Easergy P3G30, P3G32

Generator protection with machine differential protection

Publication version: P3G/en M/B004

User Manual

Trace back information:
Workspace Main version a184
Checked in 2018-12-21
Skribenta version 5.2.030

Table of Contents

1 Important information

1.1 Hazard categories and special symbols

Important Information

Read these instructions carefully and look at the equipment to become familiar with the device before trying to install, operate, service or maintain it. The following special messages may appear throughout this bulletin or on the equipment to warn of potential hazards or to call attention to information that clarifies or simplifies a procedure.

The addition of either symbol to a “Danger” or “Warning” safety label indicates that an electrical hazard exists which will result in personal injury if the instructions are not followed.

This is the safety alert symbol. It is used to alert you to potential personal injury hazards. Obey all safety messages that follow this symbol to avoid possible injury or death.

⚠ DANGER
DANGER indicates an imminently hazardous situation which, if not avoided, **will result in** death or serious injury.

⚠ WARNING
WARNING indicates a potentially hazardous situation which, if not avoided, **can result in** death or serious injury.

⚠ CAUTION
CAUTION indicates a potentially hazardous situation which, if not avoided, **can result in** minor or moderate injury or equipment damage.

NOTICE
NOTICE is used to address practices not related to physical injury or equipment damage.

Protective grounding

The user is responsible for compliance with all the existing international and national electrical codes concerning protective grounding of any device.

Please Note

Use the device's password protection feature to prevent untrained persons from interacting with this device.

⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

Electrical equipment should be installed, operated, serviced, and maintained only by trained and qualified personnel. No responsibility is assumed by Schneider Electric for any consequences arising out of the use of this material.

Failure to follow this instruction will result in death or serious injury.

1.2 Legal notice

Copyright

Disclaimer

No responsibility is assumed by Schneider Electric for any consequences arising out of the use of this document. This document is not intended as an instruction manual for untrained persons. This document gives instructions on device installation, commissioning and operation. However, the manual cannot cover all conceivable circumstances or include detailed information on all topics. In the event of questions or specific problems, do not take any action without proper authorization. Contact Schneider Electric and request the necessary information.

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1.3 Purpose

This document contains instructions on the installation, commissioning and operation of Easergy P3G30, P3G32.

This document is intended for persons who are experts on electrical power engineering, and it covers the relay models as described by the order code in Chapter 13 Order code.

Related documents

Document	Identification*)
P3 Advanced Quick Start	P3x3x/EN QS/xxxx
Easergy Pro Setting and Configuration Tool User Manual	P3eSetup/EN M/xxxx
RTD and mA Output/Input Modules User Manual	P3VIO12A/EN M/A001
Profibus Interface Module User Manual	P3VPA3CG/EN M/A001
IEC 61850 interface in Easergy P3 relays configuration instruction	P3APS17001EN
Rapid Spanning Tree Protocol (RSTP)	P3APS17002EN
EtherNet/IP configuration instructions	P3APS17003EN
Parallel Redundancy Protocol for Easergy P3 relays with dual-port 100 Mbps Ethernet interface	P3APS17004EN
Communication parameter protocol mappings	P3TDS17005EN
Easergy P3 protection functions' parameters and recorded values	P3TDS17006EN
DeviceNet and EtherNet/IP data model	P3APS17008EN
IEC103 Interoperability List	P3TDS17009EN
DNP 3.0 Device Profile Document	P3TDS17010EN
P3 Advanced Series facia label instruction	P3TDS17012EN
Principles of numerical protection techniques	P3INS17019EN

*) *xxxx = revision number*

Download the latest software from easergy.schneider-electric.com.

1.4 EU directive compliance

EMC compliance

CE 2014/30/EU

Compliance with the European Commission's EMC Directive. Product Specific Standard was used to establish conformity:

- EN 60255-26 2013

Product safety

CE 2014/35/EU

Compliance with the European Commission's Low Voltage Directive. Product Specific Safety Standard was used to establish conformity:

- EN 60255-27 2014

1.5 Abbreviations and terms

AFD	Arc flash detection
ANSI	American National Standards Institute. A standardization organisation.
bps	Bits per second
CB	Circuit breaker
CBFP	Circuit breaker failure protection
CLPU	Cold load pickup
CM	Common mode
Controlling output	Heavy duty output rated for the circuit breaker controlling
CPU	Central processing unit
cosφ	Active power divided by apparent power = P/S. (See power factor PF). Negative sign indicates reverse power.
CT	Current transformer
CT_{PRI}	Nominal primary value of current transformer
CT_{SEC}	Nominal secondary value of current transformer
Dead band	See hysteresis.
DI	Digital input
Digital output	Refers to relay's output contacts.
DM	Differential mode
DO	Digital output
Document file	Stores information about the relay settings, events and fault logs.
DSM	Distribution management system
DSR	Data set ready. An RS232 signal. Input in front panel port of Easergy P3 relays to disable rear panel local port.
DST	Daylight saving time. Adjusting the official local time forward by one hour for summer time.
DT	Definite time
DTR	Data terminal ready. An RS232 signal. Output and always true (+8 Vdc) in front panel port of Easergy P3 relays.
Easergy P3 Standard	Refers to P3U10, P3U20 and P3U30 relays
Easergy P3 Advanced	Refers to P3F30, P3L30, P3M30/32, P3GH30/32 and P3T32 relays
eSetup Easergy Pro	Setting and configuration tool for Easergy P3 protection relays, later called Easergy Pro
GOOSE	Generic object-oriented substation event: a specific definition of a type of generic substation event, for peer-peer communication.
Hysteresis	I.e. dead band. Used to avoid oscillation when comparing two near by values.
IDMT	Inverse definite minimum time
I_{MODE}	Nominal current of the selected mode. In feeder mode, I_{MODE}= $VT_{PRIMARY}$. In motor mode, I_{MODE}= I_{MOT}.
I_{MOT}	Nominal current of the protected motor
I_{GN}	Nominal current of the protected relay
I_N	Nominal current. Rating of CT primary or secondary.
I_{SET}	Pickup setting value I>

I_{0N}	Nominal current of I_0 input in general
IEC	International Electrotechnical Commission. An international standardization organisation.
IEC-101	Abbreviation for communication protocol defined in standard IEC 60870-5-101
IEC-103	Abbreviation for communication protocol defined in standard IEC 60870-5-103
IEEE	Institute of Electrical and Electronics Engineers
IRIG-B	Inter-Range Instrumentation Group time code B: standard for time transfer
LAN	Local area network. Ethernet-based network for computers and devices.
Latching	Digital outputs and indication LEDs can be latched, which means that they are not released when the control signal is releasing. Releasing of latched devices is done with a separate action.
LCD	Liquid crystal display
LED	Light-emitting diode
NTP	Network Time Protocol for LAN and WWW
OVF	Indication of the event overflow
P	Active power. Unit = [W]
PF	Power factor. The absolute value is equal to cosφ, but the sign is 'IND' for inductive i.e. lagging current and 'CAP' for capacitive i.e. leading current.
PLC	Programmable logic controller
P_M	Nominal power of the prime mover. (Used by reverse/under power protection.)
pu	Per unit. Depending of the context the per unit refers to any nominal value. For example for overcurrent setting 1 pu = 1 x I_{GN}.
P3G30	Refers P3G30 generator protection relay
Q	Reactive power. Unit = [var]
RELxxxxx	Short order code
RH	Relative humidity
RMS	Root mean square
RS232 or RS485 (EIA-232 or EIA-485)	Standard defining the electrical characteristics of a serial communication interface
RTU	Remote terminal unit
S	Apparent power. Unit = [VA]
SCADA	Supervisory control and data acquisition
SF	Alarm duty watchdog output is energized when the auxiliary power supply is on and the product status is operative. This output is referenced as "service status output" in the setting tool.
Signaling output	Alarm duty output rated, not suitable for direct circuit breaker controlling
SNTP	Simple Network Time Protocol for LAN and WWW
SOTF	Switch on to fault
SPST	Single pole single throw
SPDT	Single pole double throw
TCS	Trip circuit supervision
THD	Total harmonic distortion
U_{0SEC}	Voltage at input U_c at zero ohm ground fault. (Used in voltage measurement mode “2LL+U_0”)
U_A	Voltage input for U_{12} or U_{L1} depending of the voltage measurement mode

U_B	Voltage input for U_{23} or U_{L2} depending of the voltage measurement mode
U_C	Voltage input for U_{31} or U_0 depending of the voltage measurement mode
U_N	Nominal voltage. Rating of VT primary or secondary
UMI	User Machine Interface
USB	Universal serial bus
UTC	Coordinated Universal Time (used to be called GMT = Greenwich Mean Time)
Webset	http configuration interface
VI	Virtual input
VO	Virtual output
VT	Voltage transformer
VT_{PRI}	Nominal primary value of voltage transformer
VT_{SEC}	Nominal secondary value of voltage transformer

2 Introduction

2.1 Product overview

The relay has a modular design, and it can be optimized to medium and big sized generators.

Main characteristic and options

- The relay is a generator-block transformer protection relay for medium sized generators in power generation. Synchrochec and auto-reclosing extend automatic network control
- The relay has an optional interface for connecting 4 arc flash point sensors.
- Two alternative display options
  -128 x 128 LCD matrix
  -128 x 128 LCD matrix detachable
- Power quality measurements and disturbance recorder enable capture of quick network phenomena
- Wide range of communication protocols i.e. IEC61850, Profibus DP to Modbus TCP

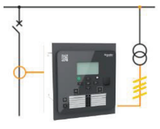
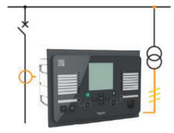
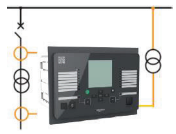
The following options depend on the order code:

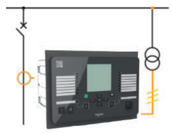
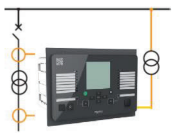
- multiple power supply options
- earth fault overcurrent input sensitivity
- amount of digital inputs
- amount of trip contacts
- integrated arc-options (point sensors)
- various possibilities with communication interfaces

The relay has good protection against harsh environments. The front panel protection level is IP54.

2.2 Product selection guide

The selection guide by application suggests Easergy P3 types suitable for your protection requirements, based on your application characteristics. The most typical applications are presented along with the associated Easergy P3 type.

		Easergy P3 Standard			Easergy P3 Advanced	
						
Voltage		-	-	P3U30 with directional o/c with voltage protection		-
Feeder		P3U10	P3U20		P3F30 w. directional P3L30 w. line diff. & distance	-
Transformer					-	P3T32 with differential
Motor					P3M30	P3M32 with differential
Generator					P3G30	P3G32 with differential
Measuring inputs	Phase Current	1/5A CT (x3)			1/5A CT (x3)	1/5A CT (x6)
	Residual Current	1/5A CT or 0.2/1A CT			5/1A+1/0.2A	5/1A+1/0.2A + 5/1A CT
	Voltage	VT (x1)		VT (x4)	VT (x4)	VT (x4)
Arc-flash sensor input		-			0 to 4 point sensor	0 to 4 point sensor
Digital	Input	2	8/10	16	6 to 36	6 to 16
	Output	5 + SF	5/8 + SF	8 + SF	10 to 21 + SF	10 to 13 + SF
Analogue	Input	-	0 or 4 [4]		0 or 4 [4]	
	Output	-	0 or 4 [4]		0 or 4 [4]	
Temperature sensor input		-	0 or 8 or 12 [4]		0 or 8 or 12 [4]	
Front port		USB			USB	
Nominal power supply		24 V dc or 48-230 V ac/dc			24-48 V dc or 110-240 V ac/dc	
Ambient temperature, in service		-40 to 60°C (-40 to 140°F)			-40 to 60°C (-40 to 140°F)	

		Easergy P3 Standard			Easergy P3 Advanced	
						
Communication						
Rear ports	RS-232	-	■		■	■
	IRIG/B		■		■	■
	RS-485	-	■		Using external I/O module	Using external I/O module
	ETHERNET	-	■		■	■
Protocols	IEC61850 Ed1 & Ed2	-	■	■	■	■
	IEC 60870-5-101	-	■	■	■	■
	IEC 60870-5-103	-	■	■	■	■
	DNP3 Over Ethernet	-	■	■	■	■
	Modbus serial	-	■	■	■	■
	Modbus over Ether-net	-	■	■	■	■
	EtherNet/IP	-	■	■	■	■
	DeviceNet	-	■	■	■	■
	Profibus DP	-	■	■	■	■
	SPAbus	-	■	■	■	■
Redund-ancy proto-cols	RSTP	-	■	■	■	■
	PRP	-	■	■	■	■
Others						
Control		1 object Mimic	6 objects + 2 monitored objects Mimic		6 objects + 2 monitored objects Mimic	
Logic	Matrix	■			■	
	Logic Equations	■			■	
Cyber security		Password			Password	
Withdrawability (Pluggable connector)		■			-	
Remote UMI		-			■	

NOTE: The numbers in the following tables represent the amount of stages available for each Easergy P3 type.

Protection functions	ANSI code	Feeder P3U10/20	Feeder P3U30	Motor P3U10/20	Motor P3U30	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Distance	21	-	-	-	-	-	1	-	-	-	-	-
Under-impedance	21G	-	-	-	-	-	-	-	-	2	2	-
Fault locator	21FL	-	1	-	1	1	1	-	-	-	-	-
Overfluxing	24	-	-	-	-	-	-	-	-	1	1	1
Synchronization check (5)	25	-	2	-	2	2	2	2	2	2	2	2
Undervoltage	27	-	3	-	3	3	3	3	3	3	3	3
Positive sequence under-voltage	27P	-	-	-	-	-	-	-	-	2	2	-
Directional active under-power	32	-	2	-	2	2	2	2	2	2	2	2
Phase undercurrent	37	1	1	1	1	-	-	1	1	-	-	-
Temperature monitoring	38/49T	12 (4)	12 (4)	12 (4)	12 (4)	12 (4)	12 (4)	12 (4)	12 (4)	12 (4)	12 (4)	12 (4)
Loss of field	40	-	-	-	-	-	-	-	-	1	1	-
Under-reactance	21/40	-	-	-	-	-	-	-	-	2	2	-
Negative sequence overcur-rent (motor, generator)	46	-	-	2	2	-	-	2	2	2	2	2
Cur. unbalance, broken con-ductor	46BC	1	1	-	-	1	1	-	-	-	-	-
Incorrect phase sequence	47	-	-	1	1	-	-	1	1	-	-	-
Excessive start time, locked rotor	48/51LR	-	-	1	1	-	-	1	1	-	-	-
Thermal overload	49	1	1	1	1	1	1	1	1	1	1	1
Phase overcurrent	50/51	3	3	3	3	3	3	3	3	3	3	3
Earth fault overcurrent	50N/51N	5	5	5	5	5	5	5	5	5	5	5
Breaker failure	50BF	1	1	1	1	1	1	1	1	1	1	1
SOTF	50HS	1	1	1	1	1	1	1	1	1	1	1
Capacitor bank unbalance (1)	51C	2	2	2	2	2	2	2	2	2	2	2
Voltage-dependent overcur-rent	51V	-	1	-	1	1	1	-	-	1	1	-
Overvoltage	59	-	3	-	3	3	3	3	3	3	3	3
Capacitor overvoltage	59C	1	1	-	-	1	1	-	-	-	-	-
Neutral voltage displacement	59N	3	3	3	3	2	2	2	2	2	2	2
CT supervision	60	1	1	1	1	1	1	1	1	1	2	2
VT supervision	60FL	-	1	-	1	1	1	1	1	1	1	1
Restricted earth fault (low impedance)	64REF	-	-	-	-	-	-	-	-	-	1	1
Stator earth fault	64S	-	-	-	-	-	-	-	-	1	1	-
Frequent start inhibition	66	-	-	1	1	-	-	1	1	-	-	-
Directional phase overcurrent	67	-	4	-	4	4	4	4	4	4	4	4
Directional earth fault o/c	67N	3	3	3	3	3	3	3	3	3	3	3
Transient intermittent	67NI	1	1	-	-	1	1	-	-	-	-	-
Magnetizing inrush detection	68F2	1	1	1	1	1	1	1	1	1	1	1
Fifth harmonic detection	68H5	1	1	1	1	1	1	1	1	1	1	1
Pole slip	78PS	-	-	-	-	-	-	-	-	1	1	-

Protection functions	ANSI code	Feeder P3U10/20	Feeder P3U30	Motor P3U10/20	Motor P3U30	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Auto-Recloser	79	5	5	-	-	5	5	-	-	-	-	-
Over or under frequency	81	-	2/2	-	2/2	2/2	2/2	2/2	2/2	2/2	2/2	2/2
Rate of change of frequency	81R	-	1	-	1	1	1	1	1	1	1	1
Under frequency	81U	-	2	-	2	2	2	2	2	2	2	2
Lockout	86	1	1	1	1	1	1	1	1	1	1	1
Line differential	87L	-	-	-	-	-	2	-	-	-	-	-
Machine differential	87M	-	-	-	-	-	-	-	2	-	2	-
Transformer differential	87T	-	-	-	-	-	-	-	-	-	-	2
Programmable stages	99	8	8	8	8	8	8	8	8	8	8	8
Arc flash detection (AFD)		-	-	-	-	8	-	8	8	8	8	8
Cold load pickup (CLPU)		1	1	1	1	1	1	1	1	1	1	1
Programmable curves		3	3	3	3	3	3	3	3	3	3	3
Setting groups (2)		4	4	4	4	4	4	4	4	4	4	4

Control functions	P3U10/20	P3U30	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Switchgear control and monitoring	1/2	4	6	6	6	6	6	6	6
Switchgear monitoring only	-	-	2	2	2	2	2	2	2
Programmable switchgear interlocking	■	■	■	■	■	■	■	■	■
Local control on single-line diagram	■	■	■	■	■	■	■	■	■
Local control with O/I keys	■	■	■	■	■	■	■	■	■
Local/remote function	■	■	■	■	■	■	■	■	■
Function keys	2	2	2	2	2	2	2	2	2
Custom logic (logic equations)	■	■	■	■	■	■	■	■	■
Control with Smart App	■	■	■	■	■	■	■	■	■

Measurement	P3U10/20	P3U30	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
RMS current values	■	■	■	■	■	■ (3)	■	■ (3)	■ (3)
RMS voltage values	■	■	■	■	■	■	■	■	■
RMS active, reactive and apparent power	-	■	■	■	■	■	■	■	■
Frequency	■	■	■	■	■	■	■	■	■
Fundamental frequency current values	■	■	■	■	■	■ (3)	■	■ (3)	■ (3)
Fundamental frequency voltage values	-	■	■	■	■	■	■	■	■
Fundamental frequency active, reactive and apparent power values	-	■	■	■	■	■	■	■	■
Power factor	-	■	■	■	■	■	■	■	■
Energy values active and reactive	-	■	■	■	■	■	■	■	■
Energy transmitted with pulse outputs	-	■	■	■	■	■	■	■	■
Demand values: phase currents	■	■	■	■	■	■	■	■	■
Demand values: active, reactive, apparent power and power factor	-	■	■	■	■	■	■	■	■
Min and max demand values: phase currents	■	■	■	■	■	■	■	■	■
Min and max demand values: RMS phase currents	■	■	■	■	■	■	■	■	■
Min and max demand values: active, reactive, apparent power and power factor	-	■	■	■	■	■	■	■	■

Measurement	P3U10/20	P3U30	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Maximum demand values over the last 31 days and 12 months: active, reactive, apparent power	-	■	■	■	■	■	■	■	■
Minimum demand values over the last 31 days and 12 months: active, reactive power	-	■	■	■	■	■	■	■	■
Max and min values: currents	■	■	■	■	■	■	■	■	■
Max and min values: voltages	-	■	■	■	■	■	■	■	■
Max and min values: frequency	■	■	■	■	■	■	■	■	■
Max and min values: active, reactive, apparent power and power factor	-	■	■	■	■	■	■	■	■
Harmonic values of phase current and THD	■	■	■	■	■	■ (3)	■	■ (3)	■ (3)
Harmonic values of voltage and THD	-	■	■	■	■	■	■	■	■
Voltage sags and swells	-	■	■	■	■	■	■	■	■

Logs and Records	P3U10/20	P3U30	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Sequence of event record	■	■	■	■	■	■	■	■	■
Disturbance record	■	■	■	■	■	■	■	■	■
Tripping context record	■	■	■	■	■	■	■	■	■

Monitoring functions	P3U10/20	P3U30	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Trip circuit supervision (ANSI 74)	1	1	1	1	1	1	1	1	1
Circuit breaker monitoring	1	1	1	1	1	1	1	1	1
Relay monitoring	■	■	■	■	■	■	■	■	■

NOTE:

(1) Capacitor bank unbalance protection is connected to the earth fault overcurrent input and shares 2 stages with the earth fault overcurrent protection.

(2) Not all protection functions have 4 setting groups. See details in the manual.

(3) Function available on both sets of CT inputs

(4) Using external RTD module

(5) The availability depends on the selected voltage measurement mode (in the **Scaling** setting view in Easergy Pro).

2.3 Presentation

Protection functions

- Universal, adaptive protection functions for user-configurable generator and block transformer protection applications
- Neutral voltage displacement, overvoltage and frequency protection including synchrocheck for two breakers
- Single-line diagram, measurements and alarms in the user-machine interface (UMI)
- User-configurable interlocking for primary object control
- Current and voltage injection by manipulating the database of the product by setting tool disturbance recorder file playback through the product's database

Robust hardware

- User-selectable Ethernet, RS485 or RS232 -based communication interfaces
- Designed for demanding industrial conditions with conformal-coated printed circuit boards
- Standard USB connection (type B) for Easergy Pro setting software

Common technology for cost efficiency

- Powerful CPU supporting IEC 61850
- Thanks to four setting groups, adaptation to various protection schemes is convenient

User-machine interface (UMI)

- Clear LCD display for alarms and events
- Single-line diagram mimic with control, indication and live measurements
- Programmable function keys and LEDs
- Circuit breaker ON/OFF control
- Common firmware platform with other other Easergy P3 range protection relays

2.4 Operating levels

The relay has three operating levels: **User**, **Operator** and **Configurator**. The purpose of the access levels is to prevent accidental or unwanted change of relay configurations, parameters or settings.

USER level

Use:	Possible to read for example parameter values, measurements and events
Opening:	Level permanently open
Closing:	Closing not possible

OPERATOR level

Use:	Possible to control objects and to change for example the settings of the protection stages
Opening:	The default password is 1.
Closing:	The level is automatically closed after 10 minutes idle time. Giving the password 9999 also closes the level.

CONFIGURATOR level

Use:	The configurator level is needed during the commissioning of the relay. For example the scaling of the voltage and current transformers can be set.
Opening:	The default password is 2.
Closing:	The level is automatically closed after 10 minutes idle time. Giving the password 9999 also closes the level.

Logging in via the front panel

1. Push and OK on the front panel. The **Enter password** view opens.

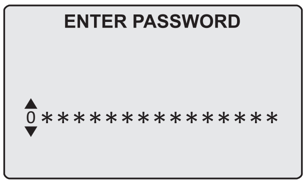


*Figure 2.1: **Enter password** view*

2. Enter the password for the desired access level. Select the desired digit value using , and if the password is longer than one digit, move to the next digit position using .

NOTE: There are 16 digit positions in the **Enter password** view. Enter the password starting from the first digit position.

Example: If the password is 2, you may enter 2*** or **2* or ***2 to log in. Do not type number 0 if it is not part of the password.

3. Push OK to confirm the password.

Password handling

You can change the passwords:

- in the **General > Device info** setting view in Easergy Pro connected to the USB port in the relay's front panel
- via Ethernet using Easergy Pro or the web server

NOTE: The password can contain 1-16 digits (no alphabets).

It is possible to restore a password if the password is lost or forgotten. To restore a password, a relay program is needed. The virtual serial port settings are 38400 bps, 8 data bits, no parity and 1 stop bit. The bit rate is configurable via the front panel.

Command	Description
get pwd_break	Get the break code (Example: 6569403)
get serno	Get the serial number of the relay (Example: 12345)

Send both numbers to your nearest Schneider Electric Customer Care Centre and ask for a password break. A relay-specific break code is sent back to you. That code is valid for the next two weeks.

Command	Description
set pwd_break=4435876	Restore the factory default passwords (“4435876” is just an example. The actual code should be asked from your nearest Schneider Electric Customer Care Centre.)

Now the passwords are restored to the default values.

Login to HTTP server and FTP

Protocol	Login name	Login password
HTTP	conf	2
FTP	easergy	config

2.5 Front panel

Easergy P3G30, P3G32 has a 128 x 128 LCD matrix display.

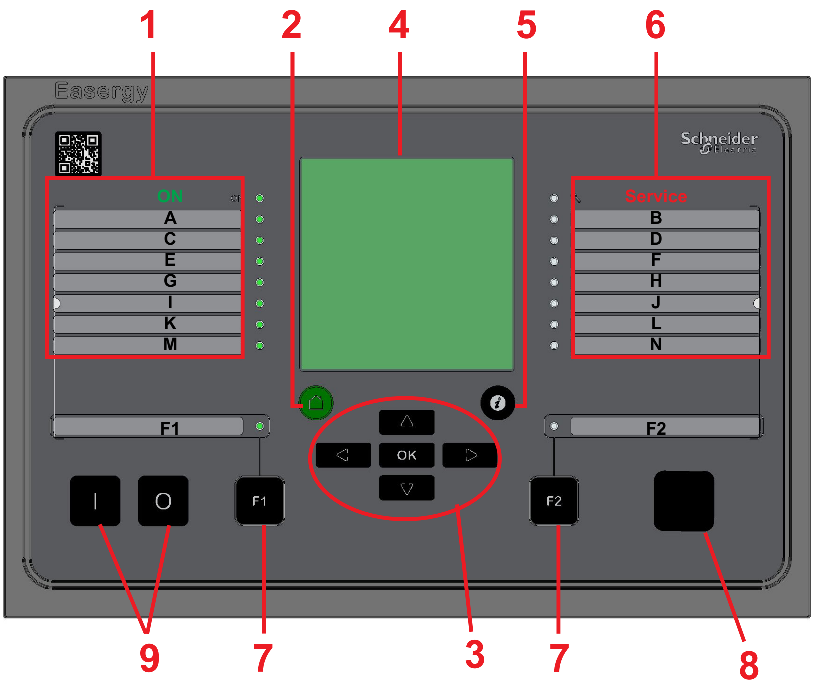


Figure 2.2: Easergy P3G30, P3G32 front panel

1	Power LED and 7 programmable LEDs
2	CANCEL push-button
3	Navigation push-buttons
4	LCD
5	INFO push-button
6	Status LED and 7 programmable LEDs
7	Function push-buttons and LEDs showing their status
8	Local port
9	Object control buttons

2.5.1 Push-buttons

Symbol	Function
	HOME/CANCEL push-button for returning to the previous menu. To return to the first menu item in the main menu, press the button for at least 3 seconds.
	INFO push-button for viewing additional information, for entering the password view and for adjusting the LCD contrast.
F1	Programmable function push-button. (*)
F2	Programmable function push-button. (*)
OK	ENTER push-button for activating or confirming a function.
△	UP navigation push-button for moving up in the menu or increasing a numerical value.
▽	DOWN navigation push-button for moving down in the menu or decreasing a numerical value.
◁	LEFT navigation push-button for moving backwards in a parallel menu or selecting a digit in a numerical value.
▷	RIGHT navigation push-button for moving forwards in a parallel menu or selecting a digit in a numerical value.
I	Circuit breaker ON push-button
O	Circuit breaker OFF push-button

NOTE:

*) The default names of the function buttons are Function button 1 and 2. You can change the names of the buttons in the **Inputs/outputs > Names for logic outputs** setting view.

2.5.2 LED indicators

The relay has 18 LEDs on the front panel:

- 2 LEDs for function buttons (F1 and F2)
- 2 LEDs represent the unit's general status (POWER and STATUS)
- 14 user-configurable LEDs (A - N)

When the relay is powered, the “POWER” LED lits as green. During normal use, the "STATUS" LED is not active, it activates only when an error occurs or the relay is not operating correctly. Should this happen, contact your local representative for further guidance.

The "STATUS" LED and watchdog contact are assigned to work together. Hardwire the status output into the substation's automation system for alarm purposes.

A LED can lit either green or red. The LEDs on the front panel can be configured in Easergy Pro.

To customise the LED texts on the front panel, the texts can be written on a template and then printed on a transparency. The transparencies can be placed in the pockets beside the LEDs.

You can also customize the LED texts that are shown on the screen for active LEDs via Easergy Pro.

Configuring the LED names via Easergy Pro

1. Go to **General > LED names**.
2. To change a LED name, click the LED **Description** text and type a new name. To save the new name, press **Enter**.

Led Names

LED	Description	LED	Description
LED A (green)	LED A (green)	LED B (green)	LED B (green)
LED A (red)	LED A (red)	LED B (red)	LED B (red)
LED C (green)	LED C (green)	LED D (green)	LED D (green)
LED C (red)	LED C (red)	LED D (red)	LED D (red)
LED E (green)	LED E (green)	LED F (green)	LED F (green)
LED E (red)	LED E (red)	LED F (red)	LED F (red)
LED G (green)	LED G (green)	LED H (green)	LED H (green)
LED G (red)	LED G (red)	LED H (red)	LED H (red)
LED I (green)	LED I (green)	LED J (green)	LED J (green)
LED I (red)	LED I (red)	LED J (red)	LED J (red)
LED K (green)	LED K (green)	LED L (green)	LED L (green)
LED K (red)	LED K (red)	LED L (red)	LED L (red)
LED M (green)	LED M (green)	LED N (green)	LED N (green)
LED M (red)	LED M (red)	LED N (red)	LED N (red)

Figure 2.3: LED NAMES menu in Easergy Pro for LED configuration

2.5.3 Controlling the alarm screen

You can enable or disable the alarm screen either via the relay's local display or using Easergy Pro:

- On the local display, go to **Events > Alarms**.
- In Easergy Pro, go to **General > Local panel conf**.

2.5.4 Accessing operating levels

1. On the front panel, press and OK.
2. Enter the four-digit password and press OK.

2.5.5 Adjusting the LCD contrast

Prerequisite: You have entered the correct password.

1. Press and adjust the contrast.
   - To increase the contrast, press .
   - To decrease the contrast, press .
2. To return to the main menu, press .

NOTE: By nature, the LCD display changes its contrast depending on the ambient temperature. The display may become dark or unreadable at low temperatures. However, this condition does not affect the proper operation of the protection or other functions.

2.5.6 Testing the LEDs and LCD screen

You can start the test sequence in any main menu window.
To start the LED and LCD test:

1. Press .
2. Press .

The relay tests the LCD screen and the functionality of all LEDs.

2.5.7 Controlling an object with selective control

Prerequisite: You have entered the correct password and enabled selective control in the OBJECTS setting view.
When selective control is enabled, the control operation needs confirmation (select before operate).

1. Press I to close object.
   - Press I again to confirm.
   - Press to cancel.
2. Press O to open object.
   - Press O again to confirm.
   - Press to cancel.

2.5.8 Controlling an object with direct control

Prerequisite: You have entered the correct password and enabled selective control in the OBJECTS setting view.

When direct control is enabled, the control operation is done without confirmation.

1. Log in to the system.
2. Press I to close object.
3. Press O to open object.

2.5.9 Menus

This section gives an overview of the menus that you can access via the relay's front panel.

The main menu

Press the right arrow to access more measurements in the main menu.

Table 2.1: Main menu

Menu name	Description
Active LEDs	User-configurable texts for active LEDs
Measure-ments	User-configurable measurements
Single line	Single line or Single line mimic, measurements and control view. This is a default start view. To return to this view from any location, press the HOME/CANCELL button for at least 3 seconds.
Info	Information about the relay: relay's name, order code, date, time and firmware version
P	Power: power factor and frequency values calculated by the relay. Press the right arrow to view more energy measurements.
E	Energy: the amount of energy that has passed through the protected line, calculated by the relay from the currents and voltages. Press the right arrow to view more energy measurements.
I	Current: phase currents and demand values of phase currents. Press the right arrow to view more current measurements.
U	Line-to-line voltages. Press the right arrow to view other voltage measurements.
Dema	Minimum and maximum phase current and power demand values
Umax	Minimum and maximum values of voltage and frequency
Imax	Minimum and maximum voltage values
Pmax	Minimum and maximum power values
Month	Monthly maximum current and power values
FL	Short-circuit locator applied to incomer or feeder
Evnt	Event log: event codes and time stamps
DR	Disturbance recorder configuration settings

Menu name	Description
Runh	Running hour counter
TIMR	Timers: programmable timers that you can use to preset functions
DI	Digital input statuses and settings
DO	Digital output statuses and settings
Arc	Arc flash protection settings
Prot	Protection: settings and statuses for various protection functions
I>, I>>, etc.	Protection stage settings and statuses. The availability of the menus are depends on the activated protection stages.
AR	Auto-reclosure settings, statuses and registers
OBJ	Objects: settings related to object status data and object control (open/closed)
Lgic	Logic events and counters
CONF	General device setup: CT and VT scalings, frequency adaptation, units, device info, date, time, clock, etc.
Bus	Communication port settings
Slot	Slot info: card ID (CID) that is the name of the card used by the relay firmware
Diag	Diagnosis: various diagnostic information

Moving in the menus

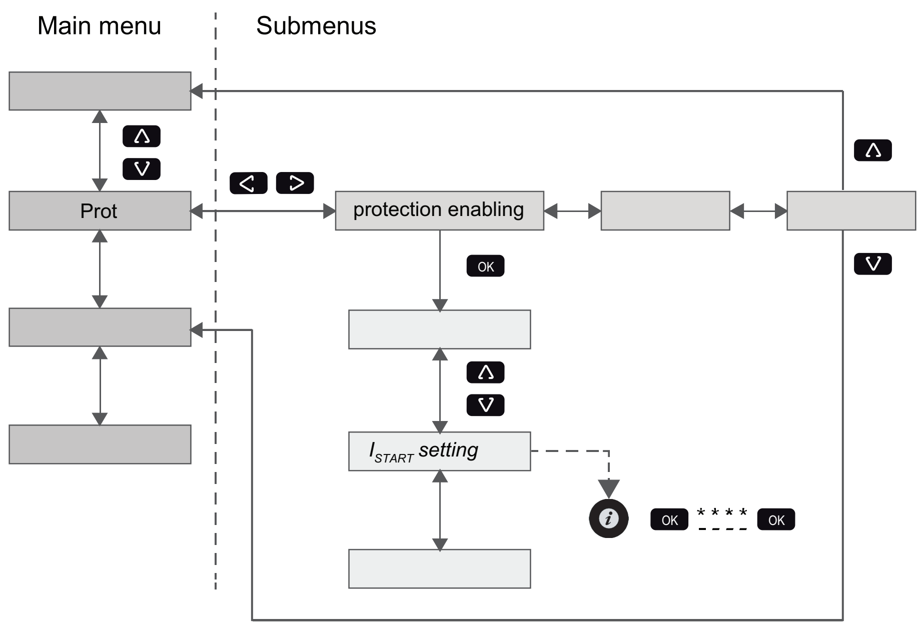


Figure 2.4: Moving in menus using the front panel

- To move in the main menu, press △ or ▽.
- To move in the submenus, press ▷ or ◁.
- While in the submenu, press △ or ▽ to jump to the root.
- To enter a submenu, press OK and use ▽ or △ for moving down or up in the menu.
- To edit a parameter value, press ⓘ and OK . Enter the four-digit password and press OK.
- To go back to the previous menu, press .
- To go back to the first menu item in the main menu, press for at least three seconds.

NOTE: To enter the parameter edit mode, enter the password. When the value is in edit mode, its background is dark.

Local panel messages

Value is not editable:	The value can not be edited or password is not given
Control disabled:	Object control disabled due to wrong operating level
Change will cause autoboot:	Notification that if the parameter is changed the relay boots itself

2.6 Easergy Pro setting and configuration tool

⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

Only qualified personnel should operate this equipment. Such work should be performed only after reading this entire set of instructions and checking the technical characteristics of the device.

Failure to follow this instruction will result in death or serious injury.

Easergy Pro is a software tool for configuring Easergy P3 relays. It has a graphical interface where the relay settings and parameters are grouped under seven tabs:

- General
- Measurements
- Inputs/outputs
- Protection
- Matrix
- Logs
- Communication

The contents of the tabs depend on the relay type and the selected application mode.

Easergy Pro stores the relay configuration in a setting file. The configuration of one physical relay is saved in one setting file. The configurations can be printed out and saved for later use.

For more information, see the Easergy Pro user manual.

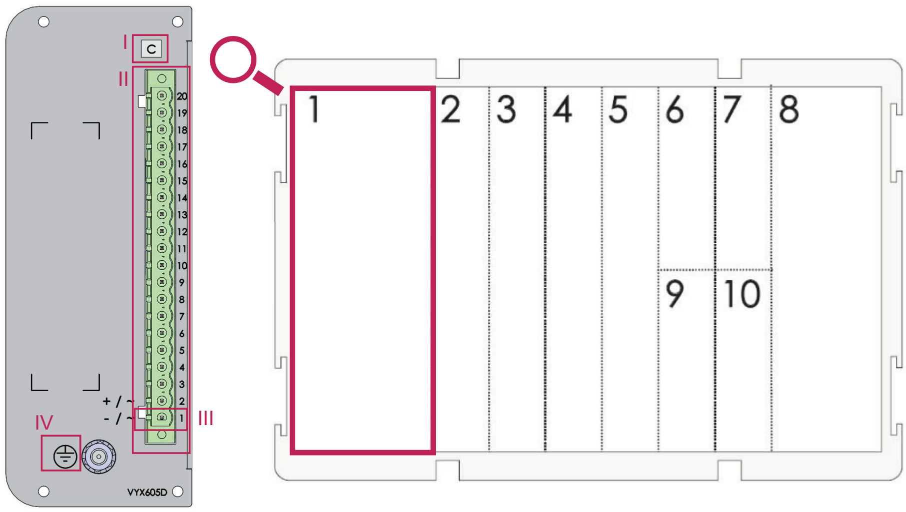
NOTICE
RISK OF SYSTEM SHUTDOWN After writing new settings or configurations to a relay, perform a test to verify that the relay operates correctly with the new settings. **Failure to follow these instructions can result in unwanted shutdown of the electrical installation.**

3 Mechanical structure

3.1 Modularity

The relay has a modular structure. The relay is built from hardware modules that are installed into 10 different slots at the back of the relay. The location of the slots is shown in Figure 3.1.

The type of the hardware modules is defined by the order code.



I	Card C	1	Supply voltage [V]
II	Connector 2	2, 3	I/O card
III	Pin 1	4, 5	I/O or analog measurement card
IV	Protective grounding	6, 9	Communication or I/O option card
		7, 8, 10	Analog measurement card (I, U)
		9, 10	Communication interface I and II

Figure 3.1: Slot numbering and card options in the Easergy P3G30, P3G32 rear panel and an example of defining the pin address 1/C/1:1

For complete availability information on the different option cards, see Chapter 13 Order code.

Chapter 10.5 Connections contains detailed information on each card.

Table 3.1: Example of typical model P3G30-CGIII-DAENA-BB

SLOT	NAME	TYPE
	Application	G30 = Generator protection relay
1	Supply voltage	C = 110 – 240 Vac/dc (6 x DO: 1 change over signal duty and 5 tripping duty)
2	I/O card I	G = 6DI+4DO (6 x DI, 4 x DO)
3	I/O card II	I = 10DI (10 x DI)
4	I/O card III	I = 10DI (10 x DI)
5	I/O card IV	I = 10DI (10 x DI)
6	Option card I	D = 4Arc (4 x Arc sensor)
7	Future option	A = None
8	Analog measurement card (See application)	E = 3L(5A)+4U+2IO (5/1A+1/0.2A)
9	Communication interface I	N = 2 x RJ (Ethernet RJ 100Mbs, RSTP, PRP)
10	Future option	A = None
	Display type	B = 128x128 (128 x 128 LCD matrix)
	DI nominal voltage	B = 110 Vdc/ac, with conformal coating
	Digital inputs	36 pcs
	Trip contacts	9 pcs
	Alarm contacts	1 pc
	Self-supervision contact	1 pc
	Phase currents (5A)	3 pcs
	Voltage channels	4 pcs
	Earth fault overcurrents (5/1A + 1/0.2A)	2 pcs
	Display	fixed in the relay

3.2 Slot info and order code

The relay's configuration can be checked via the front panel or Easergy Pro menu called **Slot** or **Slot info**. “Card ID” is the name of the card used by the relay firmware.

Slot Info

Slot	Card ID	Trace ID	FPGA program	Status
1	Power C	C577631644201450VB526F	-	OK
2	6DI+4DO	F837661650209172VB464F	-	OK
3	None	-	-	-
4	3'L+I'o	F862831641000075VB574C	-	OK
5	None	-	-	-
6	None	-	-	-
7	None	-	-	-
8	3L+4U+2Io	C577651650202217VB529F	-	OK
9	2EthRJ	C577731651201081VB577B	-	OK
10	None	-	-	-
Display	128x128	C581401647201973VB519F	-	OK
MB	3xx MB	F598471651005854VB356N	V1.09	OK

Figure 3.2: Hardware configuration example view from Easergy Pro configuration tool.

NOTE: See Chapter 13 Order code for the relay ordering options.

4 Measurement functions

Easergy P3 has various amounts of analog inputs depending on the model in use. Table 4.1 introduces directly measured and calculated quantities for the power system monitoring. See Chapter 2.2 Product selection guide.

The current scaling impacts the following functions:

- Protection stages
- Measurements
- Disturbance recorder
- Fault location calculation

Table 4.1: Measurement functions in Easergy P3

Measurements Specification	P3U10/20	P3U30	P3x3x	Measurement range	Inaccuracy
RMS phase current	■	■	■	0.025-50 x I_N	I ≤ 1.5 x I_N: ±0.5 % of value or ±15 mA I > 1.5 x I_N: ±3 % of value
RMS earth fault overcurrent	■	■	■	0.003-2 x I_N	I ≤ 1.5 xI0N: ±0.3 % of value or ±0.2 % of I0N I > 1.5 xI0N: ±3 % of value
RMS line-to-line voltage	-	■	■	0.005-1.7 x U_N	±0.5 % or ±0.3 V
RMS phase-to-neutral voltage	-	■	■	0.005-1.7 x U_N	±0.5 % or ±0.3 V
RMS active power (PF >0.5)	-	■	■	±0.1-1.5 x P_N	±1 % for range 0.3-1.5xP_N ±3 % for range 0.1-0.3xP_N
RMS reactive power (PF >0.5)	-	■	■	±0.1-1.5 x Q_N	±1 % for range 0.3-1.5xQ_N ±3 % for range 0.1-0.3xQ_N
RMS apparent power (PF >0.5)	-	■	■	±0.1-1.5 x S_N	±1 % for range 0.3-1.5xS_N ±3 % for range 0.1-0.3xS_N
Frequency	■	■	■	16 Hz-75 Hz	±10 mHz
Fundamental frequency current values	■	■	■	0.025-50 x I_N	I ≤ 1.5 x I_N: ±0.5 % of value or ±15 mA I > 1.5 x I_N: ±3 % of value
Fundamental frequency voltage values	-	■	■	0.005-1.7 x U_N	±0.5 % or ±0.3 V
Fundamental frequency active, reactive and apparent power values	-	■	■	±0.1-1.5 x P_N	±1 % for range 0.3-1.5xP_N ±3 % for range 0.1-0.3xP_N
Fundamental frequency active power values	-	■	■	±0.1-1.5 x Q_N	±1 % for range 0.3-1.5xQ_N ±3 % for range 0.1-0.3xQ_N
Fundamental frequency reactive power values	-	■	■	±0.1-1.5 x S_N	±1 % for range 0.3-1.5xS_N ±3 % for range 0.1-0.3xS_N
Power factor	-	■	■	0.02-1	±2° or ±0.02 for PF > 0.5
Active energy	-	■	■		±1 % for range 0.3-1.5xEP_N
Reactive energy	-	■	■		±1 %/1h for range 0.3-1.5xEQ_N ±3 %/1h for range 0.1-0.3xEQ_N
Energy transmitted with pulse outputs	-	■	■		±1 %/1h for range 0.3-1.5xEP_N ±3 %/1h for range 0.1-0.3xEP_N

Measurements Specification	P3U10/20	P3U30	P3x3x	Measurement range	Inaccuracy
Demand values: phase currents	■	■	■	0.025-50 x I_N	I ≤ 1.5 x I_N: ±0.5 % of value or ±15 mA I > 1.5 x I_N ±3 % of value
Active power demand	-	■	■	±0.1-1.5 x P_N	±1 % for range 0.3-1.5xP_N ±3 % for range 0.1-0.3xP_N
Reactive power demand	-	■	■	±0.1-1.5 x Q_N	±1 % for range 0.3-1.5xQ_N ±3 % for range 0.1-0.3xQ_N
Apparent power demand	-	■	■	±0.1-1.5 x S_N	±1 % for range 0.3-1.5xS_N ±3 % for range 0.1-0.3xS_N
Power factor demand	-	■	■		±2° or ±0.02 for PF > 0.5
Min and max demand values: phase currents	■	■	■	0.025-50 x I_N	I ≤ 1.5 x I_N: ±0.5 % of value or ±15 mA I > 1.5 x I_N ±3 % of value
Min and max demand values: RMS phase currents	■	■	■	0.025-50 x I_N	I ≤ 1.5 x I_N: ±0.5 % of value or ±15 mA I > 1.5 x I_N ±3 % of value
Min and max demand values: active, reactive, apparent power and power factor	-	■	■		±1 % for range 0.3-1.5xP_N, Q_N, S_N ±3 % for range 0.1-0.3xP_N, Q_N, S_N
Maximum demand values over the last 31 days and 12 months: active, reactive, apparent power	-	■	■		±1 % for range 0.3-1.5xP_N, Q_N, S_N ±3 % for range 0.1-0.3xP_N, Q_N, S_N
Minimum demand values over the last 31 days and 12 months: active, reactive power	-	■	■		±1 % for range 0.3-1.5xP_N, Q_N, S_N ±3 % for range 0.1-0.3xP_N, Q_N, S_N
Max and min values: currents	■	■	■	0.025-50 x I_N	I ≤ 1.5 x I_N: ±0.5 % of value or ±15 mA I > 1.5 x I_N ±3 % of value
Max and min values: voltages	-	■	■	0.005-1.7 x U_N	±0.5 % or ±0.3 V
Max and min values: frequency	■	■	■	16 Hz-75 Hz	±10 mHz
Max andmin values: active, reactive, apparent power and power factor	-	■	■	±0.1-1.5 x P_N, Q_N, S_N	±1 % for range 0.3-1.5xP_N, Q_N, S_N ±3 % for range 0.1-0.3xP_N, Q_N, S_N ±2° or ±0.02 for PF > 0.5
Harmonic values of phase current and THD	■	■	■	2nd-15th	
Harmonic values of voltage and THD	-	■	■	2nd-15th	
Voltage sags and swells	-	■	■	0.005-1.7 x U_N	±2° or ±0.02 for PF > 0.5

NOTE: Measurement display's refresh rate is 0.2 s.

4.1 Primary, secondary and per unit scaling

Many measurement values are shown as primary values although the relay is connected to secondary signals. Some measurement values are shown as relative values - per unit or per cent. Almost all start setting values use relative scaling.

The phase current and earth fault overcurrent scaling parameters are listed in Table 4.2.

Table 4.2: Scaling parameters

Parameter	Description
CT' primary	Primary current value of the current transformer at I' side (only P3x32 relays)
CT' secondary	Secondary current value of the current transformer at I' side (only P3x32 relays)
Nominal input (IL side)	Rated value of the phase current input. The given thermal withstand, burden and impedance are based on this value. See Table 10.26 for details.
Nominal input (I'L side)	Rated value of the phase current input at I' side. The given thermal withstand, burden and impedance are based on this value (only P3x32 relays). See Table 10.26 for details.
CT primary	Primary current value of the IL current transformer
CT secondary	Secondary current value of the IL current transformer
Io1 CT primary	Primary current value of the earth fault Io1 overcurrent transformer
Io1 CT secondary	Secondary current value of the earth fault Io1 overcurrent transformer
Nominal Io1 input	Selectable nominal input rating for the earth fault overcurrent input. Select either 5A or 1A depending on which Io input is used. The given thermal withstand, burden and impedance are based on this value. See Table 10.26 for details.
Io2 CT primary	Primary current value of the earth fault Io2 overcurrent transformer
Io2 CT secondary	Secondary current value of the earth fault Io2 overcurrent transformer
Nominal Io2 input	Selectable nominal input rating for the earth fault overcurrent input. Select either 1A or 0.2A depending on which Io input is used. The given thermal withstand, burden and impedance are based on this value. See Table 10.26 for details.
Io3 CT primary	Primary current value of the earth fault Io3 overcurrent transformer
Io3 CT secondary	Secondary current value of the earth fault Io3 overcurrent transformer
Nominal Io3 input	Selectable nominal input rating for the earth fault overcurrent input. Select either 1A or 0.2A depending on which Io input is used. The given thermal withstand, burden and impedance are based on this value. See Table 10.26 for details.
VT primary	Primary voltage value of the voltage transformer
VT secondary	Secondary voltage alue of the voltage transformer
VTo secondary	Secondary voltage value of the neutral voltage displacement voltage transformer
Voltage measurement mode	The relay can be connected either to zero-sequence voltage, line-to-line voltage or line-to-neutral voltage. Set the voltage measurement mode according to the type of connection used.

Parameter	Description
Frequency adaptation mode	Parameter used to set the system frequency. There are three modes available: manual, auto and fixed. For more information, see section Frequency adaptation mode.
Adapted frequency	When the frequency adaption mode is set to manual, you can set the frequency in the **Adapted frequency** field, and it is not be updated even if the measured frequency is different.
Angle memory duration	Time setting for the directional overcurrent stage to keep the phase angle fixed if the system voltage collapses
I' 180 deg. angle turn	A setting to turn I' currents 180 degrees (only P3x32 relays)
Generator nominal power	Electrical power of the generator
Generator nominal voltage	Nominal voltage of the generator
Nominal shaft power Pm	Nominal mechanical power of the generator

The **Scaling** setting view in Easergy Pro is shown in Figure 4.1

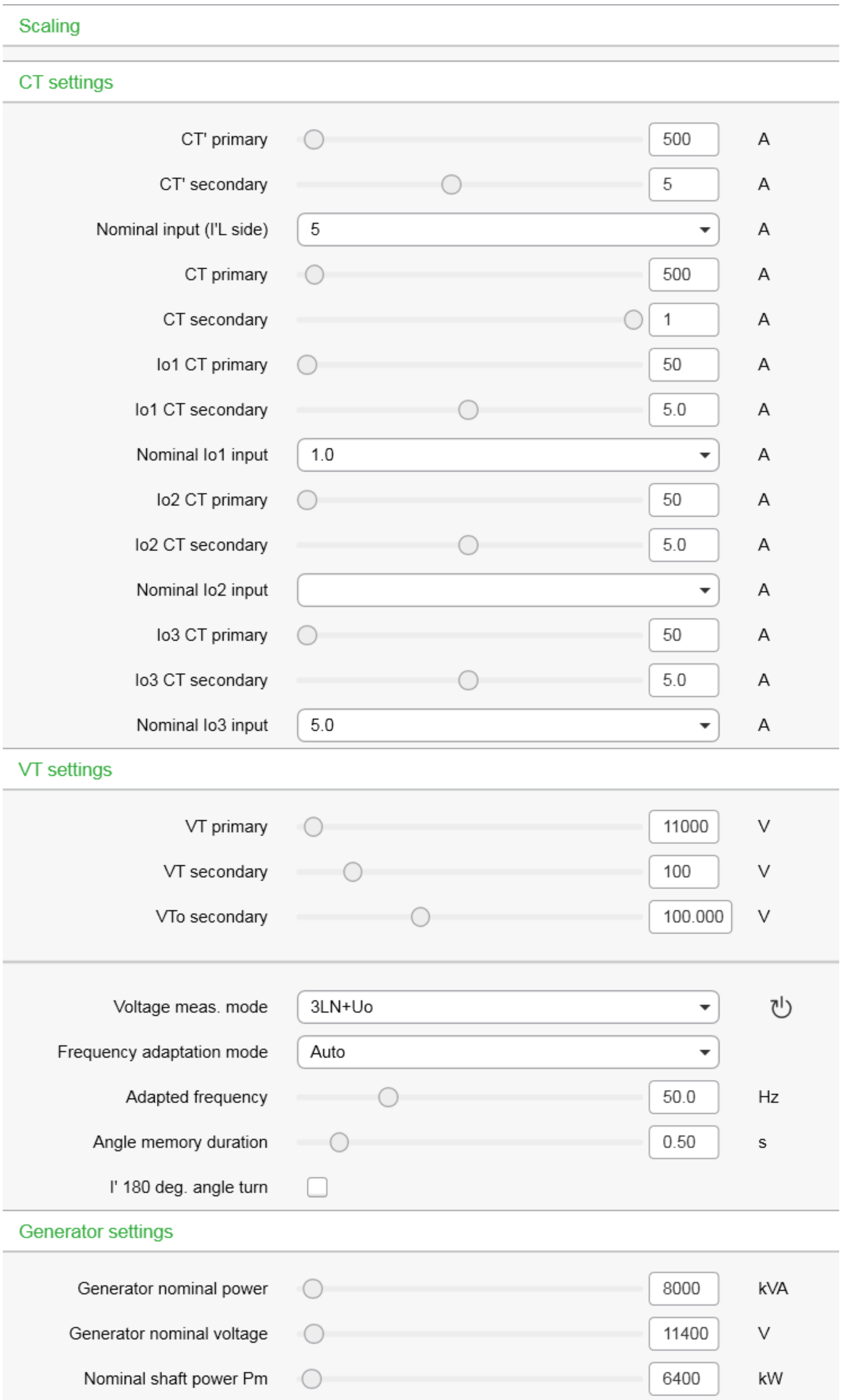


Figure 4.1: Scaling setting view

The scaling equations presented in Chapter 4.1.2 Current scaling and Chapter 4.1.3 Voltage scaling for analogue module E, F are useful when doing secondary testing.

4.1.1 Frequency adaptation mode

You can set the system frequency in **General > Scaling** in Easergy Pro. See .

There are three frequency adaptation modes available:

- **Manual**: When the adaption mode is set to manual, you can set the frequency in the **Adapted frequency** field, and it will not be updated even if the measured frequency is different. However, the relay monitors the system frequency internally and adapts to the new frequency even if the frequency has been set manually.
- **Auto**: The network frequency is automatically updated when the relay has measured the voltage for approximately 45 seconds. The **Adapted frequency** field is updated even if it has been set previously. The frequency is measured from the voltage signals listed in Table 4.3.

  Table 4.3: Voltage signals

Voltage measurement mode	Voltage	Voltage channel
2LL+U_0, 2LL+U_0/LNy, 2LL+U_0/LLy	U12, U23	U1, U2
3LN, 3LN+U_0, 3LN/LNy, 3LN/LLy	UL1, UL2	U1, U2
LN+$U_{0/y/z}$	UL1	U1
LL+$U_{0/y/z}$	U12	U1

- **Fixed**: The frequency is not updated based on the measured voltage and only the set value is used. This mode is recommended to be used for the line-differential function.

4.1.2 Current scaling

NOTE: The rated value of the relay's current input, for example 5 A or 1A, does not have any effect in the scaling equations, but it defines the measurement range and the maximum allowed continuous current. See Table 10.26 for details.

Primary and secondary scaling

	Current scaling
secondary → primary	$I_{PRI} = I_{SEC} \cdot \frac{CT_{PRI}}{CT_{SEC}}$
primary → secondary	$I_{SEC} = I_{PRI} \cdot \frac{CT_{SEC}}{CT_{PRI}}$

For earth fault overcurrent to input I_0, use the corresponding CT_{PRI} and CT_{SEC} values. For ground fault stages using I_{0Calc} signals, use the phase current CT values for CT_{PRI} and CT_{SEC}.

Examples:

1. **Secondary to primary**
   CT = 500 / 5
   Current to the relay's input is 4 A.
   => Primary current is I_{PRI} = 4 x 500 / 5 = 400 A
2. **Primary to secondary**
   CT = 500 / 5
   The relay displays I_{PRI} = 400 A
   => Injected current is I_{SEC} = 400 x 5 / 500 = 4 A

Per unit [pu] scaling

For phase currents excluding ArcI> stage:

1 pu = 1 x I_{GN} = 100 %, where I_{GN} is the rated current of the generator.

The rated current for high voltage side (HV) and low voltages side (LV) are calculated by the relay itself using Equation 4.1.

Equation 4.1:

$$I_{GN} = \frac{S_{GN}}{\sqrt{3} \cdot U_{GN}}$$

I_{GN} =	The rated current 1 pu.
S_{GN} =	Rated apparent power of the protected relay
U_{GN} =	Rated line-to-line voltage of the protected relay

For earth fault overcurrents and ArcI> stage:

1 pu = 1 x CT_{SEC} for secondary side and 1 pu = 1 x CT_{PRI} for primary side.

	Phase current scaling excluding ArcI> stage	Earth fault overcurrent ($3I_0$) scaling
secondary → per unit	$I_{PU} = \frac{I_{SEC} \cdot CT_{PRI}}{CT_{SEC} \cdot I_{GN}}$	$I_{PU} = \frac{I_{SEC}}{CT_{SEC}}$
per unit → secondary	$I_{SEC} = I_{PU} \cdot CT_{SEC} \cdot \frac{I_{GN}}{CT_{PRI}}$	$I_{SEC} = I_{PU} \cdot CT_{SEC}$

Examples:

1. **Secondary to per unit for ArcI>**
   CT = 750 / 5
   Current injected to the relay's inputs is 7 A.
   Per unit current is I_{PU} = 7 / 5 = 1.4 pu = 140 %
2. **Secondary to per unit for phase currents excluding ArcI>**
   CT = 750/5
   I_{GN} = 525 A
   Current injected to the relay's inputs is 7 A.
   Per unit current is I_{PU} = 7 x 750 / (5 x 525) = 2.00 pu = 2.00 x I_{GN} = 200 %

3. **Per unit to secondary for ArcI>**
   CT = 750 / 5
   The relay setting is 2 pu = 200 %.
   Secondary current is I_{SEC} = 2 x 5 = 10 A
4. **Per unit to secondary for phase currents**
   CT = 750 / 5
   I_{GN} = 525 A
   The relay setting is 2 x I_{GN} = 2 pu = 200 %.
   Secondary current is I_{SEC} = 2 x 5 x 525 / 750 = 7 A
5. **Secondary to per unit for earth fault overcurrent**
   Input is I_{01}.
   CT_0 = 50 / 1
   Current injected to the relay's input is 30 mA.
   Per unit current is I_{PU} = 0.03 / 1 = 0.03 pu = 3 %
6. **Secondary to per unit for earth fault overcurrent**
   Input is I_{01}.
   CT_0 = 50 / 1
   The relay setting is 0.03 pu = 3 %.
   Secondary current is I_{SEC} = 0.03 x 1 = 30 mA
7. **Secondary to per unit for earth fault overcurrent**
   Input is I_{0Calc}.
   CT = 750 / 5
   Currents injected to the relay's I_{L1} input is 0.5 A.
   I_{L2} = I_{L3} = 0.
   Per unit current is I_{PU} = 0.5 / 5 = 0.1 pu = 10 %
8. **Secondary to per unit for earth fault overcurrent**
   Input is I_{0Calc}.
   CT = 750 / 5
   The relay setting is 0.1 pu = 10 %.
   If I_{L2} = I_{L3} = 0, then secondary current to I_{L1} is
   I_{SEC} = 0.1 x 5 = 0.5 A

4.1.3 Voltage scaling for analogue module E, F

NOTE: Voltage transformer scaling is based on the line-to-line voltages in all voltage measurements modes.

Primary/secondary scaling of line-to-line voltages

	Line-to-line voltage scaling	
	Voltage measurement mode = "2LL+U_0"	Voltage measurement mode = "3LN"
secondary → primary	$U_{PRI} = U_{SEC} \cdot \frac{VT_{PRI}}{VT_{SEC}}$	$U_{PRI} = \sqrt{3} \cdot U_{SEC} \cdot \frac{VT_{PRI}}{VT_{SEC}}$
primary → secondary	$U_{SEC} = U_{PRI} \cdot \frac{VT_{SEC}}{VT_{PRI}}$	$U_{SEC} = \frac{U_{PRI}}{\sqrt{3}} \cdot \frac{VT_{SEC}}{VT_{PRI}}$

Examples

1. **Secondary to primary. Voltage measurement mode is "2LL+U_0"**
   VT = 12000/110
   Voltage connected to the relay's input U_A or U_B is 100 V.
   => Primary voltage is U_{PRI} = 100x12000/110 = 10909 V.
2. **Secondary to primary. Voltage measurement mode is "3LN**
   VT = 12000/110
   Three phase symmetric voltages connected to the relay's inputs U_A, U_B and U_C are 57.7 V.
   => Primary voltage is U_{PRI} = $\sqrt{3}$ x58x12000/110 = 10902 V
3. **Primary to secondary. Voltage measurement mode is "2LL+U_0"**
   VT = 12000/110
   The relay displays U_{PRI} = 10910 V.
   => Secondary voltage is U_{SEC} = 10910x110/12000 = 100 V
4. **Primary to secondary. Voltage measurement mode is "3LN**
   VT = 12000/110
   The relay displays $U_{12} = U_{23} = U_{31}$ = 10910 V.
   => Symmetric secondary voltages at U_A, U_B and U_C are U_{SEC} = 10910/$\sqrt{3}$ x110/12000 = 57.7 V.

Per unit [pu] scaling of line-to-line voltages

One per unit = 1 pu = 1xU_N = 100 %, where U_N = rated voltage of the VT.

	Line-to-line voltage scaling	
	Voltage measurement mode = "2LL+U_0", "1LL+U_0/LLy", "2LL/LLy", "LL/LLy/LLz"	**Voltage measurement mode = "3LN"**
secondary → per unit	$U_{PU} = \frac{U_{SEC}}{VT_{SEC}} \cdot \frac{VT_{PRI}}{U_N}$	$U_{PU} = \sqrt{3} \cdot \frac{U_{SEC}}{VT_{SEC}} \cdot \frac{VT_{PRI}}{U_N}$
per unit → secondary	$U_{SEC} = U_{PU} \cdot VT_{SEC} \cdot \frac{U_N}{VT_{PRI}}$	$U_{SEC} = U_{PU} \cdot \frac{VT_{SEC}}{\sqrt{3}} \cdot \frac{U_N}{VT_{PRI}}$

Examples

1. **Secondary to per unit. Voltage measurement mode is "2LL+U_0"**
   VT = 12000/110
   Voltage connected to the relay's input U_A or U_B is 110 V.
   => Per unit voltage is U_{PU} = 110/110 = 1.00 pu = 1.00xU_N = 100 %
2. **Secondary to per unit. Voltage measurement mode is "3LN"**
   VT = 12000/110
   Three symmetric phase-to-neutral voltages connected to the relay's inputs U_A, U_B and U_C are 63.5 V
   => Per unit voltage is U_{PU} = $\sqrt{3}$x63.5/110x12000/11000 = 1.00 pu = 1.00xU_N = 100 %
3. **Per unit to secondary. Voltage measurement mode is "2LL+U_0"**
   VT = 12000/110
   The relay displays 1.00 pu = 100 %.
   => Secondary voltage is U_{SEC} = 1.00x110x11000/12000 = 100.8 V
4. **Per unit to secondary. Voltage measurement mode is "3LN"**
   VT = 12000/110
   U_N = 11000 V
   The relay displays 1.00 pu = 100 %.
   => Three symmetric phase-to-neutral voltages connected to the relay 's inputs U_A,U_B and U_C are
   U_{SEC} = 1.00x110/$\sqrt{3}$ x11000/12000 = 58.2 V

Per unit [pu] scaling of neutral displacement voltage

	Neutral displacement voltage (U_0) scaling	
	Voltage measurement mode = "2LL+U_0", "1LL+U_0/LLy"	Voltage measurement mode = "3LN"
secondary → per unit	$U_{PU} = \frac{U_{SEC}}{U_{0SEC}}$	$U_{PU} = \frac{1}{VT_{SEC}} \cdot \frac{\left\lvert \overline{U}_a + \overline{U}_b + \overline{U}_c \right\rvert_{SEC}}{\sqrt{3}}$
per unit → secondary	$U_{SEC} = U_{PU} \cdot U_{0SEC}$	$\left\lvert \overline{U}_a + \overline{U}_b + \overline{U}_c \right\rvert_{SEC} = \sqrt{3} \cdot U_{PU} \cdot VT_{SEC}$

Examples

1. **Secondary to per unit. Voltage measurement mode is "2LL+U_0"**
   U_{0SEC} = 110 V (This is a configuration value corresponding to U_0 at full earth fault.)
   Voltage connected to the relay's input U_C is 22 V.
   => Per unit voltage is U_{PU} = 22/110 = 0.20 pu = 20 %
2. **Secondary to per unit. Voltage measurement mode is "3LN"**
   VT = 12000/110
   Voltage connected to the relay's input U_A is 38.1 V, while $U_A = U_B = 0$.
   => Per unit voltage is U_{PU} = ($\underline{38.1}$+$\underline{0}$+$\underline{0}$)/($\sqrt{3}$x110) = 0.20 pu = 20 %
3. **Per unit to secondary. Voltage measurement mode is "2LL+U_0"**
   U_{0SEC} = 110 V (This is a configuration value corresponding to U_0 at full earth fault.)
   The relay displays U_0 = 20 %.
   => Secondary voltage at input U_C is U_{SEC} = 0.20x110 = 22 V
4. **Per unit to secondary. Voltage measurement mode is "3LN"**
   VT = 12000/110
   The relay displays U_0 = 20 %.
   => If $U_B = U_C = 0$, then secondary voltages at U_A is
   USEC = $\sqrt{3}$x0.2x110 = 38.1 V

4.2 Measurements for protection functions

The relay uses root mean square (RMS) measurement for the protection stages if not stated otherwise in the protection stage description.

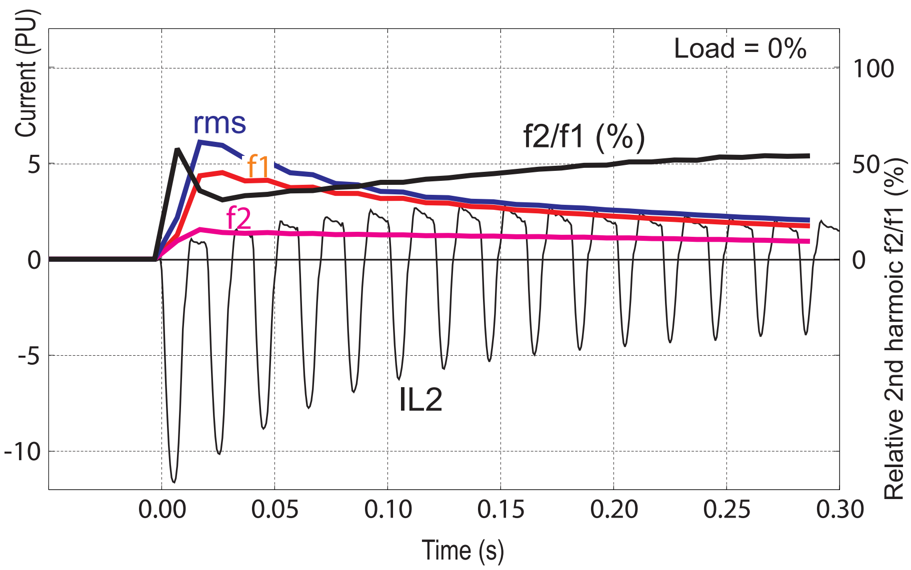


Figure 4.2: Example of various current values of a transformer inrush current

All the direct measurements are based on fundamental frequency values. The exceptions are frequency and instantaneous current for arc protection. Most protection functions are also based on the fundamental frequency values.

Figure 4.2 shows a current waveform and the corresponding fundamental frequency component f1, second harmonic f2, and RMS value in a special case where the current deviates significantly from a pure sine wave.

4.3 Measurements for arc protection function

The three-phase current measurement and ground fault current measurement for arc protection are done with electronics (see Figure 4.3). The electronics compares the current levels to the start settings - THRESHOLDs - and gives a binary signals “I>” or “I_{01}>” to the arc protection function if limit is exceeded. All the frequency components of the currents are taken into account.

Signals “I>” or “I_0>” are connected to a FPGA chip which implements the arc protection function. The start settings are named “I> int” and “I_{01}> int” in the local LCD panel or Easergy Pro views, these settings are used to set the THRESHOLD levels for the electronics.

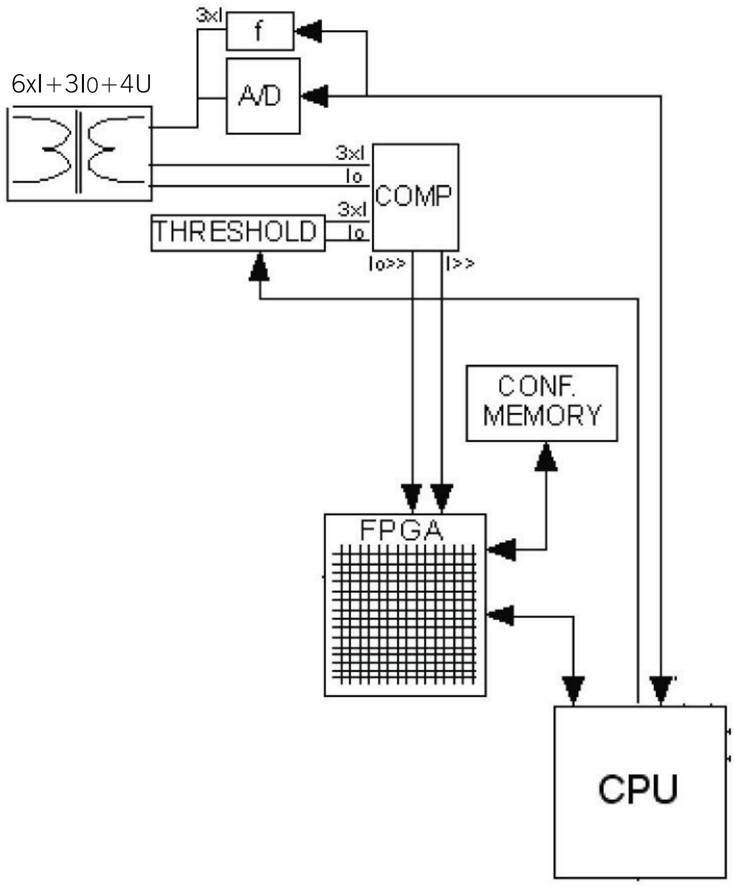


Figure 4.3: Measurement logic for the arc flash protection function

4.4 RMS values

RMS currents

The relay calculates the RMS value of each phase current. The minimum and maximum RMS values are recorded and stored (see Chapter 4.7 Minimum and maximum values).

$$I_{RMS} = \sqrt{I_{f1}^{\,2} + I_{f2}^{\,2} + \ldots + I_{f15}^{\,2}}$$

RMS voltages

The relay calculates the RMS value of each voltage input. The minimum and the maximum of RMS values are recorded and stored (see Chapter 4.7 Minimum and maximum values).

$$U_{RMS} = \sqrt{U_{f1}^{\,2} + U_{f2}^{\,2} + \ldots + U_{f15}^{\,2}}$$

4.5 Harmonics and total harmonic distortion (THD)

The relay calculates the the total harmonic distortions (THDs) as a percentage of the currents and voltages values measured at the fundamental frequency. The relay calculates the harmonics from the 2nd to the 15th of phase currents and voltages. (The 17th harmonic component is also shown partly in the value of the 15th harmonic component. This is due to the nature of digital sampling.)

The harmonic distortion is calculated

$$THD = \frac{\sqrt{\sum_{i=2}^{15} f_i^2}}{h_1}$$

f_1 = Fundamental value

f_{2-15} = Harmonics

Example

f_1 = 100 A, f_3 = 10 A, f_7 = 3 A, f_{11} = 8 A

$$THD = \frac{\sqrt{10^2 + 3^2 + 8^2}}{100} = 13.2\%$$

For reference the RMS value is

$$RMS = \sqrt{100^2 + 10^2 + 3^2 + 8^2} = 100.9A$$

Another way to calculate THD is to use the RMS value as reference instead of the fundamental frequency value. In the example above, the result would then be 13.0 %.

4.6 Demand values

The relay calculates average i.e. demand values of phase currents I_{L1}, I_{L2}, I_{L3} and power values S, P and Q.
The demand time is configurable from 10 to 60 minutes with the parameter "Demand time".

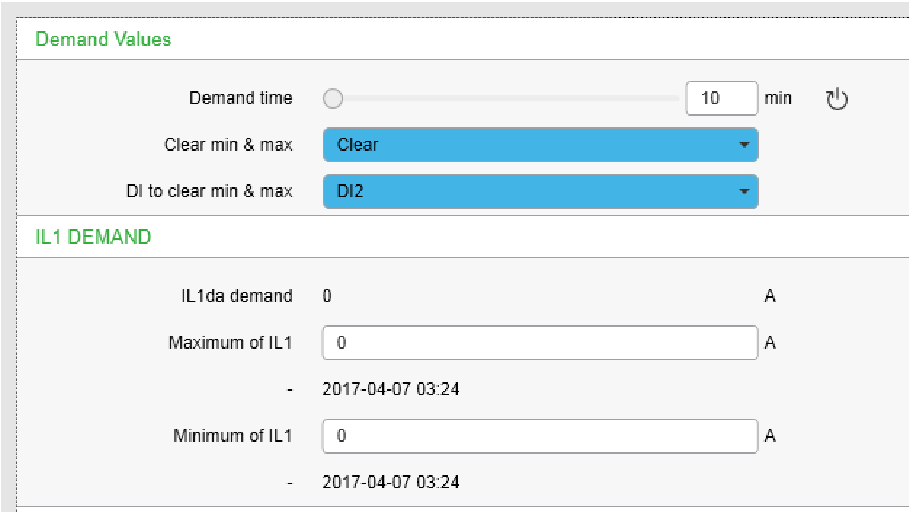


Figure 4.4: Demand values

Table 4.4: Demand value parameters

Parameter	Value	Unit	Description	Set
Time	10 – 30	min	Demand time (averaging time)	Set
Fundamental frequency values				
IL1da		A	Demand of phase current IL1	
IL2da		A	Demand of phase current IL2	
IL3da		A	Demand of phase current IL3	
Pda		kW	Demand of active power P	
PFda			Demand of power factor PF	
Qda		kvar	Demand of reactive power Q	
Sda		kVA	Demand of apparent power S	
RMS values				
IL1RMSda		A	Demand of RMS phase current IL1	
IL2RMSda		A	Demand of RMS phase current IL2	
IL3RMSda		A	Demand of RMS phase current IL3	
Prmsda		kW	Demand of RMS active power P	
Qrmsda		kvar	Demand of RMS reactive power Q	
Srmsda		kVA	Demand of RMS apparent power S	

Set = An editable parameter (password needed).

4.7 Minimum and maximum values

Minimum and maximum values are registered with time stamps since the latest manual clearing or since the relay has been restarted. The available registered values are listed in Table 4.5.

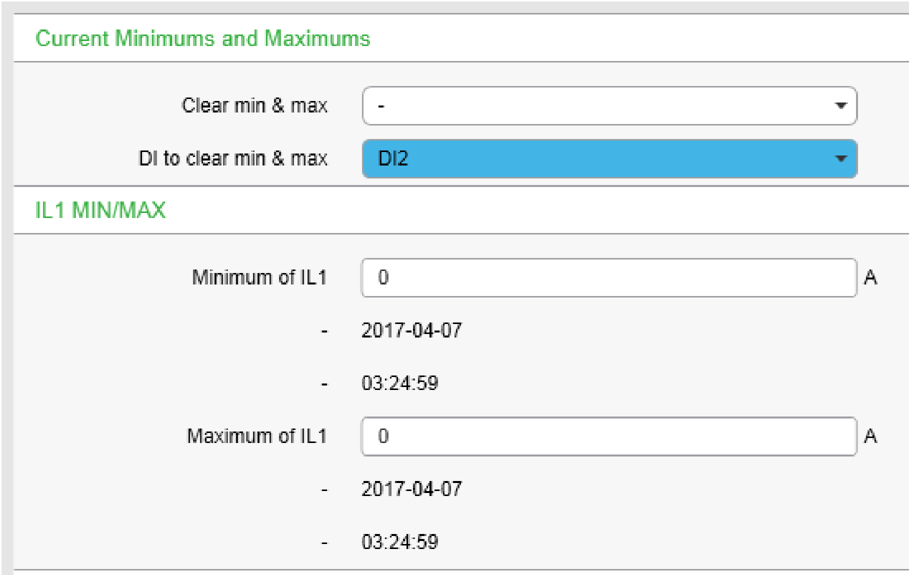


Figure 4.5: Minimum and maximum values

Table 4.5: Minimum and maximum measurement values

Min & Max measurement	Description
IL1, IL2, IL3	Phase current, fundamental frequency value
IL1RMS, IL2RMS, IL3RMS	Phase current, RMS value
I_{01}, I_{02}	Earth fault overcurrent, fundamental value
U_A, U_B, U_C, U_D	Voltages, fundamental frequency values
U_ARMS, U_BRMS, U_CRMS, U_DRMS	Line-to-neutral voltages, RMS value
Uo	Neutral voltage displacement, fundamental value
f	Frequency
P, Q, S	Active, reactive, apparent power
IL1da, IL2da, IL3da	Demand values of phase currents
IL1da, IL2da, IL3da (rms value)	Demand values of phase currents, rms values
P.F.	Power factor

The clearing parameter "ClrMax" is common for all these values.

Table 4.6: Parameters

Parameter	Value	Description	Set
ClrMax	-; Clear	Reset all minimum and maximum values	Set

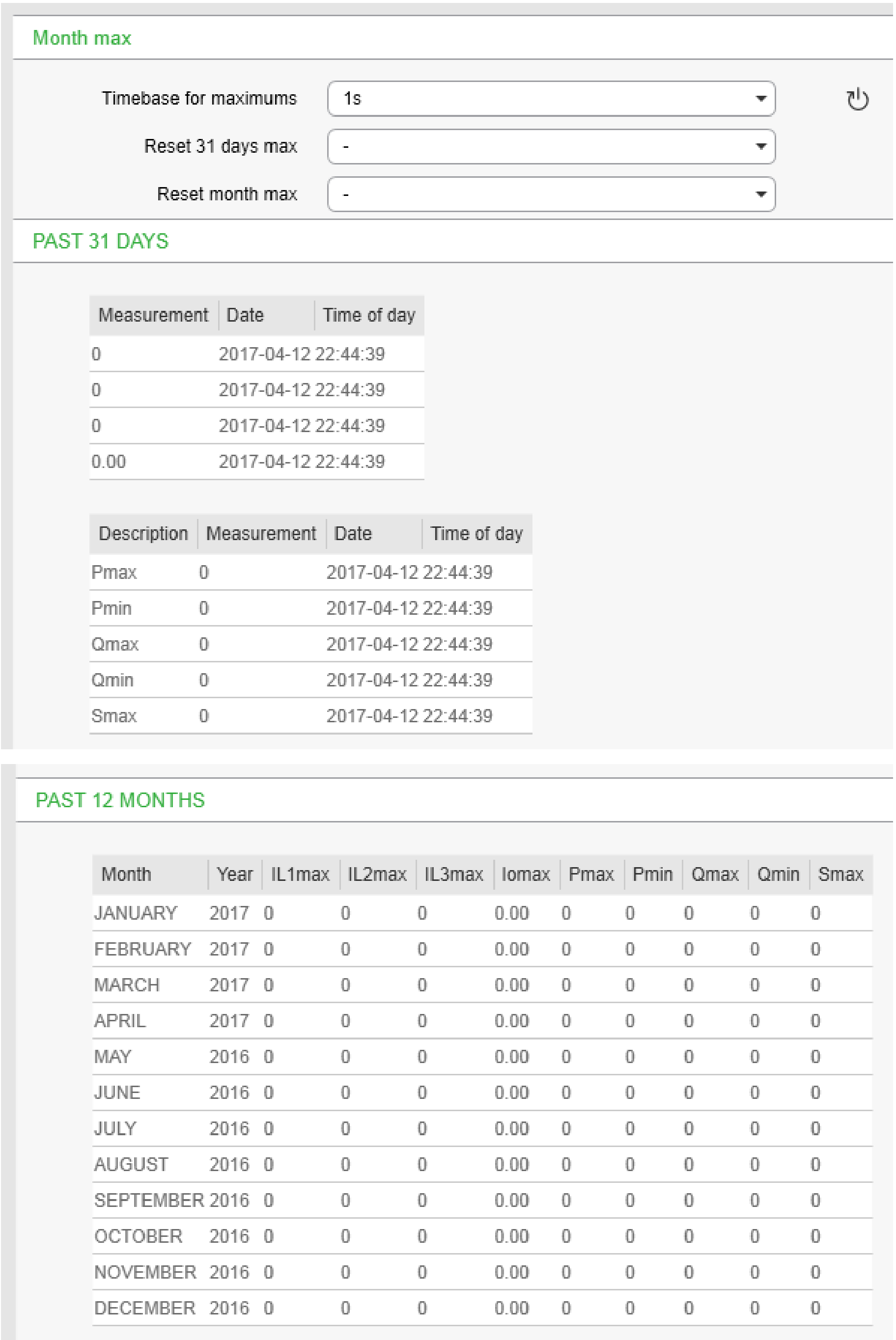
Set = An editable parameter (password needed).

4.8 Maximum values of the last 31 days and 12 months

The maximum and minimum values of the last 31 days and the last 12 months are stored in the relay's non-volatile memory.

NOTE: The saving process starts every 30 minutes and it takes a while. If the relay's auxiliary supply power is switched off before all values have been saved, the old values remain for the unsaved ones.

Corresponding time stamps are stored for the last 31 days. The registered values are listed in Table 4.7.



Measurement	Date	Time of day
0	2017-04-12	22:44:39
0	2017-04-12	22:44:39
0	2017-04-12	22:44:39
0.00	2017-04-12	22:44:39

Description	Measurement	Date	Time of day
Pmax	0	2017-04-12	22:44:39
Pmin	0	2017-04-12	22:44:39
Qmax	0	2017-04-12	22:44:39
Qmin	0	2017-04-12	22:44:39
Smax	0	2017-04-12	22:44:39

Month	Year	IL1max	IL2max	IL3max	Iomax	Pmax	Pmin	Qmax	Qmin	Smax
JANUARY	2017	0	0	0	0.00	0	0	0	0	0
FEBRUARY	2017	0	0	0	0.00	0	0	0	0	0
MARCH	2017	0	0	0	0.00	0	0	0	0	0
APRIL	2017	0	0	0	0.00	0	0	0	0	0
MAY	2016	0	0	0	0.00	0	0	0	0	0
JUNE	2016	0	0	0	0.00	0	0	0	0	0
JULY	2016	0	0	0	0.00	0	0	0	0	0
AUGUST	2016	0	0	0	0.00	0	0	0	0	0
SEPTEMBER	2016	0	0	0	0.00	0	0	0	0	0
OCTOBER	2016	0	0	0	0.00	0	0	0	0	0
NOVEMBER	2016	0	0	0	0.00	0	0	0	0	0
DECEMBER	2016	0	0	0	0.00	0	0	0	0	0

Figure 4.6: Past 31 days and 12 month maximums/minimums can be viewed in “month max” menu.

Table 4.7: Maximum registered values of the last 31 days and 12 months

12 months Measurement	Max	Min	Description	31 days	12 months
IL1, IL2, IL3	X		Phase current (fundamental frequency value)		
Io1, Io2	X		Earth fault overcurrent		
S	X		Apparent power	X	X
P	X	X	Active power	X	X
Q	X	X	Reactive power	X	X

The timebase can be a value from one cycle to one minute. Also a demand value can be used as the timebase and its value can be set between 10 and 60 minutes. The demand value menu is located under the “MEASUREMENTS” view.

Table 4.8: Parameters of the day and month registers

Parameter	Value	Description	Set
Timebase		Parameter to select the type of the registered values	Set
	20 ms	Collect min & max of one cycle values (*)	
	200 ms	Collect min & max of 200 ms average values	
	1 s	Collect min & max of 1 s average values	
	1 min	Collect min & max of 1 minute average values	
	demand	Collect min & max of demand values (Chapter 4.6 Demand values)	
ResetDays		Reset the 31 day registers	Set
ResetMon		Reset the 12 month registers	Set

Set = An editable parameter (password needed).

(*) This is the fundamental frequency RMS value of one cycle updated every 20 ms.

4.9 Power and current direction

Figure 4.7 shows the concept of three-phase current direction and sign of cosφ and power factor PF (the absolute value is equal to cosφ, but the sign is 'IND' for inductive i.e. lagging current and 'CAP' for capacitive i.e. leading current). Figure 4.8 shows the same concepts on a PQ-power plane.

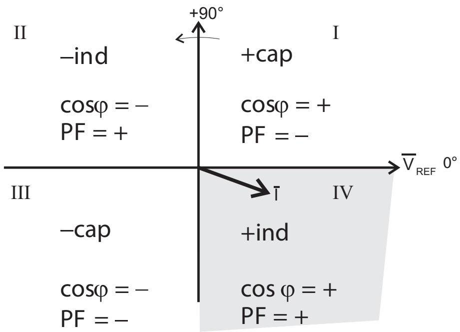


Figure 4.7: Quadrants of voltage/current phasor plane

I: Forward capacitive power current is leading

II: Reverse inductive power current is leading

III: Reverse capacitive power current is lagging

IV: Forward inductive power current is lagging

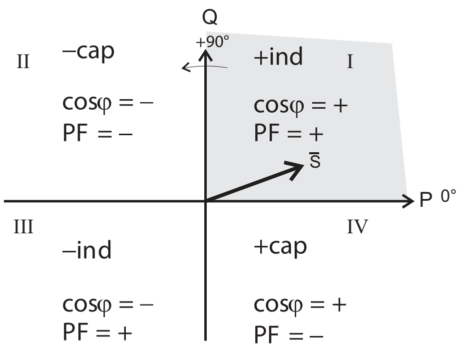


Figure 4.8: Quadrants of power plane

I: Forward inductive power current is lagging

II: Reverse capacitive power current is lagging

III: Reverse inductive power current is leading

IV: Forward capacitive power current is leading

Table 4.9: Power quadrants

Power quadrant	Current related to voltage	Power direction	cosφ	Power factor PF
+ inductive	Lagging	Forward	+	+
+ capacitive	Leading	Forward	+	-
- inductive	Leading	Reverse	-	+
- capacitive	Lagging	Reverse	-	-

4.10 Symmetric components

In a three-phase system, the voltage or current phasors may be divided in symmetric components.

- Positive sequence 1
- Negative sequence 2
- Zero sequence 0

Symmetric components are calculated according to the following equations:

$$\begin{bmatrix} \underline{S}_0 \\ \underline{S}_1 \\ \underline{S}_2 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & \underline{a} & \underline{a}^2 \\ 1 & \underline{a}^2 & \underline{a} \end{bmatrix}\begin{bmatrix} \underline{S}_\mathrm{A} \\ \underline{S}_\mathrm{B} \\ \underline{S}_\mathrm{C} \end{bmatrix}$$

$\underline{S}_0$ = zero sequence component

$\underline{S}_1$ = positive sequence component

$\underline{S}_2$ = negative sequence component

$\underline{a} = 1\angle 120^\circ = -\frac{1}{2} + j\frac{\sqrt{3}}{2}$, a phase rotating constant

$\underline{S}_A$ = phasor of phase L1 (phase current or voltage)

$\underline{S}_B$ = phasor of phase L2

$\underline{S}_C$ = phasor of phase L3

5 Control functions

5.1 Digital outputs

The digital outputs are also called controlling outputs, signaling outputs and self-supervision outputs. Trip contacts can be controlled by using the relay output matrix or logic function. Also forced control is possible. To use forced control, you must enable it in the **Relays** setting view.

Any internal signal can be connected to the digital outputs in the **Matrix > Arc matrix - output** setting views.

The **Output matrix** and **Relays** setting views represent the state (de-energized / energized) of the digital output's coil. For example, a bright green vertical line in the **Output matrix** and a logical "1" in the **Relays** view represent the energized state of the coil. The same principle applies for both NO and NC type digital outputs. The actual position (open / closed) of the digital outputs' contacts in coil's de-energized and energized state depends on the type (NO / NC) of the digital outputs. De-energized state of the coil corresponds to the normal state of the contacts. A digital output can be configured as latched or non-latched. Chapter 5.5 Releasing latches describes releasing latches procedure.

The difference between trip contacts and signal contacts is the DC breaking capacity. The contacts are **single pole single throw (SPST)** normal open (NO) type, except signal relay A1 which has a changeover contact **single pole double throw (SPDT)**.

In addition to this, the relay has so called heavy duty outputs available in the power supply modules C and D. For more details, see Table 10.26.

Programming matrix

1. Connected (single bullet)
2. Connected and latched (single bullet rounded with another circle)
3. Not connected (line grossing is empty)

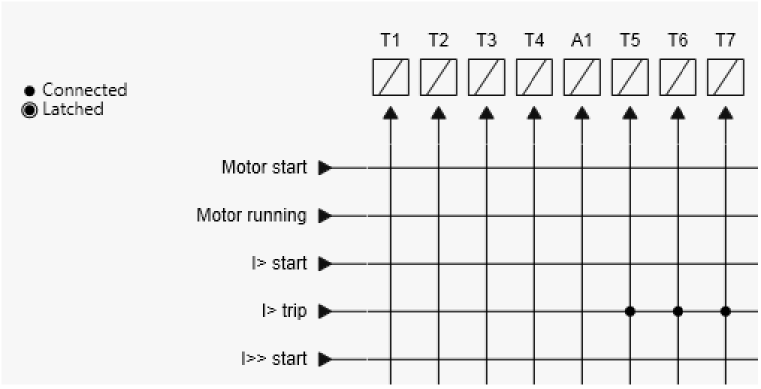


*Figure 5.1: Trip contacts can be connected to protection stages or other similar purpose in the **Output matrix** setting view*

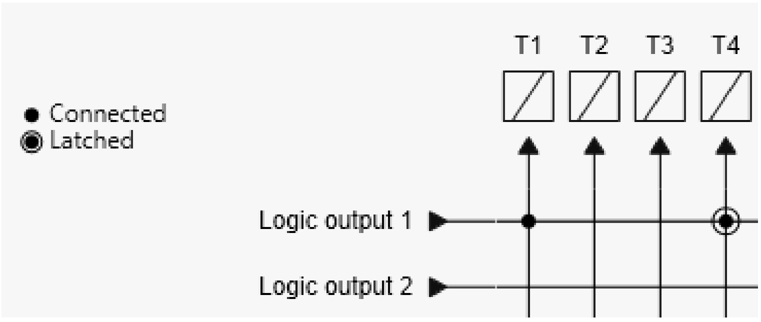


Figure 5.2: Trip contacts can be assigned directly to outputs of logical operators

NOTE: Logic outputs are assigned automatically in the output matrix as well when logic is built.

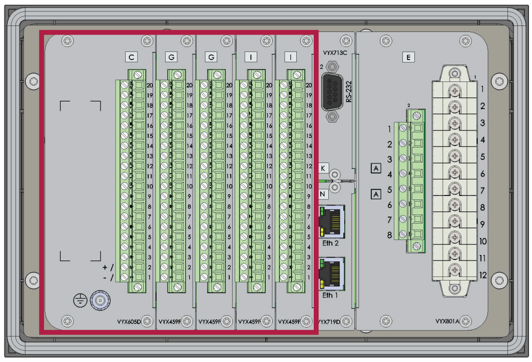
Trip contact status can be viewed and forced to operate in the **Relays** setting view. Logical "0" means that the output is not energized and logical "1" states that the output is set active.

*Figure 5.3: **Relays** setting view*

Default numbering of DI / DO

Every option card and slot has default numbering. Below is an example of model P3x30 CGGII-AAEAA-BA showing the default numbering of digital outputs.

You can see the default digital output numbering and change the numbering of the following option cards in the **Inputs/Outputs > Relay config** setting view: slot 2, 3, 4, 5: G, I.



C: T1, T9 – 12, A1, SF
G: T13-16
G: T17-20
I: -
I: -

Figure 5.4: Default numbering of digital outputs for model P3x30-CGGII-AAEAA-BA

Power supply card outputs are not visible in the **Relay config** setting view.

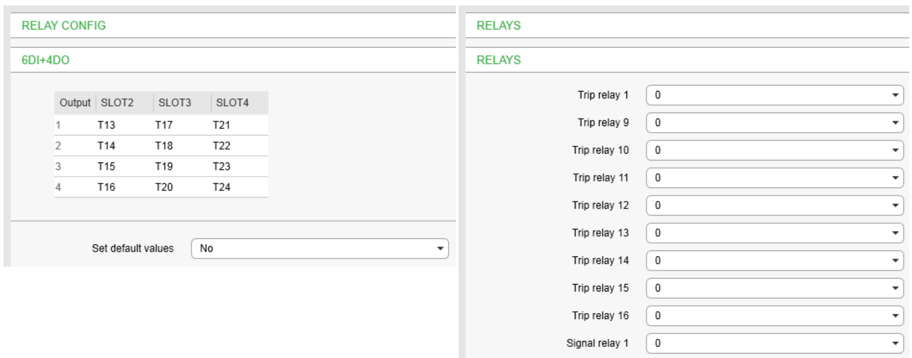


*Figure 5.5: **Relay config** setting view*

Table 5.1: Parameters of digital outputs

Parameter	Value	Unit	Description	Note
T1 – Tx the available parameter list depends on the number and type of the I/O cards.	0 1		Status of trip controlling output	F
A1	0 1		Status of alarm signalling output	F
SF	0 1		Status of the SF relay In Easergy Pro, it is called as "Service status output"	F
Force	On Off		Force flag for digital output forcing for test purposes.	Set
Names for output relays (editable with Easergy Pro only)				
Description	String of max. 32 characters		Names for DO on Easergy Pro screens. Default is "Trip relay n", n=1 – x or "Signal relay n", n=1	Set

F = Editable when force flag is on. Set = An editable parameter (password needed).

5.2 Digital inputs

Digital inputs are available for control purposes. The number of available inputs depends on the number and type of option cards.

The polarity normal open (NO) / normal closed (NC) and a delay can be configured according to the application by using the front panel or Easergy Pro.

Digital inputs can be used in many operations. The status of the input can be checked in the **Output matrix** and **Digital inputs** setting views. The digital inputs make it possible to change group, block/enable/disable functions, to program logics, indicate object status, etc.

The digital inputs require an external control voltage (ac or dc). The digital inputs are activated after the activation voltage is exceeded. Deactivation follows when the voltage drops below threshold limit. The activation voltage level of digital inputs can be selected in the order code when such option cards are equipped.

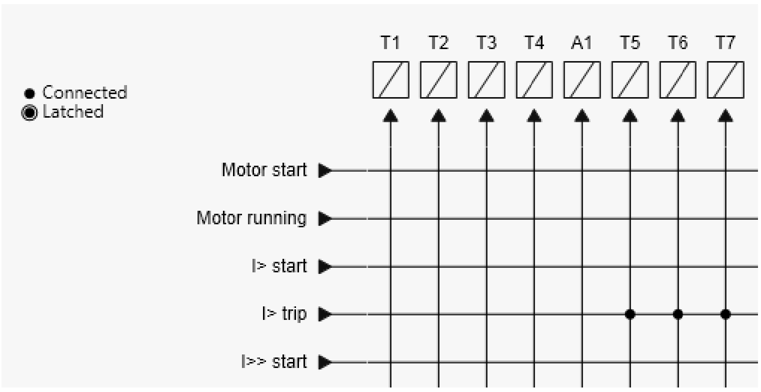


*Figure 5.6: Digital inputs can be connected, latched or unlatched to trip contacts or other similar purpose in **Output matrix** setting view.*

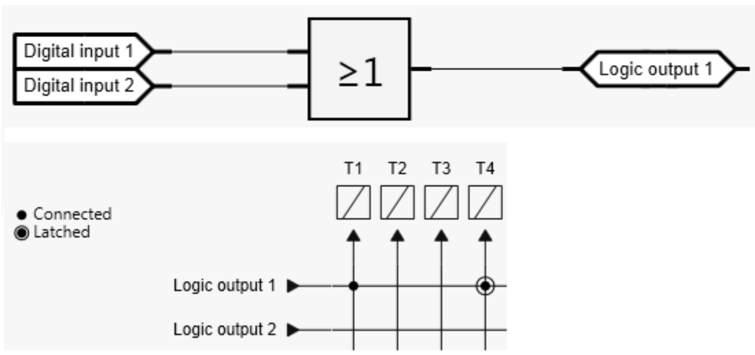


Figure 5.7: Digital inputs can be assigned, latched or unlatched directly to inputs/outputs of logical operators.

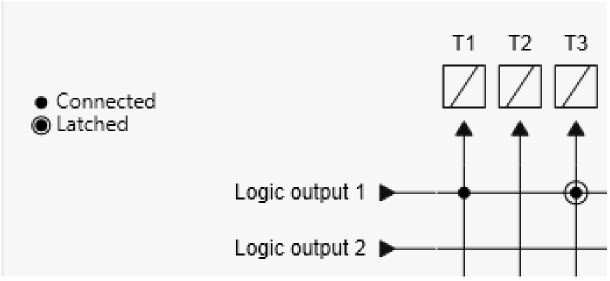


*Figure 5.8: Digital inputs can be viewed, named and changed between NO/NC in **Digital inputs** setting view.*

If inputs are energized by using ac voltage, “mode” has to be selected as ac.

All essential information on digital inputs can be found in the same location in the **Digital inputs** setting view. DI on/off events and alarm display (pop-up) can be enabled and disabled in **Digital inputs** setting view. Individual operation counters are located in the same view as well.

Label and description texts can be edited with Easergy Pro according to the demand. Labels are the short parameter names used on the local panel and descriptions are the longer names used by Easergy Pro.

The digital input activation thresholds are hardware-selectable.

Digital input delay determines the activation and de-activation delay for the input. Figure 5.9 shows how the digital input behaves when the delay is set to 1 second.

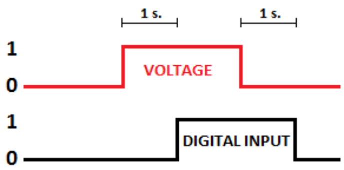


Figure 5.9: Digital inputs behaviour when delay is set to 1 second.

Table 5.2: Parameters of digital inputs

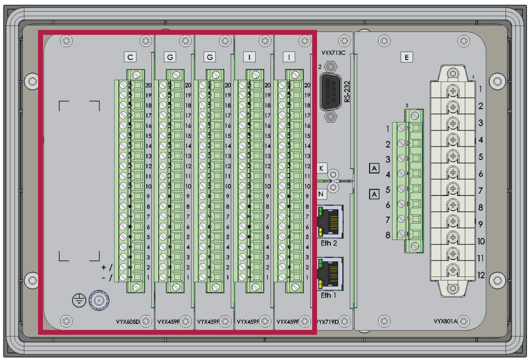
Parameter	Value	Unit	Description	Note
Mode	dc, ac		Used voltage of digital inputs	Set
Input	DI1 – DIx		Number of digital input. The available parameter list depends on the number and type of the I/O cards.	
Slot	2 – 6		Card slot number where option card is installed.	
State	0, 1		Status of digital input 1 – digital input x.	
Polarity	NO NC		For normal open contacts (NO). Active edge is 0 > 1 For normal closed contacts (NC) Active edge is 1 > 0	Set
Delay	0.00 – 60.00	s	Definite delay for both on and off transitions	Set
On event	On		Active edge event enabled	Set
	Off		Active edge event disabled	
Off event	On		Inactive edge event enabled	Set
	Off		Inactive edge event disabled	
Alarm display	no		No pop-up display	Set
	yes		Alarm pop-up display is activated at active DI edge	
Counters	0 – 65535		Cumulative active edge counter	(Set)
NAMES for DIGITAL INPUTS (editable with Easergy Pro only)				
Label	String of max. 10 characters		Short name for DIs on the local display Default is "DI1 – DIx". x is the maximum number of the digital input.	Set
Description	String of max. 32 characters		Long name for DIs. Default is "Digital input 1 – Digital input x". x is the maximum number of the digital input.	Set

Set = An editable parameter (password needed).

Every option card and slot has default numbering. After making any changes to the numbering, read the settings from the relay after the relay has rebooted.

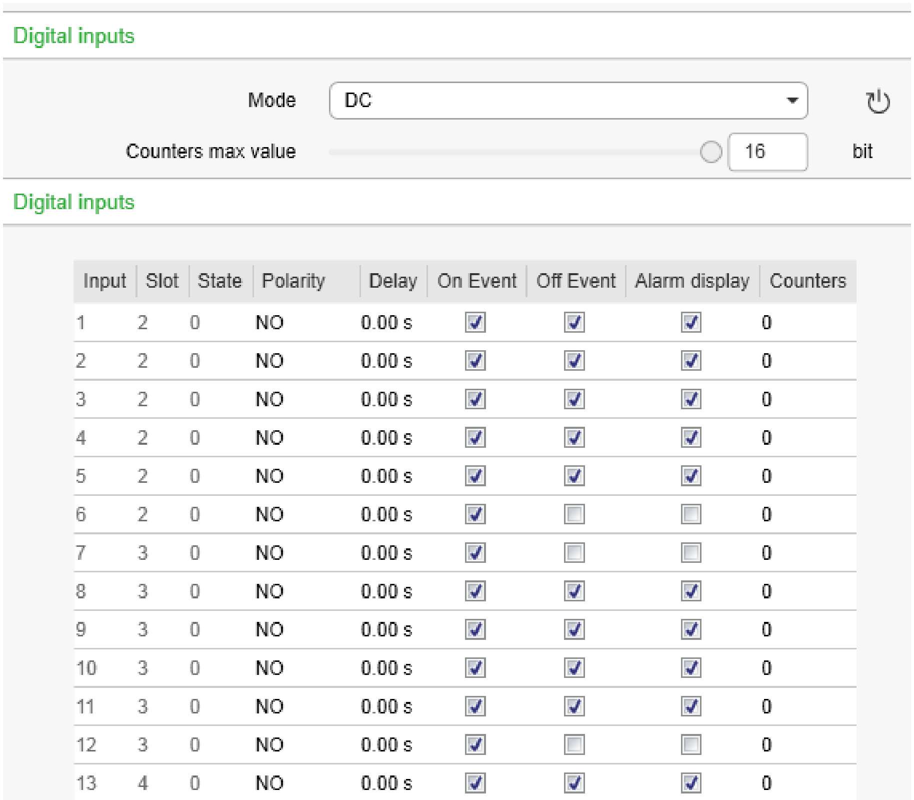
Below is an example of model P3x30-CGGII-AAEAA-BAAAA showing default numbering of DI.

You can see the default digital input numbering and change the numbering of the following option cards in the **Inputs/Outputs > Digital inputs** setting view: slot 2, 3, 4, 5: G, I.



C: -
G: DI1–6
G: DI7–12
I: DI13–22
I: DI23–32

Figure 5.10: Default numbering of digital inputs for model P3x30-CGGII-AAEAA-BA



Digital inputs

Mode	DC	
Counters max value	16	bit

Digital inputs

Input	Slot	State	Polarity	Delay	On Event	Off Event	Alarm display	Counters
1	2	0	NO	0.00 s	☑	☑	☑	0
2	2	0	NO	0.00 s	☑	☑	☑	0
3	2	0	NO	0.00 s	☑	☑	☑	0
4	2	0	NO	0.00 s	☑	☑	☑	0
5	2	0	NO	0.00 s	☑	☑	☑	0
6	2	0	NO	0.00 s	☑	☐	☐	0
7	3	0	NO	0.00 s	☑	☐	☐	0
8	3	0	NO	0.00 s	☑	☑	☑	0
9	3	0	NO	0.00 s	☑	☑	☑	0
10	3	0	NO	0.00 s	☑	☑	☑	0
11	3	0	NO	0.00 s	☑	☑	☑	0
12	3	0	NO	0.00 s	☑	☐	☐	0
13	4	0	NO	0.00 s	☑	☑	☑	0

*Figure 5.11: **Digital inputs** setting view*

5.3 Virtual inputs and outputs

There are virtual inputs and virtual outputs that can in many places be used like their hardware equivalents except that they are located in the memory of the relay. The virtual inputs act like normal digital inputs. The status of the virtual input can be changed via the local display, communication bus and Easergy Pro. For example setting groups can be changed using virtual inputs.

Virtual inputs can be used in many operations. The status of the input can be checked in the **Output matrix** and **Virtual inputs** setting views. The status is also visible on local mimic display, if so selected. Virtual inputs can be selected to be operated with the function buttons F1 and F2, the local mimic or simply by using the virtual input menu. Virtual inputs have similar functions as digital inputs: they enable changing groups, block/enable/disable functions, to program logics and other similar to digital inputs.

The activation and reset delay of the input is approximately 5 ms.

NOTE: The default names of the logic outputs are Logic output 1-n. You can change the names of the outputs in the **General > Names for logic outputs** setting view.

Table 5.3: Virtual input and output

Number of inputs	20
Number of outputs	20
Activation time / Reset time	< 5 ms

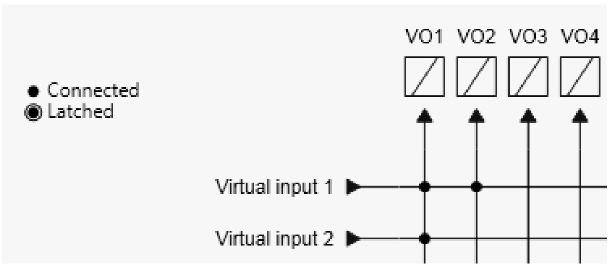


*Figure 5.12: Virtual inputs and ouputs can be used for many purpose in the **Output matrix** setting view.*

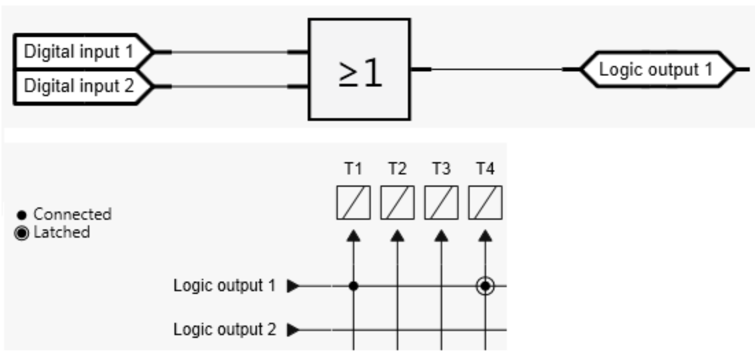


Figure 5.13: Virtual inputs and outputs can be assigned, latched or unlatched directly to inputs/outputs or logical operators.

Virtual input

The virtual inputs can be viewed, named and controlled in the **Virtual inputs** setting view.

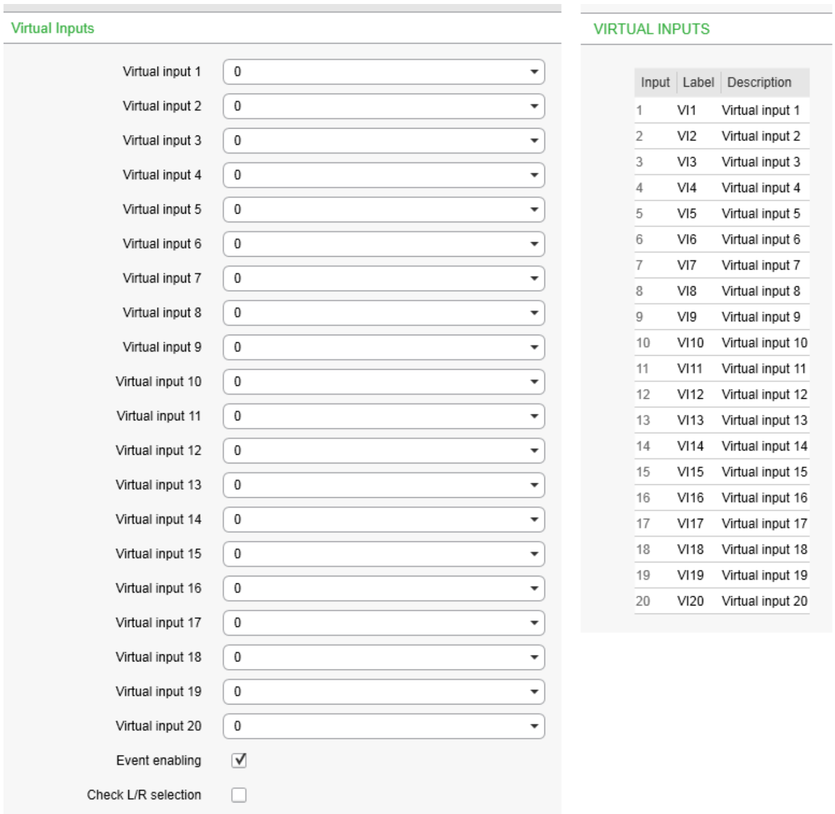


*Figure 5.14: **Virtual inputs** setting view*

Table 5.4: Parameters of virtual inputs

Parameter	Value	Unit	Description	Set
VI1-VI20	0 1		Status of virtual input	
Events	On Off		Event enabling	Set
NAMES for VIRTUAL INPUTS (editable with Easergy Pro only)				
Label	String of max. 10 characters		Short name for VIs on the local display Default is "VIn", n = 1–20	Set
Description	String of max. 32 characters		Long name for VIs. Default is "Virtual input n", n = 1–20	Set

Set = An editable parameter (password needed).

Virtual output

In Easergy Pro, the **Virtual outputs** setting view is located **Inputs/Outputs** view.

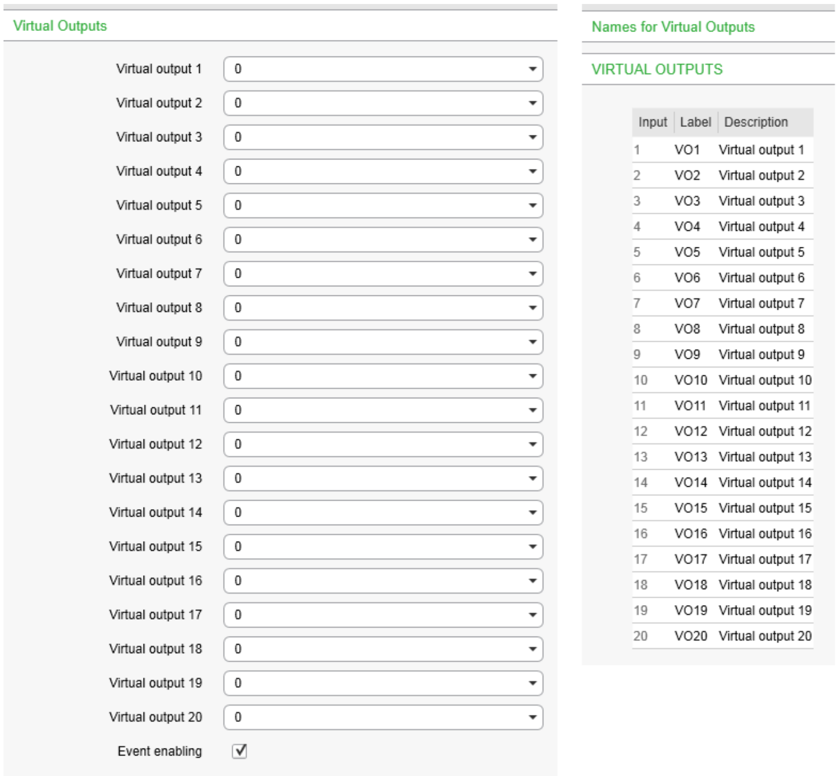


*Figure 5.15: **Virtual outputs** setting view*

Table 5.5: Parameters of virtual outputs

Parameter	Value	Unit	Description	Set
VO1-VO20	0 1		Status of virtual output	F
Events	On Off		Event enabling	Set
NAMES for VIRTUAL OUTPUTS (editable with Easergy Pro only)				
Label	String of max. 10 characters		Short name for VOs on the local display Default is "VOn", n=1-20	Set
Description	String of max. 32 characters		Long name for VOs. Default is "Virtual output n", n=1-20	Set

Set = An editable parameter (password needed). F = Editable when force flag is on.

5.4 Matrix

The relay has several matrices that are used for configuring the relay:

- **Output matrix**
  used to link protection stage signals, digital inputs, virtual inputs, function buttons, object control, logic output, relay's internal alarms, GOOSE signals and release latch signals to outputs, disturbance recorder trig input and virtual outputs
- **Block matrix**
  used to block protection stages
- **LED matrix**
  used to control LEDs on the front panel
- **Object block matrix**
  used to inhibit object control
- **Arc matrix**
  used to control current and light signals to arc stages and arc stages to the high-speed outputs

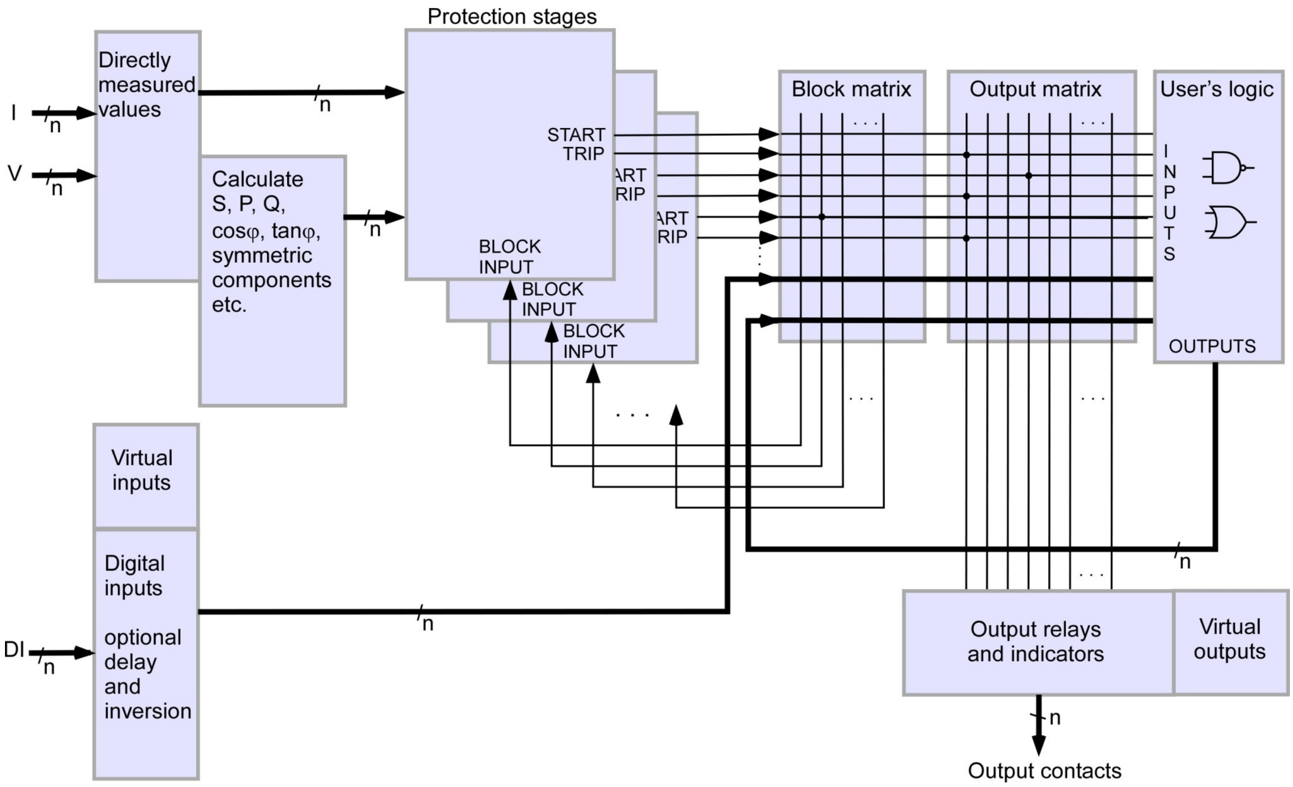


Figure 5.16: Blocking matrix and output matrix

NOTE: Blocking matrix can not be used to block the arc protection stages.

5.4.1 Output matrix

With the output matrix, the output signals of the various protection stages, digital inputs, logic outputs and other internal signals can be connected to the digital outputs, virtual outputs and so on.

NOTE: For configuring the high-speed operations of the arc protection, use the **Arc matrix – output** view. The configuration also becomes visible in the output matrix. The output matrix shows the status of the FPGA-driven outputs whereas the other electro-mechnical outputs can also be configured in the output matrix.

There are general-purpose LED indicators – "A", "B", "C" to ”N” – available for customer-specific indications on the front panel. Their usage is define in a separate LED MATRIX.

There are two LED indicators specified for keys F1 and F2. The triggering of the disturbance recorder (DR) and virtual outputs are configurable in the output matrix.

A digital output or indicator LED can be configured as latched or non-latched. A non-latched relay follows the controlling signal. A latched relay remains activated although the controlling signal releases.

There is a common "release all latches" signal to release all the latched relays. This release signal resets all the latched digital outputs and indicators. The reset signal can be given via a digital input, via front panel or remotely through communication. Chapter 5.5 Releasing latches describes releasing latches procedure.

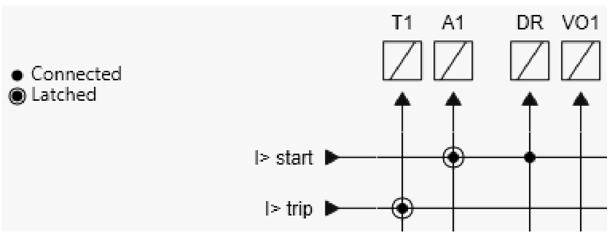


Figure 5.17: Trip and alarm relays together with virtual outputs can be assigned in output matrix. Also automatic triggering of disturbance recorder is done in output matrix.

5.4.2 Blocking matrix

By means of a blocking matrix, the operation of any protection stage (except the arc protection stages) can be blocked. The blocking signal can originate from the digital inputs or it can be a start or trip signal from a protection stage or an output signal from the user's programmable logic. In the Figure 5.16, an active blocking is indicated with a black dot (•) in the crossing point of a blocking signal and the signal to be blocked.

The maximum amount of stages to be blocked is 32.

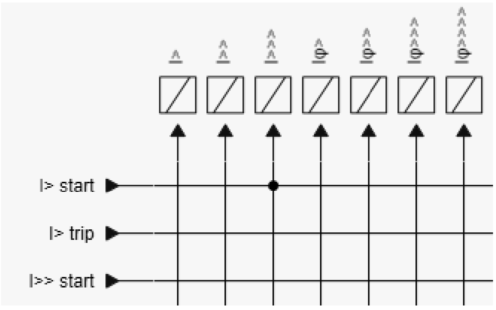


Figure 5.18: All protection stages (except Arc stages) can be blocked in block matrix.

The Blocked status becomes visible only when the stage is about to activate.

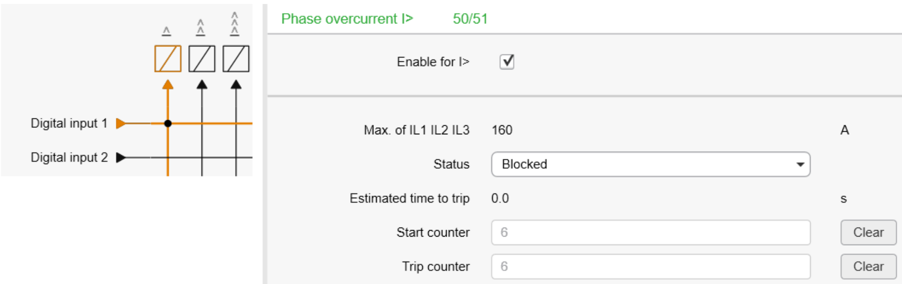


Figure 5.19: A view from the setting tool showing a DI input blocking connection (left picture) and the result for the I> stage when the DI is active and the stage exceeds its current start value.

NOTICE
RISK OF NUISANCE TRIPPING • The blocking matrix is dynamically controlled by selecting and deselecting protection stages. • Activate the protection stages first, then store the settings in a relay. After that, refresh the blocking matrix before configuring it. **Failure to follow these instructions can result in unwanted shutdown of the electrical installation.**

5.4.3 LED matrix

The LED matrix is used to link digital inputs, virtual inputs, function buttons, protection stage outputs, object statuses, logic outputs, alarm signals and GOOSE signals to various LEDs located on the front panel.

In the **LED configuration** setting view, each LED has three checkboxes with which the behavior of the LED is configured.

LED configuration

LED	Description	Latch	Blink	Store
LED A (green)	LED A (green)	☑	☐	☑
LED A (red)	LED A (red)	☐	☑	☐
LED B (green)	LED B (green)	☑	☑	☐
LED B (red)	LED B (red)	☐	☐	☐
LED C (green)	LED C (green)	☑	☐	☐
LED C (red)	LED C (red)	☐	☐	☐
LED D (green)	LED D (green)	☑	☐	☐

Figure 5.20: LED configuration

LEDs are assigned to control signals in the **LED matrix** setting view. It is not possible to control LEDs directly with logics.

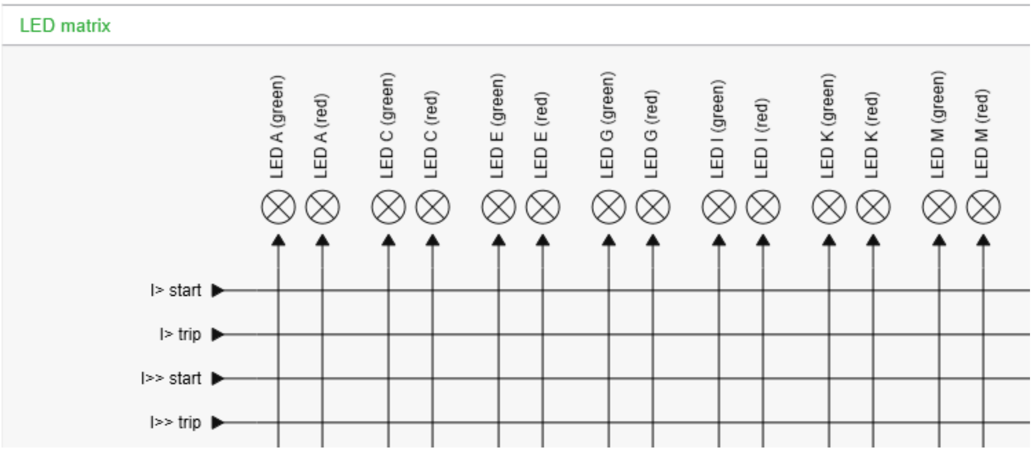


Figure 5.21: LED matrix

Normal setting

With no checkboxes selected, the assigned LED is active when the control signal is active. After deactivation, the LED turns off. LED activation and deactivation delay when controlled is approximately 10 ms.

Latch setting

A latched LED activates when the control signal activates but remains active when the control signal deactivates. Latched LEDs are released using the procedure described in Chapter 5.5 Releasing latches.

Blink setting

When the **Blink** setting is selected, the LED blinks when it is active.

Store setting

To use the **Store** setting, the **Latch** setting must also be selected. The **Store** setting means that the latched state is retained after a restart.

Inputs for LEDs

Inputs for LEDs can be assigned in the LED matrix. All 14 LEDs can be assigned as green or red. The connection can be normal, latched or blink-latched. In addition to protection stages, there are lots of functions that can be assigned to output LEDs. See Table 5.6.

Table 5.6: Inputs for LEDs A-N

Input	LED map-ping	Latch	Description	Note
Protection, Arc and pro-gram-mable stages	LED A–N green or red	Normal/ Latched/ BlinkLatch	Different type of protection stages can be assigned to LEDs	Set
Digital/Virtual inputs and function buttons	LED A–N green or red	Normal/ Latched/ BlinkLatch	All different type of inputs can be assigned to LEDs	Set
Object open/close, ob-ject final trip and object failure information	LED A–N green or red	Normal/ Latched/ BlinkLatch	Information related to objects and object control	Set
Local control enabled	LED A–N green or red	Normal/ Latched/ BlinkLatch	While remote/local state is selec-ted as local the “local control en-abled” is active	Set
Logic output 1–20	LED A–N green or red	Normal/ Latched/ BlinkLatch	All logic outputs can be assigned to LEDs at the LED matrix	Set
Manual control indica-tion	LED A–N green or red	Normal/ Latched/ BlinkLatch	When the user has controlled the objectives	Set
COM 1–5 comm.	LED A–N green or red	Normal/ Latched/ BlinkLatch	When the communication port 1 - 5 is active	Set
Setting error, seldiag alarm, pwd open and setting change	LED A–N green or red	Normal/ Latched/ BlinkLatch	Self diagnostic signal	Set
GOOSE NI1–64	LED A–N green or red	Normal/ Latched/ BlinkLatch	IEC 61850 goose communication signal	Set

Input	LED mapping	Latch	Description	Note
GOOSEERR1–16	LED A–N green or red	Normal/ Latched/ BlinkLatch	IEC 61850 goose communication signal	Set

5.4.4 Object block matrix

The object block matrix is used to link digital inputs, virtual inputs, function buttons, protection stage outputs, logic outputs, alarm signals and GOOSE signals to inhibit the control of objects, that is, circuit breakers, isolators and earthing switches.

Typical signals to inhibit controlling of the objects like circuit breaker are:

- protection stage activation
- statuses of other objects
- interlocking made with logic
- GOOSE signals

These and other signals are linked to objects in the object block matrix.

There are also event-type signals that do not block objects as they are on only for a short time, for example "Object1" open and "Object1 close" signals.

5.5 Releasing latches

5.5.1 Releasing latches using Easergy Pro

Go to **General > Release latches** and select **Release** from the **Release latches** drop-down menu.

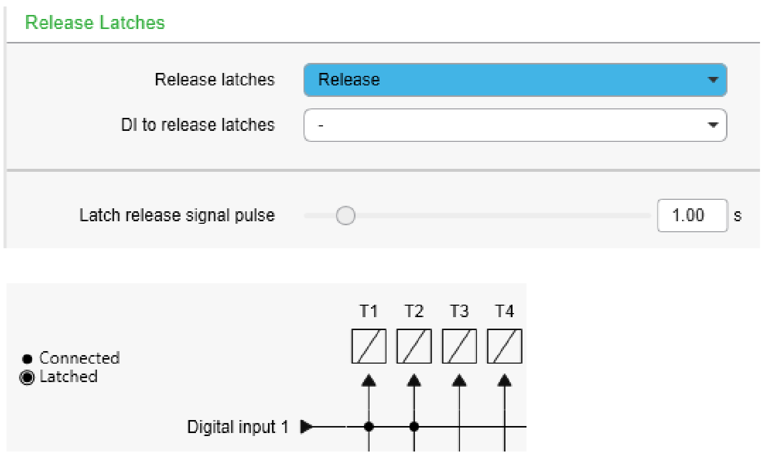


Figure 5.22: Latched output matrix signals released by using Easergy Pro setting tool.

5.5.2 Releasing latches using buttons and local panel display

Prerequisite: You have entered the correct password.

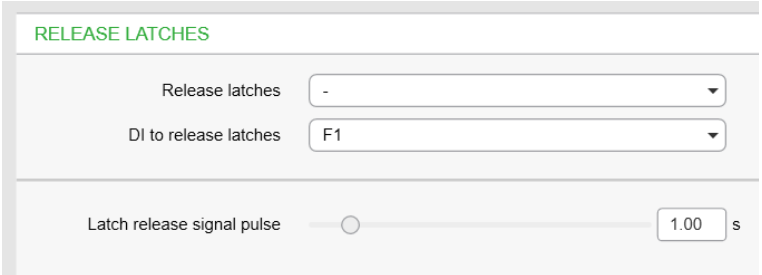
1. Press .
2. Press .
3. Select “Release” and press OK.

5.5.3 Releasing latches using F1 or F2 buttons

You can use the function buttons F1 or F2 to release all latches after configuring this function in Easergy Pro. You can make the configuration either under **GENERAL > RELEASE LATCHES** or under **INPUTS/OUTPUTS > FUNCTION BUTTONS**

To configure F1 to release latches under **GENERAL > RELEASE LATCHES:**

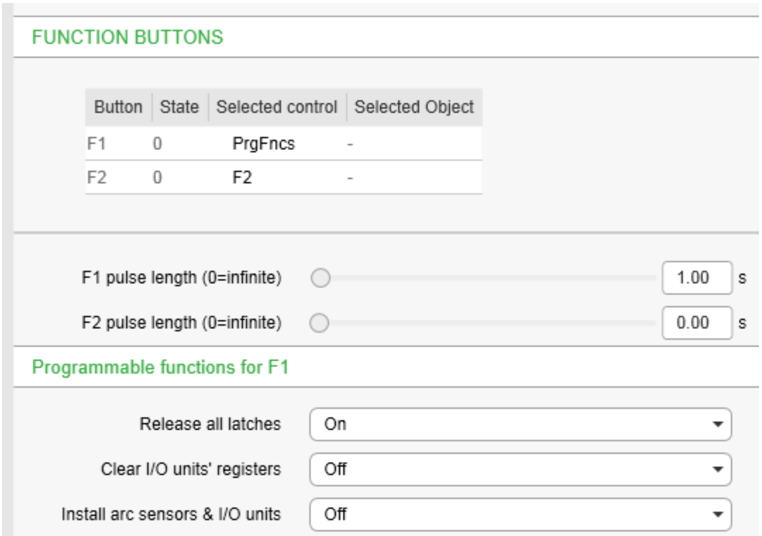
1. In Easergy Pro, go to **GENERAL > RELEASE LATCHES**.
2. Under **RELEASE LATCHES** select F1 from the **DI to release latches** drop-down menu.
3. Set 1 s delay for **Latch release signal pulse**.



After this, pressing the F1 button on the relay's front panel releases all latches.

To configure F1 to release latches under **Inputs/Outputs > Function buttons**:

1. Under **Function buttons**, for F1, select PrgFncs from the **Selected control** drop down menu.
2. Set 1 s delay for **F1 pulse length**.
3. Under **Programmable functions for F1**, select "On" from the **Release all latches** drop-down menu.



After this, pressing the F1 button on the relay's front panel releases all latches.

NOTE: The latch release signal can be activated only if the latched output is active.

5.6 Controllable objects

The relay allows controlling six objects, that is, circuit breakers, disconnectors and earthing switches by the "select before operate" or "direct control" principle.

The object block matrix and logic functions can be used to configure interlocking for a safe controlling before the output pulse is issued. The objects 1–6 are controllable while the objects 7–8 are only able to show the status.

Controlling is possible in the following ways:

- through the object control buttons
- through the front panel and display using a single-line diagram
- through the function keys
- through a digital input
- through a remote communication
- through Easergy Pro setting tool
- through Web server
- through Smart APP

The connection of an object to specific controlling outputs is done via an output matrix (object 1–6 open output, object 1–6 close output). There is also an output signal “Object failed” that is activated if the control of an object is not completed.

Object states

Each object has the following states:

Setting	Value	Description
Object state	Undefined (00)	Actual state of the object
	Open	
	Close	
	Undefined (11)	

Basic settings for controllable objects

Each controllable object has the following settings:

Setting	Value	Description
DI for ‘obj open’	None, any digital input, virtual input or virtual output	Open information
DI for ‘obj close’		Close information
DI for ‘obj ready’		Ready information
Max ctrl pulse length	0.02 – 600 s	Pulse length for open and close commands. Control pulse stops once object changes its state

Setting	Value	Description
Completion timeout	0.02 – 600 s	Timeout of ready indication
Object control	Open/Close	Direct object control

If changing the states takes longer than the time defined by the “Max ctrl pulse length” setting, the object is inoperative and the “Object failure” matrix signal is set. Also, an undefined event is generated. “Completion timeout” is only used for the ready indication. If “DI for ‘obj ready’” is not set, the completion timeout has no meaning.

Output signals of controllable objects

Each controllable object has 2 control signals in matrix:

Output signal	Description
Object x Open	Open control signal for the object
Object x Close	Close control signal for the object

These signals send control pulse when an object is controlled by digital input, remote bus, auto-reclose etc.

Settings for read-only objects

Each read-only object has the following settings:

Setting	Vale	Description
DI for ‘obj open’	None, any digital input, virtual input or virtual output	Open information
DI for ‘obj close’		Close information
Object timeout	0.02 – 600 s	Timeout for state changes

If changing states takes longer than the time defined by “Object timeout” setting, and “Object failure” matrix signal is set. Also undefined-event is generated.

5.6.1 Object control with digital inputs

Objects can be controlled with digital inputs, virtual inputs or virtual outputs. There are four settings for each controllable object:

Setting	Active
DI for remote open / close control	In remote state
DI for local open / close control	In local state

If the relay is in local control state, the remote control inputs are ignored and vice versa. An object is controlled when a rising edge is detected from the selected input. The length of digital input pulse should be at least 60 ms.

5.6.2 Local or remote selection

In local mode, digital outputs can be controlled via the front panel but they cannot be controlled via a remote serial communication interface.

In remote mode, digital outputs cannot be controlled via a front panel but they can be controlled via a remote serial communication interface.

The local or remote mode can be selected by using the front panel or via one selectable digital input. The digital input is normally used to change a whole station to local or remote mode. You can select the L/R digital input in the **Objects** setting view in Easergy Pro.

Table 5.7: Local or remote selection

Action	Control through Easergy Pro or SmartApp		Control through communication protocol	
Local/Remote switch status	**Local**	**Remote**	**Local**	**Remote**
CB control	Yes	No	No	Yes
Setting or configuration changes	Yes	Yes	Yes	Yes
Communication configuration	Yes	Yes	Yes	Yes
Virtual inputs [1]	Yes	No	No	Yes

1) Virtual inputs have a general parameter "Check L/R selection" for disabling the L/R check.

5.6.3 Object control with I and O buttons

The relay also has dedicated control buttons for objects. (I) stands for object closing and (O) controls object open command internally. Control buttons are configured in the OBJECTS view.

Table 5.8: Parameters of function keys

Parameter	Value	Unit	Description	Set
Disabled Object 1 – 6	- Obj1 – Obj6		Button I closes selected object if password is enabled Button O opens selected object if password is enabled	Set
Mode for control butons	Selective Direct		Control operation needs confirmation (select-execute) Control operation is done without confirmation	

5.6.4 Object control with F1 and F2

Objects can be controlled with the function buttons F1 and F2.

By default, the F1 and F2 buttons are configured to control F1 and F2 variables that can further be assigned to control objects.

Table 5.9: Parameters of F1 and F2

Parameter	Value	State	Pulse length*)	Description
F1	F1, V1-V20, ObjCtrl	0.1	0600 s	F1 controls F1, V1-V20 or ObjCtrl parameters.
F2	F2, V1-V20, ObjCtrl	0.1	0-600 s	F2 controls F2, V1-V20 and ObjCtrl parameters.

*) Pulse length applies to values F1 and F2 only

You can configure the button funtions in the **Inputs/outputs > Function buttons** setting view in Easergy Pro.

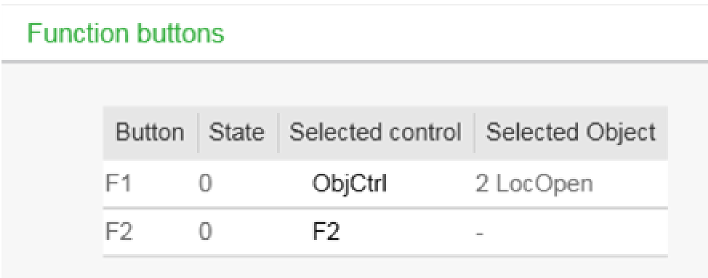


Figure 5.23: Function buttons setting view

If **ObjCtrl** has been selected under **Selected control**, the selected object is shown under **Selected object**. Otherwise, this column is empty.

When selecting **ObjCtrl**, link the function button to the appropriate object in the **General > Objects** setting view.

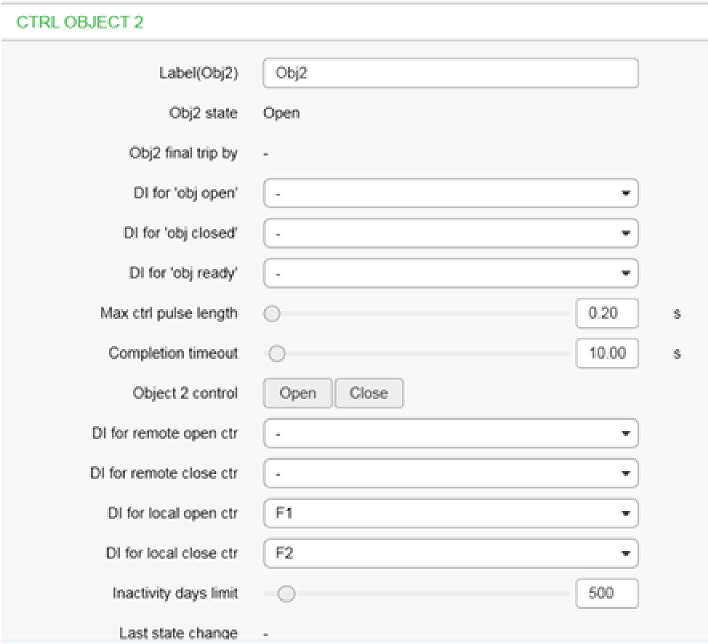


Figure 5.24: Ctrl object 2 setting view

5.7 Logic functions

The relay supports customer-defined programmable logic for boolean signals. User-configurable logic can be used to create something that is not provided by the relay as a default. You can see and modify the logic in the **General > Logic** setting view in the Easergy Pro setting tool.

Table 5.10: Available logic functions and their memory use

Locig functions	No. of gates reserved	Max. no. of input gates	Max. no. of logic outputs
AND	1	32 (An input gate can include any number of inputs.)	20
OR	1		
XOR	1		
AND+OR	2		
CT (count+reset)	2		
INVAND	2		
INVOR	2		
OR+AND	2		
RS (set+reset)	2		
RS_D (set+D+load+reset)	4		

The consumed memory is dynamically shown on the configuration view in percentage. The first value indicates the memory consumption of inputs, the second value the memory consumption of gates and the third value the memory consumption of outputs. The logic is operational as long the memory consumption of the inputs, gates or outputs remains individually below or equal to 100 %.

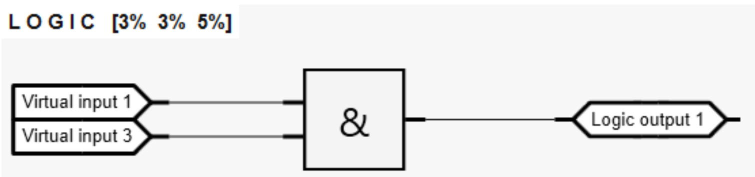
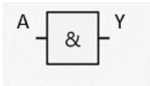
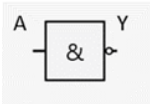
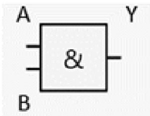
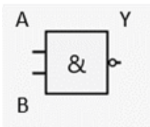
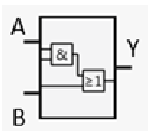
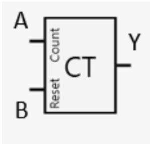


Figure 5.25: Logic and memory consumption

Truth tables

Table 5.11: Truth table

<table>
<tr><th>Gate</th><th>Symbol</th><th>Truth table</th></tr>
<tr><td rowspan="4">AND</td><td></td><td><table><tr><td>In</td><td>Out</td></tr><tr><td>A</td><td>Y</td></tr><tr><td>0</td><td>0</td></tr><tr><td>1</td><td>1</td></tr></table></td></tr>
<tr><td></td><td><table><tr><td>In</td><td>Out</td></tr><tr><td>A</td><td>Y</td></tr><tr><td>0</td><td>1</td></tr><tr><td>1</td><td>0</td></tr></table></td></tr>
<tr><td></td><td><table><tr><td colspan="2">In</td><td>Out</td></tr><tr><td>A</td><td>B</td><td>Y</td></tr><tr><td>0</td><td>0</td><td>0</td></tr><tr><td>1</td><td>1</td><td>1</td></tr><tr><td>1</td><td>0</td><td>0</td></tr><tr><td>0</td><td>1</td><td>0</td></tr></table></td></tr>
<tr><td></td><td><table><tr><td colspan="2">In</td><td>Out</td></tr><tr><td>A</td><td>B</td><td>Y</td></tr><tr><td>0</td><td>0</td><td>1</td></tr><tr><td>1</td><td>1</td><td>0</td></tr><tr><td>1</td><td>0</td><td>1</td></tr><tr><td>0</td><td>1</td><td>1</td></tr></table></td></tr>
<tr><td>AND+OR</td><td></td><td><table><tr><td colspan="2">In</td><td>Out</td></tr><tr><td>A</td><td>B</td><td>Y</td></tr><tr><td>0</td><td>0</td><td>0</td></tr><tr><td>1</td><td>1</td><td>1</td></tr><tr><td>1</td><td>0</td><td>1</td></tr><tr><td>0</td><td>1</td><td>1</td></tr></table></td></tr>
</table>

<table>
<tr><th>Gate</th><th>Symbol</th><th>Truth table</th></tr>
<tr><td>CT (count+reset)</td><td>
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<table>
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<tr><td>Cont</td><td>Reset</td><td>Seting</td><td>New</td></tr>
<tr><td>1</td><td></td><td>3</td><td>0</td></tr>
<tr><td>1</td><td></td><td>3</td><td>0</td></tr>
<tr><td>1</td><td></td><td>3</td><td>1</td></tr>
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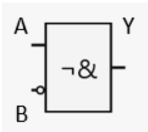
</td></tr>
<tr><td>INVAND</td><td>
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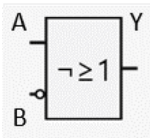
</td></tr>
<tr><td>INVOR</td><td>
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<table>
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<tr><td>1</td><td>1</td><td>1</td></tr>
<tr><td>1</td><td>0</td><td>1</td></tr>
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</td></tr>
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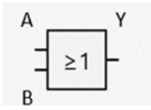
<table>
<tr><th>Gate</th><th>Symbol</th><th>Truth table</th></tr>
<tr><td>OR</td><td>
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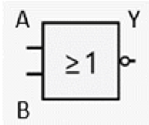
<tr><td></td><td>
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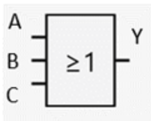
<tr><td></td><td>
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<tr><td>1</td><td>0</td><td>0</td><td>1</td></tr>
<tr><td>1</td><td>1</td><td>0</td><td>1</td></tr>
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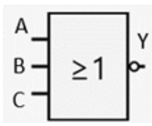
<tr><td></td><td>
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<tr><td>1</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>1</td><td>1</td><td>0</td><td>0</td></tr>
<tr><td>0</td><td>1</td><td>0</td><td>0</td></tr>
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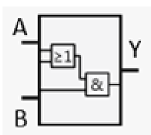
<tr><td>OR+AND</td><td>
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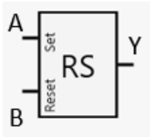
<tr><td>1</td><td>1</td><td>1</td></tr>
<tr><td>1</td><td>0</td><td>0</td></tr>
<tr><td>0</td><td>1</td><td>0</td></tr>
</table></td></tr>
</table>

<table>
<tr><th>Gate</th><th>Symbol</th><th>Truth table</th></tr>
<tr><td>RS (set+reset)</td><td>
</td><td>
<table>
<tr><td>A</td><td>B</td><td>Y</td></tr>
<tr><td>Set</td><td>Reset</td><td>Y</td></tr>
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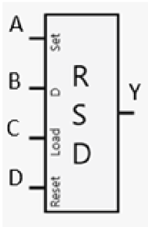
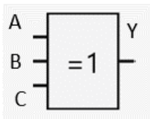
<tr><td>1</td><td>1</td><td>0</td></tr>
<tr><td>0</td><td>0</td><td>0</td></tr>
<tr><td>0</td><td>1</td><td>0</td></tr>
</table>
</td></tr>
<tr><td>RS_D (set+D+load+re-set)</td><td>
</td><td>
<table>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>Y</td></tr>
<tr><td>Set</td><td>D</td><td>Load</td><td>Reset</td><td>State</td></tr>
<tr><td>0</td><td>0</td><td>0</td><td>0</td><td>0 *)</td></tr>
<tr><td>1</td><td>X</td><td>X</td><td>0</td><td>1</td></tr>
<tr><td>1</td><td>X</td><td>X</td><td>1</td><td>0</td></tr>
<tr><td>0</td><td>1</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>0</td><td>1</td><td>1</td><td>0</td><td>1</td></tr>
<tr><td>0</td><td>1</td><td>1</td><td>1</td><td>0 **)</td></tr>
</table>
X = Any state

*) Initial state

**) The state remains 1
until Reset is set active

If Set or D + Load are high, the state returns to high if Reset returns to low.
</td></tr>
<tr><td>XOR</td><td>
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<tr><td>1</td><td>0</td><td>0</td><td>1</td></tr>
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<tr><td>1</td><td>1</td><td>1</td><td>1</td></tr>
</table>
</td></tr>
</table>

Logic element properties

After you have selected the required logic gate in Easergy Pro, you can change the function of the gate in the **Element properties** window by clicking the gate.

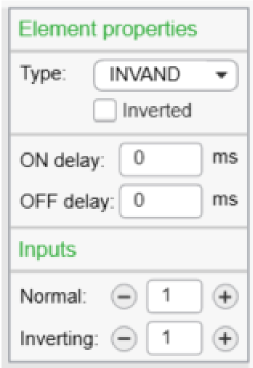


Figure 5.26: Logic element properties

The settings listed in Table 5.12 are available for the logical gates depending on the selected element.

Table 5.12: Logic element properties

Property	Description
Element properties	
Type	Change the logical function of the gate
Inverted	Inverts the output state of the logical gate
ON delay	Time delay to activate the output after logical conditions are met
OFF delay	Time delay for how long the gate remain active even the logical condition is reset
Count	Setting for counter (CT gate only)
Reverse	Use to reverse AND and OR gates (AND+OR gate only)
Inputs	
Normal - / +	Use to increase or decrease number of inputs
Inverting - / +	Use to increase or decrease number of inverted inputs. This setting is visible for INVAND and INVOR gates only
Count	Use to increase or decrease number of count inputs (CT gate only)
Reset	Use to increase or decrease number of count inputs (CT gate only)
AND	Use to increase or decrease number of inputs for AND gates (AND+OR gate only)
OR	Use to increase or decrease number of inputs for OR gates (AND+OR gate only)
Set	Use to increase or decrease number of Set inputs (RS_D gate only)
D	Use to increase or decrease number of Data inputs (RS_D gate only)
Load	Use to increase or decrease number of Load inputs (RS_D gate only)
Reset	Use to increase or decrease number of Reset inputs (RS_D gate only)

5.8 Local panel

Easergy P3G30, P3G32 has one LCD matrix display.

All the main menus are located on the left side and to get in to certain submenu, move up and down the main menus.

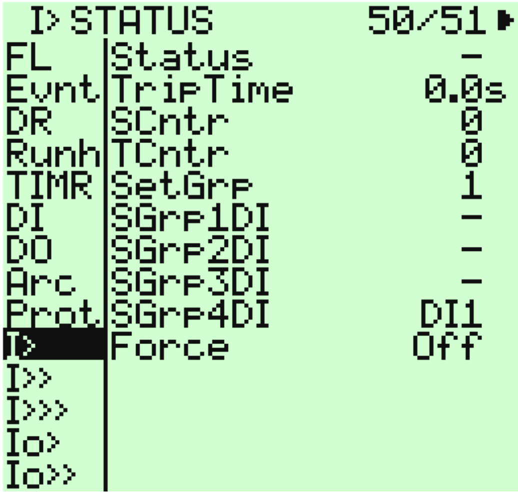


Figure 5.27: The main menu locates on the left side of the display.

5.8.1 Mimic display

Easergy P3G30, P3G32 has a mimic display enabled as a default. Mimic can be modified according to the application or disabled if not needed. The mimic display can be configured only by using Easergy Pro setting tool. Mimic cannot be created using the relay's front panel.

You can modify the local panel mimic in the **Mimic** that is located under the **Device menu** leaflet. The mimic menu has to be enabled in the **Local panel configuration**. Mimic cannot be enabled or disabled using the relay's local panel.

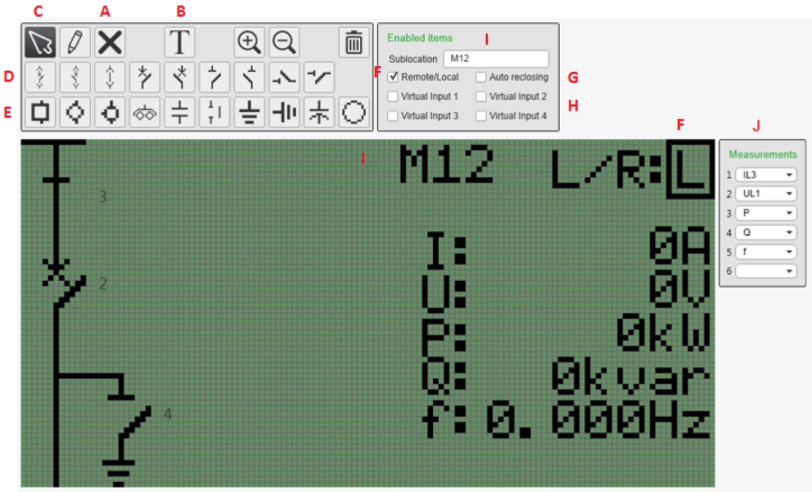


Figure 5.28: MIMIC menu setting view

A) To clear an object or drawing, first point an empty square (B) with the mouse. Then point the object item with the mouse. The color of the object item turns red. To clear the whole mimic, click on the empty area.

B) Text tool

C) To move an existing drawing or object, point it with the mouse. The color turns green. Hold down the left mouse button and move the object.

D) Different type of configurable objects. The object's number corresponds to the number in **General > Objects**.

E) Some predefined drawings.

F) The remote/local selection defines whether certain actions are granted or not. In remote state, it is not possible to locally enable or disable auto-reclosing or to control objects. The remote/local state can be changed in **General > Objects**.

G) Creates auto-reclosing on/off selection to mimic.

H) Creates virtual input activation on the local mimic display.

I) Describes the relay's location. Text comes from the relay info menu.

J) Up to six configurable measurements.

Table 5.13: Mimic functionality

Parameter	Value	Unit	Description	Set
Sublocation	Text field		Up to 9 characters. Fixed location.	Set
Object 1–8	1–8		Double-click on top of the object to change the control number between 1 and 8. Number 1 corresponds to object 1 in **General > Objects**.	Set
Local / Remote mode	L R		Local / Remote control. R stands for remote. Remote local state can be changed in **General > Objects** as well. Position can be changed.	Set
Auto-reclosure	0 1		Possible to enable/disable auroreclosure localy in local mode (L) or remotely in remote mode (R). Position can be changed.	Set
Measurement display 1–6	IL1–IL3 I0 U12, U23, U31, UL1, UL2, UL3, U0 f, P, Q, S, P.F. CosPhi E+, Eq+, E-, Eq- ARStart, ARFaill, ARShot1–5 IFLT Starts, Trips I0Calc IL1–IL3da, IL Pda, Qda, Sda T fSYNC, USYNC I'L1–I'L3 dIL1–dIL3 VAI1–VAI5 ExtAI1–6*		Up to 6 freely selectable measurements.	Set
Virtual input 1–4	0 1		Change the status of virtual inputs while the password is enabled. Position can be changed.	Set

Set = Settable.

* Requires serial communication interface and External IO protocol activated.

NOTE: The measurement display data selection depends on the voltage measurement mode selected in the SCALING setting view.

5.8.2 Local panel configuration

Information displayed on the measurement view is configured in **General > Local panel conf**.

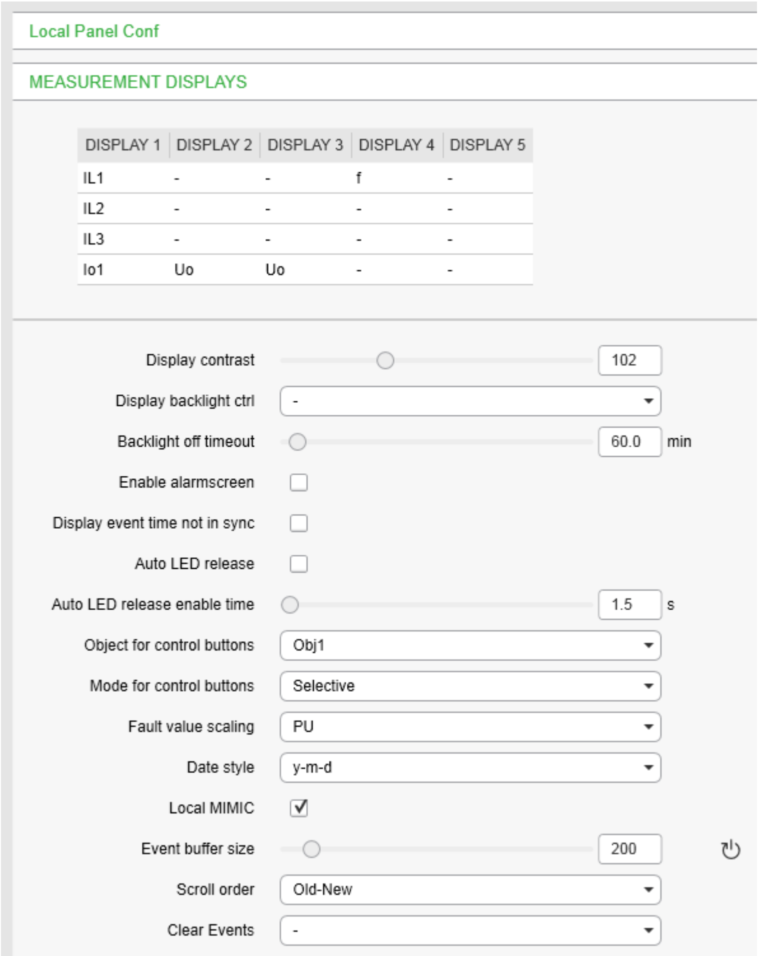


Figure 5.29: Local panel configuration menu

Table 5.14: Local panel configuration

Parameter	Value	Unit	Description	Set
Display 1–5	IL1–3 I0 U12, U23, U31, UL1, UL2, UL3, U0 f, P, Q, S, P.F. CosPhi E+, Eq+, E-, Eq- ARStart, ARFaill, ARShot1–5 IFLT Starts, Trips I0Calc IL IL1–3da IL1–3 max IL1–3 min IL1–3daMax Pda, Qda, Sda T fSYNC, USYNC I'L1–3 dIL1–3 VAI1–5 ExtAI1–6* SetGrp		20 (5 x 4) freely configurable measurement values can be selected	Set **
Display contrast	50–210		Contrast can be changed in the relay menu as well.	Set
Display backlight control	DI1–44, Arc1–3, ArcF, BI, VI1–4, LED1–14, VO1–6		Activates the backlight of the display.	Set **
Backlight off timeout	0.0–2000.0	min	Configurable delay for backlight to turns off when the relay is not used. Default value is 60 minutes. When value is zero (0.0) backlight stays on all the time.	Set
Enable alarm screen	Checked Unchecked		Pop-up text box for events. pop-up events can be checked individually by pressing enter, but holding the button for 2 seconds checks all the events at once.	Set
AR info for mimic display	Checked Unchecked		Auto reclosure status visible on top of the local mimic display.	Set
Sync I info for mimic display	Checked Unchecked		Synchro-check status visible on top of the local mimic display. Operates together with auto-reclosure.	Set
Auto LED release	Checked Unchecked		Enables automatix LED release functionality.	Set
Auto LED release enable time	0.1–600	s	Default 1.5 s. When new LEDs are latched, the previous active latches are released automatically if the set time has passed.	Set
Fault value scaling	PU, Pri		Fault values per unit or primary scsaled.	Set

Parameter	Value	Unit	Description	Set
Local MIMIC	Checked Unchecked		Enable / disable the local mimic (enabled as default).	Set
Event buffer size	50–2000		Event buffer size. Default setting is 200 events.	Set ***

Set = Settable.

* Requires serial communication interface and External IO protocol activated.

** Inputs vary according to the relay type.

*** The existing events are lost if the event buffer size is changed.

6 Protection functions

Each protection stage can independently be enabled or disabled according to the requirements of the intended application.

6.1 Maximum number of protection stages in one application

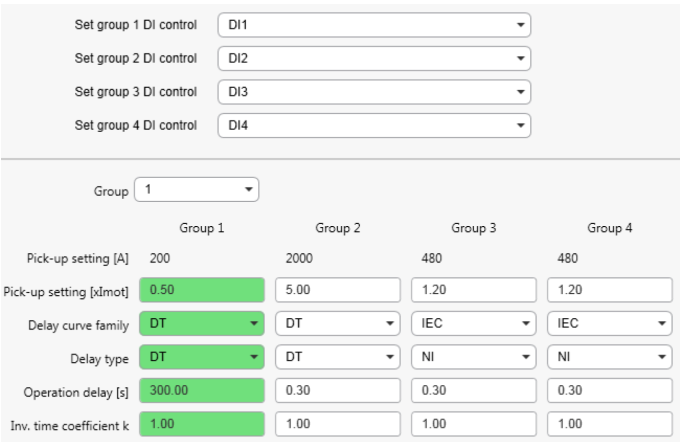
The relay limits the maximum number of enabled protection stages to about 30. The exact number depends on the central processing unit's load consumption and available memory as well as the type of the stages.

The individual protection stage and total load status can be found in the **Protection > Protection stage status** setting view in the Easergy Pro setting tool.

6.2 General features of protection stages

Setting groups

Setting groups are controlled by using digital inputs, function keys or virtual inputs, via the front panel or custom logic. When none of the assigned inputs are active, the setting group is defined by the parameter ‘SetGrp no control state’. When controlled input activates, the corresponding setting group is activated as well. If the control signal of the setting group is lost, the setting “Keep last” forces the last active group into use. If multiple inputs are active at the same time, the active setting group is defined by ‘SetGrp priority’. By using virtual I/O, the active setting group can be controlled using the local panel display, any communication protocol or the inbuilt programmable logic functions. All protection stages have four setting groups.



Example

Any digital input can be used to control setting groups but in this example, DI1, DI2, DI3 and DI4 are chosen to control setting groups 1 to 4. This setting is done with the parameter “Set group x DI control” where x refers to the desired setting group.

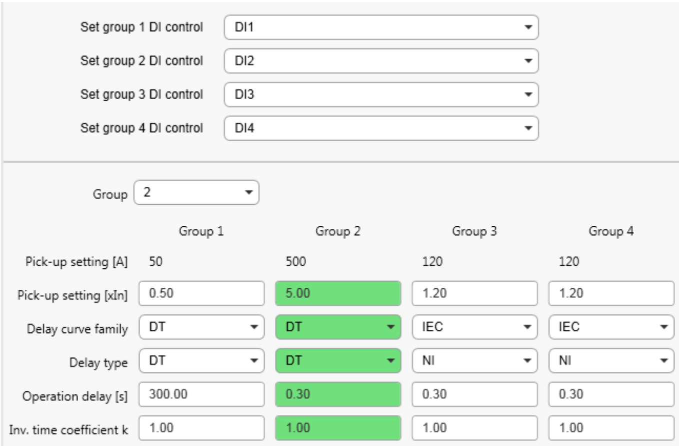


Figure 6.1: DI1, DI2, DI3, DI4 are configured to control Groups 1 to 4 respectively.

Use the 'SetGrp common change' parameter to force all protection stages to group 1, 2, 3 or 4. The control becomes active if there is no local control in the protection stage. You can activate this parameter using Easergy Pro.

“SetGrp priority” is used to give a condition to a situation where two or more digital inputs, controlling setting groups, are active at the same time. SetGrp priority could have values “1 to 4” or “4 to 1”.

Figure 6.2: SetGrp priority setting is located in the Valid Protection stages view.

Assuming that DI2 and DI3 are active at the same time and SetGrp priority is set to “1 to 4”, setting group 2 becomes active. If SetGrp priority is reversed, that is, set to “4 to 1”, the setting group 3 becomes active.

Protection stage statuses

The status of a protection stage can be one of the followings:

- **Ok = '-'**
  The stage is idle and is measuring the analog quantity for the protection. No power system fault detected.
- **Blocked**
  The stage is detecting a fault but blocked by some reason.
- **Start**
  The stage is counting the operation delay.
- **Trip**
  The stage has tripped and the fault is still on.

The blocking reason may be an active signal via the block matrix from other stages, the programmable logic or any digital input. Some stages also have inbuilt blocking logic. For more details about the block matrix, see Chapter 5.4.2 Blocking matrix.

Protection stage counters

Each protection stage has start and trip counters that are incremented when the stage starts or trips. The start and trip counters are reset on relay reboot.

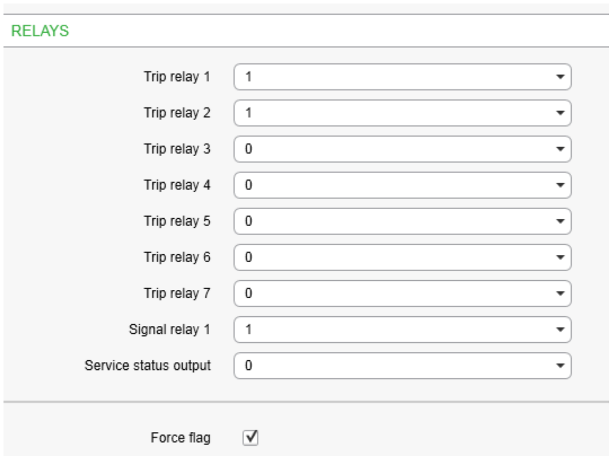
Forcing start or trip condition for testing purposes

There is a "Forcing flag" parameter which, when activated, allows forcing the status of any protection stage to be "start" or "trip" for half a second. By using this forcing feature, current or voltage injection is not necessary to check the output matrix configuration, to check the wiring from the digital outputs to the circuit breaker and also to check that communication protocols are correctly transferring event information to a SCADA system.

After testing, the forcing flag is automatically reset five minutes after the last local panel push button activity.

The force flag also enables forcing the digital outputs and the optional mA outputs.

The force flag can be found in the Relays menu.



Start and trip signals

Every protection stage has two internal binary output signals: start and trip. The start signal is issued when a fault has been detected. The trip signal is issued after the configured operation delay unless the fault disappears before the end of the delay time.

The hysteresis, as indicated in the protection stage's characteristics data, means that the signal is regarded as a fault until the signal drops below the start setting determined by the hysteresis value.

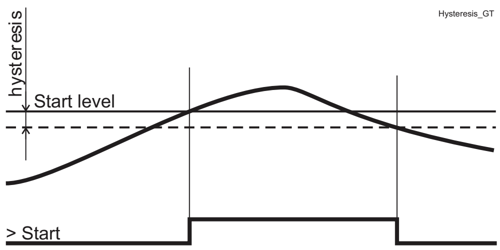


Figure 6.3: Behaviour of a greater than comparator. For example in overvoltage stages the hysteresis (dead band) acts according this figure.

Output matrix

Using the output matrix, you can connect the internal start and trip signals to the digital outputs and indicators. For more details, see Chapter 5.4.1 Output matrix.

Blocking

Any protection function, except arc protection, can be blocked with internal and external signals using the block matrix (Chapter 5.4.2 Blocking matrix). Internal signals are for example logic outputs and start and trip signals from other stages and external signals are for example digital and virtual inputs.

Some protection stages have also inbuilt blocking functions. For example under-frequency protection has inbuilt under-voltage blocking to avoid tripping when the voltage is off.

When a protection stage is blocked, it does not start if a fault condition is detected. If blocking is activated during the operation delay, the delay counting is frozen until the blocking goes off or the start reason, that is the fault condition, disappears. If the stage is already tripping, the blocking has no effect.

Dependent time operation

The operate time in the dependent time mode is dependent on the magnitude of the injected signal. The bigger the signal, the faster the stage issues a trip signal and vice versa. The tripping time calculation resets if the injected quantity drops below the start level.

Definite time operation

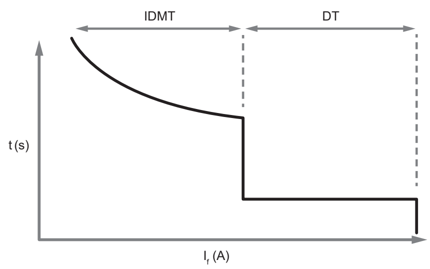


Figure 6.4: Dependent time and definite time operation curves

The operate time in the definite time mode is fixed by the operation delay setting. The timer starts when the protection stage activates and counts until the set time has elapsed. After that, the stage issues a trip command. Should the protection stage reset before the definite time operation has elapsed, then the stage resets.

Overshoot time

Overshoot time is the time the protection relay needs to notice that a fault has been cleared during the operate time delay. This parameter is important when grading the operate time delay settings between relays.

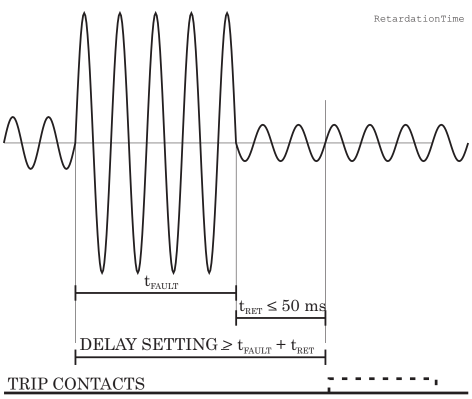


Figure 6.5: Definition for overshoot time. If the delay setting would be slightly shorter, an unselective trip might occur (the dash line pulse).

For example, when there is a big fault in an outgoing feeder, it might start both the incoming and outgoing feeder relay. However, the fault must be cleared by the outgoing feeder relay and the incoming feeder relay must not trip. Although the operating delay setting of the incoming feeder is more than at the outgoing feeder, the incoming feeder might still trip if the operate time difference is not big enough. The difference must be more than the overshoot time of the incoming feeder relay plus the operate time of the outgoing feeder circuit breaker.

Figure 6.5 shows an overvoltage fault seen by the incoming feeder when the outgoing feeder clears the fault. If the operation delay setting would be slightly shorter or if the fault duration would be slightly longer than in the figure, an unselective trip might happen (the dashed 40 ms pulse in the figure). In Easergy P3 relays, the overshoot time is less than 50 ms.

Reset time

Figure 6.6 shows an example of reset time, that is, release delay when the relay is clearing an overcurrent fault. When the relay's trip contacts are closed, the circuit breaker (CB) starts to open. After the CB contacts are open, the fault current still flows through an arc between the opened contacts. The current is finally cut off when the arc extinguishes at the next zero crossing of the current. This is the start moment of the reset delay. After the reset delay the trip contacts and start contact are opened unless latching is configured. The precise reset time depends on the fault size; after a big fault, the reset time is longer. The reset time also depends on the specific protection stage.

The maximum reset time for each stage is specified under the characteristics of every protection function. For most stages, it is less than 95 ms.

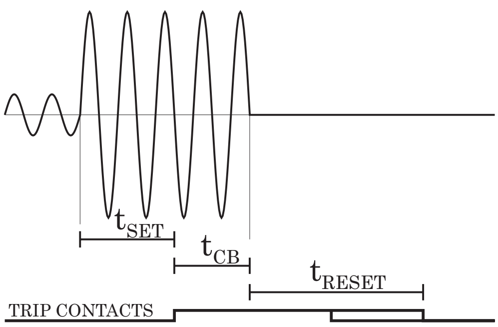


Figure 6.6: Reset time is the time it takes the trip or start relay contacts to open after the fault has been cleared.

Hysteresis or dead band

When comparing a measured value against a start value, some amount of hysteresis is needed to avoid oscillation near equilibrium situation. With zero hysteresis, any noise in the measured signal or any noise in the measurement itself would cause unwanted oscillation between fault-on and fault-off situations.

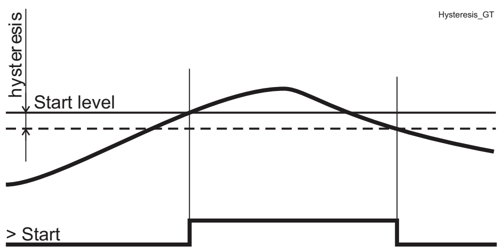


Figure 6.7: Example of behaviour of an over-protection with hysteresis

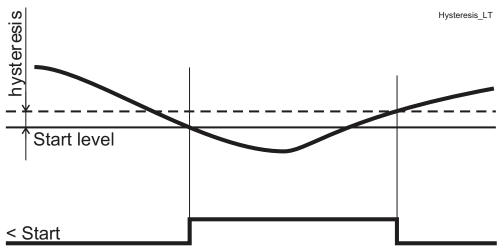


Figure 6.8: Example of behaviour of an under-protection with hysteresis

Time grading

When a fault occurs, the protection scheme only needs to trip circuit breakers whose operation is required to isolate the fault. This selective tripping is also called discrimination or protection coordination and is typically achived by time grading. Protection systems in successive zones are arranged to operate in times that are graded through the sequence of equipment so that upon the occurrence of a fault, although a number of protections devices respond, only those relevant to the faulty zone complete the tripping function.

The recommended discrimination time between two Easergy P3 relays in an MV network is 170–200 ms. This is based on the following facts:

- T_c: circuit breaker operating time, 60 ms
- T_m: upstream protection overshoot time (retardation time), 50 ms
- δt: time delay tolerance, 25 ms
- m: safety margin, 10 ms
- Δt: discrimination time, 170–200 ms

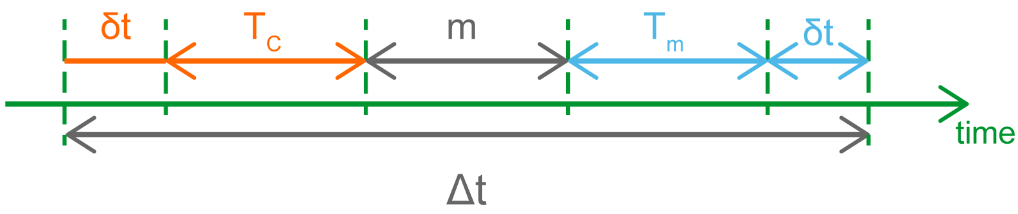


Figure 6.9: Time grading

Recorded values of the last eight faults

There is detailed information available on the last eight faults for each protection stage. The recorded values are specific for the protection stages and can contain information like time stamp, fault value, elapsed delay, fault current, fault voltage, phase angle and setting group.

NOTE: The recorded values are lost if the relay power is switched off.

6.3 Dependent operate time

The dependent operate time - that is, the inverse definite minimum time (IDMT) type of operation - is available for several protection functions. The common principle, formulae and graphic representations of the available dependent delay types are described in this chapter.

Dependent delay means that the operate time depends on the measured real time process values during a fault. For example, with an overcurrent stage using dependent delay, a bigger a fault current gives faster operation. The alternative to dependent delay is definite delay. With definite delay, a preset time is used and the operate time does not depend on the size of a fault.

Stage-specific dependent delay

Some protection functions have their own specific type of dependent delay. Details of these dedicated dependent delays are described with the appropriate protection function.

Operation modes

There are three operation modes to use the dependent time characteristics:

- Standard delays
  Using standard delay characteristics by selecting a curve family (IEC, IEEE, IEEE2, RI) and a delay type (Normal inverse, Very inverse etc). See Chapter 6.3.1 Standard dependent delays using IEC, IEEE, IEEE2 and RI curves.
- Standard delay formulae with free parameters
  selecting a curve family (IEC, IEEE, IEEE2) and defining one's own parameters for the selected delay formula. This mode is activated by setting delay type to ‘Parameters’, and then editing the delay function parameters A – E. See Chapter 6.3.2 Free parameterization using IEC, IEEE and IEEE2 curves.
- Fully programmable dependent delay characteristics
  Building the characteristics by setting 16 [current, time] points. The relay interpolates the values between given points with second degree polynomials. This mode is activated by the setting curve family to ‘PrgN’’. There is a maximum of three different programmable curves available at the same time. Each programmed curve can be used by any number of protection stages. See Chapter 6.3.3 Programmable dependent time curves.

Dependent time limitation

The maximum dependent time is limited to 600 seconds.

Local panel graph

The relay shows a graph of the currently used dependent delay on the local panel display. The up and down keys can be used for zooming. Also the delays at 20 x I_{SET}, 4 x I_{SET} and 2 x I_{SET} are shown.

Dependent time setting error signal

If there are any errors in the dependent delay configuration, the appropriate protection stage uses the definite time delay.

There is a signal 'Setting Error' available in the output matrix that indicates different situations:

1. Settings are currently changed with Easergy Pro or local panel.
2. There is temporarily an illegal combination of curve points. For example, if previous setting was IEC/NI and then curve family is changed to IEEE, this causes a setting error because there is no NI type available for IEEE curves. After changing valid delay type for IEEE mode (for example MI), the 'Setting Error' signal releases.
3. There are errors in formula parameters A – E, and the relay is not able to build the delay curve.
4. There are errors in the programmable curve configuration, and the relay is not able to interpolate values between the given points.

Limitations

The maximum measured secondary phase current is 50 x I_N and the maximum directly measured earth fault current is 10 x I_{0N} for earth fault overcurrent input. The full scope of dependent delay curves goes up to 20 times the setting. At a high setting, the maximum measurement capability limits the scope of dependent curves according to Table 6.1.

Table 6.1: Maximum measured secondary currents and settings for phase and earth fault overcurrent inputs

Current input	Maximum measured secondary current	Maximum secondary scaled setting enabling dependent delay times up to full 20x setting
I_{L1}, I_{L2}, I_{L3} and I_{0Calc}	250 A	12.5 A
I_{01} = 5 A	50 A	2.5 A
I_{01} = 1 A	10 A	0.5 A
I_{01} = 0.2 A	2 A	0.1 A

1. **Example of limitation**

   CT = 750 / 5

   CT_0= 100 / 1 (cable CT is used for earth fault overcurrent)

   The CT_0 is connected to a 1 A terminals of input I_{01}.

   For overcurrent stage I>, Table 6.1 gives 12.5 A. Thus, the maximum setting the for I> stage giving full dependent delay range is 12.5 A / 5 A = 2.5 xI_N = 1875 $A_{Primary}$.

   For earth fault stage I_0>, Table 6.1 gives 0.5 A. Thus, the maximum setting for the I_0> stage giving full dependent delay range is 0.5 A / 1 A = 0.5 xI_{0N} = 50 $A_{Primary}$.

2. **Example of limitation**

   CT = 750 / 5

   Application mode is Motor

   Rated current of the motor = 600 A

   I_{0Calc} (= I_{L1} + I_{L2} + I_{L3}) is used for earth fault overcurrent

   At secondary level, the rated motor current is 600 / 750*5 = 4 A

   For overcurrent stage I>, Table 6.1 gives 12.5 A. Thus, the maximum setting giving full dependent delay range is 12.5 A / 4 A = 3.13 x I_{MOT} = 1875 $A_{Primary}$.

   For earth fault stage I_0>, Table 6.1 gives 12.5 A. Thus, the maximum setting for the I_0> stage giving full dependent delay range is 12.5 A / 5 A = 2.5 x I_{0N} = 1875 $A_{Primary}$.

6.3.1 Standard dependent delays using IEC, IEEE, IEEE2 and RI curves

The available standard dependnet delays are divided in four categories called dependent curve families: IEC, IEEE, IEEE2 and RI. Each category contains a set of different delay types according to Table 6.2.

Dependent time setting error signal

The dependent time setting error signal activates if the delay category is changed and the old delay type does not exist in the new category. See Chapter 6.3 Dependent operate time for more details.

Limitations

The minimum definite time delay starts when the measured value is twenty times the setting, at the latest. However, there are limitations at high setting values due to the measurement range. SeeChapter 6.3 Dependent operate time for more details.

Table 6.2: Available standard delay families and the available delay types within each family.

Delay type		Curve family				
		DT	IEC	IEEE	IEEE2	RI
DT	Definite time	X				
NI	Normal inverse		X		X	
VI	Very inverse		X	X	X	
EI	Extremely inverse		X	X	X	
LTI	Long time inverse		X	X		
LTEI	Long time extremely inverse			X		
LTVI	Long time very inverse			X		
MI	Moderately inverse			X	X	
STI	Short time inverse			X		
STEI	Short time extremely inverse			X		
RI	Old ASEA type					X
RXIDG	Old ASEA type					X

IEC dependent operate time

The operate time depends on the measured value and other parameters according to Equation 6.1. Actually this equation can only be used to draw graphs or when the measured value I is constant during the fault. A modified version is implemented in the relay for real time usage.

Equation 6.1:

$$t = \frac{k\ A}{\left(\frac{I}{I_{START}}\right)^{B} - 1}$$

t = Operation delay in seconds

k = User’s multiplier Inv. time coefficient k

I = Measured value

I_{START} = Start setting

A, B = Constants parameters according Table 6.3.

There are three different dependent delay types according to IEC 60255-3, Normal inverse (NI), Extremely inverse (EI), Very inverse (VI) and a VI extension. In addition, there is a de facto standard Long time inverse (LTI).

Table 6.3: Constants for IEC dependent delay equation

Delay type		Parameter	
		A	B
NI	Normal inverse	0.14	0.02
EI	Extremely inverse	80	2
VI	Very inverse	13.5	1
LTI	Long time inverse	120	1

Example of the delay type "Normal inverse (NI)":

k = 0.50

I = 4 pu (constant current)

I_{PICKUP} = 2 pu

A = 0.14

B = 0.02

$$t = \frac{0.50 \cdot 0.14}{\left(\frac{4}{2}\right)^{0.02} - 1} = 5.0$$

The operate time in this example is five seconds. The same result can be read from Figure 6.10.

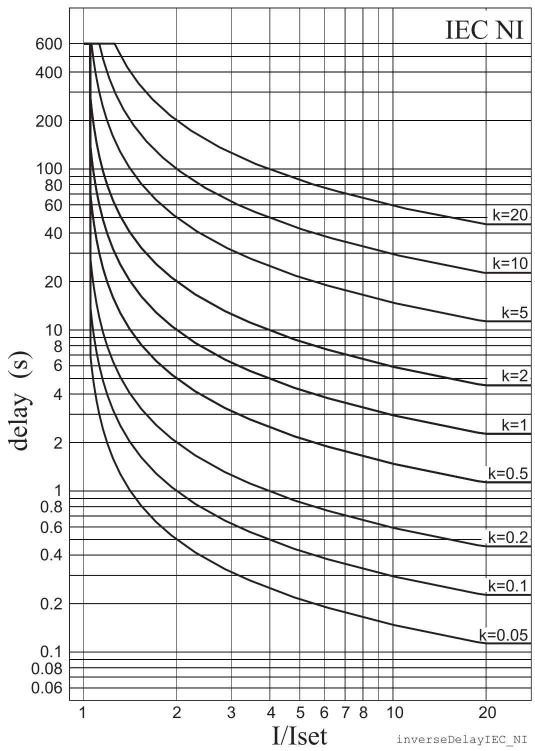


Figure 6.10: IEC normal inverse delay

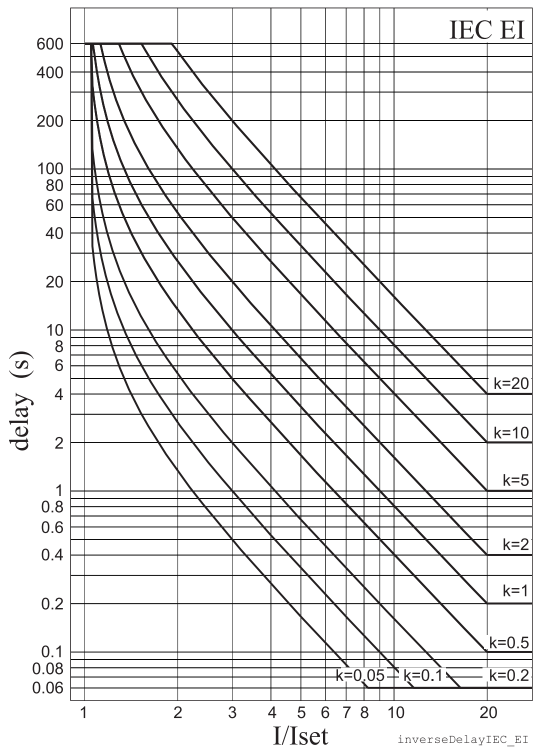


Figure 6.11: IEC extremely inverse delay

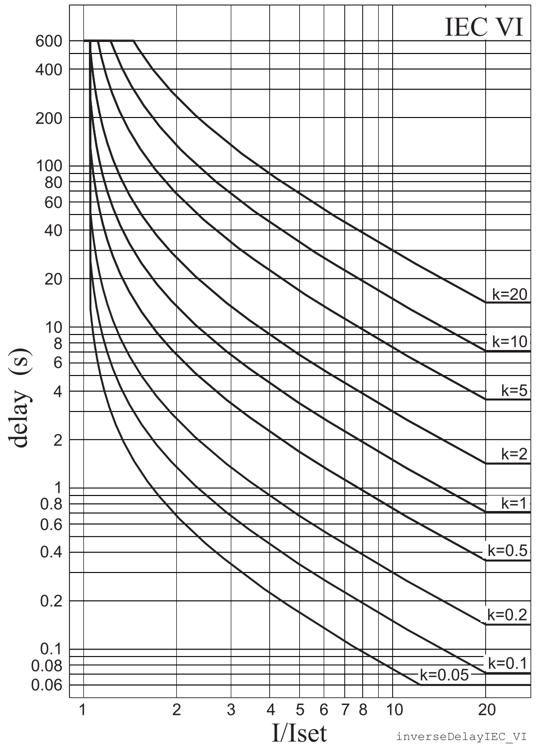


Figure 6.12: IEC very inverse delay

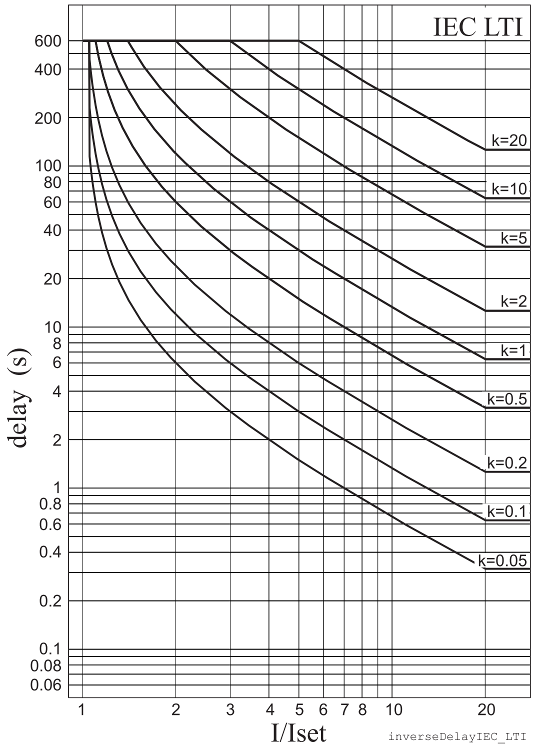


Figure 6.13: IEC long time inverse delay

IEEE/ANSI dependent operate time

There are three different delay types according to IEEE Std C37.112-1996 (MI, VI, EI) and many de facto versions according to Table 6.4. The IEEE standard defines dependent delay for both trip and release operations. However, in the Easergy P3 relay only the trip time is dependent according to the standard but the reset time is constant.

The operate delay depends on the measured value and other parameters according to Equation 6.2. Actually, this equation can only be used to draw graphs or when the measured value I is constant during the fault. A modified version is implemented in the relay for real-time usage.

Equation 6.2:

$$t = k\left[\frac{A}{\left(\frac{I}{I_{START}}\right)^{C} - 1} + B\right]$$

t = Operation delay in seconds

k = User’s multiplier

I = Measured value

I_{START} = Start setting

A,B,C = Constant parameter according to Table 6.4.

Table 6.4: Constants for IEEE/ANSI inverse delay equation

Delay type		Parameter		
		A	B	C
LTI	Long time inverse	0.086	0.185	0.02
LTVI	Long time very inverse	28.55	0.712	2
LTEI	Long time extremely inverse	64.07	0.250	2
MI	Moderately inverse	0.0515	0.1140	0.02
VI	Very inverse	19.61	0.491	2
EI	Extremely inverse	28.2	0.1217	2
STI	Short time inverse	0.16758	0.11858	0.02
STEI	Short time extremely inverse	1.281	0.005	2

Example of the delay type "Moderately inverse (MI)":

k = 0.50

I = 4 pu

I_{PICKUP} = 2 pu

A = 0.0515

B = 0.114

C = 0.02

$$t = 0.50 \cdot \left[\frac{0.0515}{\left(\frac{4}{2}\right)^{0.02} - 1} + 0.1140 \right] = 1.9$$

The operate time in this example is 1.9 seconds. The same result can be read from Figure 6.17.

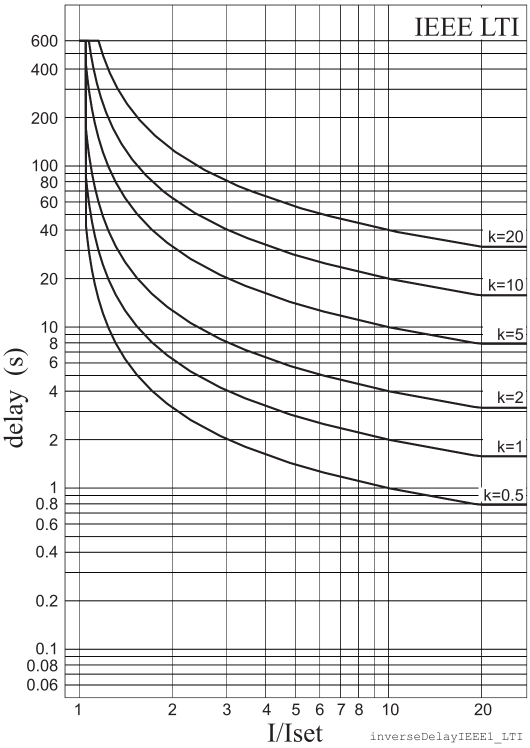


Figure 6.14: ANSI/IEEE long time inverse delay

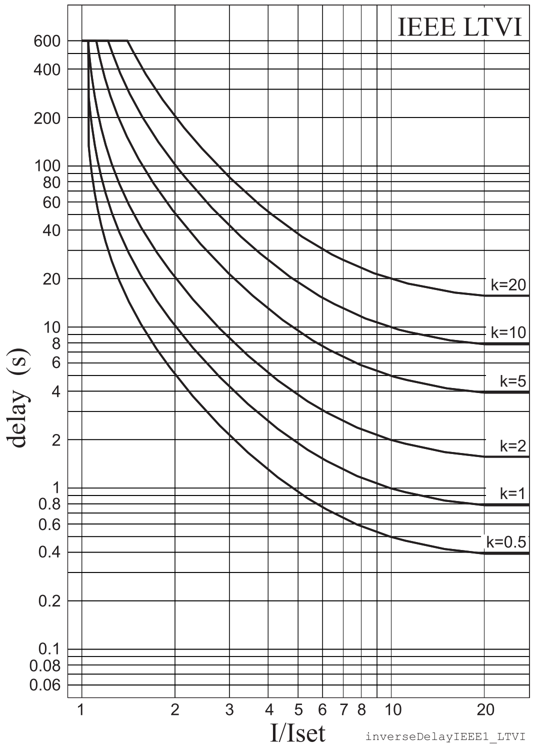


Figure 6.15: ANSI/IEEE long time very inverse delay

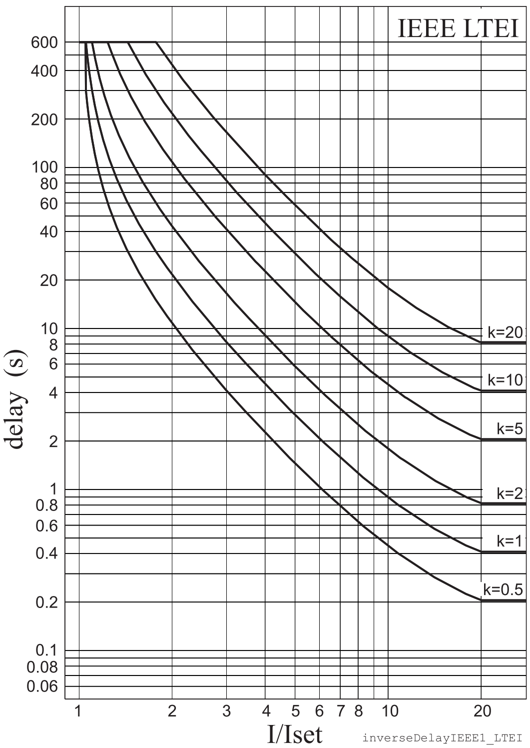


Figure 6.16: ANSI/IEEE long time extremely inverse delay

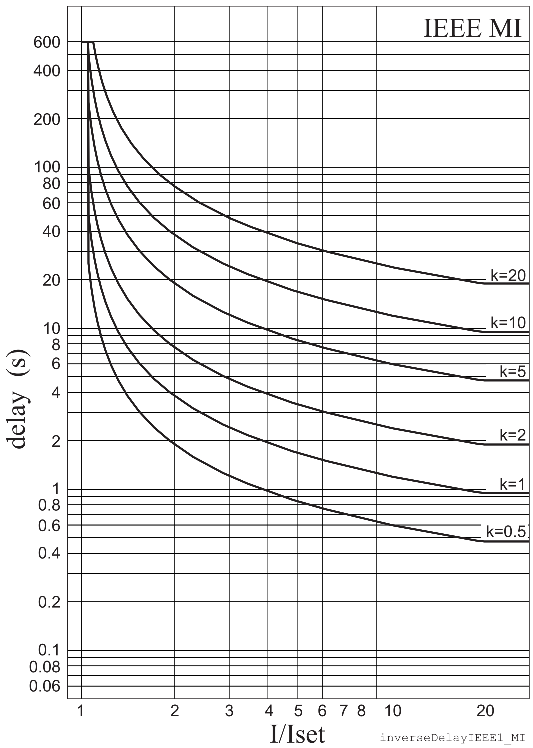


Figure 6.17: ANSI/IEEE moderately inverse delay

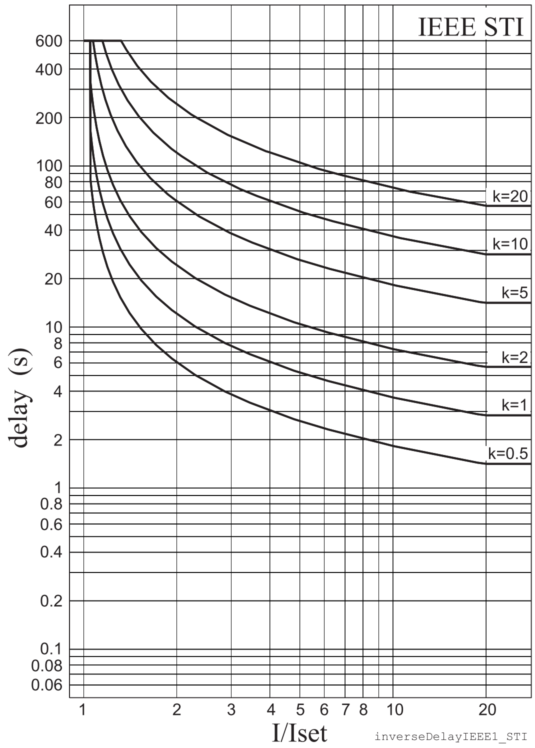


Figure 6.18: ANSI/IEEE short time inverse delay

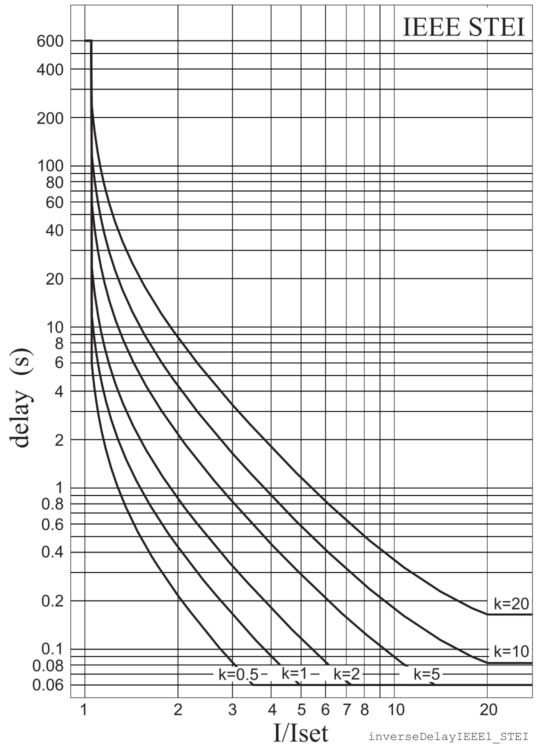


Figure 6.19: ANSI/IEEE short time extremely inverse delay

IEEE2 dependent operate time

Before the year 1996 and ANSI standard C37.112 microprocessor relays were using equations approximating the behaviour of various induction disc type relays. A quite popular approximation is Equation 6.3 which in Easergy P3 relays is called IEEE2. Another name could be IAC because the old General Electric IAC relays have been modeled using the same equation.

There are four different delay types according to Table 6.5. The old electromechanical induction disc relays have dependent delay for both trip and release operations. However, in Easergy P3 relays, only the trip time is dependent and the reset time is constant.

The operate delay depends on the measured value and other parameters according to Equation 6.3. Actually, this equation can only be used to draw graphs or when the measured value I is constant during the fault. A modified version is implemented in the relay for real-time usage.

Equation 6.3:

$$t = k\left[A + \frac{B}{\left(\frac{I}{I_{START}} - C\right)} + \frac{D}{\left(\frac{I}{I_{START}} - C\right)^2} + \frac{E}{\left(\frac{I}{I_{START}} - C\right)^3}\right]$$

t = Operation delay in seconds

k = User’s multiplier

I = Measured value

I_{START} = User’s start setting

A, B, C, D = Constant parameter according Table 6.5.

Table 6.5: Constants for IEEE2 inverse delay equation

Delay type		Parameter				
		A	B	C	D	E
MI	Moderately inverse	0.1735	0.6791	0.8	-0.08	0.1271
NI	Normally inverse	0.0274	2.2614	0.3	-0.1899	9.1272
VI	Very inverse	0.0615	0.7989	0.34	-0.284	4.0505
EI	Extremely inverse	0.0399	0.2294	0.5	3.0094	0.7222

Example of the delay type "Moderately inverse (MI)":

k = 0.50

I = 4 pu

I_{START} = 2 pu

A = 0.1735

B = 0.6791

C = 0.8

D = -0.08

E = 0.127

$$t = 0.5 \cdot \left[0.1735 + \frac{0.6791}{\left(\frac{4}{2} - 0.8\right)} + \frac{-0.08}{\left(\frac{4}{2} - 0.8\right)^2} + \frac{0.127}{\left(\frac{4}{2} - 0.8\right)^3}\right] = 0.38$$

The operate time in this example is 0.38 seconds. The same result can be read from Figure 6.20.

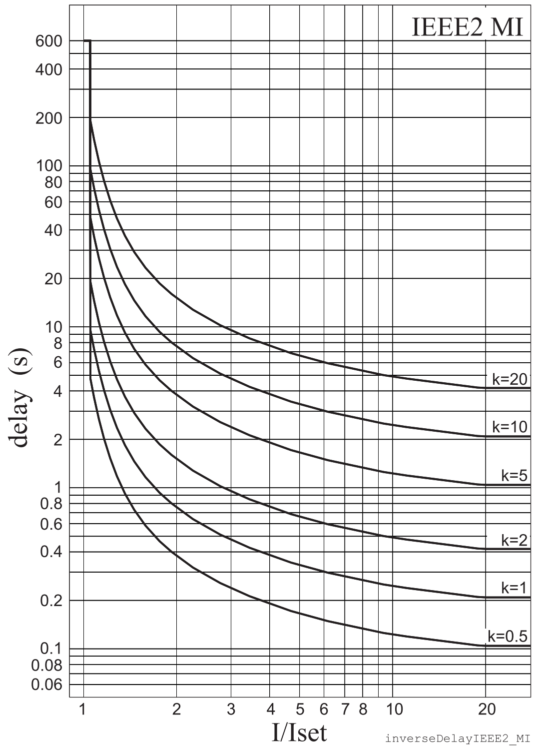


Figure 6.20: IEEE2 moderately inverse delay

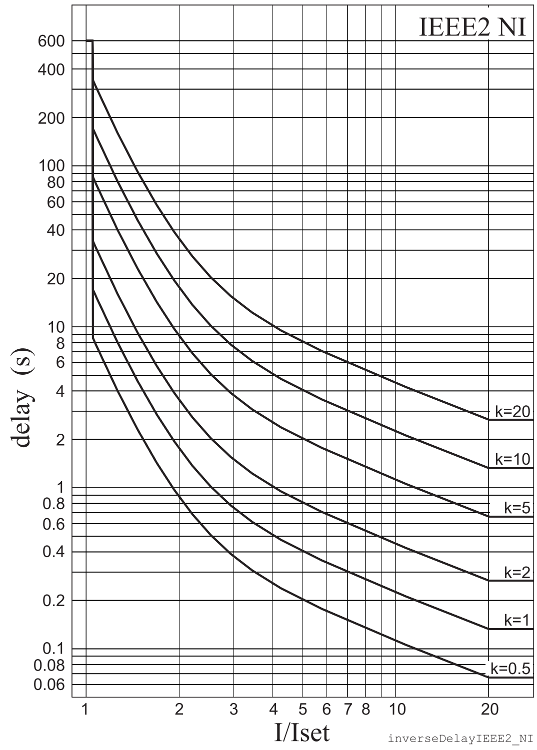


Figure 6.21: IEEE2 normal inverse delay

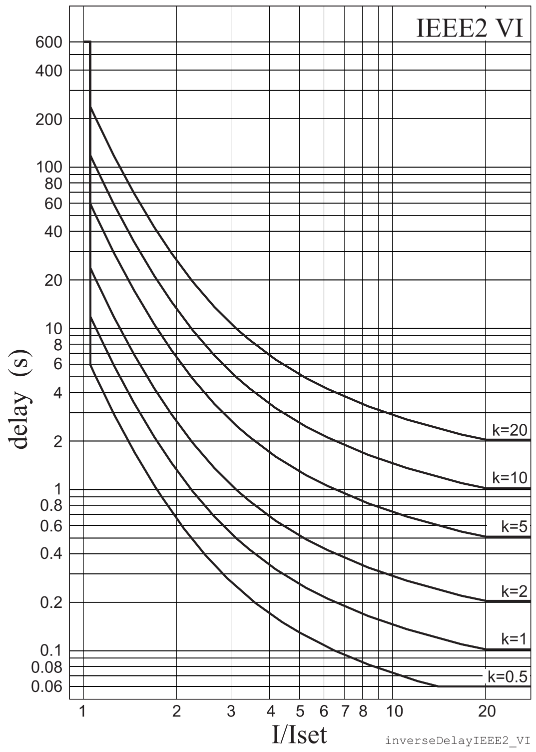


Figure 6.22: IEEE2 very inverse delay

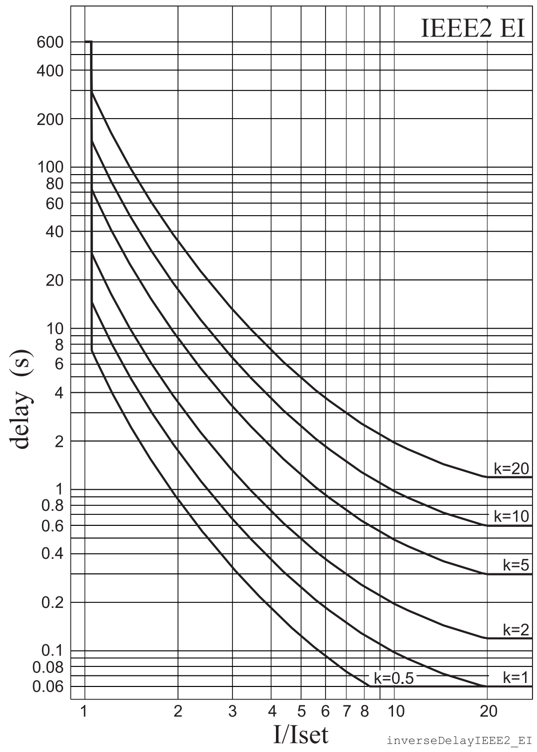


Figure 6.23: IEEE2 extremely inverse delay

RI and RXIDG type dependent operate time

These two dependent delay types have their origin in old ASEA (nowadays ABB) earth fault relays.

The operate delay of types RI and RXIDG depends on the measured value and other parameters according to Equation 6.4 and Equation 6.5. Actually, these equations can only be used to draw graphs or when the measured value I is constant during the fault. Modified versions are implemented in the relay for real-time usage.

Equation 6.4: RI

$$t_{RI} = \frac{k}{0.339 - \frac{0.236}{\left(\frac{I}{I_{START}}\right)}}$$

Equation 6.5: RXIDG

$$t_{RXIDG} = 5.8 - 1.35 \ln \frac{I}{k\, I_{START}}$$

t = Operate delay in seconds

k = User's multiplier

I = Measured value

I_{START} = Start setting

Example of the delay type RI

k = 0.50

I = 4 pu

I_{START} = 2 pu

$$t_{RI} = \frac{0.5}{0.339 - \frac{0.236}{\left(\frac{4}{2}\right)}} = 2.3$$

The operate time in this example is 2.3 seconds. The same result can be read from Figure 6.24.

Example of the delay type RXIDG

k = 0.50

I = 4 pu

I_{START} = 2 pu

$$t_{RXIDG} = 5.8 - 1.35 \ln \frac{4}{0.5 \cdot 2} = 3.9$$

The operate time in this example is 3.9 seconds. The same result can be read from Figure 6.25.

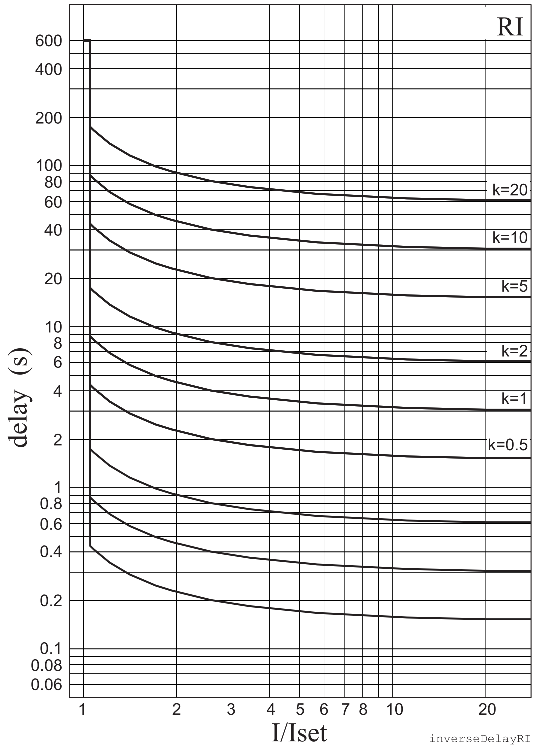


Figure 6.24: RI dependent delay

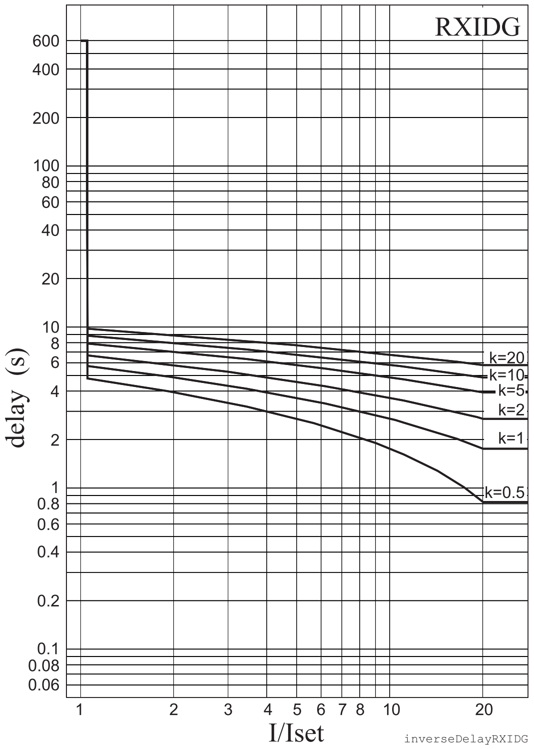


Figure 6.25: RXIDG dependent delay

6.3.2 Free parameterization using IEC, IEEE and IEEE2 curves

This mode is activated by the setting delay type to 'Parameters', and then editing the delay function constants, that is, the parameters A – E. The idea is to use the standard equations with one's own constants instead of the standardized constants as in the previous chapter.

Example of the GE-IAC51 delay type:

k = 0.50

I = 4 pu

I_{START} = 2 pu

A = 0.2078

B = 0.8630

C = 0.8000

D = - 0.4180

E = 0.1947

$$t = 0.5 \cdot \left[0.2078 + \frac{0.8630}{\left(\frac{4}{2} - 0.8\right)} + \frac{-0.4180}{\left(\frac{4}{2} - 0.8\right)^2} + \frac{0.1947}{\left(\frac{4}{2} - 0.8\right)^3} \right] = 0.37$$

The operate time in this example is 0.37 seconds.

The resulting time/current characteristic of this example matches quite well the characteristic of the old electromechanical IAC51 induction disc relay.

Dependent time setting error signal

The dependent time setting error signal actives if interpolation with the given parameters is not possible. See Chapter 6.3 Dependent operate time for more details.

Limitations

The minimum definite time delay starts at the latest when the measured value is twenty times the setting. However, there are limitations at high setting values due to the measurement range. See Chapter 6.3 Dependent operate time for more details.

6.3.3 Programmable dependent time curves

Programming dependent time curves requires Easergy Pro setting tool and rebooting the unit.

The [current, time] curve points are programmed using Easergy Pro PC program. There are some rules for defining the curve points:

- the configuration must begin from the topmost line
- the line order must be as follows: the smallest current (longest operate time) on the top and the largest current (shortest operate time) on the bottom
- all unused lines (on the bottom) should be filled with [1.00 0.00s]

Here is an example configuration of curve points:

Point	Current I/I_{START}	Operate delay
1	1.00	10.00 s
2	2.00	6.50 s
3	5.00	4.00 s
4	10.00	3.00 s
5	20.00	2.00 s
6	40.00	1.00 s
7	1.00	0.00 s
8	1.00	0.00 s
9	1.00	0.00 s
10	1.00	0.00 s
11	1.00	0.00 s
12	1.00	0.00 s
13	1.00	0.00 s
14	1.00	0.00 s
15	1.00	0.00 s
16	1.00	0.00 s

Dependent time setting error signal

The dependent time setting error signal activates if interpolation with the given points fails. See Chapter 6.3 Dependent operate time for more details.

Limitations

The minimum definite time delay starts at the latest when the measured value is twenty times the setting. However, there are limitations at high setting values due to the measurement range. See Chapter 6.3 Dependent operate time for more details.

6.4 Underimpedance (ANSI 21G)

Underimpedance protection can be used to detect near short-circuit faults, even when excitation of the generator collapse thus is limiting the available short-circuit current. It is an alternative for the voltage dependent overcurrent protection (Chapter 6.20 Voltage-dependent overcurrent (ANSI 51V)). When the generator's short-circuit current capacity is limited, a instantaneous overcurrent stage might not activate, but an underimpedance stage detects the fault.

The stage is sensitive to the positive sequence impedance Z_1, that is calculated using the equation

$$Z_1 = \frac{U_1}{I_1}$$

Z_1 = absolute value of positive sequence impedance

U_1 = positive sequence voltage

I_1 = positive sequence current

The trip region of underimpedance stage is a circle in origin. The radius Z< is the setting value. The bigger circle "stator limit" represents the rated power of the generator.

The impedance relay is insensitive to the phase angle between current and voltage. Its characteristic in an impedance plane is a circle in origin where the horizontal axis represents resistance R and the vertical axis represents reactance jX (Figure 6.26).

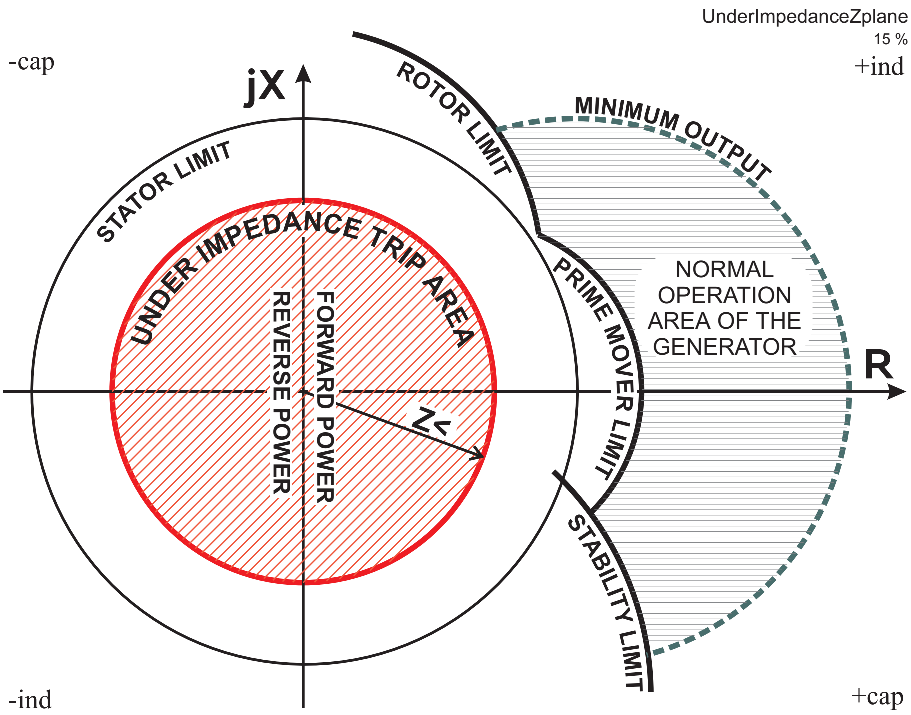


Figure 6.26: The underimpedance Z plane characteristic

Whenever the positive sequence impedance goes inside the circle, the stage starts. The radius Z< of the circle and the definite delay time are the setting parameters.

Figure 6.27 shows the underimpedance characteristics drawn in power plane assuming that the voltage is constant. The trip area is now outside the circle having radius $U_2/Z<$ where Z< is the start setting.

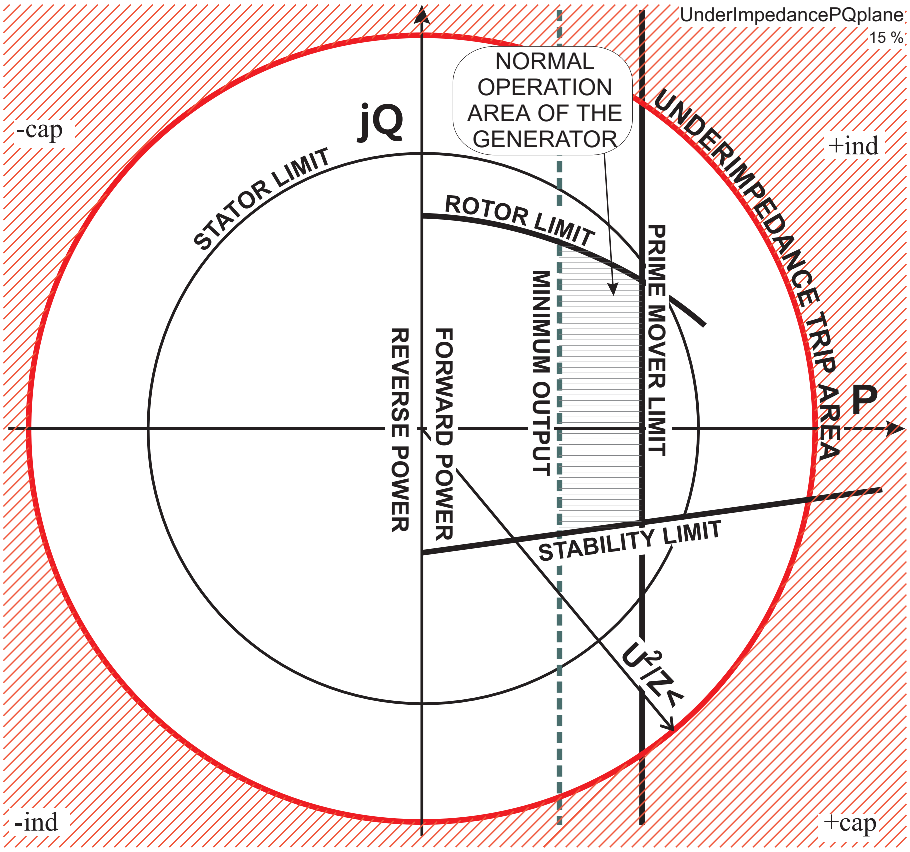


Figure 6.27: Underimpedance plane with a constant voltage

Undercurrent blocking

When for some reason the voltage collapses but currents remain at normal load levels, the calculated impedance may fall into the trip area. An inverted start signal from the most sensitive overcurrent stage can be used to block the underimpedance stages during abnormal voltages not caused by short-circuit faults.

Characteristic on a PQ power plane

In Figure 6.27, the same characteristic as in the previous figure is drawn on a PQ power plane assuming a constant voltage of 1 PU. The transformation is $\underline{S} = U_2/Z^*$, where U is the voltage and Z* is the complex conjugate of impedance Z.

The borderline of the underimpedance trip area in the power plane is still a circle in origin, but now the trip area is outside the circle. The shape of the normal operation area is totally different. For example the maximum active power (prime mover limit) is just a vertical line while in impedance plane (Figure 6.26), it is a circle touching the jX axis.

When the current is zero, the impedance calculation gives infinite as the result. Thus, the stage does not start in a machine standstill situation.

Two independent underimpedance stages

There are two separately adjustable stages available: Z< and Z<<.

Setting groups

This stage has one setting group.

Characteristics

Table 6.6: Underimpedance stages Z<, Z<< (21G)

Start value	0.05 – 2.00 x Z_N
Definite time function: - Operate time	 0.08** – 300.00 s (step 0.02 s)
Start time	Typically 60 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio	1.05
Inaccuracy: - Starting - Operate time at definite time function	 ±4 % of set value or ±0.01 x Z_N ±1 % or ±30 ms

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

6.5 Volts/hertz overexcitation protection U_f> (ANSI 24)

The saturation of any inductive network components like transformers, inductors, motors and generators depends on the voltage and frequency. The lower the frequency, the lower is the voltage at which the saturation begins.

The volts/hertz overexcitation protection stage is sensitive to the voltage/frequency ratio instead of voltage only. Figure 6.28 shows the difference between volts/hertz and a standard overvoltage function. The highest of the three line-to-line voltages is used regardless of the voltage measurement mode (Chapter 10.6 Voltage measurement modes). By using line-to-line voltages, any line-to-neutral overvoltages during earth faults have no effect. (The earth fault protection functions take care of earth faults.)

The used net frequency is automatically adopted according to the local network frequency.

Overexcitation protection is needed for generators that are excitated even during startup and shutdown. If such a generator is connected to a unit transformer, also the unit transformer needs volts/hertz overexcitation protection. Another application is sensitive overvoltage protection of modern transformers with no flux density margin in networks with unstable frequency.

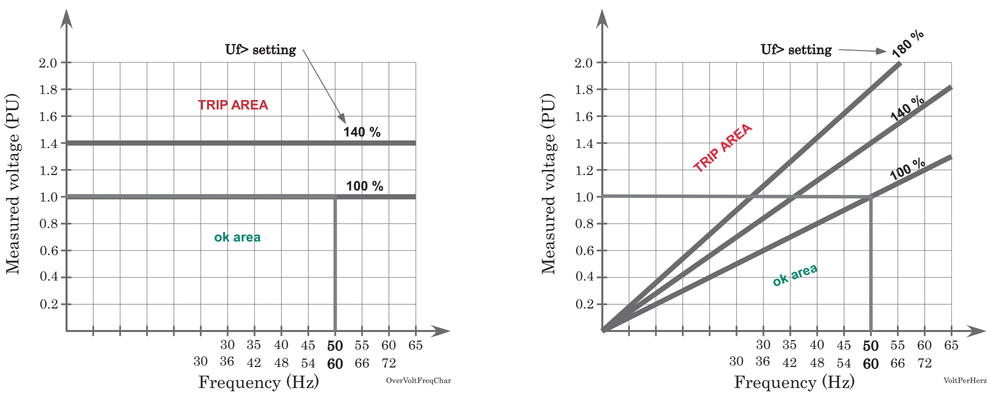


Figure 6.28: This figure shows the difference between volts/hertz and normal overvoltage protection. The volts/hertz characteristics on the left depend on the frequency, while the standard overvoltage function on the right is insensitive to frequency. The network frequency, 50 Hz or 60 Hz, is automatically adopted by the relay.

Setting groups

There are four setting groups available for each stage.

Characteristics

Table 6.7: Volts/hertz over-excitation protection U_f>, U_f>> (24)

Start setting range	100 – 200 %
Operating time	0.3 – 300.0 s
Start time	Typically 200 ms
Reset time	< 450 ms
Reset ratio	0.995
Inaccuracy:	
- Starting	U < 0.5 % unit f < 0.05 Hz
- Operating time at definite time function	±1 % or ±150 ms

6.6 Synchrocheck (ANSI 25)

Description

The relay includes a synchrocheck function that checks the synchronism before giving or enabling the circuit breaker close command. The function monitors the voltage amplitude, frequency and phase angle difference between two voltages. Since there are two stages available, it is possible to monitor three voltages. The voltages can be busbar and line or busbar and busbar (bus coupler).

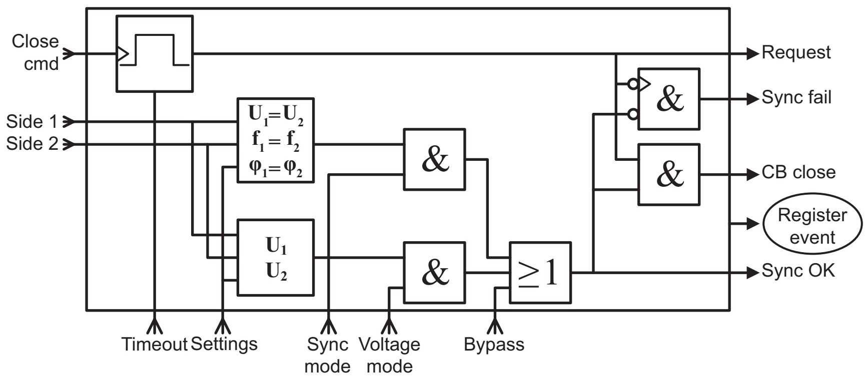


Figure 6.29: Synchrocheck function

The synchrocheck stage includes two separate synchronism criteria that can be used separately or combined:

- voltage only
- voltage, frequency, and phase

The voltage check simply compares voltage conditions of the supervised objects. The supervised object is considered dead (not energized) when the measured voltage is below the U_{dead} setting limit. Similarly, the supervised object is considered live (energized) when the measured voltage is above the U_{live} setting limit. Based on the measured voltage conditions and the selected voltage check criteria, synchronism is declared.

When the network sections to be connected are part of the same network, the frequency and phase are the same. Therefore, the voltage check criteria is safe to use without frequency and phase check.

The frequency and phase check compares the voltages, frequency and phase of the supervised objects. Synchronism is declared if the voltages are above the U_{live} limit and all three difference criteria are within the given limits. This synchronism check is dynamic by nature, and the object close command is given at a certain moment of time, depending on the selected mode of operation.

When two networks are running at slightly different frequencies, there is also a phase difference between these two networks. Because of the different frequency, the phase angle tends to rotate. The time for one cycle depends on the frequency difference. The stress for electrical components is lowest when two networks are connected at zero phase difference.

In the “Sync” mode, the circuit breaker closing is aimed at the moment of zero phase difference. Therefore, the close command is advanced by the time defined by the CB close time setting. In the “Async” mode, the circuit breaker closing is aimed at the moment when the synchronism conditions are met, that is, when the phase difference is within the given phase difference limit.

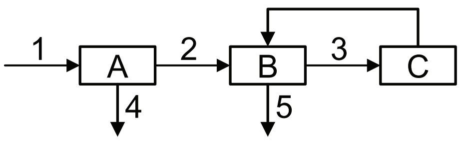
When two network sections to be connected are from different sources or generators, the voltage criteria alone is not safe, so also frequency and phase check must be used.

When two networks with different frequencies are to be connected, the request timeout setting must be long enough to allow the synchronism criteria to be met. For example, if the frequency difference is 0.1 Hz, the synchronism criteria is met only once in ten seconds.

The synchrocheck stage starts from an object close command that generates a request to close the selected circuit breaker when the synchronism conditions are met. The synchrocheck stage provides a "request" signal that is active from the stage start until the synchronism conditions are met or the request timeout has elapsed. When the synchronism conditions are not met within the request timeout, a “fail” pulse is generated. The fail pulse has a fixed length of 200 ms. When the synchronism conditions are met in a timely manner, the object close command is initiated for the selected object. This signal is purely internal and not available outside the synchrocheck stage. When the synchronism conditions are met, the “OK” signal is always active. The activation of the bypass input bybasses the synchronism check and declares synchronism at all times.

The request, OK, and fail signals are available in the output matrix.

The synchronized circuit breaker close execution order is shown in Figure 6.30.



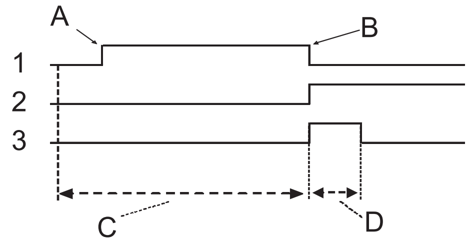
A. Synchrocheck stage

B. Object

C. Circuit breaker (physical)

1. Object close command from mimic, digital inputs or communication protocol
2. Synchronism declared
3. Circuit breaker close command
4. Sync fail signal if request timeout elapsed before synchronism conditions met
5. Object fail signal if CB failed to operate

Figure 6.30: Synchrocheck execution order



1. Sync request
2. Sync OK
3. Object close command

A. The object close command given (minic or bus) actually only makes a sync request.

B. The sync request ends when the synchronism conditions are met and CB command is given or if the request timeout elapsed.

C. If the request timout elapsed before synchronism conditions are met, sync fail pulse is generated.

D. Normal object close operation

Figure 6.31: Synchrocheck function principle

The synchrocheck function is available when one of the following analog measurement modules and a suitable measuring mode are in use:

Voltage measuring mode	Number of synchrocheck stages
3LN+LLy	1
3LN+LNy	1
2LL+U_0+LLy	1
2LL+U_0+LNy	1
LL+U_0+LLy+LLz	2
LN+U_0+LNy+LNz	2

Connections for synchrocheck

The voltage used for sychrochecking is always line-to-line voltage U12 even when UL1 is measured. The sychrocheck stage 1 always compares U12 with U12y. The compared voltages for the stage 2 can be selected (U12 / U12y, U12 / U12z, U12y / U12z). See Chapter 10.6 Voltage measurement modes.

NOTE: To perform its operation, the synchrocheck stage 2 converts the voltages LNy and LNz to line-to-line voltage U12. As such, the measured voltage for LNy and LNz must be U1-N.

NOTE: The wiring of the secondary circuits of voltage transformers to the relay terminal depends on the selected voltage measuring mode.

See the synchrocheck stage's connection diagrams in Chapter 10.6 Voltage measurement modes.

Characteristics

Table 6.8: Synchrocheck function Δf, ΔU, Δφ (25)

Input signal	U_{L1} – U_{L4}
Synchrocheck mode (S_{MODE})	Off; Async; Sync *
Voltage check mode (U_{MODE})	DD; DL; LD; DD/DL; DD/LD; DL/LD; DD/DL/LD **
CB closing time	0.04 – 0.6 s
U_{DEAD} limit setting	10 – 120 %U_N
U_{LIVE} limit setting	10 – 120 %U_N
Frequency difference	0.01 – 1.00 Hz
Voltage difference	1 – 60 %U_N
Phase angle difference	2° – 90°
Request timeout	0.1 – 600.0 s
Stage operation range	46.0 – 64.0 Hz
Reset ratio (U)	<0.97
Inaccuracy: - voltage - frequency - phase angle - operate time	 ±3 %U_N ±20 mHz ±2° (when Δf < 0.2 Hz, else ±5°) ±1% or ±30 ms

*)

- Off – Frequency and phase criteria not in use
- Async – d_F, d_U and d angle criteria are used. Circuit breaker close is aimed at the moment when the phase angle is within phase angle difference limit. Slip frequency d_F determines how much the close command needs to be advanced to make the actual connection at the moment when the phase angle is within the phase angle limit.
- Sync mode – d_F, d_U and d angle criteria are used. Circuit breaker close is aimed at the moment when the phase angle becomes zero. Slip frequency d_F determines how much the close command needs to be advanced to make the actual connection at zero phase angle.

**)

- The first letter refers to the reference voltage and the second letter to the comparison voltage.
- D means that the side must be “dead” when closing (dead = The voltage is below the dead voltage limit setting).
- L means that the side must be “live” when closing (live = The voltage is higher than the live voltage limit setting).
- Example: DL mode for stage 1: The U12 side must be “dead” and the U12y side must be “live”.

6.7 Undervoltage (ANSI 27)

Description

Undervoltage protection is used to detect voltage dips or sense abnormally low voltages to trip or trig load shedding or load transfer. The function measures the three line-to-line voltages, and whenever the smallest of them drops below the start setting of a particular stage, this stage starts and a start signal is issued. If the fault situation remains on longer than the operate time delay setting, a trip signal is issued.

Blocking during voltage transformer fuse failure

As all the protection stages, the undervoltage function can be blocked with any internal or external signal using the block matrix. For example if the secondary voltage of one of the measuring transformers disappears because of a fuse failure (See the voltage transformer supervision function in Chapter 7.8 Voltage transformer supervision (ANSI 60FL)). The blocking signal can also be a signal from the custom logic (see Chapter 5.7 Logic functions).

Low-voltage self blocking

The stages can be blocked with a separate low-limit setting. With this setting, the particular stage is blocked when the biggest of the three line-to-line voltages drops below the given limit. The idea is to avoid unwanted tripping when the voltage is switched off. If the operate time is less than 0.08 s, the blocking level setting should not be less than 15 % for the blocking action to be fast enough. The self blocking can be disabled by setting the low-voltage block limit equal to zero.

Figure 6.32 shows an example of low voltage self blocking.

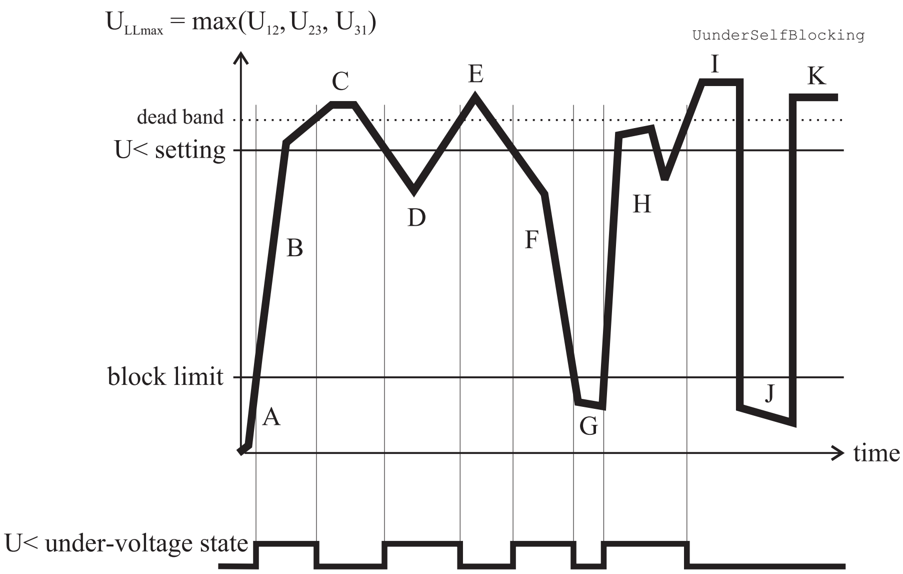


Figure 6.32: Under voltage state and block limit

- A The maximum of the three line-to-line voltages U_{LLmax} is below the block limit. This is not regarded as an undervoltage situation.
- B The voltage U_{LLmin} is above the block limit but below the start level. This is an undervoltage situation.
- C The voltage is OK because it is above the start limit.
- D This is an undervoltage situation.
- E Voltage is OK.
- F This is an undervoltage situation.
- G The voltage U_{LLmin} is under block limit and this is not regarded as an undervoltage situation.
- H This is an undervoltage situation.
- I Voltage is OK.
- J Same as G
- K Voltage is OK.

Three independent stages

There are three separately adjustable stages: U<, U<< and U<<<. All these stages can be configured for the definite time (DT) operation characteristic.

Setting groups

There are four setting groups available for all stages.

Characteristics

Table 6.9: Undervoltage U< (27)

Input signal	U_{L1} – U_{L3}
Start value	20 – 120 %U_N (step 1%)
Definite time characteristic: - Operate time	 0.08[**] – 300.00 s (step 0.02)
Hysteresis (reset ratio)	1.001 – 1.200 (0.1 – 20.0 %, step 0.1 %)
Self-blocking value of the undervoltage	0 – 80 %U_N
Start time	Typically 60 ms
Release delay	0.06 – 300.00 s (step 0.02 s)
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio (Block limit)	0.5 V or 1.03 (3 %)
Reset ratio	1.03 (depends on the hysteresis setting)
Inaccuracy: - Starting - Blocking - Operate time	 ±3% of the set value ±3% of set value or ±0.5 V ±1% or ±30 ms

Table 6.10: Undervoltage U<< (27)

Input signal	U_{L1} – U_{L3}
Start value	20 – 120 %U_N (step 1%)
Definite time characteristic: - Operate time	 0.06[**] – 300.00 s (step 0.02)
Hysteresis (reset ratio)	1.001 – 1.200 (0.1 – 20.0 %, step 0.1 %)
Self-blocking value of the undervoltage	0 – 80 %U_N
Start time	Typically 60 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio (Block limit)	0.5 V or 1.03 (3 %)
Reset ratio	1.03 (depends on the hysteresis setting)
Inaccuracy: - Starting - Blocking - Operate time	 ±3% of the set value ±3% of set value or ±0.5 V ±1% or ±30 ms

Table 6.11: Undervoltage U<<< (27)

Input signal	U_{L1} – U_{L3}
Start value	20 – 120 %U_N (step 1%)
Definite time characteristic: - Operate time	 0.04** – 300.00 s (step 0.01)
Hysteresis (reset ratio)	1.001 – 1.200 (0.1 – 20.0 %, step 0.1 %)
Self-blocking value of the undervoltage	0 - 80 %U_N
Start time	Typically 30 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio (Block limit)	0.5 V or 1.03 (3 %)
Reset ratio	1.03 (depends on the hysteresis setting)
Inaccuracy: - Starting - Blocking - Operate time	 ±3% of the set value ±3% of set value or ±0.5 V ±1% or ±25 ms

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

6.8 Positive sequence under voltage (ANSI 27P)

This is a special undervoltage protection function for generator applications where the voltage is measured at the generator side of the generator circuit breaker. There are special self-blocking features for starting up and shutting down a generator.

This undervoltage function measures the positive sequence of the fundamental frequency component U_1 of the measured voltages (for calculation of U_1, see Chapter 4.10 Symmetric components). By using the positive sequence, all three phases are supervised with one value and if the generator looses the connection to the network (loss of mains), the undervoltage situation is detected faster than by using just the lowest of the three line-to-line voltages.

Whenever the positive sequence voltage U_1 drops below the start setting of a particular stage, this stage activates and a start signal is issued. If the fault situation remains on longer than the time defined in the operate time delay setting, a trip signal is issued.

Blocking during VT fuse failure

Like all the protection stages, the undervoltage function can be blocked with any internal or external signal using the block matrix, for example, if the secondary voltage of one of the measuring transformers disappears because of a fuse failure (See VT supervision function in Chapter 7.8 Voltage transformer supervision (ANSI 60FL)). The blocking signal can also be a signal from the user's logic (see Chapter 5.7 Logic functions).

Selfblocking at very low voltage

The stages are blocked when the voltage is below a separate low-voltage blocking setting. With this setting, LVBlk, both stages are blocked when the voltage U_1 drops below the given limit. The idea is to avoid purposeless alarms when the generator is not running. The LVBlk setting is common for both stages. The selfblocking can not be disabled.

Temporary selfblocking at very low currents

Further the start can be delayed by using the setting I<Blk. When the maximum of the three measured phase currents is less than 1 % of the rated generator current, this delay is enabled. The idea is to avoid purposeless alarms, when the generator circuit breaker is open and the excitation is switched off. By setting the delay equal to zero, this feature is disabled.

Initial selfblocking

When the voltage U_1 has been below the block limit, the stages are blocked until the start setting has been reached.

Figure 6.33 shows an example of low voltage selfblocking.

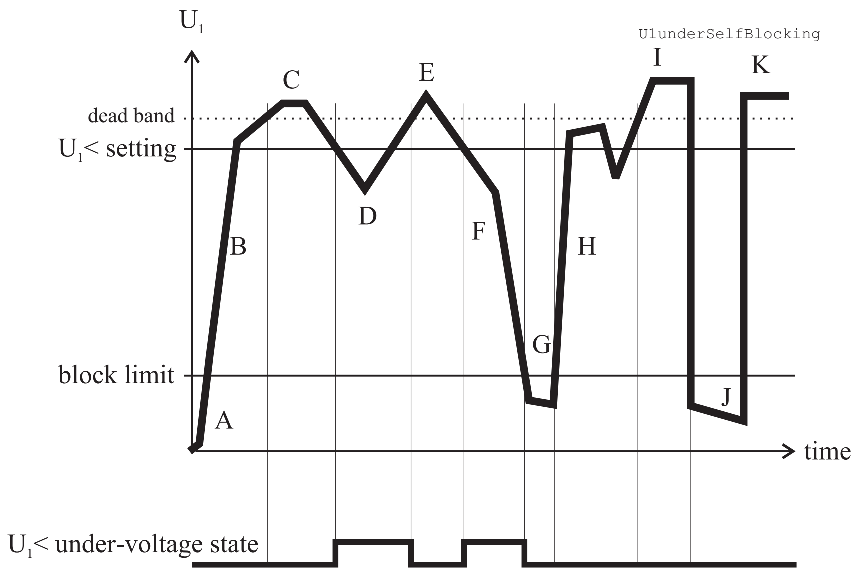


Figure 6.33: Positive sequence under voltage state and block limit.

A	The positive sequence voltage U_1 is below the block limit. This is not regarded as an undervoltage situation.
B	The positive sequence voltage U_1 is above the block limit but below the start level. However, this is not regarded as an undervoltage situation because the voltage has never been above the start level since being below the block limit.
C	The voltage is OK because it is above the start limit.
D	This is an undervoltage situation.
E	The voltage is OK.
F	This is an undervoltage situation.
G	The voltage is below the block limit and this is not regarded as an undervoltage situation.
H	Same as B.
I	The voltage is OK.
J	Same as G.
K	The voltage is OK.

Two independent stages

There are two separately adjustable stages: U_1< and U_1<<. Both stages can be configured for definite time (DT) operate characteristic.

Setting groups

There are four setting groups available for each stage.

Characteristic

Table 6.12: Positive sequence undervoltage stages $U_1<$, $U_1<<$ (27P)

Start value	20 – 120% x U_N
Definite time function: - Operate time	 0.08**) – 300.00 s
Undervoltage blocking - Blocking time, when I< 1% x I_{GN}	2 – 100% x U_N (common for both stages) 2 – 100% x U_{GN} (common for both stages) 0 – 30 s (common for both stages)
Start time	Typically 60 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio	1.05
Inaccuracy: - Starting - Operate time	 1% unit ±1% or ±30 ms

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

6.9 Directional power (ANSI 32)

Description

The directional power function can be used, for example, to disconnect a motor if the supply voltage is lost and thus prevent power generation by the motor. It can also be used to detect loss of load of a motor.

The directional power function is sensitive to active power. For the directional power function, the start value is negative. For the underpower function, a positive start value is used. Whenever the active power goes under the start value, the stage starts and issues a start signal. If the fault situation stays on longer than the delay setting, a trip signal is issued.

The start setting range is from -200 % to +200 % of the nominal apparent power S_N. The nominal apparent power is determined by the configured voltage and current transformer values.

Equation 6.6:

$$S_n = VT_{Rated\,\mathrm{Pr}\,imary} \cdot CT_{Rated\,\mathrm{Pr}\,imary} \cdot \sqrt{3}$$

There are two identical stages available with independent setting parameters.

Setting groups

There are four setting groups available for all stages.

Characteristics

Table 6.13: Directional power stages P<, P<< (32)

Input signal	$I_{L1} – I_{L3}$ $U_{L1} – U_{L3}$
Start value	-200.0 to +200.0 %P_M (step 0.5)
Definite time function: - Operate time	 0.3 – 300.0 s (step 0.1)
Start time	Typically 200 ms
Reset time	<500 ms
Reset ratio	1.05
Inaccuracy: - Starting - Operate time at definite time function	 ±3 % of set value or ±0.5 % of rated value ±1 % or ±150 ms

NOTE: When the start setting is +1 to +200% ,an internal block is activated if the max. voltage of all phases drops below 5% of rated.

6.10 Loss of field (ANSI 40)

Synchronous machines need some minimum level of excitation to remain stable throughout their load range. If the excitation is too low, the machine may drop out of synchronism. The under-excitation protection protects the generator against the risk of lost of synchronism.

When the generator produces capacitive power, that is when the reactive component of the power phasor is negative, the excitation current can be so low that the synchronism is lost.

This stage supervises the amount of capacitive power. If it exceeds the setting value, a start signal is issued. If the fault continues longer than user's operate delay time setting, a trip signal is issued.

The measurement of the degree of excitation is based on a complex three-phase power vector that is calculated from the fundamental components of the phase currents and line-to-line voltages.

Trip area on a PQ plane

The tripping area of the stage on a PQ plane is defined with two parameters: Q1 and Q2, see Figure 6.34 and Figure 6.35. When the tip of the power phasor lies on the left side of the left side of a straight line drawn through Q1 and Q2 and on the negative side of the P axis, the stage activates.

The P coordinate of the setting point Q1 has a fixed value equal to zero and the Q coordinate is adjustable.

The P coordinate of the setting point Q2 has a fixed value of 80 % of the rated power of the generator and the Q coordinate is adjustable.

In Figure 6.34, the operation depends on both P and Q because the operating line has an 8° slope (Q1-Q2 = 14 %). The shaded area is the area of operation.

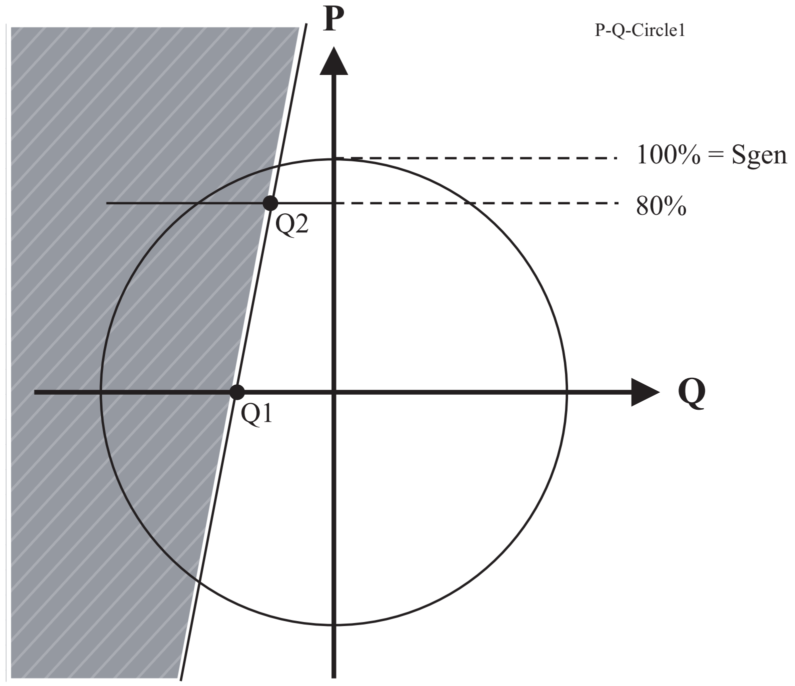


Figure 6.34: Trip area on a PQ plane, setting 1

In Figure 6.35, the operation solely depends on the reactive power because the operating line is vertical (Q1-Q2 = 0 %). The shaded area is the area of operation.

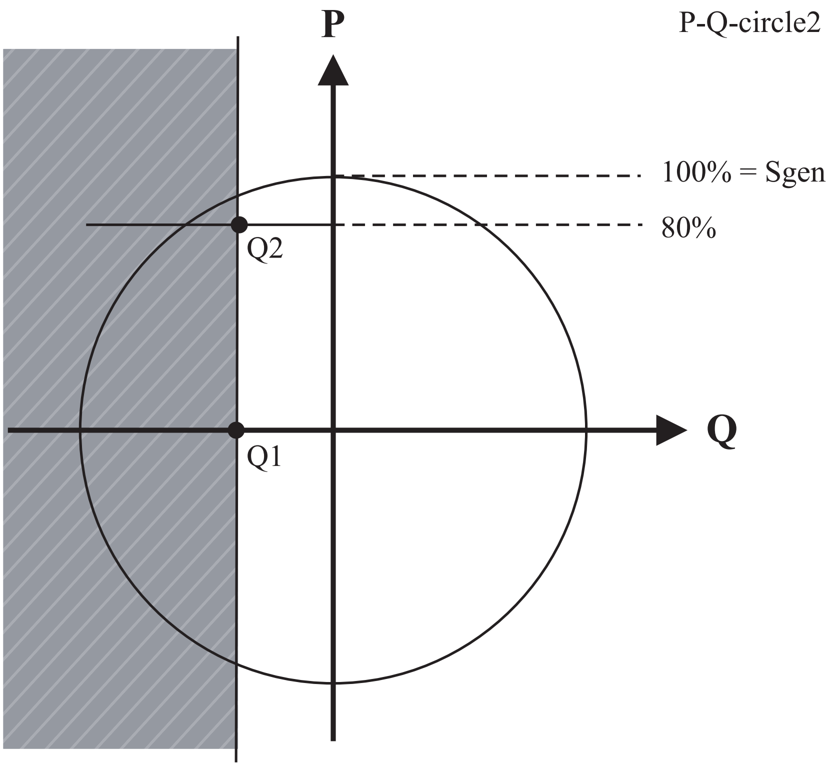


Figure 6.35: Trip area on a PQ plane, setting 2

Power swing

A release time setting is available against prolonged power swings. In a power swing situation, the power phasor is swinging back and forth between capacitive and inductive power. With a long enough release time setting, the stage accumulates the total fault time and eventually trips.

Setting groups

There are two settings groups available. Switching between the setting groups can be controlled by digital inputs, virtual inputs (mimic display, communication, logic) and manually.

6.11 Under-reactance (ANSI 21/40)

Synchronous machines need some minimum level of excitation to remain stable throughout their load range. If excitation is lost or is too low, the machine may drop out of synchronism. The under-reactance stages X< and X<< are used to make sure that the synchronous machine is working in the stable area.

The protection is based on positive sequence impedance as viewed from the machine terminals. This impedance is calculated using the measured three-line-to-line voltages and phase currents according to the following equation:

Equation 6.7:

$$\overline{Z}_1 = \frac{\overline{U}_1}{\overline{I}_1}$$

Z1 = positive sequence impedance

U1 = positive sequence voltage phasor

I1 = positive sequence current phasor

If this impedance goes under the steady state stability limit, the synchronous machine may loose its stability and drop out of synchronism.

Detecting power swinging

A release time setting is available against prolonged power swings. In a power swing situation, the power phasor is swinging back and forth between capacitive and inductive power. With a long enough release time, the stage accumulates the total fault time and eventually trips.

Undercurrent blocking

When for some reason, the voltage collapses but the currents remain at normal load levels, the calculated impedance may fall into the trip area. Inverted start signal from the most sensitive overcurrent stage can be used to block the under-reactance stages during abnormal voltages not caused be short-circuit faults.

Characteristic on an impedance plane

The characteristic on an impedance plane is a circle covering the unstable area of the synchronous machine (Figure 6.36). The radius X< and centre point [Roffset, Xoffset] of the circle are editable. Whenever the positive sequence impedance goes inside this circle, the stage activates. If the fault stays on longer than the definite time delay setting, the stage issues a trip signal.

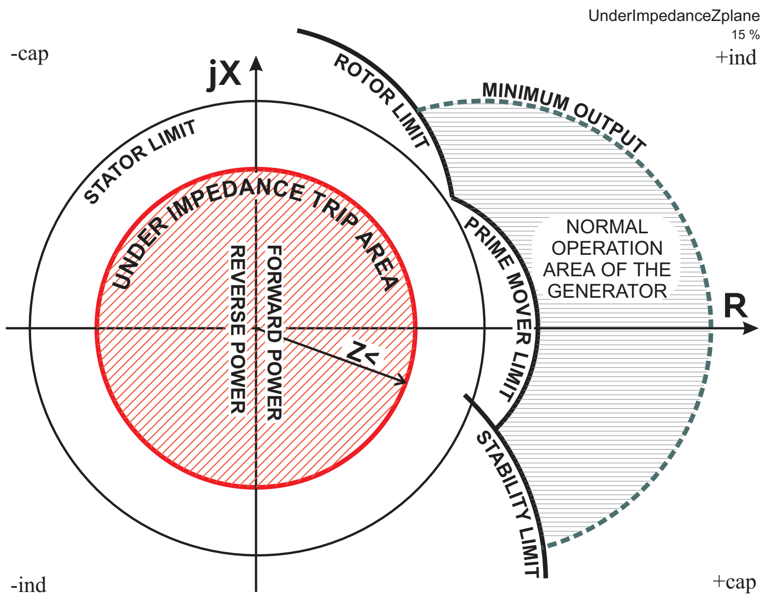


Figure 6.36: The trip region of loss of excitation stage is a circle covering the unstable area of the generator. The radius X<, Roffset and Xoffset are the setting parameters. Whenever the positive sequence impedance falls inside the X< circle, the stage activates.

Calculating setting values

The machine manufacturer specifies:

X_d = synchronous unsaturated reactance

X'_d = transient reactance for the synchronous machine

The settings for loss of excitation stages can be derived from these machine parameters, but there are many practices to do it. Here is one:

Radius of the circle X< = $X_d/2$

Resistive offset Ros = 0.14 ($X'_d + X_d/2$)

Reactive offset Xos = -($X'_d + X_d/2$)

All the settings are per unit.

$$X_{PU} = \frac{X}{Z_N}$$

X_{PU} = Reactance (or resistance) per unit

X = Reactance (or resistance) in ohms

Z_N = Nominal impedance of the machine

$$Z_N = \frac{U_N^2}{S_N}$$

Z_N = Nominal impedance of the machine

U_N = Nominal voltage of the machine

S_N = Nominal power of the machine

Characteristic on power plane

In Figure 6.37, the same characteristics as in the previous figure are drawn on a PQ-power plane assuming a constant voltage of 1 PU. The transformation is $\underline{S} = U^2/Z^*$, where U is the voltage and Z* is the complex conjugate of impedance Z.

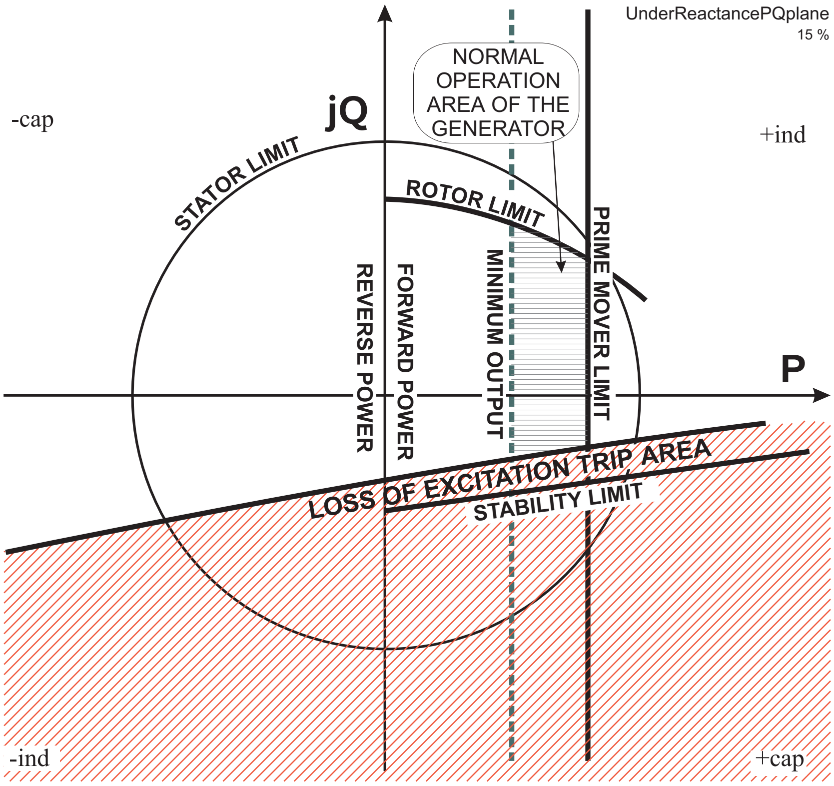


Figure 6.37: The loss of excitation characteristic drawn on a power plane.

Two independent under-reactance stages

There are two separately adjustable stages available: X< and X<<.

Setting groups

There are four setting groups available for each stage.

Characteristics

Table 6.14: Under-reactance (21/40)

Trip area radius setting range	0.05 – 2.00 x Z_N
Resistive offset Ros	-2.00 – 2.00 x Z_N
Reactive offset Xos	-2.00 – 2.00 x Z_N
Definite time function: - Operating time	 0.08** – 300.00 s (step 0.02 s)
Start time	<80 ms
Reset time	0.08 – 300.00 s (step 0.02 s)
Reset ratio	1.05
Inaccuracy: - Starting - Operating time at definite time function	 ±4 % of set value or ±0.01 x Z_N ±1 % or ±30 ms

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

6.12 Negative sequence overcurrent (ANSI 46)

Description

Negative sequence overcurrent protects against unbalanced phase currents and single phasing. The protection is based on the negative sequence current. Both definite time and dependent time characteristics are available. The dependent delay is based on Equation 6.8. Only the base frequency components of the phase currents are used to calculate the negative sequence value I_2.

The negative sequence overcurrent protection is based on the negative sequence of the base frequency phase currents. Both definite time and dependent time characteristics are available.

Dependent time delay

The dependent time delay is based on the following equation:

Equation 6.8:

$$T = \frac{K_1}{\left(\frac{I_2}{I_{GN}}\right)^2 - K_2^2}$$

T =	Operate time
K_1 =	Delay multiplier
I_2 =	Measured and calculated negative sequence phase current of fundamental frequency.
I_{GN} =	Rated current of the generator
K_2 =	Start setting I_2> in pu. The maximum allowed degree of unbalance.

Example

K_1 =	15 s
I_2 =	22.9 % = 0.229 x I_{GN}
K_2 =	5 % = 0.05 x I_{GN}

$$t = \frac{15}{\left(\frac{0.229}{1}\right)^2 - 0.05^2} = 300.4$$

The operate time in this example is five minutes.

More stages (definite time delay only)

If more than one definite time delay stages are needed for negative sequence overcurrent protection, the freely programmable stages can be used (chapter Chapter 6.35 Programmable stages (ANSI 99)).

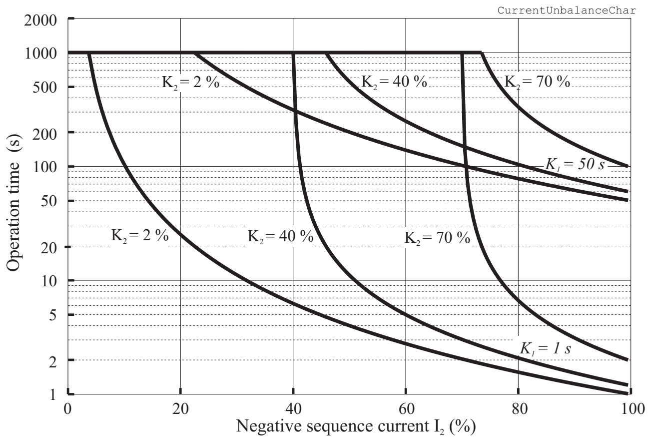


Figure 6.38: Dependent operation delay of negative sequence overcurrent I_2> (ANSI 46). The longest delay is limited to 1000 seconds (=16min 40s).

Setting groups

There are four setting groups available.

Characteristics

Table 6.15: Negative sequence overcurrent I_2>, I'_2>(46)

Input signal	$I_{L1} – I_{L3}$
Start value	2 – 70% (step 1%)
Definite time characteristic: - Operate time	 1.0 – 600.0 s (step 0.1 s)
Dependent time characteristic: - 1 characteristic curve - Time multiplier - Upper limit for dependent time	 Inv 1 – 50 s (step 1) 1000 s
Start time	Typically 300 ms
Reset time	< 450 ms
Reset ratio	<0.95
Inaccuracy: - Starting - Operate time	 ±1% - unit ±5% or ±200 ms

NOTE: The stage is operational when all secondary currents are above 250 mA.

6.13 Thermal overload (ANSI 49G)

Description

The thermal overload function protects the generator stator windings against excessive temperatures.

Thermal model

The temperature is calculated using RMS values of phase currents and a thermal model according IEC60255-149. The RMS values are calculated using harmonic components up to the 15th.

Trip time: $t = \tau \cdot \ln \frac{I^2 - I_P^{\,2}}{I^2 - a^2}$, τ unit: second

Alarm: $a = k \cdot k_\Theta \cdot I_{GN} \cdot \sqrt{alarm}$ (alarm 60% = 0.6)

Trip: $a = k \cdot k_\Theta \cdot I_{GN}$

Reset time: $t = \tau \cdot C_\tau \cdot \ln \frac{I_P^{\,2}}{a^2 - I^2}$, τ unit: second

Trip release: $a = \sqrt{0.95} \times k \times I_{GN}$

Start release: $a = \sqrt{0.95} \times k \times I_{GN} \times \sqrt{alarm}$ (alarm 60% = 0.6)

T =	Operate time
τ =	Thermal time constant tau (setting value)
ln =	Natural logarithm function
I =	Measured RMS phase current (the max. value of three phase currents)
Ip =	Preload current, $I_P = \sqrt{\theta} \times k \times I_{GN}$ (If temperature rise is 120% -> θ = 1.2). This parameter is the memory of the algorithm and corresponds to the actual temperature rise.
k =	Overload factor (Maximum continuous current), i.e. service factor (setting value).
kΘ =	Ambient temperature factor (permitted current due to tamb).
I_{GN} =	The rated current of the generator

$C_\tau =$ Relay cooling time constant (setting value)

Time constant for cooling situation

Cooling time constant Cт parameter is used to indicate how quickly the protected object can cool down in the application. This parameter become active when current is less than 0.3 x I_{GN}.

Heat capacitance, service factor and ambient temperature

The trip level is determined by the maximum allowed continuous current I_{MAX} corresponding to the 100 % temperature rise Θ_{TRIP} for example the heat capacitance of the generator. I_{MAX} depends of the given service factor k and ambient temperature Θ_{AMB} and settings I_{MAX40} and I_{MAX70} according the following equation.

$$I_{MAX} = k \cdot k_{\Theta} \cdot I_{GN}$$

The value of ambient temperature compensation factor kΘ depends on the ambient temperature Θ_{AMB} and settings I_{MAX40} and I_{MAX70}. See Figure 6.39. Ambient temperature is not in use when kΘ = 1. This is true when

- I_{MAX40} is 1.0
- Samb is “n/a” (no ambient temperature sensor)
- ΘAMB is +40 °C.

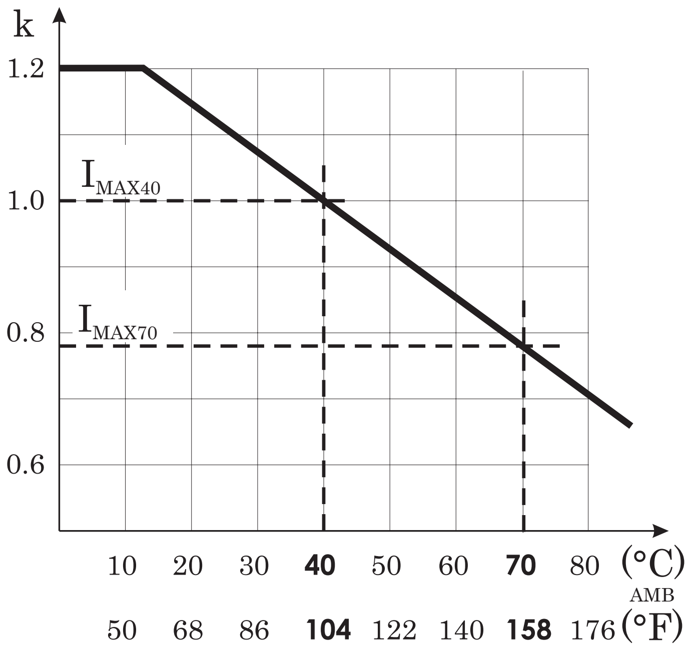


Figure 6.39: Ambient temperature correction of the overload stage T>

Example of the thermal model behaviour

Figure 6.39 shows an example of the thermal model behaviour. In this example τ = 30 minutes, k = 1.06 and kΘ = 1 and the current has been zero for a long time and thus the initial temperature rise is 0 %. At time = 50 minutes the current changes to 0.85 xI_{GN} and the temperature rise starts to approach value $(0.85/1.06)^2$ = 64 % according to the time constant. At time = 300 min, the temperature is nearly stable, and the current increases to 5 % over the maximum defined by the rated current and the service factor k. The temperature rise starts to approach value 110 %. At about 340 minutes, the temperature rise is 100 % and a trip follows.

Initial temperature rise after restart

When the relay is switched on, an initial temperature rise of 70 % is used. Depending on the actual current, the calculated temperature rise then starts to approach the final value.

Alarm function

The thermal overload stage is provided with a separately settable alarm function. When the alarm limit is reached, the stage activates its start signal.

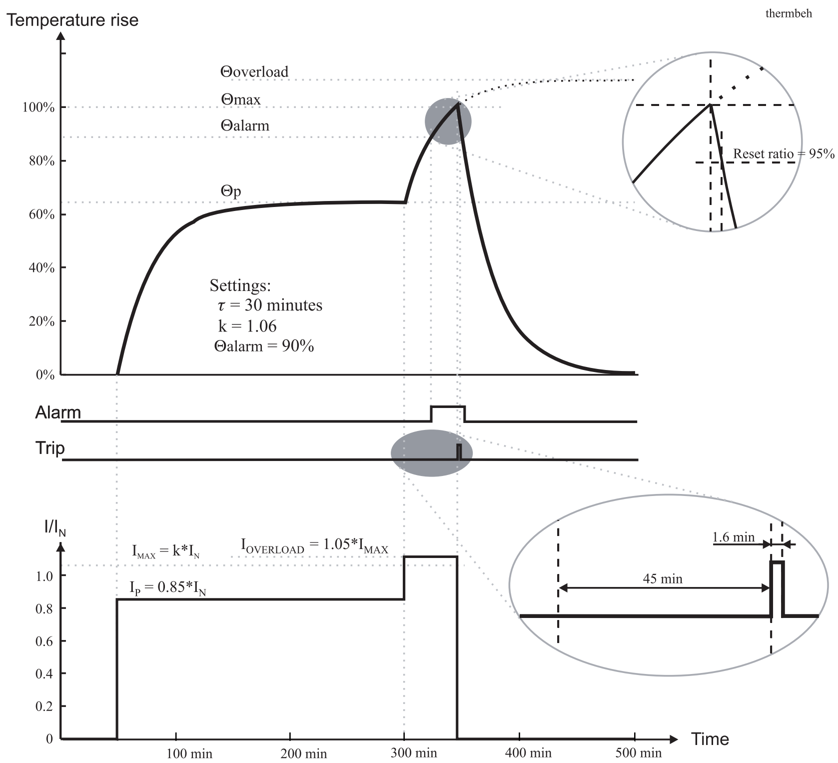


Figure 6.40: Example of the thermal model behaviour.

Setting groups

This stage has one setting group.

Characteristics

Table 6.16: Thermal overload (49G)

Input signal	I_{L1} – I_{L3}
Maximum continuous current	0.1 – 2.40 x I_{GN}
Alarm setting range	60 – 99 % (step 1%)
Time constant τ	2 – 180 min (step 1)
Cooling time coefficient	1.0 – 10.0 x τ (step 0.1)
Max. overload at +40°C	70 – 120 %I_{GN} (step 1)
Max. overload at +70°C	50 – 100 %I_{GN} (step 1)
Ambient temperature	-55 – 125°C (step 1°)
Reset ratio (Start & trip)	0.95
Operate time inaccuracy	Relative inaccuracy ±5% or absolute inaccuracy 1 s of the theoretical value

6.14 Phase overcurrent (ANSI 50/51)

Description

Phase overcurrent protection is used against short-circuit faults and heavy overloads.

The overcurrent function measures the fundamental frequency component of the phase currents. The protection is sensitive to the highest of the three phase currents. Whenever this value exceeds the user's start setting of a particular stage, this stage starts and a start signal is issued. If the fault situation remains on longer than the operation delay setting, a trip signal is issued.

Block diagram

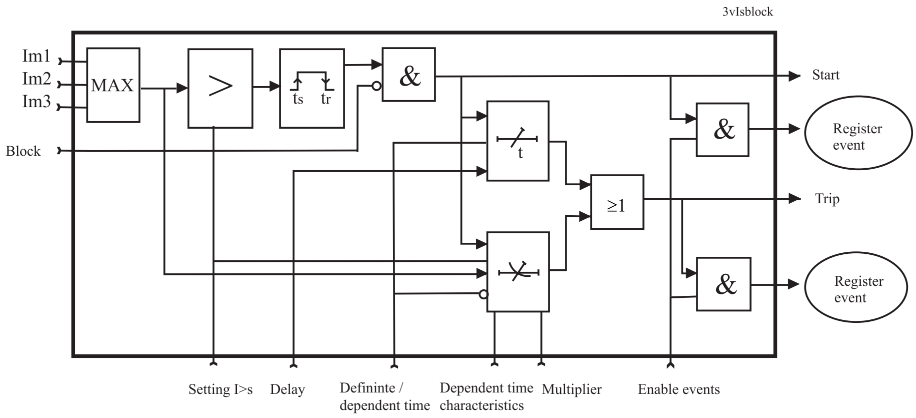


Figure 6.41: Block diagram of the three-phase overcurrent stage I>

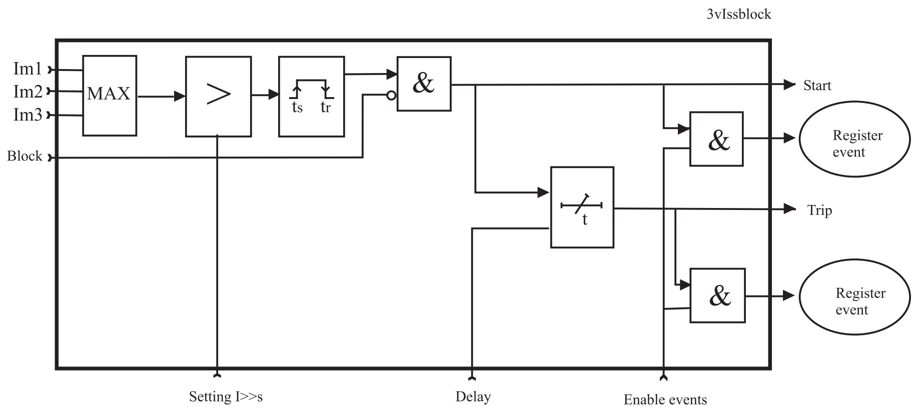


Figure 6.42: Block diagram of the three-phase overcurrent stage I>> and I>>>

Three independent stages

There are three separately adjustable overcurrent stages: I>, I>> and I>>>. The first stage I> can be configured for definite time (DT) or dependent operate time (IDMT) characteristic. The stages I>> and I>>> have definite time operation characteristic. By using the definite delay type and setting the delay to its minimum, an instantaneous (ANSI 50) operation is obtained.

Figure 6.41 shows a functional block diagram of the I> overcurrent stage with definite time and dependent time operate time. Figure 6.42 shows a functional block diagram of the I>> and I>>> overcurrent stages with definite time operation delay.

Dependent operate time

Dependent operate time means that the operate time depends on the amount the measured current exceeds the start setting. The bigger the fault current is, the faster is the operation. The dependent time delay types are described in Chapter 6.3 Dependent operate time. The relay shows the currently used dependent operate time curve graph on the local panel display.

Dependent time limitation

The maximum measured secondary current is 50 x I_N. This limits the scope of *dependent curves* with high start settings. See Chapter 6.3 Dependent operate time for more information.

Include harmonics setting

The I> and I>> (50/51) overcurrent protection stages have a setting parameter to include harmonics. When this setting is activated, the overcurrent stage calculates the sum of the base frequency and all measured harmonics. This feature is used to determine the signal's true root mean square value to detect the signal's real heating factor. The operate time is 5 ms more when harmonics are included in the measurement. Activate the "Include harmonics" setting if the overcurrent protection is used for thermal protection and the content of the harmonics is known to exist in the power system.

Cold load and inrush current handling

See Chapter 7.3 Cold load start and magnetising inrush.

Setting groups

There are four setting groups available for each stage.

Characteristics

Table 6.17: Phase overcurrent stage I> (50/51)

Input signal	$I_{L1} – I_{L3}$
Start value	0.05 – 5.00 xI_{GN} (step 0.01)
Definite time function: - Operate time	DT** 0.04 – 300.00 s (step 0.01 s)
IDMT function: - Delay curve family - Curve type - Inv. time coefficient k	 (DT), IEC, IEEE, RI Prg EI, VI, NI, LTI, MI…, depends on the family* 0.025 – 20.0, except 0.50 – 20.0 for RXIDG, IEEE and IEEE2
Start time	Typically 30 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio	<0.97
Transient overreach, any τ	< 10 %
Inaccuracy: - Starting - Operate time at definite time function - Operate time at IDMT function	 ±3% of the set value or 5 mA secondary ±1% or ±25 ms ±5% or at least ±25 ms**

Table 6.18: Phase overcurrent stage I>> (50/51)

Input signal	$I_{L1} – I_{L3}$
Start value	0.10 – 20.00 xI_{GN} (step 0.01)
Definite time function: - Operate time	DT** 0.04 – 1800.00 s (step 0.01 s)
Start time	Typically 30 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio	<0.97
Transient overreach, any τ	< 10 %
Inaccuracy: - Starting - operate time	 ±3% of the set value or 5 mA secondary ±1% or ±25 ms

Table 6.19: Phase overcurrent stage I>>> (50/51)

Input signal	$I_{L1} – I_{L3}$
Start value	0.10 – 40.00 xI_{GN} (step 0.01)
Definite time function: - Operate time	DT** 0.03 – 300.00 s (step 0.01 s)
Instant operate time: I_M / I_{SET} ratio > 1.5 I_M / I_{SET} ratio 1.03 – 1.5	 <30 ms < 50 ms
Start time	Typically 20 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio	0.97
Inaccuracy: - Starting - Operate time DT (I_M/I_{SET} ratio > 1.5) - Operate time DT (I_M/I_{SET} ratio 1.03 – 1.5)	 ±3% of the set value or 5 mA secondary ±1% or ±15 ms ±1% or ±25 ms

*) EI = Extremely Inverse, NI = Normal Inverse, VI = Very Inverse, LTI = Long Time Inverse, MI= Moderately Inverse

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

6.15 Breaker failure 1 (ANSI 50BF)

Description

The circuit breaker failure protection stage (CBFP) can be used to operate any upstream circuit breaker (CB) if the programmed output matrix signals, selected to control the main breaker, have not disappeared within a given time after the initial command. The supervised output contact is defined by the “Monitored Trip Relay” setting. An alternative output contact of the relay must be used for this backup control selected in the OUTPUT MATRIX setting view.

The CBFP operation is based on the supervision of the signal to the selected output contact and the time. The following output matrix signals, when programmed into use, start the CBFP function:

- protection functions
- control functions
- supporting functions
- GOOSE signals (through communication)

If the signal is longer than the CBFP stage’s operate time, the stage activates another output contact defined in the OUTPUT MATRIX setting view. The output contact remains activated until the signal resets. The CBFP stage supervises all the signals assigned to the same selected output contact.

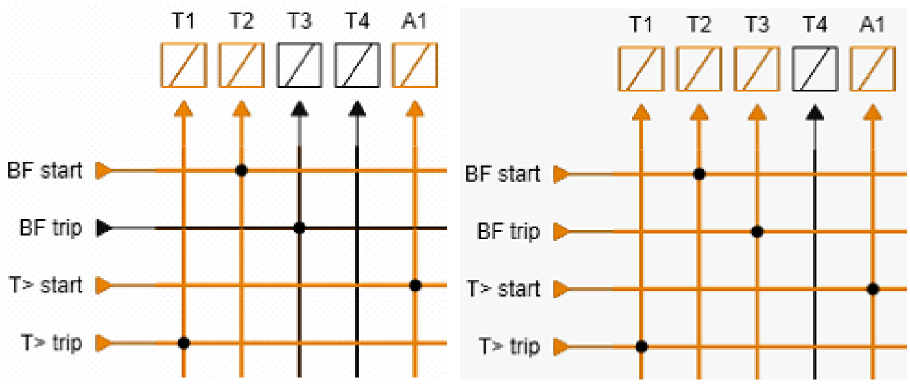


Figure 6.43: Both the trip and CBFP start signals activate simultaneously (left picture). If T> trip fails to control the CB through T1, the CBFP activates T3 after the breaker failure operate time.

NOTE: For the CBFP, always select the ”Connected” crossing symbol in the OUTPUT MATRIX setting view.

Characteristics

Table 6.20: Breaker failure (50BF)

Relay to be supervised	T1 – T4 (depending on the order code)
Definite time function: - Operate time	 0.1** – 10.0 s (step 0.1 s)
Inaccuracy: - Operate time	 ±20 ms

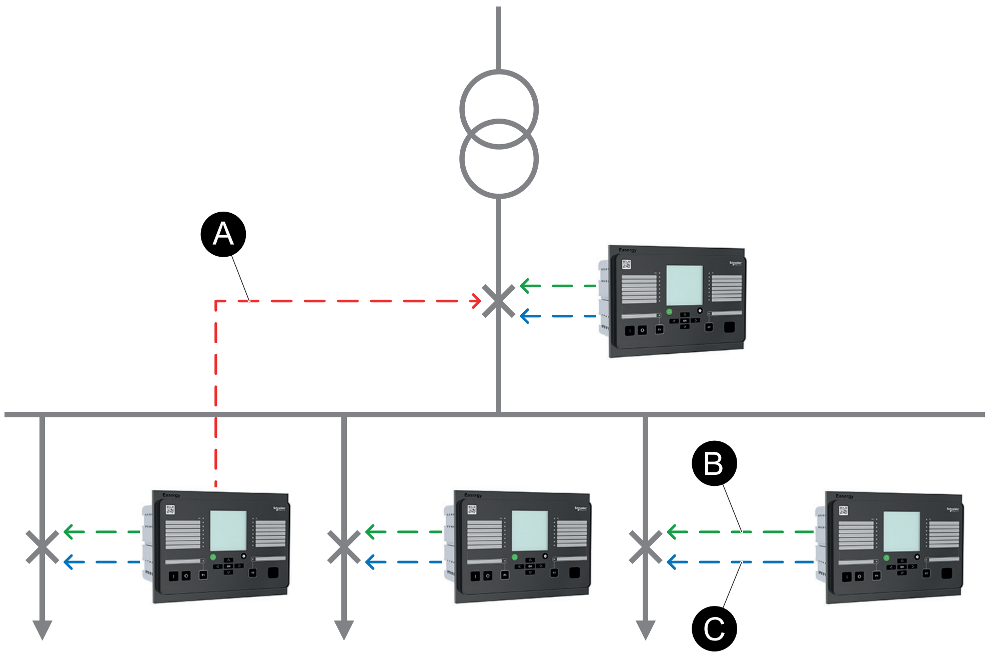
**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

6.16 Breaker failure 2 (ANSI 50BF)

Description

Power system protection should always have some sort of backup protection available. Backup protection is intended to operate when a power system fault is not cleared or an abnormal condition is not detected in the required time because of a failure or the inability of the primary protection to operate or failure of the appropriate circuit breakers to trip. Backup protection may be local or remote.

Circuit breaker failure protection (CBFP) is part of the local backup protection. CBFP provides a backup trip signal to an upstream circuit breaker (CB) when the CB nearest to fault fails to clear fault current. The CB may fail to operate for several reasons, for example burnt open coil or a flashover in the CB.



A. CBFP trip

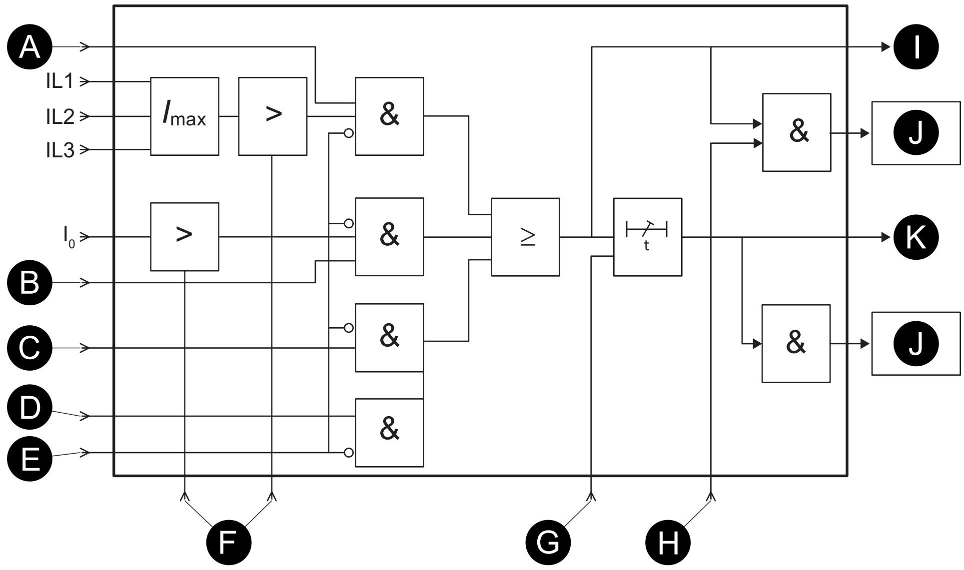
B. Normal trip

C. Re-trip

Figure 6.44: CBFP implementation

Two separate stages are provided to enable re-trip and CBFP trip commands. The first stage can be used to give re-trip command (for example to control second/backup open coil of the main CB) while the second stage can give dedicated CBFP trip command to an upstream circuit breaker. Select the required outputs for re-trip and CBFP trip through the output matrix.

Block diagram



A.	Condition 1	**G.**	Delay setting
B.	Condition 2	**H.**	Enable events setting
C.	Condition 3	**I.**	Start
D.	Condition 4	**J.**	Event register
E.	Block	**K.**	Trip
F.	Zero-current setting		

Figure 6.45: Breaker failure 2 operation

CBFP operation

The CBFP function can be enabled and disabled with the **Enable for BF2** selection. The CBFP function activates when any of the selected start signals becomes and stays active.

The CBFP operation can be temporarily blocked by the stage block signal from the block matrix. When the stage is blocked by the block signal, the stage timer stops but it does not reset. The stage timer continues its operation when the block signal is disabled. When the block signal is active, the stage output signals are disabled.

The CBFP stage provides the following events:

- start on
- start off
- trip on
- trip off

Events can be activated via the **Enable events** setting view.

Condition selectors

The CBFP function has four condition selectors that can be used separately or all together to activate and reset the CBFP function.

The four condition selectors are almost identical. The only difference is that condition selectors 1 and 2 are for all protection functions that benefit from zero-current detection for resetting the CBFP as described in section Zero-current detector, and selectors 3 and 4 are for all the protection functions that do not benefit from zero-current detection for CBFP.

Condition selector 4 can be used to support selectors 1, 2 and 3. For example, if there are too many stages to be monitored in condition set 1, condition selector 4 can be used to monitor the output contacts. Monitoring digital inputs is also possible if the backup protection is based on external current relay, for example. The only CBFP reset criteria for condition set 4 are the monitored input and output signals.

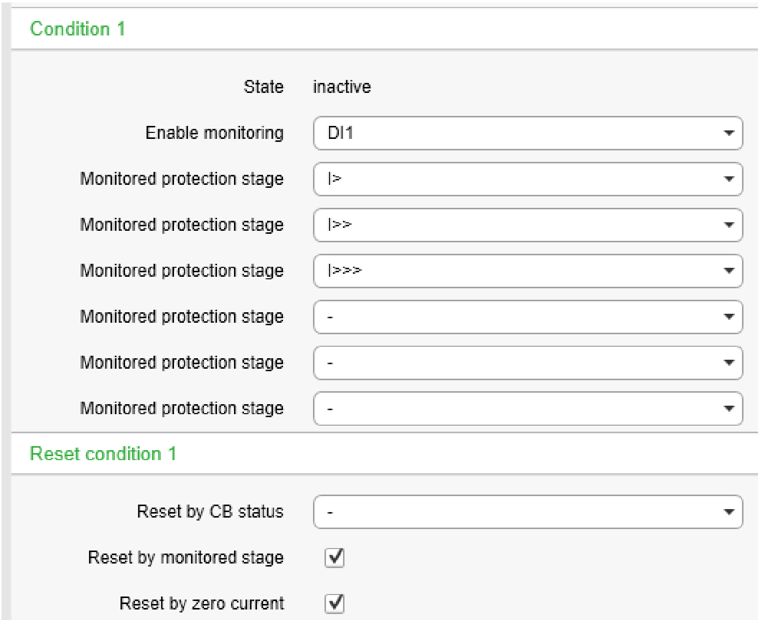


Figure 6.46: Start signal and reset condition setting view for Condition 1

Separate zero-current detection with dedicated start settings exists for phase overcurrent and earth fault overcurrent signals. Zero-current detection is independent of the protection stages.

The condition criteria, available signals and reset conditions are listed in Table 6.21.

NOTE: The start signal can be selected for each condition in advance from the pull-down menu even if the concerned stage is not enabled. For the CBFP activation, the concerned stage must be enabled from the protection stage menu and the stage has to start to activate the CBFP start signal.

Table 6.21: CBFP condition selectors

Criteria	Start signal	Reset condition
Condition 1	I>, I>>, I>>>, Iv>, I2>, dI>, dI>>, Iφ>, Iφ>>, Iφ>>>, Iφ>>>>, T>, If2>, X<, X<<, I'>, I'>>, If5, SOTF	**Reset by CB status:** DI1 – DIx (1, F1, F2, VI1-20, VO1–20, GOOSE_NI1–64, POC1–16, Obj1-8Op **Monitored stage:** On/Off **Zero-current detection:** On/Off
Condition 2	Io>, Io>>, Io>>>, Io>>>>, Io>>>>>, Ioφ>, Ioφ>>, Ioφ>>>, dIo>, dIo>>	
Condition 3	Uof3<, U>, U>>, U>>>, U<, U<<, U<<<, U1<, U1<<, Uo>, Uo>>, P<, P<<, Q<, Z<, Z<<, Pgr1-8, f<, f<<, fx, fxx, df/dt, Uf>, Pslip	**Reset by CB status:** DI1 – DIx (1, F1, F2, VI1-20, VO1–20, GOOSE_NI1–64, POC1–16, Obj1-8Op **Monitored stage:** On/Off
Condition 4	Outputs: A1, T1-Tx (1 Inputs: DI1 – DIx (1, F1, F2, VI1-20, VO1 – 20, GOOSE_NI1 – 64, POC1 – 16 Arc sensor 3- 10, ArcStg1-8, I>int, Io>int	

In addition to the selection of the start signal, the CBFP reset condition needs to be selected.

If no reset conditions are selected, the stage uses **Reset by monitored stage** as the reset condition. This prevents a situation where the stage never releases.

The reset condition **Reset by CB status** is useful if the current is already zero when the CB is opened (for example unloaded CB).

When more than one selection criteria are selected, AND condition is used, for example “zero current detection” AND “object open”. See Figure 6.45 for details.

Stage timer

The operate delay timer is started by a signal activated by the monitored stages (condition selectors). The operate time delay is a settable parameter. When the given time delay has elapsed, the stage provides a trip signal through the output matrix and the event codes.

The timer delay can be set between 40 and 200 ms.

Zero-current detector

The zero-current detector is an undercurrent condition to reset the CBFP function when all phase currents are below the start (pick-up) setting value. This separate undercurrent condition is needed to properly detect successful CB operation. For example, in a CB failure condition where one or more CB poles are partly conducting when the CB is open, the fault current can be small enough to reset the primary protection stage (for example overcurrent stage), in which case the CBFP does not operate. When a separate undercurrent limit is used, CBFP reset can be performed only when the fault current really is zero or near zero instead of relying on the protection stage reset.

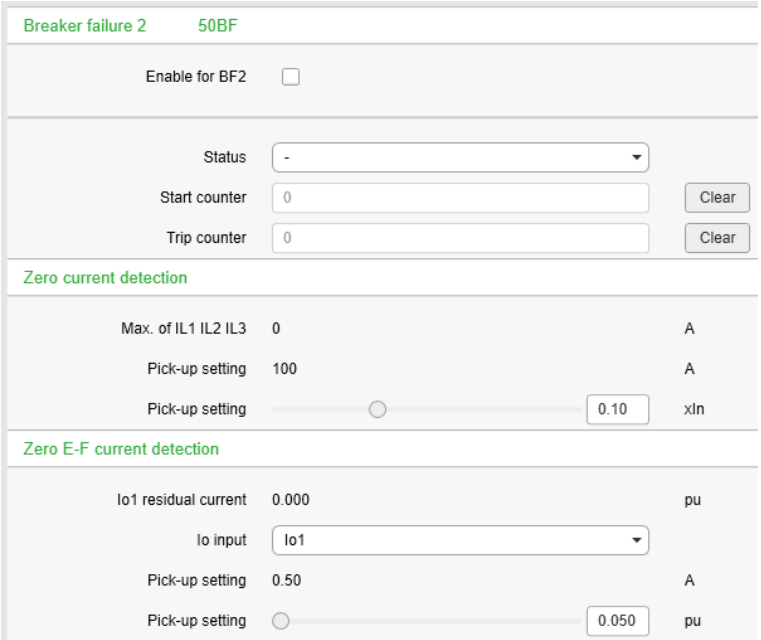
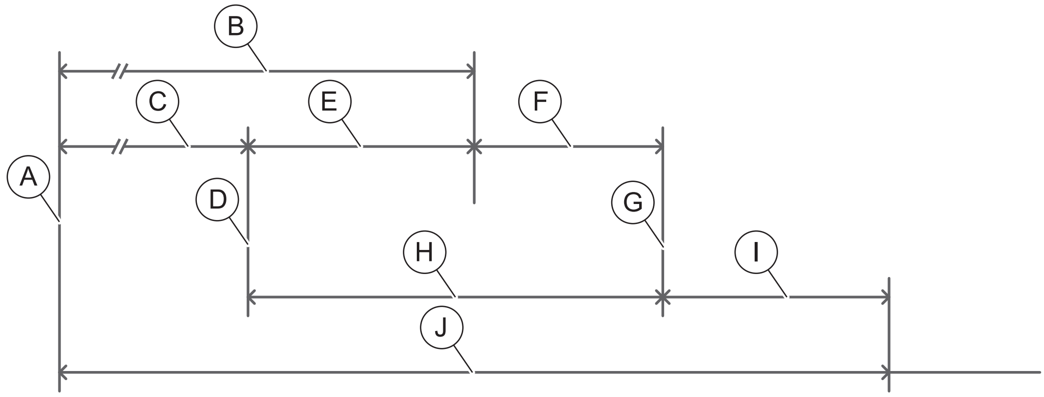


Figure 6.47: Zero-current detector setting view

The setting range of the zero-current detector is always associated with the CT nominal value, even in case of motor and transformer protection. The setting range minimum depends on the relay accuracy. Instead of zero, a small minimum value can be accepted. See Table 6.22.

CBFP coordination

The CBFP delay setting has to be coordinated according to the CB operation time and the reset time of protection stages monitored by the CBFP function as described in Figure 6.48.



A. Fault occurrence

B. Normal fault clearing time

C. Protection delay

D. CBFP stage start

E. CB operate time

F. Protection stage reset time + safety margin

G. CBFP trip

H. CBFP stage operate delay (CB operate time + protection stage reset time + safety margin)

I. CB operate time

J. Total fault clearing time in case of failed CB operation but successful CBFP operation

Figure 6.48: CBFP coordination

Characteristics

Table 6.22: Breaker failure 2 (ANSI 50BF)

Zero-current detection: - Phase overcurrent - Earth fault overcurrent	 0.05–0.2 x In 0.005–20 x p.u.
Definite time function: - Operate time	 0.04–0.2 s
Inaccuracy: - Operate time	 ±20 ms

6.17 Switch-onto-fault (ANSI 50HS)

Description

The switch-onto-fault (SOTF) protection function offers fast protection when the circuit breaker (CB) is closed manually against a faulty line. Overcurrent-based protection does not clear the fault until the intended time delay has elapsed. SOTF gives a trip signal without additional time delay if the CB is closed and a fault is detected after closing the CB.

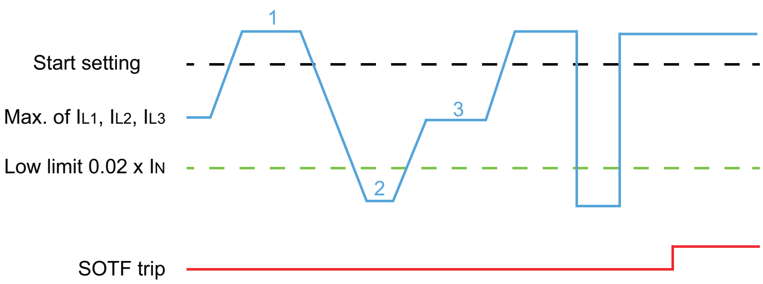


Figure 6.49: Switch-onto-fault function operates when the CB has detected open and the fault current reaches start setting value.

1. Switch-onto-fault does not activate if the CB has not been in open position before the fault. Open CB detection is noticed from the highest phase current value which has to be under a fixed low-limit threshold (0.02 x I_N). Opening of the CB can be detected also with digital inputs (Dead line detection input = DI1 – DIx, VI1 – VIx). The default detection input is based on the current threshold, so the dead line detection input parameter has value "–".
2. Dead line detection delay defines how long the CB has to be open so that the SOTF function is active. If the set time delay is not fulfilled and the highest phase current value (maximum of I_{L1}, I_{L2}, I_{L3}) rises over the start setting, the SOTF does not operate.
3. If the highest phase current value of I_{L1}, I_{L2}, I_{L3} goes successfully under the low limit and rises to a value between the low limit and the start value, then if the highest phase current value rises over the start setting value before the set SOTF active after CB closure time delay has elapsed, the SOTF trips. If this time delay is exceeded, the SOTF does not trip even if the start setting value is exceeded.

Setting groups

This stage has one setting group.

Characteristics

Table 6.23: Switch-onto-fault SOTF (50HS)

Start value	1.00 – 3.00 x I_N (step 0.01)
Dead line detection delay	0.00 – 60.00 s (step 0.01)
SOTF active after CB closure	0.10 – 60.00 s (step 0.01)
Operate time	< 30 ms (When I_M/I_{SET} ratio > 1.5)
Reset time	< 95 ms
Reset ratio	<0.97
Inaccuracy	±3% of the set value or 5 mA secondary

6.18 Earth fault overcurrent (ANSI 50N/51N)

Description

The purpose of the undirectional earth fault overcurrent protection is to detect earth faults in low-impedance earthed networks. In high-impedance earthed networks, compensated networks and isolated networks, undirectional earth fault overcurrent can be used as backup protection.

The undirectional earth fault overcurrent function is sensitive to the fundamental frequency component of the earth fault overcurrent $3I_0$. The attenuation of the third harmonic is more than 60 dB. Whenever this fundamental value exceeds the start setting of a particular stage, this stage starts and a start signal is issued. If the fault situation remains on longer than the operate time delay setting, a trip signal is issued.

Block diagram

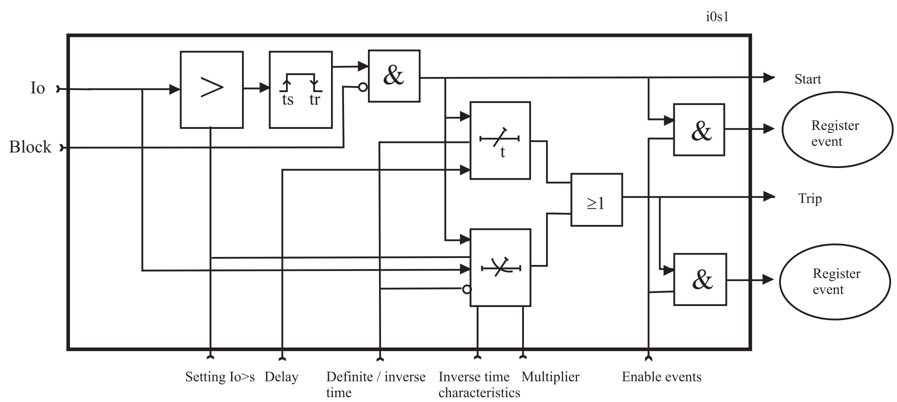


Figure 6.50: Block diagram of the earth fault stage overcurrent I_0>

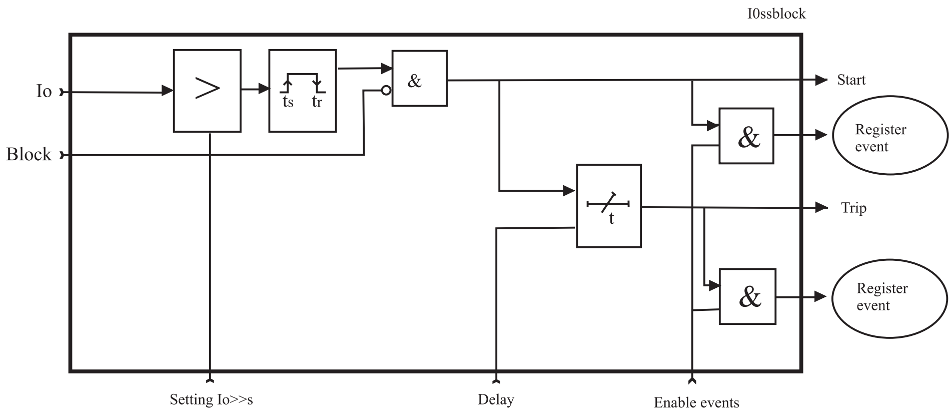


Figure 6.51: Block diagram of the earth fault stages overcurrent I_0>>, I_0>>>, I_0>>>>

Input signal selection

Each stage can be connected to supervise any of the following inputs and signals:

- Input I_{01} for all networks other than solidly earthed.
- Input I_{02} for all networks other than solidly earthed.
- Calculated signal I_{0Calc} for solidly and low-impedance earthed networks. $I_{0Calc} = I_{L1} + I_{L2} + I_{L3}$.

Four or six independent undirectional earth fault overcurrent stages

There are four separately adjustable earth fault overcurrent stages: I_0>, I_0>>, I_0>>>, and I_0>>>>. The first stage I_0> can be configured for definite time (DT) or dependent time operation characteristic (IDMT). The other stages have definite time operation characteristic. By using the definite delay type and setting the delay to its minimum, an instantaneous (ANSI 50N) operation is obtained.

Using the directional earth fault overcurrent stages (Chapter 6.26 Directional earth fault overcurrent (ANSI 67N)) in undirectional mode, two more stages with dependent operate time delay are available for undirectional earth fault overcurrent protection.

Dependent time limitation

The maximum measured secondary earth fault overcurrent is 10 x I_{0N} and the maximum measured phase current is 50 x I_N. This limits the scope of dependent curves with high start settings.

Setting groups

There are four setting groups available for each stage.

Characteristics

Table 6.24: Earth fault overcurrent I_0> (50N/51N)

Input signal	I_{01}, I_{02} I_{0Calc} (= $I_{L1} + I_{L2} + I_{L3}$)
Start value	0.005–8.00 pu (when I_{01} or I_{02}) (step 0.001) 0.05–20.0 pu (when I_{0Calc})
Definite time function: - Operate time	DT** 0.04** – 300.00 s (step 0.01 s)
IDMT function: - Delay curve family - Curve type - Inv. time coefficient k	 (DT), IEC, IEEE, RI Prg EI, VI, NI, LTI, MI..., depends on the family* 0.025–20.0, except 0.50–20.0 for RXIDG, IEEE and IEEE2
Start time	Typically 30 ms
Reset time	<95 ms
Reset ratio	<0.95
Inaccuracy: - Starting - Starting (Peak mode) - Operate time at definite time function - Operate time at IDMT function	 ±2% of the set value or ±0.3% of the rated value ±5% of the set value or ±2% of the rated value (Sine wave <65 Hz) ±1% or ±25 ms ±5% or at least ±25 ms**

Table 6.25: Earth fault overcurrent I_0>>, I_0>>>, I_0>>>> (50N/51N)

Input signal	I_{01}, I_{02} I_{0Calc} (= $I_{L1} + I_{L2} + I_{L3}$)
Start value	0.01–8.00 pu (When I_{01} or I_{02}) (step 0.01) 0.05–20.0 pu (When I_{0Calc}) (step 0.01)
Definite time function: - Operate time	 0.04** – 300.00 s (step 0.01 s)
Start time	Typically 30 ms
Reset time	<95 ms
Reset ratio	<0.95
Inaccuracy: - Starting - Starting (Peak mode) - Operate time	 ±2% of the set value or ±0.3% of the rated value ±5% of the set value or ±2% of the rated value (Sine wave <65 Hz) ±1% or ±25 ms

*) EI = Extremely Inverse, NI = Normal Inverse, VI = Very Inverse, LTI = Long Time Inverse, MI= Moderately Inverse

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operation time of the trip contacts.

6.18.1 Earth fault faulty phase detection algorithm

The earth fault overcurrent stage (ANSI 50N/51N) and directional earth fault overcurrent stage (ANSI 67N) have an inbuilt detection algorithm to detect a faulty phase. This algorithm is meant to be used in radial-operated distribution networks. The faulty phase detection can be used in solidly-earthed, impedance-earthed or resonant-earthed networks.

Operation

The faulty phase detection starts from the earth fault stage trip. At the moment of stage start, the phase currents measured prior to start are registered and stored as prior-to-fault currents. At the moment of trip, phase currents are registered again. Finally, faulty phase detection algorithm is performed by comparing prior-to-fault currents to fault currents. The algorithm also uses positive sequence current and negative sequence current to detect faulty phase.

The detection algorithm can be enabled and disabled by selecting or unselecting a checkbox in the protection stage settings. Correct network earthing configuration must be selected in the stage settings, too. In the earth fault overcurrent stage settings, you can select between RES and CAP network earthing configuration. This selection has no effect on the protection itself, only on the faulty phase detection. In the directional earth fault overcurrent stage settings, the detection algorithm uses the same network earthing type as selected for protection. RES is used for solidly-earther, impedance-earthed and resonant-earthed networks. CAP is only used for isolated networks.

The detected faulty phase is registered in the protection stage fault log (and also in the event list and alarm screen). Faulty phase is also indicated by a line alarm and line fault signals in the output matrix.

Possible detections of faulty phases are L1-N, L2-N, L3-N, L1-L2-N, L1-L3-N, L2-L3-N, L1-L2-L3-N, and REV. If the relay protection coordination is incorrect, REV indication is given in case of a relay sympathetic trip to a reverse fault.

6.19 Capacitor bank unbalance (ANSI 51C)

NOTE: Configure the capacitor bank unbalance protection through the earth fault overcurrent stages I_0>>> and I_0>>>>.

Description

The relay enables capacitor, filter and reactor bank protection with its five current measurement inputs. The fifth input is typically useful for unbalance current measurement of a double-wye connected unearthed bank.

The unbalance protection is highly sensitive to internal faults of a bank because of the sophisticated natural unbalance compensation. The location method enables easy maintenance monitoring for a bank.

This protection scheme is specially used in double-wye-connected capacitor banks. The unbalance current is measured with a dedicated current transformer (like 5A/5A) between two starpoints of the bank.

As the capacitor elements are not identical and have acceptable tolerances, there is a natural unbalance current between the starpoints of the capacitor banks. This natural unbalance current can be compensated to tune the protection sensitive against real faults inside the capacitor banks.

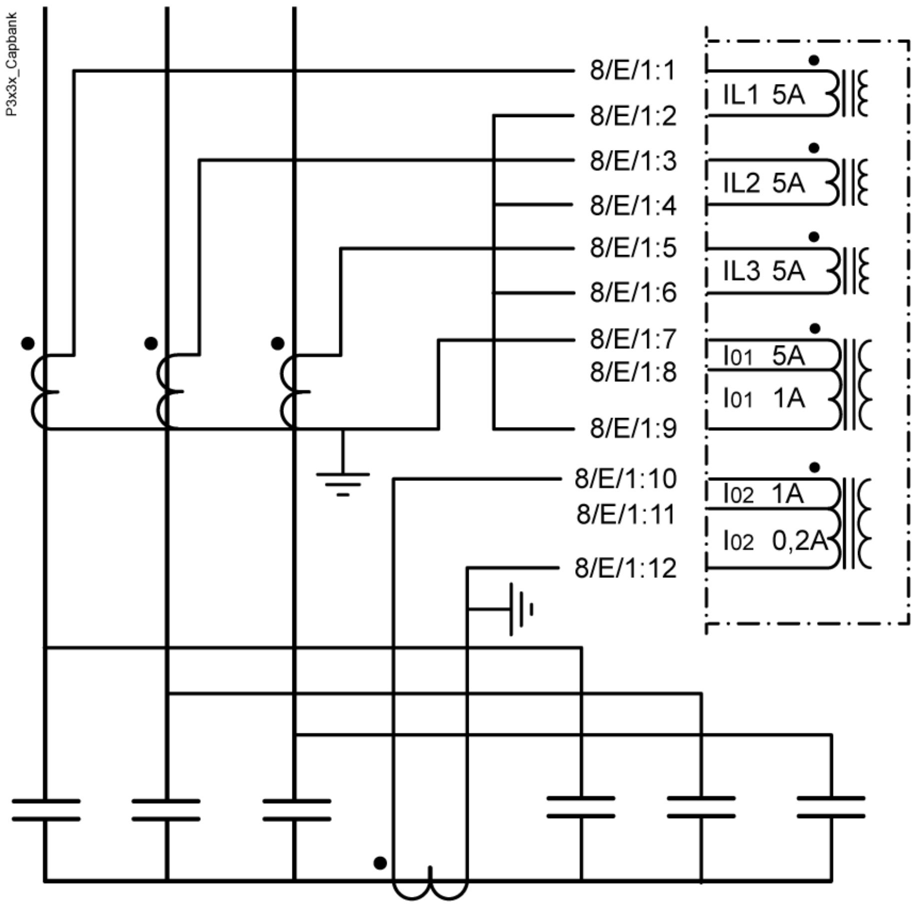


Figure 6.52: Typical capacitor bank protection application with Easergy P3 relays

Compensation method

The method of unbalance protection is to compensate for the natural unbalance current. The compensation is triggered manually when commissioning. The phasors of the unbalance current and one phase current are then recorded. This is because one polarizing measurement is needed. When the phasor of the unbalance current is always related to I_{L1}, the frequency changes or deviations have no effect on the protection. After the recording, the measured unbalance current corresponds to the zero-level and therefore, the setting of the stage can be very sensitive.

Compensation and location

The most sophisticated method is to use the compensation method described above with an add-on feature that locates the branch of each faulty element (the broken fuse).

This feature is implemented to the stage I_0>>>>, while the other stage I_0>>> can still function as normal unbalance protection stage with the compensation method. Normally, the I_0>>>> could be set as an alarming stage while stage I_0>>> trips the circuit breaker.

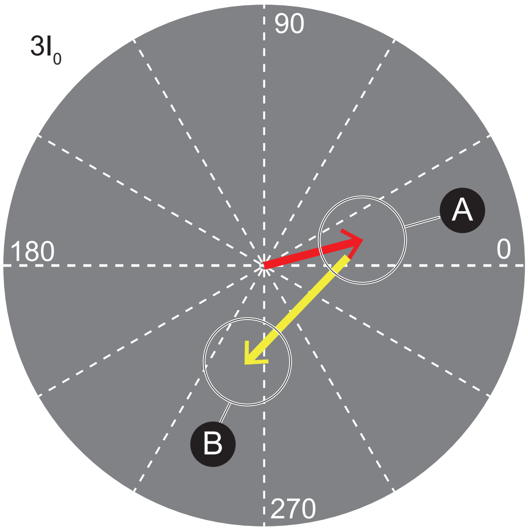
The stage I_0>>>> should be set based on the calculated unbalance current change of one faulty element. You can calculate this using the following formula:

$$3I_0 = \frac{\dfrac{U_{L-N}}{(2 \cdot \pi \cdot f \cdot C_1)^{-1}} - \dfrac{U_{L-N}}{(2 \cdot \pi \cdot f \cdot C_2)^{-1}}}{3}$$

C1 = Capacitor unit capacitance (µF)

C2 = Capacitor unit capacitance, after one element fails (µF)

However, the setting must be 10 % smaller than the calculated value, since there are some tolerances in the primary equipment as well as in the relay measurement circuit. Then, the time setting of I_0>>>> is not used for tripping purposes. The time setting specifies, how long the relay must wait until it is certain that there is a faulty element in the bank. After this time has elapsed, the stage I_0>>>> makes a new compensation automatically, and the measured unbalance current for this stage is now zero. Note, the automatic compensation does not affect the measured unbalance current of stage I_0>>>.

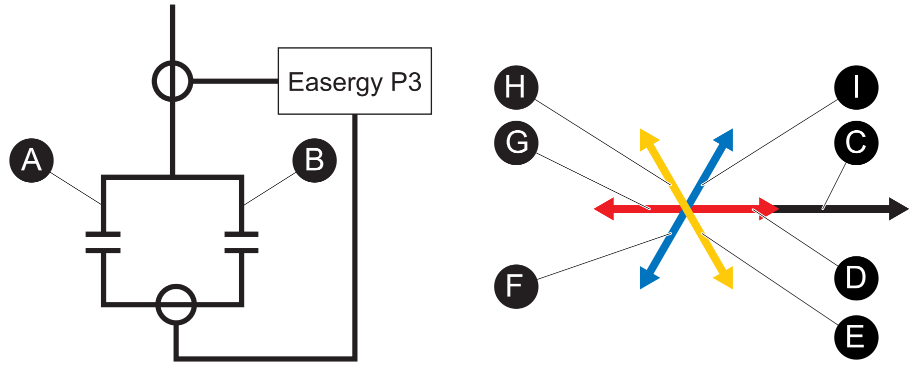


A. The natural unbalance is compensated for.

B. When the I_0 current increases above the set start value (normally 90 % of a single capacitor unit) according to the angle ratio between I_0 and I_{L1}, it is decided in which branch and phase the fault occurred. The fault is memorised and compensation is completed automatically. After the set amount of faults, the stage trips.

Figure 6.53: Natural unbalance compensation and a single capacitor fault

If there is an element failure in the bank, the algorithm checks the phase angle of the unbalance current related to the phase angle of the phase current I_{L1}. Based on this angle, the algorithm can increase the corresponding faulty elements counter (there are six counters).



A. Branch 1

B. Branch 2

C. IL1 as reference

D. Phase 1 fault in branch 1

E. Phase 3 fault in branch 2

F. Phase 2 fault in branch 1

G. Phase 1 fault in branch 2

H. Phase 3 fault in branch 1

I. Phase 2 fault in branch 2

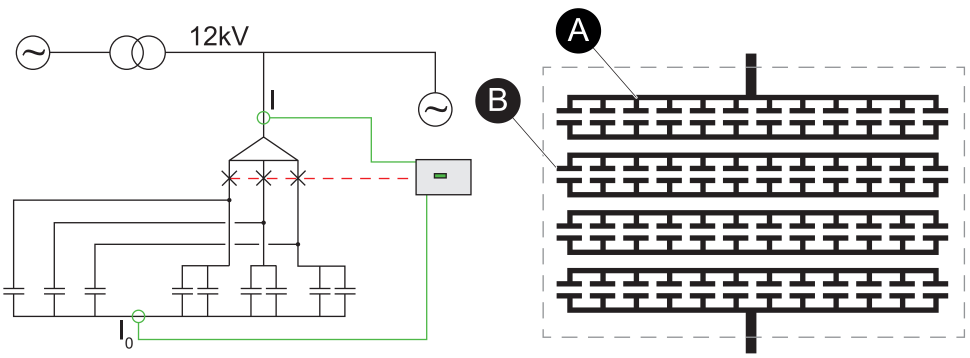
Figure 6.54: How a failure in different branches of the bank affects the I_0 measurement

You can set for the stage I_0>>>> the allowed number of faulty elements. For example, if set to three elements, the fourth fault element will issue the trip signal.

The fault location is used with internal fused capacitor and filter banks. There is no need to use it with fuseless or external fused capacitor and filter banks, nor with the reactor banks.

Application example

An application example is presented below. Each capacitor unit has 12 elements in parallel and four elements in series.



A. 12 in parallel

B. Four in series

Figure 6.55: 131.43 µF Y-Y connected capacitor bank with internal fuses

Taking unbalance protection into use

1. Enable the capacitor bank protection:
   - in Easergy Pro, in the **Protection > I_0>>>> Unbalance** setting view, select **Location** for **Compensation mode**.

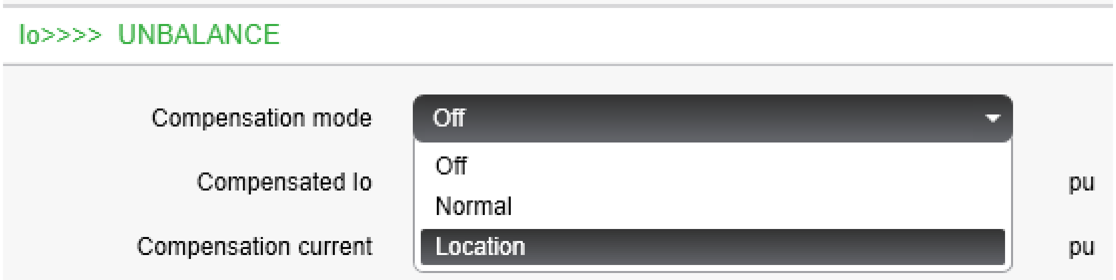


Figure 6.56: Enabling unbalance protection

   - via the relay's front panel: go to the **I_0>>>>** menu, scroll right to **1 SET 50N/51N**, and select **Location** for **CMode**.
2. Save the natural unbalance:
   - in Easergy Pro, in the **Protection > I_0>>>> Unbalance** setting view, select **Get** for **Save unbalance current**.

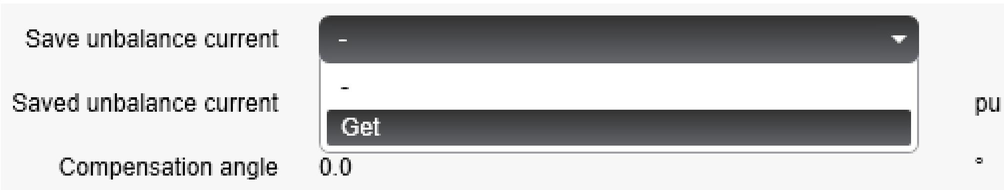


Figure 6.57: Saving the unbalance current

   - via the relay's front panel: go to the **I_0>>>>** menu, scroll right to **SET2 50N/51N**, and select **Get** for **SaveBal**.

NOTE: **CMode** has to be selected as **Location** before proceeding to this step.

3. Set the start value for both branches.
   Total capacitance of the bank is 131.43 μF. In each phase, there are three capacitor units (1+2), so the capacitance of one unit is 43.81 μF. Failure of one element inside the capacitor unit makes the total capacitance decrease to 41.92 μF (Ohm's law). This value is important when calculating the start value.

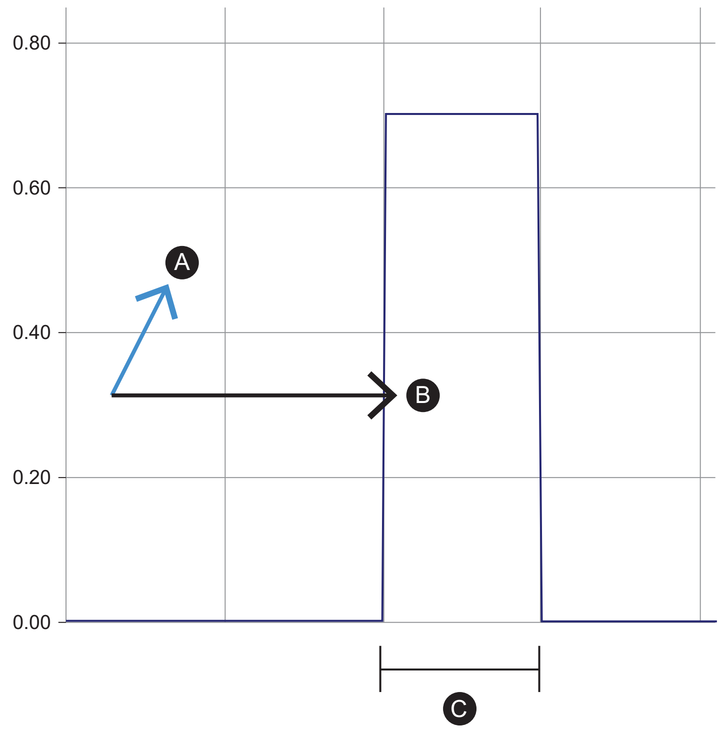
$$3I_0 = \frac{\dfrac{U_{L-N}}{(2\cdot\pi\cdot f\cdot C_1)^{-1}} - \dfrac{U_{L-N}}{(2\cdot\pi\cdot f\cdot C_2)^{-1}}}{3}$$

$$3I_0 = \frac{\dfrac{6928}{(2\cdot\pi\cdot 50\cdot 43.81\cdot 10^{-6})^{-1}} - \dfrac{6928}{(2\cdot\pi\cdot 50\cdot 43.81\cdot 10^{-6})^{-1}}}{3}$$

$$3I_0 = 1.37A$$

Failure of one element inside the bank on the left branch causes approximately 1.37 ampere unbalance current at the star point. On the right branch, there are two capacitor units in parallel, and therefore, a failure of one element causes only 0.69 ampere unbalance. A different start value for each branch is necessary. Set the start value to 80% of the calculated value.

4. Test the operation of the unbalance protection.



A. Phase 2 fault in branch 2

B. IL1 as reference

C. Set operation delay

Figure 6.58: Testing

Conduct testing by injecting current to channels IL1 and I01 of the relay. In the example above, 0.69 A primary current is injected to the I01 channel. I01 is leading the phase current IL1 by 60 degrees. This means the fault has to be on the right branch and in phase 2. Compensation happens automatically after the set operate time until the allowed total amount of failed units is exceeded (Max. allowed faults). In this application, the fourth failed element would cause the stage to trip.

NOTE: If branch 1 faults occur in branch 2, change the polarity of the I_0 input. Clear the location counters when the commissioning of the relay has been completed.

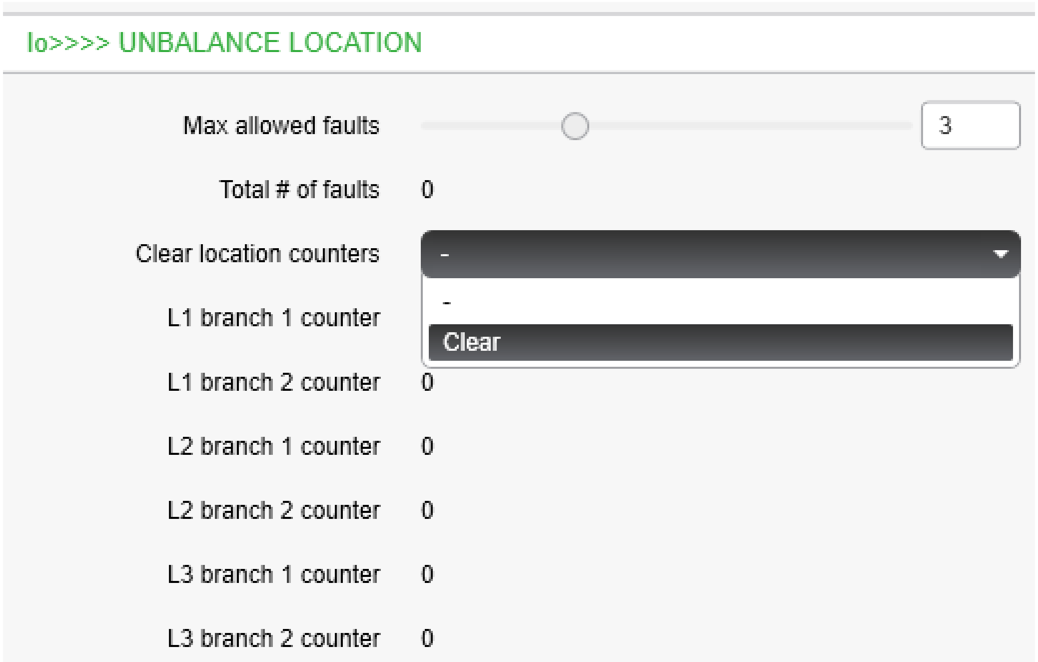


Figure 6.59: Clearing location counters

Characteristics

Table 6.26: Capacitor bank unbalance I_0>>> and I_0>>>> (51C)

Start value	0.01-20.0 pu (step 0.01)
Operate time	0.04-300 s (step 0.01)
Start time	Typically 30 ms
Reset time	<95 ms
Reset ratio	0.95
Inaccuracy: - Starting - Operate time	 ±2% of the set value or ±0.3% of the rated value ±1% or ±25 ms

6.20 Voltage-dependent overcurrent (ANSI 51V)

NOTE: The voltage-dependent overcurrent stage can be configured to be either voltage-restrained or voltage-controlled.

Description

The voltage-dependent overcurrent stage I_V> is typically used for generator short-circuit protection in applications where the static excitation system of the generator is fed only from the generator terminals. Other possible applications are conditions where the fault current level depends on the sources feeding the fault.

In close-by short circuits, the fault current rapidly decreases, thus jeopardizing the operation of the high-set short circuit protection. The operation can be secured using the voltage-dependent overcurrent function.

The voltage-dependent overcurrent stage operates with definite time characteristic. The start current I_V> and the operate time t> can be set by the user.

Voltage-restained overcurrent principle

The current start limit of the voltage-restrained overcurrent function is conditional to the control voltage (fundamental frequency component positive sequence voltage U_1).

The operation characteristic of the voltage-restrained overcurrent function is shown in Figure 6.60.

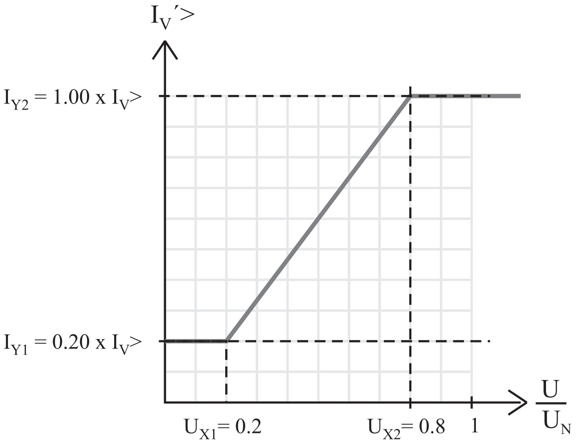


Figure 6.60: Characteristics of the voltage-restrained overcurrent function I_V>.

When the generator terminal or busbar voltage falls below the set voltage level, the start current level of the overcurrent stage I_V> also starts falling linearly controlled by the control voltage according to the characteristic curve. See Figure 6.60.

Voltage-controlled overcurrent principle

When the setting parameters are selected according to Figure 6.61, the function is said to be voltage-controlled.

NOTE: The overcurrent function can be used as a normal high-set overcurrent stage I>>> if I_{Y1} and I_{Y2} are set to 100%.

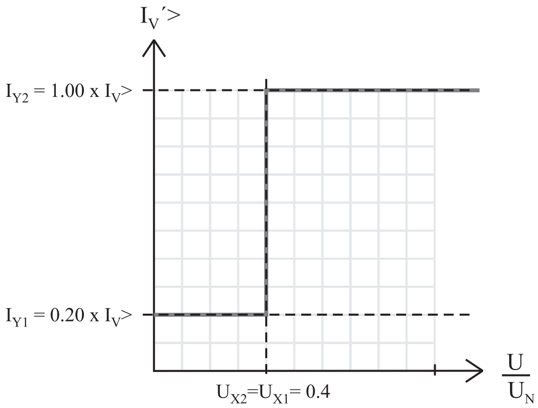


Figure 6.61: Voltage-controlled overcurrent characteristics

The voltage setting parameters U_{X1} and U_{X2} are proportional to the rated voltage of the generator. They define the voltage limits, within which the start current of the overcurrent unit is restrained. The multipliers I_{Y1} and I_{Y2} are used for setting the area of change of the start level of the overcurrent function in proportion to the U_{X1} and U_{X2} settings.

Cold load and inrush current handling

See Chapter 7.3 Cold load start and magnetising inrush.

Setting groups

There are four setting groups available.

Characteristics

Table 6.27: Voltage-dependent overcurrent I_V> (51V)

Settings: - I_V> - U_{X1}, U_{X2} - I_{Y1}, I_{Y2}	 0.50–4.00 x I_{GN} 0–150 % 0–200 %I_V>
Definite time function: - Operate time	 0.08**–300.00 s (step 0.02 s)
Start time	Typically 60 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio	<0.97
Transient overreach, any τ	< 10 %
Inaccuracy: - Starting - Operate time at definite time function	 ±3% of set value ±1% or ±30 ms

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

6.21 Overvoltage (ANSI 59)

Description

Overvoltage protection is used to detect too high system voltages or to check that there is sufficient voltage to authorize a source transfer.

The overvoltage function measures the fundamental frequency component of the line-to-line voltages regardless of the voltage measurement mode (Chapter 10.6 Voltage measurement modes). By using line-to-line voltages any line-to-neutral over-voltages during earth faults have no effect. (The earth fault protection functions take care of earth faults.) Whenever any of these three line-to-line voltages exceeds the start setting of a particular stage, this stage starts and a start signal is issued. If the fault situation remains on longer than the operate time delay setting, a trip signal is issued.

In solidly earthed, four-wire networks with loads between phase and neutral voltages, overvoltage protection may be needed for line-to-neutral voltages, too. In such applications, the programmable stages can be used. Chapter 6.35 Programmable stages (ANSI 99).

Three independent stages

There are three separately adjustable stages: U>, U>> and U>>>. All the stages can be configured for the definite time (DT) operation characteristic.

Configurable release delay

The U> stage has a settable reset delay that enables detecting intermittent faults. This means that the time counter of the protection function does not reset immediately after the fault is cleared, but resets after the release delay has elapsed. If the fault appears again before the release delay time has elapsed, the delay counter continues from the previous value. This means that the function eventually trips if faults are occurring often enough.

Configurable hysteresis

The dead band is 3 % by default. This means that an overvoltage fault is regarded as a fault until the voltage drops below 97 % of the start setting. In a sensitive alarm application, a smaller hysteresis is needed. For example, if the start setting is about only 2 % above the normal voltage level, the hysteresis must be less than 2 %. Otherwise, the stage does not release after fault.

Block diagram

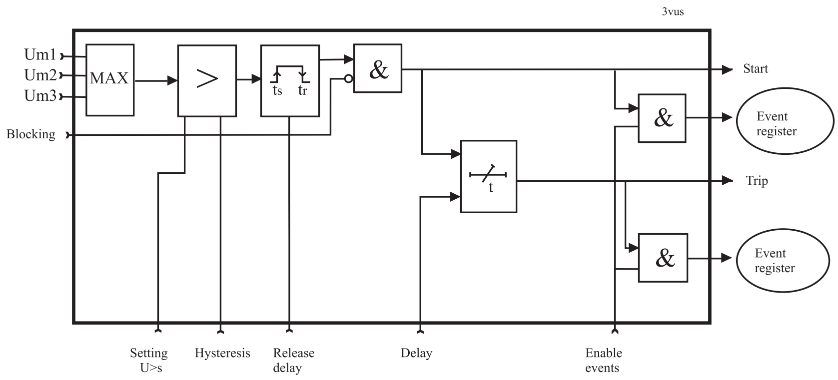


Figure 6.62: Block diagram of the three-phase overvoltage stages U>, U>> and U>>>

Setting groups

There are four setting groups available for each stage.

Characteristics

Table 6.28: Overvoltage stage U> (59)

Input signal	U_{L1} – U_{L3}
Start value	50 – 150 %U_N (step 1%)
Definite time characteristic: - operate time	 0.08** – 300.00 s (step 0.02)
Hysteresis	0.99 – 0.800 (0.1 – 20.0 %, step 0.1 %)
Start time	Typically 60 ms
Release delay	0.06 – 300.00 s (step 0.02)
Reset time	<95 ms
Overshoot time	< 50 ms
Inaccuracy: - Starting - operate time	 ±3% of the set value ±1% or ±30 ms

Table 6.29: Overvoltage stage U>> (59)

Input signal	U_{L1} – U_{L3}
Start value	50 – 150 %U_N (step 1%) The measurement range is up to 160 V. This limit is the maximum usable setting when rated VT secondary is more than 100 V.
Definite time characteristic: - Operate time	 0.06** – 300.00 s (step 0.02)
Hysteresis	0.99 – 0.800 (0.1 – 20.0 %, step 0.1 %)
Start time	Typically 60 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Inaccuracy: - Starting - Operate time	 ±3% of the set value ±1% or ±30 ms

Table 6.30: Overvoltage stage U>>> (59)

Input signal	U_{L1} – U_{L3}
Start value	50 – 160 %U_N (step 1%) The measurement range is up to 160 V. This limit is the maximum usable setting when rated VT secondary is more than 100 V.
Definite time characteristic: - Operate time	 0.04** – 300.00 s (step 0.01)
Hysteresis	0.99 – 0.800 (0.1 – 20.0 %, step 0.1 %)
Start time	Typically 30 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Inaccuracy: - Starting - Operate time	 ±3% of the set value ±1% or ±25 ms

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

6.22 Neutral voltage displacement (ANSI 59N)

Description

The neutral voltage displacement protection is used as unselective backup for earth faults and also for selective earth fault protections for motors having a unit transformer between the motor and the busbar.

This function is sensitive to the fundamental frequency component of the neutral voltage displacement voltage. The attenuation of the third harmonic is more than 60 dB. This is essential because third harmonics exist between the neutral point and earth also when there is no earth fault.

Whenever the measured value exceeds the start setting of a particular stage, this stage starts and a start signal is issued. If the fault situation remains on longer than the operate time delay setting, a trip signal is issued.

Measuring the neutral displacement voltage

The neutral displacement voltage is either measured with three voltage transformers (for example broken delta connection), one voltage transformer between the motor's neutral point and earth or calculated from the measured phase-to-neutral voltages according to the selected voltage measurement mode (see Chapter 10.6 Voltage measurement modes):

- When the voltage measurement mode is 3LN: the neutral displacement voltage is calculated from the line-to-line voltages and therefore a separate neutral displacement voltage transformer is not needed. The setting values are relative to the configured voltage transformer (VT) voltage/ $\sqrt{3}$.
- When the voltage measurement mode contains "+U_0": The neutral displacement voltage is measured with voltage transformer(s) for example using a broken delta connection. The setting values are relative to the VT_0 secondary voltage defined in configuration.
- Connect the U_0 signal according to the connection diagram to achieve correct polarization.

Two independent stages

There are two separately adjustable stages: U_0> and U_0>>. Both stages can be configured for the definite time (DT) operation characteristic.

The neutral voltage displacement function comprises two separately adjustable neutral voltage displacement stages (stage U_0> and U_0>>).

Block diagram

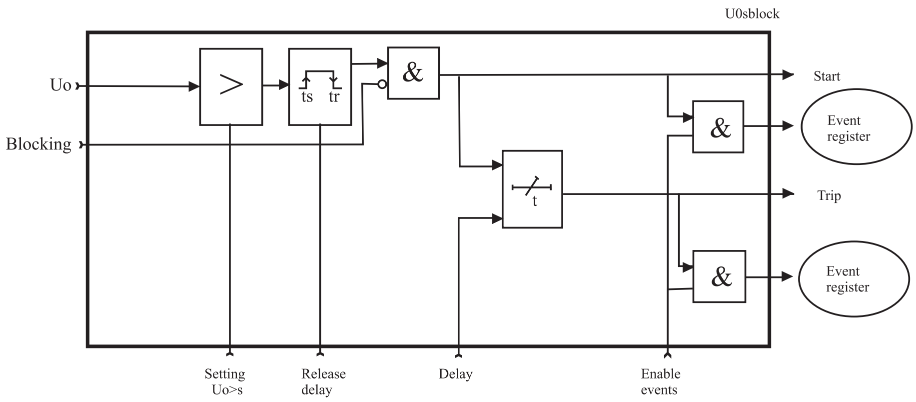


Figure 6.63: Block diagram of the neutral voltage displacement stages U_0>, U_0>>

Setting groups

There are four setting groups available for both stages.

Characteristics

Table 6.31: Neutral voltage displacement stage U_0> (59N)

Input signal	U_0 U_{0Calc} (= U_{L1} + U_{L2} + U_{L3})
Start value	1 – 60 %U_{0N} (step 1%)
Definite time function: - Operate time	 0.3 – 300.0 s (step 0.1 s)
Start time	Typically 200 ms
Reset time	< 450 ms
Reset ratio	<0.97
Inaccuracy: - Starting - Starting UoCalc (3LN mode) - Operate time	 ±2% of the set value or ±0.3% of the rated value ±1 V ±1 % or ±150 ms

Table 6.32: Neutral voltage displacement stage U_0>> (59N)

Input signal	U_0 U_{0Calc} (= U_{L1} + U_{L2} + U_{L3})
Start value	1 – 60 %U_{0N} (step 1%)
Definite time function: - Operate time	 0.08 – 300.0 s (step 0.02 s)
Start time	Typically 60 ms
Reset time	<95 ms
Reset ratio	<0.97
Inaccuracy: - Starting - Starting U_{0Calc} (3LN mode) - Operate time	 ±2% of the set value or ±0.3% of the rated value ±1 V ±1% or ±30 ms

6.23 Stator earth-fault (ANSI 64S)

Description

NOTE: This protection stage is available only in the voltage measurement modes 2LL + U_0 and 3LN + U_0 (see chapter Chapter 10.6 Voltage measurement modes).

For this function, the neutral voltage displacement voltage must be measured from the generator's neutral point and the earth.

A unit transformer is usually needed between the generator and the busbar for this function's selective operation.

The third harmonic undervoltage stage can be used to detect earth faults near a high-impedance earthed generator's neutral point or even at the neutral point. These kind of faults are rare, but if a second earth fault would occur in one of the phases, the consequences would be severe because the first earth fault had made the network solidly earthed. By using the U_{0F3}< stage, such a situation can be avoided.

Neutral point is a blind point for conventional earth fault function

If there is an earth fault near the neutral point or even at the neutral point , the earth fault current and neutral voltage displacement voltage caused by such a fault are negligible or even zero. Thus, a conventional earth fault protection based on fundamental frequency I_0 and/or U_0 measurement is not able to detect such faults. On the other hand, faults near the neutral point are rare because the voltage stress is low.

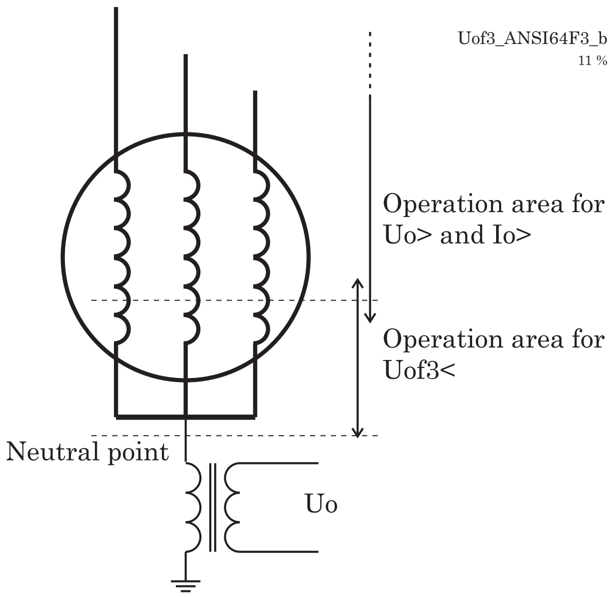


Figure 6.64: The overlapping coverage of winding earth fault protection of basic protection stages and the third harmonic undervoltage protection stage.

100 % coverage of the windings

The "one hundred per cent" in the title is slightly misleading. Actually, the 100 % coverage is achieved only when this stage is used together with conventional earth fault protection.

The operation range of fundamental frequency earth fault functions 59N and 51N covers about 95 % of the stator windings starting from the HV end, but never 100 % of the windings. The coverage of the U_{0f3}< stage is about 10%–30 % of the windings but starting from the LV end, that is, the neutral point. Thus, the ranges overlap as in Figure 6.64 and 59N or 51N together with this 64F3 covers 100 % of the stator windings.

Natural 3rd harmonic at the neutral point

The voltage of the generator is not ideal pure sine wave. There is a small amount of harmonics as well. At the neutral point, there is some amount of 3rd, 6th, 9th, 12th ..., that is, 3n harmonics. The base frequency and other than 3n harmonics in line-to-line voltages cancel each other at the neutral point (Figure 6.65 and Figure 6.66). The third harmonic residual undervoltage stage U_{0f3}< is supervising the level of the 3rd harmonic at the neutral point. If there is an earth fault near the neutral point, this 150 Hz or 180 Hz voltage drops below the setting and the stage activates.

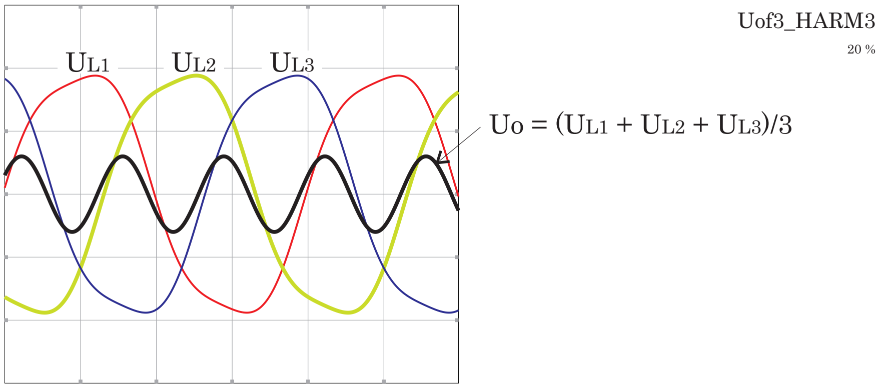


Figure 6.65: When symmetric line-to-neutral voltages containing third harmonic are summed together, the result is not zero.

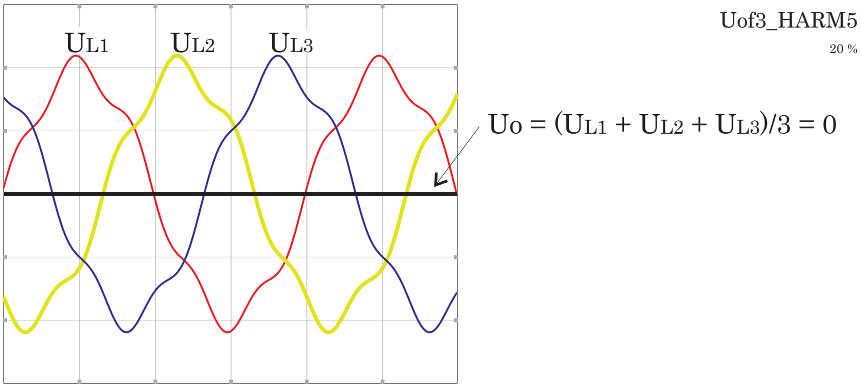


Figure 6.66: When the line-to-neutral voltages do contain fifth harmonic, they cancel each other when summed and the resulting zero sequence voltage U_0 is zero.

Finding out the correct start setting

A problem with this third harmonic undervoltage stage is to find a proper start setting. In practice, an empirical value is used, because the natural 3rd harmonic at the neutral point depends on:

- Construction of the generator
- Loading and the power factor
- Amount of excitation
- Earthing circuitry
- Transformers connected.

The relay itself can be used to measure the actual level of 3rd, U_0 harmonic during various situations. Typically, the generator is producing its minimum amount of 3rd harmonic when the load is small and the excitation is low. The start setting must be below this minimum value. A typical operation delay is one minute.

Blocking the protection

The squelch of voltage measurement blocks the stage when the generator is stopped. Using the block matrix, blocking by undervoltage, underpower, circuit breaker position and other blocking schemes is possible.

Setting groups

There are four setting groups available.

Characteristics

Table 6.33: Stator earth-fault (64S)

Start value	1 – 50 %
Definite time function: - Operate time	 0.5 – 30.0 minutes
Start time	<2 s
Reset time	<4 s
Reset ratio	1.05 (When start setting is below 5%, reset value is less than set value +0.5 % unit)
Fundamental low voltage block limit (U12 and U23)	Blocked when U_{12} and U_{23} < 65 % of nominal
Inaccuracy: - Starting - Operat time at definite time function	 ±1 % units ±1% or ±2 s

6.24 Restricted earth fault (ANSI 64REF)

Description

The restricted earth fault (REF) protection function is used to detect earth faults in solidly-earthed or impedance-earthed power transformers, earthing transformers and shunt reactors. REF protection can also be used to protect rotating machines if the machine's neutral point is earthed.

A traditional REF protection scheme is based on a high-impedance REF protection principle. Modern REF protection operation is based on a low-impedance principle that overcomes some drawbacks of the high-impedance REF principle. Figure 6.67 to Figure 6.70 describe the basic low-impedance REF protection schemes.

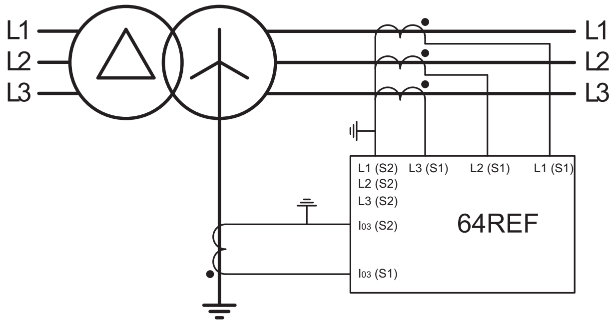


Figure 6.67: Restricted earth fault protection of a solidly-earthed transformer

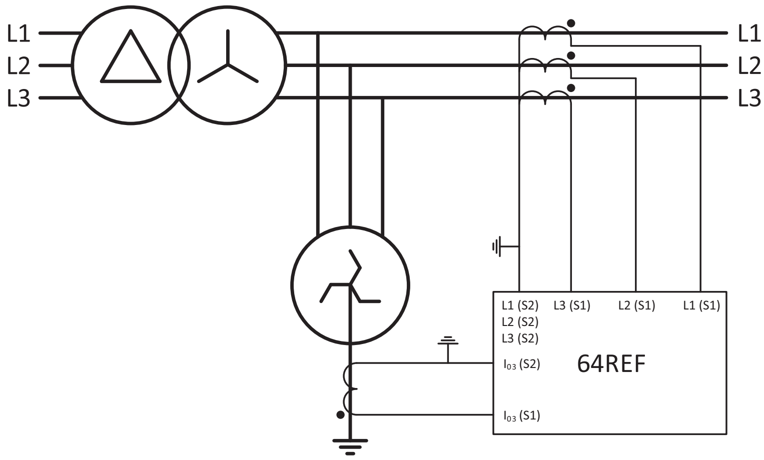


Figure 6.68: Restricted earth fault protection of a transformer and neutral point reactor

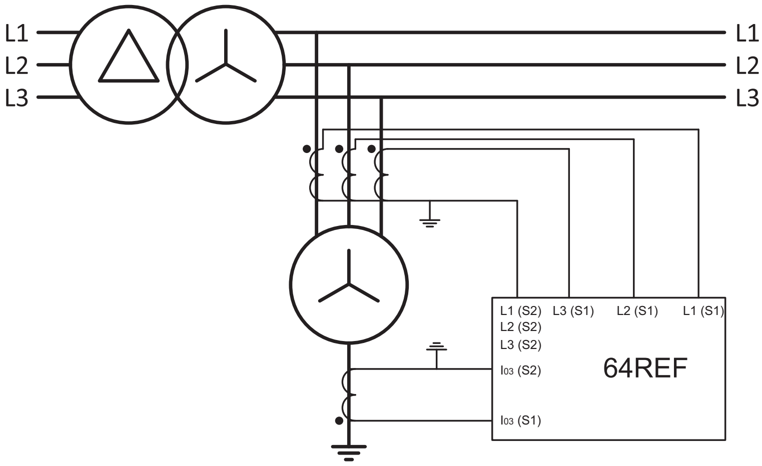


Figure 6.69: Restricted earth fault protection of a shunt reactor

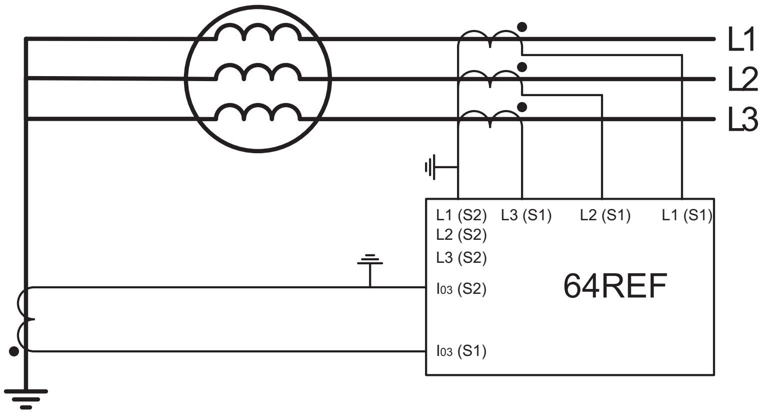


Figure 6.70: Restricted earth fault protection of a rotating machine

The REF protection principle has several advantages. It is very selective because the protection zone is limited between the current transformers that are used for the REF protection. Because of its selectivity, the REF protection requires no additional time delay for protection coordination. Therefore, REF protection is especially suitable for the protection of transformers and rotating machines against internal earth faults. Because of the differential protection principle, it is also very sensitive which makes it suitable for detecting faults located near the neutral point of transformers and rotating machines.

Restricted earth fault protection principle

The REF protection function is based on the differential protection principle and is sensitive to the fundamental frequency component of the measured currents. Figure 6.71 depicts the differential protection principle applied to REF protection.

The protection zone is determined by the location of current transformers. The direction of currents in REF protection are defined so that currents entering the protection zone have positive direction and currents leaving the zone have negative direction.

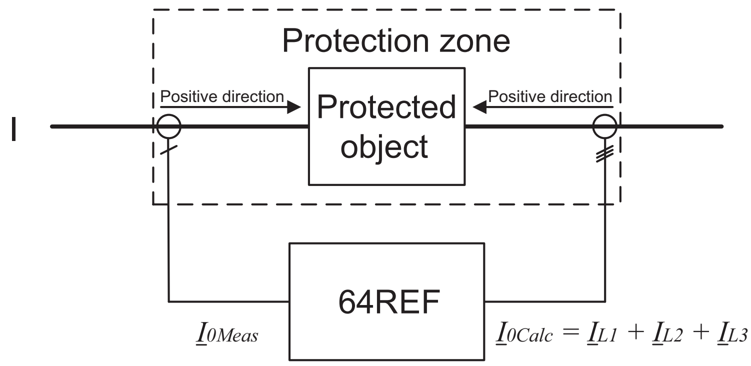


Figure 6.71: Differential protection principle applied to REF protection

The function is based on the difference of the current measured at the neutral point (I_{0Meas}) and the calculated residual current (I_{0Calc}). The function calculates the differential current I_D according to Equation 6.9. So the function is based on the absolute value of I_D that is a sum of the current vectors I_{0Meas} and I_{0Calc}.

NOTE: Nominal current of the I_{0Meas} and I_{0Calc} are current transformer ratings.

Equation 6.9:

$$I_D = |\underline{I}_{0Meas} + \underline{I}_{0Calc}|$$

During healthy conditions, the neutral point current (I_{0Meas}) is near or equal to zero and the same is true for the residual current or the calculated sum of the phase currents $\underline{I}_{0Calc} = 3\underline{I}_0 = \underline{I}_{L1} + \underline{I}_{L2} + \underline{I}_{L3}$. During healthy conditions, the differential current I_D is also close to zero and the REF protection stage does not start.

Figure 6.72 depicts through-fault conditions and a fault in the protected zone.

During a through-fault condition, an earth fault current flowing from the faulty phase to earth returns to the system's neutral point. Because of the convention of current directions, the resulting neutral point current (I_{0Meas}) and calculated residual current (I_{0Calc}) are flowing in opposite directions resulting in zero or very small differential current I_D according to Equation 6.10.

When a fault occurs inside the protection zone, the neutral point current flowing into the protection zone has a positive current direction according to the current direction convention. Depending on the network conditions, an additional fault current may or may not flow into the zone along the line. This additional fault current manifests itself as a residual current. Additional fault currents flowing into the protection zone have a positive current direction, too. In other words, the neutral point current and residual current are in a phase which results in a high differential current I_D according to Equation 6.10.

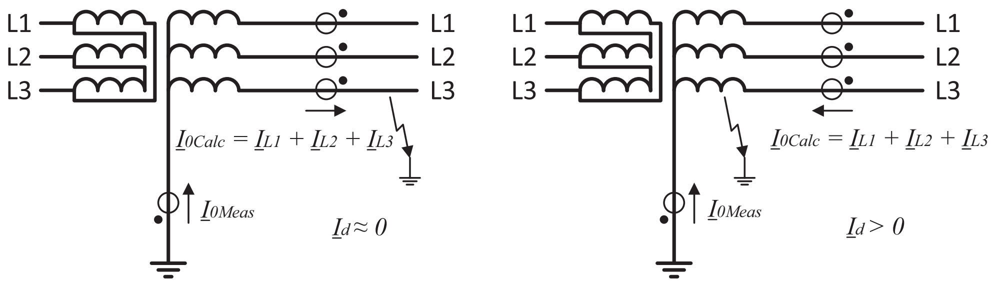


Figure 6.72: Through-fault condition (left) and earth fault in protected zone (right)

During a through-fault or short-circuit fault outside the protection zone, the current transformers may be exposed to very high currents. These high fault currents may lead to different saturation of the phase current transformers resulting in an erroneous residual current. To ensure correct operation of the protection stage, a stabilization method is provided. Protection stage stabilisation is based on the calculated bias current I_B and programmable operating characteristics. The bias current is calculated according to Equation 6.10.

Equation 6.10:

$$I_B = \frac{|I_{L1}| + |I_{L2}| + |I_{L3}|}{3}$$

This bias current stabilization method is used in the dI_0> stage. The dI_0>> stage does not consider the stabilization current I_B and is purely based on the differential current I_D. Both the differential current I_D and stabilization current I_B are current transformer ratings.

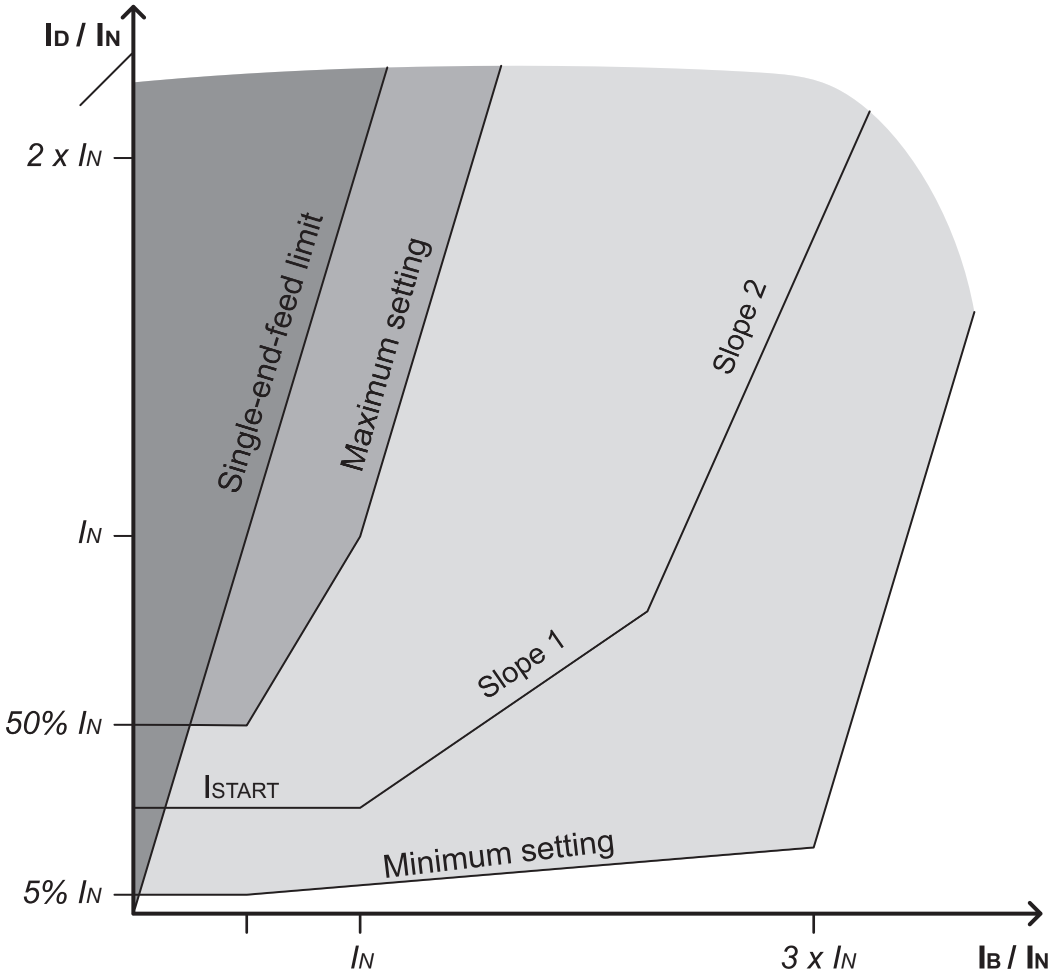


Figure 6.73: Restricted earth fault protection operating characteristics

Additional stabilisation can be activated by selecting the directional blocking feature. When directional blocking is used, the trip command is issued only when the measured neutral current and calculated residual current are less than ±88° apart. Normal second harmonic blocking and cold-load blocking can be used to block the stage via the blocking matrix.

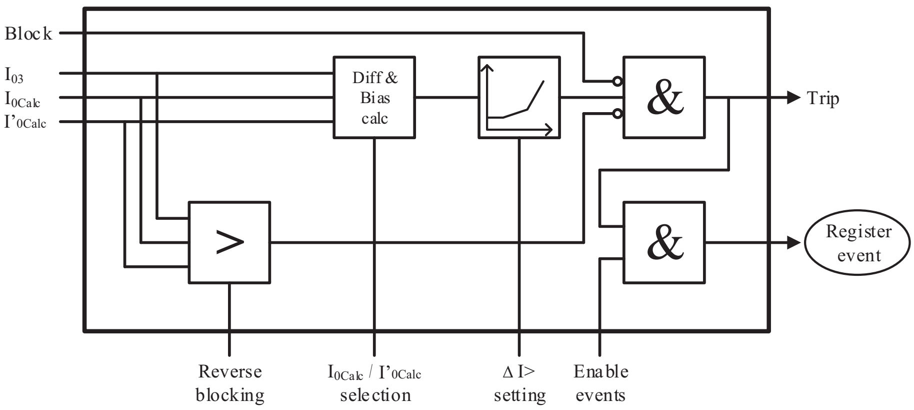


Figure 6.74: Block diagram of REF protection stage

Characteristics

Table 6.34: Restricted earth fault overcurrent (64REF)

	dIo>	dIo>>
Input signals - Measured earth fault overcurrent input - Calculated earth fault overcurrent source	 I_{03} I_{0Calc} or I'_{0Calc}	 I_{03} I_{0Calc} or I'_{0Calc}
Start value - dIo>	 5–50 % of I_N	 5–50 % of In
Ibias for start of slope 1	0.5 x I_N	-
Slope 1	5–100 %	-
Ibias for start of slope 2	1–3 x I_N	-
Slope 2	100–200 %	-
Directional blocking	On/off	-
Operate time (I_D > 1.2 x I_{SET})	< 60 ms	-
Operate time (I_D > 3.5 x I_{SET})	< 50 ms	< 50 ms
Reset time Reset ratio	< 95 ms 0.95	< 95 ms 0.95
Inaccuracy of starting	±3% of set value or 0.02 x In when currents are < 200 mA	±3 % of the set value or ±0.5 % of the rated value

6.25 Directional phase overcurrent (ANSI 67)

Description

Directional overcurrent protection can be used for directional short circuit protection. Typical applications are:

- Short-circuit protection of two parallel cables or overhead lines in a radial network.
- Short-circuit protection of a looped network with single feeding point.
- Short-circuit protection of a two-way feeder, which usually supplies loads but is used in special cases as an incoming feeder.
- Directional overcurrent protection in low impedance earthed networks. In this case, the relay has to connected to line-to-neutral voltages instead of line-to-line voltages. In other words, the voltage measurement mode has to be "3LN" (See chapter Chapter 10.6 Voltage measurement modes).

The stages are sensitive to the amplitude of the highest fundamental frequency current of the three measured phase currents.

In line-to-line and in three-phase faults, the fault angle is determined by using angles between positive sequence of currents and voltages. In line-to-neutral faults, the fault angle is determined by using fault-phase current and the healthy line to line voltage. For details of power direction, see Chapter 4.9 Power and current direction.

A typical characteristic is shown in Figure 6.75. The base angle setting is -30°. The stage starts if the tip of the three phase current phasor gets into the grey area.

NOTE: If the maximum possible earth fault current is greater than the used most sensitive directional over current setting, connect the relay to the line-to-neutral voltages instead of line-to-line voltages to get the right direction for earth faults, too. For networks having the maximum possible earth fault current less than the over current setting, use 67N, the directional earth fault stages.

Voltage memory

An adjustable 0.2–3.2 second cyclic buffer storing the phase-to-earth voltages is used as the voltage memory. The stored phase angle information is used as direction reference if all the line-to-line voltages drop below 1% during a fault. To adjust the voltage memory, set the **Angele memory duration** parameter in the **Scalings** setting view in Easergy Pro.

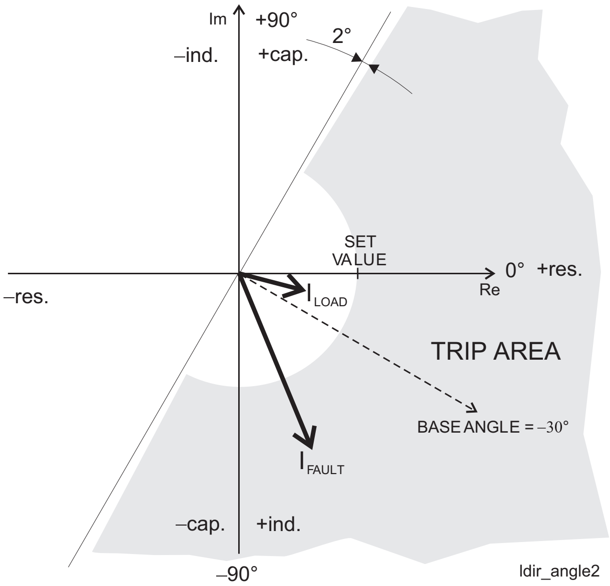


Figure 6.75: Example of the directional overcurrent function's protection area

Three modes are available: dirctional, non-direct, and directional+back-up (Figure 6.76). In the non-directional mode, the stage is acting just like an ordinary overcurrent 50/51 stage.

Directional+back-up mode works the same way as the directional mode, but it has undirectional backup protection in case a close-up fault forces all voltages to about zero. After the angle memory hold time, the direction would be lost. Basically the directional+backup mode is required when operate time is set longer than voltage memory setting and no other undirectional back-up protection is in use.

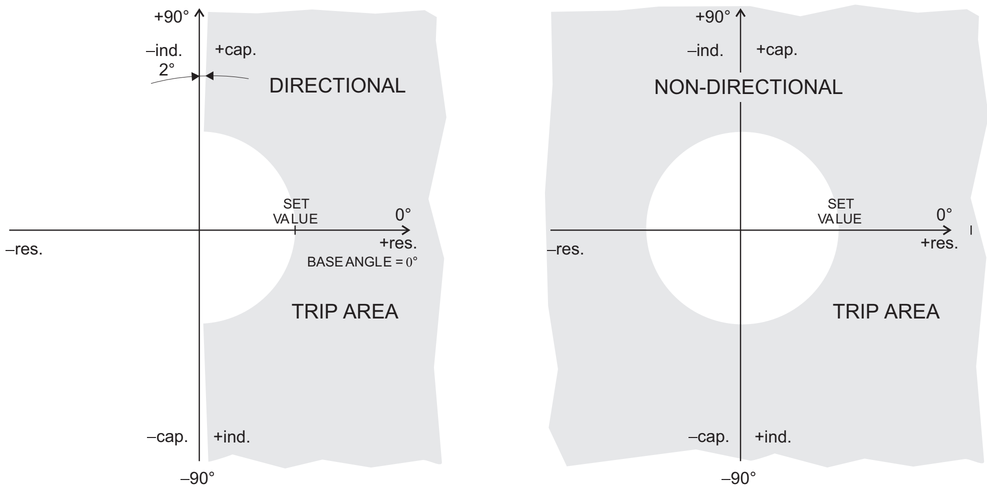


Figure 6.76: Difference between directional mode and non-directional mode. The grey area is the trip region.

An example of bi-directional operation characteristic is shown in Figure 6.77. The right side stage in this example is the stage I_{φ}> and the left side is I_{φ}>>. The base angle setting of the I_{φ}> is 0° and the base angle of I_{φ}>> is set to -180°.

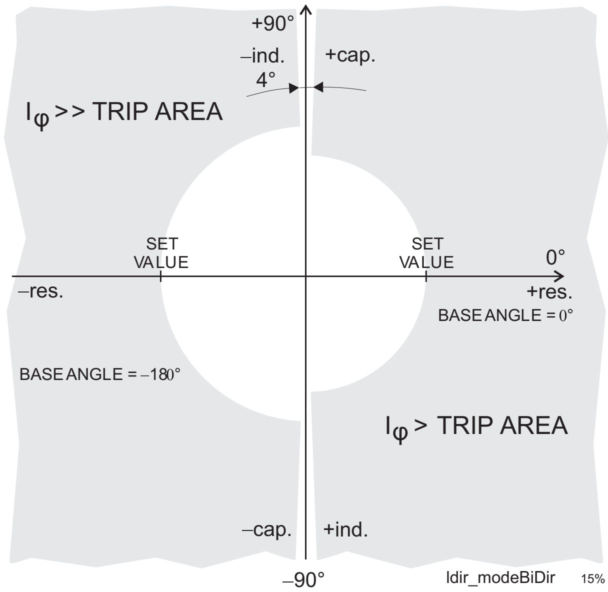


Figure 6.77: Bi-directional application with two stages I_{φ}> and I_{φ}>>.

When any of the three phase currents exceeds the setting value and, in directional mode, the phase angle including the base angle is within the active ±88° wide sector, the stage starts and issues a start signal. If this fault situation remains on longer than the delay setting, a trip signal is issued.

Four independent stages

There are four separately adjustable stages available: I_{φ}>, I_{φ}>>, I_{φ}>>> and I_{φ}>>>>.

Dependent operate time

Stages I_{φ}> and I_{φ}>> can be configured for definite time or dependent time characteristic. See Chapter 6.3 Dependent operate time for details of the available dependent delays. Stages I_{φ}>>> and I_{φ}>>>> have definite time (DT) operation delay. The relay shows a scaleable graph of the configured delay on the local panel display.

Dependent time limitation

The maximum measured secondary current is 50 x I_N. This limits the scope of dependent curves with high start settings. See Chapter 6.3 Dependent operate time for more information.

Setting groups

There are four setting groups available for each stage.

Characteristics

Table 6.35: Directional phase overcurrent I_{φ}>, I_{φ}>> (67)

Input signal	I_{L1} – I_{L3} U_{L1} – U_{L3}
Start value	0.10–4.00 xI_{GN} (step 0.01)
Mode	Directional/Directional+BackUp
Minimum voltage for the direction solving	2 $V_{SECONDARY}$
Base angle setting range	-180° – +179°
Operate angle	±88°
Definite time function: - Operate time	DT** 0.04–300.00 s (step 0.01)
IDMT function: - Delay curve family - Curve type - Inv. time coefficient k	 (DT), IEC, IEEE, RI Prg EI, VI, NI, LTI, MI…depends on the family* 0.025–20.0, except 0.50–20.0 for RXIDG, IEEE and IEEE2
Start time	Typically 30 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio	<0.95
Reset ratio (angle)	2°
Transient overreach, any τ	< 10 %
Angle memory duration	0.2–3.2 s
Inaccuracy: - Starting (rated value I_N= 1–5A) - Angle - Operate time at definite time function - Operate time at IDMT function	 ±3% of the set value or ±0.5% of the rated value ±2° U>5 V ±30° U= 0.1–5.0 V ±1% or ±25 ms ±5% or at least ±30 ms**

Table 6.36: Directional phase overcurrent I_{φ}>>>, I_{φ}>>>> (67)

Input signal	$I_{L1} – I_{L3}$ $U_{L1} – U_{L3}$
Start value	0.10 – 20.00 x I_{MODE} (step 0.01)
Mode	Directional/Directional+BackUp
Minimum voltage for the direction solving	2 $V_{SECONDARY}$
Base angle setting range	-180° – +179°
Operate angle	±88°
Definite time function: - Operate time	DT** 0.04 – 300.00 s (step 0.01)
Start time	Typically 30 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio	<0.95
Reset ratio (angle)	2°
Transient overreach, any τ	< 10 %
Angle memory duration	0.2 – 3.2 s
Inaccuracy: - Starting (rated value I_N= 1 – 5A) - Angle - Operate time at definite time function	 ±3% of the set value or ±0.5% of the rated value ±2° U> 5 V ±30° U= 0.1 – 5.0 V ±1% or ±25 ms

*) EI = Extremely Inverse, NI = Normal Inverse, VI = Very Inverse, LTI = Long Time Inverse, MI= Moderately Inverse

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

6.26 Directional earth fault overcurrent (ANSI 67N)

Description

The directional earth fault protection is used for generator's stator earth faults in networks where a selective and sensitive earth fault protection is needed and in applications with varying network structure and length.

The earth fault protection is adapted for various network earth systems.

The function is sensitive to the fundamental frequency component of the earth fault overcurrent and neutral voltage displacement voltage and the phase angle between them. The attenuation of the third harmonic is more than 60 dB. Whenever the size of I_0 and U_0 and the phase angle between I_0 and U_0 fulfils the start criteria, the stage starts and a start signal is issued. If the fault situation remains on longer than the operate time delay setting, a trip signal is issued.

Polarization

The neutral displacement voltage, used for polarization, is measured by energizing input U_0, that is, the angle reference for I_0. Connect the U_0 signal according to the connection diagram. Alternatively, the U_0 can be calculated from the line-to-line voltages internally depending on the selected voltage measurement mode (see Chapter 10.6 Voltage measurement modes):

- 3LN/LL_Y, 3LN/LN_Y and 3LN/U_0: the zero sequence voltage is calculated from the line-to-line voltages and therefore any separate zero sequence voltage transformers are not needed. The setting values are relative to the configured voltage transformer (VT) voltage/$\sqrt{3}$.
- 3LN+U_0, 2LL+U_0, 2LL+U_0+LLy, 2LL+U_0+LNy, LL+U_0+LLy+LLz, and LN+U_0+LNy+LNz: the neutral voltage displacement voltage is measured with voltage transformer(s) for example using a broken delta connection. The setting values are relative to the VT_0 secondary voltage defined in the configuration.
- 3LN: the zero sequence voltage is calculated from the line-to-line voltages and therefore any separate zero sequence voltage transformers are not needed. The setting values are relative to the configured voltage transformer (VT) voltage/$\sqrt{3}$.
- 3LN+U_0 and 2LL+U_0: the zero sequence voltage is measured with voltage transformer(s) for example using a broken delta connection. The setting values are relative to the VT_0 secondary voltage defined in configuration.

Modes for different network types

The available modes are:

- ResCap
  This mode consists of two sub modes, Res and Cap. A digital signal can be used to dynamically switch between these two submodes. When the digital input is active (DI = 1), Cap mode is in use and when the digital input is inactive (DI = 0), Res mode is in use. This feature can be used with compensated networks when the Petersen coil is temporarily switched off.
  - Res
    The stage is sensitive to the resistive component of the selected I_0 signal. This mode is used with compensated **networks** (resonant earthing) and **networks earthed with a high resistance**. Compensation is usually done with a Petersen coil between the neutral point of the main transformer and earth. In this context, high resistance means that the fault current is limited to be less than the rated phase current. The trip area is a half plane as drawn in Figure 6.79. The base angle is usually set to zero degrees.
  - Cap
    The stage is sensitive to the capacitive component of the selected I_0 signal. This mode is used with **unearthed networks**. The trip area is a half plane as drawn in Figure 6.79. The base angle is usually set to zero degrees.
- Sector
  This mode is used with **networks earthed with a small resistance**. In this context, "small" means that a fault current may be more than the rated phase currents. The trip area has a shape of a sector as drawn in Figure 6.80. The base angle is usually set to zero degrees or slightly on the lagging inductive side (negative angle).
- Undir
  This mode makes the stage equal to the undirectional stage $I_0>$. The phase angle and U_0 amplitude setting are discarded. Only the amplitude of the selected I_0 input is supervised.

Input signal selection

Each stage can be connected to supervise any of the following inputs and signals:

- Input I_{01} for all networks other than solidly earthed.
- Input I_{02} for all networks other than solidly earthed.
- Calculated signal I_{0Calc} for solidly and low-impedance earthed networks. $I_{0Calc} = I_{L1} + I_{L2} + I_{L3} = 3I_0$.

Intermittent earth fault detection

Short earth faults make the protection start but does not cause a trip. A short fault means one cycle or more. For shorter than 1 ms transient type of intermittent earth faults in compensated networks, there is a dedicated stage I_{0INT}> 67NI. When starting happens often enough, such intermittent faults can be cleared using the intermittent time setting.

When a new start happens within the set intermittent time, the operation delay counter is not cleared between adjacent faults and finally the stage trips.

Two independent stages

There are two separately adjustable stages: $I_{0\varphi}$> and $I_{0\varphi}$>>. Both stages can be configured for definite time delay (DT) or dependent time delay operate time.

Dependent operate time

Accomplished dependent delays are available for all stages $I_{0\varphi}$> and $I_{0\varphi}$>>. The relay shows a scaleable graph of the configured delay on the local panel display.

Dependent time limitation

The maximum measured secondary earth fault overcurrent is 10 x I_{0N} and the maximum measured phase current is 50 x I_N. This limits the scope of dependent curves with high start settings.

Block diagram

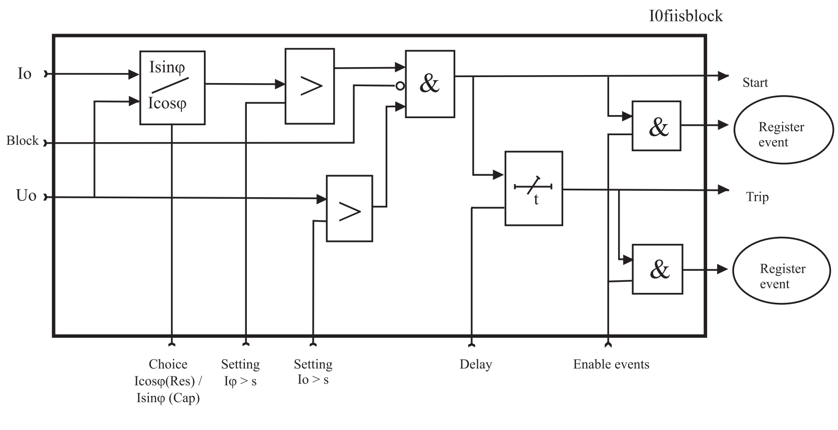


Figure 6.78: Block diagram of the directional earth fault overcurrent stages $I_{0\varphi}$>, $I_{0\varphi}$>>

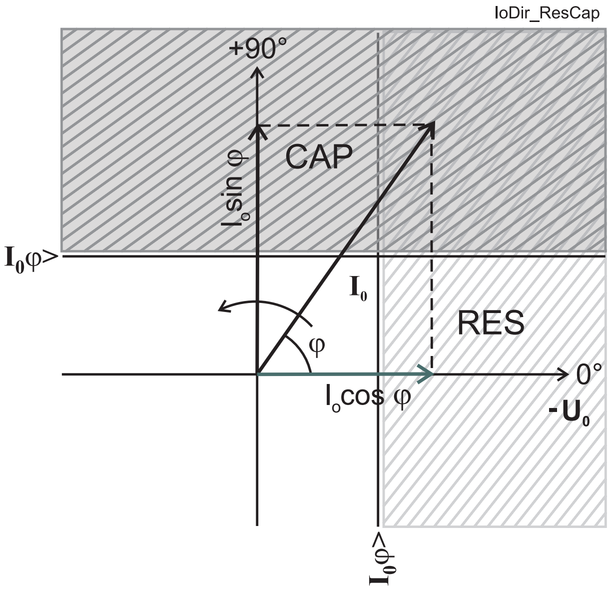


Figure 6.79: Operation characteristic of the directional earth fault protection in Res or Cap mode. Res mode can be used with compensated networks and Cap mode is used with unearthed networks.

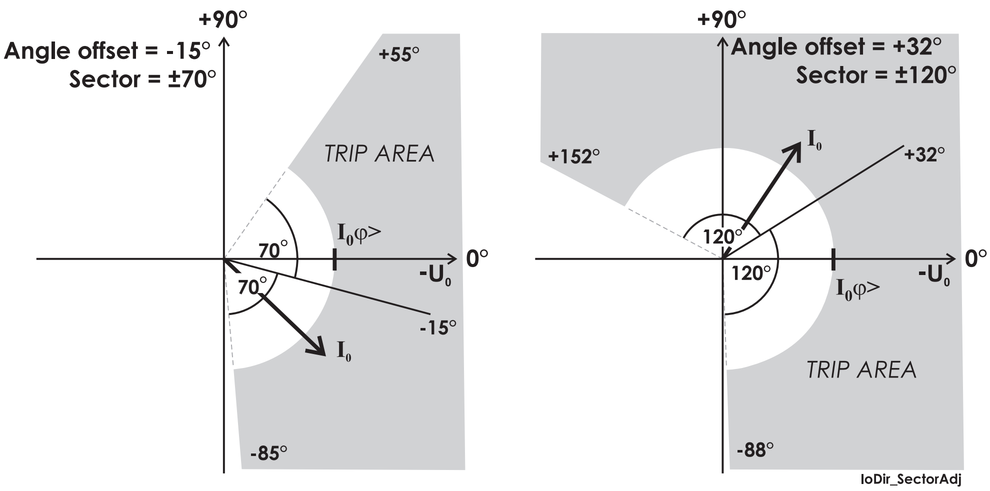


Figure 6.80: Two example of operation characteristics of the directional earth fault stages in sector mode. The drawn I_0 phasor in both figures is inside the trip area. The angle offset and half sector size are user's parameters.

Setting groups

There are four setting groups available for each stage.

Characteristics

Table 6.37: Directional earth fault overcurrent $I_{0\varphi}$>, $I_{0\varphi}$>> (67N)

Input signal	I_0, U_0 I_{0Calc} (= I_{L1} + I_{L2} + I_{L3})
Start value	0.005–20.00 x I_{0N} (up to 8.00 for inputs other than I_{0Calc})
Start voltage	1–50 %U_{0N} (step 1%)
Mode	Non-directional/Sector/ResCap
Base angle setting range	-180°–179°
Operate angle	±88°
Definite time function: - Operate time	 0.10** – 300.00 s (step 0.02 s)
IDMT function: - Delay curve family - Curve type - Inv. time coefficient k	 (DT), IEC, IEEE, RI Prg EI, VI, NI, LTI, MI…, depends on the family* 0.025–20.0, except 0.50–20.0 for RI, IEEE and IEEE2
Start time	Typically 60 ms
Reset time	<95 ms
Reset ratio	<0.95
Reset ratio (angle)	2°
Inaccuracy:	
- Starting U_0 & I_0 (rated value In= 1–5A)	±3% of the set value or ±0.3% of the rated value
- Starting U_0 & I_0 (Peak Mode when, rated value I_{0n}= 1–10A)	±5% of the set value or ±2% of the rated value (Sine wave <65 Hz)
- Starting U_0 & I_0 (I_{0Calc})	±3% of the set value or ±0.5% of the rated value
- Angle	±2° when U> 1V and I_0> 5% of I_{0N} or > 50 mA else ±20°
- Operate time at definite time function	±1% or ±30 ms
- Operate time at IDMT function	±5% or at least ±30 ms**

Table 6.38: Directional earth fault overcurrent $I_{0\varphi}$>>> (67N)

Input signal	I_0, U_0 I_{0Calc} (= I_{L1} + I_{L2} + I_{L3})
Start value	0.005 – 20.00 x I_{0N} (up to 8.00 for inputs other than I_{0Calc})
Start voltage	1 – 50 %U_{0N} (step 1%)
Mode	Non-directional/Sector/ResCap
Base angle setting range	-180° – 179°
Operation angle	±88°
Definite time function: - Operate time	 0.10** – 300.00 s (step 0.02 s)
IDMT function: - Delay curve family - Curve type - Inv. time coefficient k	 (DT), IEC, IEEE, RI Prg EI, VI, NI, LTI, MI…, depends on the family* 0.05 – 20.0, except 0.50 – 20.0 for RI, IEEE and IEEE2
Start time	Typically 60 ms
Reset time	<95 ms
Reset ratio	<0.95
Reset ratio (angle)	2°
Inaccuracy:	
- Starting U_0 & I_0 (rated value In= 1 – 5A)	±3% of the set value or ±0.3% of the rated value
- Starting U_0 & I_0 (Peak Mode when, rated value I_{0n}= 1 – 10A)	±5% of the set value or ±2% of the rated value (Sine wave <65 Hz)
- Starting U_0 & I_0 (I_{0Calc})	±3% of the set value or ±0.5% of the rated value
- Angle	±2° when U> 1V and I_0> 5% of I_{0N} or > 50 mA else ±20°
- Operate time at definite time function	±1% or ±30 ms
- Operate time at IDMT function	±5% or at least ±30 ms**

*) EI = Extremely Inverse, NI = Normal Inverse, VI = Very Inverse, LTI = Long Time Inverse, MI= Moderately Inverse

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operation time of the trip contacts.

6.26.1 Earth fault faulty phase detection algorithm

The earth fault overcurrent stage (ANSI 50N/51N) and directional earth fault overcurrent stage (ANSI 67N) have an inbuilt detection algorithm to detect a faulty phase. This algorithm is meant to be used in radial-operated distribution networks. The faulty phase detection can be used in solidly-earthed, impedance-earthed or resonant-earthed networks.

Operation

The faulty phase detection starts from the earth fault stage trip. At the moment of stage start, the phase currents measured prior to start are registered and stored as prior-to-fault currents. At the moment of trip, phase currents are registered again. Finally, faulty phase detection algorithm is performed by comparing prior-to-fault currents to fault currents. The algorithm also uses positive sequence current and negative sequence current to detect faulty phase.

The detection algorithm can be enabled and disabled by selecting or unselecting a checkbox in the protection stage settings. Correct network earthing configuration must be selected in the stage settings, too. In the earth fault overcurrent stage settings, you can select between RES and CAP network earthing configuration. This selection has no effect on the protection itself, only on the faulty phase detection. In the directional earth fault overcurrent stage settings, the detection algorithm uses the same network earthing type as selected for protection. RES is used for solidly-earther, impedance-earthed and resonant-earthed networks. CAP is only used for isolated networks.

The detected faulty phase is registered in the protection stage fault log (and also in the event list and alarm screen). Faulty phase is also indicated by a line alarm and line fault signals in the output matrix.

Possible detections of faulty phases are L1-N, L2-N, L3-N, L1-L2-N, L1-L3-N, L2-L3-N, L1-L2-L3-N, and REV. If the relay protection coordination is incorrect, REV indication is given in case of a relay sympathetic trip to a reverse fault.

6.27 Magnetishing inrush detection (ANSI 68F2)

Description

This stage is mainly used to block other stages. The ratio between the second harmonic component and the fundamental frequency component is measured on all the phase currents. When the ratio in any phase exceeds the setting value, the stage gives a start signal. After a settable delay, the stage gives a trip signal.

The start and trip signals can be used for blocking the other stages.

The trip delay is irrelevant if only the start signal is used for blocking.

The trip delay of the stages to be blocked must be more than 60 ms to ensure a proper blocking.

Block diagram

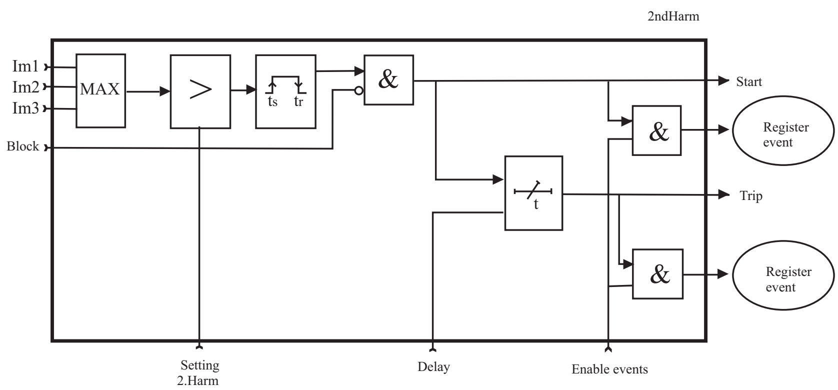


Figure 6.81: Block diagram of the magnetishing inrush dection stage

Characteristics

Table 6.39: Magnetishing inrush detection (68F2)

Input signal	$I_{L1} – I_{L3}$
Settings: - Start value - Operate time	 10 – 100 % (step 1%) 0.03 – 300.00 s (step 0.01 s)
Inaccuracy: - Starting	 ±1% - unit

NOTE: The amplitude of second harmonic content has to be at least 2% of the nominal of CT. If the nominal current is 5 A, the 100 Hz component needs to exceed 100 mA.

6.28 Fifth harmonic detection (ANSI 68H5)

Description

Overexiting a transformer creates odd harmonics. The fifth harmonic detection stage can be used detect overexcitation. This stage can also be used to block some other stages.

The ratio between the fifth harmonic component and the fundamental frequency component is measured on all the phase currents. When the ratio in any phase exceeds the setting value, the stage activates a start signal. After a settable delay, the stage operates and activates a trip signal.

The trip delay of the stages to be blocked must be more than 60 ms to ensure a proper blocking.

Characteristics

Table 6.40: Fifth harmonic detection (68H5)

Input signal	I_{L1} – I_{L3}
Settings: - Setting range over excitation - Operate time	 10 – 100 % (step 1%) 0.03 – 300.00 s (step 0.01 s)
Inaccuracy: - Starting	 ±2%- unit

6.29 Pole slip protection (ANSI 78)

NOTE: This protection stage is available only in the voltage measurement modes 3LN, 3LN + U_0, 3LN+LLy, and 3LN+LNy (see chapter Chapter 10.6 Voltage measurement modes).

Dynamic changes in a power system such as prolonged short circuits, load jumps or line switching operations may lead to power system oscillations know as power swings. A power swing manifests itself as regular large fluctuations in currents, voltages and power angles between power system parts.

In a stable power swing situation, power oscillations decay and diminish within few seconds. After a stable power swing, synchronism is recaptured and the system reaches new stable equilibrium conditions. Such a stable power swing should not cause a generator or power system part to be separated from the rest of the power system.

In an unstable power swing, power oscillations continue to grow eventually causing loss of synchronism or pole slipping. Pole slipping can very quickly result in generator overloading and damages. When a generator is working out of step or pole slipping occurs, the generator is alternatively producing generating and motoring action in a cycle of some seconds. This oscillation between the generating and motoring mode causes high mechanical stress to generator and prime mover and also high electrical overload. Unstable operation conditions may also cause propagation of disturbances in the power system leading to possible widespread outages. A generator under out-of-step condition must be separated from the rest of power system.

The generator may pole slip because of various reasons. A few most obvious reasons are:

- the prime mover of governor failure
- the failure in generator operating close to its stability limits
- prolonged clearance of low-impedance fault
- generator unsynchronized connection to a power system
- any disturbance in the network switching action

Pole slip protection principle

A common method to implement pole slipping protection is to measure the apparent impedance in the generator or block transformer terminals and track impedance vector trajectory in the RX plane. Apparent generator impedance measured on generator terminals (Point A) varies as a function of the power angle and ratio of the generator and power system voltages. Apparent impedance is plotted on the RX plane where a characteristic set of impedance loci is shown. The decision to separate the generator from the power system is based on an actual course of impedance vectors (loci) on the RX plane.

As pole slipping is essentially a symmetrical phenomenon, the apparent impedances are calculated from the positive sequences' fundamental frequency components of the voltages and currents.

A common practice to illustrate pole slipping is to use a simplified two-machine model. The following diagram shows the generator, power network and equivalent voltages $\underline{U}_G$ and $\underline{U}_N$. The generator, power network and possible transformer impedances lie between these two sources. Total system impedance Z_{tot} is the sum of component impedances $\underline{Z}_G$, $\underline{Z}_{TR}$ and $\underline{Z}_N$.

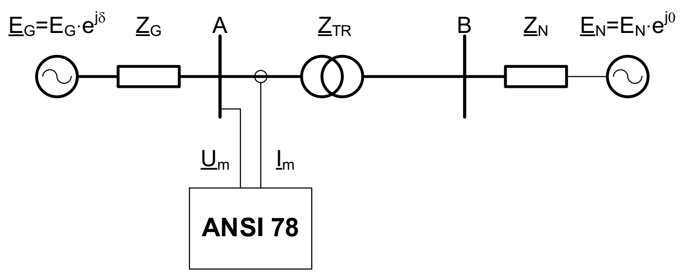


Figure 6.82: Two machine model of power swing

The following equations apply on location A:

Equation 6.11: Total impedance

$$\underline{Z}_{tot} = \underline{Z}_G + \underline{Z}_{TR} + \underline{Z}_N$$

Equation 6.12: Measured current, independent of location

$$\underline{I}_m = \underline{I} = \frac{\underline{E}_G - \underline{E}_N}{\underline{Z}_{tot}}$$

Equation 6.13: Measured voltage at location A

$$\underline{U}_m = \underline{E}_G - \underline{Z}_G \cdot \underline{I}$$

Equation 6.14: Measured apparent impedance

$$\underline{Z}_m = \frac{\underline{U}_m}{\underline{I}}$$

Substitute U_M and I with Equation 6.12 and Equation 6.13 in Equation 6.14.

Equation 6.15:

$$\underline{Z}_m = \frac{\underline{E}_G}{\underline{E}_G - \underline{E}_N} \cdot \underline{Z}_{tot} - \underline{Z}_G = \frac{\underline{Z}_{tot}}{1 - \frac{\underline{E}_N}{\underline{E}_G}} - \underline{Z}_G$$

As $\underline{E}_G = E_G \cdot e^{-j\delta}$ and $\underline{E}_N = E_N \cdot e^{-j0} = E_N$, Equation 6.15 becomes as

Equation 6.16:

$$\underline{Z}_m = \frac{\underline{Z}_{tot}}{1 - \frac{E_N}{E_G} \cdot e^{j\delta}} - \underline{Z}_G$$

Equation 6.16 represents the impedance behavior of a two-machine model in the pole slipping condition. Plotting impedances on the RX plane as a function of power angle δ and voltage ratio E_N/E_G gives a set of impedance loci representing apparent impedance behavior with the given power angle δ and voltage ratio E_N/E_G.

In stable operation conditions, the power angle δ depends on the generator load and it is essentially constant. In stable operation conditions, the power angle δ varies between 30° and 60° depending on the generator load. During pole slipping, the power angle δ can vary between 0° and 360° and therefore, impedance behavior according to Equation 6.16 should be plotted with a power angle ranging from 0° to 360°. While plotting impedance loci, the voltage ratio E_N/E_G is assumed to be constant during the pole slip, resulting in a circular impedance loci.

Figure 6.83 represents the general concept of apparent impedance behavior during the pole slip.

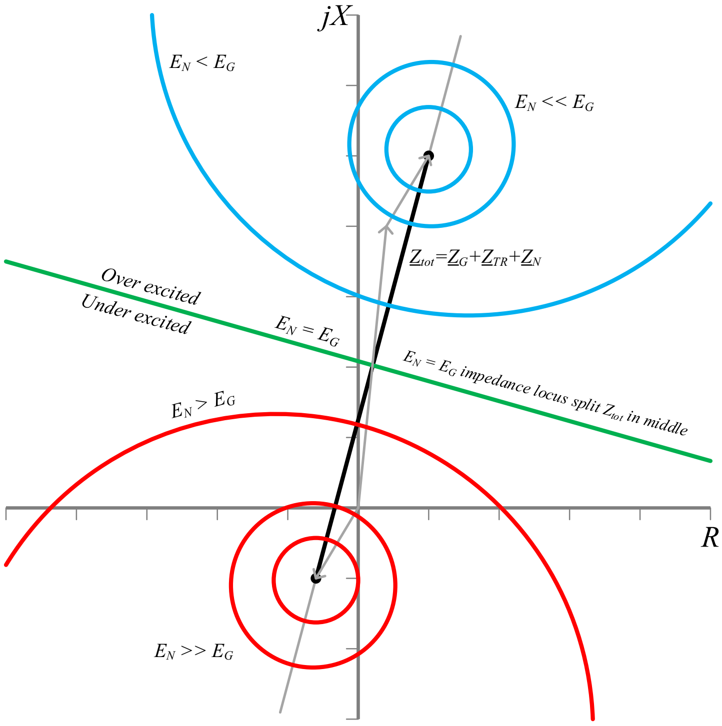


Figure 6.83: Pole slipping impedance loci

Protection settings

The pole slip protection stage has a rectangular power swing detection characteristic that is set by forward and reverse R and X. The setting values are given as relative to the generator nominal impedance. As the measured apparent impedance locus passes the set power swing characteristic, the pole slip is detected and count. The pole slip is counted only if the positive sequence current exceeds the minimum threshold value.

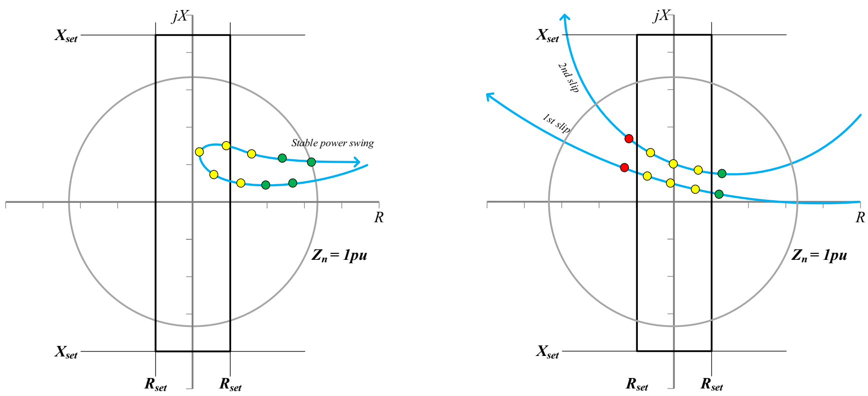


Figure 6.84: Stable and unstable power swing (pole slip) in reference to the detection characteristics

The first detected pole slip starts the stage counter. If the required number of pole slips occurs within the set time window, the stage trips. The tripping pulse has a fixed length of 100 ms. Figure 6.85 shows the stage starting and tripping actions.

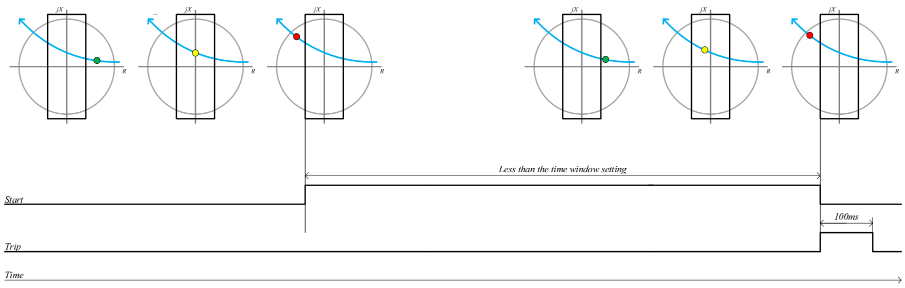


Figure 6.85: Pole slip protection stage starting and tripping

Finding out the settings

Plotting Equation 6.16 in the RX plan when E_N=E_G and adding total impedance line Ztot together with two lines connecting the swing center line and both source impedances gives a graphical presentation of the E_N/E_G ratio and power angle δ. This graphical presentation is a great aid in determining the out-of-step stage setting.

Figure 6.86 shows the impedance swing locus, source impedances connected with total impedance vector Z_{tot} and three points on swing trajectory representing three different generator operating conditions.

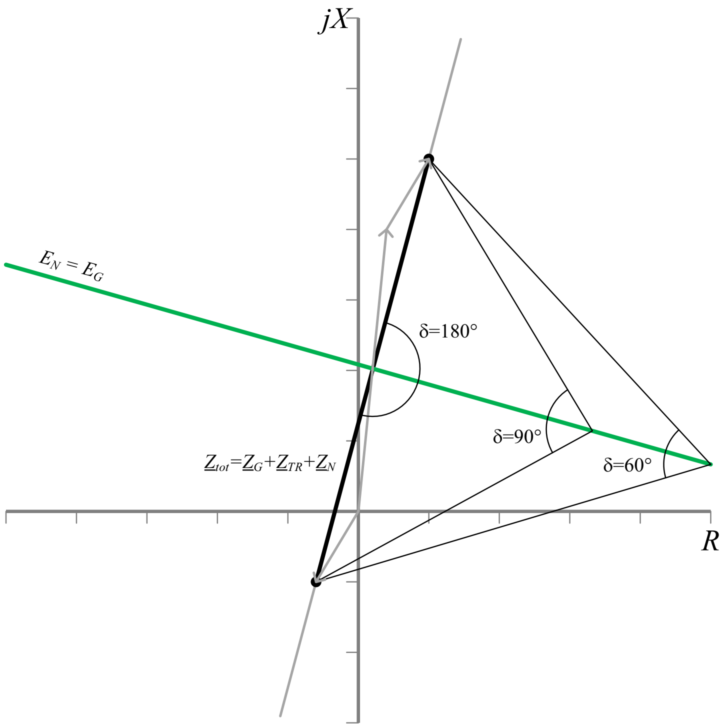


Figure 6.86: Total impedance line and swing center line in RX plane

The rightmost operating point identifies the operating point where the power angle δ=60°. This can be considered to be within an acceptable power angle range. Therefore, the stage setting should rule out this operating point.

The operating point δ=90° is the stability limit of the two-machine model shown in Figure 6.82. Setting R_{set} according to δ=90° is a good candidate for the setting point. To have some safety margin, a somewhat bigger power angle δ can be selected.

The last operating point in Figure 6.86 indicates the moment of E_N and E_G phase reversal. Initiating circuit breaker trip command when E_N and E_G are in phase reversal results in CB opening in the moment of the highest load. This should be avoided.

Reactance settings of the stage are defined in accordance of source reactance and transformer and line reactance. In pole slipping conditions, the generator synchronous impedance X_d is not valid but transient impedance X'_d should be used. In source direction reactance, a setting of $2X'_d$ can be used and in line direction, the setting value can be set in a range of 1–1.5 x X_{TR}. Figure 6.87 shows the setting values for the out-of-step stage.

Pole slip frequency is a characteristic property of the power system that is determined by generator torque and inertia. Slip frequency can not be determined analytically but utilizing transient stability studies. The slip frequency is not constant. From the protection point of view, the start of pole slipping it the most important moment. At the first moment of an unstable power swing, the slipping frequency may be in a range of 0.5–2.5Hz.

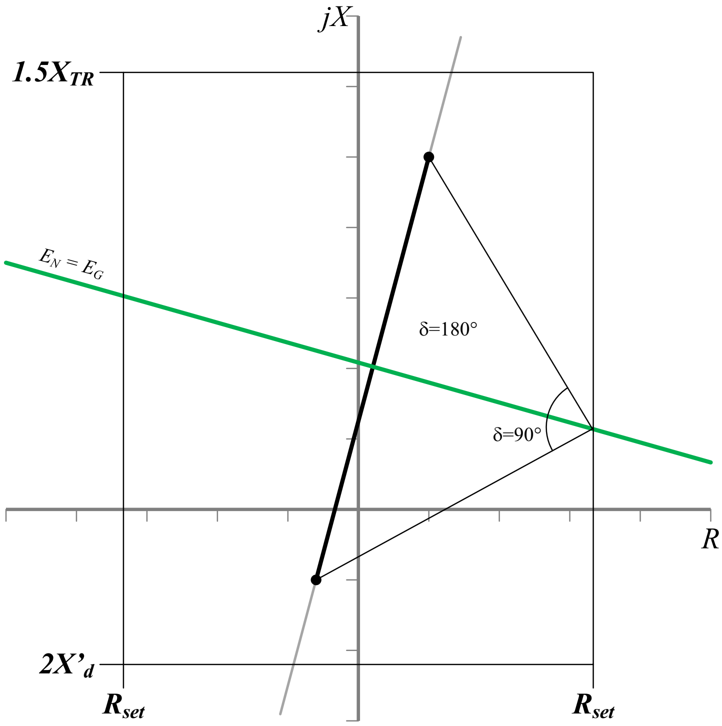


Figure 6.87: Pole slip stage setting principles

Setting groups

There are four setting groups available for each stage.

Characteristics

Table 6.41: Pole slipping stage (78)

R setting forward	0.10 – 1.00 xZ_N
R setting reverse	0.10 – 1.00 xZ_N
X setting reverse	0.10 – 1.00 xZ_N
X setting reverse	0.10 – 1.00 xZ_N
I1 min setting	0.10 – 1.00 xZ_N
Number of pole slips	1 – 10
Time window	0.10 – 600.0 s

6.30 Overfrequency and underfrequency (ANSI 81)

Description

Frequency protection is used for load sharing, loss of power system detection and as a backup protection for overspeeding.

The frequency function measures the frequency from the two first voltage inputs. At least one of these two inputs must have a voltage connected to be able to measure the frequency. Whenever the frequency crosses the start setting of a particular stage, this stage starts, and a start signal is issued. If the fault remains on longer than the operating delay setting, a trip signal is issued. For situations where no voltage is present, an adapted frequency is used.

Protection mode for f>< and f>><< stages

These two stages can be configured either for overfrequency or for underfrequency.

Undervoltage self-blocking of underfrequency stages

The underfrequency stages are blocked when the biggest of the three line-to-line voltages is below the low-voltage block limit setting. With this common setting, LVBlk, all stages in underfrequency mode are blocked when the voltage drops below the given limit. The idea is to avoid purposeless alarms when the voltage is off.

Initial self-blocking of underfrequency stages

When the biggest of the three line-to-line voltages has been below the block limit, the underfrequency stages are blocked until the start setting has been reached.

Four independent frequency stages

There are four separately adjustable frequency stages: f><, f>><<, f<, f<<. The two first stages can be configured for either overfrequency or underfrequency usage. So totally four underfrequency stages can be in use simultaneously. Using the programmable stages even more can be implemented (chapter Chapter 6.35 Programmable stages (ANSI 99)). All the stages have definite operate time delay (DT).

Setting groups

There are four setting groups available for each stage.

Characteristics

Table 6.42: Overfrequency and underfrequency f><, f>><< (81H/81L)

Input signal	$U_{L1} – U_{L3}$
Frequency measuring area	16.0 – 75.0 Hz
Current and voltage meas. range	45.0 – 65.0 Hz
Frequency stage setting range	40.0 – 70.0 Hz (step 0.01)
Low voltage blocking	10 – 100 %U_N
Definite time function: -Operate time	 0.10** – 300.0 s (step 0.02 s)
Start time	< 100 ms
Reset time	<120 ms
Reset ratio (LV block)	Instant (no hysteresis)
Inaccuracy: - Starting - Starting (LV block) - operate time	 ±20 mHz 3% of the set value or ±0.5 V ±1% or ±30 ms

NOTE: If the relay restarts for some reason, there is no trip even if the frequency is below the set limit during the start-up (Start and trip is blocked). To cancel this block, frequency has to rise above the set limit.

Table 6.43: Underfrequency f<, f<< (81L)Underfrequency stages f<, f<< (81L)

Input signal	$U_{L1} – U_{L3}$
Frequency measuring area	16.0 – 75.0 Hz
Current and voltage meas. range	45.0 – 65.0 Hz
Frequency stage setting range	40.0 – 64.0 Hz
Low voltage blocking	10 – 100 %U_N
Definite time function: -operate time	 0.10** – 300.0 s (step 0.02 s)
Undervoltage blocking	2 – 100 %
Start time	< 100 ms
Reset time	<120 ms
Reset ratio	>1.002
Reset ratio (LV block)	Instant (no hysteresis)
Inaccuracy: - Starting - starting (LV block) - operate time	 ±20 mHz 3% of the set value or ±0.5 V ±1% or ±30 ms

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

6.31 Rate of change of frequency (ANSI 81R)

Description

The rate of change of frequency (ROCOF or df/dt) function is used for fast load shedding, to speed up operate time in overfrequency and underfrequency situations and to detect loss of grid. For example, a centralized dedicated load shedding relay can be omitted and replaced with distributed load shedding, if all outgoing feeders are equipped with Easergy P3 relays.

A special application for ROCOF is to detect loss of grid (loss of mains, islanding). The more the remaining load of the local generator differs from the load before the loss of grid, the better the ROCOF function detects the situation.

Frequency behaviour during load switching

Load switching and fault situations may generate change in frequency. A load drop may increase the frequency and increasing load may decrease the frequency, at least for a while. The frequency may also oscillate after the initial change. After a while, the control system of any local generator may drive the frequency back to the original value. However, in case of a heavy short-circuit fault or if the new load exceeds the generating capacity, the average frequency keeps on decreasing.

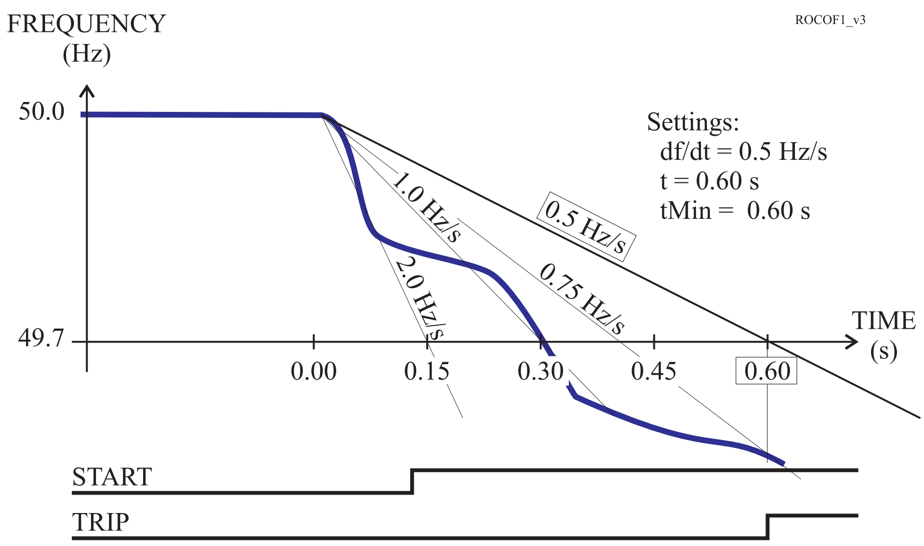


Figure 6.88: An example of definite time df/dt operate time. At 0.6 s, which is the delay setting, the average slope exceeds the setting 0.5 Hz/s and a trip signal is generated.

ROCOF implementation

The ROCOF function is sensitive to the absolute average value of the time derivate of the measured frequency |df/dt|. Whenever the measured frequency slope |df/dt| exceeds the setting value for 80 ms time, the ROCOF stage starts and issues a start signal after an additional 60 ms delay. If the average |df/dt|, since the start moment, still exceeds the setting, when the operation delay has elapsed, a trip signal is issued. In this definite time mode the second delay parameter "minimum delay, t_{MIN}" must be equal to the operation delay parameter "t".

If the frequency is stable for about 80 ms and the time t has already elapsed without a trip, the stage resets.

ROCOF and overfrequency and underfrequency stages

One difference between the overfrequency and underfrequency and the df/dt function is the speed. Often a df/dt function can predict an overfrequency or underfrequency situation and is thus faster than a simple overfrequency or underfrequency function. However, in most cases, standard overfrequency and underfrequency stages must be used together with ROCOF to ensure tripping also if the frequency drift is slower than the slope setting of ROCOF.

Definite operate time characteristics

Figure 6.88 shows an example where the df/dt start value is 0.5 Hz/s and the delay settings are t = 0.60 s and t_{MIN} = 0.60 s. Equal times t = t_{MIN} gives a definite time delay characteristic. Although the frequency slope fluctuates, the stage does not release but continues to calculate the average slope since the initial start. At the defined operate time, t = 0.6 s, the average slope is 0.75 Hz/s. This exceeds the setting, and the stage trips.

At slope settings less than 0.7 Hz/s, the fastest possible operate time is limited according to the Figure 6.89.

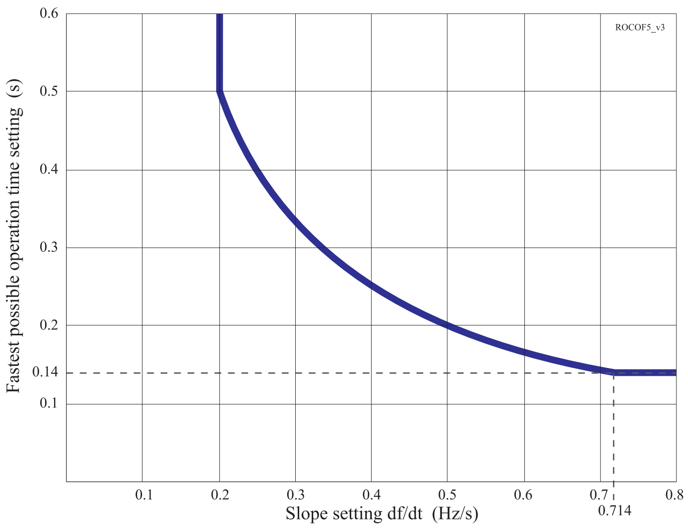


Figure 6.89: At very sensitive slope settings the fastest possible operate time is limited.

Dependent operate time characteristics

By setting the second delay parameter t_{MIN} smaller than the operate time delay t, a dependent type of operate time characteristic is achieved.

Figure 6.91 shows one example, where the frequency behaviour is the same as in the first figure, but the t_{MIN} setting is 0.15 s instead of being equal to t. The operate time depends on the measured average slope according to the following equation:

Equation 6.17:

$$t_{TRIP} = \frac{s_{SET} \cdot t_{SET}}{|s|}$$

t_{TRIP} = Resulting operate time (seconds).

s_{SET} = df/dt i.e. slope setting (hertz/seconds).

t_{SET} = Operate time setting t (seconds).

s = Measured average frequency slope (hertz/seconds).

The minimum operate time is always limited by the setting parameter t_{MIN}. In the example, the fastest operate time, 0.15 s, is achieved when the slope is 2 Hz/s or more. The leftmost curve in Figure 6.90 shows the dependent characteristics with the same settings as in Figure 6.91.

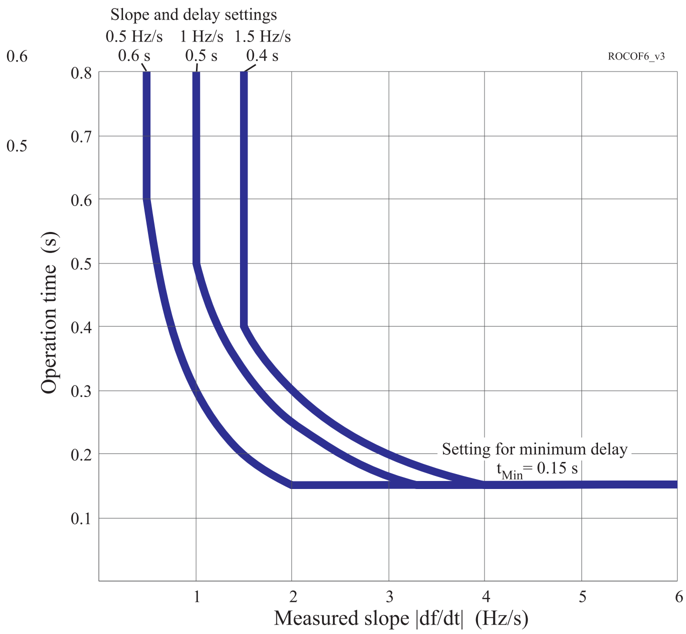


Figure 6.90: Three examples of possible dependent df/dt operate time characteristics. The slope and operation delay settings define the knee points on the left. A common setting for tMin has been used in these three examples. This minimum delay parameter defines the knee point positions on the right.

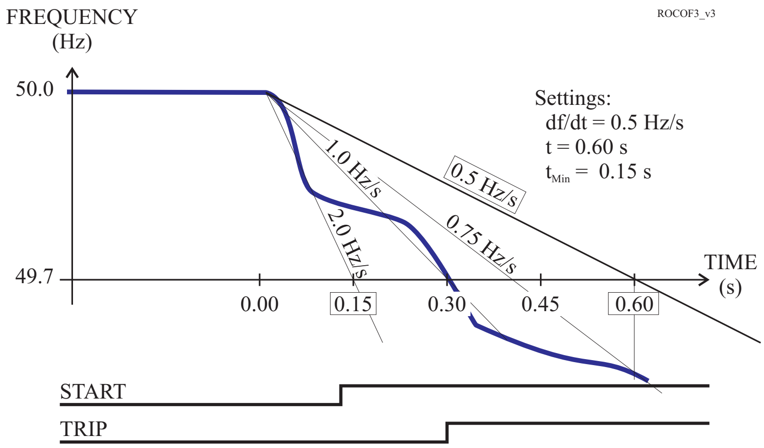


Figure 6.91: An example of dependent df/dt operate time. The time to trip will be 0.3 s, although the setting is 0.6 s, because the average slope 1 Hz/s is steeper than the setting value 0.5 Hz/s.

Setting groups

There are four setting groups available.

Characteristics

Table 6.44: Rate of change of frequency df/dt> (81R)

Start setting df/dt	0.2 – 10.0 Hz/s (step 0.1 Hz/s)
Definite time delay (t> and t_{Min}> are equal): - Operate time t>	 0.14** – 10.00 s (step 0.02 s)
Dependent time delay (t> is more than t_{Min}>): - Minimum operate time t_{Min}>	 0.14** – 10.00 s (step 0.02 s)
Start time	Typically 140 ms
Reset time	150 ms
Overshoot time	< 90 ms
Reset ratio	1
Inaccuracy: - Starting - Operate time(overshoot ≥ 0.2 Hz/s)	 10% of set value or ±0.1 Hz/s ±35 ms, when area is 0.2 – 1.0 Hz/s

NOTE: ROCOF stage is using the same low voltage blocking limit as the frequency stages.

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

6.32 Lockout (ANSI 86)

Description

The lockout feature, also called latching, can be programmed for outputs in the OUTPUT MATRIX setting view. Any protection stage start or trip, digital input, logic output, alarm and GOOSE signal connected to the following outputs can be latched when required:

- output contacts T1 – T7, A1
- LEDs on the front panel
- virtual outputs VO1- VO20

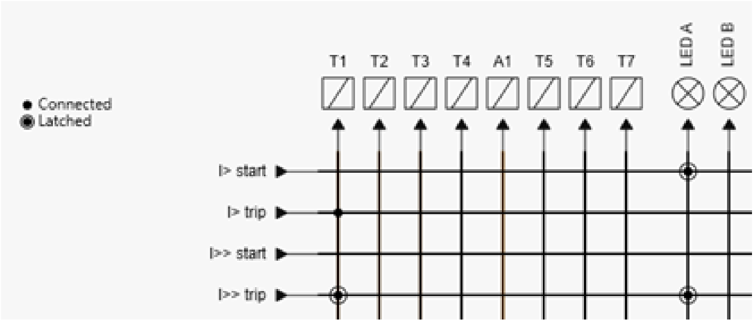


Figure 6.92: The lockout programmed for LED A and I>> trip signals. The latched signal is identified with a dot and circle in the matrix signal line crossing.

The lockout can be released through the display or via the Easergy Pro. See Chapter 5 Control functions.

Set the relay output, LED and virtual output latches to restore to their original state detected before the power off by selecting the **Store latch state** checkbox in the **General > Release latches** setting view.

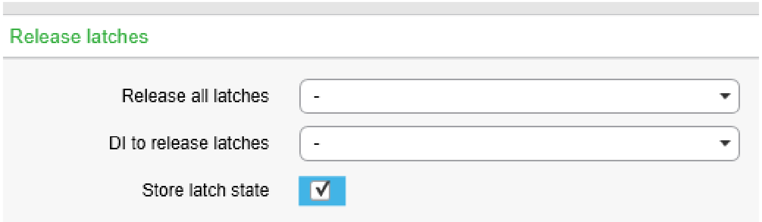


Figure 6.93: Store latch setting view

6.33 Differential overcurrent protection (ANSI 87M)

Description

The differential overcurrent protection comprises of two separately adjustable stages, stage ΔI> and stage ΔI>>.

The differential protection is based on the winding currents' difference between IL and I'L side. In a Yy0 connection, the measured currents are also winding currents, see Figure 6.94. In pure generator applications, the connection group is always Yy0. But should the generator also have a block transformer, the connection group is dependent on both the generator and transformer groups.

WindingCurrent1

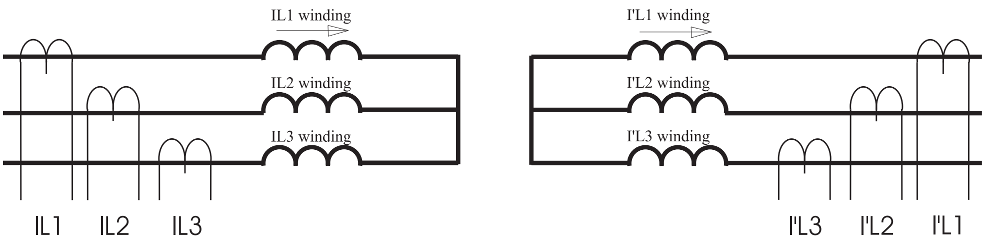


Figure 6.94: Winding currents in connection group Yy0

In the second example, if the transformer IL side is connected to open delta for example Dy11, then the winding currents are calculated on the delta side (IL side), see Figure 6.95.

WindingCurrent2

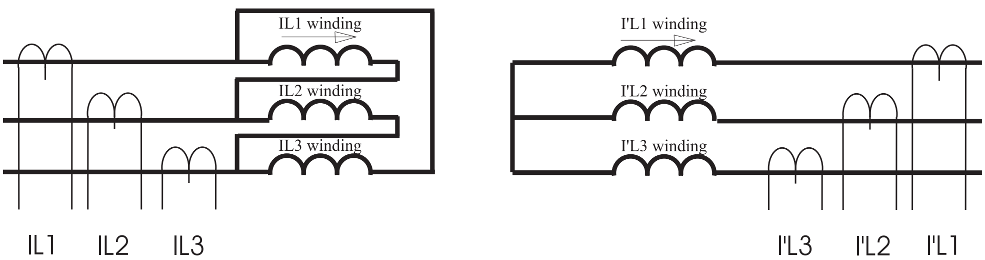


Figure 6.95: Winding currents in connection group Dy11

Equation 6.18: Winding current calculation in delta side, Dy11 connection

$$\frac{\overline{I_{L1W}} = \left(\overline{I_{L1}} - \overline{I_{L2}}\right)}{\sqrt{3}}$$

$$\frac{\overline{I_{L2W}} = \left(\overline{I_{L2}} - \overline{I_{L3}}\right)}{\sqrt{3}}$$

$$\frac{\overline{I_{L3W}} = \left(\overline{I_{L3}} - \overline{I_{L1}}\right)}{\sqrt{3}}$$

Equation 6.19: Winding currents in star side, Dy11 connection

$$\overline{I'_{L1W}} = \overline{I'_{L1}}$$
$$\overline{I'_{L2W}} = \overline{I'_{L2}}$$
$$\overline{I'_{L3W}} = \overline{I'_{L3}}$$

Equation 6.20: Bias current

$$I_b = \frac{\left|\overline{I}_W\right| + \left|\overline{I}'_W\right|}{2}$$

Equation 6.21: Differential current

$$I_d = \left|\overline{I}_W + \overline{I}'_W\right|$$

Bias current calculation is only used in protection stage ΔI>. Bias current describes the average current flow in the transformer. Bias and differential currents are calculated individually for each phase.

If the transformer is earthed, for example having the connection group Dyn11, then zero current must be compensated before differential and bias current calculation. Zero current compensation can be selected individually for the IL and I’L side.

Table 6.45 describes the connection group and zero current compensation for different connection groups. If the protection area is only generator, then the connection group setting is always Yy0, see Table 6.46. Also the settings of Un and U’n are set to be the same, for example generator nominal voltage.

Table 6.45: Zero current compensation in transformer applications

Transformator	Relay setting		
Connection group	ConnGrp	Io cmps	I'o cmps
YNy0	Yy0	ON	OFF
YNyn0	Yy0	ON	ON
Yy0	Yy0	OFF	OFF
Yyn0	Yy0	OFF	ON
YNy6	Yy6	ON	OFF
YNyn6	Yy6	ON	ON
Yy6	Yy6	OFF	OFF
Yyn6	Yy6	OFF	ON
Yd1	Yd1	OFF	OFF
YNd1	Yd1	ON	OFF
Yd5	Yd5	OFF	OFF
YNd5	Yd5	ON	OFF
Yd7	Yd7	OFF	OFF
YNd7	Yd7	ON	OFF
Yd11	Yd11	OFF	OFF
YNd11	Yd11	ON	OFF
Dy1	Dy1	OFF	OFF
Dyn1	Dy1	OFF	ON
Dy5	Dy5	OFF	OFF
Dyn5	Dy5	OFF	ON
Dy7	Dy7	OFF	OFF
Dyn7	Dy7	OFF	ON
Dy11	Dy11	OFF	OFF
Dyn11	Dy11	OFF	ON

Table 6.46: Zero current compensation in generator applications

Genarator only	Relay setting		
	ConnGrp	Io cmps	I'o cmps
No earthing	Yy0	OFF	OFF

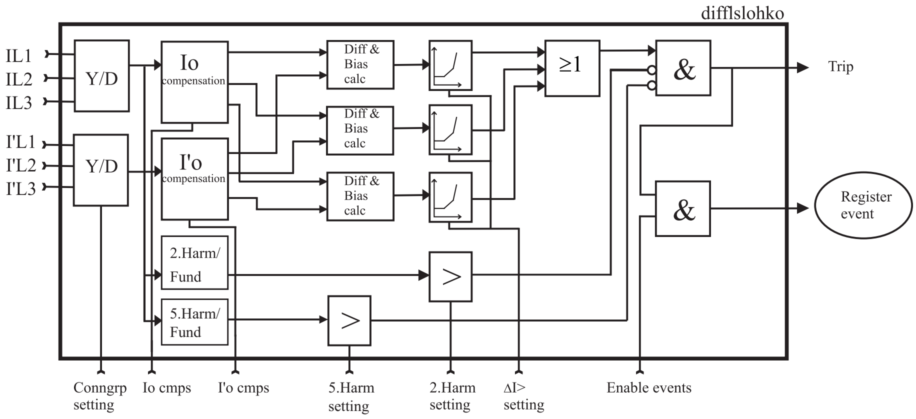


Figure 6.96: Block diagram of the differential overcurrent stage ΔI>

The stage ΔI> can be configured to operate as shown in Figure 6.97. This dual slope characteristic allows more differential current at higher currents before tripping.

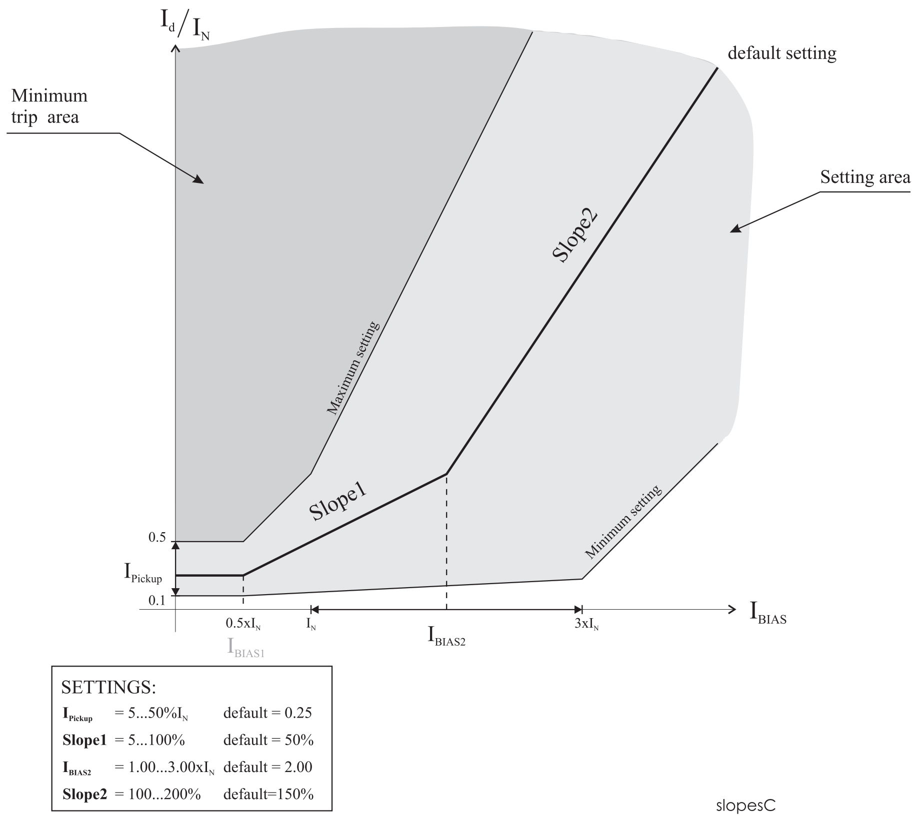


Figure 6.97: Example of differential overcurrent characteristics

The stage also includes second harmonic blocking. The second harmonic is calculated from winding currents. Harmonic ratio is:

100 x $I_{f2\_Winding}$ / $I_{f1\_Winding}$ [%].

The fast differential overcurrent stage ΔI>> does not include slope characteristics or second harmonics blocking.

Current transformer supervision

The current transformer supervision (CTS) feature is used to detect a failure of one or more of the phase current inputs to the relay. Failure of a phase CT or an open circuit of the interconnecting wiring can result in incorrect operation of any current-operated element. Additionally, interruption in the current circuit generates dangerous CT secondary voltages.

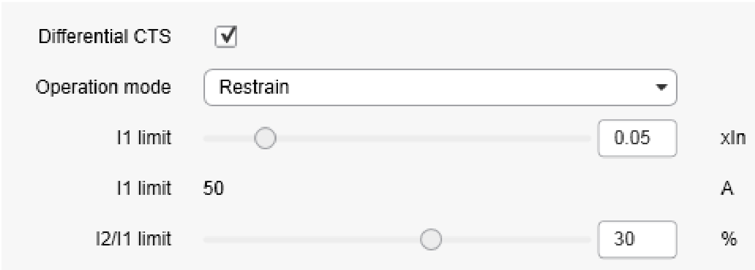


Figure 6.98: Current transformer supervision settings

The differential CTS method uses the ratio between positive and negative sequence currents at both ends of the protected line to determine a CT failure. This algorithm relies on ANSI85 communication and is inbuilt in the LdI> stage.

When this ratio is small (zero), one of four conditions is present:

- The system is unloaded – both I2 and I1 are zero
- The system is loaded but balanced – I2 is zero
- The system has a 3-phase fault – I2 is zero
- There is a 3-phase CT failure – unlikely to happen

When the ratio is non-zero, one of the following two conditions is present:

- The system has an asymmetric fault – both I2 and I1 are non-zero
- There is a 1 or 2 phase CT fault – both I2 and I1 are non-zero

The I2 to I1 ratio is calculated at both ends of the protected line. Both relays calculate their own ratio and the other end's ratio using their own measurements and measurements received via ANSI85. With this information, we can assume that:

- If the ratio is non-zero at both ends, there is a real fault in the network and the CTS should not operate.
- If the ratio is non-zero only at one end, there is a change of CT failure and the CTS should operate.

Another criterion for CTS is to check whether the differential system is loaded or not. For this purpose, the positive sequence current I1 is checked at both ends. If load current is detected only at one end, it is assumed that there is an internal fault condition and CTS is prevented from operating, but if load current is detected at both line ends, CTS operation is permitted.

There are three modes of operation:

- indication mode: CTS alarm is raised but there is no effect on tripping
- restrain mode: an alarm is raised and the differential current percentage setting value increased by 100 (for example 30 % + 100 % = 130 %). The new value is theoretically the maximum amount of differential current that a CT failure can produce in a normal full-load condition.
- block mode: an alarm is raised and differential protection is prevented from tripping

The differential CTS block mode is not recommended for two reasons:

- If there is a real fault during a CT failure, the differential protection would not protect the line at all.
- Blocking the protection could slow down the operate time of the differential protection because of transients in the beginning of the fault on the protected line.

Setting groups

This stage has one setting group.

Characteristics

Table 6.47: Differential overcurrent stage ΔI> (87)

Start value	5 – 50 % I_N
Bias current for start of slope 1	0.50 x I_N
Slope 1	5 – 100 %
Bias current for start of slope 2	1.00 – 3.00 x I_N
Slope 2	100 – 200 %
Second harmonic blocking	5 – 30 %, or disable
Fifth harmonic blocking	20 – 50 %, or disable
Reset time Reset ratio	< 95 ms 0.95
Inaccuracy:	
- Second harmonic blocking	±2% - unit
- Fifth harmonic blocking	±3% - unit
- Starting	±3% of set value or 0.02 x I_N when currents are < 200 mA
- Operate time (I_D > 1.2 x I_{SET})	< 60 ms
- Operate time (I_D > 3.5 x I_{SET})	< 50 ms

Table 6.48: Differential overcurrent stage ΔI>> (87)

Start value	5.0 – 40.0 x I_N
Reset time Reset ratio	< 95 ms 0.95
Inaccuracy:	
- Starting	±3% of set value or ±0.5% of rated value
- Operate time (I_D > 3.5 x I_{SET})	< 40 ms

6.34 Arc flash protection (AFD)

6.34.1 Arc flash protection, general principle

The arc flash protection contains 8 arc stages that can be used to trip for example the circuit breakers. Arc stages are activated with overcurrent and light signals (or light signals alone). The allocation of different current and light signals to arc stages is defined in arc flash protection matrices: current, light and output matrix. The matrices are programmed via the arc flash protection menus. Available matrix signals depend on the order code (see Chapter 13 Order code).

Available signal inputs and outputs for arc protection depend on the relay's hardware configuration.

6.34.2 Arc flash protection menus

The arc flash protection menus are located in the main menu under ARC. The ARC menu can be viewed either on the front panel, or by using Easergy Pro.

Arc protection

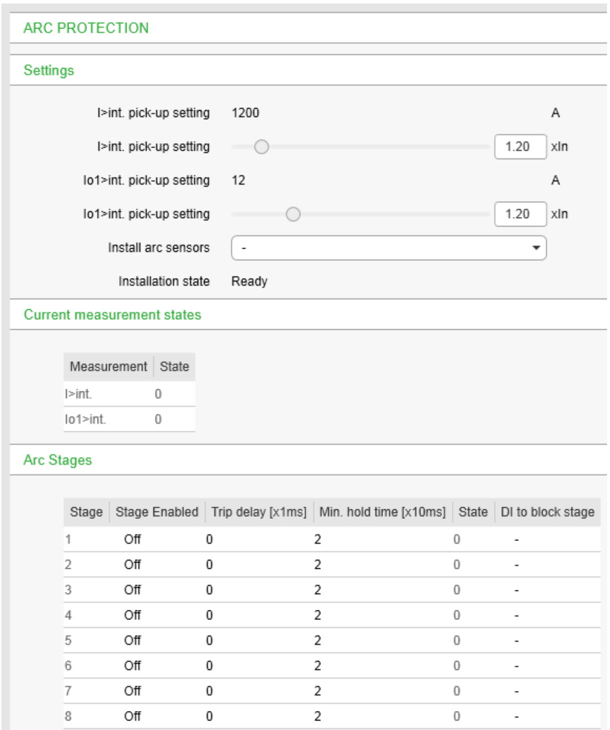


*Figure 6.99: Example view of **Arc protection***

Table 6.49: Arc priotection parameter group

Item	Default	Range	Description
I>int. start setting	1.00 xIn	0.50–8.00 x In	Phase L1, L2, L3 overcurrent start level
Io>int. start setting	1.00 xIn	0.10–5.00 x In	Residual overcurrent start level
Install arc sensors	-	-, Install	Installs all connected sensors
Installation state	Ready	Installing, Ready	Installation state
Link Arc selfdiag to SF relay	On	On, Off	Links Arc protection selfsupervision signal to SF relay
Stage Enabled	On or Off	On, Off	Enables the arc protection stage
Trip delay [ms]	0	0–255	Trip delay for the arc protection stage
Min. hold time [10ms]	2	2–255	Minimum trip pulse lenght for the arc protection stage (Overshoot time <35ms)

NOTE: Use trip delay for a separate arc stage as circuit breaker failure protection (CBFP).

Arc matrix – current

In the **Arc matrix – current** setting view, the available current signals (left column) are linked to the appropriate arc stages (1–8).

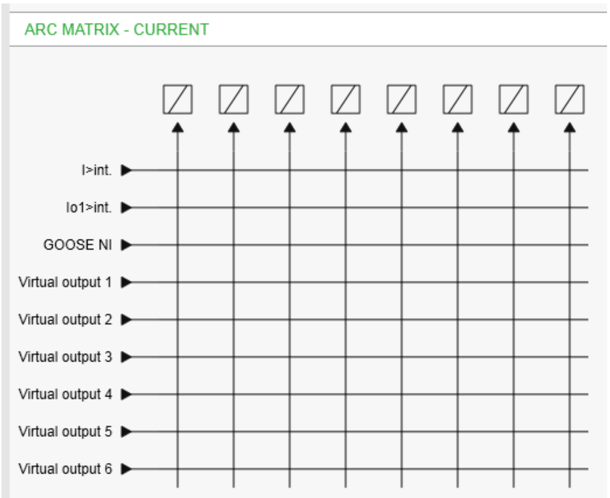


*Figure 6.100: Example view of**Arc matrix – current***

Table 6.50: Arc matrix – current parameter group

Item	Default	Range	Description
I>int.	-	On, Off	Phase L1, L2, L3 internal overcurrent signal
Io>int.	-	On, Off	Residual overcurrent signal
GOOSE NI	-	On, Off	Goose network input
Virtual output 1 – 6	-	On, Off	Virtual output
Arc stage 1 – 8	-	On, Off	Arc protection stage 1–8

Arc matrix – light

In the **Arc matrix – light** setting view, the available arc light signals (left column) are linked to the appropriate arc stages (1–8).

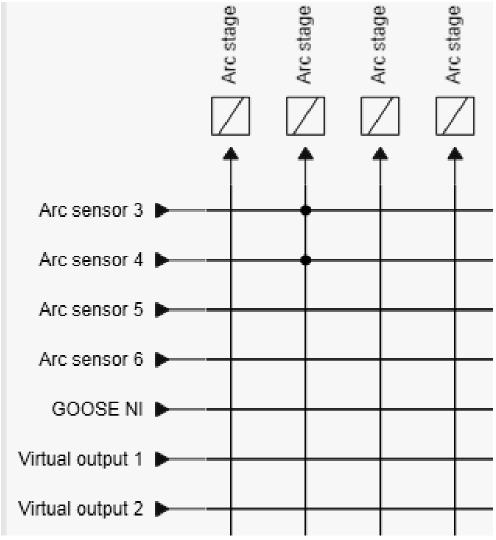


*Figure 6.101: Example view of **Arc matrix – light***

Table 6.51: Arc matrix – light parameter group

Item	Default	Range	Description
Arc_matrix_light	-	On, Off	Internal arc flash sensor 1–10
GOOSE NI	-	On, Off	Goose network input
Virtual output 1 – 6	-	On, Off	Virtual output
Arc stage 1 – 8	-	On, Off	Arc protection stage 1–8

Arc matrix – output

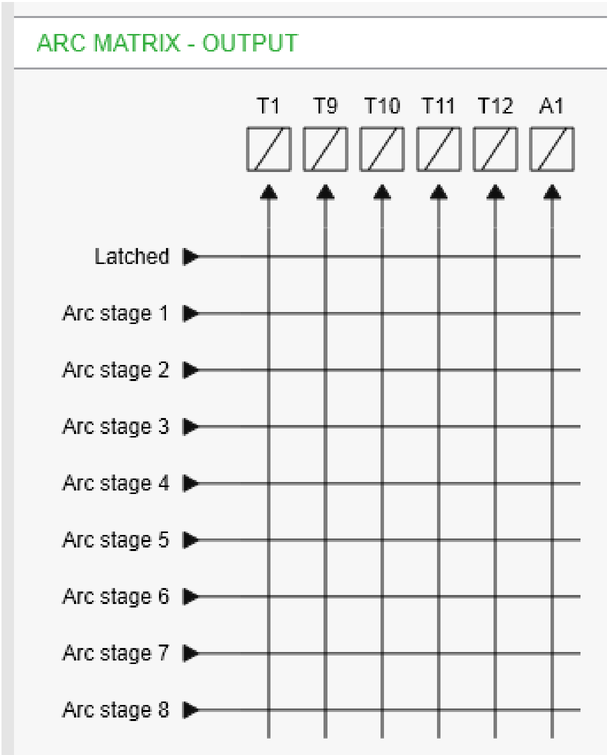


*Figure 6.102: Example view of **Arc matrix – output***

In the **Arc matrix – output** setting view, the used Arc stages (1–8) are connected to the required outputs. A possible latched function per output is also determined in this view. The available outputs depend on the order code.

The matrix connection done in the **Arc matrix – output** view also becomes visible in the output matrix.

Table 6.52: Arc matrix – output parameter group

Item	Default	Range	Description
Latched	-	On, Off	Output latch
Arc stage 1–8	-	On, Off	Arc protection stage 1–8
T1–4	-	On, Off	Trip digital output 1–4
A1	-	On, Off	Signal alarm relay 1

MATRIX correlation principle

When determining the activating conditions for a certain arc stage, a logical AND operator is made between the outputs from the arc light matrix and arc current matrix.

If an arc stage has selections in only one of the matrixes, the stage operates on a light-only or on current-only principle.

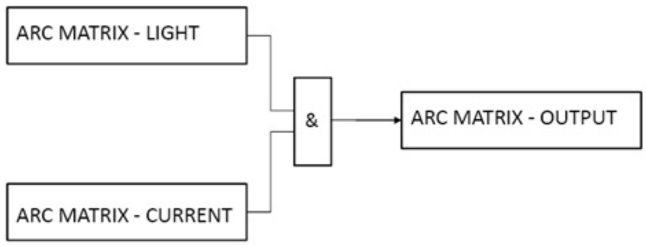


Figure 6.103: Matrix correlation principle with the logical AND operator

Arc event enabling

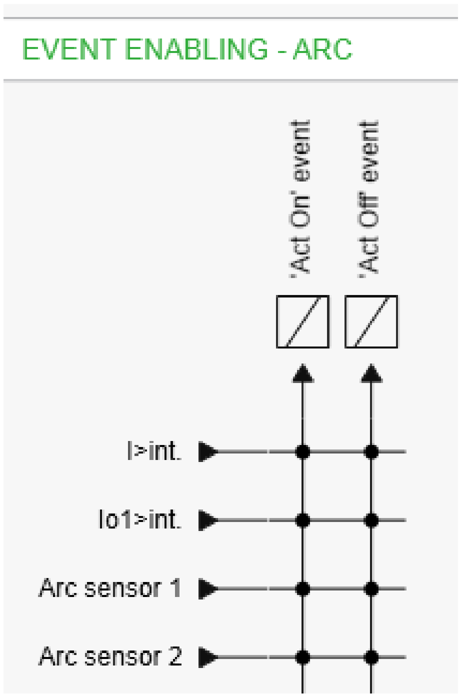


Figure 6.104: Example view of Arc event enabling

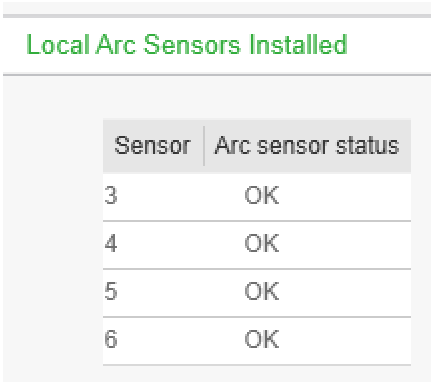
Table 6.53: Arc event enabling parameter group

Item	Default	Range	Description
I>int.	On	On, Off	Internal I overcurrent signal
Io>int.	On	On, Off	Internal Io overcurrent signal
Arc sensor 1 – 2	On	On, Off	Arc flash sensor 1–2
Arc stage 1 – 8	On	On, Off	Arc protection stage 1–8
‘Act On’ event	On	On, Off	Event enabling
‘Act Off’’ event	On	On, Off	Event enabling

6.34.3 Example of arc flash protection configuration

Installing the arc flash sensors

1. Go to **Protection > Arc protection**.
2. Under **Settings**, click the **Install arc sensors** drop-down list and select **Install**.
3. Wait until the **Installation state** shows **Ready**. The communication between the system components is created.
4. The installed sensors and units can be viewed at the bottom of the **ARC PROTECTION** group view.


Local Arc Sensors Installed

Sensor	Arc sensor status
3	OK
4	OK
5	OK
6	OK

On the Easergy Pro group list, select ARC PROTECTION.

5. Click the Arc Stages 1, 2, and select Stage 1 and 2 'On'.
6. Click the Trip delay[ms] value, set it to for example '0' and press Enter.
7. Click the DI block value, set it to for example '-' and press Enter.

Configuring the current start values

The **General > Scaling** setting view contains the primary and secondary values of the CT. However, the **Arc protection** menu calculates the primary value only after the **I start setting** value is given.

For example:

1. Go to **General > Scaling**.
2. Click the **CT primary** value, set it to for example *1200 A* and press **Enter**.
3. Click the **CT secondary** value, set it to for example *5 A* and press **Enter**.
4. On the Easergy Pro group list, select **Protection > Arc protection**.
5. Define the **I start setting** value for the relay.
6. Define the Io start setting in a similar manner.

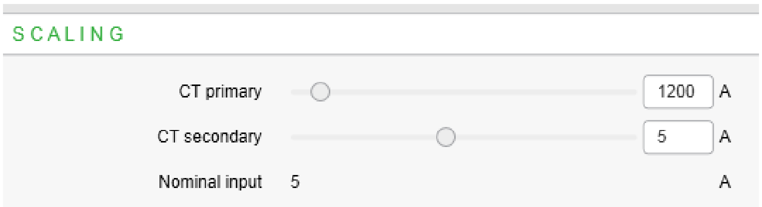


Figure 6.105: Example of setting the current transformer scaling values

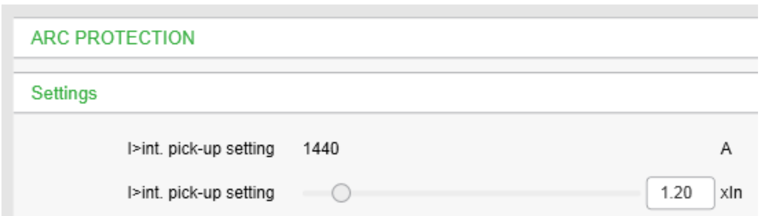


Figure 6.106: Example of defining the I start setting value

Configuring the current matrix

Define the current signals that are received in the arc flash protection system's relay. Connect currents to Arc stages in the matrix.

For example:

The arc flash fault current is measured from the incoming feeder, and the current signal is linked to **Arc stage 1** in the current matrix.

1. Go to **Matrix > Arc matrix - Current**
2. In the matrix, select the connection point of **Arc stage 1** and **I>int**.
3. On the **Communication** menu, select **Write Changed Settings To Device.**

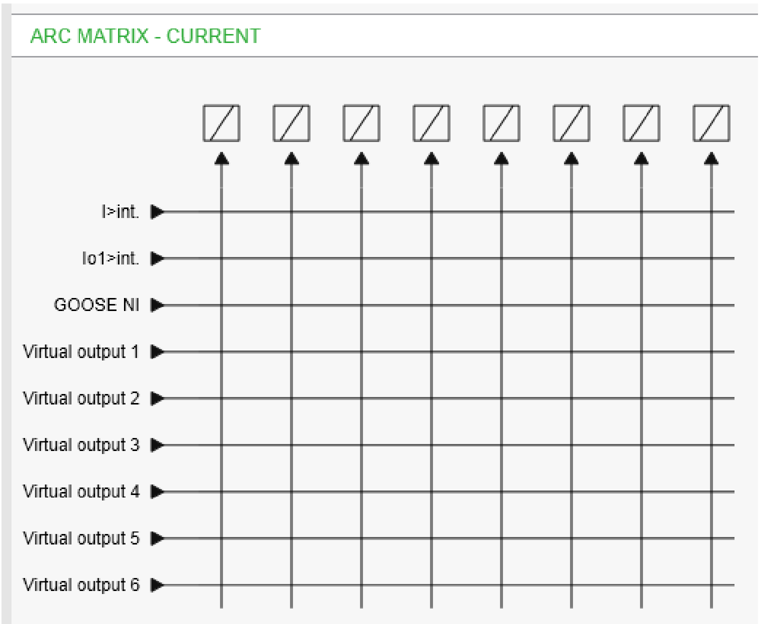


Figure 6.107: Configuring the current matrix – an example

Configuring the light matrix

Define what light sensor signals are received in the protection system. Connect the light signals to the arc stages in the matrix.

For example:

1. Go to **Matrix > Arc matrix - Light**
2. In the matrix, select the connection point of **Arc sensor 1** and **Arc stage 2**.
3. Select the connection point of **Arc sensor 2** and **Arc stage 2**.
4. On the **Communication** menu, select **Write Changed Settings To Device.**

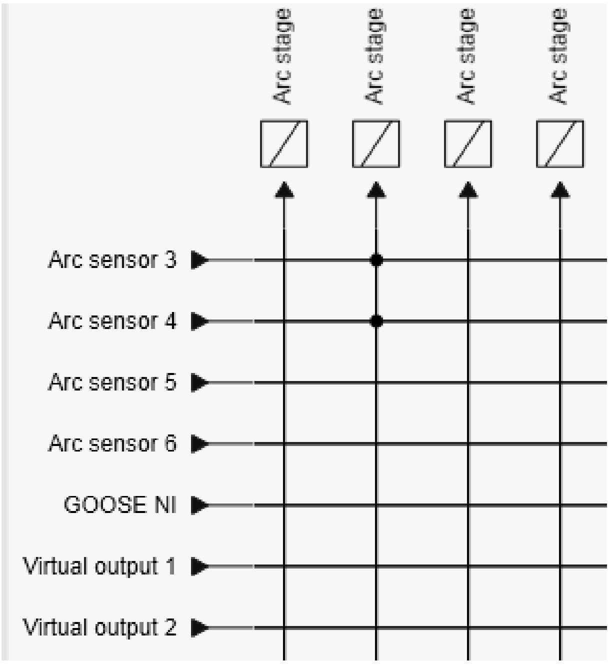


Figure 6.108: Configuring the light arc matrix

Configuring the output matrix

Define the trip relays that the current and light signals affect.
For example:

1. Go to **Matrix > Arc matrix - Output**
2. In the matrix, select the connection point of **Arc stage 1** and **T1**.
3. Select the connection points of **Latched** and **T1** and **T9**.
4. Select the connection point of **Arc stage 2** and **T9**.
5. On the **Communication** menu, select **Write Changed Settings To Device.**

NOTE: It is recommended to use latched outputs for the trip outputs.
Arc output matrix includes only outputs which are directly controlled by FPGA.

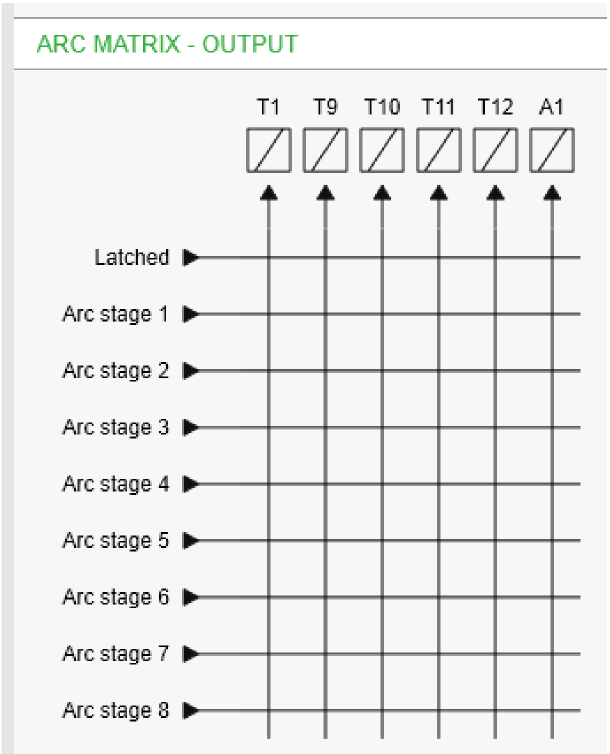


Figure 6.109: Configuring the output matrix - an example

Configuring the arc events

Define which arc events are written to the event list in this application. For example:

1. Go to **Logs > Event enabling - Arc**
2. In the matrix, enable both **‘Act On’ event** and **‘Act Off” event** for **Arc sensor 1**, **Arc stage 1**, and **Arc stage 2**.
3. On the **Communication** menu, select **Write Changed Settings To Device.**

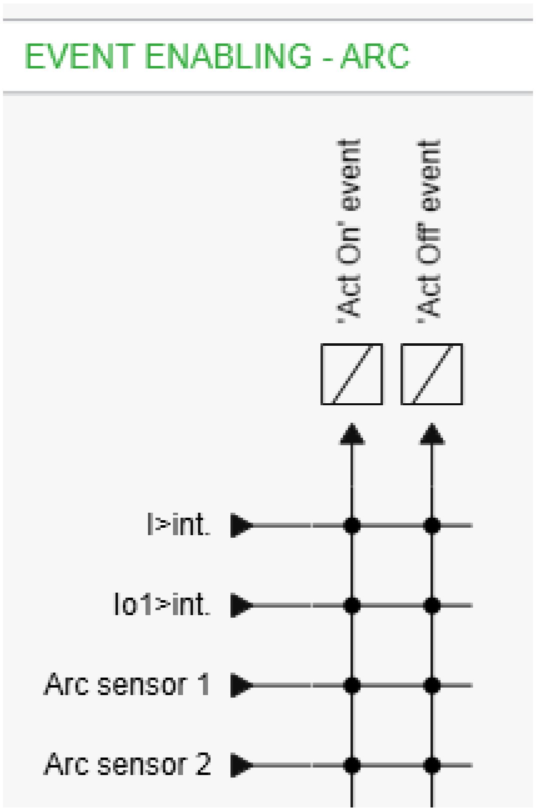


Figure 6.110: Configuring the arc events – an example

6.34.4 Arc fault protection (optional)

The operation of the arc protection depends on the setting value of the I> int and $I_0$1> int current limits.

The arc current limits cannot be set, unless the relay is provided with the optional arc protection card.

Characteristics

Table 6.54: Arc protection stage

Start value (I> int) Start value ($I_0$1> int)	0.5–8.0 x I_N 0.1–5.0 x In
Operate time - Light only - 4 x Iset and light - Arc stage delay	T1, T9–T12 ≤9 ms ≤9 ms 0 – 255 ms
Inaccuracy: - Starting (I> int, $I_0$1> int)	 10% of the set value

6.35 Programmable stages (ANSI 99)

Description

For special applications, you can build your own protection stages by selecting the supervised signal and the comparison mode.

The following parameters are available:

- **Priority**
  If operate times less than 80 milliseconds are needed, select 10 ms. For operate times under one second, 20 ms is recommended. For longer operation times and THD signals, 100 ms is recommended.
- **Coupling A**
  The selected supervised signal in “>” and “<” mode. The available signals are shown in the table below.
- **Coupling B**
  The selected supervised signal in "Diff" and "AbsDiff" mode. This selection becomes available once "Diff" or "AbsDiff" is chosen for Coupling A.
- **Compare condition**
  Compare mode. ‘>’ for over or ‘<’ for under comparison, “Diff” and “AbsDiff” for comparing Coupling A and Coupling B.
- **AbsDiff | d |**
  Coupling A – coupling B. The stage activates if the difference is greater than the start setting.
- **Diff d**
  Coupling A – coupling B. The stage activates if the sign is positive and the difference greater than the start setting.
- **Start**
  Limit of the stage. The available setting range and the unit depend on the selected signal.
- **Operation delay**
  Definite time operation delay
- **Hysteresis**
  Dead band (hysteresis). For more information, see Chapter 6.2 General features of protection stages.
- **No Compare limit for mode <**
  Only used with compare mode under (‘<’). This is the limit to start the comparison. Signal values under NoCmp are not regarded as fault.

Table 6.55: Available signals to be supervised by the programmable stages

IL1, IL2, IL3	Phase currents (RMS values)
Io	Earth fault overcurrent
U12, U23, U31	Line-to-line voltages
UL1, UL2, UL3	Line-to-neutral voltages
Uo	Neutral displacement voltage
f	Frequency
P	Active power
Q	Reactive power
S	Apparent power
Cos Phi	Cosine φ
IoCalc	Phasor sum $\underline{I}_{L1} + \underline{I}_{L2} + \underline{I}_{L3}$
I1	Positive sequence current
I2	Negative sequence current
I2/I1	Relative negative sequence current
I2/In	Negative sequence current in pu
U1	Positive sequence overvoltage
U2	Negative sequence overvoltage
U2/U1	Relative negative sequence voltage
IL	Average $(I_{L1} + I_{L2} + I_{L3)} / 3$
Tan Phi	Tangent φ [= tan(arccosφ)]
PRMS	Active power RMS value
QRMS	Reactive power RMS value
SRMS	Apparent power RMS value
THDIL1	Total harmonic distortion of I_{L1}
THDIL2	Total harmonic distortion of I_{L2}
THDIL3	Total harmonic distortion of I_{L3}
$THDU_A$	Total harmonic distortion of input U_A
$THDU_B$	Total harmonic distortion of input U_B
$THDU_C$	Total harmonic distortion of input U_C
fy	Frequency behind circuit breaker
fz	Frequency behind 2nd circuit breaker
IL1RMS	IL1 RMS for average sampling
IL2RMS	IL2 RMS for average sampling
IL3RMS	IL3 RMS for average sampling
ILmin, ILmax	Minimum and maximum of phase currents
ULNmin, ULNmax	Minimum and maximum of line-to-line voltages
VAI1, VAI2, VAI3, VAI4, VAI5	Virtual analog inputs 1, 2, 3, 4, 5 (GOOSE)

Signals available depending on slot 8 options.

Eight independent stages

The relay has eight independent programmable stages. Each programmable stage can be enabled or disabled to fit the intended application.

Setting groups

There are four settings groups available.

See Chapter 6.2 General features of protection stages for more details.

7 Supporting functions

7.1 Event log

Event log is a buffer of event codes and time stamps including date and time. For example, each start-on, start-off, trip-on or trip-off of any protection stage has a unique event number code. Such a code and the corresponding time stamp is called an event.

As an example, a typical event of programmable stage trip event is shown in Table 7.1.

Table 7.1: Example of Pgr1 stage trip on event and its visibility in local panel and communication protocols

EVENT	Description	Local panel	Communication protocols
Code: 01E02	Channel 1, event 2	Yes	Yes
Prg1 trip on	Event text	Yes	No
2.7 x In	Fault value	Yes	No
2007-01-31	Date	Yes	Yes
08:35:13.413	Time	Yes	Yes

Events are the major data for a SCADA system. SCADA systems are reading events using any of the available communication protocols. The Event log can also be scanned using the front panel or Easergy Pro. With Easergy Pro, the events can be stored to a file especially if the relay is not connected to any SCADA system.

Only the latest event can be read when using communication protocols or Easergy Pro. Every reading increments the internal read pointer to the event buffer. (In case of communication interruptions, the latest event can be reread any number of times using another parameter.) On the local panel, scanning the event buffer back and forth is possible.

Event enabling/masking

An uninteresting event can be masked, which prevents it to be written in the event buffer. By default, there is room for 200 latest events in the buffer. The event buffer size can be modified from 50 to 2000. The existing events are lost if the event buffer size is changed.

You can make this modification in the “Local panel conf” menu.

An indication screen (popup screen) can also be enabled in the same menu in Easergy Pro. The oldest event is overwritten when a new event occurs. The shown resolution of a time stamp is one millisecond, but the actual resolution depends on the particular function creating the event. For example, most protection stages create events with 5 ms, 10 ms or 20 ms resolution. The absolute accuracy of all time stamps depends on the relay's time synchronization. See Chapter 7.4 System clock and synchronization for system clock synchronizing.

Event buffer overflow

The normal procedure is to poll events from the relay all the time. If this is not done, the event buffer could reach its limits. In that case, the oldest event is deleted and the newest displayed with OVF (overflow) code on the front panel.

Table 7.2: Setting parameters for events

<table>
<tr><th>Parameter</th><th>Value</th><th>Description</th><th>Note</th></tr>
<tr><td>Count</td><td></td><td>Number of events</td><td></td></tr>
<tr><td>ClrEv</td><td>-
Clear</td><td>Clear event buffer</td><td>Set</td></tr>
<tr><td>Order</td><td>Old-New
New-Old</td><td>Order of the event buffer for local display</td><td>Set</td></tr>
<tr><td rowspan="3">FVScal</td><td></td><td>Scaling of event fault value</td><td rowspan="3">Set</td></tr>
<tr><td>PU</td><td>Per unit scaling</td></tr>
<tr><td>Pri</td><td>Primary scaling</td></tr>
<tr><td>Display
Alarms</td><td>On
Off</td><td>Indication dispaly is enabled
No indication display</td><td>Set</td></tr>
<tr><td rowspan="2">Sync</td><td></td><td>Controls event time format</td><td></td></tr>
<tr><td>On
Off</td><td>Event time shown normally if relay is synchronized
Event time is shown in brakets if relay is not synchronized</td><td></td></tr>
<tr><td colspan="4">FORMAT OF EVENTS ON THE LOCAL DISPLAY</td></tr>
<tr><td colspan="2">Code: CHENN</td><td colspan="2">CH = event channel, NN=event code (channel number is not shown in case channel is zero)</td></tr>
<tr><td colspan="2">Event description</td><td colspan="2">Event channel and code in plain text</td></tr>
<tr><td colspan="2">yyyy-mm-dd</td><td colspan="2">Date
(for available date formats, see Chapter 7.4 System clock and synchronization)</td></tr>
<tr><td colspan="2">hh:mm:ss.nnn</td><td colspan="2">Time</td></tr>
</table>

7.2 Disturbance recording

The disturbance recording can be used to record all the measured signals, that is, currents, voltage and the status information of digital inputs (DI) and digital outputs (DO). If the sample rate is slower than 1/10 ms, also the calculated signals like active power, power factor, negative sequence overcurrent and so on can be recorded. For a complete list of signals, see Table 7.3.

The digital inputs also include the arc protection signals.

The available recording channels depend on the voltage measurement mode, too. If a channel is added for recording and the added signal is not available because of the used settings, the signal is automatically rejected from the recording channel list.

Triggering the recording

The recording can be triggered by any start or trip signal from any protection stage, by a digital input, logic output or GOOSE signals. The triggering signal is selected in the output matrix (vertical signal DR). The recording can also be triggered manually. All recordings are time-stamped.

Reading recordings

The recordings can be uploaded with Easergy Pro program. The recording is in COMTRADE format. This also means that other programs can be used to view and analyse the recordings made by the relay.

Number of channels

A maximum of 12 records can be stored. Up to 12 channels per record can be stored. Both the digital inputs and the digital outputs (including all inputs and outputs) use one channel out of the total of 12.

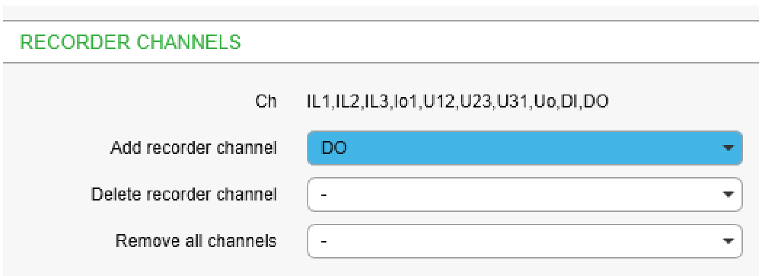


Table 7.3: Disturbance recording parameters

Parameter	Value	Unit	Description	Note
Mode			Behavior in memory full situation:	Set
	Saturated		No more recordings are accepted	
	Overflow		The oldest recording is overwritten	
SR			Sample rate	Set
	32/cycle		Waveform	
	16/cycle		Waveform	
	8/cycle		Waveform	
	1/10ms		One cycle value *)	
	1/20ms		One cycle value **)	
	1/200ms		Average	
	1/1s		Average	
	1/5s		Average	
	1/10s		Average	
	1/15s		Average	
	1/30s		Average	
	1/1min		Average	
Time		s	Recording length	Set
PreTrig		%	Amount of recording data before the trig moment	Set
MaxLen		s	Maximum time setting. This value depends on the sample rate, number and type of the selected channels and the configured recording length.	
ReadyRec			Readable recordings	
Status			Status of recording	
	-		Not active	
	Run		Waiting a triggering	
	Trig		Recording	
	FULL		Memory is full in saturated mode	
ManTrig	-, Trig		Manual triggering	Set
ReadyRec	n/m		n = Available recordings / m = maximum number of recordings The value of 'm' depends on the sample rate, number and type of the selected channels and the configured recording length.	

Parameter	Value	Unit	Description	Average	Waveform
AddCh			Add one channel. The maximum number of channels used simultaneously is 12.		
	IL1, IL2, IL3		Phase current	X	X
	I'L1, I'L2, I'L3		Phase current (IV side)	X	X
	Io1, Io2, Io3		Measured earth fault overcurrent	X	X
	U12, U23, U31		Line-to-line voltage	X	X
	UL1, UL2, UL3		Phase-to-neutral voltage	X	X
	Uo		Neutral displacement voltage	X	X
	f		Frequency	X	
	P, Q, S		Active, reactive, apparent power	X	
	P.F.		Power factor	X	
	CosPhi		cosφ	X	
	IoCalc		Phasor sum Io = (IL1+IL2+IL3)/3	X	
	I1		Positive sequence current	X	
	I2		Negative sequence current	X	
	I2/I1		Relative current unbalance	X	
	I2/Ign		Negative sequence overcurrent [x I_{GN}]	X	
	IL		Average (IL1 + IL2 + IL3) / 3	X	
	DI		Digital inputs: DI1–20, F1, F2, BIOin, VI1-4, Arc1, Arc2	X	X
	DI_2		Digital inputs: DI21–40	X	X
	DI_3		Virtual inputs: VI5–20, A1–A5, VO1–VO6	X	X
	DO		Digital outputs: T1–15	X	X
	DO_2		Rest of the outputs	X	X
	DO_3		Virtual outputs, VO7–VO20	X	X
	TanPhi		tanφ	X	
	THDIL1, THDIL2, THDIL3		Total harmonic distortion of IL1, IL2 or IL3	X	
	Prms		Active power rms value	X	
	Qrms		Reactive power rms value	X	
	Srms		Apparent power rms value	X	
	fy		Frequency behind circuit breaker	X	
	fz		Frequency behind 2nd circuit breaker	X	
	IL1RMS, IL2MRS, IL3RMS		IL1, IL2, IL3 RMS for average sampling	X	
	Arc***)		Arc protection signals	X	
	Starts		Protection stage start signals	X	X
	Trips		Protection stage trip signals	X	X
ClrCh	-, Clear		Remove all channels		

Set = An editable parameter (password needed).

*) This is the fundamental frequency rms value of one cycle updated every 10 ms.

**) This is the fundamental frequency rms value of one cycle updated every 20 ms.

***) Arc events are polled in every 5 ms.

Signal available depending on the slot 8 options.

NOTE: The selection of signals depends on the relay type, the used voltage connection and the scaling mode.

Characteristics

Table 7.4: Disturbance recording

Mode of recording	Saturated / Overflow
Sample rate: - Waveform recording - Trend curve recording	 32/cycle, 16/cycle, 8/cycle 10, 20, 200 ms 1, 5, 10, 15, 30 s 1 min
Recording time (one record)	0.1 s–12 000 min (According recorder setting)
Pre-trigger rate	0–100%
Number of selected channels	0–12
File format	IEEE Std C37.111-1999

The recording time and the number of records depend on the time setting and the number of selected channels.

Configuring the disturbance recorder

The disturbance recorder can be used to record all the measured signals, that is, currents, voltages and the status information of digital inputs (DI) and digital outputs (DO).

For this application example, select the channels and sample rate for the disturbance recorder.

1. go to **General > Disturbance recorder**.
2. Click the **Add recorder channel** drop-down list and select the channel IL1.
3. Similarly select the channels IL2, IL3, DO and Arc.
4. Click the **Sample rate** drop-down list and select the rate 1/20ms.

To download the disturbance recorder file, select **Tools > Download disturbance records**.

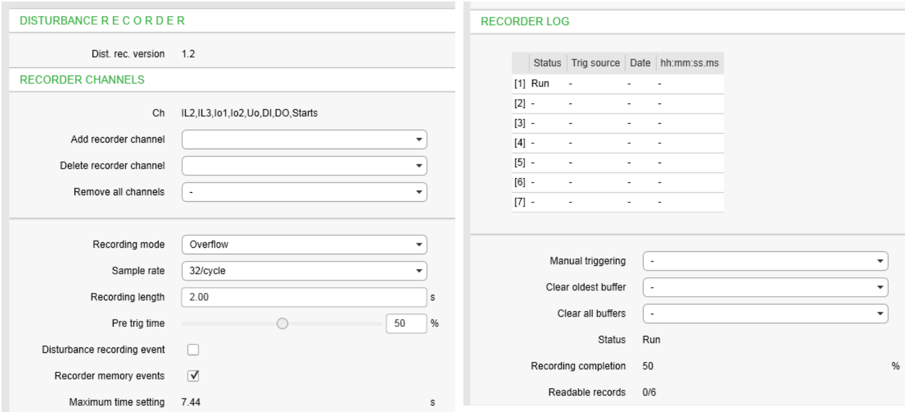


Figure 7.1: Configuring the disturbance recorder for the application example

Writing the setting to the relay

1. On the Easergy Pro toolbar, select **Write settings > Write all settings** to save the configuration in the relay.

NOTE: To save the relay's configuration information for later use, also save the Easergy Pro setting file on the PC.

Use WaweWin or another customer preferred tool to analyze disturbance recorder file.

Saving the setting file on your PC

1. On the Easergy Pro toolbar, click the **Save** icon. The **Save a file** window opens.
2. Browse to the folder where you want to save the file. Type a descriptive file name, and click **Save**.

NOTE: By default, the setting file *.epz is saved in the eSetup Easergy Pro folder.

7.3 Cold load start and magnetising inrush

Cold load start

A situation is regarded as cold load when all the three phase currents have been below a given idle value and then at least one of the currents exceeds a given start level within 80 ms. In such a case, the cold load detection signal is activated for the time set as **Maximum time** or until the measured signal returns below the value set as **Pickup current**. This signal is available for the output matrix and blocking matrix. Using virtual outputs of the output matrix setting group control is possible.

Application for cold load detection

Right after closing a circuit breaker, a given amount of overload can be allowed for a given limited time to take care of concurrent thermostat-controlled loads. The cold load start function does this, for example, by selecting a more coarse setting group for overcurrent stages. It is also possible to use the cold load detection signal to block any set of protection stages for a given time.

Magnetising inrush detection

Magnetising inrush detection is quite similar to the cold load detection but it also includes a condition for second harmonic content of the currents. When all phase currents have been below a given idle value and then at least one of them exceeds a given start level within 80 ms and the second harmonic ratio to fundamental frequency, I_{f2}/I_{f1}, of at least one phase exceeds the given setting, the inrush detection signal is activated. This signal is available for the output matrix and blocking matrix. Using virtual outputs of the output matrix setting group control is possible.

By setting the second harmonic start parameter for I_{f2}/I_{f1} to zero, the inrush signal will behave equally with the cold load start signal.

Application for inrush current detection

The inrush current of transformers usually exceeds the start setting of sensitive overcurrent stages and contains a lot of even harmonics. Right after closing a circuit breaker, the start and tripping of sensitive overcurrent stages can be avoided by selecting a more coarse setting group for the appropriate overcurrent stage with an inrush detect signal. It is also possible to use the detection signal to block any set of protection stages for a given time.

NOTE: Inrush detection is based on the fundamental component calculation which requires a full cycle of data for analyzing the harmonic content. Therefore, when using the inrush blocking function, the cold load start starting conditions are used for activating the inrush blocking when the current rise is noticed. If a significant ratio of second harmonic components is found in the signal after the first cycle, the blocking is continued. Otherwise, the second-harmonic-based blocking signal is released. Inrush blocking is recommended to be used on time-delayed overcurrent stages while the non-blocked instant overcurrent stage is set to 20 % higher than the expected inrush current. By this scheme, a fast reaction time in short circuit faults during the energization can be achieved while time-delayed stages are blocked by the inrush function.

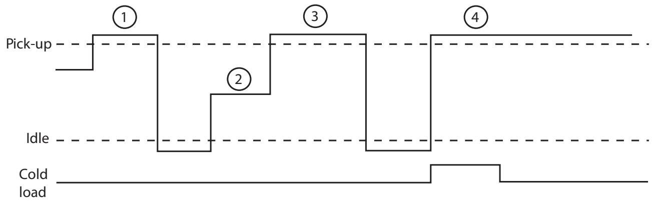


Figure 7.2: Functionality of cold load / inrush current feature.

1. No activation because the current has not been under the set I_{DLE} current.
2. Current dropped under the I_{DLE} current level but now it stays between the I_{DLE} current and the start current for over 80ms.
3. No activation because the phase two lasted longer than 80ms.
4. Now we have a cold load activation which lasts as long as the operate time was set or as long as the current stays above the start setting.

Characteristics

Table 7.5: Magnetizing inrush detection

Cold load settings: - Idle current - Start current - Maximum time	 0.01 – 0.50 x I_N 0.30 – 10.00 x I_N 0.01** – 300.00 s (step 0.01 s)
Inrush settings: - Start for 2nd harmonic	 0 – 99 %

**) This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

7.4 System clock and synchronization

Description

The relay's internal clock is used to time-stamp events and disturbance recordings.

The system clock should be externally synchronised to get comparable event time stamps for all the relays in the system.

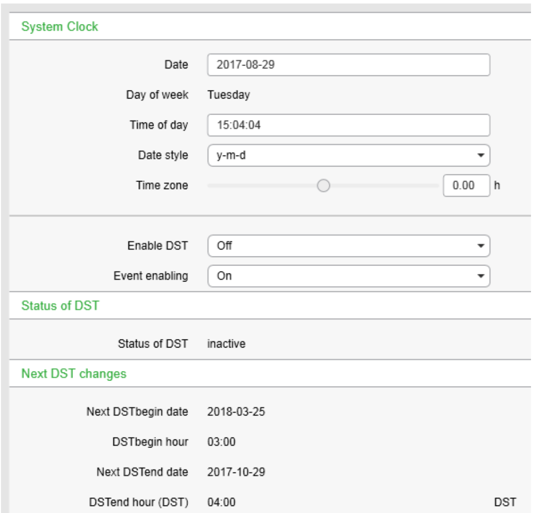
The synchronizing is based on the difference of the internal time and the synchronising message or pulse. This deviation is filtered and the internal time is corrected softly towards a zero deviation.

Time zone offsets

Time zone offset (or bias) can be provided to adjust the relay's local time. The offset can be set as a Positive (+) or Negative (-) value within a range of -15.00 to +15.00 hours and a resolution of 0.01/h. Basically, resolution by a quarter of an hour is enough.

Daylight saving time (DST)

The relay provides automatic daylight saving adjustments when configured. A daylight saving time (summer time) adjustment can be configured separately and in addition to a time zone offset.

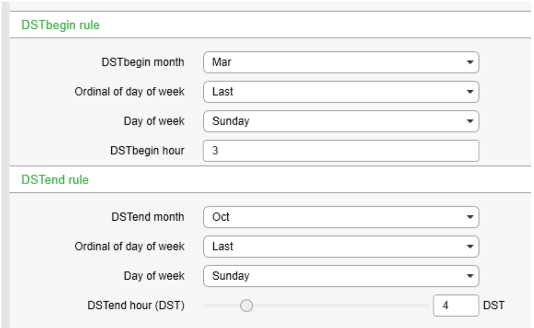


Daylight time standards vary widely throughout the world. Traditional daylight/summer time is configured as one (1) hour positive bias. The new US/Canada DST standard, adopted in the spring of 2007 is one (1) hour positive bias, starting at 2:00am on the second Sunday in March, and ending at 2:00am on the first Sunday in November. In the European Union, daylight change times are defined relative to the UTC time of day instead of local time of day (as in U.S.) European customers, carefully check the local country rules for DST.

The daylight saving rules are by default UTC +2:00 (24-hour clock):

- Daylight saving time start: Last Sunday of March at 03.00

- Daylight saving time end: Last Sunday of October at 04.00



To ensure proper hands-free year-around operation, automatic daylight time adjustments must be configured using the “Enable DST” and not with the time zone offset option.

Adapting the auto-adjust function

During tens of hours of synchronizing, the relay learns its average deviation and starts to make small corrections by itself. The target is that when the next synchronizing message is received, the deviation is already near zero. Parameters "AAIntv" and "AvDrft" show the adapted correction time interval of this ±1 ms auto-adjust function.

Time drift correction without external sync

If any external synchronizing source is not available and the system clock has a known steady drift, it is possible to roughly correct the clock deviation by editing the parameters "AAIntv" and "AvDrft". The following equation can be used if the previous "AAIntv" value has been zero.

$$AAIntv = \frac{604.8}{DriftInOneWeek}$$

If the auto-adjust interval "AAIntv" has not been zero, but further trimming is still needed, the following equation can be used to calculate a new auto-adjust interval.

$$AAIntv_{NEW} = \frac{1}{\frac{1}{AAIntv_{PREVIOUS}} + \frac{DriftInOneWeek}{604.8}}$$

The term *DriftInOneWeek*/604.8 may be replaced with the relative drift multiplied by 1000 if some other period than one week has been used. For example, if the drift has been 37 seconds in 14 days, the relative drift is 37*1000/(14*24*3600) = 0.0306 ms/s.

Example 1

If there has been no external sync and the relay's clock is leading sixty-one seconds a week and the parameter AAIntv has been zero, the parameters are set as

$$AvDrft = Lead$$

$$AAIntv = \frac{604.8}{61} = 9.9s$$

With these parameter values, the system clock corrects itself with –1 ms every 9.9 seconds which equals –61.091 s/week.

Example 2

If there is no external sync and the relay's clock has been lagging five seconds in nine days and the AAIntv has been 9.9 s, leading, then the parameters are set as

$$AAIntv_{NEW} = \frac{1}{\frac{1}{9.9} - \frac{5000}{9 \cdot 24 \cdot 3600}} = 10.6$$

$$AvDrft = Lead$$

When the internal time is roughly correct – the deviation is less than four seconds – no synchronizing or auto-adjust turns the clock backwards. Instead, if the clock is leading, it is softly slowed down to maintain causality.

Table 7.6: System clock parameters

Parameter	Value	Unit	Description	Note
Date			Current date	Set
Time			Current time	Set
Style			Date format	Set
	y-d-m		Year-Month-Day	
	d.m.y		Day.Month.Year	
	m/d/y		Month/Day/Year	
SyncDI	Possible values depends on the types of I/O cards		The digital input used for clock synchronization.	***)
	-		DI not used for synchronizing	
TZone	-15.00 – +15.00 *)		UTC time zone for SNTP synchronization. Note: This is a decimal number. For example for state of Nepal the time zone 5:45 is given as 5.75	Set
DST	No; Yes		Daylight saving time for SNTP	Set

Parameter	Value	Unit	Description	Note
SySrc			Clock synchronization source	
	Internal		No sync recognized since 200s	
	DI		Digital input	
	SNTP		Protocol sync	
	SpaBus		Protocol sync	
	ModBus		Protocol sync	
	ModBus TCP		Protocol sync	
	ProfibusDP		Protocol sync	
	IEC101		Protocol sync	
	IEC103		Protocol sync	
	DNP3		Protocol sync	
	IRIG-B003		IRIG timecode B003 ****)	
MsgCnt	0 – 65535, 0 – etc.		The number of received synchronization messages or pulses	
Dev	±32767	ms	Latest time deviation between the system clock and the received synchronization	
SyOS	±10000.000	s	synchronization correction for any constant deviation in the synchronizing source	Set
AAIntv	±1000	s	Adapted auto-adjust interval for 1 ms correction	Set**)
AvDrft	Lead; Lag		Adapted average clock drift sign	Set**)
FilDev	±125	ms	Filtered synchronization deviation	

Set = An editable parameter (password needed).

*) A range of -11 h – +12 h would cover the whole Earth but because the International Date Line does not follow the 180° meridian, a more wide range is needed.

**) If external synchronization is used, this parameter is set automatically.

***) Set the DI delay to its minimum and the polarity such that the leading edge is the synchronizing edge.

****) Relay needs to be equipped with suitable hardware option module to receive IRIG-B clock synchronization signal. (Chapter 13 Order code).

Synchronization with DI

The clock can be synchronized by reading minute pulses from digital inputs, virtual inputs or virtual outputs. The sync source is selected with the **SyncDI** setting. When a rising edge is detected from the selected input, the system clock is adjusted to the nearest minute. The length of the digital input pulse should be at least 50 ms. The delay of the selected digital input should be set to zero.

Synchronization correction

If the sync source has a known offset delay, it can be compensated with the **SyOS** setting. This is useful for compensating hardware delays or transfer delays of communication protocols. A positive value compensates a lagging external sync and communication delays. A negative value compensates any leading offset of the external synch source.

Sync source

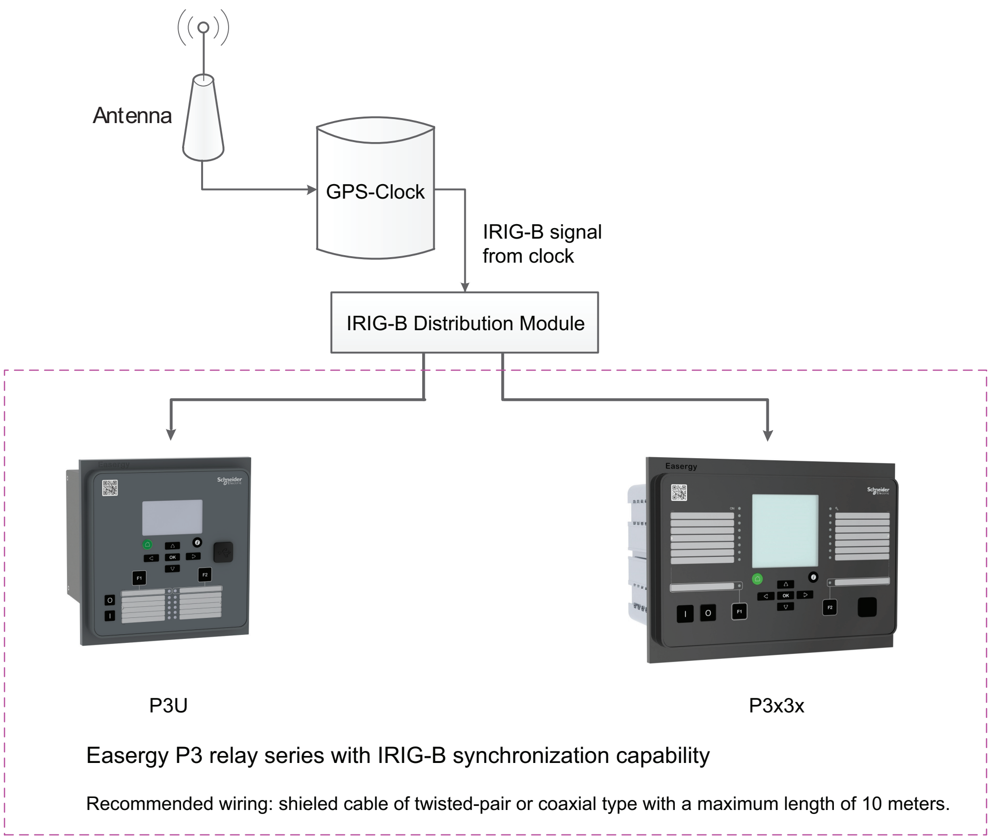
When the relay receives new sync message, the sync source display is updated. If no new sync messages are received within the next 1.5 minutes, the relay switches over to internal sync mode.

Sync source: IRIG-B

IRIG standard time formats B003 and B004 are supported with a dedicated communication option (See Chapter 13 Order code).

IRIG-B input clock signal voltage level is TLL. The input clock signal originated in the GPS receiver must be taken to multiple relays trough an IRIG-B distribution module. This module acts as a centralized unit for a point-to-multiple point connection.

NOTE: Daisy chain connection of IRIG-B signal inputs in multiple relays must be avoided.



The recommended cable must be shielded and either of coaxial or twisted pair type. Its length must not exceed 10 meters.

Deviation

The time deviation means how much the system clock time differs from the sync source time. The time deviation is calculated after receiving a new sync message. The filtered deviation means how much the system clock was really adjusted. Filtering takes care of small deviation in sync messages.

Auto-lag/lead

The relay synchronizes to the sync source, meaning that it starts automatically leading or lagging to stay in perfect sync with the master. The learning process takes a few days.

7.5 Voltage sags and swells

Description

The power quality of electrical networks has become increasingly important. Sophisticated loads (for example computers) require an uninterruptible supply of “clean” electricity. The Easergy P3 protection platform provides many power quality functions that can be used to evaluate and monitor the quality and alarm on the basis of the quality. One of the most important power quality functions is voltage sag and swell monitoring.

Easergy P3 provides separate monitoring logs for sags and swells. The voltage log is triggered if any voltage input either goes under the sag limit (U<) or exceeds the swell limit (U>). There are four registers for both sags and swells in the fault log. Each register contains start time, phase information, duration and the minimum, average and maximum voltage values of each sag and swell event. Furthermore, it contains the total number of sags and swells counters as well as the total number of timers for sags and swells.

The voltage power quality functions are located under the submenu “U”.

Table 7.7: Setting parameters of sags and swells monitoring

Parameter	Value	Unit	Default	Description
U>	20 – 150	%	110	Setting value of swell limit
U<	10 – 120	%	90	Setting value of sag limit
Delay	0.04 – 1.00	s	0.06	Delay for sag and swell detection
SagOn	On; Off	-	On	Sag on event
SagOff	On; Off	-	On	Sag off event
SwelOn	On; Off	-	On	Swell on event
SwelOf	On; Off	-	On	Swell off event

Table 7.8: Recorded values of sags and swells monitoring

	Parameter	Value	Unit	Description
Recorded values	Count		-	Cumulative sag counter
	Total		-	Cumulative sag time counter
	Count		-	Cumulative swell counter
	Total		-	Cumulative swell time counter
Sag / swell logs 1 – 4	Date		-	Date of the sag/swell
	Time		-	Time stamp of the sag/swell
	Type		-	Voltage inputs that had the sag/swell
	Time		s	Duration of the sag/swell
	Min1		% Un	Minimum voltage value during the sag/swell in the input 1
	Min2		% Un	Minimum voltage value during the sag/swell in the input 2
	Min3		% Un	Minimum voltage value during the sag/swell in the input 3
	Ave1		% Un	Average voltage value during the sag/swell in the input 1
	Ave2		% Un	Average voltage value during the sag/swell in the input 2
	Ave3		% Un	Average voltage value during the sag/swell in the input 3
	Max1		% Un	Maximum voltage value during the sag/swell in the input 1
	Max2		% Un	Maximum voltage value during the sag/swell in the input 2
	Max3		% Un	Maximum voltage value during the sag/swell in the input 3

Characteristics

Table 7.9: Voltage sag & swell

Voltage sag limit	10 – 120 %U_N (step 1%)
Voltage swell limit	20 – 150 %U_N (step 1%)
Definite time function: - Operate time	DT 0.08 – 1.00 s (step 0.02 s)
Low voltage blocking	0 – 50 %
Reset time	< 60 ms
Reset ration: - Sag - Swell	 >1.03 <0.97
Block limit	0.5 V or 1.03 (3 %)
Inaccuracy: - Activation - Activation (block limit) - Operate time at definite time function	 ±0.5 V or 3% of the set value ±5% of the set value ±1% or ±30 ms

If one of the line-to-line voltages is below sag limit and above block limit but another line-to-line voltage drops below block limit, blocking is disabled.

7.6 Voltage interruptions

Description

The relay includes a simple function to detect voltage interruptions. The function calculates the number of voltage interruptions and the total time of the voltage-off time within a given calendar period. The period is based on the relay's real-time clock. The available periods are:

- 8 hours, 00:00 – 08:00, 08:00 – 16:00, 16:00 – 24:00
- one day, 00:00 – 24:00
- one week, Monday 00:00 – Sunday 24:00
- one month, the first day 00:00 – the last day 24:00
- one year, 1st January 00:00 – 31st December 24:00

After each period, the number of interruptions and the total interruption time are stored as previous values. The interruption counter and the total time are cleared for a new period. Previous values are overwritten.

Voltage interruption is based on the value of the positive sequence voltage U_1 and a limit value you can define. Whenever the measured U_1 goes below the limit, the interruption counter is increased, and the total time counter starts increasing.

The shortest recognized interruption time is 40 ms. If the voltage-off time is shorter, it may be recognized depending on the relative depth of the voltage dip.

If the voltage has been significantly over the limit U_1< and then there is a small and short under-swing, it is not recognized (Figure 7.3).

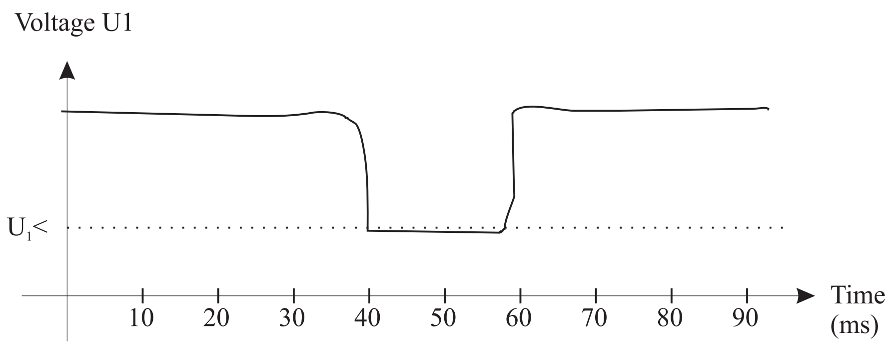


Figure 7.3: A short voltage interruption which is probably not recognized

On the other hand, if the limit U_1< is high and the voltage has been near this limit, and then there is a short but very deep dip, it is not recognized (Figure 7.4).

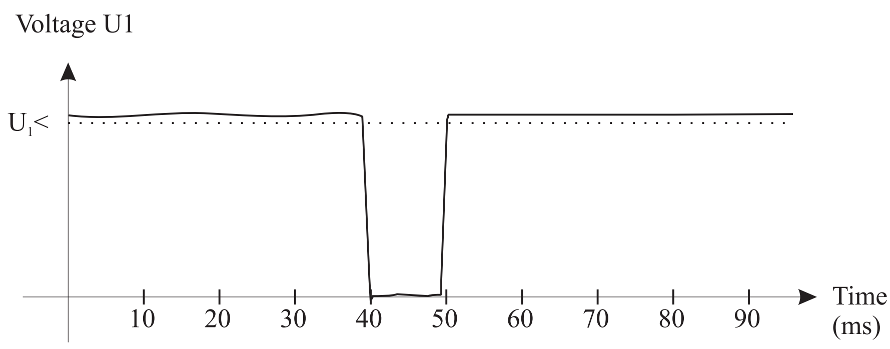


Figure 7.4: A short voltage interrupt that will be recognized

Table 7.10: Setting parameters of the voltage sag measurement function

Parameter	Value	Unit	Default	Description
U1<	10.0 – 120.0	%	64	Setting value
Period	8h Day Week Month	-	Month	Length of the observation period
Date		-	-	Date
Time		-	-	Time

Table 7.11: Measured and recorded values of voltage sag measurement function

	Parameter	Value	Unit	Description
Measured value	Voltage	LOW; OK	-	Current voltage status
	U1		%	Measured positive sequence voltage
Recorded values	Count		-	Number of voltage sags during the current observation period
	Prev		-	Number of voltage sags during the previous observation period
	Total		s	Total (summed) time of voltage sags during the current observation period
	Prev		s	Total (summed) time of voltage sags during the previous observation period

Characteristics

Table 7.12: Voltage interruptions

Voltage low limit (U_1)	10 – 120 %U_N (step 1%)
Definite time function: - Operate time	DT <60 ms (Fixed)
Reset time	< 60 ms
Reset ratio	>1.03
Inaccuracy: - Activation	3% of the set value

7.7 Current transformer supervision (ANSI 60)

Description

The relay supervises the current transformers (CTs) and the external wiring between the relay terminals and the CTs. This is a safety function as well, since an open secondary of a CT causes dangerous voltages.

The CT supervision function measures phase currents. If one of the three phase currents drops below the I_{MIN}< setting while another phase current exceeds the I_{MAX}> setting, the function issues an alarm after the operation delay has elapsed.

Table 7.13: Setting parameters of CT supervision

Parameter	Value	Unit	Default	Description
Imax>	0.0 – 10.0	xIn	2.0	Upper setting for CT supervision current scaled to primary value, calculated by relay
Imin<	0.0 – 10.0	xIn	0.2	Lower setting for CT supervision current scaled to primary value, calculated by relay
t>	0.02 – 600.0	s	0.10	Operation delay
CT on	On; Off	-	On	CT supervision on event
CT off	On; Off	-	On	CT supervision off event

Table 7.14: Measured and recorded values of CT

	Parameter	Value	Unit	Description
Measured value	ILmax		A	Maximum of phase currents
	ILmin		A	Minimum of phase currents
Display	Imax>, Imin<		A	Setting values as primary values
Recorded values	Date		-	Date of CT supervision alarm
	Time		-	Time of CT supervision alarm
	Imax		A	Maximum phase current
	Imin		A	Minimum phase current

Characteristics

Table 7.15: Current transformer supervision

I_{MAX}> setting I_{MIN}< setting	0.00 – 10.00 x I_N (step 0.01) 0.00 – 10.00 x I_N (step 0.01)
Definite time function: - Operate time	DT 0.04 – 600.00 s (step 0.02 s)
Reset time Reset ratio I_{MAX}> Reset ratio I_{MIN}<	< 60 ms 0.97 1.03
Inaccuracy: - Activation - Operate time at definite time function	 ±3% of the set value ±1% or ±30 ms

7.8 Voltage transformer supervision (ANSI 60FL)

Description

The relay supervises the voltage transformers (VTs) and VT wiring between the relay terminals and the VTs. If there is a fuse in the voltage transformer circuitry, the blown fuse prevents or distorts the voltage measurement. Therefore, an alarm should be issued. Furthermore, in some applications, protection functions using voltage signals should be blocked to avoid false tripping.

The VT supervision function measures three line-to-line voltages and currents. The negative sequence voltage U_2 and the negative sequence current I_2 are calculated. If U_2 exceed the $U_2>$ setting and at the same time, I_2 is less than the $I_2<$ setting, the function issues an alarm after the operation delay has elapsed.

Table 7.16: Setting parameters of VT supervision

Parameter	Value	Unit	Default	Description
U2>	0.0 – 200.0	% Un	34.6	Upper setting for VT supervision
I2<	0.0 – 200.0	% In	100.0	Lower setting for VT supervision
t>	0.02 – 600.0	s	0.10	Operation delay
VT on	On; Off	-	On	VT supervision on event
VT off	On; Off	-	On	VT supervision off event

Table 7.17: Measured and recorded values of VT supervision

	Parameter	Value	Unit	Description
Measured value	U2		$\%U_N$	Measured negative sequence voltage
	I2		$\%I_N$	Measured negative sequence current
Recorded Values	Date		-	Date of VT supervision alarm
	Time		-	Time of VT supervision alarm
	U2		$\%U_N$	Recorded negative sequence voltage
	I2		$\%I_N$	Recorded negative sequence current

Characteristics

Table 7.18: Voltage transformer supervision

U_2> setting I_2< setting	0.0 – 200.0 % (step 0.1%) 0.0 – 200.0 % (step 0.1%)
Definite time function: - Operate time	DT 0.04 – 600.00 (step 0.02s)
Reset time	< 60 ms
Reset ratio	3% of the start value
Inaccuracy: - Activation U_2> - Activation I_2< - Operate time at definite time function	 ±1%-unit ±1%-unit ±1% or ±30 ms

7.9 Circuit breaker condition monitoring

Description

NOTE: In the device's user interface, this function is called CB wear.

The relay has a condition monitoring function that supervises circuit breaker (CB) wear. The condition monitoring can provide an alarm about the need of CB maintenance well before the CB condition is critical.

The CB condition monitoring measures the breaking current of each CB pole separately and then estimates CB wear according to the permissible cycle diagram. The breaking current is registered when the trip relay supervised by the circuit breaker failure protection (CBFP) is activated. (See Chapter 6.15 Breaker failure 1 (ANSI 50BF) for CBFP and the setting parameter "CBrelay" through front panel and "Monitored Trip relay" using Easergy Pro.)

Circuit breaker curve and its approximation

The permissible cycle diagram is usually available in the documentation of the CB manufacturer (Figure 7.5). The diagram specifies the permissible number of cycles for every level of the breaking current. This diagram is parameterised to the condition monitoring function with a maximum of eight [current, cycles] points. See Table 7.19. If fewer than eight points are needed, the unused points are set to [I_{BIG}, 1], where I_{BIG} is more than the maximum breaking capacity.

If the CB wear characteristics or a part of them is a straight line on a log/log graph, the two end points are enough to define that part of the characteristics. This is because the relay is using logarithmic interpolation for any current values falling in between the given current points 2-8.

The points 4-8 are not needed for the CB in Figure 7.5. Thus, they are set to 100 kA and one operation in the table is discarded by the algorithm.

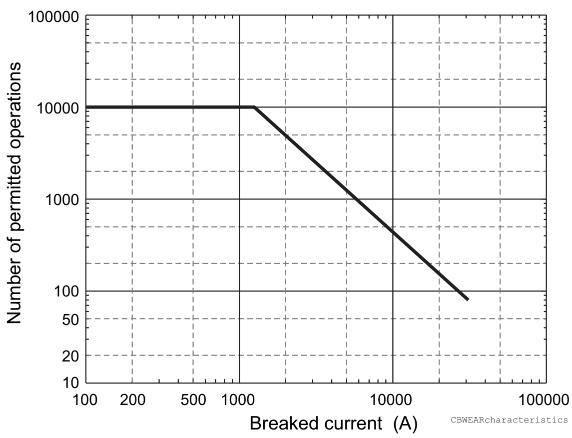


Figure 7.5: An example of a circuit breaker wear characteristic graph.

Table 7.19: An example of circuit breaker wear characteristics.

Point	Interrupted current (kA)	Number of permitted operations
1	0 (mechanical age)	10000
2	1.25 (rated current)	10000
3	31.0 (maximum breaking current)	80
4	100	1
5	100	1
6	100	1
7	100	1
8	100	1

The values are taken from the figure above. The table is edited with Easergy Pro under menu "BREAKER CURVE".

Setting alarm points

There are two alarm points available having two setting parameters each.

- Current
  The first alarm can be set for example to the CB's nominal current or any application-typical current. The second alarm can be set for example according to a typical fault current.
- "Operations left" alarm limit
  An alarm is activated when there are less operations left at the given current level than this limit.

Any actual interrupted current is logarithmically weighted for the two given alarm current levels and the number of operations left at the alarm points is decreased accordingly. When the number of remaining operations goes under the given alarm limit, an alarm signal is issued to the output matrix. Also, an event is generated depending on the event enabling.

Clearing "operations left" counters

After the CB curve table is filled and the alarm currents are defined, the wearing function can be initialised by clearing the decreasing operation counters with the parameter "Clear" (Clear oper. left cntrs). After clearing, the relay shows the maximum allowed operations for the defined alarm current levels.

Operation counters to monitor the wearing

The operations left can be read from the counters "Al1Ln" (Alarm 1) and "Al2Ln" (Alarm2). There are three values for both alarms, one for each phase. The smallest value is supervised by the two alarm functions.

Logarithmic interpolation

The permitted number of operations for the currents in between the defined points is logarithmically interpolated using equation Equation 7.1.

Equation 7.1:

$$C = \frac{a}{I^n}$$

C = permitted operations
I = interrupted current
a = constant according Equation 7.2
n = constant according Equation 7.3

Equation 7.2:

$$n = \frac{\ln \frac{C_k}{C_{k+1}}}{\ln \frac{I_{k+1}}{I_k}}$$

Equation 7.3:

$$a = C_k I_k^2$$

ln =	natural logarithm function
C_k, C_{k+1} =	permitted operations. k = row 2 – 7 in Table 7.19.
I_k, I_{k+1} =	corresponding current. k = row 2 – 7 in Table 7.19.

Example of the logarithmic interpolation

Alarm 2 current is set to 6 kA. The maximum number of operations is calculated as follows.

The current 6 kA lies between points 2 and 3 in the table. That gives value for the index k. Using

k = 2
C_k = 10000
C_{k+1} = 80
I_{k+1} = 31 kA
I_k = 1.25 kA

and the Equation 7.2 and Equation 7.3, the relay calculates

$$n = \frac{\ln \frac{10000}{80}}{\ln \frac{31000}{1250}} = 1.5038$$

$$a = 10000 \cdot 1250^{1.5038} = 454 \cdot 10^6$$

Using Equation 7.1 the relay gets the number of permitted operations for current 6 kA.

$$C = \frac{454 \cdot 10^6}{6000^{1.5038}} = 945$$

Thus, the maximum number of current-breaking operations at 6 kA is 945. This can be verified with the original CB curve in Figure 7.5. Indeed, the figure shows that at 6 kA, the operation count is between 900 and 1000. A useful alarm level for operations left could be in this case for example 50 which is about five percent of the maximum.

Example of operation counter decrementing when the CB is breaking a current

Alarm2 is set to 6 kA. The CB failure protection is supervising trip relay T1, and a trip signal of an overcurrent stage detecting a two-phase fault is connected to this trip relay T1. The interrupted phase currents are 12.5 kA, 12.5 kA and 1.5 kA. By what number are Alarm2 counters decremented?

Using Equation 7.1 and values n and a from the previous example, the relay gets the number of permitted operations at 10 kA.

$$C_{10kA} = \frac{454 \cdot 10^6}{12500^{1.5038}} = 313$$

At alarm level 2, 6 kA, the corresponding number of operations is calculated according to Equation 7.4.

Equation 7.4:

$$\Delta = \frac{C_{AlarmMax}}{C}$$

$$\Delta_{L1} = \Delta_{L2} = \frac{945}{313} = 3$$

Thus, Alarm2 counters for phases L1 and L2 are decremented by 3. In phase L1, the current is less than the alarm limit current 6 kA. For such currents, the decrement is one.

$\Delta_{L3} = 1$

Table 7.20: Local panel parameters of CBWEAR function

Parameter	Value	Unit	Description	Set
CBWEAR STATUS				
 Al1L1 Al1L2 Al1L3 Al2L1 Al2L2 Al2L3			Operations left for - Alarm 1, phase L1 - Alarm 1, phase L2 - Alarm 1, phase L3 - Alarm 2, phase L1 - Alarm 2, phase L2 - Alarm 2, phase L3	
Latest trip				
Date time			Time stamp of the latest trip operation	
IL1 IL2 IL3		A A A	Broken current of phase L1 Broken current of phase L2 Broken current of phase L3	
CBWEAR SET				
Alarm1				
Current	0.00 – 100.00	kA	Alarm1 current level	Set
Cycles	100000 – 1		Alarm1 limit for operations left	Set
Alarm2				
Current	0.00 – 100.00	kA	Alarm2 current level	Set
Cycles	100000 – 1		Alarm2 limit for operations left	Set
CBWEAR SET2				
Al1On	On ; Off		'Alarm1 on' event enabling	Set
Al1Off	On ; Off		'Alarm1 off' event enabling	Set
Al2On	On ; Off		'Alarm2 on' event enabling	Set
Al2Off	On ; Off		'Alarm2 off' event enabling	Set
Clear	-; Clear		Clearing of cycle counters	Set

Set = An editable parameter (password needed).

The CB curve table is edited with Easergy Pro.

7.10 Circuit breaker condition monitoring 1 and 2

NOTE: In the device's user interface, this function is called CB wear 1 and 2. Stages 1 and 2 are identical and allow monitoring two circuit breakers simultaneously.

Description

The relay has five measurement functions that collect the following types of data to enable circuit breaker (CB) condition monitoring:

- number of operations
- cumulative breaking current
- operate times (CB opening and closing times)
- charging time
- number of racking out operations

Number of operations

The purpose of this counter is to record the number of CB operation cycles. The counter is incremented by one each time the CB changes its position from closed to open and from open to closed. The counter is incremented independently of the origin of the operation that can be for example:

- protection relay
- mechanical push buttons on CB front
- external wired command
- control unit

To implement this counter, use the two auxiliary contacts' switching which give the CB position to increment the counter.

There is also a sub-counter that counts the operations that are triggered by a protection function.

The counters have the following access types:

- read: access via MODBUS serial or TCP protocol
- write: it is possible to overwrite this data from a parametrization tool with special access rights

Cumulative breaking current

Each time the CB opens, the breaking current is added to the cumulative total and to the appropriate range of the cumulative breaking current.

The cumulative breaking current is given in $(kA)^2$.

In addition to the total cumulative breaking current, there are five cumulative breaking current ranges to assess the breaking device pole condition:

- 0-2 In
- 2-5 In
- 5-10 In
- 10-40 In
- > 40 In

The cumulative breaking current is also computed by phase.

When the relay is in test mode or the CB has been withdrawn, the cumulative breaking current is not updated.

The cumulative counters have the following access types:

- read: access via MODBUS serial or TCP protocol
- write: it is possible to overwrite this data from a parametrization tool with special access rights

Operate times

The CB opening time is measured from the switching of the auxiliary contacts from the closed position to the open position.

The CB closing time is measured from the switching of the auxiliary contacts from the open position to the closed position.

The protection relay records the last 10 opening times and the last 10 closing times, each being time-stamped and independent of the origin of the operation (for example the relay itself or a mechanical push button).

These values only have read access via MODBUS serial or TCP protocol.

Charging time

The protection relay records the last 10 spring charging time operations, each being time-stamped.

These values only have read access via MODBUS serial or TCP protocol.

The charging time is computed from the switch of the CB position (from open to closed) and the change of the state of the auxiliary contact indicating the spring charged status (from discharged to charged).

Number of racking out operations

The purpose of this counter is to record the number of rack in/out operations. The counter is incremented by one each time the CB changes its position from inserted to withdrawn and from withdrawn to inserted. A cycle (in/out, out/in) counts for one operation. This counter is incremented independently of the origin of the operation that can be for example:

- mechanically from front of the switchgear
- external wired command
- control unit

This counter has the following access types:

- read: asccess via MODBUS serial or TCP protocol
- write: it is possible to overwrite this data from a parametrization tool with special access rights

The counter is computed from the change state of the rack in/out contacts (in some cases, there is a single contact, and in some cases, there are two contacts).

Characteristics

Table 7.21: Characteristics

Function	Allowed range	Accuracy	Resolution	Access type from the network interface	Stored in non-volatile memory	Data format
Number of operations	0-65535	1	1	R/W	Y	UI32bit
Cumulative breaking current	0-2^{32}-1kA^2	+/- 10 %	1kA^2	R/W	Y	UI32bit
Operate times	0-300 ms	+/- 1 ms	1 ms	R	Y	UI16bit
Charging time	0-1 min	+/- 1 s	500 ms	R	N	UI16bit
Number of racking out operations	0-65535	1	1	R/W	Y	UI32bit

Set the value that is returned when a measured value is out of the allowed range to a “dummy” value. This allows you to easily detect if something is wrong.

7.11 Energy pulse outputs

Description

The relay can be configured to send a pulse whenever a certain amount of energy has been imported or exported. The principle is presented in Figure 7.6. Each time the energy level reaches the pulse size, a digital output is activated and the relay is active as long as defined by a pulse duration setting.

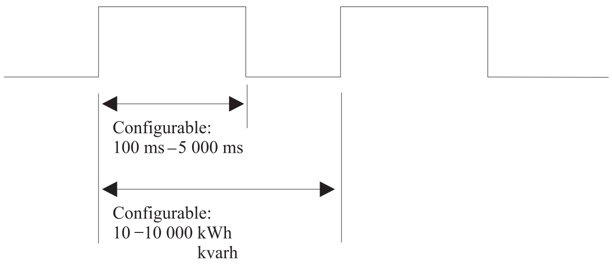


Figure 7.6: Principle of energy pulses

The relay has four energy pulse outputs. The output channels are:

- active exported energy
- reactive exported energy
- active imported energy
- reactive imported energy

Each channel can be connected to any combination of the digital outputs using the output matrix. The parameters for the energy pulses can be found in the ENERGY menu "E" under the submenus E-PULSE SIZES and E-PULSE DURATION.

Table 7.22: Energy pulse output parameters

	Parameter	Value	Unit	Description
E-PULSE SIZES	E+	10 – 10 000	kWh	Pulse size of active exported energy
	Eq+	10 – 10 000	kvarh	Pulse size of reactive exported energy
	E-	10 – 10 000	kWh	Pulse size of active imported energy
	Eq-	10 – 10 000	kvarh	Pulse size of reactive imported energy
E-PULSE DURATION	E+	100 – 5000	ms	Pulse length of active exported energy
	Eq+	100 – 5000	ms	Pulse length of reactive exported energy
	E-	100 – 5000	ms	Pulse length of active imported energy
	Eq-	100 – 5000	ms	Pulse length of reactive imported energy

Scaling examples

1. The average active exported power is 250 MW.
   The peak active exported power is 400 MW.
   The pulse size is 250 kWh.
   The average pulse frequency is 250/0.250 = 1000 pulses/h.
   The peak pulse frequency is 400/0.250 = 1600 pulses/h.
   Set pulse length to 3600/1600 - 0.2 = 2.0 s or less.
   The lifetime of the mechanical digital output is
   $50x10^6$/1000 h = 6 a.
   This is not a practical scaling example unless a digital output lifetime of about six years is accepted.
2. The average active exported power is 100 MW.
   The peak active exported power is 800 MW.
   The pulse size is 400 kWh.
   The average pulse frequency is 100/0.400 = 250 pulses/h.
   The peak pulse frequency is 800/0.400 = 2000 pulses/h.
   Set pulse length to 3600/2000 - 0.2 = 1.6 s or less.
   The lifetime of the mechanical digital output is
   $50x10^6$/250 h = 23 a.
3. Average active exported power is 20 MW.
   Peak active exported power is 70 MW.
   Pulse size is 60 kWh.
   The average pulse frequency is 25/0.060 = 416.7 pulses/h.
   The peak pulse frequency is 70/0.060 = 1166.7 pulses/h.
   Set pulse length to 3600/1167 - 0.2 = 2.8 s or less.
   The lifetime of the mechanical digital output is
   $50x10^6$/417 h = 14 a.
4. Average active exported power is 1900 kW.
   Peak active exported power is 50 MW.
   Pulse size is 10 kWh.
   The average pulse frequency is 1900/10 = 190 pulses/h.
   The peak pulse frequency is 50000/10 = 5000 pulses/h.
   Set pulse length to 3600/5000 - 0.2 = 0.5 s or less.
   The lifetime of the mechanical digital output is
   $50x10^6$/190 h = 30 a.

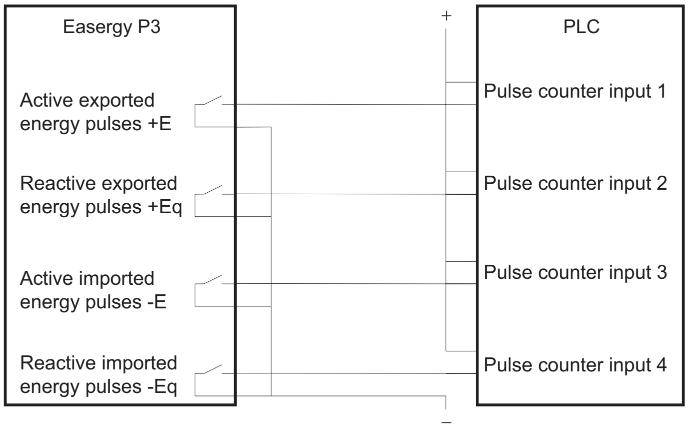


Figure 7.7: Application example of wiring the energy pulse outputs to a PLC having common plus and using an external wetting voltage

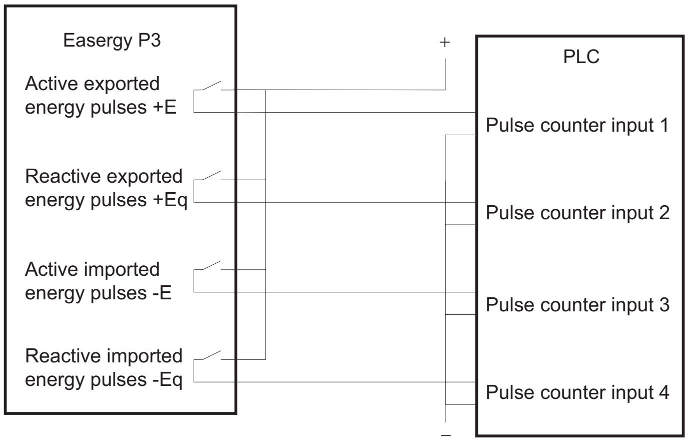


Figure 7.8: Application example of wiring the energy pulse outputs to a PLC having common minus and using an external wetting voltage

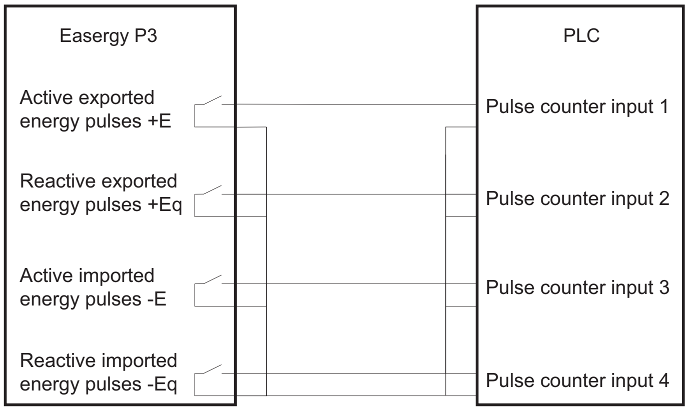


Figure 7.9: Application example of wiring the energy pulse outputs to a PLC having common minus and an internal wetting voltage.

7.12 Running hour counter

Description

The running hour counter is typically used to monitor the service time of the motor or appropriate feeder. This function calculates the total active time of the selected digital input, virtual I/O function button, GOOSE signal, POC signal or output matrix output signal. The resolution is ten seconds.

Table 7.23: Running hour counter parameters

Parameter	Value	Unit	Description	Note
Runh	0 – 876000	h	Total active time, hours Note: The label text "Runh" can be edited with Easergy Pro.	(Set)
Runs	0 – 3599	s	Total active time, seconds	(Set)
Starts	0 – 65535		Activation counter	(Set)
Status	Stop Run		Current status of the selected digital signal	
Started at			Date and time of the last activation	
Stopped at			Date and time of the last inactivation	

Set = An editable parameter (password needed).

(Set) = An informative value which can be edited as well.

7.13 Timers

Description

The Easergy P3 protection platform includes four settable timers that can be used together with the user's programmable logic or to control setting groups and other applications that require actions based on calendar time. Each timer has its own settings. The selected on-time and off-time is set, after which the activation of the timer can be set to be as daily or according to the day of the week (See the setting parameters for details). The timer outputs are available for logic functions and for the block and output matrix.

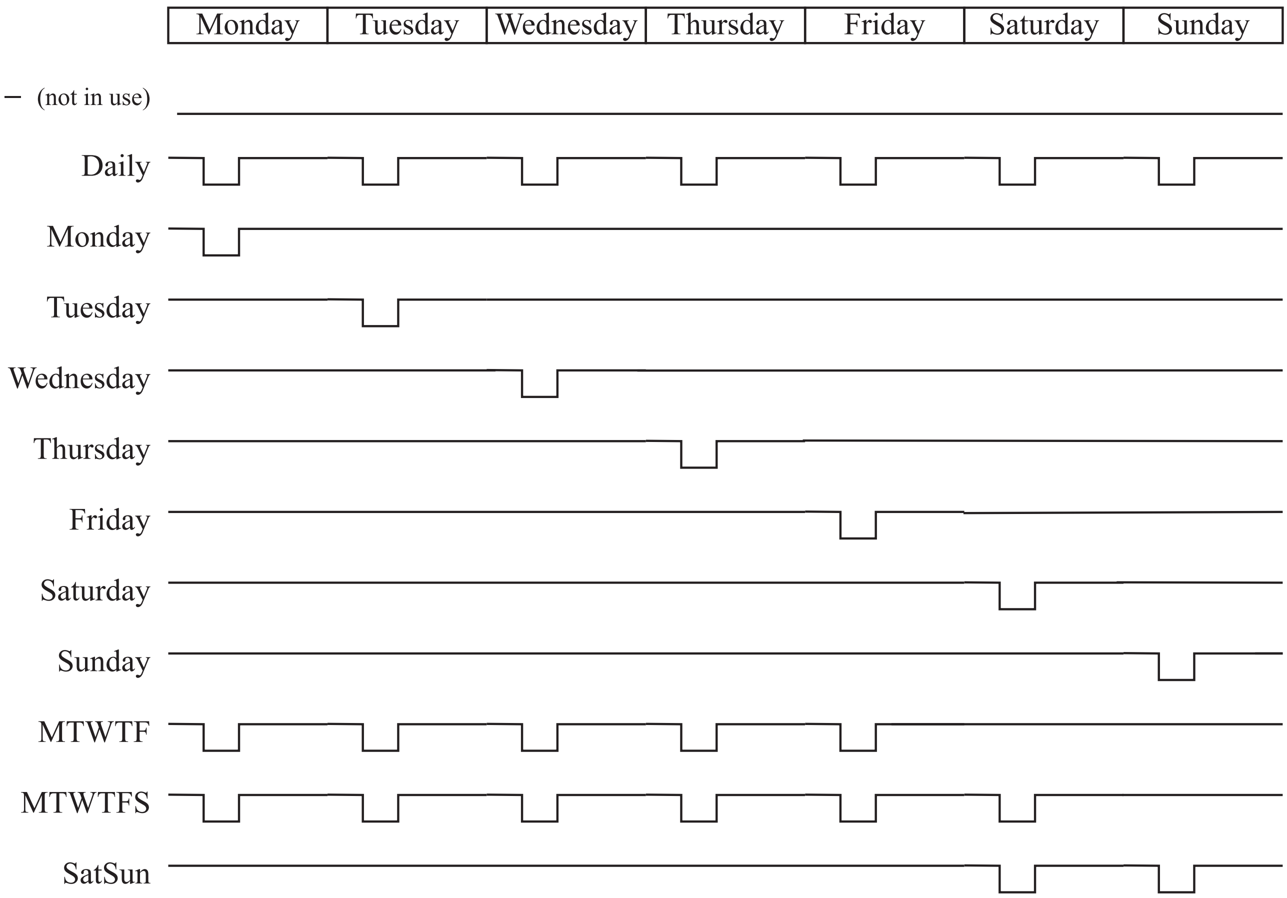


Figure 7.10: Timer output sequence in different modes

You can force any timer, which is in use, on or off. The forcing is done by writing a new status value. No forcing flag is needed as in forcing for example the digital outputs.

The forced time is valid until the next forcing or until the next reversing timed act from the timer itself.

The status of each timer is stored in the non-volatile memory when the auxiliary power is switched off. At startup, the status of each timer is recovered.

Table 7.24: Setting parameters of timers

Parameter	Value	Description
TimerN		Timer status
	-	Not in use
	0	Output is inactive
	1	Output is active
On	hh:mm:ss	Activation time of the timer
Off	hh:mm:ss	De-activation time of the timer
Mode		For each four timers there are 12 different modes available:
	-	The timer is off and not running. The output is off i.e. 0 all the time.
	Daily	The timer switches on and off once every day.
	Monday	The timer switches on and off every Monday.
	Tuesday	The timer switches on and off every Tuesday.
	Wednesday	The timer switches on and off every Wednesday.
	Thursday	The timer switches on and off every Thursday.
	Friday	The timer switches on and off every Friday.
	Saturday	The timer switches on and off every Saturday.
	Sunday	The timer switches on and off every Sunday.
	MTWTF	The timer switches on and off every day except Saturdays and Sundays
	MTWTFS	The timer switches on and off every day except Sundays.
	SatSun	The timer switches on and off every Saturday and Sunday.

7.14 Combined overcurrent status

Description

This function collects faults, fault types and registered fault currents of all enabled overcurrent stages and shows them in the event log.

The combined overcurrent status can be used as an indication of faults. Combined o/c indicates the amplitude of the last occurred fault. Also, a separate indication of the fault type is informed during the start and the trip. Active phases during the start and the trip are also activated in the output matrix. After the fault is switched off, the active signals release after the set delay “clearing delay“ has passed. The combined o/c status referres to the following over current stages: I>, I>>, I>>>, I_{φ}>, I_{φ}>>, I_{φ}>>> and I_{φ}>>>>.

Table 7.25: Line fault parameters

Parameter	Value	Unit	Description	Note
IFltLas		xI_{GN}	Current of the latest overcurrent fault	(Set)
LINE ALARM				
AlrL1 AlrL2 AlrL3	 0 1		Start (=alarm) status for each phase. 0 = No start since alarm ClrDly 1 = Start is on	
OCs	 0 1		Combined overcurrent start status. AlrL1 = AlrL2 = AlrL3 = 0 AlrL1 = 1 or AlrL2 = 1 or AlrL3 = 1	
LxAlarm	 On Off		'On' Event enabling for AlrL1 – 3 Events are enabled Events are disabled	Set
LxAlarmOff	 On Off		'Off' Event enabling for AlrL1...3 Events are enabled Events are disabled	Set
OCAlarm	 On Off		'On' Event enabling for combined o/c starts Events are enabled Events are disabled	Set
OCAlarmOff	 On Off		'Off' Event enabling for combined o/c starts Events are enabled Events are disabled	Set
IncFltEvnt	 On Off		Disabling several start and trip events of the same fault Several events are enabled *) Several events of an increasing fault is disabled **)	Set
ClrDly	0 – 65535	s	Duration for active alarm status AlrL1, Alr2, AlrL3 and OCs	Set

Parameter	Value	Unit	Description	Note
LINE FAULT				
FltL1 FltL2 FltL3	 0 1		Fault (=trip) status for each phase. 0 = No fault since fault ClrDly 1 = Fault is on	
OCt	 0 1		Combined overcurrent trip status. FltL1 = FltL2 = FltL3 = 0 FltL1 = 1 or FltL2 = 1 or FltL3 = 1	
LxTrip	 On Off		'On' Event enabling for FltL1 – 3 Events are enabled Events are disabled	Set
LxTripOff	 On Off		'Off' Event enabling for FltL1...3 Events are enabled Events are disabled	Set
OCTrip	 On Off		'On' Event enabling for combined o/c trips Events are enabled Events are disabled	Set
OCTripOff	 On Off		'Off' Event enabling for combined o/c starts Events are enabled Events are disabled	Set
IncFltEvnt	 On Off		Disabling several events of the same fault Several events are enabled *) Several events of an increasing fault is disabled **)	Set
ClrDly	0 – 65535		Duration for active alarm status FltL1, Flt2, FltL3 and OCt	Set

Set = An editable parameter (password needed).

*) Used with IEC 60870-105-103 communication protocol. The alarm screen shows the latest fault current if it is the biggest registered fault current, too. Not used with Spabus because Spabus masters usually do not like to have unpaired On/Off events.

**) Used with SPA-bus protocol because most SPA-bus masters need an off-event for each corresponding on-event.

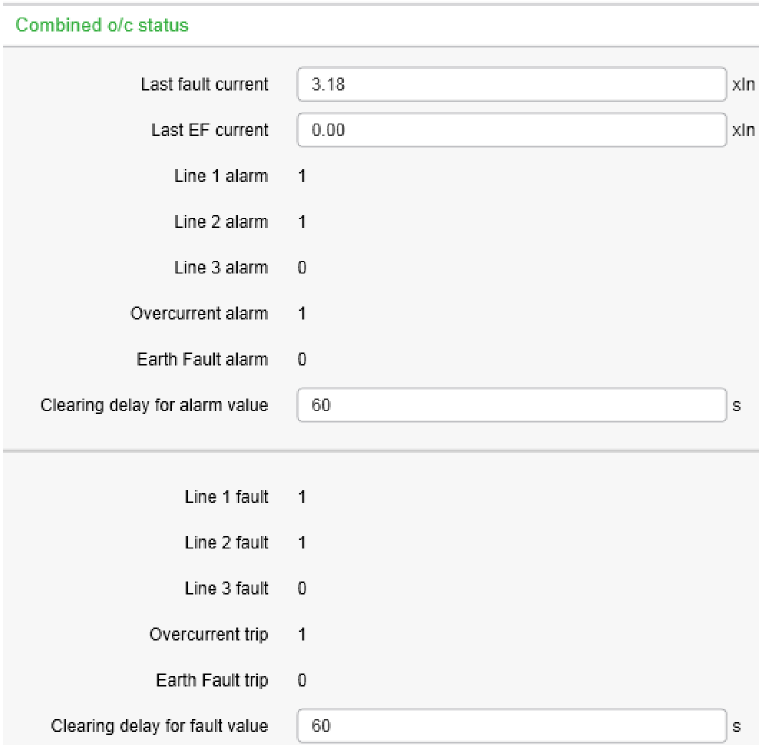


Figure 7.11: Combined o/c status

The fault that can be seen in the Figure 7.11 was 3.18 times to nominal and it increased in to a two phase short circuit L1-L2. All signals those are stated as “1” are also activated in the output matrix. After the fault disappears, the activated signals release.

The combined overcurrent status can be found from Easergy Pro through **Protection > Protection stage status 2**.

7.15 Trip circuit supervision (ANSI 74)

Description

Trip circuit supervision is used to ensure that the wiring from the protective relay to a circuit breaker (CB) is in order. Even though the trip circuit is unused most of the time, keeping it in order is important so that the CB can be tripped whenever the relay detects a fault in the network.

The digital inputs of the relay can be used for trip circuit monitoring.

Also the closing circuit can be supervised using the same principle.

NOTE: Apply trip circuit supervision using a digital input and its programmable time delay.

7.15.1 Trip circuit supervision with one digital input

The benefits of this scheme are that only one digital inputs is needed and no extra wiring from the relay to the circuit breaker (CB) is needed. Also, supervising a 24 Vdc trip circuit is possible.

The drawback is that an external resistor is needed to supervise the trip circuit on both CB positions. If supervising during the closed position only is enough, the resistor is not needed.

- The digital input is connected parallel to the trip contacts (Figure 7.12).
- The digital input is configured as normal closed (NC).
- The digital input delay is configured to be longer than the maximum fault time to inhibit any superfluous trip circuit fault alarm when the trip contact is closed.
- The digital input is connected to a relay in the output matrix giving out any trip circuit alarm.
- The trip relay must be configured as non-latched. Otherwise, a superfluous trip circuit fault alarm follows after the trip contact operates, and the relay remains closed because of latching.
- By utilizing an auxiliary contact of the CB for the external resistor, also the auxiliary contact in the trip circuit can be supervised.

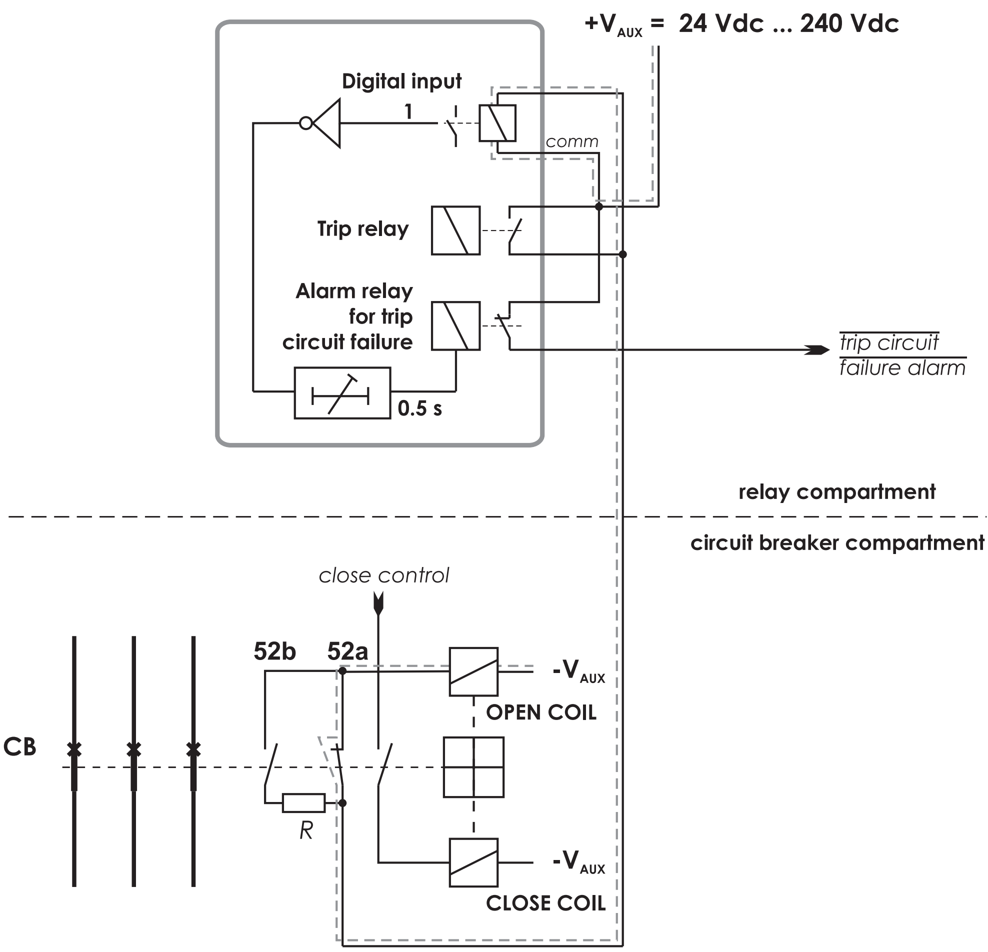


Figure 7.12: Trip circuit supervision using a single digital input and an external resistor R.

The circuit-breaker is in the closed position. The supervised circuitry in this CB position is double-lined. The digital input is in active state when the trip circuit is complete.

This is applicable for any digital inputs.

NOTE: The need for the external resistor R depends on the application and circuit breaker manufacturer's specifications.

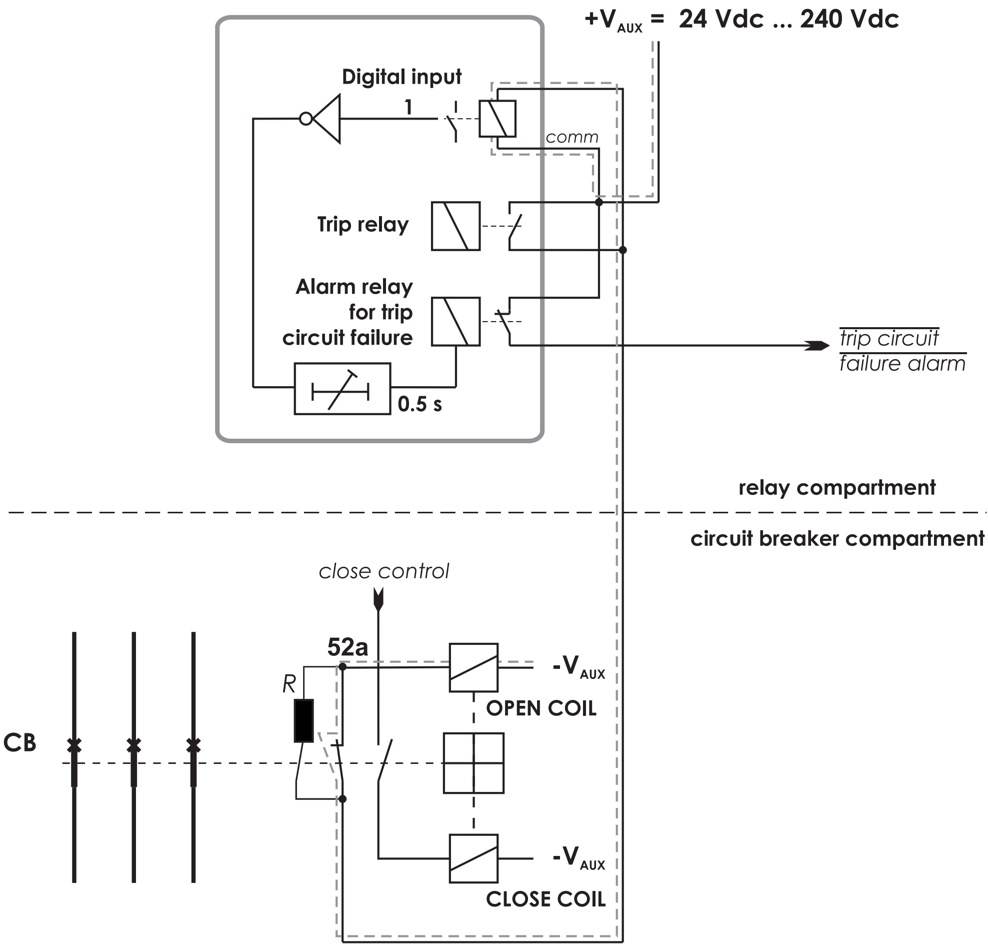


Figure 7.13: Alternative connection without using circuit breaker 52b auxiliary contacts.

Trip circuit supervision using a single digital input and an external resistor R. The circuit breaker is in the closed position. The supervised circuitry in this CB position is double-lined. The digital input is in active state when the trip circuit is complete.

Alternative connection without using circuit breaker 52b auxiliary contacts. This is applicable for any digital inputs.

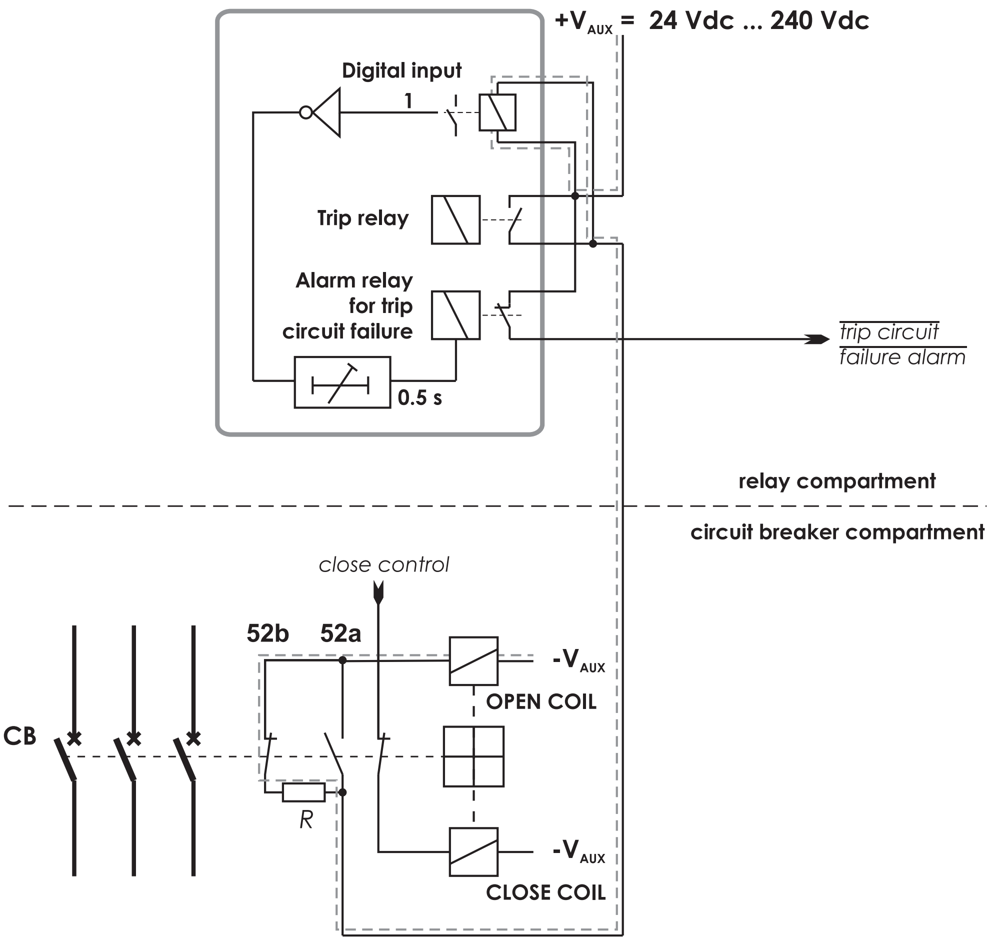


Figure 7.14: Trip circuit supervision using a single digital input when the circuit breaker is in open position.

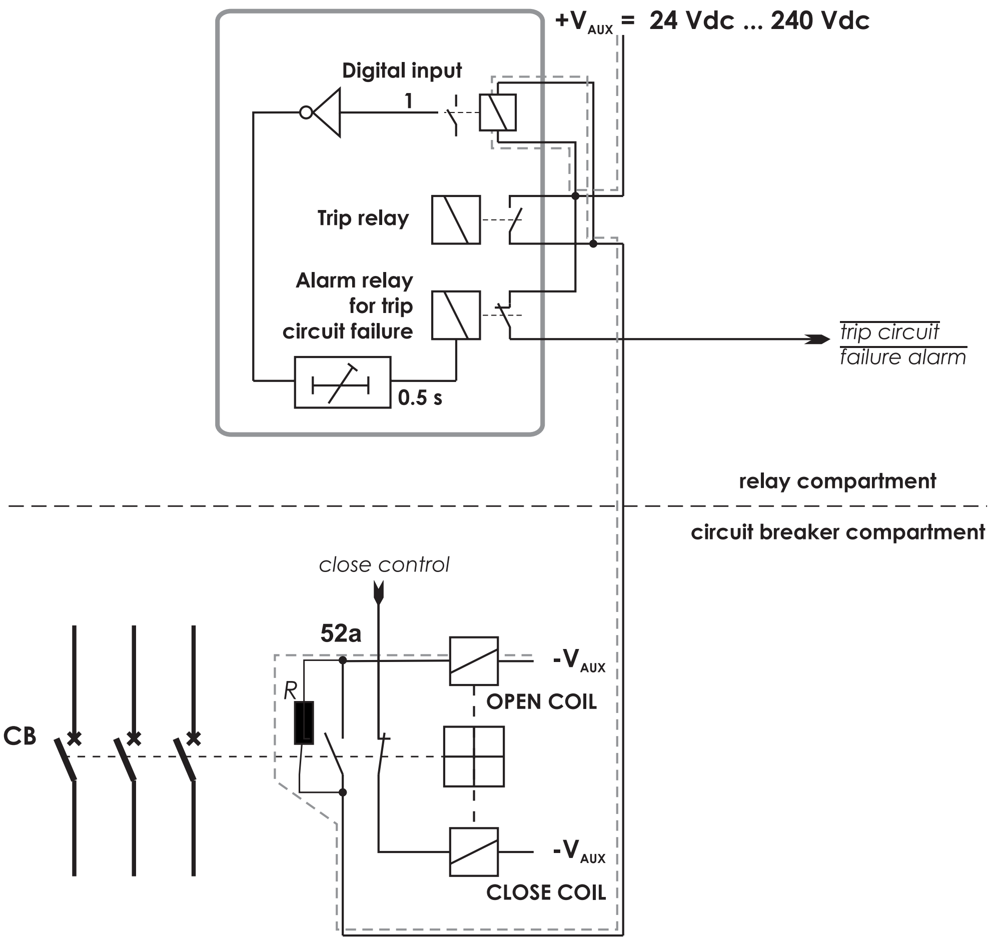


Figure 7.15: Alternative connection without using circuit breaker 52b auxiliary contacts. Trip circuit supervision using a single digital input, when the circuit breaker is in open position.

DIGITAL INPUTS

-	Input	State	Polarity	Delay	On Event	Off Event	Alarm display	Counters
On	1	0	NO	0.00	On	On	On	0
On	2	0	NO	0.00	On	On	On	0
On	3	0	NO	0.00	On	On	On	3
On	4	0	NO	0.00	On	On	On	0
On	5	0	NO	0.00	On	On	On	0
On	6	0	NO	0.00	On	On	On	0
On	7	0	NC	0.50	Off	Off	Off	1

Figure 7.16: An example of digital input DI7 configuration for trip circuit supervision with one digital input.

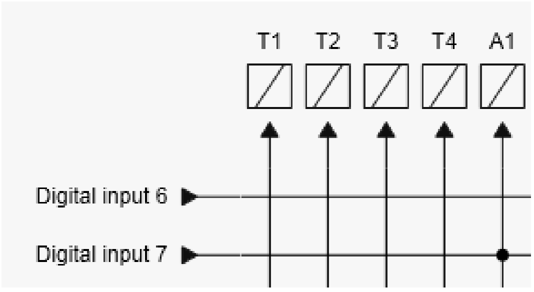


Figure 7.17: An example of output matrix configuration for trip circuit supervision with one digital input.

Example of dimensioning the external resistor R

U_{AUX} =	110 Vdc - 20 % + 10%, Auxiliary voltage with tolerance
U_{DI} =	18 Vdc, Threshold voltage of the digital input
I_{DI} =	3 mA, Typical current needed to activate the digital input including a 1 mA safety margin.
P_{COIL} =	50 W, Rated power of the open coil of the circuit breaker. If this value is not known, 0 Ω can be used for the R_{COIL}.
U_{MIN} =	U_{AUX} - 20 % = 88 V
U_{MAX} =	U_{AUX} + 10 % = 121 V
R_{COIL} =	U^2_{AUX} / P_{COIL} = 242 Ω.

The external resistance value is calculated using Equation 7.5.

Equation 7.5:

$$R = \frac{U_{MIN} - U_{DI} - I_{DI} \cdot R_{Coil}}{I_{DI}}$$

R = (88 – 18 – 0.003 x 242)/0.003 = 23.1 kΩ

(In practice, the coil resistance has no effect.)

By selecting the next smaller standard size, we get **22 kΩ**.

The power rating for the external resistor is estimated using Equation 7.6 and Equation 7.7. The Equation 7.6 is for the CB open situation including a 100 % safety margin to limit the maximum temperature of the resistor.

Equation 7.6:

$$P = 2 \cdot I_{DI}^2 \cdot R$$

P = 2 x 0.003^2 x 22000 = 0.40 W

Select the next bigger standard size, for example **0.5 W**.

When the trip contacts are still closed and the CB is already open, the resistor has to withstand much higher power (Equation 7.7) for this short time.

Equation 7.7:

$$P = \frac{U_{MAX}^2}{R}$$

P = 121^2 / 22000 = 0.67 W

A 0.5 W resistor is enough for this short time peak power, too. However, if the trip relay is closed for longer than a few seconds, a 1 W resistor should be used.

7.15.2 Trip circuit supervision with two digital inputs

The benefit of this scheme is that no external resistor is needed.

The drawbacks are that two digital inputs and two extra wires from the relay to the CB compartment are needed. Additionally, the minimum allowed auxiliary voltage is 48 V dc which is more than twice the threshold voltage of the digital input because when the CB is in open position, the two digital inputs are in series.

- The first digital input is connected parallel to the auxiliary contact of the circuit breaker's open coil.
- Another auxiliary contact is connected in series with the circuitry of the first digital input. This makes it possible to supervise also the auxiliary contact in the trip circuit.
- The second digital input is connected in parallel with the trip contacts.
- Both inputs are configured as normal closed (NC).
- The user’s programmable logic is used to combine the digital input signals with an AND port. The delay is configured to be longer than the maximum fault time to inhibit any superfluous trip circuit fault alarm when the trip contact is closed.
- The output from the logic is connected to a relay in the output matrix giving out any trip circuit alarm.

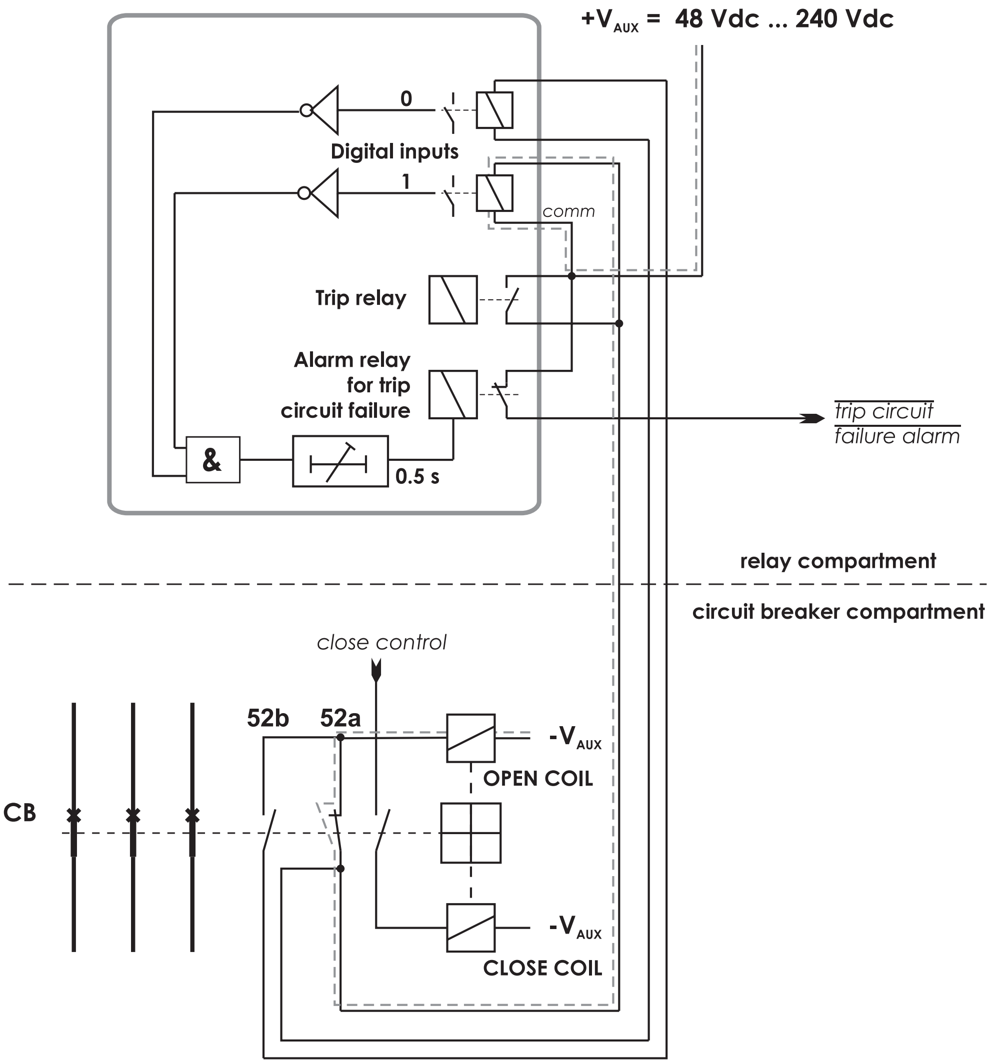


Figure 7.18: Trip circuit supervision with two digital inputs. The CB is closed. The supervised circuitry in this CB position is double-lined. The digital input is in active state when the trip circuit is complete. This is applicable for all digital inputs.

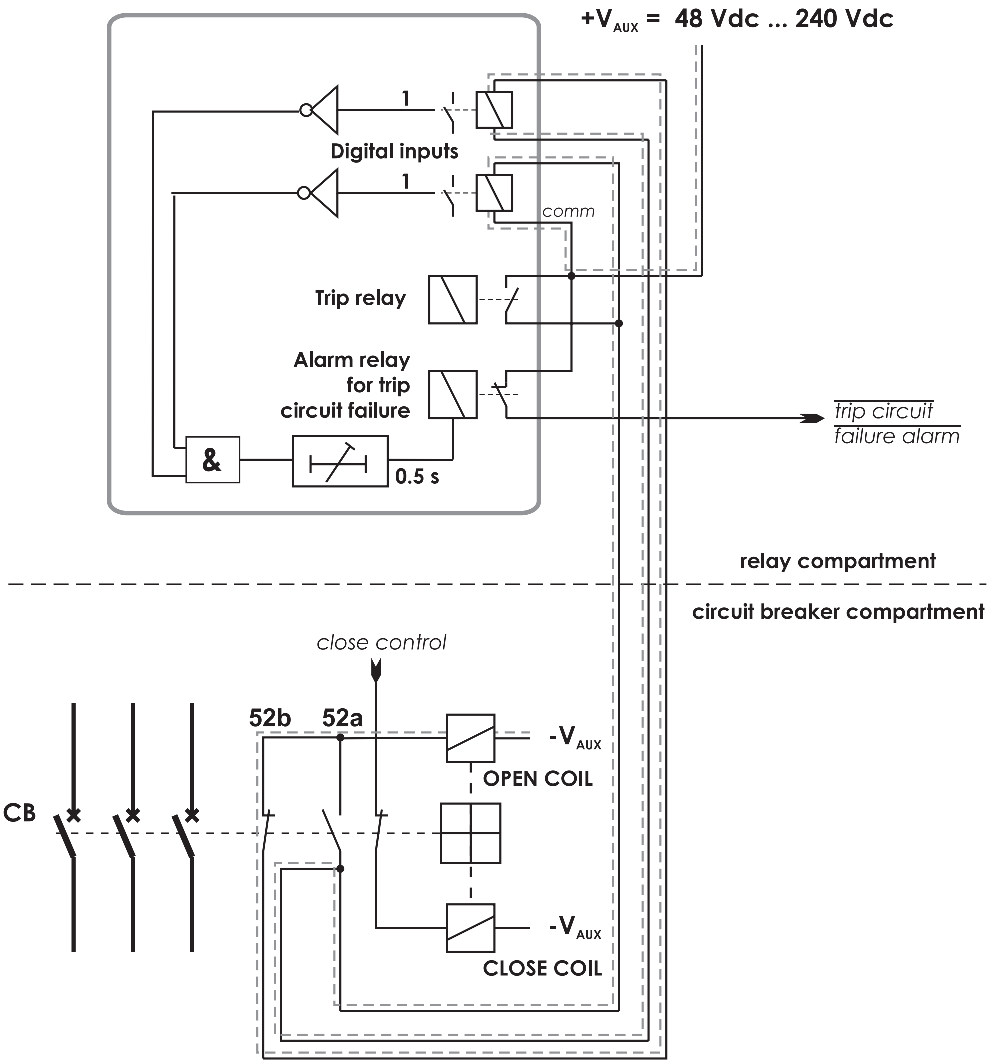


Figure 7.19: Trip circuit supervision with two digital inputs. The CB is in the open position. The two digital inputs are now in series.

DIGITAL INPUTS

Mode: DC

Counters max value: 16 bit

DIGITAL INPUTS

Input	Slot	State	Polarity	Delay	On Event	Off Event	Alarm display	Counters
1	2	1	NC	0.00	☐	☐	☐	1
2	2	1	NC	0.00	☐	☐	☐	1
3	2	0	NO	0.00	☑	☑	☑	1
4	2	0	NO	0.00	☑	☑	☑	1

Figure 7.20: An example of digital input configuration for trip circuit supervision with two digital inputs DI1 and DI2.

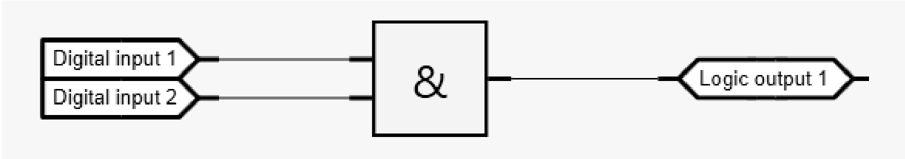


Figure 7.21: An example of logic configuration for trip circuit supervision with two digital inputs DI1 and DI2.

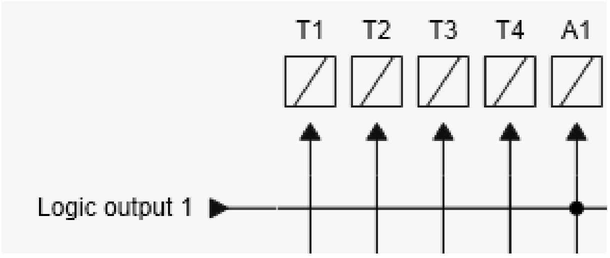


Figure 7.22: An example of output matrix configuration for trip circuit supervision with two digital inputs.

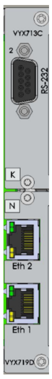
8 Communication and protocols

8.1 Communication ports

The relay has one fixed communication port: A USB port on the front panel for connection to Easergy Pro setting and configuration tool.

Optionally, the relay may have up to to 2 serial ports COM 3 and COM 4 for serial protocols (for example IEC 103) and one Ethernet port for Ethernet-based communication protocols (for example IEC 61850).

The number of available serial ports depends on the type of the communication option cards.



COM 1 and COM 2 ports

ETHERNET

NOTE: It is possible to have up to 2 serial communication protocols simultaneously in the same D9 and Ethernet connector but restriction is that same protocol can be used only once.

Protocol configuration menu contains selection for the protocol, port settings and message/error/timeout counters.

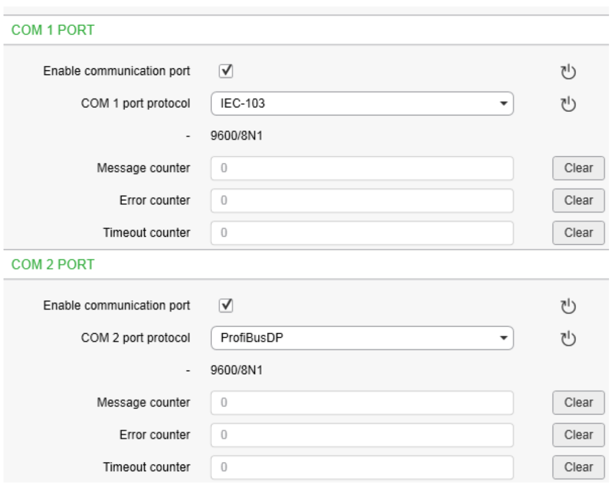


Figure 8.1: Protocols can be enabled in the “protocol configuration” menu. Only serial communication protocols are valid with RS-232 interface.

Table 8.1: Parameters

Parameter	Value	Unit	Description	Note
Protocol			Protocol selection for COM port	Set
	None		-	
	SPA-bus		SPA-bus (slave)	
	ProfibusDP		Interface to Profibus DB module VPA 3CG (slave)	
	ModbusSlv		Modbus RTU slave	
	IEC-103		IEC-60870-5-103 (slave)	
	ExternalIO		Modbus RTU master for external I/O-modules	
	IEC 101		IEC-608670-5-101	
	DNP3		DNP 3.0	
	DeviceNet		Interface to DeviceNet module VSE 009	
	GetSet		Communicationi protocola for Easergy Pro interface	
Msg#	$0 – 2^{32} - 1$		Message counter since the relay has restarted or since last clearing	Clr
Errors	$0 – 2^{16} - 1$		Protocol interruption since the re-lay has restarted or since last clearing	Clr
Tout	$0 – 2^{16} - 1$		Timeout interruption since the re-lay has restarted or since last clearing	Clr
	speed/DPS		Display of current communication parameters. speed = bit/s D = number of data bits P = parity: none, even, odd S = number of stop bits	1.

Set = An editable parameter (password needed)

Clr = Clearing to zero is possible

1. The communication parameters are set in the protocol specific menus. For the local port command line interface the parameters are set in configuration menu.

8.1.1 Ethernet port

The Ethernet port is used for Ethernet protocols like IEC61850 and Modbus TCP.

The physical interface is described in Chapter 10.5 Connections.

The parameters for the port can be set via the relay's front panel or using Easergy Pro. Two different protocols can be used simultaneously - both protocols use the same IP address and MAC address (but different port number).

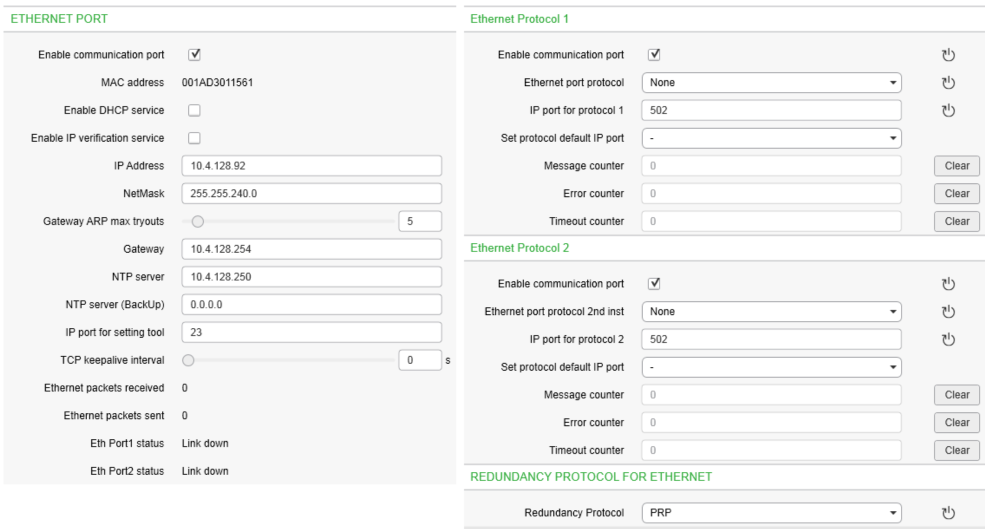


Figure 8.2: Setting view for serial and Ethernet protocols

8.2 Communication protocols

The protocols enable the transfer of the following type of data:

- events
- status information
- measurements
- control commands
- clock synchronization
- some settings through SPA bus and IEC-103 protocols

8.2.1 Modbus RTU and Modbus TCP

Modbus RTU and Modbus TCP protocols are often used in power plants and industrial applications. The difference between these two protocols is the media. Modbus TCP uses Ethernet and Modbus RTU uses RS-485, optic fibre, or RS-232.

Easergy Pro shows a list of all available data items for Modbus. They are also available as a zip file ("Communication parameter protocol mappings.zip").

The Modbus communication is activated via a menu selection with the parameter "Protocol". See Chapter 8.1 Communication ports.

For more information on Modbus configuration, see the document *P3APS18025EN Modbus configuration instructions for P3 relays*.

For the Ethernet interface configuration, see Chapter 8.1.1 Ethernet port.

8.2.2 Profibus DP

The Profibus DP protocol is widely used in the industry. An external VPA 3CG and VX072 cables are required.

Device profile "continuous mode"

In this mode, the relay is sending a configured set of data parameters continuously to the Profibus DP master. The benefit of this mode is the speed and easy access to the data in the Profibus master. The drawback is the maximum buffer size of 128 bytes, which limits the number of data items transferred to the master. Some PLCs have their own limitation for the Profibus buffer size, which may further limit the number of transferred data items.

Device profile "Request mode"

Using the request mode, it is possible to read all the available data from the Easergy P3 relay and still use only a very short buffer for

Profibus data transfer. The drawback is the slower overall speed of the data transfer and the need of increased data processing at the Profibus master as every data item must be separately requested by the master.

NOTE: In the request mode, it is not possible to read continuously only one single data item. At least two different data items must be read in turn to get updated data from the relay.

There is a separate manual for VPA 3CG for the continuous mode and request mode. The manual is available for downloading on our website.

Available data

Easergy Pro shows the list of all available data items for both modes. A separate document "Communication parameter protocol mappings.zip" is also available.

The Profibus DP communication is activated usually for remote port via a menu selection with parameter "Protocol". See Chapter 8.1 Communication ports.

8.2.3 SPA-bus

The relay has full support for the SPA-bus protocol including reading and writing the setting values. Also, reading multiple consecutive status data bits, measurement values or setting values with one message is supported.

Several simultaneous instances of this protocol, using different physical ports, are possible, but the events can be read by one single instance only.

There is a separate document "Communication parameter protocol mappings.zip" of SPA-bus data items available.

8.2.4 IEC 60870-5-103 (IEC-103)

The IEC standard 60870-5-103 "*Companion standard for the informative interface of protection equipment*" provides a standardized communication interface to a primary system (master system).

The unbalanced transmission mode of the protocol is used, and the relay functions as a secondary station (slave) in the communication. Data is transferred to the primary system using the "data acquisition by polling" principle.

The IEC functionality includes application functions:

- station initialization
- general interrogation
- clock synchronization
- command transmission.

It is not possible to transfer parameter data or disturbance recordings via the IEC 103 protocol interface.

The following application service data unit (ASDU) types can be used:

- ASDU 1: time-tagged message
- ASDU 3: Measurands I
- ASDU 5: Identification message
- ASDU 6: Time synchronization
- ASDU 8: Termination of general interrogation.

The relay accepts:

- ASDU 6: Time synchronization
- ASDU 7: Initiation of general interrogation
- ASDU 20: General command.
- ASDU 23: Disturbance recorder file transfer

The data in a message frame is identified by:

- type identification
- function type
- information number.

These are fixed for data items in the compatible range of the protocol, for example, the trip of I> function is identified by: type identification = 1, function type = 160 and information number = 90. "Private range" function types are used for such data items that are not defined by the standard (for example, the status of the digital inputs and the control of the objects).

The function type and information number used in private range messages is configurable. This enables flexible interfacing to different master systems.

For more information on IEC 60870-5-103 in Easergy P3 relays, see the "IEC 103 Interoperability List.pdf" and "Communication parameter protocol mappings.zip" documents.

8.2.5 DNP 3.0

The relay supports communication using the DNP 3.0 protocol. The following DNP 3.0 data types are supported:

- binary input
- binary input change
- double-bit input
- binary output
- analog input
- counters

For more information, see the “DNP 3.0 Device Profile Document" and "Communication parameter protocol mappings.zip". DNP 3.0 communication is activated via menu selection. RS-485 interface is often used but also RS-232 and fibre optic interfaces are possible.

8.2.6 IEC 60870-5-101 (IEC-101)

The IEC 60870-5-101 standard is derived from the IEC 60870-5 protocol standard definition. In Easergy P3 relays, the IEC 60870-5-101 communication protocol is available via menu selection. The relay works as a controlled outstation (slave) unit in unbalanced mode.

The supported application functions include process data transmission, event transmission, command transmission, general interrogation, clock synchronization, transmission of integrated totals, and acquisition of transmission delay.

For more information on IEC 60870-5-101 in Easergy P3 relays, see the "Communication parameter protocol mappings.zip" document.

8.2.7 IEC 61850

The IEC 61850 protocol is available with the optional communication module. It can be used to read or write static data from the relay or to receive events and to receive or send GOOSE messages from or to other relays.

The IEC 61850 server interface contains:

- configurable data model: selection of logical nodes corresponding to active application functions
- configurable pre-defined data sets
- supported dynamic data sets created by clients
- supported reporting function with buffered and unbuffered Report Control Blocks
- sending analogue values over GOOSE
- supported control modes:
  - direct with normal security
  - direct with enhanced security
  - select before operation with normal security
  - select before operation with enhanced security
- supported horizontal communication with GOOSE: configurable GOOSE publisher data sets, configurable filters for GOOSE subscriber inputs, GOOSE inputs available in the application logic matrix

Additional information can be obtained from the separate documents “IEC 61850 interface in Easergy P3 relays configuration instruction.pdf” and "Communication parameter protocol mappings.zip".

8.2.8 EtherNet/IP

The relay supports communication using the EtherNet/IP protocol which is a part of the Common Industrial Protocol (CIP) family. The EtherNet/IP protocol is available with the optional inbuilt Ethernet port. The protocol can be used to read or write data from or to the relay using request / response communication or via cyclic messages transporting data assigned to assemblies (sets of data).

For more detailed information and parameter lists for EtherNet/IP, refer to a separate application note “EtherNet/IP configuration instructions.pdf”.

For the complete data model of EtherNet/IP, refer to the document “DeviceNet and EtherNetIP data model.pdf” and "Communication parameter protocol mappings.zip".

8.2.9 HTTP server – Webset

The Webset HTTPS configuration interface provides the option to configure the relay with a standard web browser such as Internet Explorer, Mozilla Firefox, or Google Chrome. The feature is available when the communication option C, D, N or R is in use.

A subset of the relays's features is available in the Webset interface. The group list and group view from the relay are provided, and most groups, except the LOGIC and the MIMIC groups are configurable.

9 Applications and configuration examples

This chapter describes the protection functions in different protection applications.

The relay can be used for line/feeder protection of medium voltage networks with a grounded, low-resistance grounded, isolated or a compensated neutral point. The relays have all the required functions to be applied as a backup relay in high-voltage networks or to a transformer differential relay. In addition, the relay includes all the required functions to be applied as a motor protection relay for rotating machines in industrial protection applications.

The relays provide a circuit breaker control function. Additional primary switching relays (earthing switches and disconnector switches) can also be controlled from the front panel or the control or SCADA/automation system. A programmable logic function is also implemented in the relay for various applications, for example interlockings schemes.

9.1 Rotor earth fault protection application

Rotor earth fault protection can be utilized with an injection source connected between earth and one side of the field circuit with a capacitive coupling. The filed circuit is subjected to an alternating potential at substantially the same level throughout. An earth fault anywhere in the field system gives rise to a current that is detected by the protection relay. This scheme is suitable for generators that incorporate brushes in the main generator field winding.

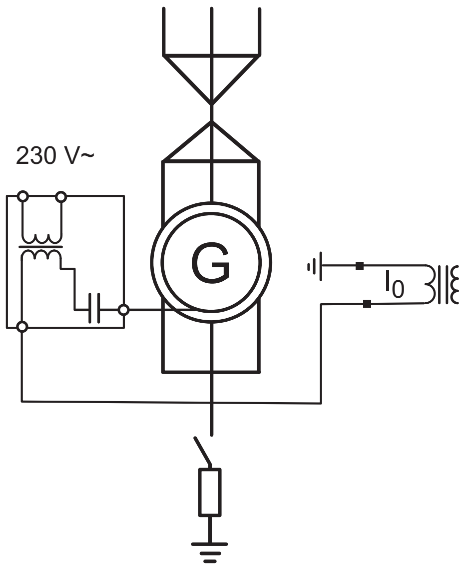


Figure 9.1: Rotor earth-fault protection principle of field circuit by alternating current injection

9.2 Using CSH120 and CSH200 with core balance CTs

General

The CSH120 and CSH200 core balance CTs are for direct earth fault overcurrent measurement. The only difference between them is the diameter. Because of their low-voltage insulation, they can only be used on cables.

These core balance CTs can be connected to the Easergy P3 protection relay range when 0.2 A I_0 input is used. This needs to be determined when ordering the protection relay (select 0.2 A for the earth fault current input in the order code).

Settings in Easergy P3 protection relay

When CSH120 or CSH200 is connected to an Easergy P3 protection relay, to secure correct operation of the protection functions and measurement values, use the following values in the **Scaling** setting view:

- I_{0X} CT primary: 470 A
- I_{0X} CT secondary: 1 A
- Nominal I_{0X} input: 0.2 A

NOTE: X refers to the I_0 input channel number (1 or 2).

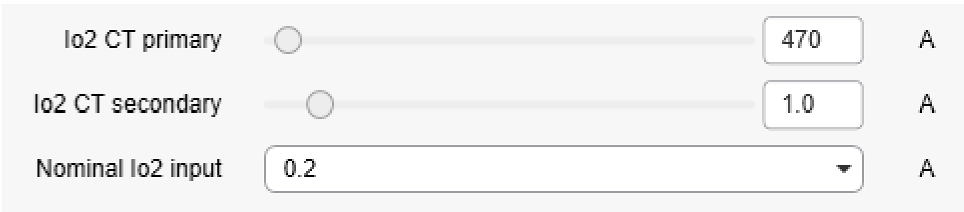


Figure 9.2: Scalings view for I_{02} input

Measuring specifications

When CSH120 or CSH200 is used with Easergy P3 protection relays the measuring range is 0.2 A–300 A of primary current. The minimum setting for primary current is 0.005xI_N which in this case means 0.005 x 470 A = 2.35 A of primary current.

Figure 9.3: Earth fault overcurrent setting view

10 Installation

10.1 Checking the consignment

Check that the unit packaging and the seal are intact at the receipt of the delivery. Our products leave the factory in closed, sealed packaging. If the transport packaging is open or the seal is broken, the confidentiality and authenticity of the information contained in the products cannot be ensured.

10.2 Product identification

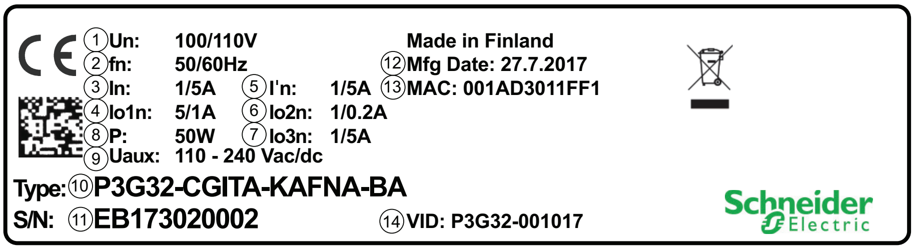
Each Easergy P3 relay is delivered in a separate package containing:

- Easergy P3 protection relay with the necessary terminal connectors
- Production testing certificate
- Quick Start manual

Optional accessories are delivered in separate packages.

To identify an Easergy P3 protection relay, see the labels on the package and on the side of the relay.

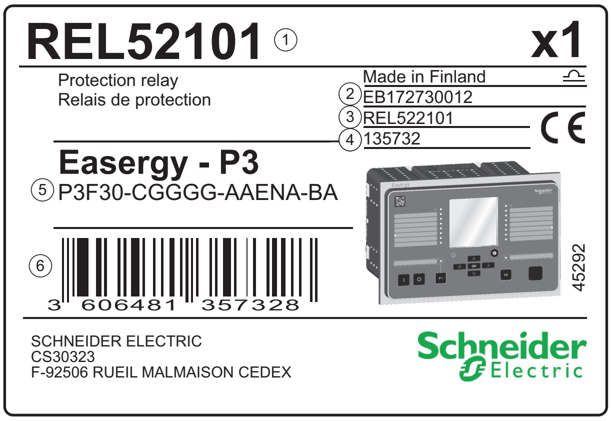
Serial number label



1. Rated voltage U_N
2. Rated frequency f_N
3. Rated phase current I_N
4. Rated earth fault current I_{01N}
5. Rated phase current I'_N (*
6. Rated earth fault current I_{02N}
7. Rated earth fault current I_{03N} (*
8. Power consumption
9. Power supply operating range U_{AUX}
10. Order code
11. Serial number
12. Manufacturing date
13. MAC address for TCP/IP communication
14. Production identification

*) Available in P3M32, P3T32 and P3G32 models only

Unit package label



1. Short order code
2. Serial number
3. Short order code
4. Internal product code
5. Order code
6. EAN13 bar code

10.3 Storage

Store the relay in its original packaging in a closed, sheltered location with the following ambient conditions:

- ambient temperature: -40 °C to +70 °C (or -40 °F to +158 °F)
- humidity < 90 %.

Check the ambient conditions and the packaging yearly.

10.4 Mounting

⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- Wear your personal protective equipment (PPE) and comply with the safe electrical work practices. For clothing refer applicable local standards.
- Only qualified personnel should install this equipment. Such work should be performed only after reading this entire set of instructions and checking the technical characteristics of the relay.
- NEVER work alone.
- Turn off all power supplying this equipment before working on or inside it. Consider all sources of power, including the possibility of backfeeding.
- Always use a properly rated voltage sensing relay to ensure that all power is off.
- Do not open the secondary circuit of a live current transformer.
- Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

Failure to follow this instruction will result in death or serious injury.

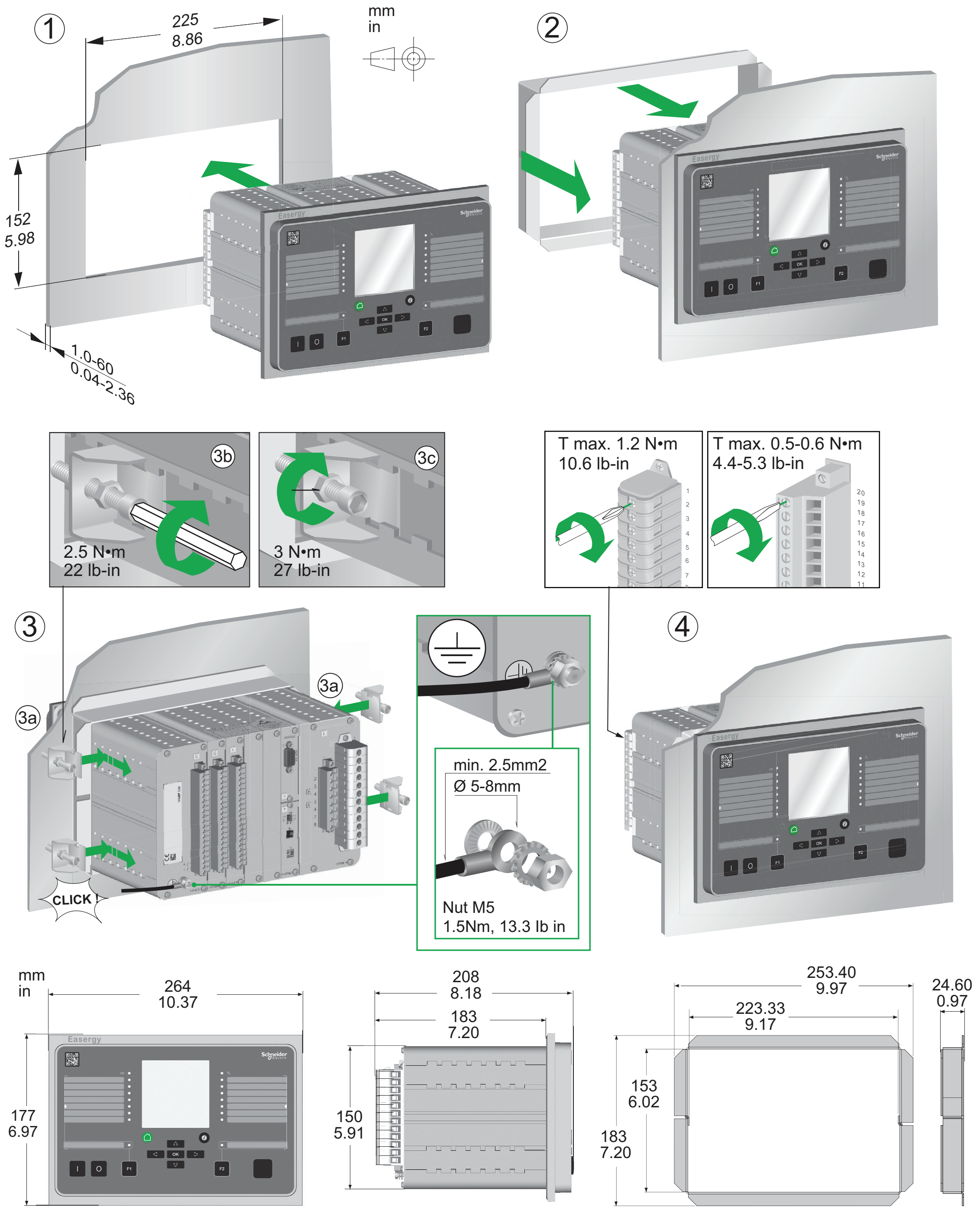
⚠ CAUTION

HAZARD OF CUTS

Trim the edges of the cut-out plates to remove any jagged edges.

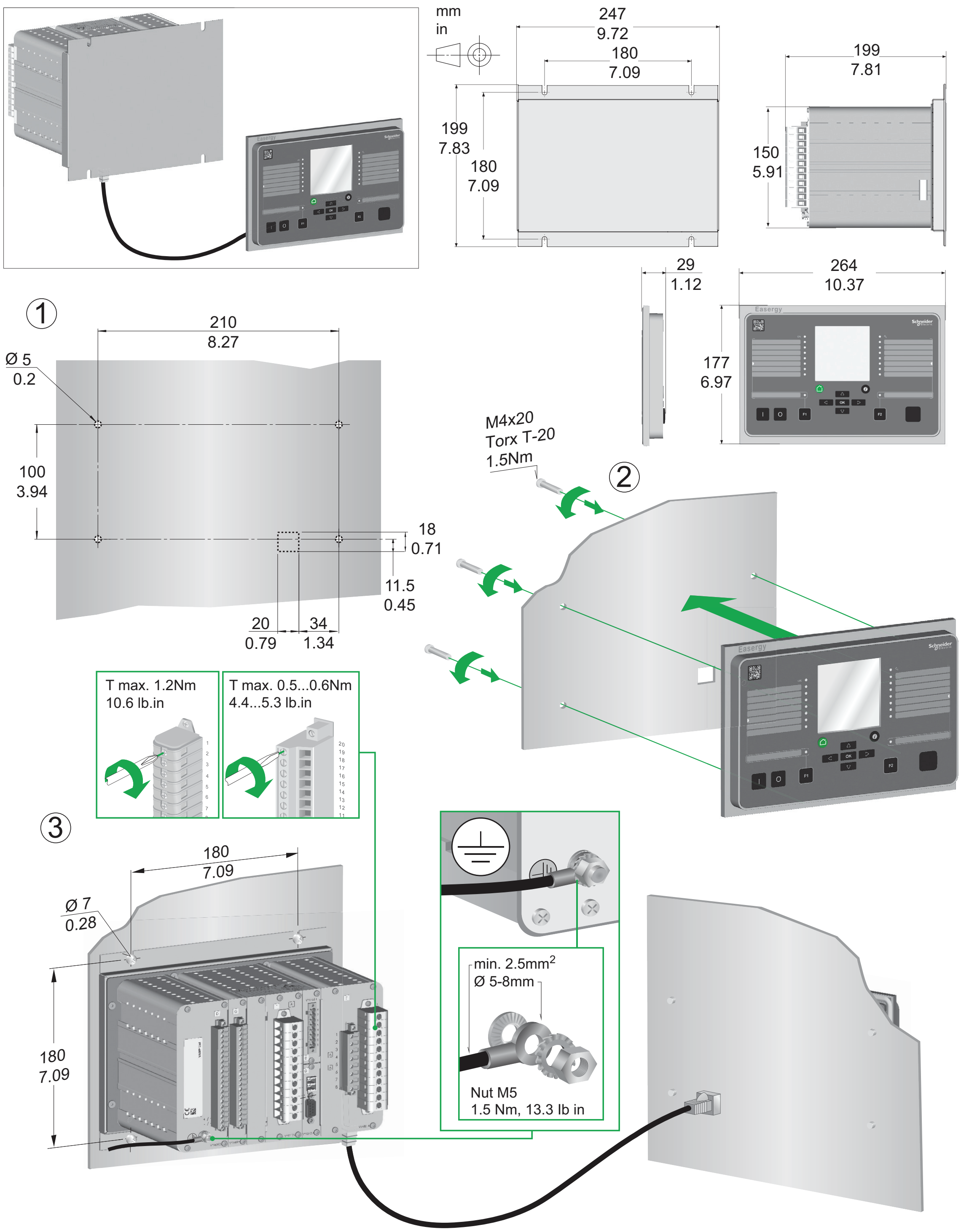
Failure to follow these instructions can result in injury.

Panel mounting



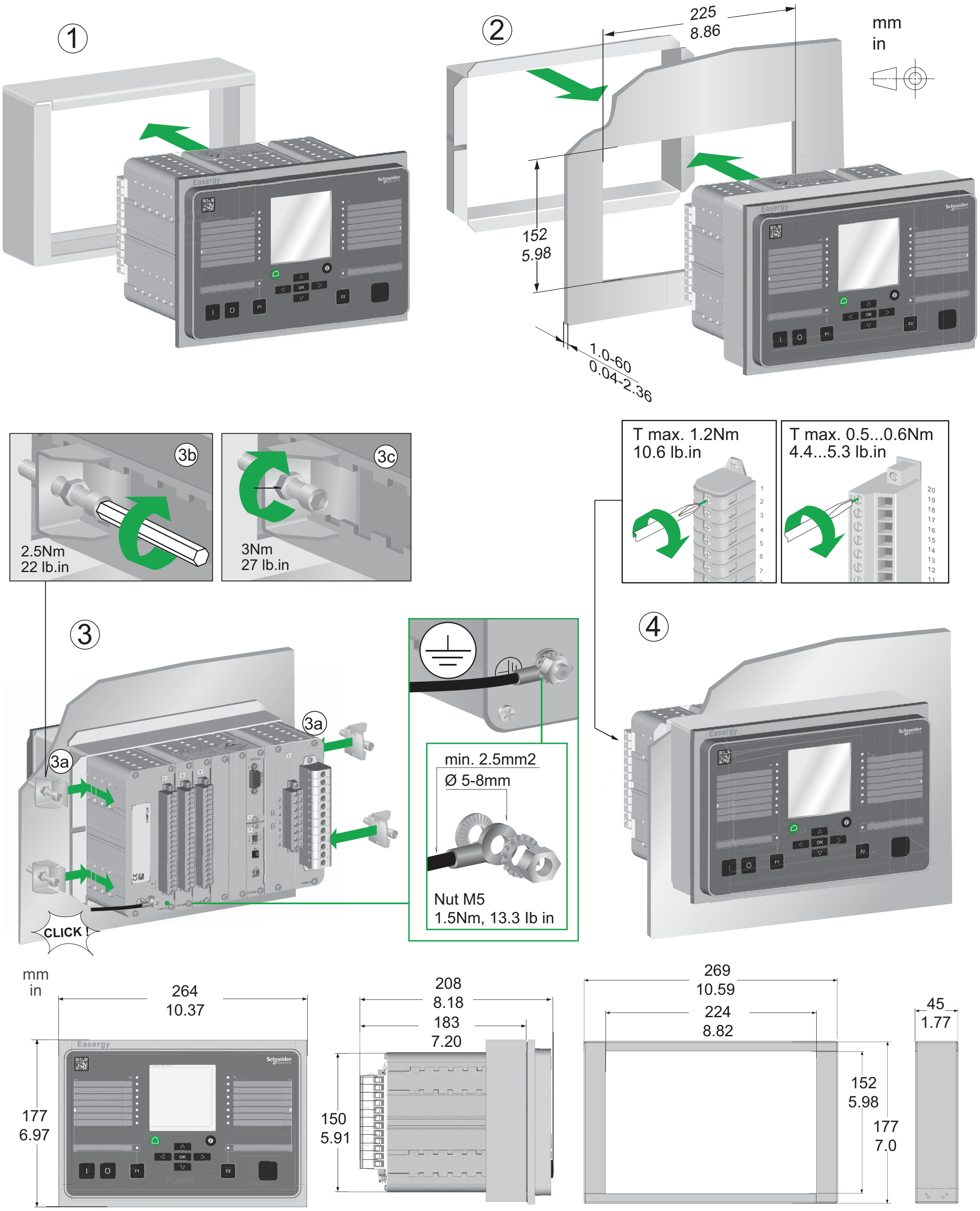
The conventional mounting technique has always been installing the relay on the secondary compartment's door. A limitation of this approach could be that the door construction is not strong enough for the relay's weight and wiring a large amount of secondary and communication cabling could be challenging.

Panel mounting with detachable display



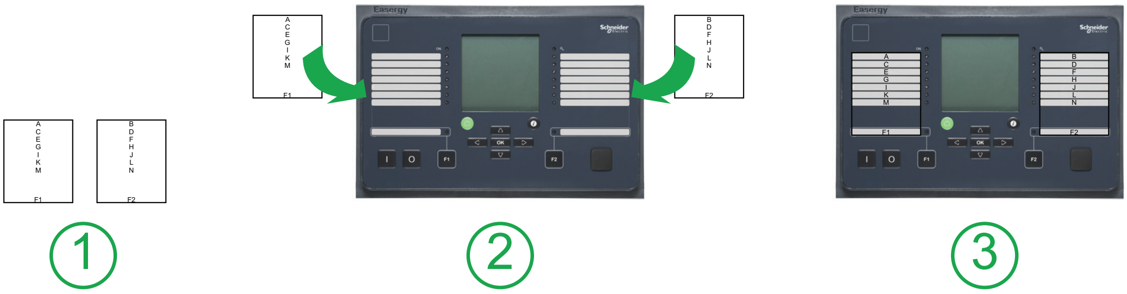
This mounting technique allows the door to be lighter as the relay's frame is installed on the back of the secondary compartment. Normally, the relay is mounted by the terminal blocks, hence the secondary wiring is short. Communication cabling is easier, too, as the door movement does not need to be considered. In this case, only the communication between relay base and display have to be wired.

Projection mounting



If the depth dimension behind the compartment door is limited, the relay can be equipped with a frame around the collar. This arrangement reduces the depth inside the compartment by 45 mm. More details please see Table 11.5.

Example of the P3 alarm facial label insertion



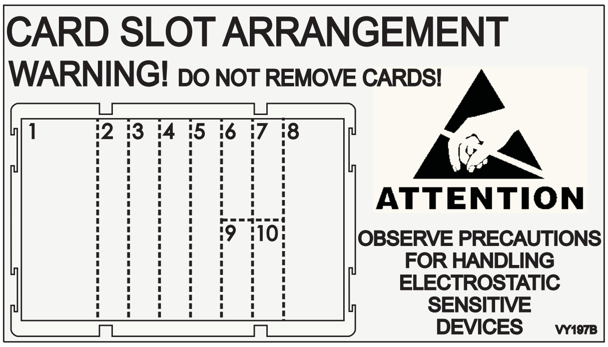
See "P3 Advanced Series facial label instruction" document for more information.

Protective film

NOTICE
RISK OF DESTRUCTION OF THE RELAY The protective film on the relay's display is plastic and can melt if exposed to high temperatures intensive sunlight. Remove the protective film after mounting the relay. **Failure to follow these instructions can result in equipment damage.**

10.5 Connections

The Easergy P3G30, P3G32 has a fixed combination of analog interface, power supply, digital input and output, communication and arc flash protection cards as per the chosen order code. Do not remove cards from the relay's card slots in any circumstances.



10.5.1 Supply voltage cards

Auxiliary voltage

⚠ DANGER

HAZARD OF ELECTRIC SHOCK

Before connecting the devices, disconnect the supply voltage to the unit.

Failure to follow these instructions will result in death or serious injury.

The external auxiliary voltage U_{AUX} (110–240 V ac/dc, or optionally 24–48 V dc) of the relay is connected to the pins 1/C/1:1–2 or 1/D/1:1–2.

NOTE: When an optional 24–48 V dc power module is used, the polarity is as follows: 1/D/2:2 positive (+), 1/D/2:1 negative (-).

NOTICE

LOSS OF PROTECTION OR RISK OF NUISENCE TRIPPING

- If the relay is no longer supplied with power or is in permanent fault state, the protection functions are no longer active and all the Easergy P3 digital outputs are dropped out.
- Check that the operating mode and SF relay wiring are compatible with the installation.

Failure to follow these instructions can result in equipment damage and unwanted shutdown of the electrical installation.

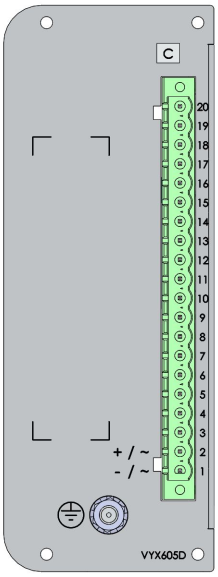


Figure 10.1: Example of supply voltage card Power C 110-240

Table 10.1: Supply voltage card Power C 110-240 & Power D 24-48

Pin No.	Symbol	Description
20	T12	Heavy duty trip relay 12 for arc protection
19	T12	Heavy duty trip relay 12 for arc protection
18	T11	Heavy duty trip relay 11 for arc protection
17	T11	Heavy duty trip relay 11 for arc protection
16	T10	Heavy duty trip relay 10 for arc protection
15	T10	Heavy duty trip relay 10 for arc protection
14	T9	Heavy duty trip relay 9 for arc protection
13	T9	Heavy duty trip relay 9 for arc protection
12	T1	Heavy duty trip relay 1 for arc protection
11	T1	Heavy duty trip relay 1 for arc protection
10	A1 NO	Signal relay 1, normal open connector
9	A1 NC	Signal relay 1, normal closed connector
8	A1 COMMON	Signal relay 1, common connector
7	SF NC	Service status output, normal closed
6	SF NO	Service status output, normal open
5	SF COMMON	Service status output, common
4		No connection
3		No connection
2	L / + / ~	Auxiliary voltage
1	N / - / ~	Auxiliary voltage

⚠ DANGER

HAZARD OF ELECTRICAL SHOCK

Connect the device's protective ground to functional earth according to the connection diagrams presented in this document.

Failure to follow these instructions will result in death or serious injury.

10.5.2 Analogue measurement cards

⚠ DANGER

HAZARD OF ELECTRICAL SHOCK

Do not open the secondary circuit of a live current transformer.

Disconnecting the secondary circuit of a live current transformer may cause dangerous overvoltages.

Failure to follow these instructions will result in death or serious injury.

10.5.2.1 "E = 3L(5/1A) + 4U + 2I_0 (5/1A+1/0.2A)"

This card contains connections for current transformers for measuring of the phase currents L1–L3 and two earth fault overcurrents I_0, and four voltage transformers for measuring the U_0, ULL or ULN.

The relay is able to measure three phase currents, and two earth fault overcurrents. It also measures up to four voltage signals: line-to-line, line-to-neutral, neutral displacement voltage and voltage from another side (synchrocheck). See the voltage modes selection below:

- 3LN+U_0, 3LN+LL_Y, 3LN+LN_Y
- 2LL+U_0+LL_Y, 2LL+U_0+LN_Y
- LL+U_0+LL_Y+LL_Z, LN+U_0+LN_Y+LN_Z

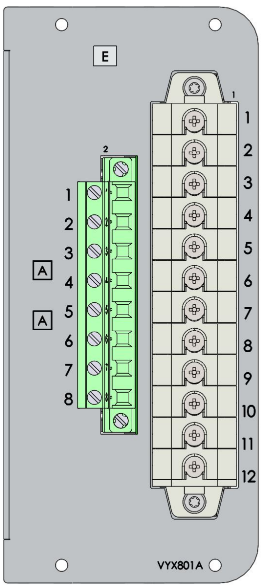


Figure 10.2: Analogue measurement card "E"

Table 10.2: Terminal pins 8/E/1:1–12

Pin No.	Symbol	Description
1	IL1 (S1)	Phase current L1 5/1A (S1)
2	IL1 (S2)	Phase current L1 5/1A (S2)
3	IL2 (S1)	Phase current L2 5/1A (S1)
4	IL2 (S2)	Phase current L2 5/1A (S2)
5	IL3 (S1)	Phase current L3 5/1A (S1)
6	IL3 (S2)	Phase current L3 5/1A (S2)
7	Io1 (S1)	Earth fault overcurrent I_{01} (S1) common for 5A and 1A
8	Io1 (S2)	Earth fault overcurrent I_{01} 5A (S2)
9	Io1 (S2)	Earth fault overcurrent I_{01} 1A (S2)
10	Io2 (S1)	Earth fault overcurrent I_{02} (S1) common for 1A and 0.2A
11	Io2 (S2)	Earth fault overcurrent Io2 1A (S2)
12	Io2 (S2)	Earth fault overcurrent Io2 0.2A (S2)

Table 10.3: Terminal pins 8/E/2:1–8

Pin No.	Symbol	Description
1	ULL/ULN	Voltage ULL (a) /ULN (a)
2	ULL/ULN	Voltage ULL (b) /ULN (n)
3	ULL/ULN	Voltage ULL (a) /ULN (a)
4	ULL/ULN	Voltage ULL (b) /ULN (n)
5	Uo/ULL/ULN	Voltage Uo (a) / ULL (a) /ULN (a)
6	Uo/ULL/ULN	Voltage Uo (b) /ULL (b) /ULN (n)
7	Uo/ULN/ULL	Voltage Uo (da) / ULL (a) / ULN (n)
8	Uo/ULN/ULL	Voltage Uo (dn) / ULL (b) / ULN (n)

10.5.2.2 "F = 3L(1A) + 4U + 2I$_0$ (5/1A+1/0.2A)"

This card contains connections for current transformers for measuring the phase currents L1–L3 and two earth fault overcurrents I_0 and four voltage transformers for measuring the U_0, ULL or ULN.

The relay is able to measure three phase currents, and two earth fault overcurrents. It also measures up to four voltage signals: line-to-line, line-to-neutral, zero-sequence voltage and voltage from another side (synchro-check). See the voltage modes selection below:

- $3LN+U_0$, $3LN+LL_Y$, $3LN+LN_Y$
- $2LL+U_0+LL_Y$, $2LL+U_0+LN_Y$
- $LL+U_0+LL_Y+LL_Z$, $LN+U_0+LN_Y+LN_Z$

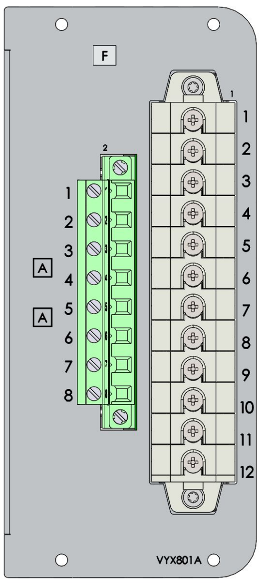


Figure 10.3: Analogue measurement card "F"

Table 10.4: Terminal pins 8/F/1:1–12

Pin No.	Symbol	Description
1	IL1 (S1)	Phase current L1 1A (S1)
2	IL1 (S2)	Phase current L1 1A (S2)
3	IL2 (S1)	Phase current L2 1A (S1)
4	IL2 (S2)	Phase current L2 1A (S2)
5	IL3 (S1)	Phase current L3 1A (S1)
6	IL3 (S2)	Phase current L3 1A (S2)
7	Io1 (S1)	Earth fault overcurrent I_{01} (S1) common for 5A and 1A
8	Io1 (S2)	Earth fault overcurrent I_{01} 5A (S2)
9	Io2 (S2)	Earth fault overcurrent I_{01} 1A (S2)
10	Io2 (S1)	Earth fault overcurrent I_{02} (S1) common for 1A and 0.2A
11	Io2 (S2)	Earth fault overcurrent Io2 1A (S2)
12	Io2 (S2)	Earth fault overcurrent Io2 0.2A (S2)

Table 10.5: Terminal pins 8/F/2:1–8

Pin No.	Symbol	Description
1	ULL/ULN	Voltage ULL (a) /ULN (a)
2	ULL/ULN	Voltage ULL (b) /ULN (n)
3	ULL/ULN	Voltage ULL (a) /ULN (a)
4	ULL/ULN	Voltage ULL (b) /ULN (n)
5	ULL/ULN	Voltage ULL (a) /ULN (a)
6	ULL/ULN	Voltage ULL (b) /ULN (n)
7	Uo/ULL/ULN	U_0 (da)/ ULL (a)/ ULN (a)
8	Uo/ULL/ULN	U_0 (dn)/ ULL (b)/ ULN (n)

10.5.2.3 “T = 3 x I (5/1A) + I_0 (5/1A)”

This card contains connections for current measurement transformers for measuring the phase currents L1, L2 and L3 and earth fault overcurrent I_0.
Totally, the relay is able to measure six phase currents, three earth fault overcurrents and additionally four voltages.

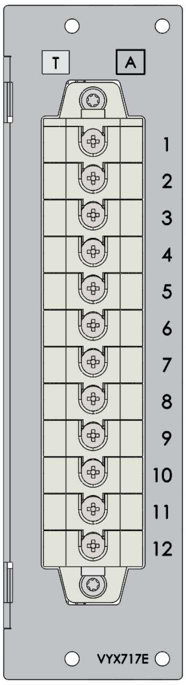


Figure 10.4: Analogue measurement card "T"

Table 10.6: Pins 4/A/1:1 – 12

Pin No.	Symbol	Description
1	I’L1	Phase current I’L1 (S1), common for 1A and 5A
2	I’L1 / 5A	Phase current I’L1 (S2)
3	I’L1 / 1A	Phase current I’L1 (S2)
4	I’L2	Phase current I’L2 (S1), common for 1A and 5A
5	I’L2 / 5A	Phase current I’L2 (S2)
6	I’L2 / 1A	Phase current I’L2 (S2)
7	I’L3	Phase current I’L3 (S1), common for 1A and 5A
8	I’L3 / 5A	Phase current I’L3 (S2)
9	I’L3 / 1A	Phase current I’L3 (S2)
10	I’o1	Earth fault overcurrent I’o1 (S1), common for 1A and 5A
11	I’o1 / 5A	Earth fault overcurrent I’o1 (S2)
12	I’o1 / 1A	Earth fault overcurrent I’o1 (S2)

10.5.3 I/O cards

10.5.3.1 I/O card "G = 6DI+4DO"

This card provides 6 digital inputs and 4 relays outputs. The threshold level is selectable in the order code.

The card is equipped with 6 dry digital inputs with hardware-selectable activation/threshold voltage and four trip contacts. Input and output contacts are normally open.

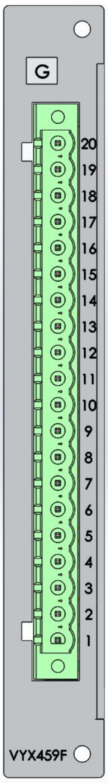


Table 10.7: Slots 2–5/G/1:1–20

Pin No.	Symbol	Description
20	Tx	Trip relay
19		
18	Tx	Trip relay
17		
16	Tx	Trip relay
15		
14	Tx	Trip relay
13		
12	DIx	Digital input
11		
10	DIx	Digital input
9		
8	DIx	Digital input
7		
6	DIx	Digital input
5		
4	DIx	Digital input
3		
2	DIx	Digital input
1		

NOTE: Digital inputs are polarity free which means that the user can freely choose "-" and "+" terminals to each digital input.

10.5.3.2 I/O card "I = 10DI"

This card provides 10 digital inputs. The threshold level is selectable in the order code.

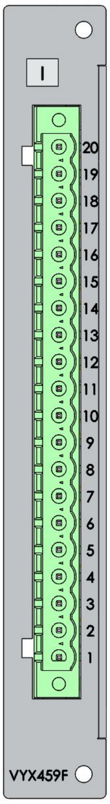


Table 10.8: Slots 2–5/I/1:1–20

Pin No.	Symbol	Description
20	DIx	Digital input
19		
18	DIx	Digital input
17		
16	DIx	Digital input
15		
14	DIx	Digital input
13		
12	DIx	Digital input
11		
10	DIx	Digital input
9		
8	DIx	Digital input
7		
6	DIx	Digital input
5		
4	DIx	Digital input
3		
2	DIx	Digital input
1		

NOTE: Digital inputs are polarity-free which means that you can freely choose "-" and "+" terminals for each digital input.

10.5.3.3 I/O card "H = 6DI + 4DO (NC)"

This card provides 6 digital inputs and 4 relays outputs which are normally closed (NC). The threshold level is selectable in the order code.

The 6xDI+4xDO option card is equipped with 6 dry digital inputs with hardware-selectable activation/threshold voltage and four normally closed (NC) trip contacts.

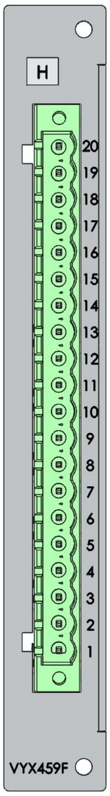


Table 10.9: Slots 2–5/G/1:1–20

Pin No.	Symbol	Description
20	Tx	Trip relay
19		
18	Tx	Trip relay
17		
16	Tx	Trip relay
15		
14	Tx	Trip relay
13		
12	DIx	Digital input
11		
10	DIx	Digital input
9		
8	DIx	Digital input
7		
6	DIx	Digital input
5		
4	DIx	Digital input
3		
2	DIx	Digital input
1		

10.5.4 I/O option card "D= 4Arc"

This card contains 4 arc point connections to 4 arc light sensors (e.g. VA 1 DA). The card provides sensors 3 to 6.

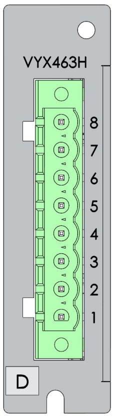


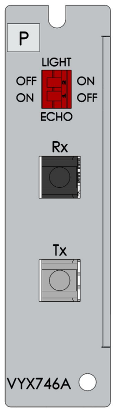
Table 10.10: Pins 6/D/1:1–8 (slot 6)

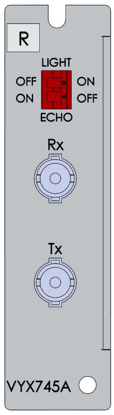
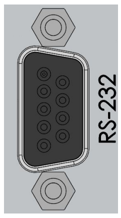
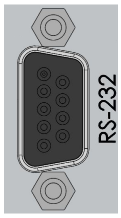
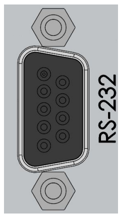
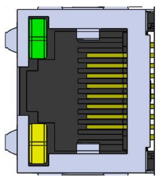
Pin No.	Symbol	Description
8	Sen 6 -	Arc sensor 6 negative terminal
7	Sen 6 +	Arc sensor 6 positive terminal
6	Sen 5 -	Arc sensor 5 negative terminal
5	Sen 5 +	Arc sensor 5 positive terminal
4	Sen 4 -	Arc sensor 4 negative terminal
3	Sen 4 +	Arc sensor 4 positive terminal
2	Sen 3 -	Arc sensor 3 negative terminal
1	Sen 3 +	Arc sensor 3 positive terminal

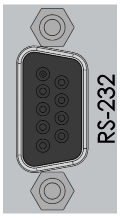
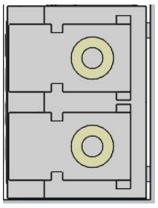
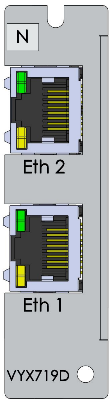
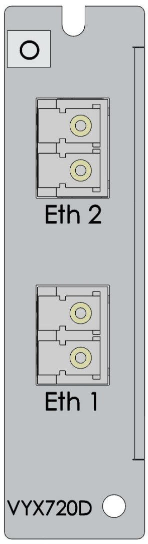
10.5.5 Communication cards

The communication card types and their pin assignments are introduced in Table 10.11.

Table 10.11: Communication option modules and their pin numbering

Type	Communication ports	Signal levels	Connectors	Pin usage
FibrePP (Slot 6 and 9)	Plastic fibre interface COM 1 port (if Slot 6 card) COM 3 port (if Slot 9 card)		Versatile Link fiber 	

Type	Communication ports	Signal levels	Connectors	Pin usage
FibreGG (Slot 6 and 9)	Glass fibre interface (62.5/125 μm) COM 1 port (if Slot 6 card) COM 3 port (if Slot 9 card)		ST 	
232 (Slot 6)	COM 1 / COM 2	RS-232	D-connector 	1 = TX COM 2 2 = TX COM 1 3 = RX COM 1 7 = GND 8 = RX COM 2 9 = +12V
232 (Slot 9)	COM 3 / COM 4	RS-232	D-connector 	1 = TX COM 4 2 = TX COM 3 3 = RX COM 3 4 = IRIG-B 5 = IRIG-B GND 6 = 7 = GND 8 = RX COM 4 9 = +12V
232+Eth RJ (Slot 9)	COM 3 / COM 4	RS-232	D-connector 	1 = TX COM 4 2 = TX COM 3 3 = RX COM 3 4 = IRIG-B 5 = IRIG-B GND 6 = 7 = GND 8 = RX COM 4 9 = +12V
	ETHERNET	ETHERNET 100 Mbps	RJ-45 	1 = Transmit + 2 = Transmit - 3 = Receive + 4 = 5 = 6 = Receive - 7 = 8 =

Type	Communication ports	Signal levels	Connectors	Pin usage
232+Eth LC (Slot 9)	COM 3 / COM 4	RS-232	D-connector 	1 = TX COM 4 2 = TX COM 3 3 = RX COM 3 4 = IRIG-B 5 = IRIG-B GND 6 = 7 = GND 8 = RX COM 4 9 = +12V
	ETHERNET	Light 100 Mbps	LC fiber connector 	1 = Receive 2 = Transmit
2EthRJ (Slot 9)	100Mbps Ethernet inter-face with IEC 61850	ETHERNET 100 Mbps	2 x RJ-45 	1=Transmit+ 2=Transmit- 3=Receive+ 4= 5= 6=Receive- 7= 8=
2EthLC (Slot 9)	100 Mbps Ethernet fibre interface with IEC 61850	Light 100 Mbps	2 x LC 	LC-connector from top: -Port 2 Tx -Port 2 Rx -Port 1 Tx -Port 1 Rx

NOTE: When a communication option module of type B, C or D is used in slot 9, serial ports COM 3 / COM 4 are available.

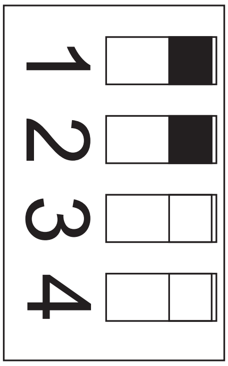


Figure 10.5: Dip switches in optic fibre options.

Dip switch number	Switch position	Function Fibre optics
1	Left	Echo off
1	Right	Echo on
2	Left	Light on in idle state
2	Right	Light off in idle state
3	Left	Not applicable
3	Right	Not applicable
4	Left	Not applicable
4	Right	Not applicable

10.5.5.1 COM 3–COM 4 ports

COM 3 and COM 4 PORT are ports for serial communication protocols. The type of the physical interface on these ports depends on the type of the selected communication option module. The use of some protocols may require a certain type of option module. The parameters for these ports are set via the front panel or with Easergy Pro in menus COM 3 PORT – COM 4 PORT.

Communication information is normally sent to the control system (SCADA), but it is also possible to use certain communication-related notifications internally, for example alarms. This is can be done for example via the logic and different matrices.

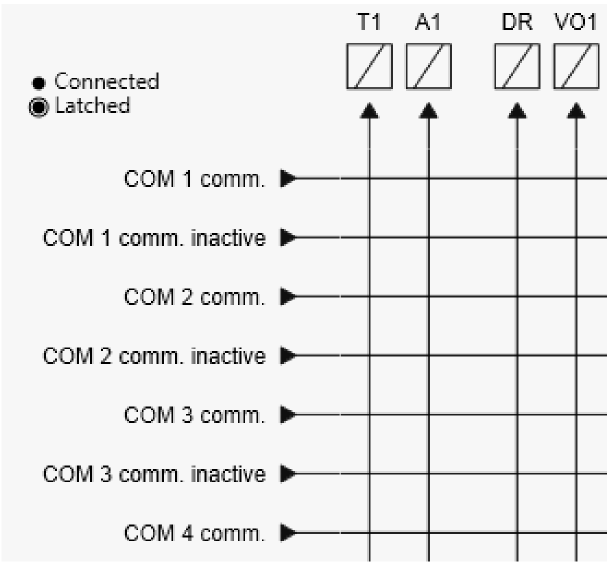
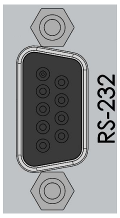


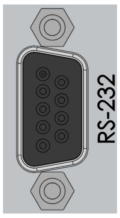
Figure 10.6: Communication-related noticifications can be connected to trip contacts in the “output matrix” menu.

Table 10.12: COM 3 port

Type	External module	Order code	Cable / order code	Typically used protocols
232+00 or 232+Eth RJ or 232+Eth LC (Slot 9) 	None	None	None	-None -IEC-101 -IRIG-B -GetSet
	VSE-009	VSE009	None	-None -DeviceNet
	VIO12-AB and VSE-002	VIO 12 AB VSE002	None	-None -ExternalIO
	VIO12-AC and VSE-002	VIO 12 AC VSE002	None	-None -ExternalIO
	VIO12-AD and VSE-002	VIO 12 AD VSE002	None	-None -ExternalIO
	VSE-001	VSE001	None	-None -IEC-103 -ModbusSlv -SpaBus
	VSE-002	VSE002	None	-None -IEC-103 -ModbusSlv -SpaBus -DNP3
	VPA-3CG	VPA3CG	VX072	-None -ProfibusDP

To be able to use COM 4 port, the RS-232 communication interface (Option B, C or D) has to be split in two by using a VX067 cable. When the VX-067 cable is connected, the below-mentioned protocols can be used in the COM 4 port:

Table 10.13: COM 4 port

Type	External module	Order code	Cable / order code	Typically used protocols
232+00 or 232+Eth RJ or 232+Eth LC +VX067 (Split cable) (Slot 9)  	None	None	None	-None -IEC-101 -IRIG-B -GetSet
	VSE-009	VSE-009	None	-None -DeviceNet
	VIO12-AB and VSE-002	VIO 12 AB VSE002	None	-None -ExternalIO
	VIO12-AC and VSE-002	VIO 12 AC VSE002	None	-None -ExternalIO
	VIO12-AD and VSE-002	VIO 12 AD VSE002	None	-None -ExternalIO
	VSE-001	VSE001	None	-None -IEC-103 -ModbusSlv -SpaBus
	VSE-002	VSE002	None	-None -IEC-103 -ModbusSlv -SpaBus -DNP3
	VPA-3CG	VPA3CG	VX068	-None -ProfibusDP

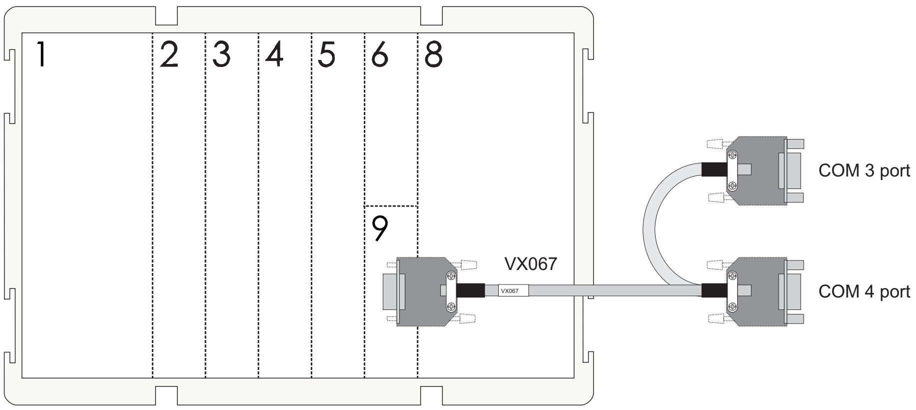


Figure 10.7: To be able to use COM 3 and COM 4 ports, VX067 must be used on the D-connector of slot 9 option card.

NOTE: It is possible to use 2 serial communication protocols simultaneously but the restriction is that the same protocol can be used only once.

The protocol configuration menu contains the selection for the protocol, port settings and message/error/timeout counters.

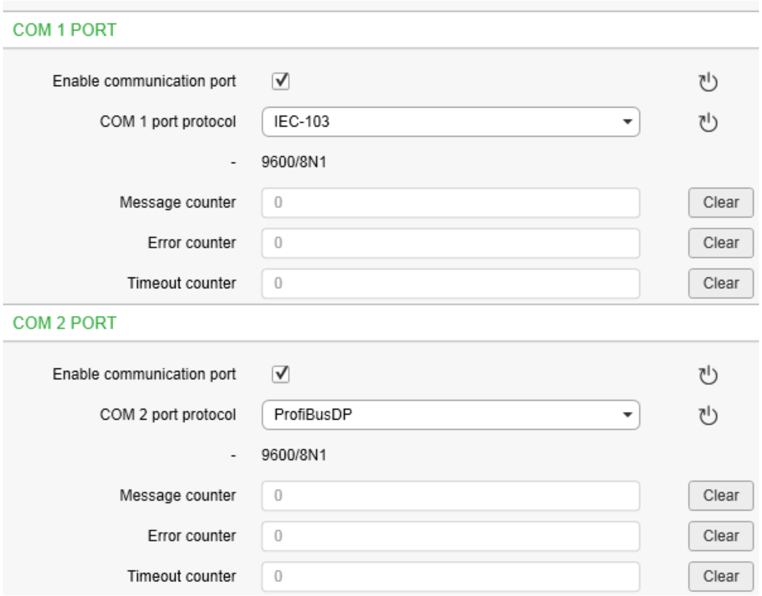


Figure 10.8: Protocols can be enabled in the “protocol configuration” menu. Only serial communication protocols are valid with the RS-232 interface.

Table 10.14: Parameters

Parameter	Value	Unit	Description	Note
Protocol			Protocol selection for COM port	Set
	None		-	
	SPA-bus		SPA-bus (slave)	
	ProfibusDP		Interface to Profibus DB module VPA 3CG (slave)	
	ModbusSlv		Modbus RTU slave	
	IEC-103		IEC-60870-5-103 (slave)	
	ExternalIO		Modbus RTU master for external I/O-modules	
	IEC 101		IEC-608670-5-101	
	DNP3		DNP 3.0	
	DeviceNet		Interface to DeviceNet module VSE 009	
	GetSet		Communicationi protocola for Easergy Pro interface	
Msg#	$0 – 2^{32} - 1$		Message counter since the relay has restarted or since last clearing	Clr
Errors	$0 – 2^{16} - 1$		Protocol interruption since the re-lay has restarted or since last clearing	Clr
Tout	$0 – 2^{16} - 1$		Timeout interruption since the re-lay has restarted or since last clearing	Clr

Parameter	Value	Unit	Description	Note
	speed/DPS		Display of current communication parameters. speed = bit/s D = number of data bits P = parity: none, even, odd S = number of stop bits	1.

Set = An editable parameter (password needed). Clr = Clearing to zero is possible.

1. The communication parameters are set in the protocol-specific menus. For the local port command line interface, the parameters are set in the configuration menu.

10.5.6 Local port (Front panel)

The relay has a USB port in the front panel.

Protocol for the USB port

The front panel USB type B port is always using the command line protocol for Easergy Pro.

The speed of the interface is defined in the CONF/DEVICE SETUP menu via the front panel. The default settings for the relay are 38400/8N1.

It is possible to change the front USB port's bit rate. This setting is visible only on the relay's local display. The bit rate can be set between 1200 and 187500. This changes the bit rate of the relay, and the Easergy Pro bit rate has to be set separately. If the bit rate in the setting tool is incorrect, it takes a longer time to establish the communication.

NOTE: Use the same bit rate in the relay and the Easergy Pro setting tool.

10.5.7 Connection data

Table 10.15: Auxiliary power supply

U_{AUX}	110 (-20%) – 240 (+10%) V ac/dc 110/120/220/240 V ac 110/125/220 V dc or 24–48 ±20% V dc 24/48 V dc
Power consumption - Normal state - Maximum state (all outputs activated)	 < 20 W < 28 W
Terminal block: - MSTB2.5–5.08	Wire cross section: Maximum 2.5 mm^2 (13–14 AWG) Minimum 1.5 mm^2 (15–16 AWG) Wire type: single strand or stranded with insulated crimp terminal

Table 10.16: Digital inputs technical data

Number of inputs	As per the order code
Voltage withstand	255 V ac/dc
(as per the order code letters) Nominal operation voltage for DI inputs	A: 24–230 V ac/dc (max. 255 V ac/dc) B: 110–230 V ac/dc (max. 255 V ac/dc) C: 220–230 V ac/dc (max. 255 V ac/dc)
Typical switching threshold (as per order code letters)	A: 12 V dc B: 75 V dc C: 155 V dc
Current drain	< 4 mA (typical approx. 3mA)
Cycle time	10 ms
Activation time dc/ac	< 11 ms / < 15 ms
Reset time dc/ac	< 11 ms / < 15 ms
Terminal block: - MSTB2.5–5.08	Wire cross section: Maximum 2.5 mm^2 (13–14 AWG) Minimum 1.5 mm^2 (15–16 AWG) Wire type: single strand or stranded with insulated crimp terminal

NOTE: Set the dc/ac mode according to the used voltage in Easergy Pro.

Table 10.17: Trip contact, high break

Number of contacts	5 normal open contacts
Rated voltage	250 V ac/dc
Continuous carry	5 A
Minimum making current	100 mA @ 24 Vdc
Make and carry, 0.5 s at duty cycle 10% Make and carry, 3 s at duty cycle 10%	30 A 15 A
Breaking capacity, AC	2 000 VA
Breaking capacity, DC (L/R=40ms) at 48 V dc: at 110 V dc: at 220 V dc	 5 A 3 A 1 A
Contact material	AgNi 90/10
Terminal block: - MSTB2.5–5.08	Wire cross section: Maximum 2.5 mm^2 (13–14 AWG) Minimum 1.5 mm^2 (15–16 AWG) Wire type: single strand or stranded with insulated crimp terminal

NOTE: High-break trip contacts exist in power module C and D only.

Table 10.18: Trip contact, Tx

Number of contacts	As per the order code
Rated voltage	250 V ac/dc
Continuous carry	5 A
Minimum making current	100 mA at 24 Vdc
Make and carry, 0.5 s Make and carry, 3 s	30 A 15 A
Breaking capacity, ac	2 000 VA
Breaking capacity, dc (L/R = 40ms)	
at 48 V dc:	1.15 A
at 110 V dc:	0.5 A
at 220 V dc:	0.25 A
Contact material	AgNi 90/10
Terminal block: - MSTB2.5 - 5.08	Wire cross section: Maximum 2.5 mm^2 (13–14 AWG) Minimum 1.5 mm^2 (15–16 AWG) Wire type: single strand or stranded with insulated crimp terminal

Table 10.19: Signal contact, A1

Number of contacts:	1
Rated voltage	250 V ac/dc
Continuous carry	5 A
Minimum making current	100 mA at 24 V ac/dc
Breaking capacity, dc (L/R = 40ms)	
at 48 V dc:	1 A
at 110 V dc:	0.3 A
at 220 V dc:	0.15 A
Contact material	AgNi 0.15 gold plated
Terminal block - MSTB2.5 - 5.08	Wire cross section Maximum 2.5 mm^2 (13–14 AWG) Minimum 1.5 mm^2 (15–16 AWG) Wire type: single strand or stranded with insulated crimp terminal

Table 10.20: Signal contact, SF

Number of contacts:	1
Rated voltage	250 V ac/dc
Continuous carry	5 A
Minimum making current	100 mA @ 24 V ac/dc
Breaking capacity, DC (L/R = 40ms)	
at 48 V dc:	1 A
at 110 V dc:	0.3 A
at 220 V dc	0.15 A
Contact material	AgNi 0.15 gold plated
Terminal block - MSTB2.5 - 5.08	Wire cross section Maximum 2.5 mm^2 (13–14 AWG) Minimum 1.5 mm^2 (15–16 AWG) Wire type: single strand or stranded with insulated crimp terminal

Table 10.21: Local serial communication port

Number of ports	1 on front
Electrical connection	USB
Data transfer rate	1 200 – 187 500 b/s
Protocols	GetSet

Table 10.22: Arc sensor inputs

Number of inputs	As per the order code
Supply to sensor	Isolated 12 V dc

Table 10.23: COM 3-4 serial communication port

Number of physical ports	0 - 1 on rear panel (option)
Electrical connection	RS-232 (option, IRIG-B included) RS-485 (option) Profibus (option, external module) Glass fibre connection (option, external module)
Protocols	Modbus RTU, master Modbus RTU, slave Spabus, slave IEC 60870-5-103 IEC 61870-5-101 Profibus DP DNP 3.0 IRIG-B

Table 10.24: Ethernet communication port

Number of ports	0–2 on rear panel (option)
Electrical connection	RJ-45 100 Mbps (option) LC 100Mbps (option)
Protocols	IEC 61850 Modbus TCP DNP 3.0 EtherNet/IP IEC 61870-5-101

Table 10.25: Fiber Ethernet communication port

Number of ports	0 or 2 on rear panel (option)
Connection type	LC 100 Mbps
Optical Characteristics:	Operates with 62.5/125 µm and 50/125 µm multimode fiber Center Wavelength: 1300 nm typical Output Optical Power: • Fiber: 62.5/125 µm, NA = 0.275 23.0 dBm • Fiber: 50/125 µm, NA = 0.20 26.0 dBm Input Optical Power: -31 dBm
Protocols	IEC 61850 Modbus TCP DNP 3.0 EtherNet/IP IEC 61870-5-101

Table 10.26: Measuring circuits

Phase current inputs I' (5/1 A)	**Slot 4:** **T = 3 x I (5/1A) + I_0 (5/1A)**	
Rated phase current - Current measuring range - Thermal withstand ● continuously ● 10 s ● 1 s ● 10 ms - Burden - Impedance	5 A 0.05–250 A 20 A 100 A 500 A 1250 A 0.075 VA 0.003 Ohm	1 A 0.02–50 A 4 A 20 A 100 A 250 A 0.02 VA 0.02 Ohm
Io input (5A and 1A)		
Rated earth fault overcurrent - Current measuring range - Thermal withstand ● continuously ● 10 s ● 1 s - Burden - Impedance	5 A 0.05–250 A 20 A 100 A 500 A 0.075 VA 0.003 Ohm	1 A 0.02–50 A 4 A 20 A 100 A 0.02 VA 0.02 Ohm
Phase current inputs I (1A, 5 A)	**Slot 8:** **E = 3L (5/1A) + 4U + 2I_0 (5/1A+1/0.2A)**	**-** **F = 3L (1 A) + 4U + 2I_0 (5/1A+1/0.2A)**
Rated phase current - Current measuring range - Thermal withstand ● continuously ● 10 s ● 1 s ● 10 ms - Burden - Impedance	5 A 0.05–250 A 20 A 100 A 500 A 1250 A 0.075 VA 0.003 Ohm	1A 0.02–50 A 4 A 20 A 100 A 250 A 0.02 VA 0.02 Ohm
I_0 input (5 A)	**Slot 8:** **E = 3L (5/1A) + 4U + 2I_0 (5/1A+1/0.2A)**	
Rated earth fault overcurrent - Current measuring range - Thermal withstand ● continuously ● 10 s ● 1 s - Burden - Impedance	5 A (configurable for CT secondaries 0.1–10 A) 0.015–50 A 20 A 100 A 500 A 0.075 VA 0.003 Ohm	
I_0 input (1 A)	**Slot 8:** **E = 3L (5/1A) + 4U + 2I_0 (5/1A+1/0.2A)**	
Rated earth fault overcurrent - Current measuring range - Thermal withstand ● continuously ● 10 s ● 1 s - Burden - Impedance	1 A (configurable for CT secondaries 0.1 – 10.0 A) 0.003–10 A 4 A 20 A 100 A 0.02 VA 0.02 Ohm	

I_0 input (0.2 A)	Slot 8: E = 3L (5/1A) + 4U + 2I_0 (5/1A+1/0.2A)
Rated earth fault overcurrent - Current measuring range - Thermal withstand ● continuously ● 10 s ● 1 s - Burden - Impedance	0.2 A (configurable for CT secondaries 0.1 – 10.0 A) 0.0006–2 A 0.8 A 4 A 20 A 0.02 VA 0.02 Ohm
Voltage inputs	
Rated voltage U_N - Voltage measuring range - Thermal withstand ● continuously ● 10 s - Burden	100 V (configurable for VT secondaries 50–250 V) 0.5–190 V (100 V / 110 V) 250 V 600 V < 0.5 VA
Frequency	
Rated frequency f_N Measuring range	45–65 Hz (protection operates accurately) 16–95 Hz < 44Hz / > 66Hz (other protection is not steady except frequency protection)

Table 10.27: Analog interface cross section and tightening torque

Terminal characteristics		
	Current inputs	Voltage inputs
Maximum wire cross section, mm^2 (AWG)	4 (10-12)	2.5 (13-14)
Maximum wiring screw tightening torque Nm (Ib-in)	1.2 (10.6)	0.5-0.6 (4.4-5.3)
Maximum connector retention tightening torgue Nm (Ib-in)	-	0.3-0.4 (2.7-3.5)
Wire type	Single strand or stranded with insulated crimp terminal	

10.5.8 External option modules

10.5.8.1 VSE-001 fiber optic interface module

⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- This equipment must only be installed or serviced by qualified electrical personnel.
- Turn off all power supplying this device and the equipment in which it is installed before working on the device or equipment.
- Connect protective ground (earth) before turning on any power supplying this device.

Failure to follow these instructions will result in death or serious injury.

An external fiber optic module VSE-001 is used to connect the relay to a fiber optic loop or a fiber optic star. There are four different types of serial fiber optic modules:

- VSE001PP (Plastic - plastic)
- VSE001GG (Glass - glass)

The modules provide a serial communication link up to 1 km (0.62 miles) with VSE 001 GG. With a serial fibre interface module it is possible to have the following serial protocols in use:

- None
- IEC-103
- Modbus slave
- SpaBus

The power for the module is taken from pin 9 of the D-connector or from an external power supply interface.

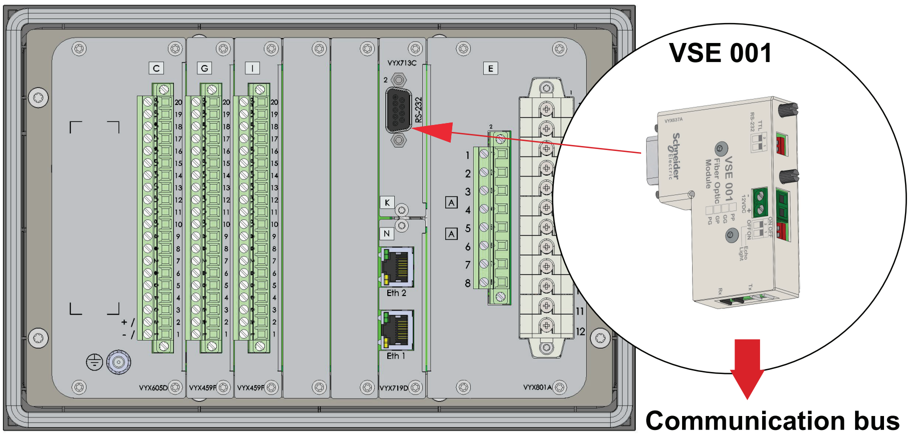


Figure 10.9: The VSE-001 module brings a serial-fiber interface to the relay. The Module is connected to the RS-232 serial port.

Module interface to the relay

The physical interface of the VSE-001 is a 9-pin D-connector. The signal level is RS-232.

NOTE: The product manual for VSE-001 can be found on our website.

10.5.8.2 VSE-002 RS-485 interface module

⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- This equipment must only be installed or serviced by qualified electrical personnel.
- Turn off all power supplying this device and the equipment in which it is installed before working on the device or equipment.
- Connect protective ground (earth) before turning on any power supplying this device.

Failure to follow these instructions will result in death or serious injury.

An external RS-485 module VSE-002 (VSE002) is used to connect Easergy P3 protection relays to RS-485 bus. With the RS-485 serial interface module, the following serial protocols can be used:

- None
- IEC-103
- ModbusSlv
- SpaBus

The power for the module is taken from pin 9 of the D-connector or from an external power supply interface.

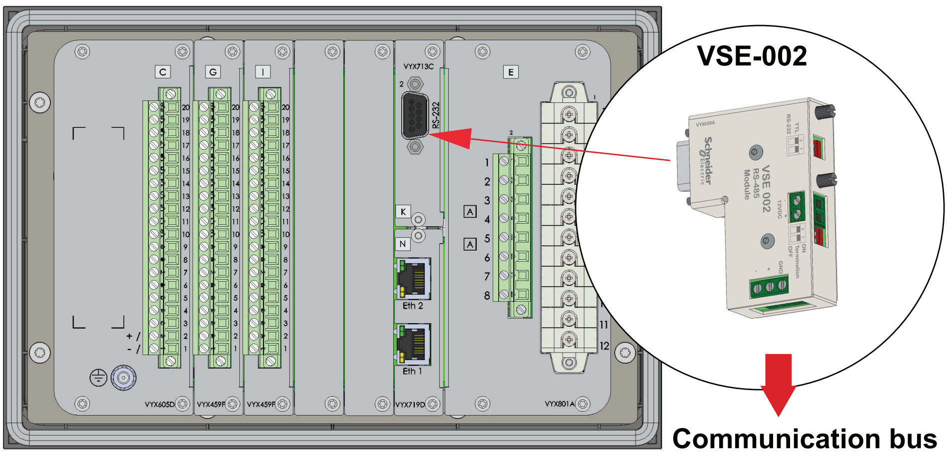


Figure 10.10: The VSE-002 module brings a serial RS-485 interface to the relay. The module is connected to the RS-232 serial port.

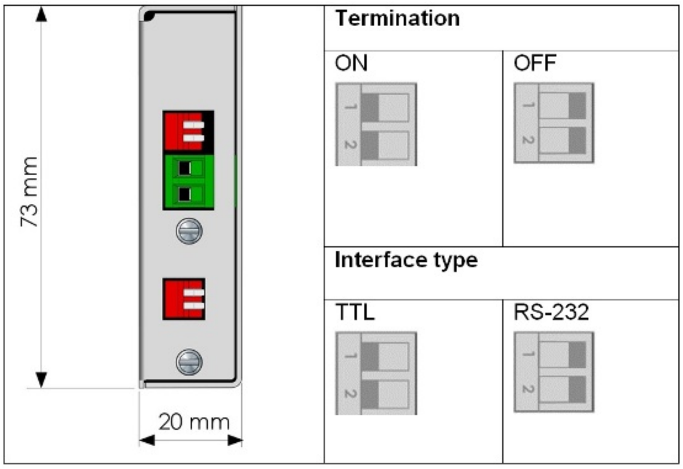
Module interface to the relay

The physical interface of the VSE-002 is a 9-pin D-connector. The signal level is RS-232 and therefore, the interface type for the module has to be selected as **RS-232**.

It is possible to connect multible relays in daisychain. “Termination” has to be selected as **on** for the last unit in the chain. The same applies when only one unit is used.

VSE-002 operates with the relay in RS-232 mode. Therefore the “interface type” has to be selected as RS-232.

Pin number	TTL mode	RS-232 mode
1	-	-
2	RXD (in)	RXD (in)
3	TXD (out)	TXD (out)
4	RTS (in)	RTS (in)
5		
6		
7	GND	GND
8		
9	+8V (in)	+8V (in)



10.5.8.3 VSE-009 DeviceNet interface module

⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- This equipment must only be installed or serviced by qualified electrical personnel.
- Turn off all power supplying this device and the equipment in which it is installed before working on the device or equipment.
- Connect protective ground (earth) before turning on any power supplying this device.

Failure to follow these instructions will result in death or serious injury.

VSE-009 (VSE009) is a DeviceNet interface module for the Easergy P3G30, P3G32. The relay can be connected to the network using DeviceNet as the protocol. VSE-009 is attached to the RS-232 D-connector at the back of the relay. With the DeviceNet interface module, the following protocols can be used:

- None
- DeviceNet

An external +24VDC power supply interface is required.

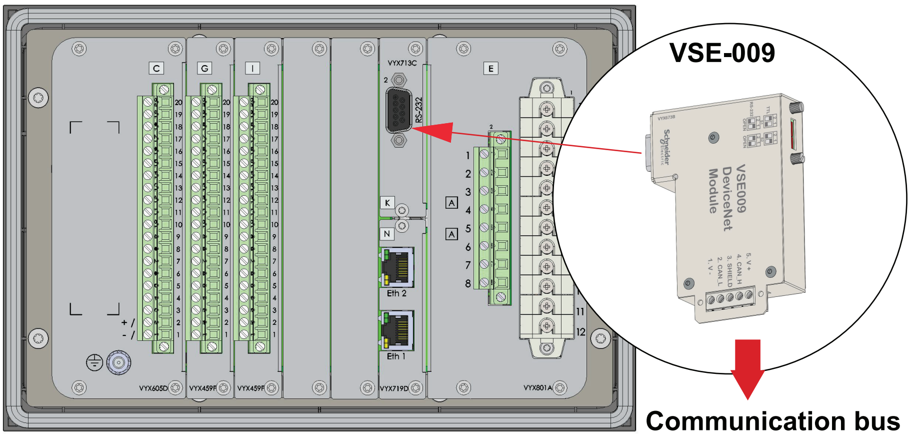


Figure 10.11: The VSE-009 module brings DeviceNet interface to the relay. The module is connected to the RS-232 serial port.

10.5.8.4 VPA-3CG profibus interface module

⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- This equipment must only be installed or serviced by qualified electrical personnel.
- Turn off all power supplying this device and the equipment in which it is installed before working on the device or equipment.
- Connect protective ground (earth) before turning on any power supplying this device.

Failure to follow these instructions will result in death or serious injury.

Easergy P3G30, P3G32 can be connected to Profibus DP by using an external profibus interface module VPA-3CG (VPA3CG). The relay can then be monitored from the host system. VPA-3CG is attached to the RS-232 D-connector at the back of the relay with a VX-072 (VX072) cable. With the profibus interface module, the following protocols can be used:

- None
- ProfibusDP

The power for the module is taken from an external power supply interface.

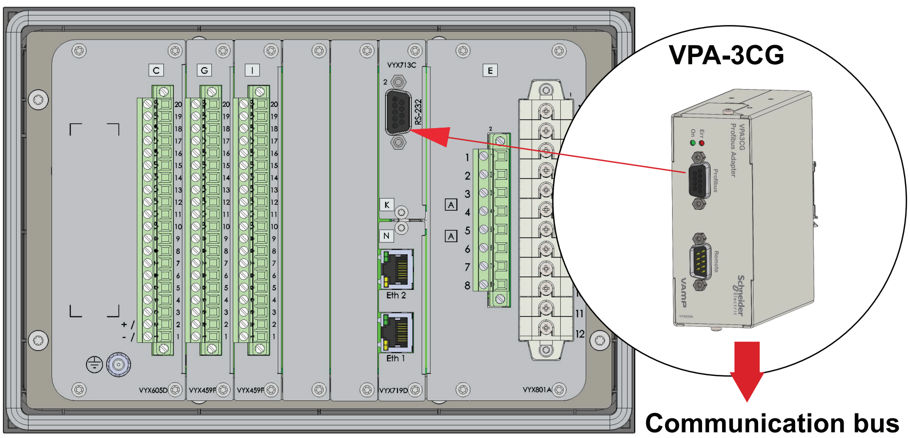


Figure 10.12: VPA-3CG module brings a profibus interface to the relay. The module is connected to the RS-232 serial port via a VX-072 cable.

Module interface to the relay

The physical interface of the VPA-3CG profibus interface module is a 9-pin D-connector.

Profibus devices are connected in a bus structure. Up to 32 stations (master or slave) can be connected in one segment. The bus is terminated by an active bus terminator at the beginning and end of each segments. When more than 32 stations are used, repeaters (line amplifiers) must be used to connect the individual bus segments.

The maximum cable length depends on the transmission speed and cable type. The specified cable length can be increased by the use of repeaters. The use of more than 3 repeaters in a series is not recommended.

A separate product manual for VPA-3CG can be found on our website.

10.5.8.5 VIO 12A RTD and analog input / output modules

VIO 12A I/O modules can be connected to Easergy P3G30, P3G32 using VSE 001 or VSE 002 interface modules.

A separate product manual for VIO 12A is available.

10.5.9 Block diagrams

The status of the output contacts is shown when the relay is energized but none of the protection, controlling or self-supervision elements are activated.

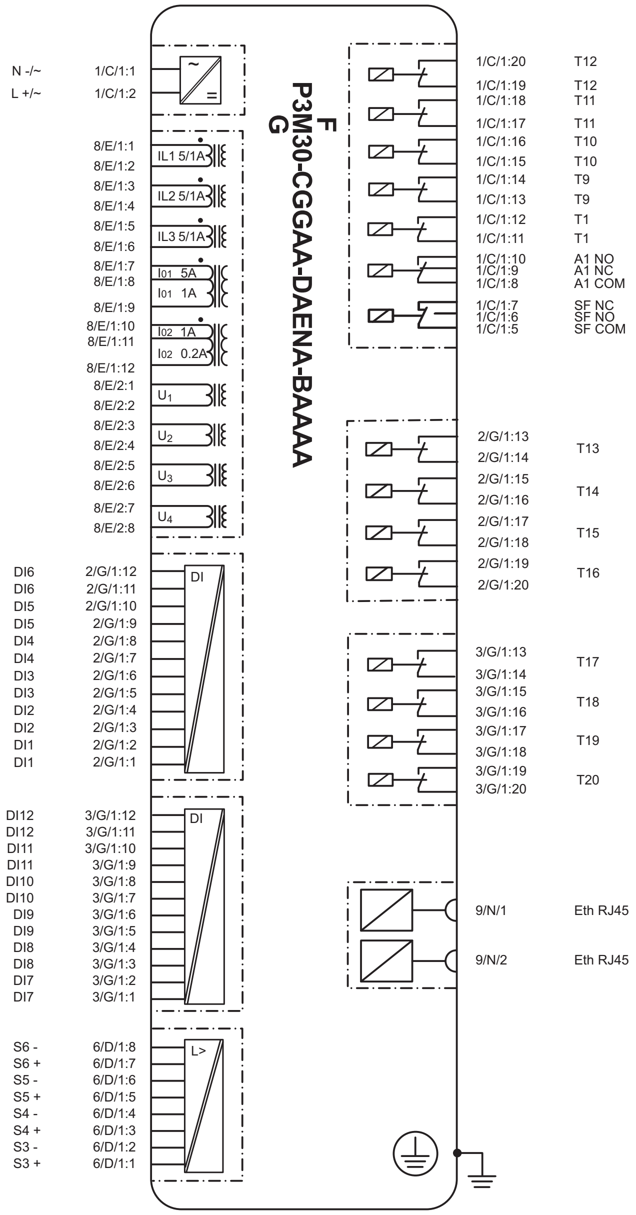


Figure 10.13: Typical block diagram for P3F30, P3M30 and P3G30 relays

⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

Failure to follow this instruction will result in death or serious injury.

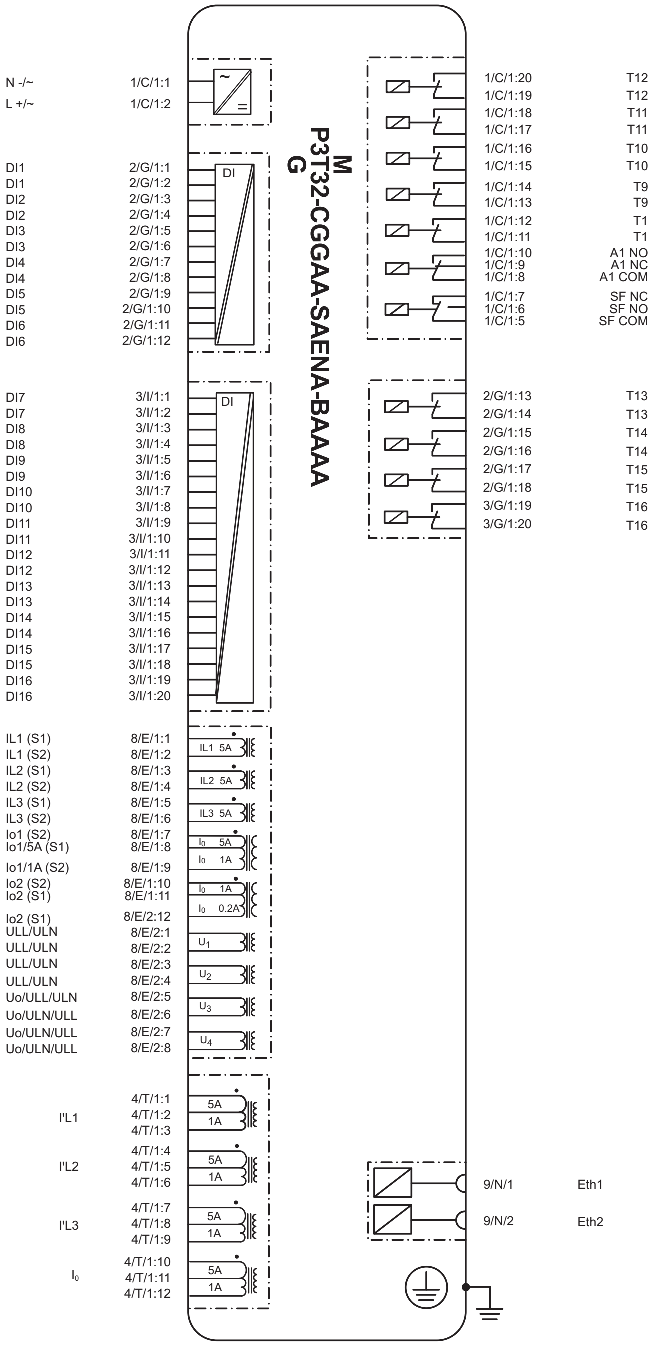
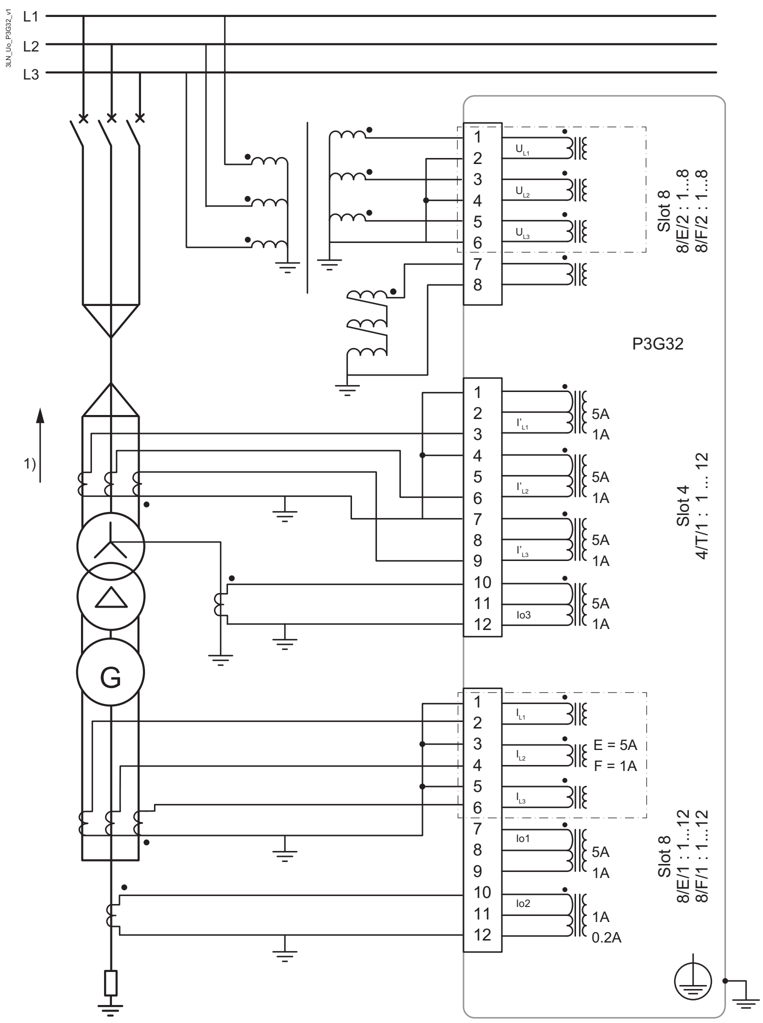


Figure 10.14: Typical block diagram for P3M32, P3T32 and P3G32 relays

> **⚠ DANGER**
>
> **HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**
>
> Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.
>
> **Failure to follow this instruction will result in death or serious injury.**

10.5.10 Connection examples



1) Power direction

Figure 10.15: Generator-block transformer connection with machine differential

⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- Always connect the polarity of the current transformer (CT) and / or the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

Failure to follow this instruction will result in death or serious injury.

10.6 Voltage measurement modes

Depending on the application and available voltage transformers, the relay can be connected either to zero-sequence voltage, line-to-line voltage or line-to-neutral voltage. The configuration parameter "Voltage measurement mode" must be set according to the type of connection used.

Voltage measuring modes correlation for E and F analogue measurement cards

U1, U2, U3 and U4 are voltage channels for the relay.

The physical voltage transformer connection in the Easergy P3G30, P3G32 depends on the used voltage transformer connection mode. This setting is defined in the scalings setting view. See Table 10.28.

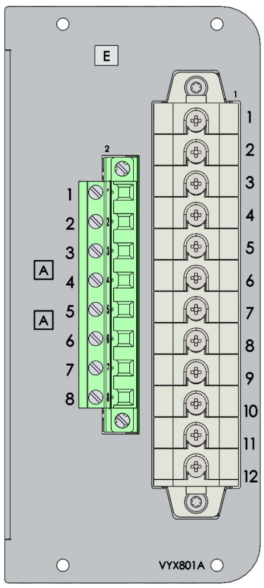


Figure 10.16: Example of Terminal 8/E/1 and 8/E/2

Table 10.28: Correlation between voltage measuring mode and physical voltage input in Terminals 8/E/1 and 8/F/2

Terminal	8/E/2 and 8/F/2							
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Voltage channel	***U1***		***U2***		***U3***		***U4***	
Mode / Used voltage								
3LN	UL1		UL2		UL3		Not in use	
3LN+U_0							U_0	
3LN+LLy							LLy	
3LN+LNy							LNy	
2LL+U_0	U12		U23		U_0		Not in use	
2LL+U_0+LLy							LLy	
2LL+U_0+LNy							LNy	
LL+LLy+Uo+LLz			U12y				U12z	
LN+LNy+Uo+LNz	UL1		UL1y				UL1z	

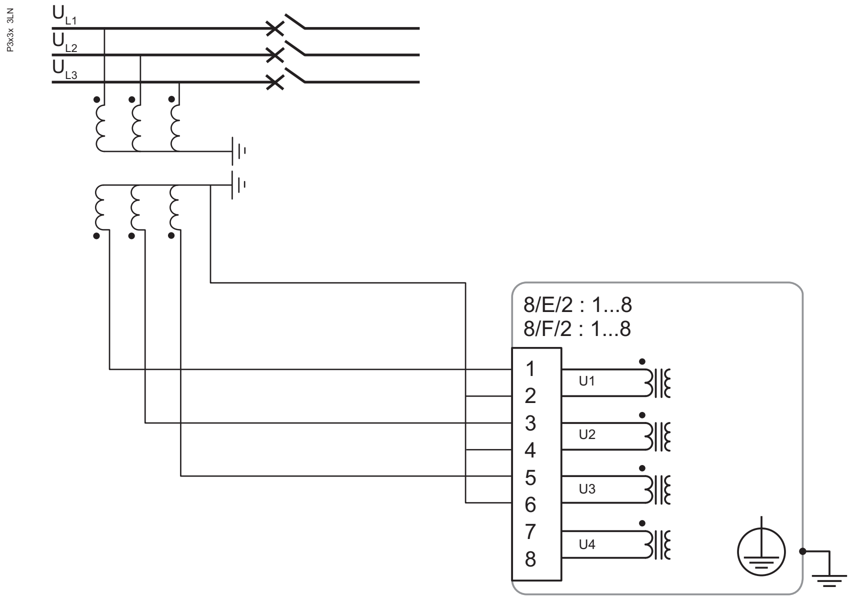
10.6.1 Multiple channel voltage measurement

The slot 8 can accommodate four different analogue measurement cards. Each of them have four voltage measurement channels.

This section introduces various voltage connections and the required voltage measuring modes for the connections. The settings are defined in the **Scalings** view.

3LN

- Voltages measured by VTs: UL1, UL2, UL3
- Values calculated: UL12, UL23, UL31, U1, U2, U2/U1, f, Uo
- Measurements available: All
- Protection functions not available: ANSI 25



⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

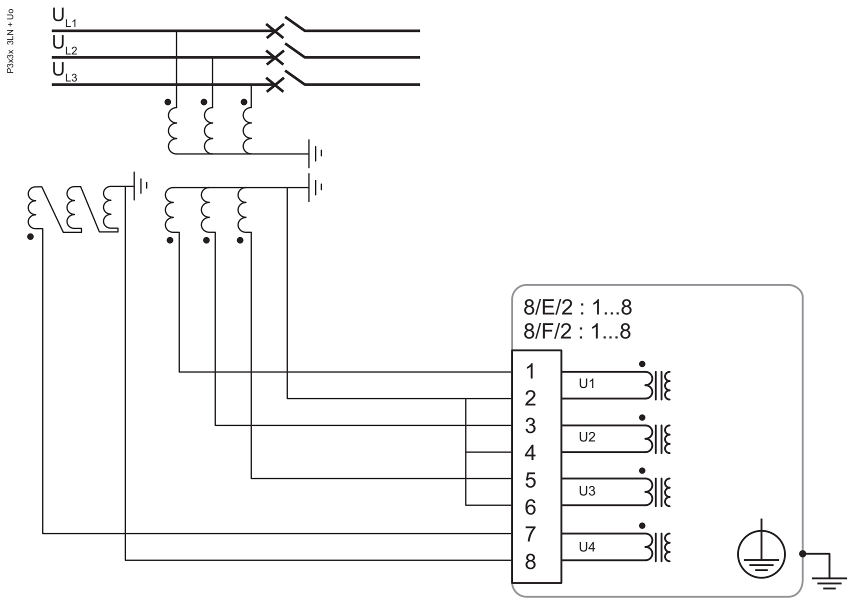
- Always connect the polarity of the current transformer (CT) and / or the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

Failure to follow this instruction will result in death or serious injury.

3LN+U_0

This connection is typically used for feeder and motor protection schemes.

- Voltages measured by VTs: UL1, UL2, UL3, Uo
- Values calculated: UL12, UL23, UL31, U1, U2, U2/U1, f
- Measurements available: All
- Protection functions not available: ANSI 25



⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- Always connect the polarity of the current transformer (CT) and / or the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

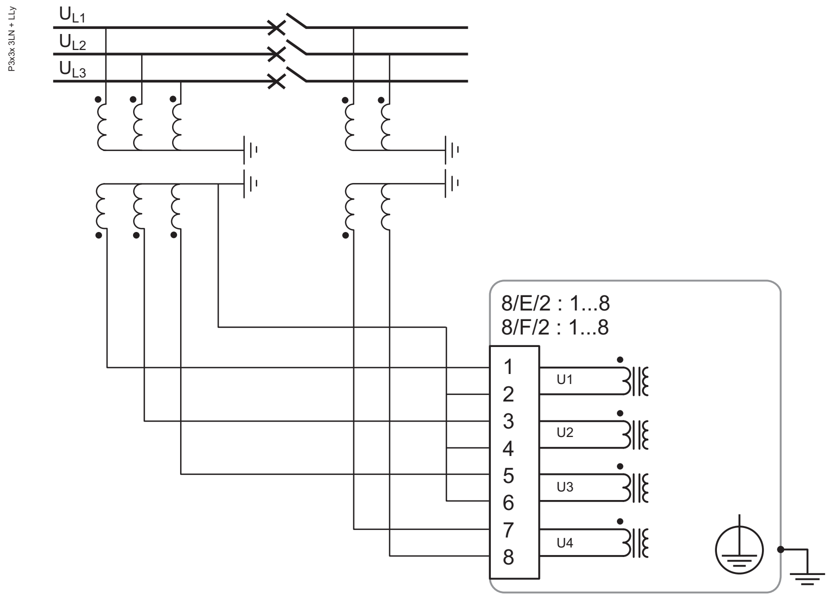
Failure to follow this instruction will result in death or serious injury.

3LN+LLy

Voltage measuring mode: **3LN+LLy**

Connection of voltage transformers for synchrocheck application. The other side of the CB has line-to-line connection for reference voltage.

- Voltages measured by VTs: UL1, UL2, UL3, UL12y
- Values calculated: UL12, UL23, UL31, U1, U2, U2/U1, f, Uo
- Measurements available: All
- Protection functions not available: ANSI 78PS



⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- Always connect the polarity of the current transformer (CT) and / or the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

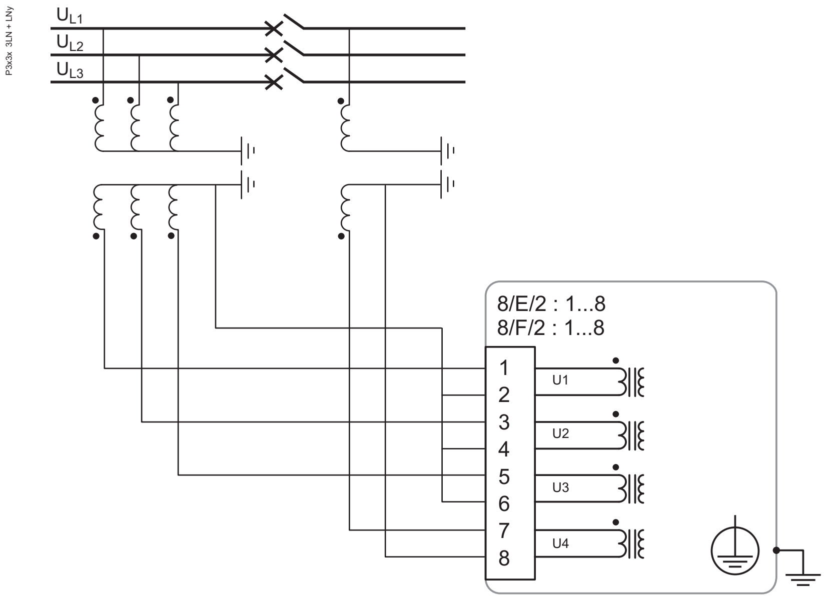
Failure to follow this instruction will result in death or serious injury.

3LN+LNy

Voltage measuring mode: **3LN+LNy**

This connection is typically used for feeder protection scheme where line-to-neutral voltage is required for synchrocheck application.

- Voltages measured by VTs: UL1, UL2, UL3, UL1y
- Values calculated: UL12, UL23, UL31, U1, U2, U2/U1, f, Uo
- Measurements available: All
- Protection functions not available: ANSI 78PS



⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

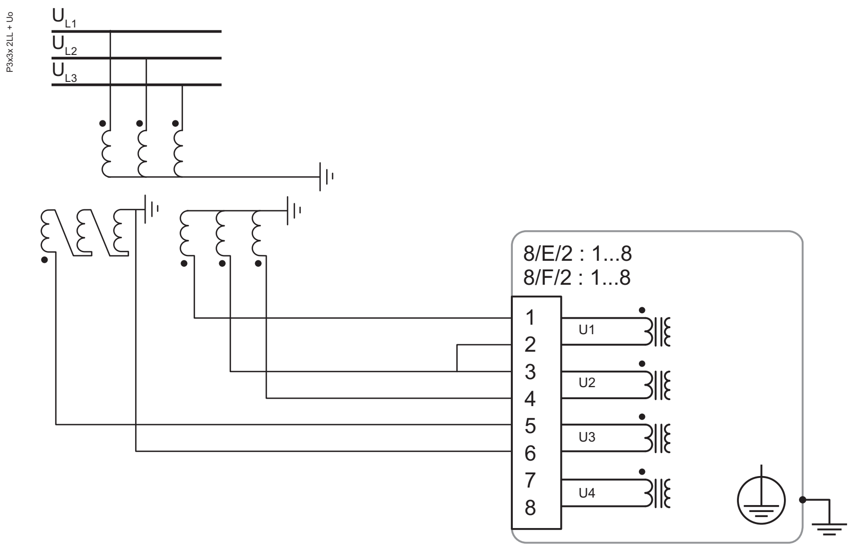
- Always connect the polarity of the current transformer (CT) and / or the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

Failure to follow this instruction will result in death or serious injury.

2LL+U_0

Connection of two line-to-line and neutral displacement voltage measurement schemes.

- Voltages measured by VTs: UL12, UL23, Uo
- Values calculated: UL31, UL1, UL2, UL3, U1, U2, U2/U1, f
- Measurements available: All
- Protection functions not available: ANSI 25, ANSI 78PS



⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

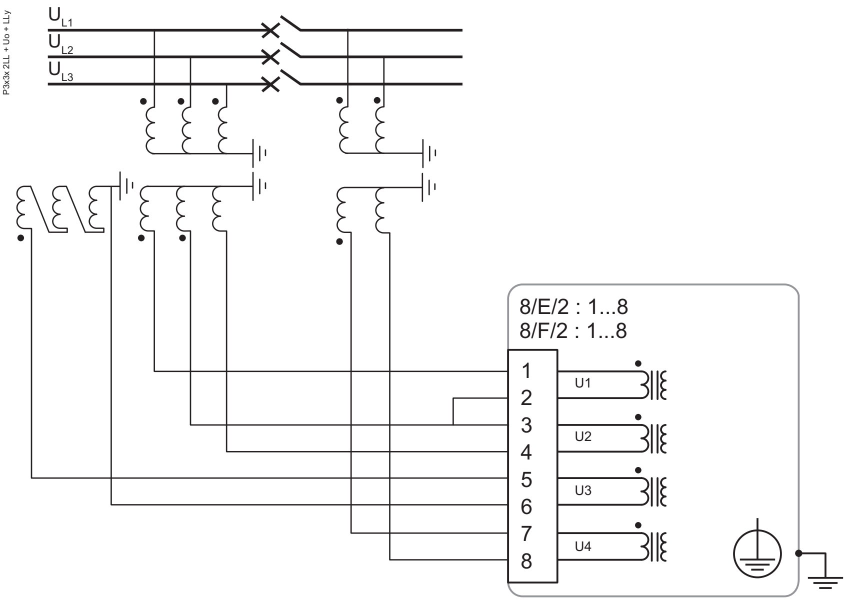
- Always connect the polarity of the current transformer (CT) and / or the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

Failure to follow this instruction will result in death or serious injury.

2LL+U_0+LLy

Connection of two line-to-line and neutral displacement voltage schemes. Line-to-line reference voltage is taken from the other side of the CB for synchrocheck scheme.

- Voltages measured by VTs: UL12, UL23, Uo, UL12y
- Values calculated: UL31, UL1, UL2, UL3, U1, U2, U2/U1, f
- Measurements available: All
- Protection functions not available: ANSI 78PS



⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

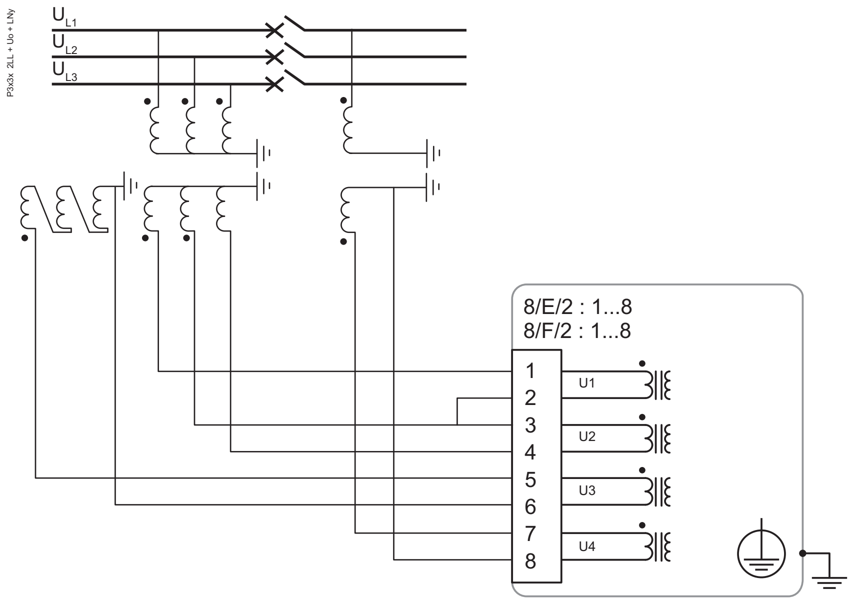
- Always connect the polarity of the current transformer (CT) and / or the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

Failure to follow this instruction will result in death or serious injury.

2LL+U_0+LNy

Connection of two line-to-line and neutral displacement voltage schemes. The other side of the CB has phase-to-neutral connection for synchrocheck.

- Voltages measured by VTs: UL12, UL23, Uo, UL1y
- Values calculated: UL31, UL1, UL2, UL3, U1, U2, U2/U1, f
- Measurements available: All
- Protection functions not available: ANSI 78PS



⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

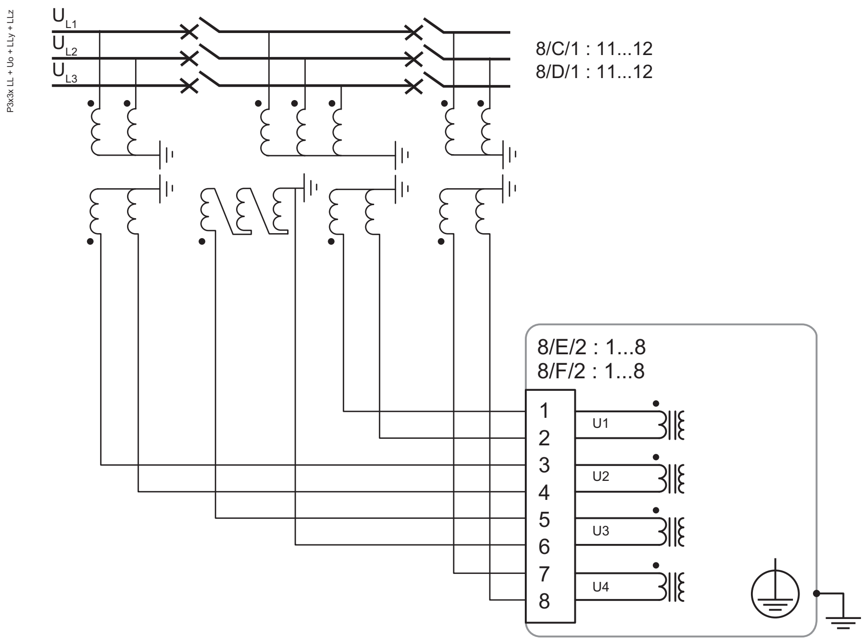
- Always connect the polarity of the current transformer (CT) and / or the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

Failure to follow this instruction will result in death or serious injury.

LL+U_0+LLy+LLz

This scheme has two CBs to be synchronized. The left side of the bus bar has line-to-line and the right side line-to-line connection for synchrocheck's reference voltages. In the middle, the system voltages are measured by phase-to-neutral and open delta connection.

- Voltages measured by VTs: UL12, Uo, UL12y, UL12z
- Values calculated: UL1, UL2, UL3, f
- Measurements available: -
- Protection functions not available: ANSI 67, ANSI 78PS



⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

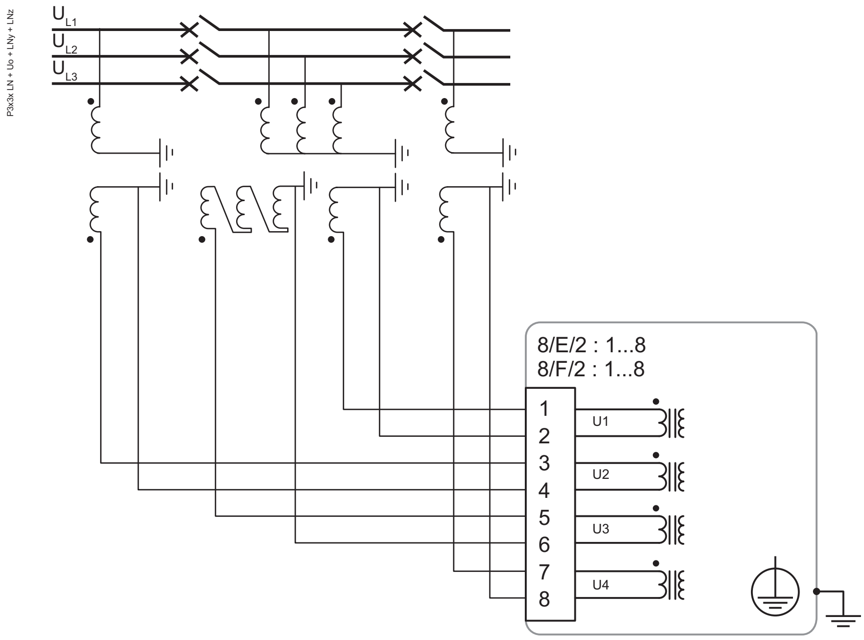
- Always connect the polarity of the current transformer (CT) and / or the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

Failure to follow this instruction will result in death or serious injury.

LN+U_0+LNy+LNz

This scheme has two CBs to be synchronized. The left and right sides of the bus bar have line-to-neutral connections for synchrocheck's reference voltages. In the middle, system voltages are measured by phase-to-neutral and broken delta connection.

- Voltages measured by VTs: UL+Uo+ULy+ULz
- Values calculated: UL12, UL23, UL31, f
- Measurements available: -
- Protection functions not available: ANSI 67, ANSI 78PS



⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- Always connect the polarity of the current transformer (CT) and / or the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

Failure to follow this instruction will result in death or serious injury.

10.7 CSH120 and CSH200 Core balance CTs

Figure 10.17: CSH120 and CSH200 core balance CTs.

Function

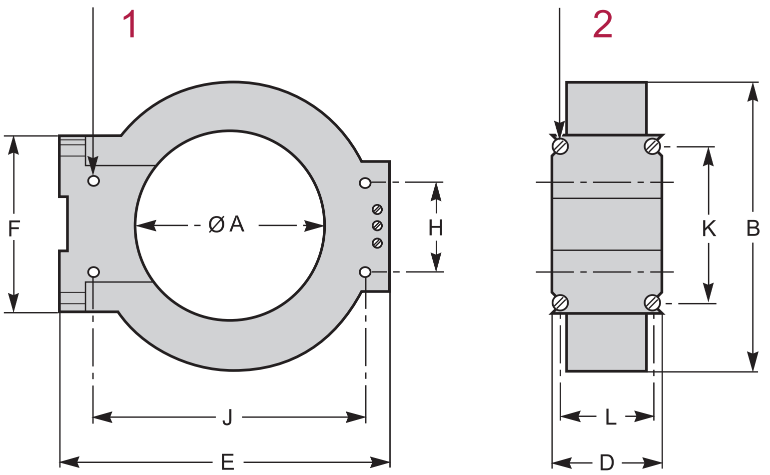
The specifically designed CSH120 and CSH200 core balance CTs are for direct earth fault overcurrent measurement. The difference between CSH120 and CSH200 is the inner diameter.

Due to their low voltage insulation, they can only be used on cables.

Characteristics

	CSH120	CSH200
Inner diameter	120 mm (4.7 in)	200 mm (7.9 in)
Weight	0.6 kg (1.32 lb)	1.4 kg (3.09 lb)
Accuracy	±5% at 20°C (68°F)	
	±6% max. from -25°C to 70°C (-13°F to +158°F)	
Transformation ratio	1/470	
Maximum permissible current	20 kA - 1 s	
Operating temperature	-25°C to +70°C (-13°F to +158°F)	
Storage temperature	-40°C to +85°C (-40°F to +185°F)	

Dimensions



(1): 4 horizontal mounting holes Ø 6

(2): 4 vertical mounting holes Ø 6

Dimensions	A	B	D	E	F	H	J	K	L
CSH120 (in)	120 (4.75)	164 (6.46)	44 (1.73)	190 (7.48)	80 (3.14)	40 (1.57)	166 (6.54)	65 (2.56)	35 (1.38)
CSH200 (in)	196 (7.72)	256 (10.1)	46 (1.81)	274 (10.8)	120 (4.72)	60 (2.36)	254 (10)	104 (4.09)	37 (1.46)

⚠ DANGER

HAZARD OF ELECTRIC SHOCK, ELECTRIC ARC OR BURNS

- Only qualified personnel should install this equipment. Such work should be performed only after reading this entire set of instructions and checking the technical characteristics of the device.
- NEVER work alone.
- Turn off all power supplying this equipment before working on or inside it. Consider all sources of power, including the possibility of backfeeding.
- Always use a properly rated voltage sensing device to confirm that all power is off.
- Only CSH120 and CSH200 core balance CTs can be used for direct earth fault overcurrent measurement.
- Install the core balance CTs on insulated cables.
- Cables with a rated voltage of more than 1000 V must also have an earthed shielding.

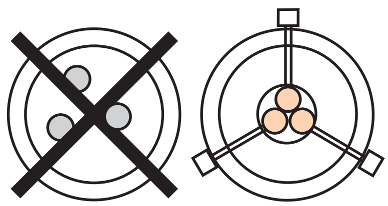
Failure to follow these instructions will result in death or serious injury.

Assembly

Group the MV cable (or cables) in the middle of the core balance CT.

Use non-conductive binding to hold the cables.

Remember to insert the 3 medium voltage cable shielding earthing cables through the core balance CT.



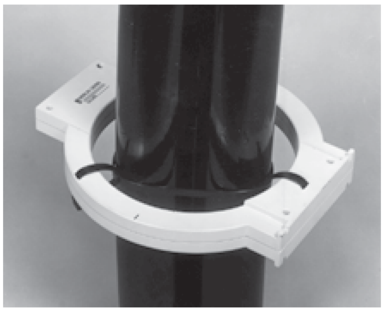


Figure 10.18: Assembly on MV cables

⚠ CAUTION

HAZARD OF NON-OPERATION

Connect the secondary circuit and the cable shielding of the CSH core balance CTs to earth in the shortest possible manner according to the connection diagram presented in this document.

Failure to follow these instructions can result in equipment damage.

Connection

Connection to Easergy P3G30, P3G32

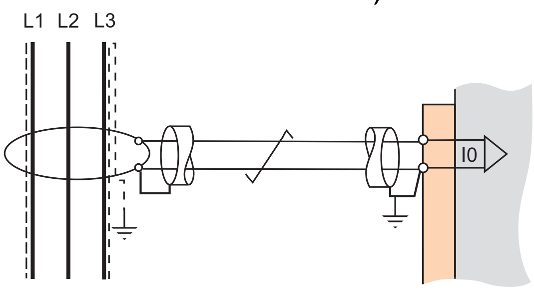
To earth fault current I_0 input, on connector X1, terminals 9 and 10 (shielding).

Recommended cable

- Sheathed cable, shielded by tinned copper braid
- Minimum cable cross-section 0.93 mm² (AWG 18)
- Resistance per unit length < 100 mΩ/m (30.5 mΩ/ft)
- Minimum dielectric strength: 1000 V (700 Vrms)
- Connect the cable shielding in the shortest manner possible to Easergy P3G30, P3G32
- Flatten the connection cable against the metal frames of the cubicle.

The connection cable shielding is grounded in Easergy P3G30, P3G32.

The maximum resistance of the Easergy P3G30, P3G32 connection wiring must not exceed 4 Ω (i.e. 20 m maximum for 100 mΩ/m or 66 ft maximum for 30.5 mΩ/ft).



11 Test and environmental conditions

Table 11.1: Disturbance tests

Test	Standard & Test class / level	Test value
Emission	**IEC/EN 60255-26 (ed3)**	
Conducted	EN 55022, Class A / IEC 60255-25 / CISPR 22	0.15 – 30 MHz
Emitted	EN 55011, Class A / IEC 60255-25 / CISPR 11	30 – 1000 MHz
Immunity	**IEC/EN 60255-26 (ed3)**	
1 Mhz damped oscillatory wave	IEC/EN 61000-4-18, IEC 60255-22-1	±2.5kVp CM ±2.5kVp DM
Static discharge (ESD)	IEC/EN 61000-4-2 Level 4, IEC 60255-22-2	±8 kV contact ±15 kV air
Emitted HF field	IEC/EN 61000-4-3 Level 3, IEC 60255-22-3	80 - 2700 MHz, 10 V/m
Fast transients (EFT)	IEC/EN 61000-4-4 Level 4, IEC 60255-22-4	±4 kV, 5/50 ns, 5 kHz
Surge	IEC/EN 61000-4-5 Level 4, IEC 60255-22-5	±4 kV, 1.2/50 µs, CM ±2 kV, 1.2/50 µs, DM
Conducted HF field	IEC/EN 61000-4-6 Level 3, IEC 60255-22-6	0.15 - 80 MHz, 10 Vrms
Power-frequency magnetic field	IEC/EN 61000-4-8	300A/m (continuous) 1000A/m 1 – 3s
Pulse magnetic field	IEC/EN 61000-4-9 Level 5	1000A/m, 1.2/50 µs
ac and dc voltage dips	IEC/EN 61000-4-29, IEC/EN 61000-4-11	0% of rated voltage - Criteria A • ac: ≥ 0.5 cycle • dc: ≥ 10 ms
		40% of rated voltage - Criteria C • ac: 10 cycles • dc: 200 ms
		70% of rated voltage - Criteria C • ac: 25 cycles • dc: 500 ms
ac and dc voltage interruptions	IEC/EN 61000-4-29, IEC/EN 61000-4-11	100% interruption - Criteria C • ac: 250 cycles • dc: 5 s
Voltage alternative component	IEC/EN 61000-4-17	15% of operating voltage (dc) / 10min

Table 11.2: Electrical safety tests

Test	Standard & Test class / level	Test value
Impulse voltage withstand	IEC/EN 60255-27, EN 60255-5, Class III	5 kV, 1.2/50 µs, 0.5 J 1 kV, 1.2/50 µs, 0.5 J Communication
Dielectric test	IEC/EN 60255-27, EN 60255-5, Class III	2 kV, 50 Hz 0.5 kV, 50 Hz Communication
Insulation resistance	IEC/EN 60255-27, EN 60255-5	
Protective bonding resistance	IEC/EN 60255-27	
Clearance and creepage distance	Design criteria for distances as per IEC 60255-27 Annex C (pollution degree 2, overvoltage category 3)	
Power supply burden	IEC 60255-1	

Table 11.3: Mechanical tests

Test	Standard & Test class / level	Test value
Device in operation		
Vibrations	IEC 60255-21-1, Class II / IEC 60068-2-6, Fc	1 Gn, 10 Hz – 150 Hz
Shocks	IEC 60255-21-2, Class II / IEC 60068-2-27, Ea	10 Gn / 11 ms
Seismic	IEC 60255-21-3 Method A, Class II	2G horizontal / 1G vertical , 1–35 Hz
Device de-energized		
Vibrations	IEC 60255-21-1, Class II / IEC 60068-2-6, Fc	2 Gn, 10 Hz – 150 Hz
Shocks	IEC 60255-21-2, Class II / IEC 60068-2-27, Ea	30 Gn / 11 ms
Bump	IEC 60255-21-2, Class II / IEC 60068-2-27, Ea	20 Gn / 16 ms

Table 11.4: Environmental tests

Test	Standard & Test class / level	Test value
Device in operation		
Dry heat	EN / IEC 60068-2-2, Bd	70°C (158°F)
Cold	EN / IEC 60068-2-1, Ad	-40°C (-40°F)
Damp heat, cyclic	EN / IEC 60068-2-30, Db	From 25°C (77°F) to 55°C (131°F) From 93% RH to 98% RH Testing duration: 6 days
Damp heat, static	EN / IEC 60068-2-78, Cab	40°C (104°F) 93% RH Testing duration: 10 days
Change of temperature	IEC / EN 60068-2-14, Nb	• Lower temp -40°C • Upper temp 70°C • 5 cycles
Flowing mixed gas corrosion test, method 1	IEC 60068-2-60, Ke	25° C (77° F), 75 % RH, 21 days 100 ppb H_2S, 500 ppb SO_2
Flowing mixed gas corrosion test, method 4	IEC 60068-2-60, Ke	25° C (77° F), 75 % RH, 21 days 10 ppb H_2S, 200 ppb NO_2, 10 ppb CL_2, 200 ppb SO_2
Device in storage		
Dry heat	EN / IEC 60068-2-2, Bb	70°C (158°F)
Cold	EN / IEC 60068-2-1, Ab	-40°C (-40°F)

Table 11.5: Environmental conditions

Ambient temperature, in-service * **	-40 – 60°C (-40 – 140°F)***
Ambient temperature, storage	-40 – 70°C (-40 – 158°F)
Relative air humidity	< 95%, no condensation allowed
Maximum operating altitude	2000 m (6561.68 ft)

*) The display contrast is affected by ambient temperatures below -25°C (-13°F).

**) After a cold start, in temperatures below -30°C (-22°F), allow the relay to stabilize for a few minutes to achieve the specified accuracy.

***)Recommended values with VYX 695 projection mounting frame:

- Easergy P3G30, P3G32 with 1 x raising frame → maximum ambient temperature 55°C
- Easergy P3G30, P3G32 with 2 x raising frame → maximum ambient temperature 50°C

Table 11.6: Casing

Degree of protection (IEC 60529)	IP54 Front panel, IP20 rear side
Dimensions (W x H x D)	270 x 176 x 230 mm / 10.63 x 6.93 x 9.06 in
Weight	4.2 kg (9.272 lb) or higher (depends of options)

12 Maintenance

⚠ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- Wear your personal protective equipment (PPE) and comply with the safe electrical work practices. For clothing refer applicable local standards.
- Only qualified personnel should install this equipment. Such work should be performed only after reading this entire set of instructions and checking the technical characteristics of the device.
- NEVER work alone.
- Turn off all power supplying this equipment before working on or inside it. Consider all sources of power, including the possibility of backfeeding.
- Always use a properly rated voltage sensing device to ensure that all power is off.
- Do not open the secondary circuit of a live current transformer.
- Always connect the polarity of the current transformer (CT) and the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional earth according to the connection diagrams presented in this document.

Failure to follow this instruction will result in death or serious injury.

The Easergy P3 protection relays and arc flash protection products together with their extension units, communication accessories, arc flash detection sensors and cabling, later called “device”, require maintenance in work according to their specification. Keep a record of the maintenance actions. The maintenance can include, but is not limited to, the following actions.

12.1 Preventative maintenance

Check the device visually when the switchgear is de-energized. During the inspection, pay attention to:

- dirty components
- loose wire connections
- damaged wiring
- indicator lights (see section LED test sequence)
- other mechanical connections

Perform visual inspection every three (3) years minimum.

12.2 Periodical testing

Test the device periodically according to the end user's safety instructions and national safety instructions or law. Carry out functional testing every five (5) years minimum.

Conduct the testing with a secondary injection principle for the protection stages used in the device and its extension units.

In corrosive or offshore environments, carry out functional testing every three (3) years. For the testing procedures, see separate testing manuals.

12.3 Hardware cleaning

Special attention must be paid that the device do not become dirty. If cleaning is required, wipe out dirt from the units.

12.4 Arc sensor condition and positioning check

After commissioning, sensor replacement, modification procedure, cleaning and periodical testing, always check that the sensor positioning remains as it was originally designed.

12.5 System status messages

If the device’s self checking detects an unindented system status, it will in most cases provide an alarm by activating the service LED and indication status notification on the LCD screen. If this happens, store the possible message and contact your local representative for further guidance.

12.6 Spare parts

Use an entire unit as a spare part for the device to be replaced. Always store spare parts in storage areas that meet the requirements stated in the user documentation.

12.7 Self-supervision

NOTICE
LOSS OF PROTECTION OR RISK OF NUISENCE TRIPPING • If the relay is no longer supplied with power or is in permanent fault state, the protection functions are no longer active and all the Easergy P3 digital outputs are dropped out. • Check that the operating mode and SF relay wiring are compatible with the installation. **Failure to follow these instructions can result in equipment damage and unwanted shutdown of the electrical installation.**

Description

The electronic parts and the associated circuitry as well as the program execution are supervised by means of a separate watchdog circuit. Besides supervising the device, the watchdog circuit attempts to restart the microcontroller in an inoperable situation. If the microcontroller does not restart, the watchdog issues a self-supervision signal indicating a permanent internal condition.

When the watchdog circuit detects a permanent fault, it always blocks any control of other digital outputs (except for the self-supervision SF output). In addition, the internal supply voltages are supervised. Should the auxiliary supply of the device disappear, an indication is automatically given because the device status inoperative (SF) output functions on a working current principle. This means that the SF relay is energized, the 1/C/1:5–7 (or 1/D/1:5-7) contact closed, when the auxiliary supply is on and the Easergy P3G30, P3G32 device is fully operational.

In addition to the dedicated self-supervision function, the protection relay has several alarm signals that can be connected to outputs through the output matrix. The alarms include:

- remote communication inactive
- extension I/O communication inactive
- communication Port 1 down
- communication Port 2 down
- selfdiag 1, 2 or 3 alarm

- password open

NOTE: SF output is referenced as "service status output" in the setting tool.

To get self-supervision alarms to SF output contact, they must be linked in the DIAGNOSIS setting view's section SELFDIAG SIGNAL CONFIGURATION. Required alarms are first linked to a Selfdiag1, Selfdiag2 or Selfdiag3 group (Figure 12.1).

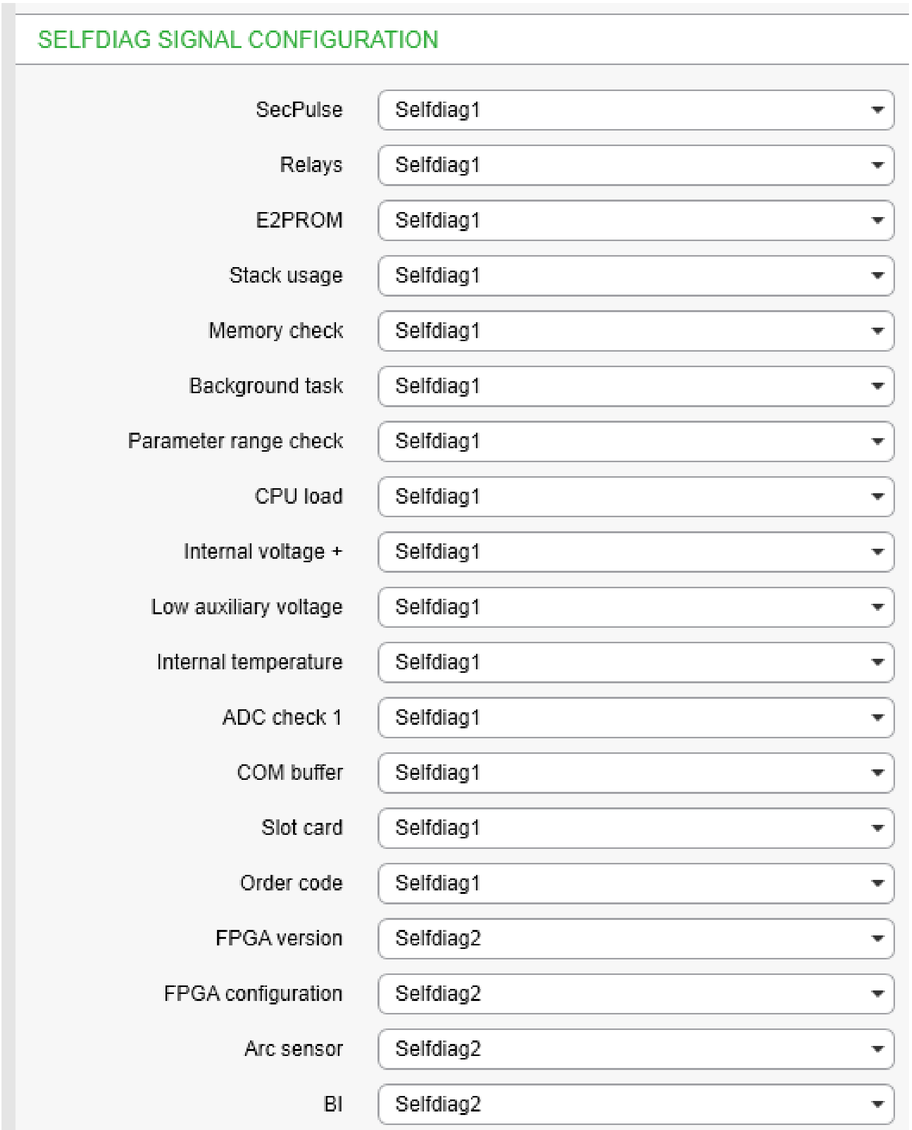


Figure 12.1: Selfdiag alarm signal configuration

Having the Seldiag alarm grouping made, the appropriate alarms can be assigned to SF relay. By default, selfdiag alarm 2 is linked to SF relay (Figure 12.2). The function of this default setup is the same as in the older systems where this configuration was not possible.

Figure 12.2: Linking Selfdiag alarm 1-3 to SF relay

It is possible to choose what selfdiag alarms 1-3 do when activated. This option can be done through the output matrix (Figure 12.3). This allows you to categorize and prioritize actions for each selfdiag alarms individually. For example, in this configuration, selfdiag alarm 3 activates VO6.

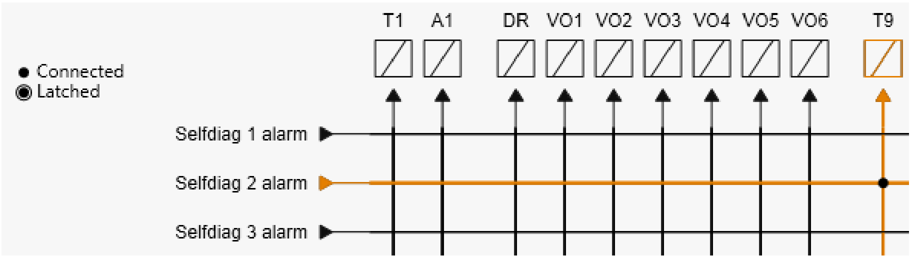


Figure 12.3: Selecting selfdiag 1-3 actions. The number of outputs varies depending on the device and order code.

12.7.1 Diagnostics

The device runs self-diagnostic tests for hardware and software in boot sequence and also performs runtime checking.

Permanent inoperative state

If a permanent inoperative state has been detected, the device releases an SF relay contact and the status LED is set on. The local panel also displays a detected fault message. The permanent inoperative state is entered when the device is not able to handle main functions.

Temporal inoperative state

When the self-diagnostic function detects a temporal inoperative state, a Selfdiag matrix signal is set and an event (E56) is generated. If the inoperative state was only temporary, an off event is generated (E57). The self-diagnostic state can be reset via the front panel.

Diagnostic registers

There are four 16-bit diagnostic registers which are readable through remote protocols. Table 12.1 shows the meaning of each diagnostic register and their bits.

Table 12.1: Readable registers through remote communication protocols

Register	Bit	Code	Description
SelfDiag1	0 (LSB)	(Reserved)	(Reserved)
	1	(Reserved)	(Reserved)
	2	T1	Detected digital output fault
	3	T2	
	4	T3	
	5	T4	
	6	T5	
	7	T6	
	8	T7	
	9	T8	
	10	A1	
	11	A2	
	12	A3	
	13	A4	
	14	A5	
	15	T9	

Register	Bit	Code	Description
SelfDiag2	0 (LSB)	T10	Detected digital output fault
	1	T11	
	2	T12	
	3	T13	
	4	T14	
	5	T15	
	6	T16	
	7	T17	
	8	T18	
	9	T19	
	10	T20	
	11	T21	
	12	T22	
	13	T23	
	14	T24	
SelfDiag4	0 (LSB)	+12V	Detected internal voltage fault
	1	ComBuff	BUS: detected buffer error
	2	Order Code	Detected order code error
	3	Slot card	Detected option card error
	4	FPGA conf.	Detected FPGA configuration error
	5	I/O unit	Detected ARC I/O unit error
	6	Arc sensor	Detected faulty arc sensor
	7	QD-card error	Detected QD-card error
	8	BI	Detected ARC BI error
	9	LowAux	Low auxiliary supply voltage

The code is displayed in self-diagnostic events and on the diagnostic menu on the local panel and Easergy Pro.

NOTE: All signals are not necessarily available in every Easergy P3 product.

13 Order code

When ordering, state:

- Order code of the relay
- Quantity
- Accessories (see the order codes in section Accessories)

Slot 1 2 3 4 5 6 7 8 9 10

P3G30 - □ G □ □ □ - □ A □ □ A - □ □ □ □ □

Application
G30 = Generator protection

Nominal Supply voltage [V]
C = Power C 110 - 230 V (80 .. 265Vac/dc, 5 x DO heavy duty, A1, SF)
D = Power D 24 - 48 V (18 .. 60Vdc, 5 x DO heavy duty, A1, SF)

I/O Card I
G = 6DI+4DO (6 x DI, 4 x DO)

I/O Card II
A = None
G = 6DI+4DO (6 x DI, 4 x DO)
H = 6DI+4DO (6 x DI, 4 x DO(NC))
I = 10DI (10 x DI)

I/O Card III
A = None
G = 6DI+4DO (6 x DI, 4 x DO)
H = 6DI+4DO (6 x DI, 4 x DO(NC))
I = 10DI (10 x DI)

I/O Card IV
A = None
G = 6DI+4DO (6 x DI, 4 x DO)
H = 6DI+4DO (6 x DI, 4 x DO(NC))
I = 10DI (10 x DI)

Option card I
A = None
D = 4Arc (4 x Arc sensor)
K = RS232 (RS232)

Future option
A = None

Analog measurement card (See application)
E = 3L(5/1A)+4U+2Io (5/1A+1/0,2A)
F = 3L(1A)+4U+2Io (5/1A+1/0.2A)

Communication interface I
A = None
B = RS232 (RS232, IRIG-B)
C = RS232+RJ (RS232, IRIG-B + Ethernet RJ-45 100 Mbs)
D = RS232+LC (RS232, IRIG-B + Ethernet LC 100 Mbs)
N = 2xRJ (Ethernet RJ 100 Mbs, RSTP)
O = 2xLC (Ethernet LC 100 Mbs, RSTP)
P = PP (Plastic / Plastic serial fibre)
R = GG (Glass / Glass serial fibre)

Reserved
A = Reserved

Display type
B = 128x128 (128 x 128 LCD matrix)
C = 128x128Ext (128 x 128 LCD matrix, detachable) [1]

DI treshhold voltage (V)
A = 24Vdc/ac
B = 110 Vdc/ac
C = 220 Vdc/ac

Product version
A = Version 2.1

Future option
A = None

Region
A = International

1) By default, the cable length is 2 m (6.56 ft). You can order cables of other length separately: VX001-1 (1 m/3.28 ft), Vx001-3 (3 m/9.84 ft) or VX001-5 (5 m/16.40 ft).

NOTE: All PCBA cards are conformally coated.

Slot	1	2	3	4	5		6	7	8	9	10						
P3G32 -	☐	G	☐	T	A	-	☐	A	☐	☐	A	-	☐	☐	☐	☐	☐

Application
G32 = Generator protection with differential protection

Nominal Supply voltage [V]
C = Power C 110 - 230 V (80 .. 265Vac/dc, 5 x DO heavy duty, A1, SF)
D = Power D 24 - 48 V (18 .. 60Vdc, 5 x DO heavy duty, A1, SF)

I/O Card I
G = 6DI+4DO (6 x DI, 4 x DO)

I/O Card II
A = None
G = 6DI+4DO (6 x DI, 4 x DO)
H = 6DI+4DO (6 x DI, 4 x DO(NC))
I = 10DI (10 x DI)

I/O Card III
T = 3xI (5/1A) + Io (5/1A) for generator differential protection

I/O Card IV
A = None

Option card I
A = None
D = 4Arc (4 x Arc sensor)
K = RS232 (RS232)

Future option
A = None

Analog measurement card (See application)
E = 3L(5A)+4U+2Io (5/1A+1/0,2A)
F = 3L(1A)+4U+2Io (5/1A+1/0.2A)

Communication interface I
A = None
B = RS232 (RS232, IRIG-B)
C = RS232+RJ (RS232, IRIG-B + Ethernet RJ-45 100 Mbs)
D = RS232+LC (RS232, IRIG-B + Ethernet LC 100 Mbs)
N = 2xRJ (Ethernet RJ 100 Mbs, RSTP)
O = 2xLC (Ethernet LC 100 Mbs, RSTP)
P = PP (Plastic / Plastic serial fibre)
R = GG (Glass / Glass serial fibre)

Reserved
A = Reserved

Display type
B = 128x128 (128 x 128 LCD matrix)
C = 128x128Ext (128 x 128 LCD matrix, detachable) (1

DI treshhold voltage (V)
A = 24Vdc/ac
B = 110 Vdc/ac
C = 220 Vdc/ac

Product version
A = Version 2.1

Future option
A = None

Region
A = International

1) By default, the cable length is 2 m (6.56 ft). You can order cables of other length separately: VX001-1 (1 m/3.28 ft), Vx001-3 (3 m/9.84 ft) or VX001-5 (5 m/16.40 ft).

NOTE: All PCBA cards are conformally coated.

Accessories

Table 13.1: Easergy P3G30, P3G32 accessories

Order code	Product Reference	Description
REL52801	VA1DA-20	Arc sensor, 20 m (66 ft)
REL52803	VA1DA-20S	Arc sensor, 20 m (66 ft), shielded
REL52804	VA1DA-6	Arc sensor, 6 m (20 ft) connect cable
REL52806	VA1DA-6S	Arc sensor, 6 m (20 ft), shielded
REL52807	VA1EH-20	Arc sensor, 20 m (66 ft) pipe sensor
REL52809	VA1EH-6	Arc sensor, 6 m (20 ft) pipe sensor
REL52812	VIO12ABSE	RTD module, 12pcs RTD inputs, RS485
REL52813	VIO12ACSE	RTD module, 12pcs RTD inputs, mA in/out
REL52814	VIO12ADSE	RTD module, 12pcs RTD inputs, mA in/out
REL52815	VPA3CGSE	Profibus interface module
REL52816	VSE001-GGSE	Fiber optic module (Glass - Glass)
REL52819	VSE001-PPSE	Fiber optic module (Plastic - Plastic)
REL52820	VSE002	RS485 module
REL52821	VSE009	DeviceNet module
REL52822	VX052-3	USB programming cable (eSetup Easergy Pro)
REL52823	VX067	P3x split cable for COM1-2&COM3-4 ports
REL52824	VX072	P3x Profibus cable
REL52832	VYX695	Raising frame, P3x, 45 mm (1.8 in)

14 Firmware revision

Table 14.1: Firmware revisions

FW revision	Changes
Version: 30.108 **Release date:** December 2018	• Intermittent earth fault (ANSI 67NI) changed: - New start setting "Sensitive/Normal" and U_0 check for trip added • CB condition monitoring upgraded with opening counts and opening, closing and charging times • Fault locator enhanced to allow multiple line segments. • LED matrix in P3x3x enhanced: - LEDs can now be configured more flexibly. - It is now possible to select for each individual LED whether it should be blinking, latched, or non-volatile (keep its state over reboot). - Each LED also has a configurable description, one for green colour and another for red. • COMTRADE files can be read over Modbus. • Product and vendor data changed to Schneider Electric in EDS file. This change affects CIP protocols: DeviceNet and EtherNet/IP. • Pole slip protection (ANSI 78) added for P30G and P3G32. • New CBFP functions added: "CBFP1" and "CBFP2". • Restricted earth fault protection (ANSI 64REF) for P3T32 and P3G32. • Faulty phase detection added for ANSI 67N (I_0Dir) stage. • Ethernet's redundancy protocols are now in separate menus.
Version: 30.106 **Release date:** 16.5.2018	• The setting "Inv. time coefficient k" in stages I>, Iφ>, Iφ>>, Io>, Ioφ>, Ioφ>>, Ioφ>>> has three decimals instead of two and the minimum value for the earth fault overcurrent was changed from 0.05 to 0.025. • Communication protocol updates
Version: 30.104 **Release date:** 2.10.2017	First release

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