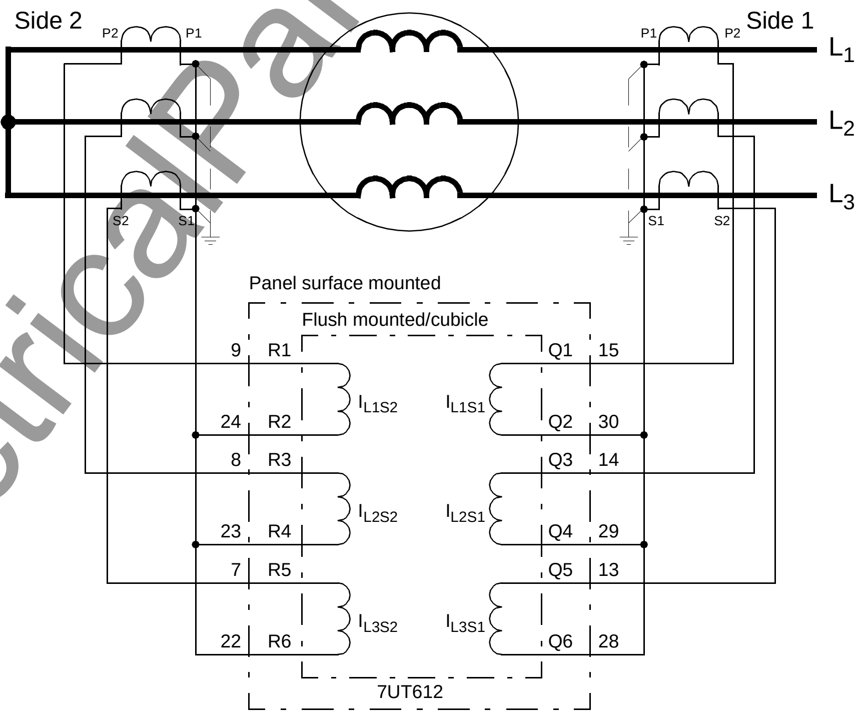


Figure A-9 Connection example 7UT612 for a generator or motor

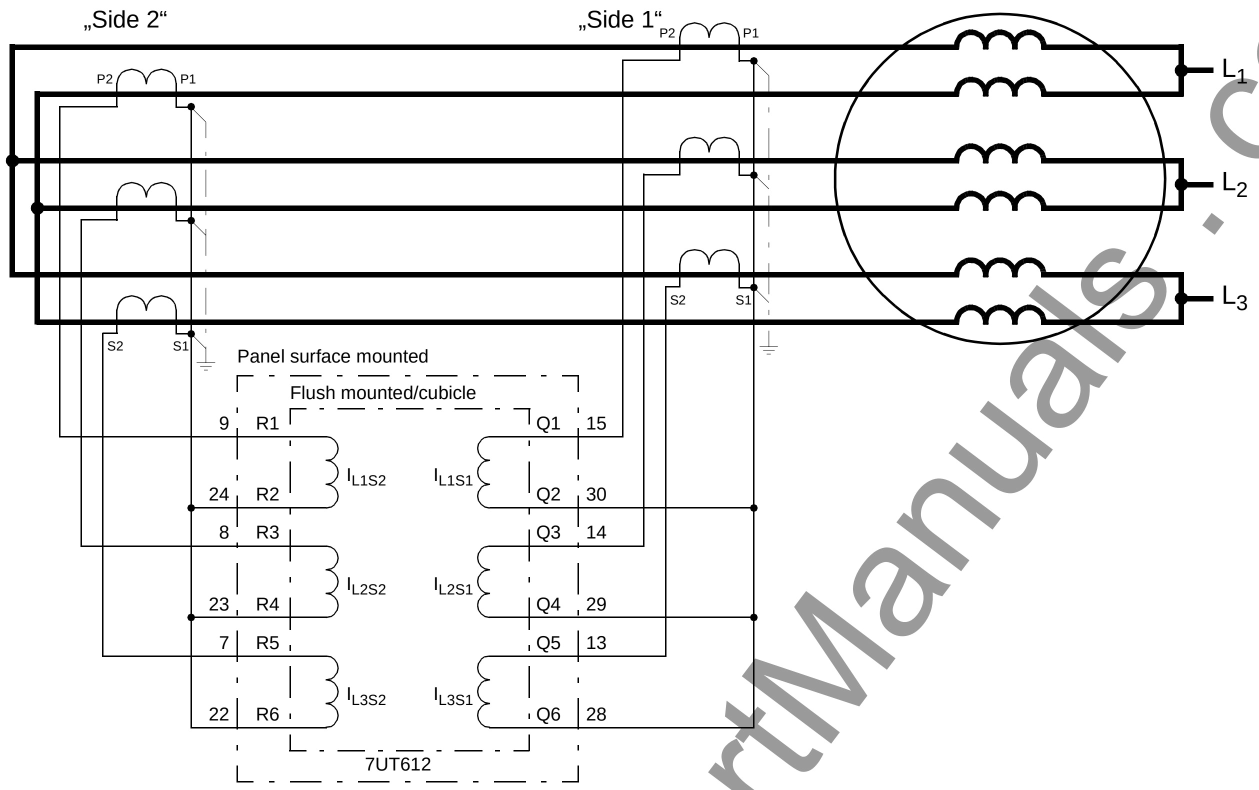


Figure A-10 Connection example 7UT612 as transversal differential protection for a generator with two windings per phase

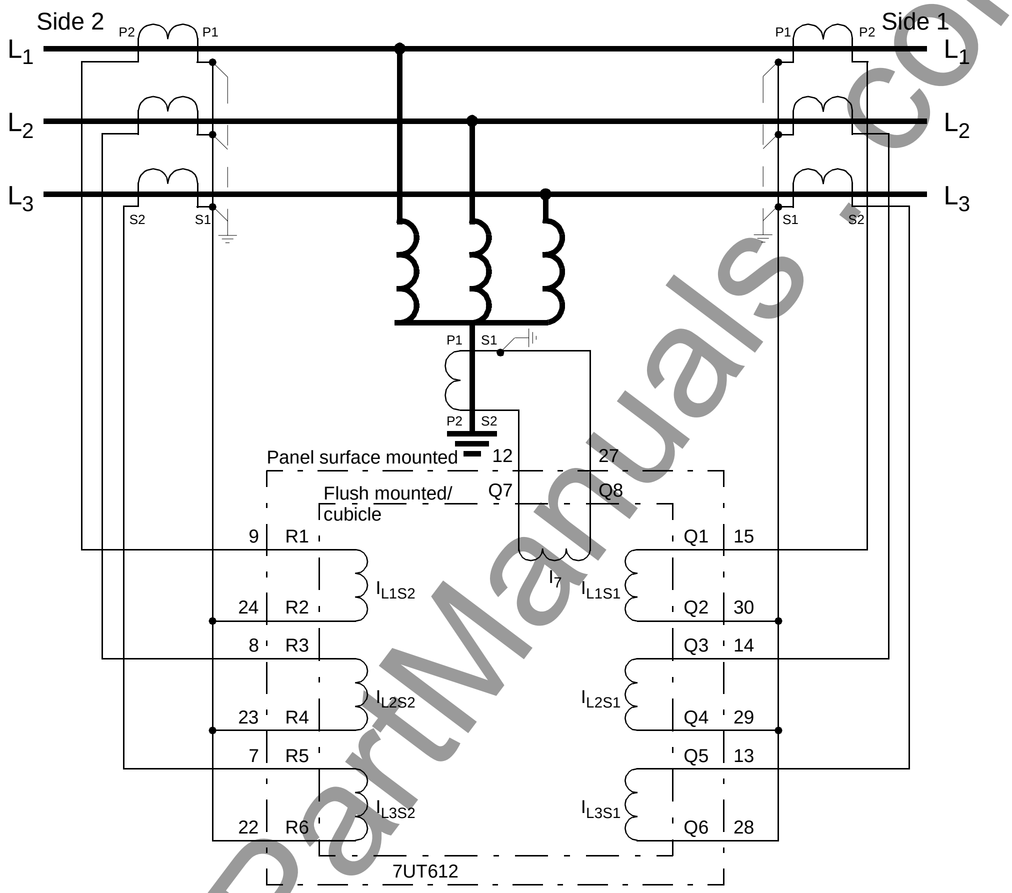


Figure A-11 Connection example 7UT612 for an earthed shunt reactor with current transformer between starpoint and earthing point

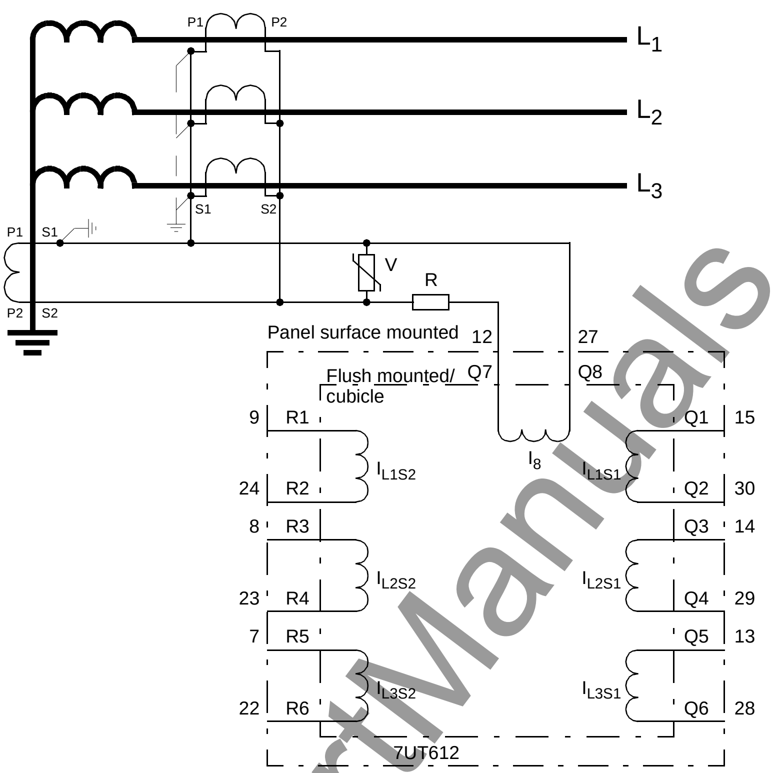


Figure A-12 Connection example 7UT612 as high-impedance protection on a transformer winding with earthed starpoint (the illustration shows the partial connection of the high-impedance protection)

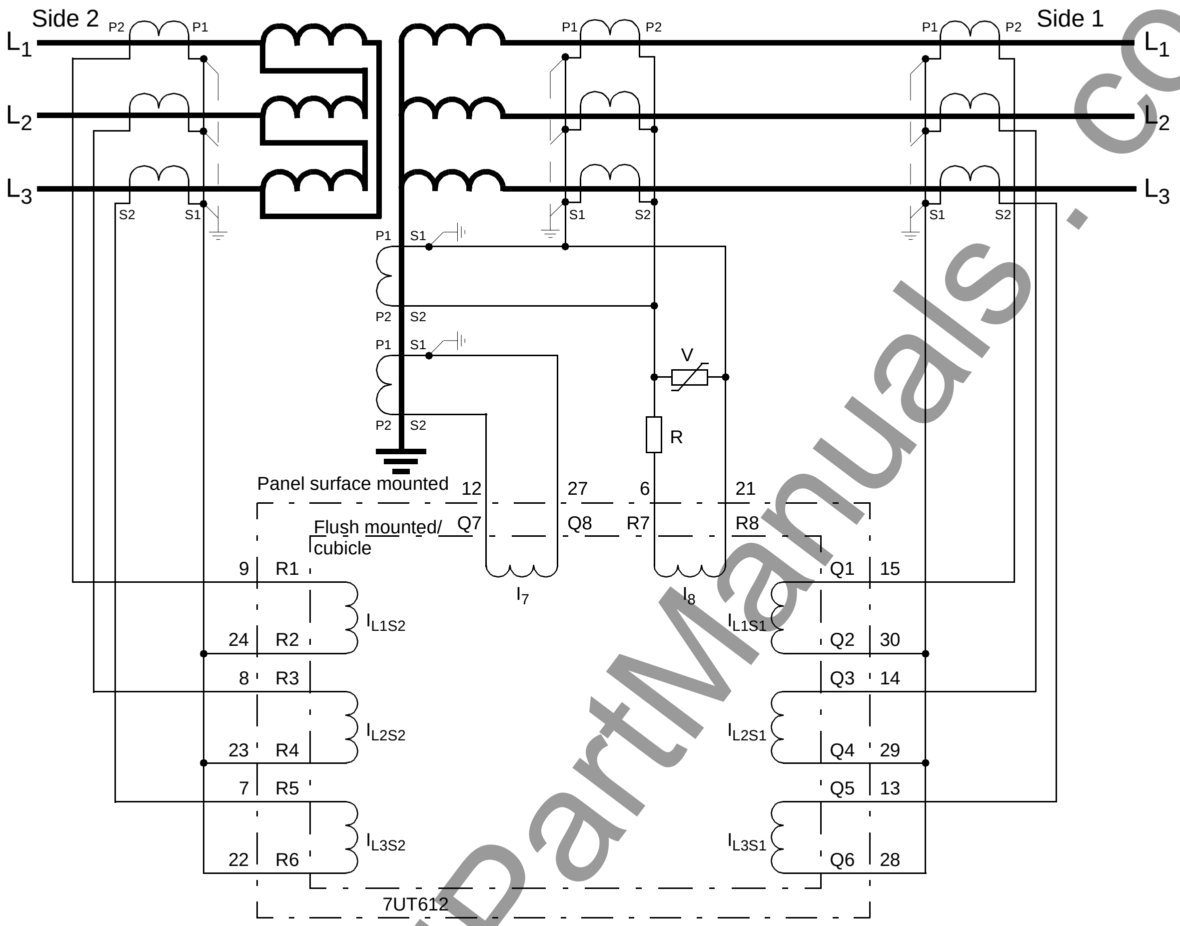


Figure A-13 Connection example 7UT612 for a three-phase power transformer with current transformers between starpoint and earthing point, additional connection for high-impedance protection

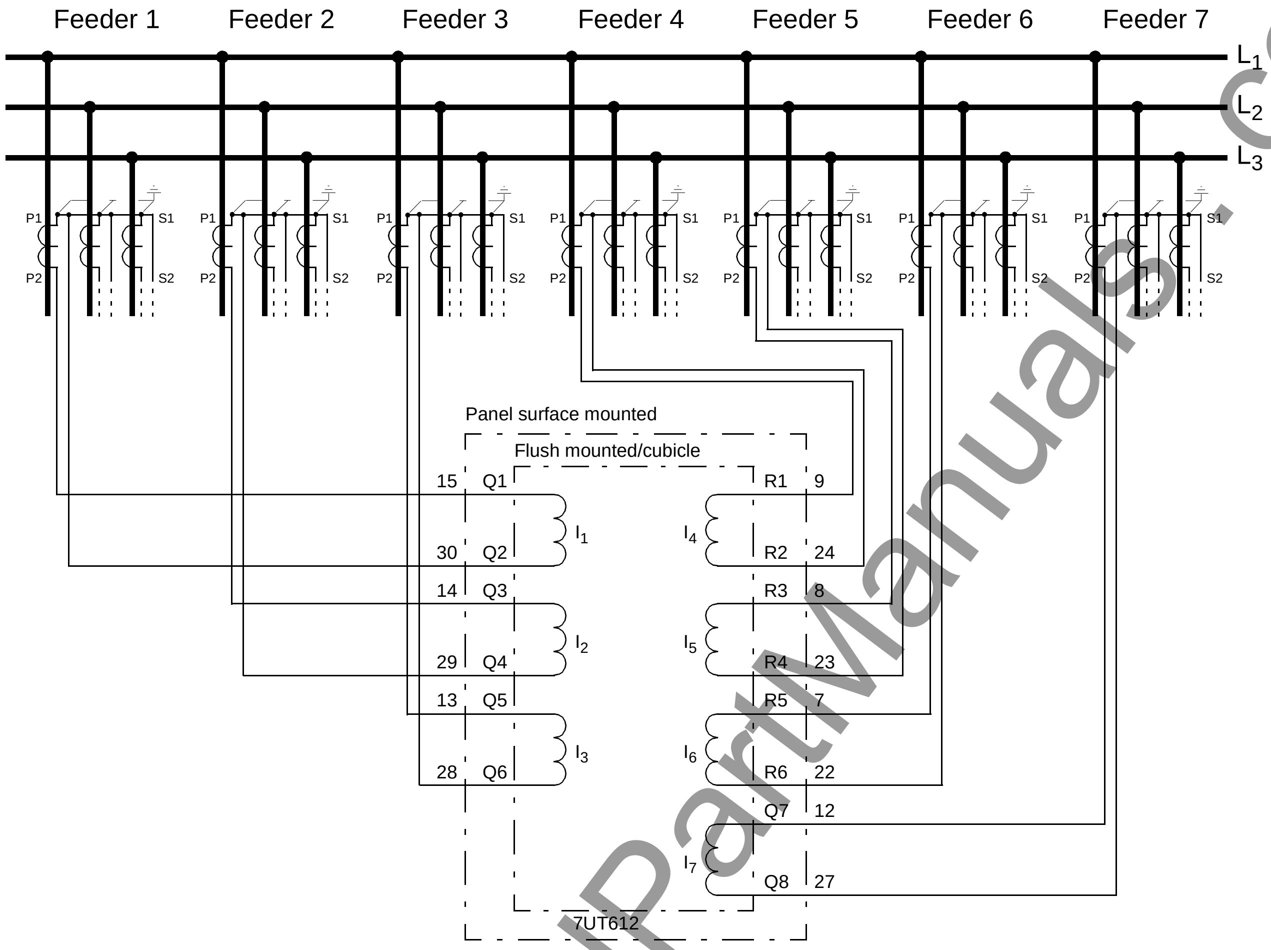


Figure A-14 Connection example 7UT612 as single-phase busbar protection, illustrated for phase L1

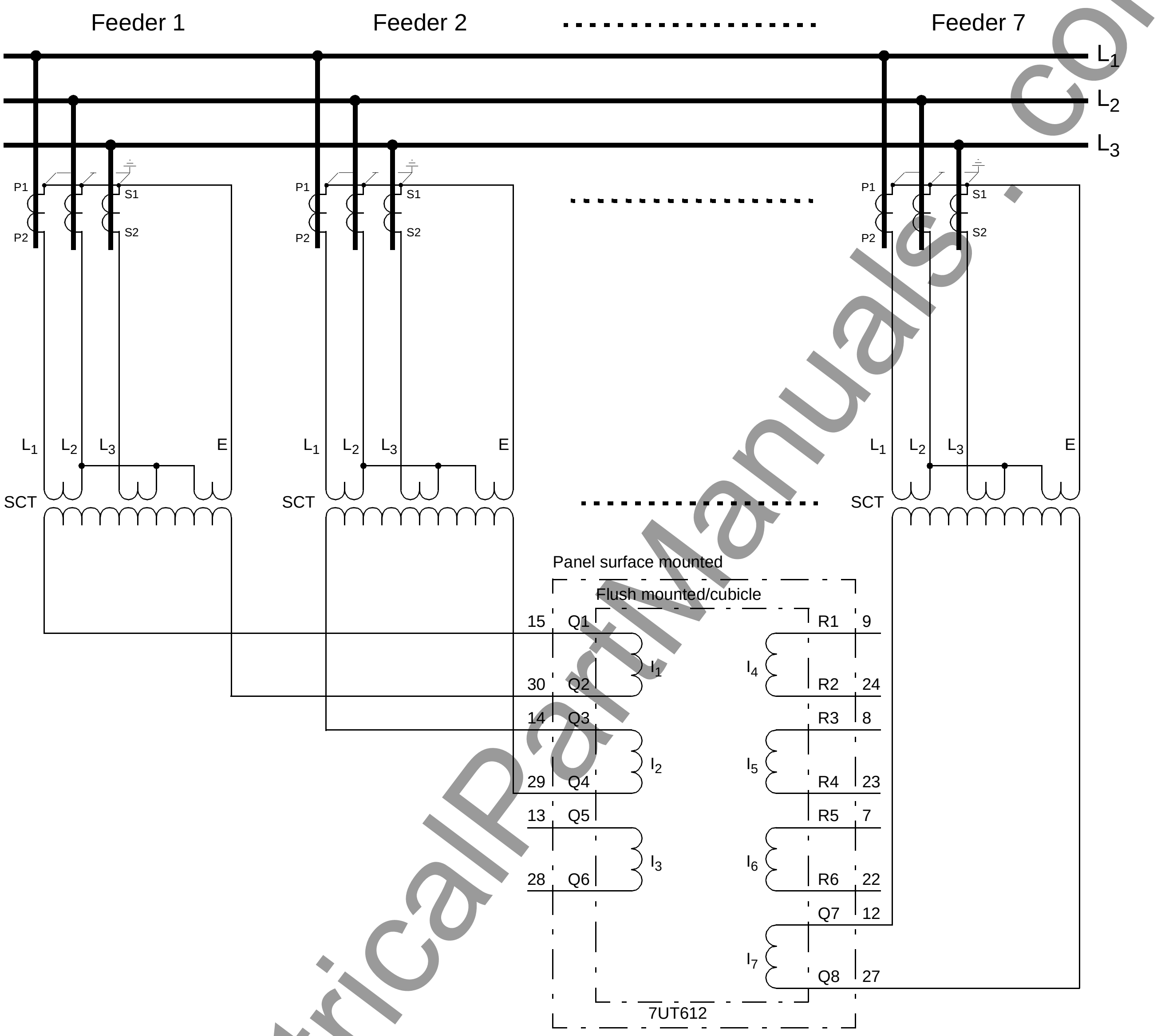


Figure A-15 Connection example 7UT612 as busbar protection, connected via external summation current transformers (SCT) — partial illustration for feeders 1, 2 and 7

A.4 Assignment of the Protection Functions to Protected Objects

Not every implemented protection function of 7UT612 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	—
Circuit breaker failure protection	X	X	X	X	X	—
Measured value monitoring	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

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
BI3	—	—	No presetting

Binary Outputs (Output Relays)

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

LED Indicators

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	—	—	no presetting
LED5	—	—	no presetting
LED6	Error Sum Alarm Alarm Sum Event	00140 00160	Group alarm of errors and disturbances, non-latched
LED7	Fault Configur.	00311	Errors during configuration or setting (inconsistent settings), non-latched

Preset CFC–Charts

7UT612 provides worksheets with preset CFC-charts. Figure A-16 shows a chart which changes binary input “`>DataStop`” from single point indication (SP) to internal single point indication (IntSP). According to Figure A-17 an reclosure interlocking will be produced. It interlocks the closure of the circuit breaker after tripping of the device until manual acknowledgement.

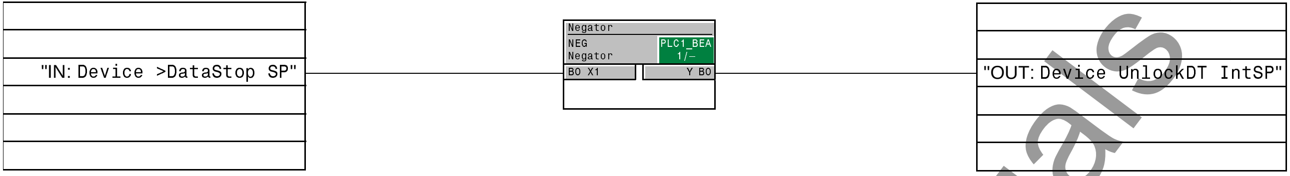


Figure A-16 CFC-chart for transmission block and testing mode

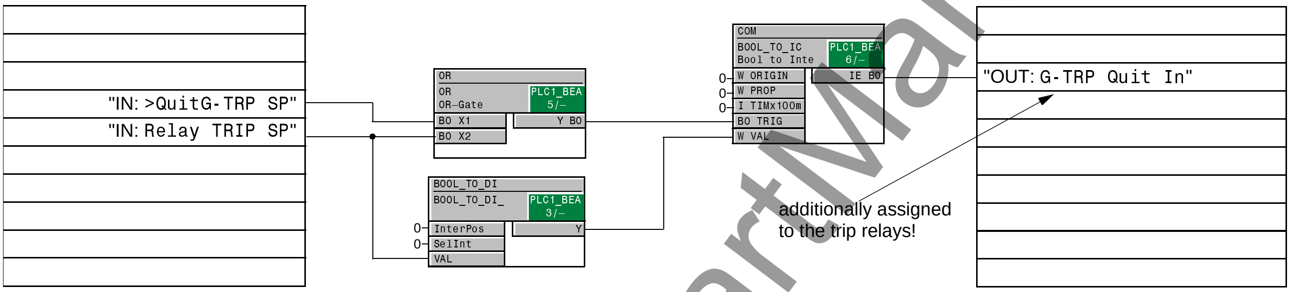


Figure A-17 CFC chart for reclosure lockout

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 annunciations” in CFC (pre-defined)	“User-defined annunciations” in CFC (pre-defined)	“User-defined annunciations” 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 table 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. For setting primary values the transformation ratio of the transformer also must be taken into consideration.

Addresses which have an “A” attached to its end can only be changed in DIGSI® 4, under “**Additional Settings**”.

Addr.	Setting Title	Setting Options	Default Setting	Comments
103	Grp Chge OPTION	Disabled Enabled	Disabled	Setting Group Change Option
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
105	PROT. OBJECT	3 phase Transformer 1 phase Transformer Autotransformer Generator/Motor 3 phase Busbar 1 phase Busbar	3 phase Transformer	Protection Object
106	NUMBER OF SIDES	2	2	Number of Sides for Multi Phase Object
106	NUMBER OF SIDES	2	2	Number of Sides for Multi Phase Object
107	NUMBER OF ENDS	3 4 5 6 7	7	Number of Ends for 1 Phase Busbar
107	NUMBER OF ENDS	3 4 5 6 7	7	Number of Ends for 1 Phase Busbar
108	I7-CT CONNECT.	not used Side 1 Side 2	not used	I7-CT connected to
108	I7-CT CONNECT.	not used Side 1 Side 2	not used	I7-CT connected to
112	DIFF. PROT.	Disabled Enabled	Enabled	Differential Protection
112	DIFF. PROT.	Disabled Enabled	Enabled	Differential Protection
113	REF PROT.	Disabled Side 1 Side 2	Disabled	Restricted earth fault protection

Addr.	Setting Title	Setting Options	Default Setting	Comments
113	REF PROT.	Disabled Side 1 Side 2	Disabled	Restricted earth fault protection
117	Coldload Pickup	Disabled Enabled	Disabled	Cold Load Pickup
117	Coldload Pickup	Disabled Enabled	Disabled	Cold Load Pickup
120	DMT/IDMT Phase	Disabled Side 1 Side 2	Disabled	DMT / IDMT Phase
120	DMT/IDMT Phase	Disabled Side 1 Side 2	Disabled	DMT / IDMT Phase
121	DMT/IDMT PH. CH	Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Definite Time only	DMT / IDMT Phase Pick Up Characteristic
121	DMT/IDMT PH. CH	Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Definite Time only	DMT / IDMT Phase Pick Up Characteristic
122	DMT/IDMT 3I0	Disabled Side 1 Side 2	Disabled	DMT / IDMT 3I0
122	DMT/IDMT 3I0	Disabled Side 1 Side 2	Disabled	DMT / IDMT 3I0
123	DMT/IDMT 3I0 CH	Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Definite Time only	DMT / IDMT 3I0 Pick Up Characteristic
123	DMT/IDMT 3I0 CH	Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Definite Time only	DMT / IDMT 3I0 Pick Up Characteristic
124	DMT/IDMT Earth	Disabled unsensitive Current Transformer I7	Disabled	DMT / IDMT Earth
124	DMT/IDMT Earth	Disabled unsensitive Current Transformer I7	Disabled	DMT / IDMT Earth
125	DMT/IDMT E CHR.	Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Definite Time only	DMT / IDMT Earth Pick Up Characteristic
125	DMT/IDMT E CHR.	Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI User Defined Pickup Curve User Defined Pickup and Reset Curve	Definite Time only	DMT / IDMT Earth Pick Up Characteristic
127	DMT 1PHASE	Disabled unsensitive Current Transformer I7 sensitive Current Transformer I8	Disabled	DMT 1Phase
127	DMT 1PHASE	Disabled unsensitive Current Transformer I7 sensitive Current Transformer I8	Disabled	DMT 1Phase

Addr.	Setting Title	Setting Options	Default Setting	Comments
140	UNBALANCE LOAD	Disabled Side 1 Side 2	Disabled	Unbalance Load (Negative Sequence)
140	UNBALANCE LOAD	Disabled Side 1 Side 2	Disabled	Unbalance Load (Negative Sequence)
141	UNBAL. LOAD CHR	Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI	Definite Time only	Unbalance Load (Neg. Sequ.) Characteris.
141	UNBAL. LOAD CHR	Definite Time only Time Overcurrent Curve IEC Time Overcurrent Curve ANSI	Definite Time only	Unbalance Load (Neg. Sequ.) Characteris.
142	Therm.Overload	Disabled Side 1 Side 2	Disabled	Thermal Overload Protection
142	Therm.Overload	Disabled Side 1 Side 2	Disabled	Thermal Overload Protection
143	Therm.O/L CHR.	classical (according IEC60255) according IEC354	classical (according IEC60255)	Thermal Overload Protec. Characteristic
143	Therm.O/L CHR.	classical (according IEC60255) according IEC354	classical (according IEC60255)	Thermal Overload Protec. Characteristic
170	BREAKER FAILURE	Disabled Side 1 Side 2	Disabled	Breaker Failure Protection
170	BREAKER FAILURE	Disabled Side 1 Side 2	Disabled	Breaker Failure Protection
181	M.V. SUPERV	Disabled Enabled	Enabled	Measured Values Supervision
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
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
186	EXT. TRIP 1	Disabled Enabled	Disabled	External Trip Function 1
187	EXT. TRIP 2	Disabled Enabled	Disabled	External Trip Function 2
187	EXT. TRIP 2	Disabled Enabled	Disabled	External Trip Function 2
190	RTD-BOX INPUT	Disabled Port C	Disabled	External Temperature Input
190	RTD-BOX INPUT	Disabled Port C	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
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	STRPNT->OBJ S1	Power System Data 1	YES NO	YES	CT-Strpnt. Side1 in Direct. of Object
202	IN-PRI CT S1	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current Side 1
203	IN-SEC CT S1	Power System Data 1	1A 5A	1A	CT Rated Secondary Current Side 1
206	STRPNT->OBJ S2	Power System Data 1	YES NO	YES	CT-Strpnt. Side2 in Direct. of Object
207	IN-PRI CT S2	Power System Data 1	1..100000 A	2000 A	CT Rated Primary Current Side 2
208	IN-SEC CT S2	Power System Data 1	1A 5A	1A	CT Rated Secondary Current Side 2
211	STRPNT->BUS I1	Power System Data 1	YES NO	YES	CT-Starpoint I1 in Direction of Busbar
212	IN-PRI CT I1	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I1
213	IN-SEC CT I1	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I1
214	STRPNT->BUS I2	Power System Data 1	YES NO	YES	CT-Starpoint I2 in Direction of Busbar
215	IN-PRI CT I2	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I2
216	IN-SEC CT I2	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I2
217	STRPNT->BUS I3	Power System Data 1	YES NO	YES	CT-Starpoint I3 in Direction of Busbar
218	IN-PRI CT I3	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I3
219	IN-SEC CT I3	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I3
221	STRPNT->BUS I4	Power System Data 1	YES NO	YES	CT-Starpoint I4 in Direction of Busbar
222	IN-PRI CT I4	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I4
223	IN-SEC CT I4	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I4
224	STRPNT->BUS I5	Power System Data 1	YES NO	YES	CT-Starpoint I5 in Direction of Busbar
225	IN-PRI CT I5	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I5
226	IN-SEC CT I5	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I5
227	STRPNT->BUS I6	Power System Data 1	YES NO	YES	CT-Starpoint I6 in Direction of Busbar
228	IN-PRI CT I6	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I6
229	IN-SEC CT I6	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I6
230	EARTH. ELECTROD	Power System Data 1	Terminal Q7 Terminal Q8	Terminal Q7	Earthing Electrod versus

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
231	STRPNT->BUS I7	Power System Data 1	YES NO	YES	CT-Starpoint I7 in Direction of Busbar
232	IN-PRI CT I7	Power System Data 1	1..100000 A	200 A	CT Rated Primary Current I7
233	IN-SEC CT I7	Power System Data 1	1A 5A 0.1A	1A	CT Rated Secondary Current I7
235	Factor I8	Power System Data 1	1.0..300.0	60.0	Factor: Prim. Current over Sek. Curr. I8
240	UN-PRI SIDE 1	Power System Data 1	0.4..800.0 kV	110.0 kV	Rated Primary Voltage Side 1
241	STARPNT SIDE 1	Power System Data 1	Solid Earthed Isolated	Solid Earthed	Starpoint of Side 1 is
242	CONNECTION S1	Power System Data 1	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 1
243	UN-PRI SIDE 2	Power System Data 1	0.4..800.0 kV	11.0 kV	Rated Primary Voltage side 2
244	STARPNT SIDE 2	Power System Data 1	Solid Earthed Isolated	Solid Earthed	Starpoint of side 2 is
245	CONNECTION S2	Power System Data 1	Y (Wye) D (Delta) Z (Zig-Zag)	Y (Wye)	Transf. Winding Connection Side 2
246	VECTOR GRP S2	Power System Data 1	0..11	0	Vector Group Numeral of Side 2
249	SN TRANSFORMER	Power System Data 1	0.20..5000.00 MVA	38.10 MVA	Rated Apparent Power of the Transformer
251	UN GEN/MOTOR	Power System Data 1	0.4..800.0 kV	21.0 kV	Rated Primary Voltage Generator/ Motor
252	SN GEN/MOTOR	Power System Data 1	0.20..5000.00 MVA	70.00 MVA	Rated Apparent Power of the Generator
261	UN BUSBAR	Power System Data 1	0.4..800.0 kV	110.0 kV	Rated Primary Voltage Busbar
265	I PRIMARY OP.	Power System Data 1	1..100000 A	200 A	Primary Operating Current
266	PHASE SELECTION	Power System Data 1	Phase 1 Phase 2 Phase 3	Phase 1	Phase selection
270	Rated Frequency	Power System Data 1	50 Hz 60 Hz 16 2/3 Hz	50 Hz	Rated Frequency
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 temparature measurement
280A	TMin TRIP CMD	Power System Data 1	0.01..32.00 sec	0.15 sec	Minimum TRIP Command Duration
283	Breaker S1 I>	Power System Data 1	0.04..1.00 A	0.04 A	Clos. Breaker Min. Current Thresh. S1
284	Breaker S2 I>	Power System Data 1	0.04..1.00 A	0.04 A	Clos. Breaker Min. Current Thresh. S2
285	Breaker I7 I>	Power System Data 1	0.04..1.00 A	0.04 A	Clos. Breaker Min. Current Thresh. I7
302	CHANGE	Change Group	Group A Group B Group C Group D Binary Input Protocol	Group A	Change to Another Setting Group

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
401	WAVEFORMTRIGGER	Oscillographic Fault Records	Save with Pickup Save with TRIP Start with TRIP	Save with Pickup	Waveform Capture
403	MAX. LENGTH	Oscillographic Fault Records	0.30..5.00 sec	1.00 sec	Max. length of a Waveform Capture Record
404	PRE. TRIG. TIME	Oscillographic Fault Records	0.05..0.50 sec	0.10 sec	Captured Waveform Prior to Trigger
405	POST REC. TIME	Oscillographic Fault Records	0.05..0.50 sec	0.10 sec	Captured Waveform after Event
406	BinIn CAPT.TIME	Oscillographic Fault Records	0.10..5.00 sec; ∞	0.50 sec	Capture Time via Binary Input
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/InO; 0	0.00 I/InO	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
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
1256A	I-ADD ON STAB.	Differential Protection	2.00..15.00 I/InO	4.00 I/InO	Pickup for Add-on Stabilization
1257A	T ADD ON-STAB.	Differential Protection	2..250 Cycle; ∞	15 Cycle	Duration of Add-on Stabilization
1261	2. HARMONIC	Differential Protection	10..80 %	15 %	2nd Harmonic Content in I-DIFF
1262A	CROSSB. 2. HARM	Differential Protection	2..1000 Cycle; 0; ∞	3 Cycle	Time for Cross-blocking 2nd Harm.
1271	n. HARMONIC	Differential Protection	10..80 %	30 %	n-th Harmonic Content in I-DIFF
1272A	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
1273A	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 / In	0.15 I / In	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 Pikkup	OFF ON	OFF	Cold-Load-Pickup Function
1702	Start CLP Phase	Cold Load Pikkup	No Current Breaker Contact	No Current	Start Condition CLP for O/C Phase
1703	Start CLP 3I0	Cold Load Pikkup	No Current Breaker Contact	No Current	Start Condition CLP for O/C 3I0
1704	Start CLP Earth	Cold Load Pikkup	No Current Breaker Contact	No Current	Start Condition CLP for O/C Earth
1711	CB Open Time	Cold Load Pikkup	0..21600 sec	3600 sec	Circuit Breaker OPEN Time
1712	Active Time	Cold Load Pikkup	1..21600 sec	3600 sec	Active Time
1713	Stop Time	Cold Load Pikkup	1..600 sec; ∞	600 sec	Stop Time
2001	PHASE O/C	Time overcurrent Phase	ON OFF	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; ∞	2.00 A	I>> Pickup
2012	T I>>	Time overcurrent Phase	0.00..60.00 sec; ∞	0.00 sec	T I>> Time Delay
2013	I>	Time overcurrent Phase	0.10..35.00 A; ∞	1.00 A	I> Pickup
2014	T I>	Time overcurrent Phase	0.00..60.00 sec; ∞	0.50 sec	T I> Time Delay
2021	Ip	Time overcurrent Phase	0.10..4.00 A	1.00 A	Ip Pickup
2022	T Ip	Time overcurrent Phase	0.05..3.20 sec; ∞	0.50 sec	T Ip Time Dial
2023	D Ip	Time overcurrent Phase	0.50..15.00; ∞	5.00	D Ip Time Dial
2024	TOC DROP-OUT	Time overcurrent Phase	Instantaneous Disk Emulation	Disk Emulation	TOC Drop-out characteristic

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
2025	IEC CURVE	Time overcurrent Phase	Normal Inverse Very Inverse Extremely Inverse Long Inverse	Normal Inverse	IEC Curve
2026	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	CROSS BLK.Phase	Time overcurrent Phase	NO YES	NO	CROSS BLOCK O/C Phase
2044	T CROSS BLK.Ph	Time overcurrent Phase	0.00..180.00 sec	0.00 sec	CROSS BLOCK Time O/C Phase
2111	I>>	Time overcurrent Phase	0.10..35.00 A; ∞	10.00 A	I>> Pickup
2112	T I>>	Time overcurrent Phase	0.00..60.00 sec; ∞	0.00 sec	T I>> Time Delay
2113	I>	Time overcurrent Phase	0.10..35.00 A; ∞	2.00 A	I> Pickup
2114	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	1.50 A	Ip Pickup
2122	T Ip	Time overcurrent Phase	0.05..3.20 sec; ∞	0.50 sec	T Ip Time Dial
2123	D Ip	Time overcurrent Phase	0.50..15.00; ∞	5.00	D Ip Time Dial
2201	3I0 O/C	Time overcurrent 3I0	ON OFF	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; ∞	0.50 A	3I0>> Pickup
2212	T 3I0>>	Time overcurrent 3I0	0.00..60.00 sec; ∞	0.10 sec	T 3I0>> Time Delay
2213	3I0>	Time overcurrent 3I0	0.05..35.00 A; ∞	0.20 A	3I0> Pickup
2214	T 3I0>	Time overcurrent 3I0	0.00..60.00 sec; ∞	0.50 sec	T 3I0> Time Delay
2221	3I0p	Time overcurrent 3I0	0.05..4.00 A	0.20 A	3I0p Pickup
2222	T 3I0p	Time overcurrent 3I0	0.05..3.20 sec; ∞	0.20 sec	T 3I0p Time Dial
2223	D 3I0p	Time overcurrent 3I0	0.50..15.00; ∞	5.00	D 3I0p Time Dial

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
2224	TOC DROP-OUT	Time overcurrent 3I0	Instantaneous Disk Emulation	Disk Emulation	TOC Drop-out Characteristic
2225	IEC CURVE	Time overcurrent 3I0	Normal Inverse Very Inverse Extremely Inverse Long Inverse	Normal Inverse	IEC Curve
2226	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
2311	3I0>>	Time overcurrent 3I0	0.05..35.00 A; ∞	7.00 A	3I0>> Pickup
2312	T 3I0>>	Time overcurrent 3I0	0.00..60.00 sec; ∞	0.00 sec	T 3I0>> Time Delay
2313	3I0>	Time overcurrent 3I0	0.05..35.00 A; ∞	1.50 A	3I0> Pickup
2314	T 3I0>	Time overcurrent 3I0	0.00..60.00 sec; ∞	0.30 sec	T 3I0> Time Delay
2321	3I0p	Time overcurrent 3I0	0.05..4.00 A	1.00 A	3I0p Pickup
2322	T 3I0p	Time overcurrent 3I0	0.05..3.20 sec; ∞	0.50 sec	T 3I0p Time Dial
2323	D 3I0p	Time overcurrent 3I0	0.50..15.00; ∞	5.00	D 3I0p Time Dial
2401	EARTH O/C	Time overcurrent Earth	ON OFF	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; ∞	0.50 A	IE>> Pickup
2412	T IE>>	Time overcurrent Earth	0.00..60.00 sec; ∞	0.10 sec	T IE>> Time Delay
2413	IE>	Time overcurrent Earth	0.05..35.00 A; ∞	0.20 A	IE> Pickup
2414	T IE>	Time overcurrent Earth	0.00..60.00 sec; ∞	0.50 sec	T IE> Time Delay
2421	IEp	Time overcurrent Earth	0.05..4.00 A	0.20 A	IEp Pickup
2422	T IEp	Time overcurrent Earth	0.05..3.20 sec; ∞	0.20 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

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
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
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; ∞	0.00 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; ∞	0.30 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	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	Unbalance Load (Negative Sequence)	OFF ON	OFF	Unbalance Load (Negative Sequence)
4002	I2>	Unbalance Load (Negative Sequence)	0.10..3.00 A	0.10 A	I2> Pickup
4003	T I2>	Unbalance Load (Negative Sequence)	0.00..60.00 sec; ∞	1.50 sec	T I2> Time Delay

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
4004	I2>>	Unbalance Load (Negative Sequence)	0.10..3.00 A	0.50 A	I2>> Pickup
4005	T I2>>	Unbalance Load (Negative Sequence)	0.00..60.00 sec; ∞	1.50 sec	T I2>> Time Delay
4006	IEC CURVE	Unbalance Load (Negative Sequence)	Normal Inverse Very Inverse Extremely Inverse	Extremely Inverse	IEC Curve
4007	ANSI CURVE	Unbalance Load (Negative Sequence)	Extremely Inverse Inverse Moderately Inverse Very Inverse	Extremely Inverse	ANSI Curve
4008	I2p	Unbalance Load (Negative Sequence)	0.10..2.00 A	0.90 A	I2p Pickup
4009	D I2p	Unbalance Load (Negative Sequence)	0.50..15.00; ∞	5.00	D I2p Time Dial
4010	T I2p	Unbalance Load (Negative Sequence)	0.05..3.20 sec; ∞	0.50 sec	T I2p Time Dial
4011	I2p DROP-OUT	Unbalance Load (Negative Sequence)	Instantaneous Disk Emulation	Instantaneous	I2p Drop-out Characteristic
4201	Ther. OVER LOAD	Thermal Overload Protection	OFF ON 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	Time Constant
4204	Θ ALARM	Thermal Overload Protection	50..100 %	90 %	Thermal Alarm Stage
4205	I ALARM	Thermal Overload Protection	0.10..4.00 A	1.00 A	Current Overload Alarm Setpoint
4207A	Kτ-FACTOR	Thermal Overload Protection	1.0..10.0	1.0	Kt-FACTOR when motor stops
4208A	T EMERGENCY	Thermal Overload Protection	10..15000 sec	100 sec	Emergency Time
4209A	I MOTOR START	Thermal Overload Protection	0.60..10.00 A; ∞	∞ A	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	0.125..128.000	1.000	Aging Rate STAGE 1 Pikkup
4227	AG. RATE ST. 2	Thermal Overload Protection	0.125..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

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
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
7001	BREAKER FAILURE	Breaker Failure Protection	OFF ON	OFF	Breaker Failure Protection
7004	Chk BRK CONTACT	Breaker Failure Protection	OFF ON	OFF	Check Breaker contacts
7005	TRIP-Timer	Breaker Failure Protection	0.06..60.00 sec; ∞	0.25 sec	TRIP-Timer
7110	FltDisp.LED/LCD	Device	Display Targets on every Pickup Display Targets on TRIP only	Display Targets on every Pickup	Fault Display on LED / LCD
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	PHASE ROTATION	Measurement Supervision	ON OFF	OFF	Phase Rotation Supervision
8111	BAL. I LIMIT S1	Measurement Supervision	0.10..1.00 A	0.50 A	Current Balance Monitor Side 1
8112	BAL. FACT. I S1	Measurement Supervision	0.10..0.90	0.50	Balance Factor for Current Monitor S1
8121	BAL. I LIMIT S2	Measurement Supervision	0.10..1.00 A	0.50 A	Current Balance Monitor Side 2
8122	BAL. FACT. I S2	Measurement Supervision	0.10..0.90	0.50	Balance Factor for Current Monitor S2
8201	TRIP Cir. SUP.	Trip Circuit Supervision	ON OFF	OFF	TRIP Circuit Supervision
8601	EXTERN TRIP 1	External Trip Functions	ON OFF	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	ON OFF	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
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

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
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
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

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
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
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
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

Addr.	Setting Title	Function	Setting Options	Default Setting	Comments
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
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

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					
00069	Daylight Saving Time (DayLightSavTime)	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

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
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
00175	Failure: Phase Sequence Current (Fail Ph. Seq. I)	Measurement Supervision	OUT	ON OFF	*			LED			BO		135	191	1	GI
00177	Failure: Battery empty (Fail Battery)	Supervision	OUT	ON OFF	*			LED			BO		135	193	1	GI
00181	Error: A/D converter (Error A/D-conv.)	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
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: NO calibration data available (Alarm NO calibr)	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
00203	Waveform data deleted (Wave. deleted)	Oscillographic Fault Records	OUT_ Ev	ON	*			LED			BO		135	203	1	
00264	Failure: RTD-Box 1 (Fail: RTD-Box 1)	Supervision	OUT	ON OFF	*			LED			BO		135	208	1	GI
00265	Failure: Phase Sequence I side 1 (FailPh.Seq I S1)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
00266	Failure: Phase Sequence I side 2 (FailPh.Seq I S2)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
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 of the Protection (Fault Configur.)	Power System Data 2	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
00356	>Manual close signal (>Manual Close)	Power System Data 2	SP	*	*			LED	BI		BO		150	6	1	GI
00390	>Warning stage from gas in oil detector (>Gas in oil)	External Annunciations of Transformer	SP	ON OFF	*			LED	BI		BO					
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					
00410	>CB1 aux. 3p Closed (>CB1 3p Closed)	Power System Data 2	SP	on off	*			LED	BI		BO		150	80	1	GI
00411	>CB1 aux. 3p Open (>CB1 3p Open)	Power System Data 2	SP	on off	*			LED	BI		BO		150	81	1	GI
00413	>CB2 aux. 3p Closed (>CB2 3p Closed)	Power System Data 2	SP	on off	*			LED	BI		BO		150	82	1	GI
00414	>CB2 aux. 3p Open (>CB2 3p Open)	Power System Data 2	SP	on off	*			LED	BI		BO		150	83	1	GI
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
00561	Manual close signal detected (Man.Clos.Detect)	Power System Data 2	OUT	ON	*			LED			BO		150	211	1	
00571	Fail.: Current symm. supervision side 1 (Fail. Isym 1)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
00572	Fail.: Current symm. supervision side 2 (Fail. Isym 2)	Measurement Supervision	OUT	ON OFF	*			LED			BO					
00576	Primary fault current IL1 side1 (IL1S1:)	Power System Data 2	OUT	*	ON OFF								150	193	4	
00577	Primary fault current IL2 side1 (IL2S1:)	Power System Data 2	OUT	*	ON OFF								150	194	4	
00578	Primary fault current IL3 side1 (IL3S1:)	Power System Data 2	OUT	*	ON OFF								150	195	4	
00579	Primary fault current IL1 side2 (IL1S2:)	Power System Data 2	OUT	*	ON OFF								150	190	4	
00580	Primary fault current IL2 side2 (IL2S2:)	Power System Data 2	OUT	*	ON OFF								150	191	4	
00581	Primary fault current IL3 side2 (IL3S2:)	Power System Data 2	OUT	*	ON OFF								150	192	4	

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
00582	Primary fault current I1 (I1:)	Power System Data 2	OUT	*	ON OFF											
00583	Primary fault current I2 (I2:)	Power System Data 2	OUT	*	ON OFF											
00584	Primary fault current I3 (I3:)	Power System Data 2	OUT	*	ON OFF											
00585	Primary fault current I4 (I4:)	Power System Data 2	OUT	*	ON OFF											
00586	Primary fault current I5 (I5:)	Power System Data 2	OUT	*	ON OFF											
00587	Primary fault current I6 (I6:)	Power System Data 2	OUT	*	ON OFF											
00588	Primary fault current I7 (I7:)	Power System Data 2	OUT	*	ON OFF											
00888	Pulsed Energy Wp (active) (Wp(puls))	Energy	PMV						BI				133	55	205	
00889	Pulsed Energy Wq (reactive) (Wq(puls))	Energy	PMV						BI				133	56	205	
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
01471	Breaker failure TRIP (BrkFailure TRIP)	Breaker Failure Protection	OUT	*	ON		M	LED			BO		166	171	2	GI
01480	Breaker failure (internal) TRIP (BkrFail intTRIP)	Breaker Failure Protection	OUT	*	ON			LED			BO		166	180	2	GI
01481	Breaker failure (external) TRIP (BkrFail extTRIP)	Breaker Failure Protection	OUT	*	ON			LED			BO		166	181	2	GI
01488	Breaker failure Not aval. for this obj. (BkrFail Not av.)	Breaker Failure Protection	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
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
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					
01549	Th. Overload Not avaliable for this obj. (O/L Not avalia.)	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

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
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
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

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
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
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

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
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 avali. for this objekt (O/C Ph. Not av.)	Time overcurrent Phase	OUT	ON	*			LED			BO					
01861	O/C 3I0 Not avali. for this objekt (O/C 3I0 Not av.)	Time overcurrent 3I0	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

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
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
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

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
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
05170	I2 TRIP (I2 TRIP)	Unbalance Load (Negative Sequence)	OUT	*	ON		M	LED			BO		70	149	2	GI
05172	I2 Not avaliable for this objekt (I2 Not avalia.)	Unbalance Load (Negative Sequence)	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: 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
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

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
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 (DiffCrosBlk2HM)	Differential Protection	OUT	*	ON OFF			LED			BO					
05658	Diff: Crossblock by n.Harmonic (DiffCrosBlknHM)	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 L1 (Diff in.char.L1)	Differential Protection	OUT	ON OFF	ON OFF			LED			BO					
05667	Diff: Increase of char. phase L2 (Diff in.char.L2)	Differential Protection	OUT	ON OFF	ON OFF			LED			BO					
05668	Diff: Increase of char. phase L3 (Diff in.char.L3)	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	
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

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
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	
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
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 pikked 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					
05835	REF err: Not avaliable for this objekt (REF Not avalia.)	Restricted Earth Fault Protection	OUT	ON	*			LED			BO					
05836	REF: 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					

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
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
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	
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

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
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
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					

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
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					
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					

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
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					
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													
30626	Accumulation of interrupted curr. I7 (ΣI7:)	Statistics	OUT													
	>Back Light on (>Light on)	Device	SP	ON OFF	*			LED	BI		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
	>Quitt Lock Out: General Trip (>QuitG-TRP)	Power System Data 2	IntSP	*	*			LED	BI	FK	BO					
	Clock Synchronization (SynchClock)	Device	IntSP_Ev	*	*			LED			BO					
	Control Authority (Cntrl Auth)	Control Authorization	IntSP	ON OFF	*			LED					101	85	1	GI
	Controlmode LOCAL (ModeLOCAL)	Control Authorization	IntSP	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					
	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	BI	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
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
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
01060	Hot spot temperature of leg 1 (Θ leg 1=)	Thermal Measurement						CFC	CD	DD
01061	Hot spot temperature of leg 2 (Θ leg 2=)	Thermal Measurement						CFC	CD	DD
01062	Hot spot temperature of leg 3 (Θ leg 3=)	Thermal Measurement						CFC	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
07740	Phase angle in phase IL1 side 1 (φIL1S1=)	Measurement						CFC	CD	DD
07741	Phase angle in phase IL2 side 1 (φIL2S1=)	Measurement						CFC	CD	DD
07742	IDiffL1(I/Inominal object [%]) (IDiffL1=)	Diff- and Rest. 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
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
07749	Phase angle in phase IL3 side 1 (φIL3S1=)	Measurement						CFC	CD	DD
07750	Phase angle in phase IL1 side 2 (φIL1S2=)	Measurement						CFC	CD	DD
07759	Phase angle in phase IL2 side 2 (φIL2S2=)	Measurement						CFC	CD	DD
07760	Phase angle in phase IL3 side 2 (φIL3S2=)	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
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
	Operating hours greater than (OpHour>)							CFC	CD	DD

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To

Siemens AG
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D–13623 Berlin
Germany

Dear reader,

printing errors can never be entirely eliminated: therefore, should you come across any when reading this manual, kindly enter them in this form together with any comments or suggestions for improvement that you may have.

From

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Corrections/Suggestions

Subject to technical alteration

Siemens Aktiengesellschaft

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